PN-ABQ 400
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ELECTRIC POWER TARIFF STUDY: POLISH POWER GRID COMPANY

Final Report

Prepared for:

U.S. AGENCY FOR INTERNATIONAL DEVELOPMENT
Bureau for Europe
Office of Development Resources
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Washington, DC 20523
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HBI Reference No. 93-D060-003

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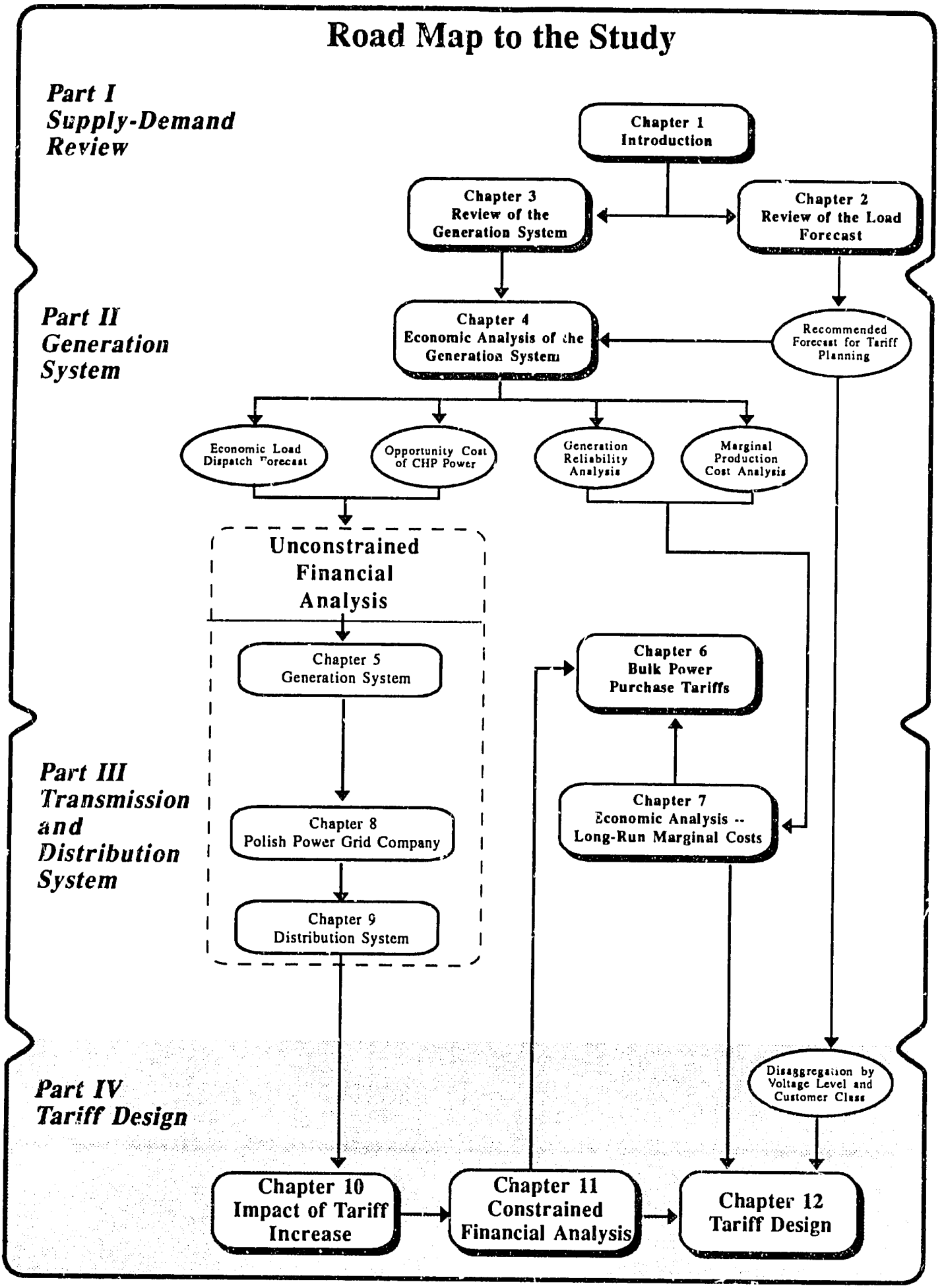
Prepared under:

PDC-0249-1-03-0090-00
Delivery Order No. 03

October 1993

Road Map to the Study



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SUMMARY

S.1 INTRODUCTION

Objectives and Acknowledgements

This study was conducted under the auspices of the Regional Energy Efficiency Project (180-0030) of the United States Agency for International Development (A.I.D.). Its objective was to assist the Government of Poland in developing retail and bulk power tariffs for the medium term, compatible with the goals of an economically efficient and financially self-sustainable power system.

RCG/Hagler Bailly, Inc. wishes to acknowledge the assistance and cooperation received from many Polish and international organizations during the execution of the study, and in particular, the Polish Power Grid Company, A.I.D., and the World Bank.

Approach to the Study

The tariff study was planned to proceed according to four major steps:

- review of load forecast and investment plans
- development of economic marginal costs
- forecast of financial revenue requirements
- development of electricity tariffs structured on the basis of economic marginal costs and designed to recover financial revenue requirements.

The study was conducted during the period June 1992 to July 1993 and in parallel with many important developments regarding the corporate structure of the power sector, the forecast of investments in the expansion and modernization of the system, and the regulatory and fiscal policies that would guide its operation and affect its cash flow over the medium term. As a result of this changing environment and of the inherently iterative nature of the analysis, the study can be best described as a two-stage process.

The first stage, carried out from June 1992 to March 1993, examined the economic structure of costs and projected the revenue requirements of the system assuming no external constraints on the feasibility of revaluating assets in the power sector or the feasibility of implementing tariff increases.

The second stage, carried out from April to July 1993, made use of the economic structures developed in the first stage. However, its financial projections took into account a practical

schedule for asset revaluations and a program of gradual tariff increases designed to minimize negative public and economic impact.

Organization of the Report

This study has four parts. The first stage of the analysis is covered by the first three parts of the study. Part I contains three chapters describing the general characteristics of the system and presents a review of Poland's supply and demand balance. Part II contains the analysis of the generation system, applying strict financial performance criteria and resulting in bulk purchase tariffs to generators. Part III carries the economic and financial analysis through the transmission and distribution components, maintaining strict financial performance criteria and resulting in bulk sales tariffs to distribution companies and large consumers and average retail tariffs.

The second stage is covered in Part IV. It first incorporates an analysis of the impact of tariff increases on the Polish economy. This is followed by different cases of financial analysis of the generation, transmission and distribution components as affected by different scenarios of constraints regarding fiscal policy and the political feasibility of tariff increases. Finally, a detailed tariff design with disaggregation by voltage level and customer class is presented on the basis of the most likely scenario of average revenues determined through the constrained financial analysis.

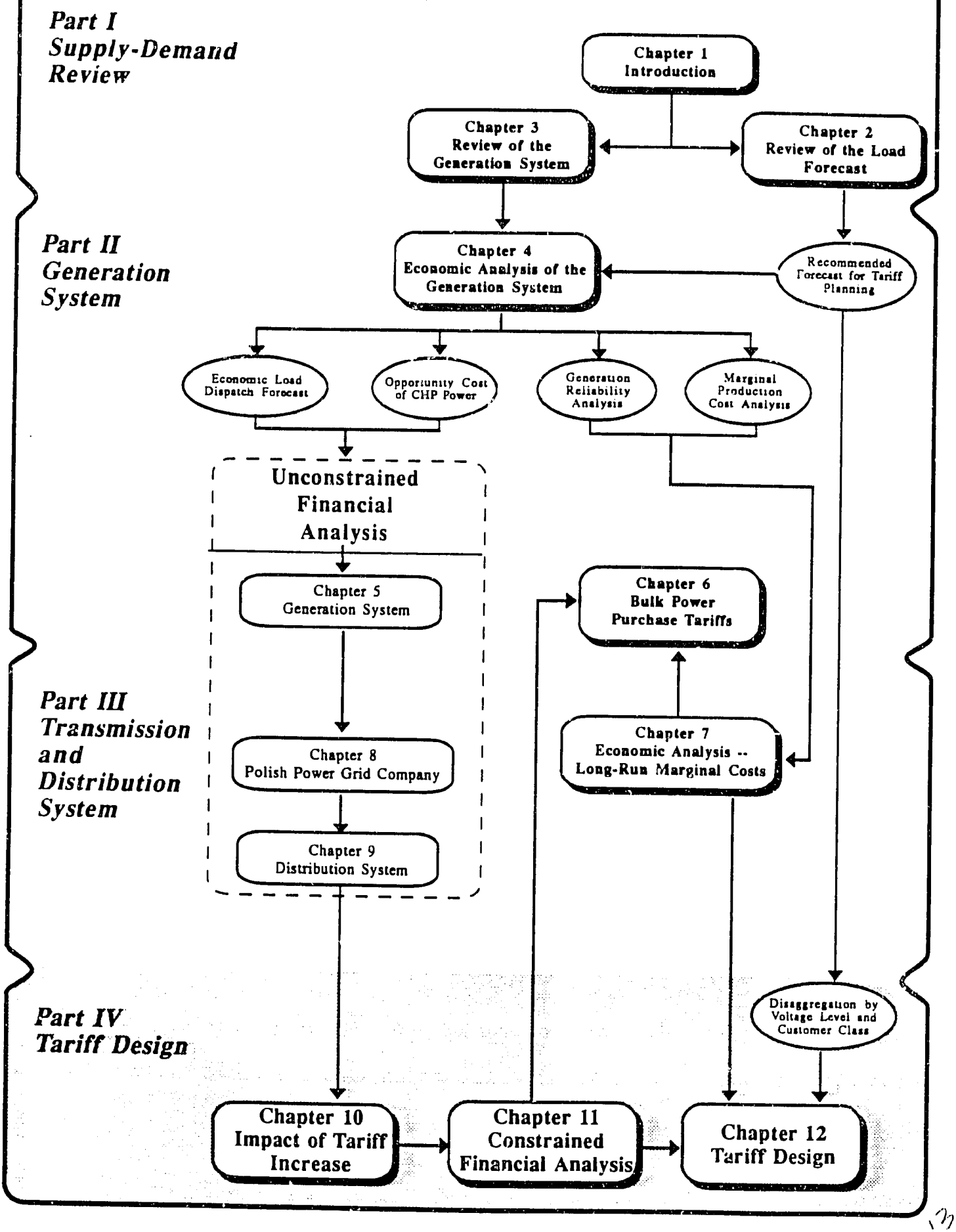
Exhibit S-1 shows the flow and main linkages among different chapters of the report. For the sake of clarity, this summary does not strictly follow the order of the main text, but the chapters where a specific subject is treated are denoted.

Price Level

All monetary values are expressed in Polish Zlotys (Zl) at mid-1992 price levels or in US dollars or cents (¢) at the mid-1992 rate of exchange of 13,400 Zlotys/US$. The analysis was conducted in real terms. As a reference for converting to current values, local inflation during 1992 and 1993 is estimated to run at approximately 40 percent per year.

EXHIBIT S-1

Road Map to the Study



S.2 FIRST STAGE - UNCONSTRAINED ANALYSIS

Supply-Demand Balance

Review of the Load Forecast (Chapter 2). Demand forecasting in Poland is complex owing to the ongoing transition of the economy and the resulting discontinuity between functional determinants of demand historically and in the future.

The review of the demand forecast concluded in the adoption of a load growth scenario that results in an average growth in sales of 1.3 percent for the period 1991-1995 and of 2 percent for the next five years. The adopted forecast of sales by customer class is shown in Exhibit S-2.

Review of the Generation System (Chapter 3). The sources of energy in the Polish power system can be classified into three categories: the public system, autoproducers, and the international exchanges. The public power system is of primary concern in this study.

The generation component of the public power system consists of thermal and hydroelectric powerplants totalling approximately 29,600 MW of installed capacity. About 90 percent of Poland's power is produced in coal- or lignite-fired steam plants that are fully dedicated to the power sector, while 10 percent is produced in combined heat and power plants. There are no thermal peaking plants in the system and load fluctuations are mostly managed through the use of pumped storage hydroelectric. Exhibit S-3 presents a summary of this system.

For the purposes of the economic analysis, the border price of coal was estimated to be 1.79 $/GJ (US dollars per Gigajoule) and internal transport costs were estimated to increase this price to a delivered opportunity cost of 2.01 $/GJ. The opportunity cost of lignite was derived from its potential to displace coal and was estimated at 76 percent of the cost of a thermal unit of coal.

The nominal capacity reserve margin of the system is over 40 percent. Actual reserves from firm resources are on the order of 28 percent, but there is also an important seasonality in both load and resources. The projected effective capacity reserves, taking into account average generating unit availabilities, were computed on the basis of forecast load, expected growth of combined heat and power plants, and the committed additions and retirements of generating units. These computations indicate that the system has adequate reserve until about the year 1997 when peaking capacity would be needed in the form of additional pumped storage hydroelectric, peaking thermal resources, or both. Base load capacity not currently under construction is not required until well into the next decade.

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EXHIBIT S-2

BASE CASE LOAD FORECAST

		1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Avg Annual Rate (%) 1991–96	Avg Annual Rate (%) 1996–01
INDUSTRY	HV	28229	28158	28146	28410	29054	29752	30180	30746	31637	31506	–0.4%	1.6%
	MV	17844	17799	17791	17958	18365	18807	19077	19435	19998	19915	–0.5%	1.6%
	LV	2914	2907	2906	2933	2999	3071	3116	3174	3266	3252	3.3%	1.6%
	Total	48988	48864	48843	49300	50419	51630	52372	53355	54900	54673	–0.2%	1.6%
TRACTION 1/	HV	155	169	185	204	208	213	215	219	225	225	–	–
	MV	5005	5462	5973	6596	6733	6881	6967	7084	7275	7283	–	–
	Total	5160	5631	6158	6800	6941	7094	7182	7303	7500	7508	7.1%	1.6%
STREET LIGHTS	LV	1375	1448	1527	1627	1676	1730	1768	1815	1882	1883	4.1%	2.4%
COMMERCIAL	MV	1229	1294	1365	1454	1498	1546	1580	1622	1682	1683	4.0%	2.4%
	LV	7953	8382	8841	9417	9705	10015	10237	10509	10896	10902	2.5%	2.4%
	Total	9192	9676	10206	10871	11203	11560	11817	12131	12578	12585	2.7%	2.4%
FARMS	MV	710	747	788	840	865	893	913	937	971	972	4.9%	2.4%
	LV	7712	8117	8562	9120	9399	9698	9913	10177	10552	10558	4.0%	2.4%
	Total	8422	8865	9351	9960	10264	10591	10826	11114	11523	11530	4.1%	2.4%
RESIDENTIAL	LV	21937	23091	24356	25943	26735	27588	28200	28949	30017	30033	5.1%	2.4%
TOTAL FINAL SALES		95073	97574	100441	104500	107238	110194	112165	114666	118400	118212	2.2%	2.0%
	HV	28384	28327	28331	28614	29262	29965	30395	30965	31862	31731	–0.3%	1.6%
	MV	24788	25302	25917	26847	27461	28127	28536	29077	29926	29852	1.5%	1.7%
	LV	41901	43945	46193	49040	50515	52102	53233	54624	56613	56629	4.2%	2.3%

EXHIBIT S-3

SUMMARY OF THE PUBLIC GENERATION SYSTEM

POLAND – SUMMARY OF THE PUBLIC GENERATION SYSTEM											
PLANT NAME	TYPE	FUEL	MEAN UNIT CAPACITY MW	NO. UNITS	NAMEPLATE CAPACITY MW	PEAKING CAPABILITY MW	PERCENT OF SYSTEM CAPABILITY	ANNUAL OPERATING EXPENSES $/KW	FUEL TRANSPORT COST $/MWH	1991 PRODUCTION GWH	PERCENT OF GENERATION REQUIREMENTS
1 BELCHATOW	GRID	LIGNITE	360	12	4320	4320	15.4%	11 27	0 00	27213	21.9%
2 PATNOW	GRID	LIGNITE	200	10	2000	2000	7 1%	12 36	0 00	7626	6 1%
3 TUROW	GRID	LIGNITE	200	10	2000	2000	7.1%	28 51	0 00	12035	9 7%
4 ADAMOW	GRID	LIGNITE	120	5	600	480	1.7%	33 90	0 00	2875	2.3%
5 KONIN	GRID	LIGNITE	65	9	583	523	1.9%	30.68	0.00	3148	2.5%
LIGNITE FIRED PUBLIC PLANTS					9503	9323	33.2%			52899	42.6%
6 OSTROLEKA B	GRID	COAL	200	3	600	600	2.1%	20 38	1.91	2864	2 3%
7 KOZIENICE	GRID	COAL	260	10	2600	2600	9.3%	17 94	1.59	7996	6 4%
8 POLANIEC	GRID	COAL	200	8	1600	1600	5.7%	18 80	1 35	7173	5 8%
9 RYBNIK	GRID	COAL	200	8	1600	1600	5.7%	20.95	0.68	9252	7.5%
10 JAWORZNO III	GRID	COAL	200	6	1200	1140	4.1%	25 14	0 71	6302	5 1%
11 DOLNA ODRA	GRID	COAL	200	8	1600	1600	5.7%	17 42	2 09	6856	5 5%
12 LAZISKA	GRID	COAL	173	6	1040	920	3.3%	29 72	0 37	4286	3 5%
13 LAGISZA	GRID	COAL	120	7	840	723	2.6%	24 48	0 85	3423	2 8%
14 SIERSZA	GRID	COAL	123	6	738	630	2.2%	29 17	0 79	3128	2 5%
15 STALOWA WOLA	GRID	COAL	64	6	384	345	1.2%	18 61	1.47	1356	1.1%
COAL FIRED FULLY DISPATCHABLE PLANTS					12202	11758	41.9%			52636	42 4%
FULLY DISPATCHABLE GRID PLANTS					21705	21081	75.2%			105535	85.0%
16 SKAWINA	GRID-C	COAL	79	7	550	495	1.8%	21.07	1 14	1919	1 5%
17 JAWORZNO II	GRID-C	COAL	50	7	350	300	1.1%	22 79	0 87	904	0 7%
18 BLACHOWNIA	GRID-C	COAL	47	6	282	244	0.9%	25 60	1 79	781	0 6%
19 HALEMBA	GRID-C	COAL	50	4	200	200	0.7%	42 33	0 23	769	0 6%
20 JAWORZNO I	GRID-C	COAL	29	5	145	93	0.3%	26 97	0 91	279	0 2%
21 MIECHOWICE	GRID-C	COAL	55	2	110	101	0.4%	30 03	0 04	295	0 2%
22 POMORZANY	GRID-C	COAL	60	2	120	112	0.4%	42.88	3.73	401	0.3%
COLLECTOR TYPE GRID PLANTS					1757	1545	5.5%			5348	4.3%
23 SIEKIERTY	CHP	COAL	125	4	500	619	2 2%	37 68	1 91	1794	1 4%
24 KRAKOW	CHP	COAL	115	4	460	446	1 6%	20 30	1 21	1791	1 4%
25 WROCLAW	CHP	COAL	100	2	200	259	0 9%	26 32	2 60	1089	0 9%
26 SMALLER CHP	CHP	COAL	30	100	2621	2174	7.8%	28 66	2.25	7895	6 4%
COMBINED HEAT AND POWER PLANTS					4180	3498	12.5%			12569	10.1%
PUBLIC THERMAL					27622	26124	93 2%			123452	99 5%
PUBLIC HYDROELECTRIC					2005	1918	6.8%			646	0 5%
TOTAL PUBLIC					29627	28042	100.0%			124098	100.0%

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The generation mix is heavily biased towards base load resources and this results in less efficient operation than otherwise possible. This distortion also complicates the computation of economic marginal costs by time period. This is because the system must incur additional off-peak costs to maintain sufficient base load capacity in order to meet peak loads that could otherwise be met by peaking resources that may be shut down during off-peak hours.

Economic Analysis of the System

Economic Analysis of the Generation System (Chapters 4, 6 and 7). The analysis of system reliability concluded that the following periods during the year have marked differences and may be used to establish differential pricing periods:

October-March	Morning Peak	07:01 to 12:59
	Evening Peak	16:01 to 20:59
	Off-Peak	all other hours
April-September	Morning Peak	07:01 to 12:59
	Evening Peak	19:01 to 21:59
	Off-Peak	all other hours

The corresponding short-run marginal costs are as follows:

October-March	Morning Peak	2.80 US ¢/kWh
	Evening Peak	4.64 US ¢/kWh
	Off-Peak	2.07 US ¢/kWh
April-September	Morning Peak	3.97 US ¢/kWh
	Evening Peak	4.64 US ¢/kWh
	Off-Peak	2.12 US ¢/kWh

The avoided cost of generation in the system was calculated by the differential economic cost of meeting the forecast load with and without the current block of power supplied by combined heat and power (CHP) plants, autoproducers, and hydroelectric (except pumped storage) resources. The cost is estimated to escalate from a current value of 4.73¢/kWh to 5.23¢/kWh by 2010.

Long-Run Marginal Economic Costs (Chapter 7). The analysis of long-run marginal costs (LRMC) was carried out by developing the LRMC at the generation level by time-of-day and then carrying it into the LRMC at the transmission and distribution levels by time-

of-day, voltage level, and customer class. Exhibit S-4 presents the bulk and retail LRMCs and compares them with the current yield.

At retail level, the average LRMC is 988 Zl/kWh (7.37¢/kWh) compared with a current yield of 542 Zl/kWh (4.04 ¢/kWh), or a difference of 82 percent. At the bulk level, the LRMC is 709 Zl/kWh (5.29 ¢/kWh) against a current yield of 340 Zl/kWh (2.53 ¢/kWh), or a difference of 109 percent.

Significant distortions from the economic cost structure above were observed in current tariffs demanding, in general, a gradual adjustment towards higher low-voltage retail tariffs in relation to high- and medium-voltage tariffs.

Unconstrained Financial Analysis of the System

Unconstrained Financial Analysis of the Generation System (Chapter 5). The financial analysis of the generating system is based on a detailed analysis of 17 individual plants consisting of Poland's four largest lignite-fired conventional grid plants and 13 of its largest coal-fired conventional and collector grid plants. This sample covers 96 percent of all the energy generated by grid plants in Poland.

A considerable effort was made by the Polish Power Grid Company (PPGC), at the consultants' request, to gather the historical financial data for each of the generating plants. These data were used to develop a financial spreadsheet model for each generating plant for the years 1990 and 1991. The purpose of this exercise was to provide a valid starting position for future projections, as well as to attempt to identify any underlying trends and ratios that might be expected to continue into the future.

In the absence of an established regulatory system, the financial analysis required several major assumptions based on either PPGC's opinion as the interim regulatory authority or on recommendations of the consultant. It was assumed that most existing generating plants will continue to be compensated for power on the basis of their production cost, but these costs (notably fuel) will tend towards a standard cost based on their economic value. Plants not entirely dedicated to the power sector, in particular CHP plants and eventually new resources, will be compensated on the basis of the economic avoided cost of power.

The first stage of the financial analysis explicitly ignored any potential constraints to a full reform of the pricing system based on acceptable criteria of financial performance. The major consequence of this approach was the proposition that gross assets, currently on the books at anywhere between one-third and one-tenth of their replacement cost, be revalued by 1994 and that generating companies must earn a 6 percent rate of return on the net revalued assets.

EXHIBIT S-4

LONG RUN MARGINAL COSTS

STRICT LONG RUN MARGINAL COST BASED TARIFF BY TARIFF CLASS - BULK

TARIFF CLASS	SERVICE VOLTAGE	COINCI-DENCE	LOAD FACTOR	ENERGY SHARES PEAK	MID - PEAK	TOTAL MARGINAL COST/MONTH CAPACITY tysZl/KW	ENERGY tysZl/KWh	TOTAL tysZl/KWh	DEMAND CHARGE SHARE	H1/1992 SALES GWh	CURRENT YIELD tysZl/KWh
DISTRIBUTION COS.	HV	1.00	0.65	0.20	0.28	121.10	0.4533	0.7085	36%	50434	0.3398
BULK SYSTEM AVERAGE				0.20	0.28	121.10	0.4533	0.7085		50434	0.3398
Equivalent tysZl/KWh						0.2552	0.4533	0.7085			
% of System Average						36%	64%	100%			

STRICT LONG RUN MARGINAL COST BASED TARIFF BY TARIFF CLASS - RETAIL

TARIFF CLASS	SERVICE VOLTAGE	COINCI-DENCE	LOAD FACTOR	ENERGY SHARES PEAK	MID - PEAK	TOTAL MARGINAL COST/MONTH CAPACITY tysZl/KW	ENERGY tysZl/KWh	TOTAL tysZl/KWh	DEMAND CHARGE SHARE	H1/1992 SALES GWh	CURRENT YIELD tysZl/KWh
INDUSTRIAL	HV	0.81	0.60	0.16	0.27	98.09	0.4354	0.6594	34%	14090	0.3874
	MV	0.63	0.42	0.18	0.31	117.62	0.4652	0.8488	45%	8884	0.4995
	LV	0.54	0.31	0.18	0.31	154.27	0.5203	1.2020	57%	1334	0.7828
TRACTION	HV	0.93	0.48	0.19	0.30	112.62	0.4534	0.7748	41%	67	0.4606
	MV	0.93	0.48	0.19	0.30	173.63	0.4671	0.9627	51%	2178	0.4715
COMMERCIAL	MV	0.63	0.49	0.20	0.32	117.62	0.4755	0.8044	41%	641	0.4934
	LV	0.55	0.30	0.20	0.32	157.13	0.5323	1.2498	57%	4464	0.7745
AGRICULTURAL	MV	0.54	0.38	0.20	0.32	100.82	0.4755	0.8390	43%	320	0.5287
RETAIL	LV	0.49	0.25	0.27	0.25	139.99	0.5479	1.3150	58%	13616	0.6310
ST. LIGHTING	LV	1.00	0.50	0.21	0.04	285.69	0.4659	1.2486	63%	742	0.7884
DISTRIBUTION COMPANY AVERAGE				0.20	0.28	128.31	0.4888	0.9879		46336	0.5421
Equivalent tysZl/KWh						0.4991	0.4888	0.9879			
% of System Average						51%	49%	100%			

Tys Zl = thousands of zloty

Any effort to revalue the assets in the generation system is likely to involve detailed engineering estimates of replacement costs or the potential revenue derived from each individual plant. For the purposes of this analysis, only a global estimate was made of the likely replacement cost of assets against their current book value. It was concluded that assets are probably undervalued by a factor of six.

The results of this analysis indicate that the 1994 revenue requirements of the generating system will average 489 Zl/kWh (3.65 c/kWh) or approximately a 63 percent real increase above the 1992 level of revenues.

Unconstrained Financial Analysis of the Polish Power Grid Company (Chapter 8). The analysis of transmission costs and the required financial revenues is essentially a financial analysis of the PPGC. Following up on the financial analysis of the generating system's revenue requirements, the objective of the financial analysis of PPGC was to determine the revenue requirements the company needs to operate as a viable commercial entity.

PPGC was formed in October 1990. Therefore, only one full year of historical data are available for the 12 months ending December 31, 1991. Furthermore, financial performance ratios have been distorted because the bulk of the transmission assets plus the pumped storage plant and associated operation and maintenance costs were not transferred to PPGC until January 1993.

The results of the analysis indicate that in 1994, PPGC would require average revenues of 563 Zl/kWh (4.20 c/kWh) or an approximate increase of 67 percent above 1992 revenue levels.

Unconstrained Financial Analysis of the Distribution System (Chapter 9). At the time this analysis was conducted, the Polish Government was leaning towards a policy of uniform bulk sales tariffs for all distribution companies, allowing each company to set its retail tariffs based on a regulated profit but taking into account the specific cost structure of each company.

The analysis of distribution costs and the required financial revenues and *average* tariff at the level of the distribution company customers was based on a consolidation or aggregation of key income statement and balance sheet data for the 33 distribution companies prepared by the Economics Department of PPGC. However, it was relevant to determine the variability that can be expected among the average retail tariffs of different distribution companies. Therefore, in addition to the consolidated case, three individual distribution companies were

analyzed -- Warsaw, Gliwice and Bialystok -- which represent major urban, mid-size urban, and rural distribution companies, respectively.

In the absence of a regulatory policy for commercial operation of the distribution companies at the time of the study, three different financial criteria were considered: 1) no increase in overall debt, 2) 6 percent return on net assets, and 3) 100 percent self-financing ratio. The first was accepted as the most prudent and implies that the distribution system must be capable of financing its equipment replacement and extending its service coverage from its revenues.

The results of the analysis of the consolidated distribution system indicate that the 1994 average revenue requirements would be 785 Zl/kWh (5.86 c/kWh) or approximately a 45 percent real increase above 1992 levels.

A comparative analysis of the 1994 revenue requirements of the three distribution companies indicates the following ratios with respect to the consolidated system: Bialystok 1.59, Gliwice 0.99, and Warsaw 1.16. Therefore, in this limited sample, the maximum difference in revenue requirements between two distribution companies is approximately 60 percent.

S.3 STAGE II - ANALYSIS OF IMPACT, CONSTRAINED FINANCIAL PROJECTIONS, AND FINAL TARIFF DESIGN

By April 1993 two things were becoming increasingly clear. First, it seemed unlikely that much progress would be made during 1993 in terms of real growth in tariff levels. Therefore, the proposed 1994 level would in effect represent a 45 percent real rate of increase with respect to 1993. Second, there would be serious constraints to a sudden revaluation of assets to their full replacement cost. Furthermore, even if assets could gradually be revalued to full replacement cost, it was unlikely that depreciation allowances for income tax purposes could be based on full replacement cost.

These circumstances were incorporated in the second stage of the study in the form of an analysis of tariff impact and a financial forecast based on a gradual process of asset revaluation.

Impact of Tariff Increases (Chapter 10)

An assessment was made of the impact of electricity tariff increases on Poland's end-users in order to adjust prices from their current levels to full cost-based pricing. The analysis focused both on the impact upon the economic output and the impact on household budgets.

A number of factors complicate the analysis of the impact of tariff increases on Poland's industries including the fact that, prior to 1990, internal incentives for Polish industry were perverse, and in many cases, cost reductions resulted in reduced profit. It was estimated that electricity accounts for about 3.4 percent of industrial costs on average. We thus concluded that electricity costs are probably not the largest problem facing Polish industry at this time. The problems associated with privatization, changing product prices, changing technology, shifts in product choice, depressed aggregate demand, and the installation of normal market incentives are probably far more critical than rising real electricity prices.

As of late 1992 it was estimated that a 75 percent real increase in electricity prices could increase household expenditures by about 2.5 to 3 percent of incomes. Of this, 2 to 2.25 percent would be through the direct use of electricity and 0.6 percent through higher food prices. Other consumption items would have very small effects. On this basis, the impact of a large electricity tariff increase on household budgets may at first appear negligible. However, taken in the context of rapidly rising prices in all sources of energy and in other sectors of the economy, the adjustments appear more burdensome. Further, even a 3 percent increase household budget expenses is dramatic if resources are strained.

Based on discussions with PPGC, it was estimated that real tariff increases on the order of 10 to 15 percent per year represent the maximum average annual upward adjustment of prices acceptable to Polish household budgets in today's economic environment.

Constrained Financial Analysis (Chapter 11)

Several financial projections were made taking into account limitations on the rate of tariff increase and the rate of asset revaluation. The scenario considered most compatible with current realities in Poland includes gradual asset revaluation to full replacement cost by 1997 with a ceiling of 70 percent of replacement cost to compute depreciation allowances for tax purposes.

A ceiling of 15 percent on the annual rate of increase in tariffs from 1994 onwards was also imposed as the limit of public acceptance, and it was assumed that only a 7 percent real increase would be achieved between mid-1992 and January 1994.

Key financial projections based on these assumptions are summarized in Exhibit S-5. These projections show that the resulting average revenue requirements at the retail level are 623 Zl/kWh (4.65 ¢/kWh) for 1994, 716 Zl/kWh (5.34 ¢/kWh) for 1995, and 814 Zl/kWh (6.07 ¢/kWh) for 1996 and 1997.

EXHIBIT S-5

CONSTRAINED BY FINANCIAL ANALYSIS

Tariff Increase Restriction and Gradual Asset Revaluation ("most likely case")

Assumptions:

Retail tariff increase: from mid-1992 to mid-1994, 15% ; then 15% per year in real terms

Asset Revaluation: 100% of replacement cost by January 1997

Tax allowance from Depreciation: 70% of replacement cost by January 1997

Investments in generation 1993 – 1997: US$ 5.8 billion

Fixed Operation Costs: decreasing

Financial criteria for DCs: no borrowing

	ESTIMATE	FORECAST			
	1992	1994	1995	1996	1997
AVERAGE TARIFFS – Zl/kWh (at mid 1992 price levels)					
Distribution Companies	542.1	623.4	716.9	814.0	814.0
PSE	336.7	378.0	411.0	517.0	567.0
Generation System	300.0	307.0	337.0	446.0	494.0
AVERAGE TARIFFS – US cents/kWh (at mid 1992 price levels)					
Distribution Companies	3.99	4.58	5.27	5.99	5.99
PSE	2.48	2.78	3.02	3.80	4.17
Generation System	2.21	2.26	2.48	3.28	3.63
NET BORROWING / CASH DEFICIENCY (SURPLUS) (billions zloty)					
Distribution Companies		165	203	199	219
PSE -- Programmed LTD		4,000	7,250	10,000	10,250
Cash		(1,738)	(2,597)	(3,429)	(5,520)
Generation System		19,942	29,399	34,032	34,356
SELF-FINANCING RATIO – %					
Distribution Companies		113.3	124.5	114.0	103.0
PSE		11.8	9.5	18.8	87.0
DEBT-TO-EQUITY (revalued) RATIO – %					
Distribution Companies		1.8	1.4	1.1	1.0
PSE		24.8	34.8	38.9	34.2
Generation System		28.6	34.3	34.7	34.2
RETURN ON NET ASSETS (revalued) – %					
Distribution Companies		15.1	18.0	10.8	2.8
PSE		6.4	6.0	6.1	5.9
Generation System		(9.9)	(5.4)	4.3	6.0
INCOME TAX FOR YEAR – billions Zl.					
Distribution Companies		5,576	8,055	6,886	3,646
PSE		543	656	771	773
Generation System		(2,664)	(2,409)	1,245	2,338
Total		3,455	6,302	8,902	6,757

Tariff Design (Chapter 12)

All of PPGC's domestic bulk sales are to 33 independent distribution companies, which in turn resell electricity to final consumers. Tariffs to each company are adjusted to permit uniform national tariffs to these end-users. PPGC's average yield on bulk sales was 334.6 Zl/kWh in October 1992, and is estimated to be a nominal 381.4 Zl/kWh as of February 1993 (339.8 Zl/kWh at mid-1992 prices).

The following are the principal features of the tariff structure that came into effect on January 1, 1993 (No. 7-Z/92).

- Tariffs are based strictly on consumer service voltage, with time-of-day rate options offered for each class.
- Based on billed sales data for the first half of 1992, tariff "A" (High Voltage, 60 to 220 kV) represents approximately 31 percent of total sales.
- Tariff "B" (Medium Voltage, 1 to 60 kV) customers account for about 26 percent of total sales. All of these customers pay both demand and energy charges.
- Tariff "C" (Low Voltage, below 1 kV) is divided into two classes. The first is customers with maximum demand above 40 kW or consumption over 80 MWh/year (tariff "C2"), which account for about 3 percent of total sales. The second is non-residential customers consuming less than 40 kW or 80 MWh/year (tariff "C1"), which comprise approximately 11 percent of total sales. Only the former group is assessed a demand charge.
- Residential and small farm customers (tariff "G") account for the remaining 29 percent of system retail sales.

Although the current tariff classes do not follow traditional customer classifications, these can be estimated from the tariff structure that was in effect throughout 1992 (No. 7-Z/91). This reveals that approximately 52 percent of total final sales go to the industrial sector.

Based on the most likely financial scenario and on the marginal cost structure developed through the economic analysis, specific tariffs for 1994 were developed as shown in Exhibit S-6.

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Exhibit S-6
Revenue Responsibility by Class and Tariff Design

	Current Yield	Strict LRMC	Revenue Responsibility	
Tariff Class	Zl/kWh	Zl/kWh	Zl/kWh	% Change
Bulk Sales	340	709	376	11%
Retail Sales				
"A"	388	660	416	7%
"B"	495	867	547	11%
"C" (>40 kW)	783	1,202	759	-3%
"C" (<40 kW)	775	1,250	789	2%
Retail ("G")	631	1,315	830	31%
St. Lighting	788	1,249	788	0%
Average Retail	542	988	623	15%

S.4 CONCLUSIONS AND RECOMMENDATIONS

Conclusions

- The Polish power system has a fairly high level of capacity reserve due to very low growth in demand over the last few years. However, even under modest growth in economic activity, the system will need additional peaking capacity as early as 1997 to overcome operational problems related to the high proportion of base load generation. Furthermore, intense investments will be needed under the modernization schedule required to meet ambitious targets of operating efficiency and environmental quality.

- Polish power plants are currently in a weak position to assume heavy financial obligations, largely because of the very low book value of their assets in relation to their likely replacement cost. Revaluation of assets to their approximate replacement cost and the allowance of reasonably attractive rates of return on their net value would generate the financial revenues necessary to meet most needs, but this would result in a steep rise in the electricity prices for 1994. In constant price levels (that is, excluding inflation), the increase would be approximately 45 percent with respect to average tariffs during 1992.

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- A gradual revaluation of assets is considered more likely and would result in average tariffs increases of not more than 15 percent from one year to the next, reaching a stable value by 1996. To meet the needs of the system with lower revenues from sales during 1994 and 1995, the generation system would need to borrow approximately US $2.9 billion. Retail tariff levels for 1994 were based on this assumption and the tariff structure was based on the estimated marginal cost of service to different customer classes.

Recommendations

- The bulk of the large thermal generating plants should continue to be compensated on the basis of their production costs with a regulated profit. Historical operating costs, including fuel costs, should be rapidly replaced by standard costs linked to their economic value. The Polish Power Grid Company should also be compensated on the basis of regulated operation cost and profit based on net assets.

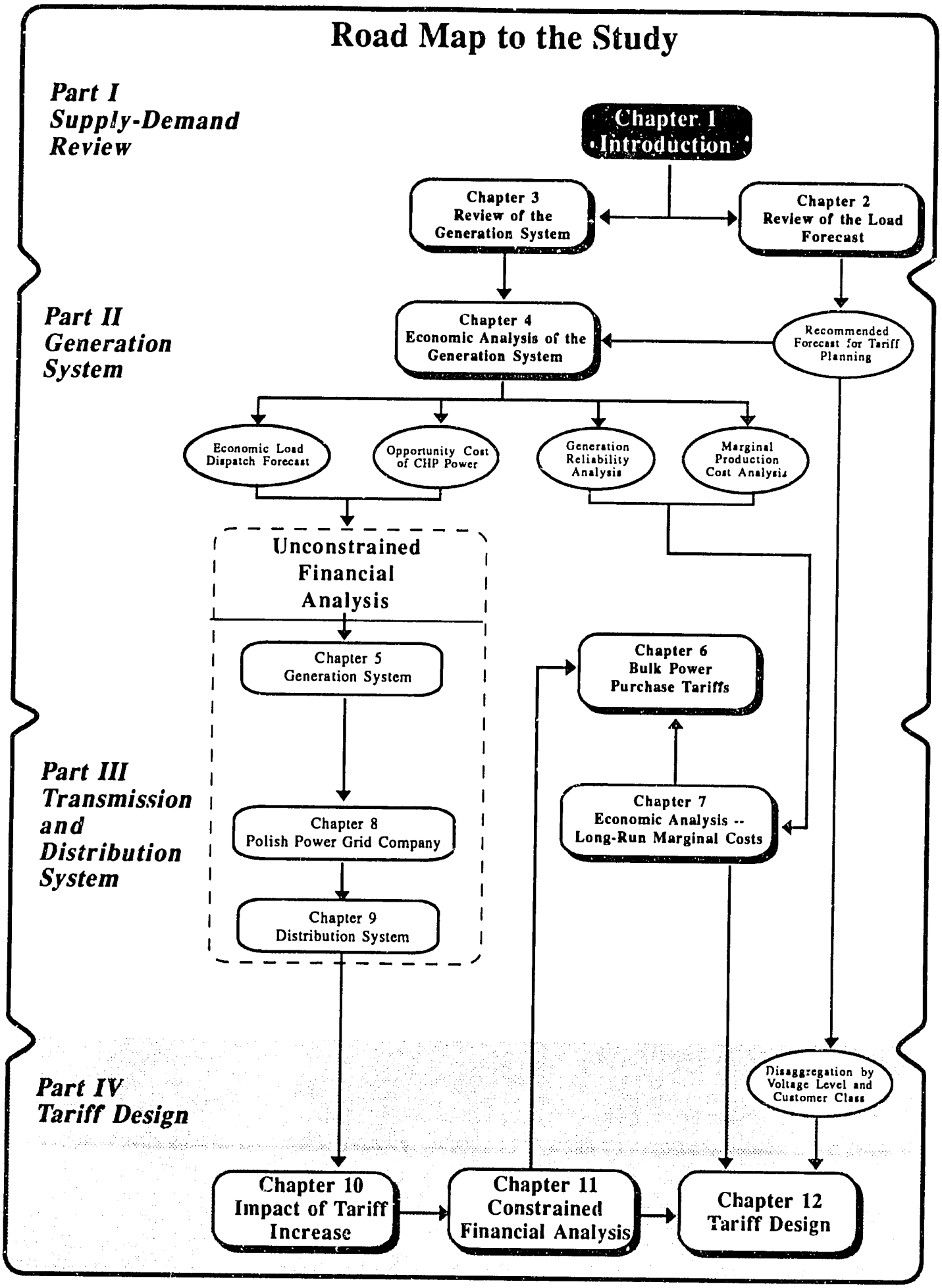
- Resources of limited dispatchability, such as combined heat and power plants, surplus from industrial autoproducers and small hydroelectric plants, should be negotiated not to exceed the avoided cost to the system resulting from the specific resource. Pumped storage hydroelectric plants provide a service to the network and should be treated as part of the asset base of the Polish Power Grid Company.

- Distribution companies should operate on the basis of a uniform bulk sales tariff and should develop specific retail tariff levels resulting in a regulated margin between wholesale and average retail tariffs. The marginal cost structure of tariffs calculated for the entire system should be observed by individual distribution utilities unless specific studies are carried out to support a different local structure of marginal costs.

- The existing principles for settlement with distribution companies and with power plants are compatible with the proposed tariff system. This includes those interim settlement mechanisms designed to compensate for deficiencies in measurement capability. However, substantial effort is needed in the development of detailed guidelines for determining standard operating costs and for the accurate computation of system avoided costs for individual resources.

It must be emphasized that the study was carried out in parallel with studies to determine the level of investments required in the transmission and distribution system and for the rehabilitation and modernization of generating plants. The results of the study are therefore based on preliminary estimates regarding these investments and should be revised as soon as the results from the aforementioned studies are available.

Road Map to the Study



CHAPTER 1: INTRODUCTION

1.1 STUDY BACKGROUND AND OBJECTIVES

As Poland changes from a centrally planned to a free market economy, the government is beginning to divest its ownership and control of virtually all means of production. In the power sector, such structural reform is particularly important because they lead to the vertical and horizontal disaggregation of a tightly integrated system of powerplants, system control, and transmission and distribution networks.

One of the primary activities in the reform of the energy sector is the elimination of subsidies and barriers to free competition, which will revitalize the sector and provide competitively priced energy to industry, business and households. Fundamental to achieving this objective is the rationalization of both the levels and structure of electricity pricing. This will provide buyers and sellers of electricity with the correct signals to make economically optimal investment and consumption decisions.

The objectives of this study are to design retail and bulk power tariffs for the medium term based on marginal cost principles, to develop transfer price principles consistent with the rationalization of the power sub-sector, and to provide practical guidelines for the implementation and phase-in of the new pricing system.

This study has been funded under the Regional Energy Efficiency Project (180-0030) of the United States Agency for International Development (A.I.D.) RCG/Hagler, Bailly, Inc. wishes to acknowledge the assistance and cooperation received from many Polish and international organizations during the execution of the study and in particular, the Polish Power Grid Company, A.I.D., and the World Bank.

1.2 OVERVIEW OF THE POLISH POWER SYSTEM

1.2.1 The Power System and Electricity Market

The Polish power industry was virtually destroyed by the end of World War II and was developed to its current form during the period 1950-1990. However, because of Poland's difficulties in obtaining financing and access to western technologies during that period, the characteristics of its electric system are substantially different from those of modern systems of comparable size in western countries.

By the end of 1990, Poland had 394 power and combined heat and power (CHP) stations with a total installed capacity of about 32,000 MW. This included 220 industrial CHP stations, 55 publicly owned thermal plants, and 119 hydroelectric powerplants. Out of the 2,000 MW of hydroelectric capacity, 1,500 MW are installed in five pumped storage plants with little net generation. Virtually all (99.5 percent) of the country's power is produced in thermal plants equipped exclusively with steam turbines that use lignite and coal as their primary fuels.

The high-voltage transmission grid consists of 220 kV, 400 kV and 750 kV lines totalling some 12,300 km. These and the system control facilities are managed by the Polish Power Grid Company (PPGC) or polish acronym (PSE). There are 48 companies involved in the distribution of power and heat in Poland.

Poland's power consumption patterns have been changing drastically since 1988, with a growing proportion accounted for by households and non-industrial consumers. Currently, industrial consumers account for 56 percent of sales, urban households for 28 percent, and commercial customers for 9 percent.

Poland exchanges electricity with several countries, and the number of these exchanges has been growing steadily since 1990. In 1992, Poland's net exports were approximately 4,000 GWh, or about 3 percent of final sales.

1.2.2 Power Sector Reform

The Polish Government, in agreement with the World Bank, has prepared and implemented a wide restructuring program in the past two years. One of the program's first accomplishments was to create in August 1990 the Polish Power Grid Company, which is fully owned by the National Treasury. Among other things, the program envisages the following:

- reorganization of all lignite mining enterprises and lignite-fired power stations into three regional organizations.
- reorganization of coal-fired powerplants into four commercial generating utilities
- reorganization of combined heat and power facilities into nine commercial utilities

- commercialization and privatization of enterprises auxiliary to the power industry

- reorganization of the distribution companies into 10 to 20 regional distribution utilities.

A regulatory authority is expected to be created to protect the public and supervise the fair operation of the power market. In the meantime the Ministry of Industry and Trade, through PPGC, supervises the entire power industry. Its responsibilities include system planning, system dispatch and control, bulk power purchases and sales, and retail tariff recommendations.

In the absence of detailed regulatory guidelines the tariff study had to adopt assumptions regarding acceptable financial performance criteria for the different components of the system. These were guided by broad principles of operation and administration of the power sector defined by PPGC which direct the power system towards standards of efficiency and environmental quality that are comparable to those of western European countries.

1.3 ROAD MAP TO THE TARIFF STUDY

The report on the tariff study is structured into four parts, each containing three chapters:

- Part I - Supply and Demand Review
- Part II - Generation System
- Part III - Transmission and Distribution System
- Part IV - Tariff Design

The structure follows the analytical flow of the study and is shaped by the uncertainties faced during its execution. The most important aspect of the structure of the report is that Part I does not necessitate any assumptions about external constraints such as the feasibility of revaluating the power sector's assets and the feasibility of electricity tariff increases; Parts II and III assume that these external constraints do not exist, while Part IV takes them into consideration. This complexity is required because of the iterative nature of the tariff design process. A description of the contents of each part follows.

Part I: Supply and Demand Review. This part of the report includes this introductory chapter and a review of the two extreme points of the power market, namely the demand for power and power generation resources. The demand for power is reviewed in Chapter 2

with respect to both total sales and the distribution of power demand by consumer groups and voltage levels. The generation system is reviewed in Chapter 3 and includes the main assumptions regarding the evolution of the generation system, the adequacy of the system to meet demands for power, and the principles for the sale of bulk power from generating companies.

Part II: Transmission and Distribution System. In this part of the report, the generation system is studied in greater detail and from two compatible but very different perspectives. In Chapter 4 the generation system is examined from the point of view of the Polish economy and includes a simulation of the system based on economic price levels. This chapter has two major outputs. The first is the forecast of production, by plant, for the 1993-2000 period; the second is the analysis of the system reliability and marginal production costs for two specific years, 1994 and 1997.

In Chapter 5 the generation system is examined from the perspective of the generating companies. Thus, while the production of each plant is derived from the forecast of Chapter 4, the production cost includes all financial costs. The final result is a computation of all the revenues that generating companies need to collect in order to provide power. These comprise all of the costs included in the economic analysis plus other costs such as taxes, interest on loans, amortization of revalued assets, and the profit that is deemed necessary for power generation to be an attractive commercial industry. It is emphasized that this forecast is not yet adjusted by any considerations about the feasibility of asset revaluation or tariff increases and is therefore is called the "unconstrained financial analysis of the generation system."

Part II ends with Chapter 6 in which the economic principles established to structure the sale of power from generating plants are combined with the financial revenue requirements to determine a bulk power tariff for transactions between generators and the power grid.

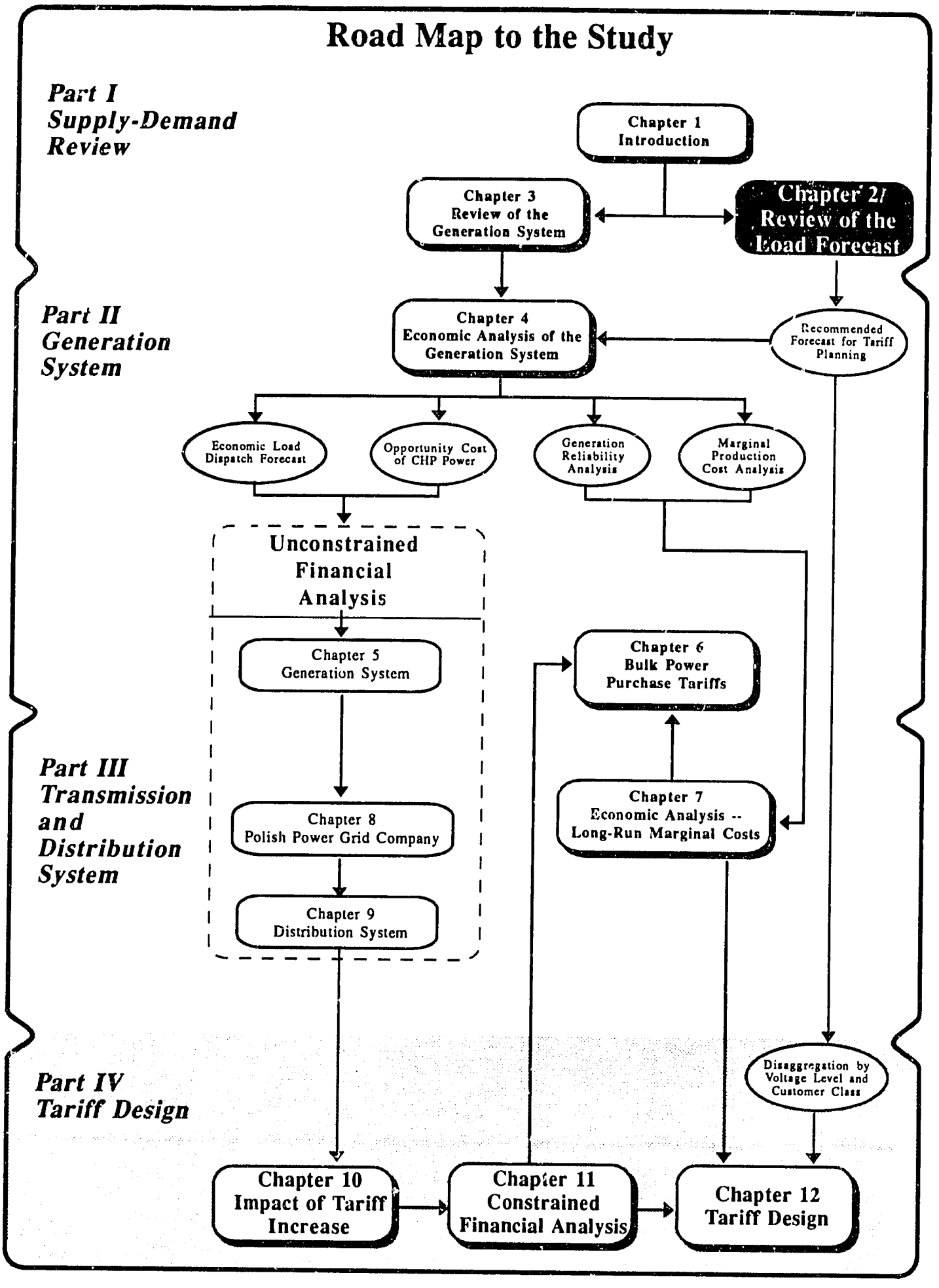
Part III: Transmission and Distribution System. This part of the report brings the results of Part II all the way down to the final consumer by first considering the structure of marginal costs at the transmission and distribution level, in Chapter 7. The financial analysis is separated into two chapters. Chapter 8 deals with the revenue requirements of the Polish Power Grid Company and Chapter 9 with the revenue requirements of distribution companies. Again, these forecasts of revenue requirements do not yet include any external considerations and are therefore called "unconstrained financial forecasts."

Part IV: Tariff Design. In Chapter 10 the impact of electricity prices is reviewed both with respect to different economic activities and with respect to the impact on the standard of

living in Poland. The results are incorporated in Chapter 11, where new financial forecasts are developed based on the analyses carried out in Chapters 5, 8 and 9, but this time adjusted by different scenarios of limitations on the extent of tariff increases and limitations on the extent and schedule of asset revaluation. From Chapter 11 emerges a "most likely" forecast of revenue requirements which is then used in Chapter 12 for the detailed tariff design.

This process is shown schematically in the road map that appears at the beginning of this chapter. To guide the reader through this complex process, the exhibit is repeated at the beginning of each chapter, showing the position of the subject matter being discussed and its relation to the rest of the study.

Road Map to the Study



CHAPTER 2: REVIEW OF THE LOAD FORECAST

The purpose of this task was to specify a ten-year (1992-2001) load forecast for use in subsequent activities within the overall study. For tariff planning, this forecast must be disaggregated by voltage level and by customer class, and must incorporate planning uncertainty.

Although this task was narrowly conceived as a review and adaptation of the official PPGC forecast, its focus has been expanded in light of the current climate of economic uncertainty in Poland. Our review indicates that existing forecasts adequately reflect optimistic future economic growth prospects, but do not address the possibility of slow recovery and/or low rates of economic growth. Therefore, an alternative growth scenario was developed for comparison with existing high and low load projections.

This chapter is organized as follows. After a brief background discussion of the forecasting environment (Section 2.1), Section 2.2 summarizes recent forecasts prepared in Poland, and categorizes these forecasts into three "scenarios" that reflect alternative assumptions about future economic growth. Section 2.3 compares the results of these scenarios and recommends energy and demand forecasts to be used for tariff planning. Finally, Section 2.4 presents a disaggregation of the recommended load forecasts by voltage level and tariff group for use in subsequent long-run marginal cost and financial revenue analysis.

2.1 BACKGROUND: THE FORECASTING ENVIRONMENT

The forecasting environment for Poland is clouded by both erratic historical trends and the uncertainties accompanying drastic economic reform. The recent past is characterized by significant economic contraction as the country adjusts to its new free-market course. The pace and impact of structural adjustments to the economy in the near term cannot be predicted with certainty. Further, because of the ongoing transition of the economy, there is likely to be a discontinuity between the functional determinants of demand historically and in the future. These factors suggest that the strict application of traditional econometric or elasticity-based models for load forecasting has only limited value for Poland at this time.

Recent Economic Performance

The Polish economy's historical performance is summarized in Exhibit 2-1. The economy experienced little growth in the early 1980s, and modest growth in subsequent years. After

Exhibit 2–1: Basic Economic Data

Year	Real GDP (bn Zl 1987)	Population (million)	GDP/Capita (tysZl 1987)
1980	15856	35.58	446
1981	14274	35.90	398
1982	13595	36.23	375
1983	14350	36.57	392
1984	15161	36.91	411
1985	15941	37.20	429
1986	16614	37.46	444
1987	16940	37.66	450
1988	17635	37.86	466
1989	17722	37.85	468
1990	15667	38.18	410
1991	14413	38.29	376
Average Rates of Growth:			
1980–91	–0.9%	0.7%	–1.5%
1980–85	0.1%	0.9%	–0.8%
1985–89	2.7%	0.4%	2.2%
1989–91	–9.8%	0.6%	–10.3%

Source: These series were derived from:

1) From IBRD, World Tables
2) From International Monetary Fund, "International Financial Statistics"
3) From World Economy Research Institute of the Warsaw School of Economics, "Poland International Economic Report 1991/92

1989, however, the economy contracted dramatically, and has averaged minus 10 percent annual real growth for the past two years. The degree to which the historical data series accurately incorporates the emerging private sector, or otherwise captures real growth in periods of dramatic inflation, is not known.

This disturbing performance is not unexpected in light of Poland's historic redirection from a centrally planned toward a free market economy, which began in January 1990. Immediate "shocks" included complete price liberalization, the opening of borders to foreign trade, and a sharp exchange rate devaluation. Further, the demise of the CMEA resulted in the disruption of historical trading relationships, including the loss of relatively low-cost Soviet energy supplies. Economic adjustments within Poland over the last two years have resulted in:

- a steep decline in real wages as a result of a stringent anti-inflation program, and a consequent drop in domestic expenditures
- a high and rising level of government expenditure that has outpaced growth in revenues
- a state-owned enterprise system (SOE) that has failed to adapt to new realities, and in many cases clings to its inefficiencies at great cost to the government and the banking sector, despite falling productivity
- a private sector that has increased its participation in the economy dramatically, but a privatization process that remains slow and cumbersome.

While these problems are not intractable in the long term, the pace of transition to a stable market economy is unknown and the experience of other countries can provide very little guidance.

Recent Electric Sales Data

Exhibit 2-2 reports historical sales and generation data for selected years from 1980 through 1991. Generally, sales growth has mirrored the economy, with steady increases in the 1985-1989 period, and dramatically decreasing generation and consumption from 1989 to 1991. An exception to the declining trend is the communal sector (combined residential, farm, and commercial sales), in which modest growth was maintained during the recent slowdown.

Exhibit 2-2

Republic of Poland: Historical Generation and Consumption (GWh)

	1980	1985	1986	1987	1988	1989	1990	1991	Average Annual Rate (%) 1980-85	1985-89	1989-91
PUBLIC POWER SYSTEM											
Industry	59796	61858	63779	66012	67135	65402	57312	51052	0.7%	1.4%	-11.6%
Traction	4820	5478	5627	5834	6005	5875	5346	4915	2.6%	1.8%	-8.5%
Communal	25153	32789	34546	37132	38438	39792	39851	40417	4.6%	5.0%	0.8%
Final Domestic Sales	90769	100125	103952	108978	111578	111069	102509	93384	2.0%	2.6%	-6.8%
Exports	4396	7568	7796	8703	7980	10268	11477	9326	11.5%	7.9%	-4.7%
Imports (-)	4161	5456	7833	10422	12456	12059	10437	6708	5.6%	21.9%	-25.4%
TOTAL SALES	91004	102237	103915	107259	107102	109278	103548	99002	2.4%	1.7%	-4.8%
Network Losses	12202	13337	13812	15448	14190	13345	11364	14369	1.8%	0.0%	3.8%
% of incoming	11.8%	11.5%	11.7%	12.6%	11.7%	10.9%	9.9%	12.7%			
Pumping in Hydro Plants	1246	2797	3059	3275	3307	2922	2614	2747	17.6%	1.1%	-3.0%
Self-Producer Supply to Grid (-)	835	583	524	311	307	396	495	339	-6.9%	-9.2%	-7.5%
NET GENERATION	103617	117788	120262	125671	124292	125149	117032	115779	2.6%	1.5%	-3.8%
Heat Generation Auxillary Use	-	2049	2027	2141	2045	2031	2050	2105	-	-0.2%	1.8%
Station Use	7914	9053	9299	9300	9596	9725	9132	8961	2.7%	1.8%	-4.0%
% of incoming	7.1%	7.1%	7.2%	7.1%	7.2%	7.2%	7.2%	7.2%			
GROSS GENERATION (GWh)	111531	128890	131588	137412	135933	136905	128214	126845	2.9%	1.5%	-3.7%
Load Factor											
MAXIMUM DEMAND (MW)											
OTHER PRODUCERS											
Self-Producer Factory Use	8884	7741	7695	7646	7635	7681	7170	7051	-2.7%	-0.2%	-4.2%
Self-Producer Supply to Grid	835	583	524	311	307	396	495	339	-6.9%	-9.2%	-7.5%
Other Supply to Grid	36	34	34	35	31	28	27	29	-1.1%	-4.7%	1.8%
NET GENERATION	9755	8358	8253	7992	7973	8105	7692	7419	-3.0%	-0.8%	-4.3%
Station Use	585	459	453	427	434	458	459	432	-4.7%	-0.1%	-2.9%
% of incoming	5.7%	5.2%	5.2%	5.1%	5.2%	5.3%	5.6%	5.5%			
GROSS GENERATION (GWh)	10340	8817	8706	8419	8407	8563	8151	7851	-3.1%	-0.7%	-4.2%
Load Factor											
MAXIMUM DEMAND (MW)											
TOTAL GROSS GENERATION	121871	137707	140294	145831	144340	145468	136365	134696	2.5%	1.4%	-3.8%

Exhibit 2-3 further highlights trends by customer class. It is apparent that the industry sector has experienced the most dramatic reduction in consumption. Overall, its share of total sales declined from 67 percent (1980) to 53 percent (1991). Moreover, this structural change appears to have been gradual, and not merely a response to the adjustments of the past two years.[1]

In contrast, the consumption share of the communal sector has been steadily rising. Most notably, residential sales experienced rapid growth prior to 1989, and have even reported a modest increase in the last two years. Residential sales' share of total sales rose from 12 percent (1980) to 22 percent (1991).

Impact of the Forecast on Tariff Planning

In an environment of considerable planning uncertainty, we believe that forecasts for rate-making should be conservative. In practice, financial revenue requirements determine the level of tariffs. while economic costs determine their structure. The financial revenue requirement (Zl/kWh) is defined as total annual costs (i.e., recovery of capital costs, O&M costs, self-financing requirements, and rate of return) divided by total sales. If expected sales are overestimated, the average revenue requirement will be understated. Given today's climate of uncertainty, a conservative (lower) forecast is prudent. If the forecast proves too conservative, over-recovery of revenue can be easily corrected by delaying the need for future tariff increases.

Because tariffs are set only for a year or two in advance, identifying the *structure* of the load -- by voltage level and customer class -- is as important as the precise level of total energy and capacity sales.

2.2 REVIEW OF EXISTING FORECASTS

We are aware of three different forecasting studies developed in Poland since 1990. These were prepared by:

- The Polish Academy of Sciences (PAS)

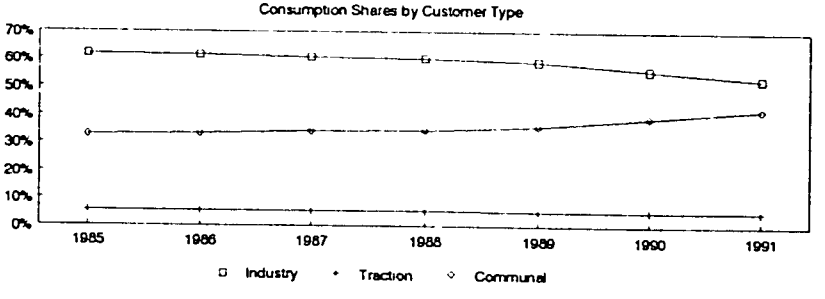
[1] The dramatic fall in low voltage (LV) industrial consumption in 1991 appears to be the result of a reclassification of some LV customers to LV commercial rather than to a total collapse of small industrial demand. We have therefore grouped these sales with commercial sales for the purposes of this analysis.

Exhibit 2-3
Republic of Poland: Historical Sales and Consumption Shares by Customer Class (GWh)

		1980	1985	1986	1987	1988	1989	1990	1991	Average Annual Rate (%) 1980-85	1985-89	1989-91
INDUSTRY	HV	–	34805	36209	37680	38531	37395	32761	29656	–	1.8%	-10.9%
	MV	–	23482	23781	24220	24271	23558	20593	18848	–	0.1%	-10.6%
	LV	–	3570	3788	4113	4333	4449	3959	2548	–	5.7%	-24.3%
	Total	59790	61858	63779	66012	67135	65402	57312	51052	0.7%	1.4%	-11.6%
TRACTION 1/	HV	–	164	169	175	180	176	160	147	–	–	–
	MV	–	5314	5458	5659	5825	5699	5186	4768	–	–	–
	Total	4820	5478	5627	5834	6005	5875	5346	4915	2.6%	1.8%	-8.5%
STREET LIGHTS	LV	670	1274	1283	1186	1355	1506	1325	1372	13.7%	4.3%	-4.6%
COMMERCIAL	MV	–	927	999	1121	1185	1225	1179	1233		7.2%	0.3%
	LV	–	7235	7640	7953	7997	8161	7039	8588		3.1%	2.6%
	Total	7645	8162	8639	9074	9182	9386	8218	9621	1.3%	3.6%	2.3%
FARMS	MV	–	599	654	728	754	745	711	682		5.6%	-4.3%
	LV	–	6629	7076	7726	7829	7888	7414	7712		4.4%	-1.1%
	Total	5360	7229	7731	8454	8582	8633	8124	8394	6.2%	4.5%	-1.4%
RESIDENTIAL	LV	11010	16126	16894	18417	19319	20267	22183	20829	7.9%	5.9%	1.4%
TOTAL FINAL SALES		84481	99962	103783	108803	111398	110893	102348	96236	3.4%	2.6%	-6.8%
	HV	89301	100126	103952	108978	111578	111069	102509	96384	2.3%	2.6%	-6.8%
	MV	–	34970	36209	37680	38531	37395	32761	29656	–	1.7%	-10.9%
	LV	–	30321	30893	31728	32035	31227	27668	25531	–	0.7%	-9.6%
		–	34835	36681	39396	40832	42271	41920	41049	–	5.0%	-1.5%

CONSUMPTION SHARES OF TOTAL SALES

	1980	1985	1986	1987	1988	1989	1990	1991
INDUSTRY	0.67	0.62	0.61	0.61	0.60	0.59	0.56	0.53
TRACTION	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
COMMUNAL	0.28	0.33	0.33	0.34	0.34	0.36	0.39	0.42
Street Lights	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Commercial	0.09	0.08	0.08	0.08	0.08	0.08	0.08	0.10
Farms	0.06	0.07	0.07	0.08	0.08	0.08	0.08	0.09
Residential	0.12	0.16	0.16	0.17	0.17	0.18	0.22	0.22
TOTAL	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00



- The Polish Power Grid Company (PPGC), Department of Development
- The Ministry of Industry (MOI) as published by the OECD/IEA.

Each of these forecasts includes its own high and low scenario, for a total of six forecasts. The projections are all based on econometric studies, and are distinguished by different underlying assumptions about future economic growth rates in Poland. A general description of each study is presented in Appendix 2.1.

Based on our review of these forecasts and their underlying economic assumptions, we have defined three "scenarios" that broadly bracket possible future economic conditions:

Scenario 1: Optimistic Growth
Scenario 2: Rapid Recovery to Steady Growth
Scenario 3: Slow Recovery to Steady Growth.

For our analysis, the high scenarios from the PAS and PPGC studies, and the medium scenario from the MOI forecast[2] can be grouped as representative of Scenario 1 (Optimistic Growth). These forecasts all assume fairly rapid average real economic growth over the next decade. Similarly, the low scenarios from all three studies are representative of Scenario 2 (Rapid Recovery to Steady Growth). These forecasts assume slow or negative economic growth in the near term with rapid recovery to steady, stable growth thereafter. The underlying macroeconomic assumptions for these two scenarios are compared in Exhibit 2-4.

Based upon our review, we concluded that existing forecasts do not adequately consider Scenario 3. We therefore developed our own forecast for this scenario. This forecast, described in Appendix 2.2, projects end-use consumption trends; it is more conservative than Scenarios 1 and 2.

The individual forecasts reviewed within each scenario are compared briefly in the following paragraphs. Exhibit 2-5 compares their respective projections of total domestic generation requirements, adjusted to base year 1991.

[2] The Ministry of Industry also prepared a High macroeconomic case, but it was deemed unrealistic in the analysis, and an associated electricity demand forecast was not developed.

Exhibit 2–4
Summary of Macroeconomic Assumptions by Scenario

SCENARIO 1: Optimistic Growth

	Economic Growth Rate (% per year)		Apartment Construction (units per year)	
	PAS/PSE	MOI	PAS/PSE	MOI
1990–95	3.2%	5.1%	200,000	170,000
1995–00	5.5%	5.1%	–	200,000
2000–05	4.1%	4.9%	–	230,000
2005–10	4.1%	4.9%	–	260,000
2010–20	3.7%	–	350,000	–

SCENARIO 2: Rapid Recovery to Steady Growth

	Economic Growth Rate (% per year)		Apartment Construction (units per year)	
	PAS/PSE	MOI	PAS/PSE	MOI
1990–95	–1.0%	3.4%	130,000	125,000
1995–00	2.6%	3.4%	–	175,000
2000–05	3.2%	2.6%	–	210,000
2005–10	3.2%	2.6%	–	215,000
2010–20	3.4%	–	220,000	–

Notes: (1) Scenario 1 includes "High" PAS/PSE and "Medium" MOI assumptions.
(2) Straight line growth assumed when interim year data not available.

Exhibit 2–5
Comparison of Forecasts of Gross Domestic Generation Requirements

SCENARIO 1: Optimistic Economic Growth

year	PAS High TWh	PAS High %	PSE High (Variant II) TWh	PSE High (Variant II) %	MOI Variant II TWh	MOI Variant II %
1991	132.0	–	132.0	–	132.0	–
1996	156.7	3.5%	155.4	3.3%	158.4	3.7%
2001	187.9	3.7%	179.4	2.9%	189.2	3.6%

SCENARIO 2: Rapid Recovery to Steady Economic Growth

year	PAS Low TWh	PAS Low %	PSE Low (Variant I) TWh	PSE Low (Variant I) %	MOI Variant I TWh	MOI Variant I %
1991	132.0	–	132.0	–	132.0	–
1996	142.1	1.5%	141.5	1.4%	150.8	2.7%
2001	160.0	2.4%	160.1	2.5%	173.1	2.8%

SCENARIOS 3: Slow Recovery to Steady Growth

year	End–Use Trends TWh	End–Use Trends %
1991	132.0	–
1996	129.9	–0.3%
2001	157.1	3.9%

Notes:
(1) All forecasts have been adjusted to base year 1991.
(2) Forecast domestic generation requirements (TWh) for Scenarios 1 and 2 have been estimated from periodic growth rates for the forecasts shown in Exhibits presented in Appendix 1.1.

Scenario 1: Optimistic Growth

Economic growth assumptions are shown in Exhibit 2-4. The PAS/PPGC forecasts assume slightly moderated economic growth averaging 3.2 percent annually from 1990 to 1995, rising to 5.5 percent over the next five years. The MOI forecast posits an average annual growth rate of 5.1 percent until 2000. It is not possible to compare economic growth assumptions for specific years because the MOI did not report interim-year assumptions.

Exhibit 2-5 compares the electricity requirements forecasts (adjusted to base year 1991) resulting from optimistic economic growth assumptions. Each forecast assumes that electricity requirements will grow in the range of 3.0 to 3.8 percent annually until the year 2000. The PAS and MOI studies imply an income elasticity of about 0.70, while the more recent PPGC study assumes the achievement of even greater energy efficiency, with a 0.55 elasticity. The PPGC forecast is lower, probably because it was prepared more recently than the other two. The difference in average annual growth rate after 10 years is about 0.5 percent.

Scenario 2: Rapid Recovery to Steady Growth

The PAS and PPGC low forecasts assume "saucer-like" macroeconomic performance, i.e., negative growth in the near term followed by recovery. But the period of adjustment to the new economic order is rapid, with negative growth in 1991 and 1992 being followed by accelerated 7 percent real economic growth until 1995. (MOI probably made a similar assumption, although values assumed for interim years are not available.) After 1995, each forecast assumes 3 percent real growth (+/-0.4 percent).

Income elasticities in the early years are unstable. From 1995 to 2000, the PAS and PPGC studies assume income elasticities in the range of 0.90 to 1.0, falling to 0.7 or 0.8 thereafter. The MOI study results imply a dramatic increase in the energy intensity of the economy, a result that we cannot explain.

As shown in Exhibit 2-5, after energy requirements forecasts are adjusted to base year 1991, they fall within a narrow band, with the earlier MOI forecast being slightly higher than the PAS/PPGC results.

Scenario 3: Slow Recovery

Our independent forecast based on end-use trends is presented in Appendix 2.2 and summarized in Exhibit 2-5. Based on the experience of the recent past, the forecast projects slow electricity sales growth until 1996, with more rapid growth thereafter. Sales are forecast to reach the level of Scenario 2 (the PPGC "low" forecast) around the year 2001. This very conservative forecast characterizes the potential electricity requirements under a slow economic recovery scenario.

2.3 RECOMMENDED FORECAST FOR TARIFF PLANNING

Exhibit 2-6 compares the electricity demand forecasts discussed in Section 2.2. (For this exhibit, the PPGC "high" and "low" forecasts were chosen as representative of Scenarios 1 and 2, respectively.) Shown graphically, the three forecasts (Scenarios 1, 2, and 3) bracket demand under optimistic, stable, and more pessimistic views of future economic conditions in Poland.

We recommend that Scenario 2 (the PPGC Variant I "low" forecast) be applied for tariff planning. This forecast is the most recent forecast (December 1991) reviewed, and it also projects the lowest average annual growth in energy demand of all forecasts prepared in Poland. This base case forecast is shown in Exhibit 2-7.

2.4 DISAGGREGATION OF THE LOAD FORECAST BY VOLTAGE LEVEL AND CUSTOMER CLASS

For the long-run marginal cost analysis, it is necessary to disaggregate the recommended load forecast by voltage level and by customer class. Following PPGC convention, we have allocated final sales by the following distinct service voltage levels:

VHV	220 kV and above
HV	61 to 220 kV
MV	1 to 60 kV
LV	below 1 kV.

The base case forecast (Scenario 2) was prepared by PPGC as a "top down" projection of total national energy demand rather than as a projection of final sales by customer category (e.g., residential, commercial, industrial) or tariff class. Thus, there is no clear basis for

Exhibit 2-6
Comparison of Generation Requirements Forecasts (GWh)

	Actual 1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Rate of Growth 1991-96	Rate of Growth 1996-01
SCENARIO 1: OPTIMISTIC GROWTH													
PSE Variant II (High)	134696	137200	142700	148300	154200	157377	161854	167900	173309	176400	179993	*3.2%*	*2.7%*
growth rate (%)		*1.9%*	*4.0%*	*3.9%*	*4.0%*	*2.1%*	*2.8%*	*3.7%*	*3.2%*	*1.8%*	*2.0%*		
SCENARIO 2: RAPID RECOVERY TO STEADY GROWTH													
PSE Variant I (Low)	134696	133200	135200	137800	141300	143400	147000	150700	154400	158300	156400	*1.3%*	*1.8%*
growth rate (%)		*-1.1%*	*1.5%*	*1.9%*	*2.5%*	*1.5%*	*2.5%*	*2.5%*	*2.5%*	*2.5%*	*-1.2%*		
SCENARIO: SLOW RECOVERY AND SLOW GROWTH													
End-Use Trends	134696	132459	130619	129593	132253	131776	136510	142721	148511	154071	157107	*-0.4%*	*3.6%*
growth rate (%)		*-1.7%*	*-1.4%*	*-0.8%*	*2.1%*	*-0.4%*	*3.6%*	*4.6%*	*4.1%*	*3.7%*	*2.0%*		

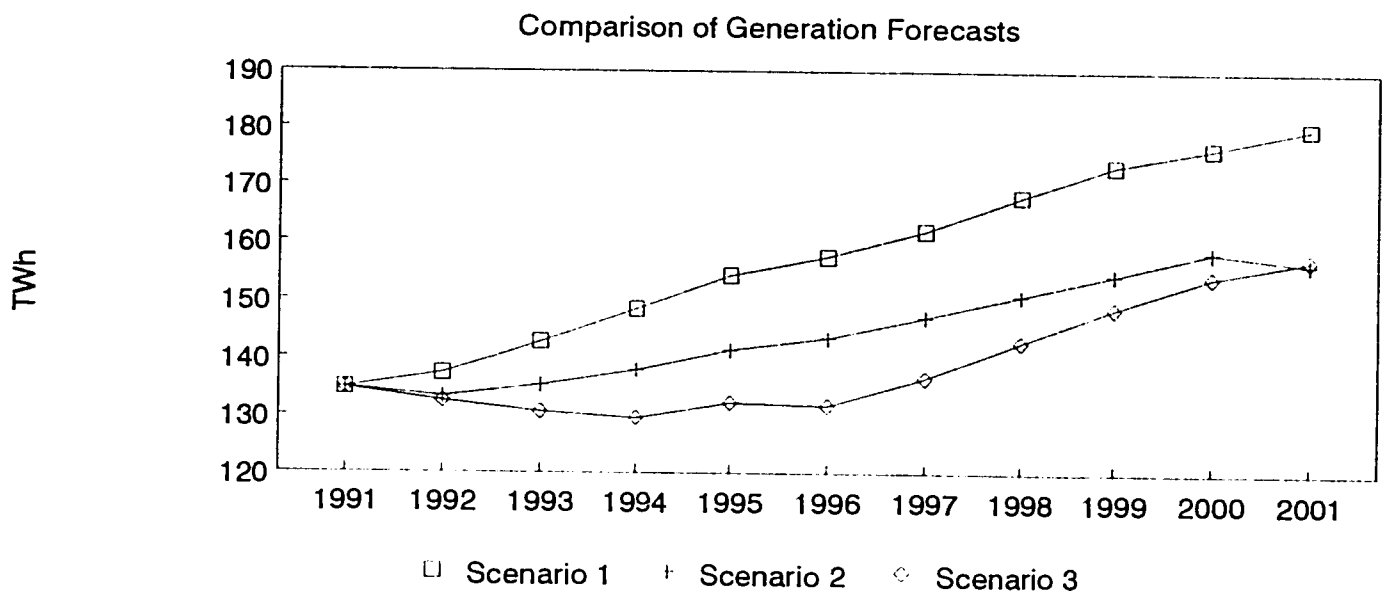


Exhibit 2–7: Base Case Forecast
Republic of Poland: PSE "Low" Forecast Generation and Consumption (GWh)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Avg Annual Rate (%) 1991–96	Avg Annual Rate (%) 1996–01
PUBLIC POWER SYSTEM												
Industry	48988	48864	48843	49300	50419	51630	52372	53355	54900	54673	–0.2%	1.6%
Traction	5160	5631	6158	6800	6941	7094	7182	7303	7500	7508	7.1%	1.6%
Com.nunal	40926	43079	45440	48400	49878	51470	52610	54009	56000	56031	4.3%	2.4%
Final Domestic Sales	95073	97574	100441	104500	107238	110194	112165	114666	118400	118212	2.2%	2.0%
Exports 1/	3200	3200	3300	3300	1900	1900	1900	1900	1900	0	–	–
Imports (–)	0	0	0	0	0	0	0	0	0	0	–	–
TOTAL SALES	98273	100774	103741	107800	109138	112094	114065	116566	120300	118212	2.0%	1.6%
Network Losses	13489	12796	12194	11500	11908	12256	12614	12974	13000	13135	–3.7%	2.0%
% of incoming	11.84%	11.05%	10.32%	9.6%	9.66%	9.68%	9.71%	9.73%	9.8%	9.72%		
Pumping in Hydro Plants 2/	2600	2600	2600	2600	2600	2600	3667	4200	4200	4200	–1.1%	10.1%
Self–Producer Supply to Grid (–)	400	400	400	400	400	400	400	400	400	400	3.4%	0.0%
NET GENERATION	113962	115771	118136	121500	123246	126550	129946	133340	137100	135147	1.3%	1.9%
Heat Generation Auxiliary Use	2152	2200	2250	2300	2339	2378	2418	2459	2500	2519	2.1%	1.5%
Station Use	8986	9129	9315	9400	9715	9972	10236	10501	10600	10634	1.6%	1.8%
% of incoming	7.18%	7.18%	7.18%	7.18%	7.18%	7.18%	7.18%	7.18%	7.18%	7.17%		
GROSS GENERATION (GWh)	125100	127100	129700	133200	135300	138900	142600	146300	150200	148300	1.3%	1.9%
Load Factor	0.648	0.653	0.657	0.662	0.672	0.673	0.676	0.677	0.681	0.670		
MAXIMUM DEMAND (MW)	22024	22224	22528	22978	22989	23570	24077	24660	25187	25260	–	1.9%
Load Growth (%)		0.91%	1.37%	2.00%	0.05%	2.53%	2.15%	2.42%	2.14%	0.29%		
OTHER PRODUCERS												
Self–Producer Factory Use	7200	7200	7200	7200	7200	7200	7200	7200	7200	7200	–	–
Self–Producer Supply to Grid	400	400	400	400	400	400	400	400	400	400	–	–
Other Supply to Grid	–	–	–	–	–	–	–	–	–	–	–	–
NET GENERATION	7600	7600	7600	7600	7600	7600	7600	7600	7600	7600	–	–
Station Use	500	500	500	500	500	500	500	500	500	500	–	–
% of incoming	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	5.2%	6.2%	6.2%	6.2%		
GROSS GENERATION (GWh)	8100	8100	8100	8100	8100	8100	8100	8100	8100	8100	–	–
Load Factor	0.648	0.653	0.657	0.662	0.672	0.673	0.676	0.677	0.681	0.670		
MAXIMUM DEMAND (MW)	1426	1416	1407	1397	1376	1375	1368	1365	1358	1380	–	0.0%
TOTAL GROSS GENERATION 3/	133200	135200	137800	141300	143400	147000	150700	154400	158300	156400	1.3%	1.8%
PSE Forecast 4/	133200	135200	137800	141300	143400	147000	150700	154400	158300	156400		
Correction Factor Used 5/	0.968	1.006	1.008	1.000	1.001	1.002	0.993	0.997	1.000	0.973		
TOTAL MAXIMUM DEMAND (PSE) 6/	23450	23640	23935	24375	24365	24945	25445	26025	26545	26640	–	1.8%
Annual Load Factor 7/	0.648	0.653	0.657	0.662	0.672	0.673	0.676	0.677	0.681	0.670		

1/ Includes 300 GWh "fee" for transit. No exports assumed after 2000.
2/ Mloty pumping is included; this load is estimated as 1067 GWh by 1998 and another 533 GWh by 1999.
3/ Includes domestic requirements plus international energy exchange estimated by PSE.
4/ PSE estimate adjusted to include international energy exchange and Mloty hydro pumping; also excludes 100 GWh unserved energy assumed by PSE after 1994.
5/ This correction factor used to scale the non–fixed items in the disaggregated sales and generation forecast to achieve the PSE total gross generation forecast.
6/ Domestic maximum demand estimated by PSE, including demand related to international energy exchange.
7/ Derived from maximum demand (PSE) and total gross generation (PSE forecast adjusted as noted in 4/ above).

mapping forecast sales by voltage. To approximate the disaggregation, we first calculated the historical percentage share of final sales occurring at each voltage. The shares at each voltage for the year 1991 were then applied to future years to disaggregate final sales over the entire study period.

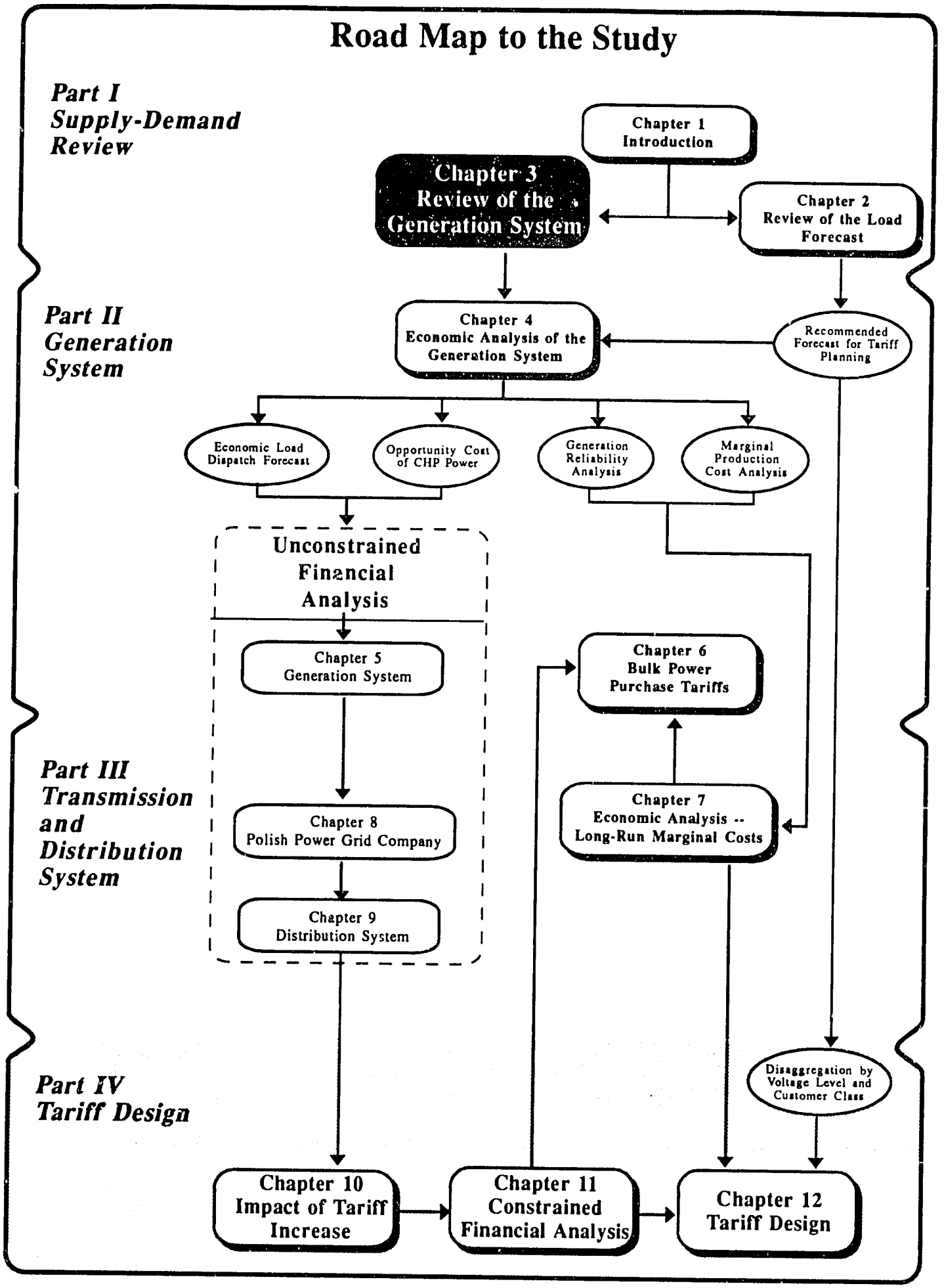
This assumption of constant consumption shares by voltage level is a simplification. The gradual movement of the economy from heavy industry toward services is not captured. Given limited historical data and probable discontinuities between historical and future trends, however, we concluded that forecasting trends would be less reliable (and the bias less clear) than the constant share assumption.

Exhibit 2-8 presents the base case load forecast disaggregated by voltage level and customer class.

Exhibit 2-8: Base Case Forecast
Republic of Poland: PSE "Low" Forecast of Sales by Customer Class (GWh)

		1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Avg Annual Rate (%) 1991-96	Avg Annual Rate (%) 1996-01
INDUSTRY	HV	28229	28158	28146	28410	29054	29752	30180	30746	31637	31506	-0.4%	1.6%
	MV	17844	17799	17791	17958	18365	18807	19077	19435	19998	19915	-0.5%	1.6%
	LV	2914	2907	2906	2933	2999	3071	3116	3174	3266	3252	3.3%	1.6%
	Total	48988	48864	48843	49300	50419	51630	52372	53355	54900	54673	-0.2%	1.6%
TRACTION 1/	HV	155	169	185	204	208	213	215	219	225	225	-	-
	MV	5005	5462	5973	6596	6733	6881	6967	7084	7275	7283	-	-
	Total	5160	5631	6158	6800	6941	7094	7182	7303	7500	7508	7.1%	1.6%
STREET LIGHTS	LV	1375	1448	1527	1627	1676	1730	1768	1815	1882	1883	4.1%	2.4%
COMMERCIAL	MV	1229	1294	1365	1454	1498	1546	1580	1622	1682	1683	4.0%	2.4%
	LV	7963	8382	8841	9417	9705	10015	10237	10509	10896	10902	2.5%	2.4%
	Total	9192	9676	10206	10871	11203	11560	11817	12131	12578	12585	2.7%	2.4%
FARMS	MV	710	747	788	840	865	893	913	937	971	972	4.9%	2.4%
	LV	771[illegible]	8117	8562	9120	9399	9698	9913	10177	10552	10558	4.0%	2.4%
	Total	8422	8865	9351	9960	10264	10591	10826	11114	11523	11530	4.1%	2.4%
RESIDENTIAL	LV	21937	23091	24356	25943	26735	27588	28200	28949	30017	30033	5.1%	2.4%
TOTAL FINAL SALES		95073	97574	100441	104500	107238	110194	112165	114666	118400	118212	2.2%	2.0%
	HV	28384	28327	28331	28614	29262	29965	30395	30965	31862	31731	-0.3%	1.6%
	MV	24788	25302	25917	26847	27461	28127	28536	29077	29926	29852	1.5%	1.7%
	LV	41901	43945	46193	49040	50515	52102	53233	54624	56613	56629	4.2%	2.3%

Road Map to the Study



CHAPTER 3: REVIEW OF THE GENERATION SYSTEM

3.1 OBJECTIVES AND APPROACH

The cost of generating power is the largest single component of the cost of power to the final consumer. This cost is the starting point for both determining a pricing structure based on marginal costs and computing financial revenue requirements.

This chapter examines the current and expected characteristics of power generation in Poland to help determine the major issues affecting the cost of power production. It also contains assumptions about the forecast of investments and operating costs for the medium term as a prelude to the economic and financial analysis of the generation system in Part II of this study.

This chapter first reviews the structure of the existing generating system in terms of power technologies and fuels. Next, it reviews the current development plans and comments on the adequacy of these plans in relation to the demand forecast scenario adopted for this study. Based on the adopted scenario of system development, a set of assumptions is presented with respect to the capital investments and operating costs that were used in the economic and financial analysis of the system. In connection with the adopted development forecast, comments are made on the assumed structure of the generation system and the recommended structure of transfer prices at the generation level.

3.2 EXISTING SYSTEM

3.2.1 The Polish Public Power System

The sources of energy in the Polish power system can be classified into three categories: the public system, autoproducers, and the international exchanges. Although the public power system is of primary concern in this tariff study, the contributions of autoproducers and international exchanges are discussed when relevant.

The generation component of the public power system consists of thermal and hydroelectric powerplants totalling approximately 29,600 MW of installed capacity. Exhibit 3-1 contains a summary of this system, showing that 93.2 percent of the installed capacity is in fossil-fired thermal plants and the rest in hydroelectric stations.

EXHIBIT 3-1

SUMMARY OF THE PUBLIC GENERATION SYSTEM

POLAND – SUMMARY OF THE PUBLIC GENERATION SYSTEM

PLANT NAME	TYPE	FUEL	MEAN UNIT CAPACITY MW	NO. UNITS	NAMEPLATE CAPACITY MW	PEAKING CAPABILITY MW	PERCENT OF SYSTEM CAPABILITY	ANNUAL OPERATING EXPENSES $/KW	FUEL TRANSPO COST $/MWH	1991 PRODUCTION GWH	PERCENT OF GENERATION REQUIREMENTS
1 BELCHATOW	GRID	LIGNITE	360	12	4320	4320	15.4%	11.27	0.00	27213	21.9%
2 PATNOW	GRID	LIGNITE	200	10	2000	2000	7.1%	12.36	0.00	7628	6.1%
3 TUROW	GRID	LIGNITE	200	10	2000	2000	7.1%	28.51	0.00	12035	9.7%
4 ADAMOW	GRID	LIGNITE	120	5	600	480	1.7%	33.90	0.00	2875	2.3%
5 KONIN	GRID	LIGNITE	65	9	583	523	1.9%	30.68	0.00	3148	2.5%
LIGNITE FIRED PUBLIC PLANTS					9503	9323	33.2%			52899	42.6%
6 OSTROLEKA B	GRID	COAL	200	3	600	600	2.1%	20.38	1.91	2864	2.3%
7 KOZIENICE	GRID	COAL	260	10	2600	2600	9.3%	17.94	1.59	7996	6.4%
8 POLANIEC	GRID	COAL	200	8	1600	1600	5.7%	18.80	1.35	7173	5.8%
9 RYBNIK	GRID	COAL	200	8	1600	1600	5.7%	20.95	0.68	9252	7.5%
10 JAWORZNO III	GRID	COAL	200	6	1200	1140	4.1%	25.14	0.71	6302	5.1%
11 DOLNA ODRA	GRID	COAL	200	8	1600	1600	5.7%	17.42	2.09	6856	5.5%
12 LAZISKA	GRID	COAL	173	6	1040	920	3.3%	29.72	0.37	4286	3.5%
13 LAGISZA	GRID	COAL	120	7	840	723	2.6%	24.48	0.85	3423	2.8%
14 SIERSZA	GRID	COAL	123	6	738	630	2.2%	29.17	0.79	3128	2.5%
15 STALOWA WOLA	GRID	COAL	64	6	384	345	1.2%	18.61	1.47	1356	1.1%
COAL FIRED FULLY DISPATCHABLE PLANTS					12202	11758	41.9%			52636	42.4%
FULLY DISPATCHABLE GRID PLANTS					21705	21081	75.2%			105535	85.0%
16 SKAWINA	GRID-C	COAL	79	7	550	495	1.8%	21.07	1.14	1919	1.5%
17 JAWORZNO II	GRID-C	COAL	50	7	350	300	1.1%	22.79	0.87	904	0.7%
18 BLACHOWNIA	GRID-C	COAL	47	6	282	244	0.9%	25.60	1.79	781	0.6%
19 HALEMBA	GRID-C	COAL	50	4	200	200	0.7%	42.33	0.23	769	0.6%
20 JAWORZNO I	GRID-C	COAL	29	5	145	93	0.3%	26.97	0.91	279	0.2%
21 MIECHOWICE	GRID-C	COAL	55	2	110	101	0.4%	30.03	0.04	295	0.2%
22 POMORZANY	GRID-C	COAL	60	2	120	112	0.4%	42.88	3.73	401	0.3%
COLLECTOR TYPE GRID PLANTS					1757	1545	5.5%			5348	4.3%
23 SIEKIERTY	CHP	COAL	125	4	500	619	2.2%	37.68	1.91	1794	1.4%
24 KRAKOW	CHP	COAL	115	4	460	446	1.6%	20.30	1.21	1791	1.4%
25 WROCLAW	CHP	COAL	100	2	200	259	0.9%	26.32	2.60	1089	0.9%
26 SMALLER CHP	CHP	COAL	30	100	2621	2174	7.8%	28.66	2.25	7895	6.4%
COMBINED HEAT AND POWER PLANTS					4160	3498	12.5%			12569	10.1%
PUBLIC THERMAL					27622	26124	93.2%			123452	99.5%
PUBLIC HYDROELECTRIC					2005	1918	6.8%			646	0.5%
TOTAL PUBLIC					29627	28042	100.0%			124098	100.0%

3.2.2 Hydroelectric System

The hydroelectric component consists of three pumped storage plants, two conventional hydroelectric plants with some pumped storage capability, and several smaller run-of-river plants. While the contribution of hydro to meeting the daily peak loads is important, Poland's total net hydroelectric production is very small. The hydro system is virtually a mechanism for shifting loads during the day, thereby minimizing load fluctuations on the thermal system and maintaining primary control in the system.

3.2.3 Thermal System

There are 55 thermal generating plants in Poland. All of them consist of steam turbines burning primarily either lignite or hard coal, and many of these plants are also used in a cogeneration cycle to supply heat to local district heating networks. Thermal plants are classified into one of three categories depending in the extent of the cogeneration process and the steam path between boilers and generators. In this study, we refer to these three categories as conventional grid plants, collector grid plants, and combined heat and power (CHP) plants. English translations of Polish documents also refer to conventional grid plants as "professional" plants or "system" grid plants.

The classification above is relevant to the objectives of the electricity pricing study because there are important differences in the institutional, operational and economic aspects of each type of plant. Grid plants, both conventional and collector, can be considered to lie entirely within the power sub-sector, while CHP plants are shared between the power and heating sub-sectors.

Conventional Grid Plants

This category of thermal plants is by far the most important in terms of power production. Conventional grid plants have a conventional arrangement of blocks or units consisting of one boiler dedicated to its own specific turbine-generator set. Some units in conventional grid plants are connected to heating networks through the removal of steam from the low-pressure segment of the turbine. This is a very efficient link because it allows the utilization of heat that would otherwise be largely wasted in the condensing process.

The 15 conventional grid plants in Poland account for 85 percent of total energy production. Five of these plants -- Belchatow, Patnow, Turow, Adamow and Konin -- are the only plants

in the system fired with lignite or "brown coal" and are among the country's largest and most economic powerplants. Thus, while lignite plants contribute roughly one-third of total installed capacity, their production amounts to 42.6 percent of the total.

Unit sizes in conventional grid plants vary between less than 10 MW and 500 MW, but most of the generation is produced by units in the 100 MW to 360 MW range. About half the capacity is in 200 MW units, making this the most representative unit size in the system.

All lignite- and coal-fired units must use small amounts of residual oil or natural gas during startup and when operating at very low output. Two blocks (boiler-turbine-generator) of the ten blocks installed in Patnow are currently fuelled with No. 6 residual fuel oil or "mazout," but there are plans for converting these to burn lignite.

Collector Grid Plants

There is no clear technical difference between a collector grid plant and a CHP plant. In both cases, the steam from several boilers is used partly for power and partly to maintain temperature and pressure in a district heating network. Also, some boilers may be exclusively dedicated to the heating network and some may be exclusively dedicated to power generation. In any case, many parts of these facilities are used for both purposes; thus, investments and operating costs are shared between the two products, power and heat.

From an institutional point of view, it is important to establish that the primary product of a collector plant is power, while the primary product of a CHP plant is heat. As such, collector plants would be expected to remain controlled by the power sub-sector through either ownership or regulatory authority, while CHP plants would be controlled by the heat sub-sector.

There are 7 collector grid plants in Poland. They are among the smallest, oldest and most expensive to operate of all grid plants. Therefore, these plants only contribute 4.3 percent of all energy produced in the country.

CHP Plants

Combined heat and power plants (CHP) supply a substantial quantity of heat to district heating networks in comparison to the heat used to supply electricity to the grid.

Many CHP plants in Poland are built for district heating and only subsequently retro-fitted to produce power. This practice generally leads to a less-efficient design than if the plant is essentially using waste heat from power generation as discussed above in the conventional grid plants section. Furthermore, the resulting design limits the flexibility in dispatching power from CHP plants because their power can, in general, be economically produced only when there is demand for the associated heat.

Like collector grid plants, CHP plants are generally small with three notable exceptions: the Siekierty, Krakow and Wroclaw plants are fitted with units in the 100 MW range. As a group, CHP plants contribute 10.1 percent of power generation to the public system, heavily concentrated during the winter heating season.

3.2.4 Current Supply-Demand Balance

With a peak load of approximately 22,000 MW in 1992 and an installed capacity of 29,627 MW, the system currently has a nominal reserve margin of about 35 percent. In addition, up to 1,290 MW are available as surplus power from autoproducers, bringing the nominal reserve to over 40 percent. Eliminating non-firm resources such as auto-producer surplus and including deratings in the existing system brings the total firm reserve margin down to about 27.5 percent.

On a monthly basis, current reserve margin levels fluctuate between 15 and 40 percent due to the monthly variations in peak demand, CHP capacity, and the capacity undergoing planned maintenance. It appears possible to reduce the monthly fluctuation in reserve margin levels by alternative scheduling of planned maintenance. However, this is not necessary at present because minimum reserve levels provide adequate generation reliability at all times.

3.3 GENERATION SYSTEM DEVELOPMENT

3.3.1 Issues

Modernization

A generating system evolves through capacity additions, which are needed to meet increasing demand and to replace old units that are being retired as they become too inefficient, too unreliable, or too costly to maintain. Other changes in the system can take place as a result of one or a combination of the following:

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- Repowering - the addition of capacity to an existing machine by changes in the turbine or generator.

- Redevelopment - changes in the power potential of an existing hydroelectric plant by modifications in water availability, reservoir storage or hydraulic head.

- Life extension - overhaul of older units to increase their reliability and efficiency, thus lowering their operating costs and delaying retirement.

- Fuel conversion - modifications to boiler and fuel supply facilities to take advantage of cheaper fuels or to achieve compliance with emission standards by burning cleaner fuels.

- Environmental control - the addition of emission controls and other facilities to render the plants in compliance with new environmental standards.

In most large systems, these additional changes are small. In Poland, the relatively low demand growth rate expected for the medium term and the introduction of tight environmental control standards are likely to make these changes, collectively called "modernizations," predominant over capacity additions.

Furthermore, programs for the expansion of CHP capacity are largely controlled by forecasts of heat demand growth, but include generation capacity associated with heat production. This further limits the need for additional capacity in system grid plants.

Fuel Issues

Two critical issues affecting the cost of power in Poland are the availability of natural gas as an alternative to expensive emission controls and the future of coal and lignite prices.

Natural gas remains a strong alternative for the future. However, at present, it is difficult to make any firm forecasts of either its price or its availability to the power sector in the vast quantities necessary to displace lignite or coal as a baseload resource.

Poland's coal sector is in crisis. As many as half the nation's coal mines are facing potential shut down because production costs are higher than internal subsidized prices, and in some

cases, border prices. The lignite sector faces mounting environmental standards that threaten to reduce its margin of competitiveness.

Power Sector Restructuring Issues

Under Poland's current policy to liberalize the power sector, it is expected that its generating utilities will follow market (i.e., pricing) forces. Thus, tariff development can only rely on generation plans to the extent that these plans appear stable under economic pricing criteria. Regardless of tariff recommendations, it is the ability of the Polish economy to adjust to these economic pricing criteria that will ultimately determine whether rehabilitations can be made, whether fuels will be available, whether more CHP will be built and, above all, whether the demand will indeed grow as planned.

3.3.2 PPGC Generation Expansion Plan

In December 1991 the Polish Power Grid Company (PPGC) issued a report describing a plan for expanding the generation system. This analysis is now being updated through an ongoing study, but its results are not yet available. A major output of the current review is expected to be the economic ranking of modernization alternatives in the existing system. While this ranking is unlikely to constitute a firm plan of modernization under the decentralization policies, it is indeed possible that such a ranking will to some extent influence the ability of generating companies to secure financing to carry out those plans.

Adopted Scenario

At present, the 1991 analysis by PPGC constitutes the best available reference by which to forecast the medium-term evolution of the system. This analysis was carried out using the Wien Automatic System Planning Package (WASP) over four major scenarios. These scenarios consist of combinations of different load growth assumptions and different conditions of availability of natural gas as a fuel for power generation.

One of these scenarios (Scenario Ic) consists of a combination of low load growth and low availability of natural gas. This scenario was used as a working assumption for this study; minor changes were made to Scenario Ic to reflect the results of the review of the load forecast reported separately (Chapter 2), new information on the generation system obtained

during the data collection efforts, and small differences in modelling the contribution of different resources to meet the load.

Comments to PPGC Expansion Plan

The following is a list of the major assumptions used in PPGC's scenario Ic regarding additions of new capacity and comments on the assumptions adopted in this study with respect to those same resources:

- PPGC assumed in 1991 that the Opole coal-fired power plant currently under construction will add 2,160 MW of capacity between 1992 and 1996. For this study, it has been assumed that the first full year of operation of the first 360 MW unit will be 1994 and that the plant will be completed by 1997.

- PPGC assumed that 350 MW of gas turbines (50 MW unit size) will be added between 1996 and 1998 without further additions until after 2000. For this study, it has been assumed that 300 MW of gas turbines (150 MW unit size) will be added in 1997 followed by one additional 150 MW unit in 2000.

- PPGC assumed that the Czorsztyn hydroelectric power plant (92 MW) will be added by 1995 and that the Mloty pumped storage hydroelectric project (750 MW) will be completed by 1999 followed by another pumped storage project, Roznow II, also of 750 MW. The assumption regarding the Mloty project was retained for the purposes of this study because it appears that this project, complemented with gas turbines, could provide much needed peak energy towards the end of the decade. Other hydroelectric projects were not included because they are not needed for capacity in the medium term.

- PPGC assumed that the CHP development plan, driven by demand from heat, will add 2,340 MW of electric capacity from these plants between now and 2000. This assumption was maintained, but the cost of this power is determined differently, as will be discussed later.

These assumptions refer only to those additions that could have an impact on or before 1997 in terms of operation costs or capital disbursements. PPGC's plan covers a much longer period (to 2010) and the assumptions over the long range are not directly relevant to this study. The only relevant addition in the long term is the first base load unit <u>not</u> belonging to

the already committed Opole project. This is a 370 MW lignite-fired unit (Belchatow II) in 2003. This assumption was retained for our study.

3.3.3 Forecast Demand Supply Balance

Based on the assumed demand forecast and system development scenario, the installed capacity reserve margin in the generation system will fluctuate between an estimated 28 and 33 percent during the period 1993-2000.

In a system of this size, such reserve margins are more than adequate to maintain acceptable reliability. Indeed, the probability of loss of load will average approximately 0.5 percent or much less if international exchanges and other non-firm resources are included.

Another useful measure of system adequacy is the effective thermal capacity reserve margin, which is obtained as the difference between total effective thermal capacity and the peak load to be carried by the thermal system. Effective capacity of a thermal generating unit is the maximum continuous rating (MCR) reduced by the fraction of time that such MCR is expected to be unavailable for maintenance or repair.

In Poland, effective thermal reserve margins are forecast to fluctuate between 8 and 14 percent. Effective reserve margins of less than 5 percent have been found to be adequate on very large systems (over 50,000 MW). Thus, the levels forecast for Poland appear adequate.

3.4 CAPITAL INVESTMENT ASSUMPTIONS

3.4.1 Investments in Modernization

PPGC assumes an extensive plan of rehabilitation in existing power units for the purposes of life extension, efficiency and reliability improvements, and also environmental compliance. According to these plans, between 1992 and 2000 there will be a total of 2,865 MW of capacity undergoing some form of rehabilitation. This includes the conversion to lignite of two units of the Patnow plant, which is currently burning residual oil (mazout), and an extensive plan of modernization of many of the existing 200 MW units. PPGC estimates that all these modernizations will include the addition of flue gas desulfurization devices (FGD) plus improvements in efficiency and reliability. The cost has been estimated by PPGC at US $800/kW or $2,292 million.

Because of the wide spectrum of possibilities and objectives in the rehabilitation of generating units, PPGC has indicated that, during the update of the expansion plan that is now underway, special emphasis will be placed on the analysis and ranking of economically feasible rehabilitation alternatives.

The bulk of the investment in modernizations will take place after 1994 and will thus not directly affect the 1994 tariff levels. It is nonetheless necessary to include an estimate of capital investments in modernizations during the 1993-1997 period. This will allow the establishment of a forecast of financial revenue requirements (Chapter 5) capable of recovering medium-term investments consistent with the emission standards by 1997 and with the most likely modernizations not directly related to compliance with emission standards.

Modernizations for Compliance with Emission Targets

As part of this study, the emission standards set by the Polish Government and the current level of compliance by different plants were reviewed in an effort to estimate the extent of investments in environmental controls required for full compliance. Some of the existing estimates of the benefit/cost ratios of different opportunities for improvements in efficiency, power output, and reliability were also reviewed.

Appendix 3.1 includes a description of the various technologies available, their costs, and the details of the estimated needs of the Polish system. The main conclusions are that about 15,500 MW of current capacity would need sulfur dioxide (SO2) emissions controls, at an estimated cost of US $200/kW and most of existing capacity will need NOx emission controls at an estimated cost of $100/kW. Further, about 465,000 tons/year of dust need controlling, at an estimated cost of $45 to $70/kW. The total estimated cost for bringing the system into full compliance with 1997 emission standards is $6.1 billion.

Modernizations Not Directly Aimed at Environmental Compliance

A review was made of studies conducted recently to assess the needs, costs and benefits of modernization of the largest coal-fired plants. Alternative efforts in modernization include the following major components: steam turbine, generator and excitation system, boiler and auxiliaries. For each of these components, several options were examined and ranked according to an objective function that includes consideration of reduced heat rate, increased availability rate, increased net output, and reduced operating and maintenance cost.

From the review of these studies, it was determined that out of approximately 30 individual types of improvements, four are sufficiently attractive to undertake in most large (120 MW and above) generating units. These are:

- Replace high-pressure turbine blading with modern design and improved seals.
- Replace entire low-pressure turbine.
- Improve insulation in the generator rotors and replace DC exciters with brushless or static exciters.
- Replace boiler ducts in start-up systems.

The cost varies with different types of units, but it is estimated that a package including these improvements could cost approximately $9.6 million for a 200 MW unit or about $48/kW. While more expensive modernizations are possible, it appears unlikely that under the current situation of adequate capacity reserve margin, such modernizations will be found justifiable in the medium term.

The estimated investments in both environmental and non-environmental modernization were incorporated into the financial analysis of individual plants (Chapter 5) by comparing estimated needs with specific rehabilitation investment plans.

3.4.2 New Generation Capacity

Only capacity additions planned up to the year 2000 can be assumed to affect revenue requirements between 1994 and 1997. These are: the Opole project (2,160 MW), the Mloty hydroelectric project (750 MW), three 150 MW gas turbines, and 2,340 MW of electric capacity in CHP plants.

The Opole project is under construction. It has an estimated cost of $1,200/kW or $2,592 million.

The 750 MW Mloty pumped storage project is estimated to require investments of $684/kW, of which $51/kW has already been spent and $633/kW remains to be disbursed, or $475 million.

PPGC estimated the capital cost of gas turbines at $340/kW. This value is consistent with international prices for large gas turbines and was used in this study in connection with units of 150 MW size. Thus, 450 MW of capacity will cost $143 million.

The capital cost of capacity installed in new CHP plants has not been estimated for this study. The pricing of CHP power will be discussed later in this report.

Although not affecting revenue requirements in the medium term, it is relevant to consider the capital cost of baseload generation (the purpose of this will become clear later in the analysis). The next baseload plant in PPGC scenario Ic consists of 370 MW of lignite-fired units; PPGC estimates its cost at $1,330/kW. This value is also considered reasonable for large plants with adequate environmental control facilities.

3.5 OPERATING COSTS ASSUMPTIONS

3.5.1 Operation and Maintenance Costs

The operation and maintenance (O&M) costs of powerplants must include salaries, maintenance contracts, lubricants and replacement of parts, and auxiliary equipment of the generating units. O&M costs do not include fuel and or any annual fixed charges on plant capital costs such as interest on debt, return on equity, depreciation, amortization and taxes. While there are no strict definitions to differentiate between regular maintenance and major rehabilitations, in general terms, any expense that is not related to fuel supply or to the book value of the assets is considered an O&M cost.

Actual cost is currently used to recover O&M expenses in the settlement of accounts between PPGC and generating plants. However, it is policy to move towards some form of cost standardization. It is a major effort to develop detailed guidelines for such a standardization, particularly given the uncertainties about real increases in wages and the additional operating expenses involved in emission reduction. For the purposes of this study, a comparison was made of O&M costs among Polish plants and in relation to comparable plants in other countries. The objective of this exercise was to develop a simple and reasonable assumption of O&M costs in Polish plants at economic level.

Such a comparison is only approximate because accounting practices vary across countries and some important cost items may or may not be included in all cases. Also, there is no uniform unit of measure; in some cases O&M costs are reported as variable costs (i.e., per unit of energy produced), in others they are reported as fixed costs (i.e., per unit of installed

capacity), and more commonly they are reported in both fixed and variable components. For simplicity all O&M costs in this study are defined as fixed costs expressed in equivalent US$ spent annually per installed kW of capacity.

The following is the range of O&M costs in Poland and other countries:

Poland:	11 to 45 US$/kW-Year
Western Europe:	10 to 58 US$/kW-Year
US and Canada:	11 to 40 US$/kW-Year
Australia:	13.6 US$/kW-Year
Japan:	77.5 US$/kW-Year

It appears that current O&M costs in Poland are not unreasonable, except that it will be necessary to keep these costs at current levels in real terms, despite the expected increases in both real wages and emissions reduction. It will be a managerial challenge to maintain costs at current real levels, and the bulk power pricing mechanism must provide the necessary signals.

Within Polish plants there is a fairly strong inverse correlation between unit O&M cost and installed capacity, as shown in Exhibit 3-2. For the purposes of allocating economic O&M costs, plants were classified into one of three groups: below 500 MW, between 500 and 1,000 MW, and above 1,000 MW of installed capacity. O&M costs of $30/kW-Year, $25/kW-Year and $15/kW-Year were assigned to each group, respectively. This is probably too simplistic a system for standard O&M costs, but any formula that is adopted should, on average, yield comparable results.

3.5.2 Fuel Costs

The underlying assumption leading to the adoption of PPGC's scenario Ic (low demand growth and low availability of natural gas) is that while natural gas may eventually prove to be economically available in sufficient quantities for baseload generation, this availability remains too uncertain to be considered in a medium-term analysis. Thus, traditional fuels (lignite and coal) are the only fuels considered for baseload operation. Natural gas is assumed to be available for peaking operation since this mode demands modest quantities of fuel and the only alternative fuel for peaking units, diesel oil, is exceedingly expensive.

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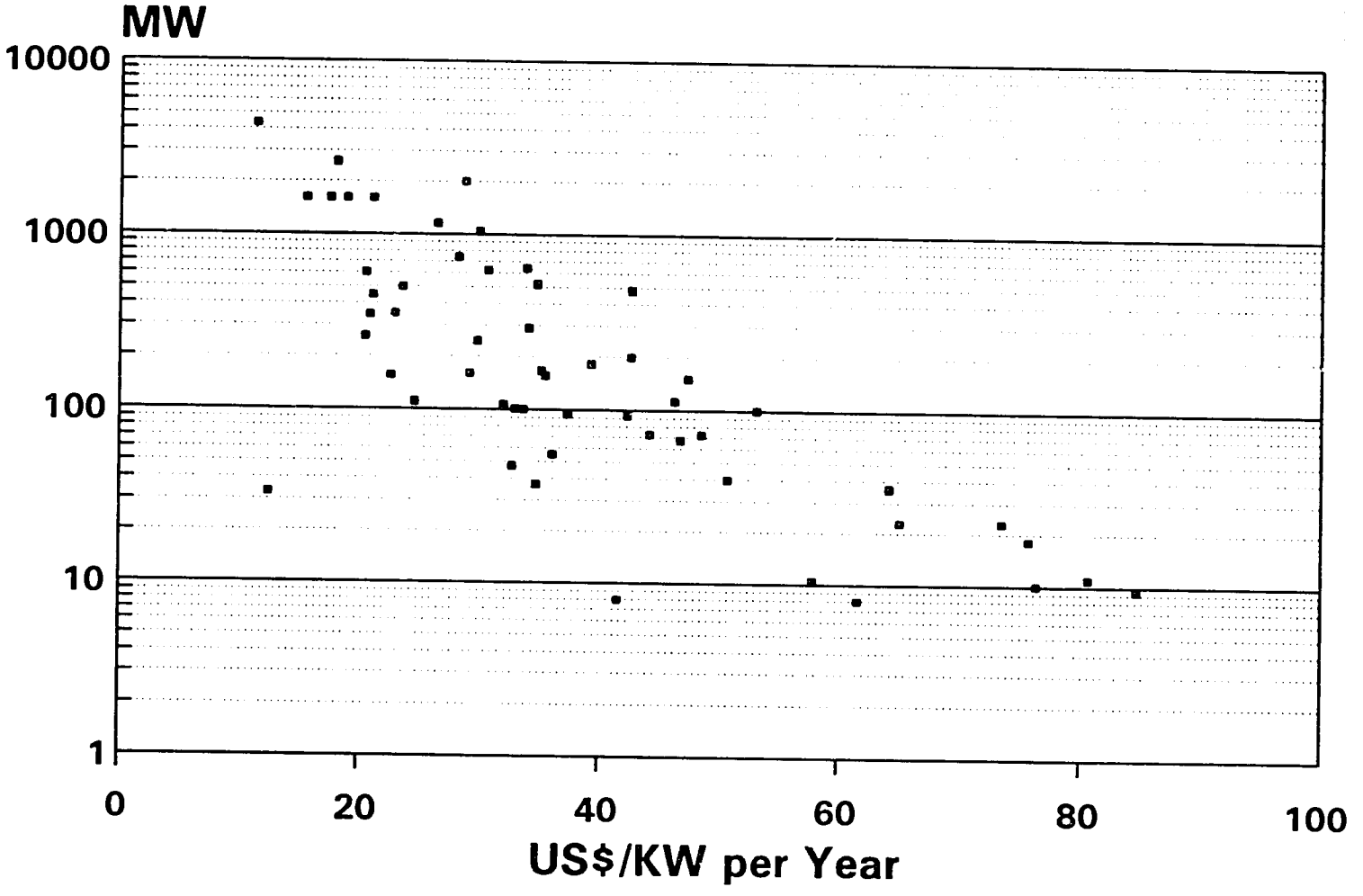
Exhibit 3.2
Operation and Maintenance Costs



RCG/Hagler, Bailly, Inc.

Economic Price of Coal

There is a wide variation in coal prices both in Poland and in the international market. For the purposes of an economic analysis, internal market prices are not relevant. Instead, the economic cost to the Polish economy must be computed on the basis of the world market price of coal delivered to the Polish border (known as the "border" price) plus the cost of inland transportation to the point of use.

We have derived the economic price of coal from two sources: the World Bank's current forecast of the international coal price and PPGC's own estimate of the cost of coal with all subsidies removed.

The World Bank forecast appears as Exhibit 3-3. The US Dollar coal price (FOB, U.S. port of loading) is adjusted for international transport to Poland (CIF port of unloading). The expected 1992 average price is $50.0 per metric tonne. Based on the heat content of the coal used in the Bank estimate, the resulting economic cost is $1.79 $/GJ[1].

PPGC has calculated the non-subsidized cost of coal used at each generating station in 1991. Exhibit 3-4 reports these values for the five largest coal plants. The weighted average cost of coal, excluding transport cost, is 1.24 $/GJ. Increasing this value by domestic inflation to 1992, the resulting economic cost of coal is 1.72 $/GJ. The World Bank annual forecast assumes variable annual real price adjustments (both positive and negative). Due to model constraints, no real price escalation has been assumed in this study.

Based on these two sources, we have assumed an average border cost of 1.79 $/GJ. This cost was further adjusted by the average value of internal transport. Exhibit 3-5 shows that transport adds a weighted average of 12.7 percent to the minemouth coal cost of the 10 largest coal stations.[2] The resulting average delivered economic cost of coal applied for this study is 2.01 $/GJ.

Exhibit 3-6 reports the financial costs of coal and lignite (i.e., contract prices with subsidies) delivered to the five largest generating stations of each type. Escalated to 1992 prices, the average cost of delivered coal is 1.53 $/GJ.

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[1] GJ = 10^9 Joules

[2] As noted above, PPGC has calculated all of these costs exclusive of subsidies, duties, and taxes.

Exhibit 3.3
World Bank Coal Forecast

IBRD Fuel Price Assumptions – Based on 10/92 IBRD Crude Forecast

Calendar Year	COAL/FOB Current $/MT	COAL/FOB CY 85 $/MT	MUV Index Imputed	COAL/FOB CY 92 $/MT	COAL/CIF CY 92 $/MT	COAL CY 92 tysZl/MT	COAL CY 92 $/GJ
1992	41.00	27.00	151.85	41.00	50.00	670.00	1.80
1993	42.00	26.00	161.54	39.48	48.48	649.65	1.74
1994	44.00	27.00	162.96	41.00	50.00	670.00	1.80
1995	46.00	27.00	170.37	41.00	50.00	670.00	1.80
1996	48.83	27.57	177.08	41.87	50.87	681.70	1.83
1997	51.83	28.16	184.05	42.76	51.76	693.65	1.86
1998	55.02	28.76	191.30	43.68	52.68	705.85	1.89
1999	58.41	29.37	198.84	44.61	53.61	718.32	1.92
2000	62.00	30.00	206.67	45.56	54.56	731.04	1.96
2001	64.23	30.00	214.11	45.56	54.56	731.04	1.96
Avg Rate	5.1%	1.2%	3.9%	1.2%	1.0%	1.0%	1.0%
Period	1992–01	1992–01	1992–01	1992–01	1992–01	1992–01	1992–01

NOTES:

13.4 tysZl/$

27.9 GJ/MT Coal

$9.00 estimated Coal transport cost per tonne from USA port of loading to port of European unloading.

Exhibit 3.4
Non–Subsidized Cost of Coal and Lignite by Plant
PPGC Estimates for 1991

	Quantity Consumed MT	Calorific Value kJ/kg	Fuel Cost tysZl/MT	Transport Cost tysZl/MT	Total Cost tysZl/MT	Fuel Cost tysZl/GJ	Total Cost tysZl/GJ	Total Cost $/GJ
Largest Lignite Stations								
EL Belchatow	27213	7633	118.731	0.000	118.731	15.555	15.555	1.161
EL Turow	12035	8949	117.882	0.000	117.882	13.173	13.173	0.983
EL Patnow	7628	9244	135.131	0.000	135.131	14.618	14.618	1.091
EL Konin	3148	9059	135.131	0.000	135.131	14.917	14.917	1.113
EL Adamow	2875	7955	149.431	0.000	149.431	18.785	18.785	1.402
Weighted Average	–	8267	123.547	0.000	123.547	15.015	15.015	1.121
Estimated 1992 Price 1/						20.721	20.721	1.546
Largest Coal Stations								
EC Rybnik	9252	21626	404.349	25.631	429.980	18.697	19.883	1.484
EC Kozienice	7996	21055	393.656	61.427	455.083	18.697	21.614	1.613
EC Polaniea	7173	18980	294.974	48.051	343.025	15.541	18.073	1.349
EC Dolna Odra	6856	21988	390.814	80.726	471.540	17.774	21.445	1.600
EC Jaworzno III	6302	17777	278.950	26.000	304.950	15.692	17.154	1.280
Weighted Average	–	20420	357.698	47.641	405.338	17.422	19.733	1.473
Estimated 1992 Price 1/						24.043	27.232	2.032
LIGNITE : COAL (%)		40%	–	–	–	86%	76%	76%

1/ 1991 prices escalated by 38% (reported annual inflation from 1991 to 1992)
2/ Foreign exchange rate assumed 13.400 tysZl / $

Exhibit 3.5
Non-Subsidized Share of Transport to Total Cost of Coal for Largest Plants
PPGC Estimates for 1991

Coal Station	Quantity Consumed MT	Fuel Cost tysZl/MT	Transport Cost tysZl/MT	Total Cost tysZl/MT	Transport Percent of Fuel Cost
EC Rybnik	9,252	404.349	25.531	429.880	6.3%
EC Kozienice	7,996	393.656	61.427	455.083	15.6%
EC Polaniea	7,173	294.974	48.051	343.025	16.3%
EC Dolna Odra	6,856	390.814	80.726	471.540	20.7%
EC Jaworzno III	6,302	278.950	28.000	306.950	10.0%
EC Ostroleka	2,864	282.901	67.300	350.201	23.8%
EC Laziska	4,286	413.504	13.272	426.776	3.2%
EC Lagisza	3,423	306.996	27.899	334.895	9.1%
EC Siersza	3,128	319.775	24.702	344.477	7.7%
EC Stalowa Wola	1,356	318.780	62.445	381.225	19.6%
Weighted Average	–	**351.619**	**43.868**	**395.487**	**12.7%**

Exhibit 3.6
Subsidized Cost of Coal and Lignite by Plant
PPGC Estimates for 1991

	Quantity Consumed MT	Calorific Value kJ/kg	Fuel Cost tysZl/MT	Transport Cost tysZl/MT	Total Cost tysZl/MT	Fuel Cost tysZl/GJ	Total Cost tysZl/GJ	Total Cost $/GJ
Largest Lignite Stations								
EL Belchatow	27213	7633	84.808	0.000	84.808	11.111	11.111	0.829
EL Turow	12035	8949	84.059	0.000	84.059	9.393	9.393	0.701
EL Patnow	7628	9244	96.522	0.000	96.522	10.442	10.442	0.779
EL Konin	3148	9059	96.522	0.000	96.522	10.655	10.655	0.795
EL Adamow	2875	7955	106.736	0.000	106.736	13.417	13.417	1.001
Weighted Average	–	8267	88.216	0.000	88.216	10.722	10.722	0.800
Estimated 1992 Price 1/						14.796	14.796	1.104
Largest Coal Stations								
EC Rybnik	9252	21626	288.749	26.531	315.280	13.352	14.579	1.088
EC Kozienice	7996	21055	281.190	61.427	342.617	13.355	16.272	1.214
EC Polaniea	7173	18980	210.696	48.051	258.747	11.101	13.633	1.017
EC Dolna Odra	6856	21988	279.153	80.726	359.879	12.696	16.367	1.221
EC Jaworzno III	6302	17777	199.964	26.000	225.964	11.248	12.711	0.949
Weighted Average	–	20420	255.602	47.862	303.464	12.450	14.772	1.102
Estimated 1992 Price 1/						17.182	20.385	1.521
LIGNITE : COAL (%)		40%	–	–	–	86%	73%	73%

1/ 1991 prices escalated by 38% (reported annual inflation from 1991 to 1992)
2/ Foreign exchange rate assumed 13.400 tysZl / $

Economic Price of Lignite

Due to its low heating value per tonne and high sulfur content, lignite does not have a well defined international trading value. As noted above, PPGC has calculated the cost of fuel exclusive of subsidies for all lignite-fired stations. Exhibit 3-4 shows the weighted average share of delivered lignite to coal cost for the five largest plants of each type. The unsubsidized lignite is estimated to cost 76 percent of the delivered cost of coal. This lower price is deemed to be fairly consistent with the additional cost of burning lignite at emission levels comparable to those of coal. This factor was applied to estimate the economic cost of lignite at 1.53 $/GJ.

The subsidized cost of lignite is estimated in Exhibit 3-6 to be 1.11 $/GJ.

Economic Price of Gas

As noted above, there are currently no gas-fired units in Poland, and domestic gas availability is limited. Although many options are being studied, no long-term international supply agreements are in place. Further, no formal gas utilization study has been prepared. Given the limited availability of gas, it is reasonable to assume that it will only be available for higher-value applications.

The price of gas was estimated from our projections of oil product prices, which are derived from the World Bank's current crude forecast. Exhibit 3-7 reports the crude price projection and estimated product price forecasts. We have assumed that mazout is priced at 80 percent of crude and distillate at 140 percent of crude on a heat equivalent basis.

The price of Gas in Germany *exclusive of tax* averaged 87 percent of distillate and 159 percent of mazout on a heat equivalent basis from 1986 through 1990. Applying these percentages to our projected oil product prices, a gas price of 3.27 $/GJ based on mazout and 3.36 $/GJ based on distillate is obtained. Thus, an average gas price of 3.32 $/GJ has been used for this study.

3.5.3 Cost for the Use of the Environment

The Polish Government levies a charge for the release of emissions and the disposal of ash from power plants. At present, this is not a proxy for the actual economic cost of reducing such emissions. Rather, it is a form of tax or internal transfer within the economy.

Exhibit 3.7
CONSTANT PRICE FUEL FORECAST (1992 PRICES)

Year	CRUDE 1992 $/bbl	MAZOUT % CRUDE	MAZOUT $/bbl	MAZOUT $/tonne	MAZOUT tysZl/tonne	MAZOUT $/mmbtu	
1992	17.400000000	80%	13.92000000	87.6960000	1,175.12640	2.18	
1993	17.094736842	80%	13.67578947	86.1574737	1,154.51015	2.14	
1994	17.247368421	80%	13.79789474	86.9267368	1,164.81827	2.16	
1995	17.857894737	80%	14.28631579	90.0037895	1,206.05078	2.23	)
1996	18.403518751	80%	14.72281500	92.7537345	1,242.90004	2.30	2.30) 3-yr avg
1997	18.965813575	80%	15.17265086	95.5877004	1,280.87519	2.37	)
1998	19.545288563	80%	15.63623085	98.5082544	1,320.01061	2.44	
1999	20.142468632	80%	16.11397491	101.5180419	1,360.34176	2.52	
2000	20.757894737	80%	16.60631579	104.6197895	1,401.90518	2.59	
2001	20.788331663	80%	16.63066533	104.7731916	1,403.96077	2.60	

Year	CRUDE 1992 $/bbl	DISTILLATE % CRUDE	DISTILLATE $/bbl	DISTILLATE $/tonne	DISTILLATE tysZl/tonne	DISTILLATE $/mmbtu	
1992	17.400000000	140%	24.36000000	172.9560000	2,317.61040	4.06	
1993	17.094736842	140%	23.93263158	169.9216842	2,276.95057	3.99	
1994	17.247368421	140%	24.14631579	171.4388421	2,297.28048	4.02	)
1995	17.857894737	140%	25.00105263	177.5074737	2,378.60015	4.17	4.16) 3-yr avg
1996	18.403518751	140%	25.76492625	182.9309764	2,451.27508	4.29	)
1997	18.965813575	140%	26.55213901	188.5201869	2,526.17050	4.43	
1998	19.545288563	140%	27.36340399	194.2801683	2,603.35426	4.56	
1999	20.142468632	140%	28.19945609	200.2161382	2,682.89625	4.70	
2000	20.757894737	140%	29.06105263	206.3334737	2,764.86855	4.84	
2001	20.788331663	140%	29.10366433	206.6360167	2,768.92262	4.85	

NOTES:

13.4 tysZl/$

6.4 mmbtu/bbl Mazout

6.3 bbl/tonne Mazout

42.6 mmbtu/tonne Distillate

7.1 bbl/tonne Distillate

0.8 Mazout:Crude price relationship

1.4 Distillate:Crude price relationship

As an internal transfer, this cost item needs to be included in the financial analysis of revenue requirements of the generating system but does not represent an economic cost any more than the income taxes or import duties paid by the power plants. The implication of these taxes for a system of transfer prices based on economic marginal costs will be addressed as part of the next section.

3.6 GENERATION SYSTEM STRUCTURE IN 1994

According to current policy, in 1994 the public generation system will be structured as follows:

- four generating utilities that own and operate the majority of conventional and collector grid plants burning coal
- Three regional lignite authorities that will own and operate all lignite mines and associated conventional grid plants
- CHP plants and some collector grid plants will be independently owned or under the authority of district heating or distribution utilities
- run-of-river hydroelectric plants owned and operated by distribution companies
- pumped storage hydroelectric plants owned and operated by PPGC.

Regardless of their ownership, all plants delivering power to the high-voltage grid (110 kV and above) will be under central dispatch control and subject to PPGC's pricing system. However, any utility or power plant may be allowed to contract directly with a distribution company when such power transfers occur outside the high-voltage grid.

3.7 PRICING PRINCIPLES FOR GENERATION IN 1994

3.7.1 Current System and Issues

The current principle of settlements for power purchases from generators is based in cost recovery. PPGC pays generating plants the actual costs deemed to have been involved in generating power, with some averaging of all plants involved in the computations of asset depreciation. The system involves elaborate accounting of all costs in each plant, and PPGC

is moving towards a system in which a majority of costs are standardized, thereby simplifying power transactions and providing signals for greater efficiency in generation.

One major issue at present is the recovery of fixed costs for capacity that is not essential to the system under the current situation of excessive capacity reserve. This non-essential capacity is the fraction of available capacity in excess of capacity ordered by central dispatch to meet short-term expected demands.

PPGC currently negotiates with each plant the fraction of fixed costs that is allowed to be recovered on non-essential capacity. However, it is unclear whether a similar type of negotiation will take place for the aggregated non-essential capacity of each generating utility.

3.7.2 Recommended Principles

The ideal pricing system for a fully decentralized power sector would be one based entirely on the value of power to the system at any given time. One form of value-based compensation is bidding. In such a system generators quote prices for power and the grid buys what it needs from the cheapest source. An alternative form of value-based compensation is avoided cost pricing. Here, the grid calculates the least cost of producing power and offers to pay that price to the generators.

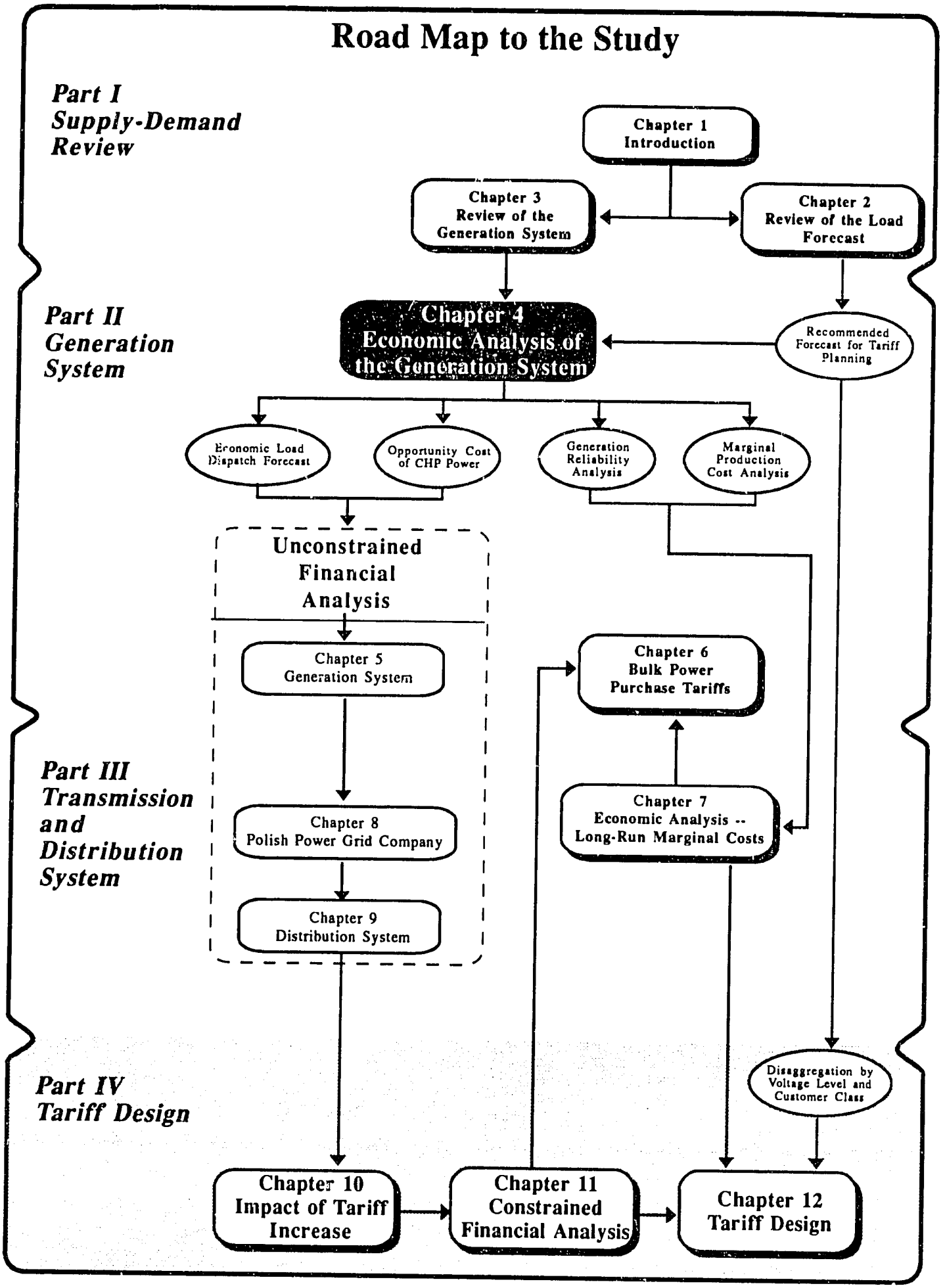
A pure value-based system is possible in Poland and may be desirable at some future time. However, it does not appear to be a practical system for 1994. The Polish generation system evolved under a centrally planned economy in which each individual component was not expected to reflect the optimum economic alternative, but rather, to fit in a plan deemed to maximize benefits across many sectors. It is therefore recommended that a prudent period of time be allowed for utilities and individual power plants to adjust their costs to competitive levels.

Within this constraint, it is possible to move ahead in the standardization of many cost components and to shift entirely to value based-pricing for some specific types of resources. In particular, a value-based system seems very adequate to be applied as early as 1994 to those resources that are not primarily dedicated to the power sector, such as CHP plants and power surplus from autoproducers.

Thus, it is recommended that the majority of power generation (i.e., from conventional grid plants) be purchased on a cost-based pricing basis with increasing reliance on standard costs. The remainder of generation should be based on avoided costs to the system.

These recommended principles will be elaborated on in Chapter 6, which deals with bulk power purchase tariffs.

Road Map to the Study



CHAPTER 4: ECONOMIC ANALYSIS OF THE GENERATION SYSTEM

4.1 OBJECTIVES AND APPROACH

The economic analysis of the generation system was used to develop the following products to be used in making recommendations for bulk power tariffs:

- *The forecast of power production by plant based on economic load dispatch principles.* This forecast was used to determine financial revenue requirements for each plant and generating company, and the generating system as a whole (Chapter 5).

- *The pattern of reliability of the generating system during the year and during different times of the week and the day.* This pattern was used to establish tariff periods to signal to customers the differential economic cost of operating at different times (Chapter 7).

- *The pattern of marginal costs of the generating system during the year and during different times of the week and the day.* This pattern was used to establish the marginal cost pricing level of each tariff period and subsequently, to shape the collection of financial revenue requirements according to a marginal cost structure.

- *The avoided cost of central heat and power (CHP) power to the power system computed through differential economic revenue requirements.* This value was used as a reference in the negotiation of avoided cost tariffs with all sources of power not entirely dedicated to the power sector (Chapter 6).

The approach taken to the economic analysis of the generation system has several steps. First, a detailed reliability analysis was conducted for the generation system, using 1997 as a year representative of the time when economic signals given in 1994 can produce an impact in terms of generation system investments and costs. This analysis provided the basis for selecting pricing periods on which marginal costs need to be determined.

The step was a detailed simulation of the operation of the generation system. Because this simulation meets several needs of both the financial and economic analyses, it needed to be both long term to allow for a determination of long-term avoided costs and plant production forecasts, and have sufficient resolution over each year to determine the operational characteristics of the generating system during each season for which marginal costs are to be differentiated. The

computation of avoided costs usee the same simulation procedure, but under different scenarios of system expansion with and without the CHP component.

The final step was to calculate the marginal production costs of the generation system for every hour of each week representative of the seasons determined above for possible differentiated pricing. These costs were also used to define the marginal cost corresponding to different pricing periods during that week.

4.2 GENERATION RELIABILITY ANALYSIS

The marginal cost of power generation fluctuates with the hourly demand for two reasons:

- the generating units typically are dispatched in order of increasing energy cost
- the higher the load, the more likely it is that it cannot be met by *all* available generating units, resulting in loss of load.

This last effect drives the demand charge or capacity component of a power tariff formula and is generally more sensitive to the demand level than the energy component. Therefore, tariff periods are based on a generation reliability analysis reflecting the capacity component only.

A detailed description of the analysis, the theoretical background, and the software involved is provided in Appendix 4.1. Only the results and the major factors influencing these results are presented in this section.

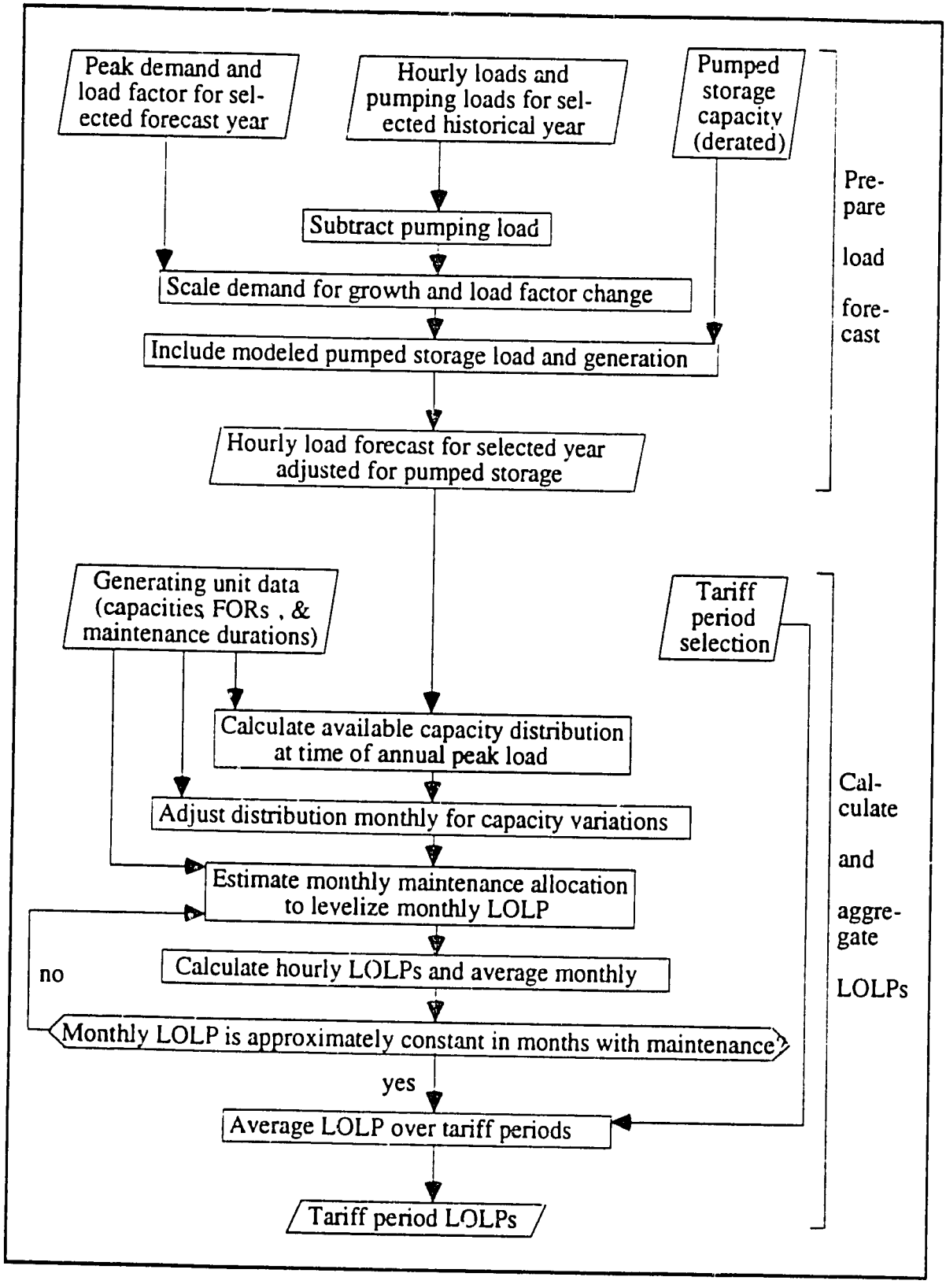
4.2.1 Loss of Load Probability

The generation reliability analysis determines the probability that the demand for power will be in excess of available capacity for each hour of a forecast year. This probability is called "loss-of-load probability," or LOLP.

The average LOLP over a period is called the "period LOLP," and it can be interpreted as the probability of loss of load at a random time in the period. The variation of LOLP over a forecast year is due primarily to the variation of the hourly loads, although it also results from changes in the generation system (typically assumed to occur at most monthly), such as seasonal changes in supply and removals of units for annual maintenance.

Exhibit 4-1 shows the major steps of the analysis for the determination of LOLP.

Exibit 4-1
LOLP Calculation Flowchart



4.2.2 Major Factors Affecting the Determination of LOLP

In addition to load variation, the two most important factors in determining LOLP in the Polish system are the dispatch of pumped storage hydro and the scheduling of planned maintenance of thermal resources. The dispatch of pumped storage affects the distribution of reliability during the day, while the scheduling of planned maintenance of thermal units affects the distribution of reliability over the year. The major conclusions are as follows:

- The current use of pumped storage is consistent with the objectives of keeping system reliability as uniform as possible, but it may be necessary to examine the operation in more detail as predominantly peaking resources, gas turbines and the Mloty project enter the system in the medium term.

- It is possible to minimize variations in reliability throughout the year by the scheduling of planned maintenance in grid plants. Because the current maintenance schedule is probably affected by other constraints, reliability throughout the year is not as smooth as it could be.

4.2.3 Recommended Pricing Periods

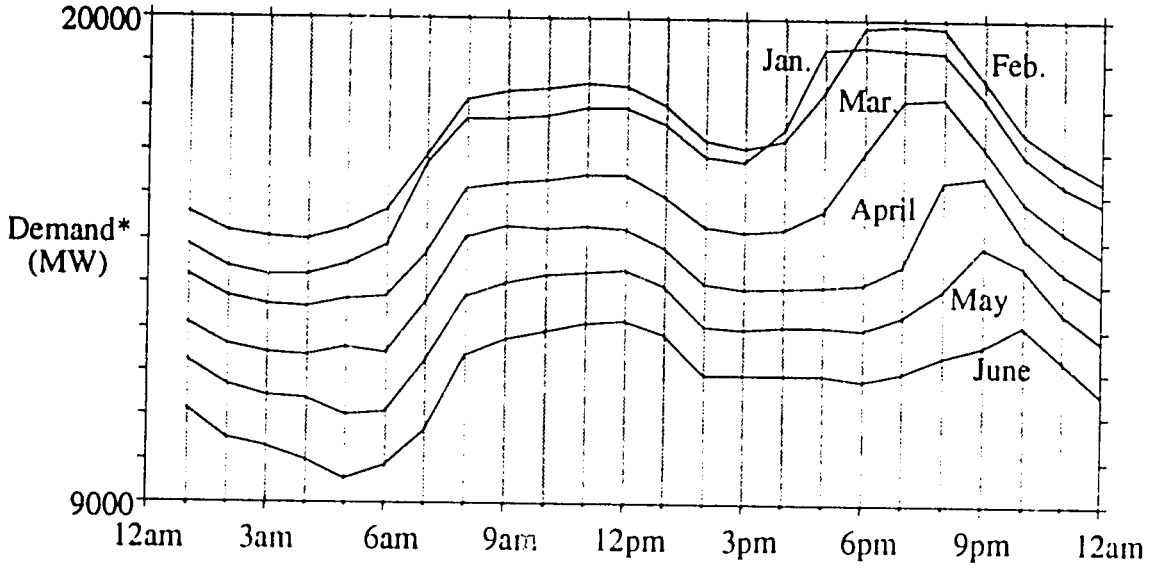
For this study, reliability was analyzed over the forecast loads for the year 1997, with the forecast load shape based on the historical 1991 data summarized in Exhibit 4-2.

Within each day, LOLP is related directly to the loads, after they are adjusted for energy-limited generation such as pumped storage. The relation between LOLP and load shows increasing sensitivity as the load increases (this is shown in Exhibit 4-1). The result is the choice of tariff periods largely determined by daily load shapes and seasonal variations, such as the historical 1991 shapes of Exhibit 4-2.

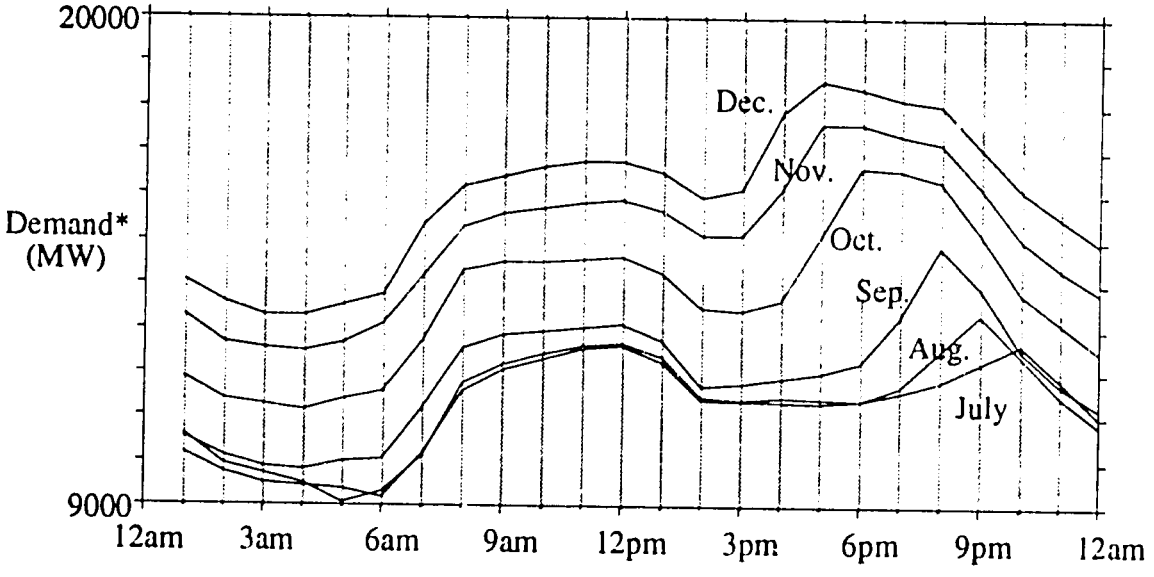
Recent (1989-1991) historical load shapes show a morning peak period of about 8 a.m. to noon and an evening peak period that gradually starts later in the day and is shorter as the summer approaches. Weekend loads are significantly lower than weekday loads, as shown in Exhibit 4-3. The LOLP results confirmed these observations and led to the recommended tariff periods shown in Exhibit 4-4. This exhibit also shows recommended LOLP factors, which are rounded base-case results, to be used in the allocation of demand charges.

The recommended tariff periods divide the year somewhat arbitrarily into two seasons. These serve to reflect changes in the evening on-peak periods rather than changes in overall reliability,

Exhibit 4.2
Average Demand by TOD for each Month of 1991



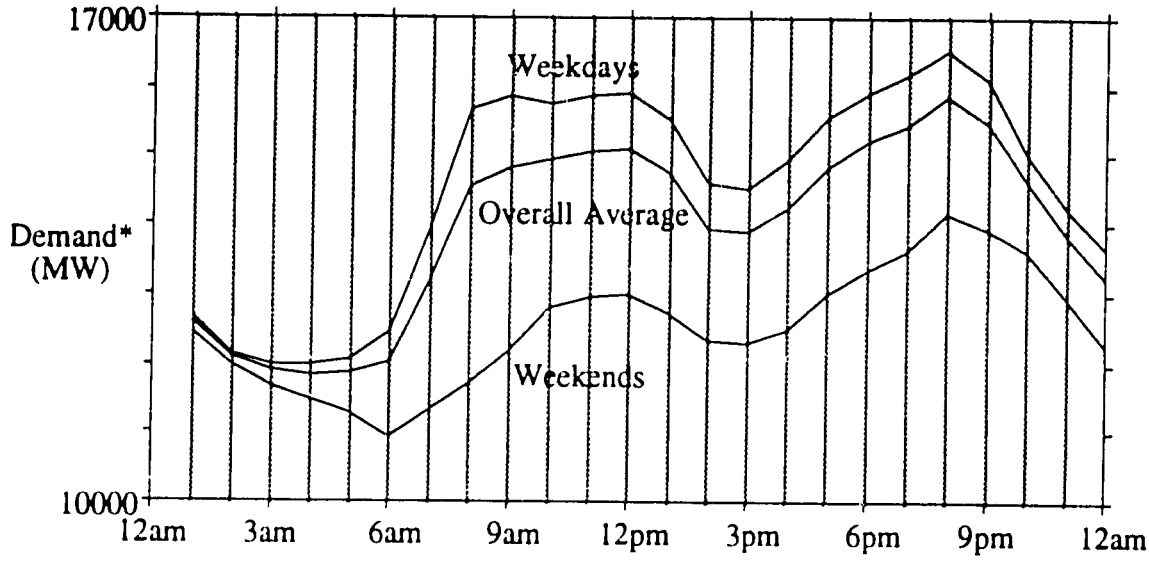
(a) January-June



(b) July-December

* Demand excludes pumping load and autoproducer self-load.

Exhibit 4.3
Average Demand by TOD for Weekdays vs. Weekends in 1991



* Demand excludes pumping load and autoproducer self-load.

Exhibit 4.4
Recommended Rating Periods and Their LOLPs

Season	Morning Peak	Evening Peak	Combined Peak	Off-Peak
Winter = October-March	7am-1pm weekdays: 186%	4pm-9pm weekdays: 395%	Morning + evening periods: 281%	Remainder of week: 12.7%
Summer = April-September	7am-1pm weekdays: 258%	7pm-10pm weekdays: 318%	Morning + evening periods: 278%	Remainder of week: 34.2%

Note: percentages are period LOLPs as a percentage of annual average LOLP, and their weighted average using period lengths as weights equals 100%, except for rounding error.

because the monthly LOLPs are approximately equal across the year (due to the maintenance allocation, modeled as described in the next section). Exhibit 4-4 also shows LOLP factors for the combined morning and evening peak periods, to provide an alternative, simpler tariff structure.

The periods in Exhibit 4-4 are similar to those used for the one-part and two-part tariff classes in a recent price list *(7-Z/92, Electricity SWW 0311, Warsaw 1992)*. However, the on-peak periods of Exhibit 4-4 exclude weekends and are somewhat broader. Also, minor monthly variations among evening on-peak periods within each season are ignored for simplicity.

4.2.4 Sensitivity Analyses

Nine sensitivity cases were studied, including the following:

- different load years
- addition and substraction of 500 MW of base load
- load forecast uncertainty included
- lower forced outage rates in generating units
- no pumping loads included
- historical vs. modelled pumped storage generation.

These analyses showed that the system is fairly insensitive to changes in assumptions, except for those concerning pumped storage operation and hourly load shapes.

Every few years, as the load shapes and generation system evolve (specially with the addition of the Mloty pumped storage plant), the choice of tariff periods and the allocation of costs to them should be reviewed. The computer software tailored for this analysis (see Appendix 4.1) can simplify such reviews.

4.3 SIMULATION OF THE OPERATION OF THE GENERATING SYSTEM

A detailed simulation of the generating system was carried out by PPGC in 1991 during the study of the system expansion plan. For the purposes of the tariff study, this simulation was updated using the model Generation Planning Tools (GPT).

The simulation was carried out for two seasons, summer and winter, of each year in the period 1993-2000. Each simulation (year-season) involves the following steps:

Step 1 - Load Duration Curve Adjustment

The model uses two load duration curves, one for summer and one for winter, obtained from the analysis of historical loads in 1991. The load duration curves are expressed in non-dimensional form; that is, they do not show hours or MW, but merely the fraction of time that a certain fraction of the peak load is exceeded. As such, these load duration curves can be used for any peak load, but the load factor (i.e., the ratio between mean load and peak load for each season) will always be the same as it was in 1991. As discussed in Chapter 2, the forecast includes changes in load factor that need to be addressed when forecasting the production of the generating system. Thus, the first step is to adjust the load duration curves to meet the load factor forecast for each year and season of the simulation.

Step 2 - Dispatch of Energy Limited Resources

Generating resources can be classified into two broad categories according to the mode in which they are dispatched to meet the load: *economically dispatchable* resources and *energy-limited* resources.

A conventional thermal plant can be considered to be a strictly economic resource in the sense that, given that its capacity is available, the only thing that limits the production of the plant is the load to be served and the cost of meeting the load with that plant in relation to other plants in the system. A hydroelectric plant, on the other hand, may produce very cheap energy and may have abundant capacity, but there is a limited amount of water available to produce energy. Thus, its production is at least partially determined by factors outside the dispatch. In between these classical examples there are many other resources that have characteristics common to both. For example, CHP plants in Poland are economically dispatched, but are constrained to produce only the amount of electric energy associated with the demand for heat.

The second step in GPT is to dispatch the energy-limited resources as if they had priority to serve load. The load served by these resources is simply subtracted from the load duration curve, creating a "residual" load duration curve to be supplied from the economically dispatchable resources.

Step 3 - Economically Dispatchable Resources

Each unit in the conventional plants is dispatched from the base to the top of the residual load duration curve in order of increasing variable costs and following the rules of probabilistic

convolution. The rules of probabilistic convolution determine that the production of any unit *i* of capacity *P* dispatched to meet load at a level *X* is a function of the availability of that capacity *P* and also of the shape of the load duration curve transformed by the probability that other units dispatched before unit *i* will be available.

The result is a sequence or "stack" of generating units operating at decreasing capacity factors and increasing cost to produce the energy of the residual load duration curve. It is a feature of the probabilistic dispatch that there is always a finite amount of energy that remains not served. This is called the "expected unserved energy" and is a reliability parameter related to the "loss of load probability" (LOLP) discussed in Section 4.2.

4.3.1 Major Features of the Simulation

For the purposes of the tariff study, the system was modelled by including all hydroelectric plants, autoproducers, and CHP as energy-limited resources and all other plants as economically dispatchable resources. There are several reasons for treating each of those resources in this way; these are discussed below.

Hydroelectric Resources

The loads used in the simulation include the pumping loads forecast in the system. Thus, pumped storage hydro was treated as peak hydro with a limited amount of available energy. Conventional hydro has both peak and base load components and was superimposed on the pumped storage so that both were treated as a single composite hydroelectric resource.

Autoproducers

Autoproducer load was netted out of the load forecast. Thus, only the surplus power from autoproducers was included in the simulation. It is not clear what this output will be in the future but it is currently being purchased directly by the distribution companies, and is, in effect, "invisible" to the dispatch process. It was therefore adequate to represent it as an energy-limited resource with base and peak load components.

CHP

CHP power is currently very much a dispatchable resource in spite of the limitations resulting from the association of CHP electric production and the demand for heat. However, there are two important factors weighing in favor of modelling this resource as energy limited:

- The economics of power and heat production from CHP plants are strongly interdependent, even though some CHP plants have power-dedicated boilers. The demand for heat is external to the power production process but acts as a constraint on how much power can be economically produced by the CHP plant.

- The representation of CHP dispatch constraints is much more accurate if treated as a limited energy resource.

Economic Dispatch Criterion

The dispatch was performed using a set of rules that are closely linked to the assumptions made in connection with economic cost standards, as discussed in Chapter 3. These include:

- All plants using the same type of fuel have the same fuel cost, and this cost is deemed to be the opportunity cost or border price of the fuel.

- Operation and maintenance costs are normalized as a function of plant size.

- Environmental costs are not included in determining the ranking order of dispatch, because it is not clear that these represent true economic costs in the sense that a dispatch based the variable costs that would result may not provide a dispatch that leads to the best allocation of economic resources.

4.3.2 Results of the Simulation

A detailed report of the simulation is presented in Appendix 4.2 and contains the actual input and output files of the computer model GPT.

The input file (Section A.4.2.1 of Appendix 4.2) contains a large number of comments describing the use of each value in the file and comments specific to the sources of data and the modelling assumptions. Nevertheless, this is only included as a reference and it is not necessary for the understanding of the results.

The output file (Section A.4.2.2 of Appendix 4.2) contains the results of summer and winter for each year of the 1993-2000 period. The output for each season and year is organized according to Steps 1, 2 and 3 described in Section 4.3.1. The last step shows the entire stack of generating units as they are dispatched with progressively less capacity factor and higher variable costs. A sample of that output is reproduced in Exhibit 4-5 to illustrate the source of two pieces of information that will be discussed later in the analysis:

- The production of each unit is obtained from this output and aggregated by plant for use in the financial analysis of revenue requirements.

- The composition of the stack of generating units, the derated capacity of each unit, the forced outage rate, and the variable production cost of each unit are utilized in the development of a table of marginal cost as a function of load level.

4.4 ANALYSIS OF SHORT-RUN MARGINAL COSTS

The short-run marginal cost (SRMC) is the cost of supplying one increment of energy without any change in the available capacity of the system. When calculated for a system in dynamic equilibrium between load growth and capacity additions, the SRMC becomes the energy component of the marginal cost of generation and, together with the capacity cost and system losses, constitutes the long-run marginal cost (LRMC), which is discussed in Chapter 7.

The objective of this analysis was to define the SRMC for the pricing periods that were determined through the reliability analysis described above in Section 4.2. The year 1997 was selected as a basis for determining LRMC because it is the year when any pricing policies will begin to impact upon the long-term evolution of the system. The analysis was carried out for 1997 and also for 1993 in order to illustrate any differences between the system today and the anticipated characteristics in 1997.

To determine the SRMC for each of the different pricing periods, it was necessary first to compute the hourly SRMC for an entire week representative of each of the different pricing seasons. The problem was to find a week that is representative of the season in every respect, including average load, peak load, and minimum load. Thus, Section 4.2.1 deals with the selection and adjustment of hourly loads prior to the determination of SRMC.

One of the challenges of the SRMC analysis was to take into account the many different conditions that the generating units may experience at any given time because of planned and forced outages. This aspect is examined in detail in Section 4.2.2.

EXHIBIT 4.5

SAMPLE RESULTS OF THE DETAILED SIMULATION OF THE GENERATION SYSTEM FOR 1997

STACK LEVEL MW	LOAD POINT MW	GENERATOR TYPE & NAME	NET RATED MW	P.MAIN. DERATED MW	FORCED OUTAGE %	EFFECTIVE CAPACITY MW	ENERGY OUTPUT GWH	CAPAC. FACTOR %	CAPITAL ANNUITY M$	FIXED O & M M$	VARIABLE O & M M$	FUEL COST M$	TOTAL COST M$	FIXED CHARGE $/KW	VARIABLE CHARGE cts/KWH
1	160	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
2	320	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
3	480	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
4	640	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
5	800	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
6	960	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
7	1120	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
8	1280	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
9	1568	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
10	1856	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
11	2144	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
12	2432	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
13	2720	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
14	3008	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
15	3296	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
16	3584	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
17	3872	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
18	4160	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
19	4448	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
20	4736	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
21	4896	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
22	5056	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
23	5216	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
24	5376	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
25	5536	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
26	5696	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
27	5856	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
28	6016	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
29	6112	4 SL-KO-100	120.0	96.3	12.10	84.7	385.00	73.25	.00	1.50	.00	6.61	8.11	12.500	1.717
30	6208	4 SL-KO-100	120.0	96.3	12.10	84.7	385.00	73.25	.00	1.50	.00	6.61	8.11	12.500	1.717
31	6293	17 SC-ST-100	106.0	85.1	11.20	75.6	311.16	67.02	.00	1.59	.00	5.54	7.13	15.000	1.782
32	6378	17 SC-ST-100	106.0	85.1	11.20	75.6	311.16	67.02	.00	1.59	.00	5.54	7.13	15.000	1.782
33	6404	21 SC-ST-000	33.0	26.5	10.00	23.8	78.84	54.55	.00	.50	.00	1.40	1.90	15.000	1.782
34	6430	21 SC-ST-000	33.0	26.5	10.00	23.8	78.84	54.55	.00	.50	.00	1.40	1.90	15.000	1.782
35	6456	21 SC-ST-000	33.0	26.5	10.00	23.8	78.84	54.55	.00	.50	.00	1.40	1.90	15.000	1.782
36	6514	5 SL-AD-100	96.0	59.0	15.80	49.7	221.28	52.63	.00	1.44	.00	3.98	5.42	15.000	1.799
37	6572	5 SL-AD-100	96.0	59.0	15.80	49.7	221.28	52.63	.00	1.44	.00	3.98	5.42	15.000	1.799
38	6630	5 SL-AD-100	96.0	59.0	15.80	49.7	221.28	52.63	.00	1.44	.00	3.98	5.42	15.000	1.799
39	6688	5 SL-AD-100	96.0	59.0	15.80	49.7	221.28	52.63	.00	1.44	.00	3.98	5.42	15.000	1.799
40	6746	5 SL-AD-100	96.0	59.0	15.80	49.7	221.28	52.63	.00	1.44	.00	3.98	5.42	15.000	1.799
41	6778	6 SL-KO-000	40.0	32.1	13.00	27.9	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
42	6810	6 SL-KO-000	40.0	32.1	13.00	27.9	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
43	6842	6 SL-KO-000	40.0	32.1	13.00	27.9	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919

EXHIBIT 4.5 (Cont.)

SAMPLE RESULTS OF THE DETAILED SIMULATION OF THE GENERATION SYSTEM FOR 1997

STACK LEVEL MW	LOAD POINT MW	GENERATOR TYPE	& NAME	NET RATED MW	P.MAIN. DERATED MW	FORCED OUTAGE %	EFFECTIVE CAPACITY MW	ENERGY OUTPUT GWH	CAPAC. FACTOR %	CAPITAL ANNUITY M$	FIXED O & M M$	VARIABLE O & M M$	FUEL COST M$	TOTAL COST M$	FIXED CHARGE $/KW	VARIABLE CHARGE cts/KWH
44	6874	6	SL-KO-000	40.0	32.1	13.00	27.9	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
45	6906	6	SL-KO-000	40.0	32.1	13.00	27.9	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
46	6938	6	SL-KO-000	40.0	32.1	13.00	27.9	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
47	6982	28	SC-PO-000	56.0	45.0	12.30	39.4	153.65	62.64	.00	.84	.00	2.96	3.80	15.000	1.929
48	7142	15	SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
49	7302	15	SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
50	7462	15	SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
51	7622	15	SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
52	7782	15	SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
53	7942	15	SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
54	8102	15	SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
55	8262	15	SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
56	8630	7	SC-KO-500	500.0	368.5	30.00	257.9	1103.76	50.40	.00	6.25	.00	22.02	28.27	12.500	1.995
57	8998	7	SC-KO-500	500.0	368.5	30.00	257.9	1103.76	50.40	.00	6.25	.00	22.02	28.27	12.500	1.995
58	9286	8	SC-OP-360	360.0	289.0	10.80	257.8	1093.94	69.38	.00	2.70	.00	21.82	24.52	7.500	1.995
59	9574	8	SC-OP-360	360.0	289.0	10.80	257.8	1093.75	69.37	.00	2.70	.00	21.82	24.52	7.500	1.995
60	9862	8	SC-OP-360	360.0	289.0	10.80	257.8	1092.45	69.28	.00	2.70	.00	21.79	24.49	7.500	1.995
61	10150	8	SC-OP-360	360.0	289.0	10.80	257.8	1088.21	69.01	.00	2.70	.00	21.71	24.41	7.500	1.995
62	10438	8	SC-OP-360	360.0	289.0	10.80	257.8	1079.40	68.46	.00	2.70	.00	21.53	24.23	7.500	1.995
63	10726	8	SC-OP-360	360.0	289.0	10.80	257.8	1065.85	67.60	.00	2.70	.00	21.26	23.96	7.500	1.995
64	10886	11	SC-PO-200	200.0	160.5	7.10	149.1	626.79	71.55	.00	1.50	.00	12.52	14.02	7.500	1.997
65	11046	11	SC-PO-200	200.0	160.5	7.10	149.1	620.29	70.81	.00	1.50	.00	12.39	13.89	7.500	1.997
66	11206	11	SC-PO-200	200.0	160.5	7.10	149.1	613.33	70.02	.00	1.50	.00	12.25	13.75	7.500	1.997
67	11366	11	SC-PO-200	200.0	160.5	7.10	149.1	605.87	69.16	.00	1.50	.00	12.10	13.60	7.500	1.997
68	11526	11	SC-PO-200	200.0	160.5	7.10	149.1	597.74	68.24	.00	1.50	.00	11.94	13.44	7.500	1.997
69	11686	11	SC-PO-200	200.0	160.5	7.10	149.1	588.71	67.20	.00	1.50	.00	11.76	13.26	7.500	1.997
70	11846	11	SC-PO-200	200.0	160.5	7.10	149.1	578.61	66.05	.00	1.50	.00	11.56	13.06	7.500	1.997
71	12006	11	SC-PO-200	200.0	160.5	7.10	149.1	567.36	64.77	.00	1.50	.00	11.33	12.83	7.500	1.997
72	12166	12	SC-RY-200	200.0	160.5	10.80	143.2	533.01	60.85	.00	1.50	.00	11.01	12.51	7.500	2.066
73	12326	12	SC-RY-200	200.0	160.5	10.80	143.2	521.13	59.49	.00	1.50	.00	10.76	12.26	7.500	2.066
74	12486	12	SC-RY-200	200.0	160.5	10.80	143.2	509.17	58.12	.00	1.50	.00	10.52	12.02	7.500	2.066
75	12646	12	SC-RY-200	200.0	160.5	10.80	143.2	497.65	56.81	.00	1.50	.00	10.28	11.78	7.500	2.066
76	12806	12	SC-RY-200	200.0	160.5	10.80	143.2	487.09	55.60	.00	1.50	.00	10.06	11.56	7.500	2.066
77	12966	12	SC-RY-200	200.0	160.5	10.80	143.2	477.86	54.55	.00	1.50	.00	9.87	11.37	7.500	2.066
78	13126	12	SC-RY-200	200.0	160.5	10.80	143.2	470.18	53.67	.00	1.50	.00	9.71	11.21	7.500	2.066
79	13286	12	SC-RY-200	200.0	160.5	10.80	143.2	464.01	52.97	.00	1.50	.00	9.58	11.08	7.500	2.066
80	13430	14	SC-LZ-200	180.0	144.5	13.40	125.1	390.27	49.50	.00	2.25	.00	8.22	10.47	12.500	2.106
81	13574	14	SC-LZ-200	180.0	144.5	13.40	125.1	387.29	49.12	.00	2.25	.00	8.16	10.41	12.500	2.106
82	13718	14	SC-LZ-200	180.0	144.5	13.40	125.1	384.59	48.78	.00	2.25	.00	8.10	10.35	12.500	2.106
83	13862	14	SC-LZ-200	180.0	144.5	13.40	125.1	381.89	48.44	.00	2.25	.00	8.04	10.29	12.500	2.106
84	13942	16	SC-LZ-100	100.0	80.3	16.20	67.3	209.96	47.94	.00	1.25	.00	4.42	5.67	12.500	2.106
85	14022	16	SC-LZ-100	100.0	80.3	16.20	67.3	208.98	47.71	.00	1.25	.00	4.40	5.65	12.500	2.106
86	14182	9	SC-OS-200	200.0	160.5	11.60	141.9	437.19	49.91	.00	2.50	.00	9.23	11.73	12.500	2.111
87	14342	9	SC-OS-200	200.0	160.5	11.60	141.9	431.31	49.24	.00	2.50	.00	9.11	11.61	12.500	2.111

EXHIBIT 4.5 (Cont.)

SAMPLE RESULTS OF THE DETAILED SIMULATION OF THE GENERATION SYSTEM FOR 1997

STACK LEVEL MW	LOAD POINT MW	GENERATOR TYPE	& NAME	NET RATED MW	P.MAIN. DERATED MW	FORCED OUTAGE %	EFFECTIVE CAPACITY MW	ENERGY OUTPUT GWH	CAPAC. FACTOR %	CAPITAL ANNUITY M$	FIXED O & M M$	VARIABLE O & M M$	FUEL COST M$	TOTAL COST M$	FIXED CHARGE $/KW	VARIABLE CHARGE cts/KWH
88	14420	9	SC-OS-200	200.0	160.5	11.60	141.9	424.15	48.42	.00	2.50	.00	8.95	11.45	12.500	2.111
89	14420	10	SC-KO-200	200.0	160.5	11.70	141.8	415.16	47.39	.00	1.50	.00	8.76	10.26	7.500	2.111
90	14420	10	SC-KO-200	200.0	160.5	11.70	141.8	405.27	46.26	.00	1.50	.00	8.56	10.06	7.500	2.111
91	14420	10	SC-KO-200	200.0	160.5	11.70	141.8	393.94	44.97	.00	1.50	.00	8.32	9.82	7.500	2.111
92	14420	10	SC-KO-200	200.0	160.5	11.70	141.8	381.06	43.50	.00	1.50	.00	8.04	9.54	7.500	2.111
93	14420	10	SC-KO-200	200.0	160.5	11.70	141.8	366.39	41.82	.00	1.50	.00	7.74	9.24	7.500	2.111
94	14420	10	SC-KO-200	200.0	160.5	11.70	141.8	349.56	39.90	.00	1.50	.00	7.38	8.88	7.500	2.111
95	14420	10	SC-KO-200	200.0	160.5	11.70	141.8	330.21	37.70	.00	1.50	.00	6.97	8.47	7.500	2.111
96	14420	10	SC-KO-200	200.0	160.5	11.70	141.8	308.04	35.16	.00	1.50	.00	6.50	8.00	7.500	2.111
97	14420	13	SC-J3-200	190.0	152.5	10.70	136.2	286.21	34.39	.00	1.42	.00	6.06	7.49	7.500	2.119
98	14420	13	SC-J3-200	190.0	152.5	10.70	136.2	257.94	31.00	.00	1.42	.00	5.46	6.89	7.500	2.119
99	14420	13	SC-J3-200	190.0	152.5	10.70	136.2	227.66	27.36	.00	1.42	.00	4.82	6.25	7.500	2.119
100	14420	13	SC-J3-200	190.0	152.5	10.70	136.2	196.36	23.60	.00	1.42	.00	4.16	5.59	7.500	2.119
101	14420	13	SC-J3-200	190.0	152.5	10.70	136.2	165.23	19.85	.00	1.42	.00	3.50	4.93	7.500	2.119
102	14420	13	SC-J3-200	190.0	152.5	10.70	136.2	135.46	16.28	.00	1.42	.00	2.87	4.29	7.500	2.119
103	14420	18	SC-LG-100	103.0	82.7	11.90	72.8	56.93	12.62	.00	1.29	.00	1.28	2.56	12.500	2.242
104	14420	18	SC-LG-100	103.0	82.7	11.90	72.8	50.59	11.21	.00	1.29	.00	1.13	2.42	12.500	2.242
105	14420	18	SC-LG-100	103.0	82.7	11.90	72.8	44.65	9.90	.00	1.29	.00	1.00	2.29	12.500	2.242
106	14420	18	SC-LG-100	103.0	82.7	11.90	72.8	39.14	8.68	.00	1.29	.00	.88	2.17	12.500	2.242
107	14420	18	SC-LG-100	103.0	82.7	11.90	72.8	34.06	7.55	.00	1.29	.00	.76	2.05	12.500	2.242
108	14420	18	SC-LG-100	103.0	82.7	11.90	72.8	29.44	6.53	.00	1.29	.00	.66	1.95	12.500	2.242
109	14420	18	SC-LG-100	103.0	82.7	11.90	72.8	25.27	5.60	.00	1.29	.00	.57	1.85	12.500	2.242
110	14420	19	SC-SI-100	105.0	84.3	11.60	74.5	21.61	4.70	.00	1.31	.00	.49	1.80	12.500	2.264
111	14420	19	SC-SI-100	105.0	84.3	11.60	74.5	18.27	3.97	.00	1.31	.00	.41	1.73	12.500	2.264
112	14420	19	SC-SI-100	105.0	84.3	11.60	74.5	15.34	3.34	.00	1.31	.00	.35	1.66	12.500	2.264
113	14420	19	SC-SI-100	105.0	84.3	11.60	74.5	12.79	2.78	.00	1.31	.00	.29	1.60	12.500	2.264
114	14420	19	SC-SI-100	105.0	84.3	11.60	74.5	10.59	2.30	.00	1.31	.00	.24	1.55	12.500	2.264
115	14420	19	SC-SI-100	105.0	84.3	11.60	74.5	8.71	1.89	.00	1.31	.00	.20	1.51	12.500	2.264
116	14420	22	SC-SK-000	45.0	36.1	10.40	32.4	3.81	1.94	.00	.68	.00	.09	.77	15.000	2.423
117	14420	22	SC-SK-000	45.0	36.1	10.40	32.4	3.43	1.74	.00	.68	.00	.08	.76	15.000	2.423
118	14420	22	SC-SK-000	45.0	36.1	10.40	32.4	3.08	1.57	.00	.68	.00	.07	.75	15.000	2.423
119	14420	24	SC-BL-000	41.0	32.9	10.70	29.4	2.76	1.54	.00	.62	.00	.07	.68	15.000	2.516
120	14420	25	SC-HA-000	50.0	40.1	11.80	35.4	2.44	1.11	.00	.75	.00	.06	.81	15.000	2.532
121	14420	25	SC-HA-000	50.0	40.1	11.80	35.4	2.18	1.00	.00	.75	.00	.06	.81	15.000	2.532
122	14420	25	SC-HA-000	50.0	40.1	11.80	35.4	1.95	.89	.00	.75	.00	.05	.80	15.000	2.532
123	14420	25	SC-HA-000	50.0	40.1	11.80	35.4	1.74	.79	.00	.75	.00	.04	.79	15.000	2.532
124	14420	23	SC-J2-000	43.0	34.5	10.40	30.9	1.57	.84	.00	.64	.00	.04	.69	15.000	2.684
125	14420	23	SC-J2-000	43.0	34.5	10.40	30.9	1.40	.74	.00	.64	.00	.04	.68	15.000	2.684
126	14420	23	SC-J2-000	43.0	34.5	10.40	30.9	1.24	.66	.00	.64	.00	.03	.68	15.000	2.684
127	14420	23	SC-J2-000	43.0	34.5	10.40	30.9	1.09	.58	.00	.64	.00	.03	.67	15.000	2.684
128	14420	23	SC-J2-000	43.0	34.5	10.40	30.9	.96	.51	.00	.64	.00	.03	.67	15.000	2.684
129	14420	23	SC-J2-000	43.0	34.5	10.40	30.9	.85	.45	.00	.64	.00	.02	.67	15.000	2.684
130	14420	23	SC-J2-000	43.0	34.5	10.40	30.9	.75	.40	.00	.64	.00	.02	.67	15.000	2.684
131	14420	27	SC-MI-000	50.0	40.1	11.80	35.4	.64	.29	.00	.75	.00	.02	.77	15.000	2.759

EXHIBIT 4.5 (Cont.)

SAMPLE RESULTS OF THE DETAILED SIMULATION OF THE GENERATION SYSTEM FOR 1997

STACK LEVEL MW	LOAD POINT MW	GENERATOR TYPE & NAME	NET RATED MW	P.MAIN. DERATED MW	FORCED OUTAGE %	EFFECTIVE CAPACITY MW	ENERGY OUTPUT GWH	CAPAC. FACTOR %	CAPITAL ANNUITY M$	FIXED O & M M$	VARIABLE O & M M$	FUEL COST M$	TOTAL COST M$	FIXED CHARGE $/KW	VARIABLE CHARGE cts/KWH
132	14420	27 SC-MI-000	50.0	40.1	11.80	35.4	.56	.26	.00	.75	.00	.02	.77	15.000	2.759
133	14420	27 SC-MI-000	50.0	40.1	11.80	35.4	.50	.23	.00	.75	.00	.01	.76	15.000	2.759
134	14420	26 SC-J1-000	19.0	15.3	15.70	12.9	.21	.26	.00	.28	.00	.01	.29	15.000	2.820
135	14420	26 SC-J1-000	19.0	15.3	15.70	12.9	.20	.24	.00	.28	.00	.01	.29	15.000	2.820
136	14420	26 SC-J1-000	19.0	15.3	15.70	12.9	.19	.23	.00	.28	.00	.01	.29	15.000	2.820
137	14420	26 SC-J1-000	19.0	15.3	15.70	12.9	.18	.21	.00	.28	.00	.00	.29	15.000	2.820
138	14420	26 SC-J1-000	19.0	15.3	15.70	12.9	.17	.20	.00	.28	.00	.00	.29	15.000	2.820
139	14420	26 SC-J1-000	19.0	15.3	15.70	12.9	.15	.19	.00	.28	.00	.00	.29	15.000	2.820
140	14420	31 CG-XX-120	120.0	109.5	12.00	96.3	.65	.12	3.07	.90	.00	.03	4.00	33.064	4.637
141	14420	31 CG-XX-120	120.0	109.5	12.00	96.3	.46	.09	3.07	.90	.00	.02	3.99	33.064	4.637

4.4.1 Selection and Adjustment of Hourly Loads

There is no single answer to the question of what week must be chosen as representative of a particular season in order to define the SRMC for different pricing periods. The following are some of the most attractive possibilities:

Peak Week of the Season

This week has the advantage that it includes the hour of highest demand and therefore will include the highest SRMC of any hour in the season. But there are two major drawbacks: 1) there may be anomalies (holidays) in the week and 2) the mean load of that week will almost always be substantially higher than the mean load of the season.

Week that Approximates Seasonal Load Factor

This week has the advantage of being the best approximation to the most representative load pattern during the season. Again, it must be examined for anomalies and it is unlikely that it will bring about the full range of SRMC that may be experienced during the season.

Average Week

The average week is made up of hourly loads that correspond to the average of all the hourly loads during that time of the week for all weeks in the season. For example, the hourly load of Monday at noon in the average week is made up of the average of all the loads experienced on Monday at noon in every week of the season. The advantage of this week is that it has "diluted" any anomalies and that it has the average load of the season. On the other hand, it reflects a greater regularity than would be typical of any individual week.

Adopted Week

In order to obtain a week of hourly loads representative of each season, the model GPT-L (Generation Planning Tools - Load Analysis Module) was used. The model works as follows:

Step 1 GPT-L examines the historical loads of one year, in this case 1991. It sorts them by season and records the peak load, mean load, base load, and load factor of each week.

Step 2 GPT-L receives as input, for each season, the peak load, mean load and base load of the target year for SRMC computation. In this case, the target year was 1997 (also 1993).

Step 3 GPT-L receives as input a criterion for week selection in each season. This may be any one of the following: peak week, seasonal load factor week, a particular week designated by the user, or the average week.

Step 4 Based on the selected week (step 3) and the characteristics of the seasonal load of the target year (step 2), GPT-L adjusts the hourly loads of the selected week in such a way that the selected week contains the peak load of that season in the target year and its mean load is equal to the mean load of the season in the target year. Furthermore, the base load of the season in the target year will be somewhat approximated (a closer approximation usually leads to excessive distortion of the weekly pattern).

Step 5 GPT-L stores the hourly loads of both the selected week and the adjusted week for future use; it also calculates and stores the non-dimensional load duration curves for each season.

A detailed output of the model GPT-L for the analysis of the years 1993 and 1997 is shown in Appendix 4.3. In Exhibits 4-6 to 4-8, some relevant results are shown. Exhibit 4-6 shows the average week for winter and summer of the historical year 1991, while Exhibits 4-7 and 4-8 show the adjusted average weeks for each season in the years 1993 and 1997, respectively.

4.4.2 Identification of the Generating System

Once a suitable set of hourly loads is selected to represent the loads for the season, then the short-run marginal cost for each hour can be computed.

The first step is to identify the generating system that will serve the load during that season. This identification consists of drawing a list, in order of increasing variable production costs, of all the individual generating units that are used to meet the load during that season. The list must include the capacity of the unit, its expected availability (i.e., one minus the probability of outage at any instant during the period), and the variable production cost computed from an economic perspective (that is, using opportunity costs for all variable expenses and not including any taxes or subsidies).

EXHIBIT 4-6

1991 AVERAGE WEEKLY PATTERN

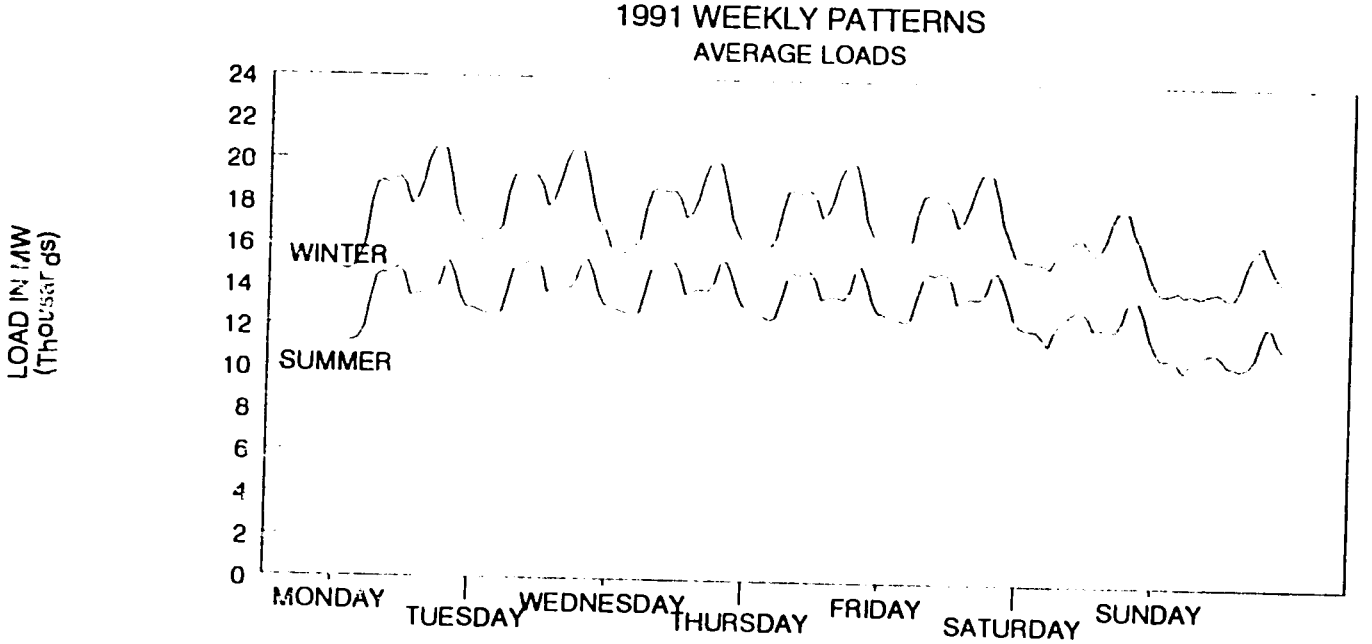


EXHIBIT 4-7

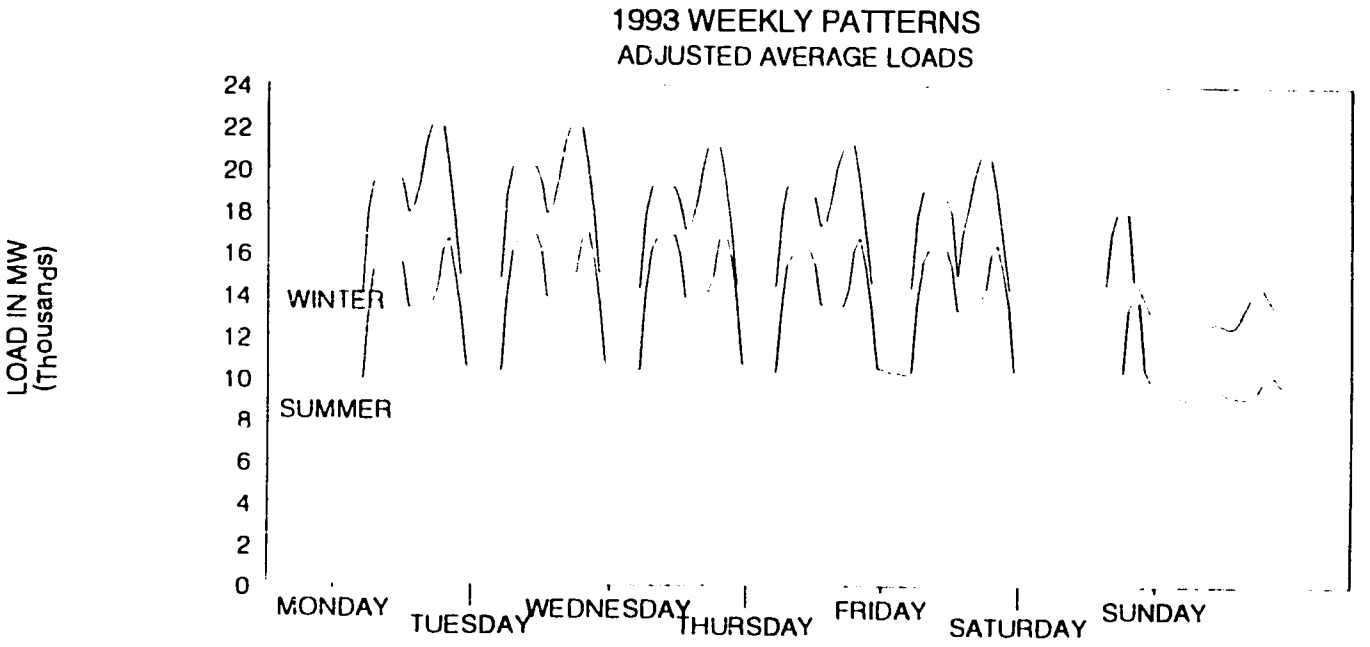
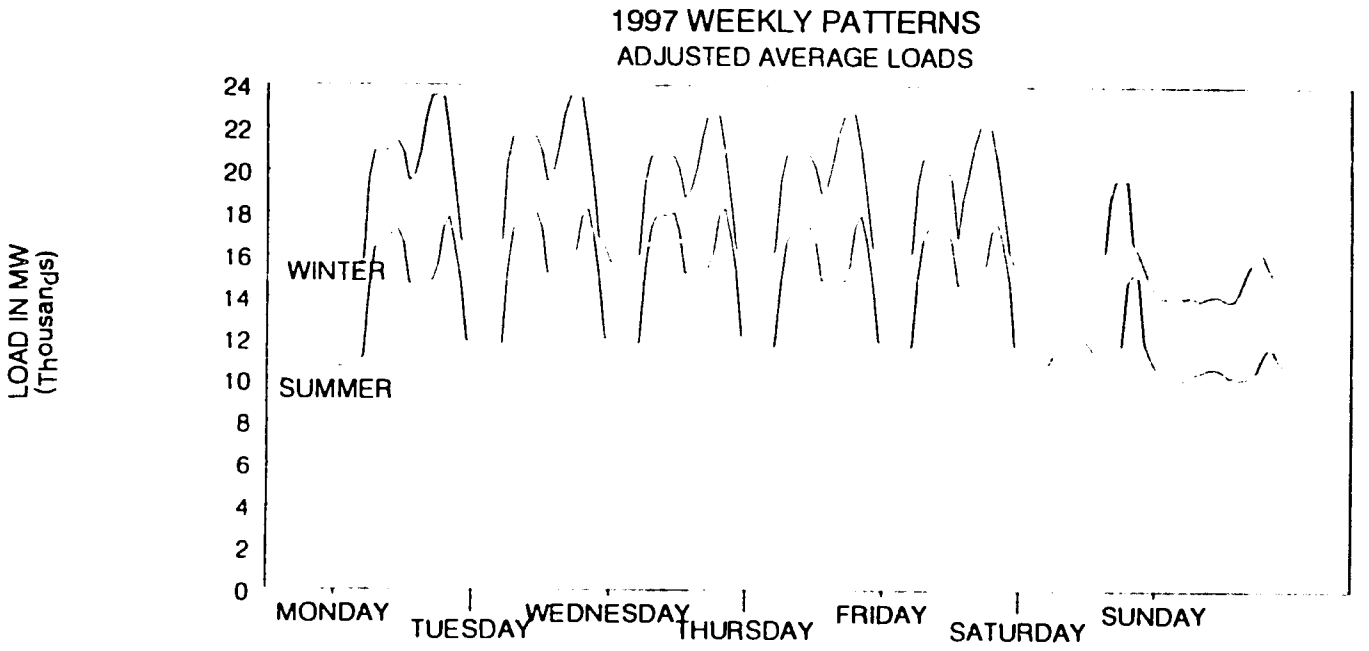

1993 WEEKLY PATTERNS
ADJUSTED AVERAGE LOADS
LOAD IN MW
(Thousands)
24
22
20
18
16
14
12
10
8
6
4
2
0
WINTER
SUMMER
MONDAY
TUESDAY
WEDNESDAY
THURSDAY
FRIDAY
SATURDAY
SUNDAY

EXHIBIT 4-8


1997 WEEKLY PATTERNS
ADJUSTED AVERAGE LOADS
LOAD IN MW
(Thousands)
24
22
20
18
16
14
12
10
8
6
4
2
0
WINTER
SUMMER
MONDAY
TUESDAY
WEDNESDAY
THURSDAY
FRIDAY
SATURDAY
SUNDAY

In this case, the list or "stack" as it is commonly called, is directly obtained from the simulation of the generation system described in Section 4.3 above. The Polish system is very large and the stack of generating units is fairly long. A sample of the stack of generating units is shown in Exhibit 4.5; the entire stack is available in Appendix 4.2 for each season and year in the period 1993-2000.

4.4.3 Computation and Allocation of Short-Run Marginal Cost

As mentioned above, one major issue is that the system may exist in any of many different conditions because of planned and forced outages. Planned outages are relatively easy to account for by either eliminating from a season those resources that will be largely out of service or, more commonly, by derating (i.e., reducing) the capacity of each resource in proportion to the time when it will be undergoing maintenance.

Forced outages, on the other hand, are a difficult problem. The traditional approach is to dispatch the stack of generating units under the load of each hour and register the unit that is at the level of the hourly load. This unit is said to be "at the margin," meaning that any increment in load will result in an incremental or marginal production from that unit. To account for forced outages, the process is repeated many times. This allows the units in the stack to be randomly present or absent in such a way that, on average, the ratio between the times when any individual unit was absent to the total times the process was repeated is close to the forced outage rate of that unit. This approach is commonly called a "Monte-Carlo" approach due to the analogy between random draws and casino gambling.

At Hagler, Bailly, a different approach was developed to yield a purely analytical and exact solution that is closely linked to the convolution theorem mentioned in Section 4.3 for the computation of loss of load probability (LOLP). Indeed, the recursive equation that constitutes the basis of the analytical approach uses as an intermediate step the convolution equation used for LOLP computation. A full description of this method requires some background on probability mathematics; a detailed description is presented in Appendix 4.4. The end result, however, is a simple relationship between the expected (i.e., the weighted average of the outcome of all possible system conditions weighted by their respective probabilities) marginal cost as a function of the load level to be served.

Hourly Allocation of Expected Marginal Costs

The resources in the stack only include those that are treated as "economically dispatchable" in the simulation. Indeed, these are the only resources that can truly be candidates for marginal production since there are no limitations, other than cost and availability, in their output.

Before the expected short-run marginal cost function can be applied to the hourly loads of the adjusted week, it is necessary to account for the "energy-limited" resources. Both the determination of the expected marginal cost function and the application of the function to the hourly loads are carried out with a computer model that is described below.

Expected Short-Run Marginal Cost Model GPT-M

The algorithm described in Appendix 4.4 constitutes the logical backbone for the computer model GPT-M (Generation Planning Tools - Marginal Cost Module). The model works as follows:

Step 1 GPT-M will read the stack of "economically dispatchable" generating units and prepare a function of the expected marginal cost of serving a specific load level.

Step 2 GPT-M will read the hourly loads, the capacity and energy available in "energy-limited" units, and the distribution of that energy into base and peak load.

Step 3 GPT-M will reduce all the hourly loads by the base load energy of all energy-limited resources and will then distribute the peak load energy in such a way as to make all loads during the week as uniform as possible.

Step 4 GPT-M will apply the expected marginal cost function (and also the LOLP function developed as an incidental result) to the hourly loads resulting from step 3.

4.4.4 Results of the Probabilistic Analysis of Short-Run Marginal Costs

The full output of the GPT-M analysis for the years 1993 and 1997 is presented in Appendix 4.5. In Exhibit 4-9, the expected marginal cost function is shown for both years and Exhibit 4-10 shows the hourly marginal costs for 1993. Exhibit 4-11 presents the average of those hourly marginal costs for 1993 and 1997 for each of the pricing periods recommended in Section 4.2.

EXHIBIT 4-9

EXPECTED MARGINAL COST FUNCTION

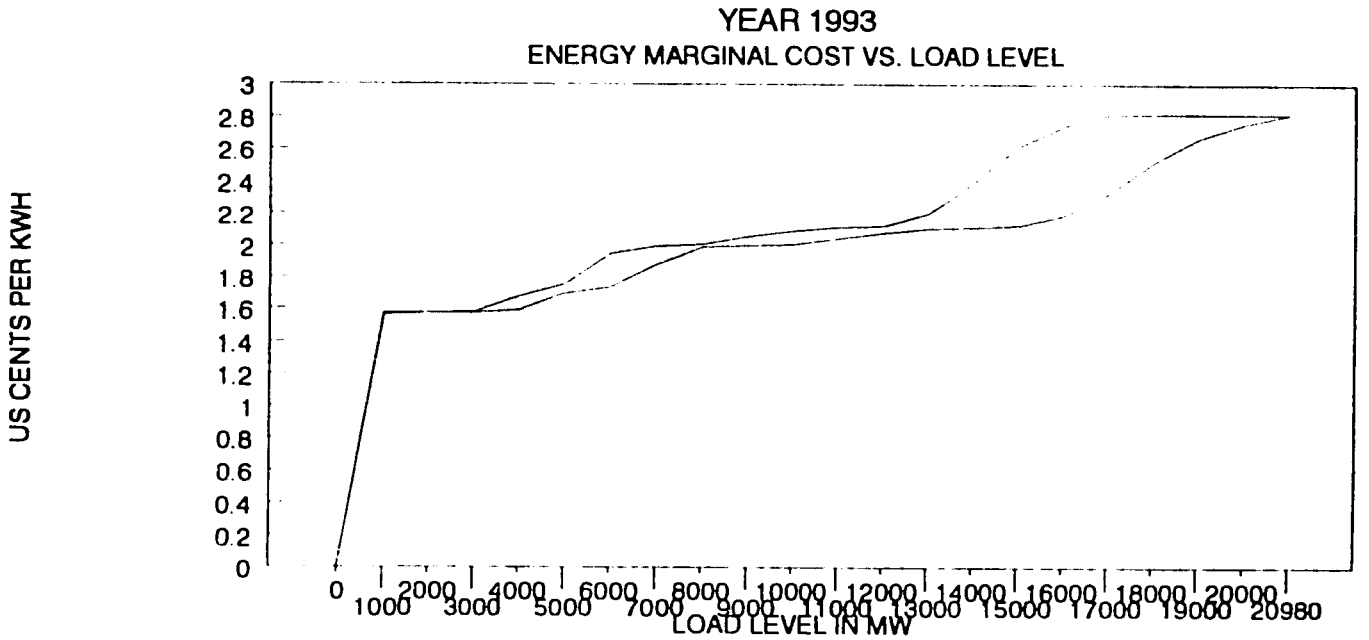


EXHIBIT 4-10

HOURLY MARGINAL COST PATTERN

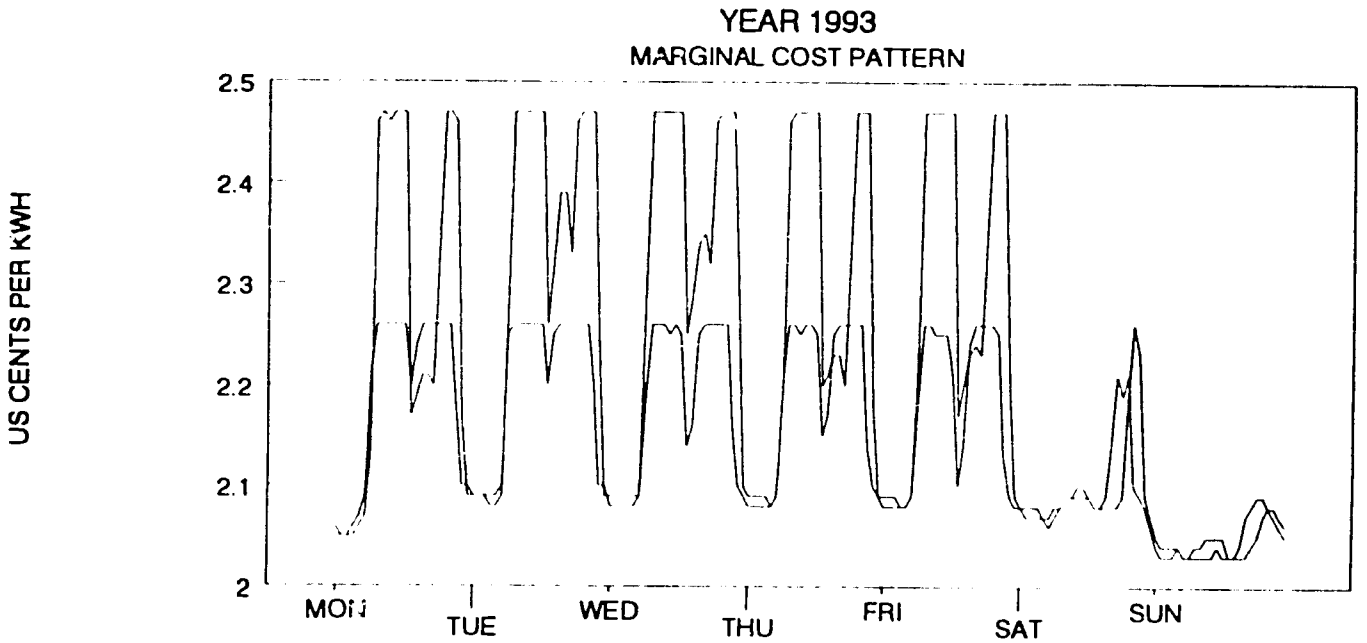


Exhibit 4-11
Probabilistic Analysis Short-Run Marginal Costs (US Cents/kWh)

1997

	Winter	Summer	Average
Morning Peak	2.20	2.45	2.33
Evening Peak	2.24	2.46	2.35
Off-Peak	2.07	2.12	2.10

These results for the generation system were used to develop the LRMC structure, which was in turn used in shaping bulk and retail tariff revenues. This analysis is described in Chapter 7.

4.4.5 Dispatch Constraints

The probabilistic analysis described above provides a very accurate structure of short run marginal costs when the generation system has adequate (i.e. close to least cost) proportions of peaking, intermediate load and base load units. However, the Polish power system does not have now and will not have achieved by 1997 such optimum generation mix but will have excessive base load capacity and insufficient peaking capacity.

When a generation system has insufficient peaking capacity it may be necessary to carry excess capacity in operation or as spinning reserve during the off-peak hours in order to have that capacity available to meet the higher loads of the peak period. This constraint results in increased cost during the off-peak hours and apparently lower costs during the peak hours. The analysis carried out above is correct as far as depicting the true marginal cost of off-peak operation but it underestimates the marginal cost of peaking operation by not accounting for the additional off-peak cost incurred to be able to meet peak loads.

An approximation to the additional marginal cost of a peaking operation with insufficient peaking capacity can be obtained by allocating to the peak hours the difference between peak and off-peak marginal costs as shown through the following formula:

$$AMCp = (MCp - MCb) \times (168-P)/P$$

where:
AMCp = additional cost of peaking operation
MCp = apparent marginal cost of peaking operation
MCb = marginal cost of normal base operation
P = hours of peaking operation

This approximation presumes a correspondence between marginal and average production costs that does not really exist in practice and the adjustment is just as likely to overestimate or underestimate the true marginal cost of peaking under dispatch constraints. Nevertheless, used carefully, it provides an adequate rationale for the purposes of tariff structure.

By 1997 it is expected that there will be a modest amount of gas turbine capacity in the system and, considering the dispatch constraints described above, it is likely that they will be at the margin at least during the evening peak. Therefore, it was decided to apply the adjustment above to the lower (morning) peak and to assume that the gas turbines will be at the margin during evening peak hours.

Based on these assumptions the marginal costs of Exhibit 4-11 are adjusted as shown in Exhibit 12.

Exhibit 4-12

Adjusted Short-Run Marginal Costs (US Cents/kWh)

	WINTER	SUMMER	AVERAGE
Morning Peak	2.80	3.97	3.39
Evening Peak	4.64	4.64	4.64
Off-Peak	2.07	2.12	2.10

4.5 MARGINAL COST AND AVOIDED COST

It may be useful to close this chapter with a brief discussion of the relationships between Short Run Marginal Costs, Long Run Marginal Costs and Avoided Costs since these three concepts are linked by alternative methods of computing marginal energy costs.

4.5.1 Average Incremental Revenue Requirements

The Short Run Marginal Cost discussed above is, by definition, only the marginal cost of energy since the SRMC is the cost of producing an increment of power with the same capacity. In Chapter 7, the SRMC is then combined with an independent estimate of the marginal cost of capacity to obtain the Long Run Marginal Cost (LRMC) of the system.

As will be further discussed during the determination of LRMC, it is possible to obtain the marginal cost of capacity and energy simultaneously by using a method known as the Average Incremental Revenue Requirements (AICR). The process consists, very briefly, of calculating the annual fixed and variable costs of two least cost expansion plans. The first corresponds to a base case load growth, the second to a higher load growth, often obtained by advancing all load levels by one year. Long run capacity and energy costs are then obtained by allocating all incremental fixed costs to the increments of capacity and all variable costs to the increments of energy.

Since the least cost expansion of the system seeks a compromise between low investment and low operating costs it is inevitable that some of the incremental fixed costs are not solely derived from the need of incremental capacity but result from the need to lower operating costs and thus are truly energy costs. The AICR method thus needs to include this correction. The AICR method has not been used in this study to determine marginal costs because current excess reserve during the short term and low load growth makes it difficult to measure incremental costs. However, a related method was used to estimate the economic avoided cost of non-disptachable resources as described below.

4.5.2 Differential Revenue Requirements

As will be discussed in Chapter 6 it is often desirable to determine the value of a resource to the generation system without reference to its own production cost. This is normally done by computing the cost of expanding the system with and without the resource in question and then allocating differential fixed costs to capacity and differential variable costs to energy. The

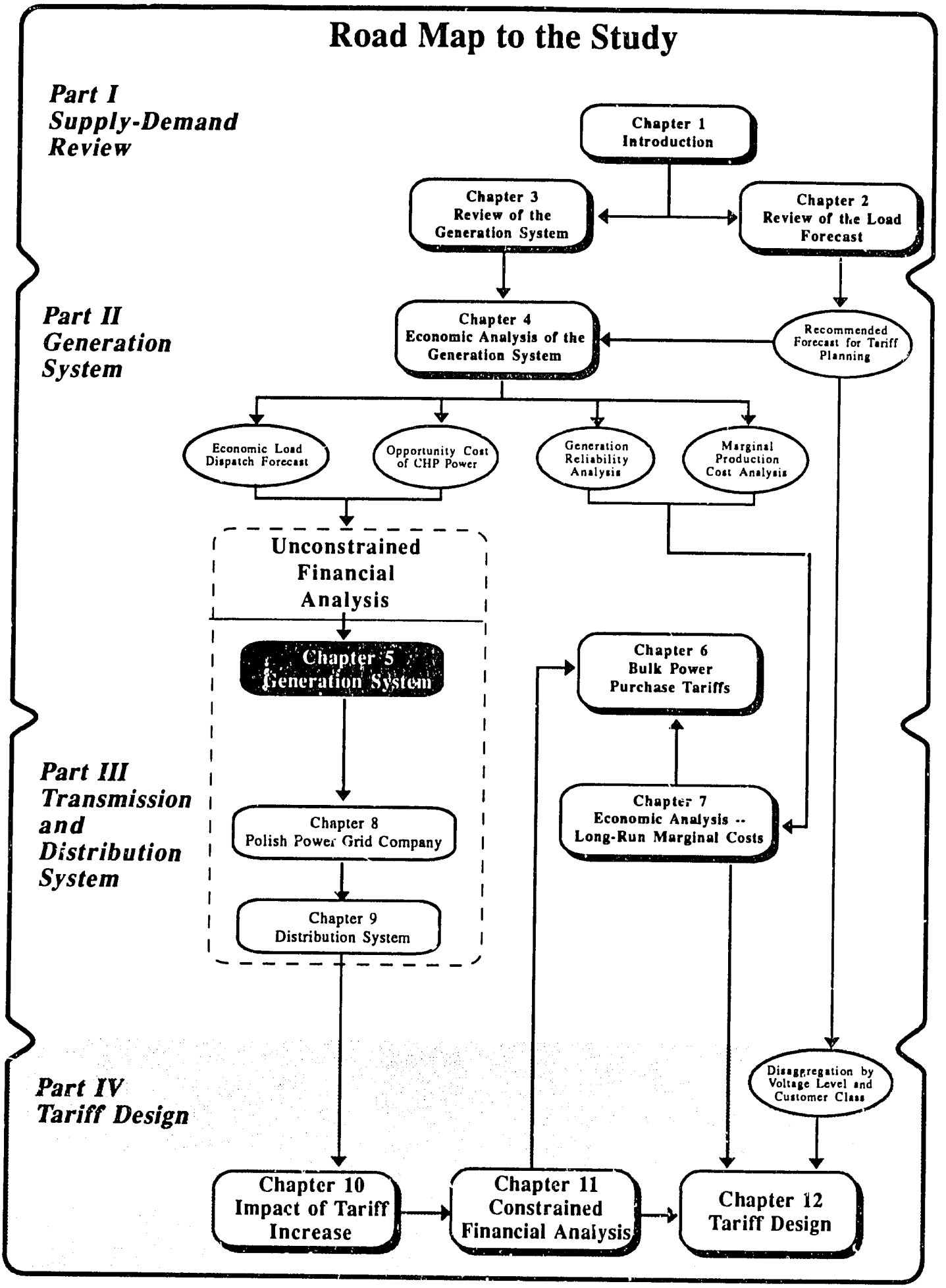
process, known as Differential Revenue Requirements (DRR) method sounds very similar to the AICR method described above to compute marginal costs.

Clearly, the cost of serving a small increment of load (AICR) is related to the cost of replacing a small decrement of resources (DRR). However, in the case of the AICR the increment of load has the system load factor whereas in the case of the DRR for the purpose of avoided cost computation the decrement of resources is equivalent to the addition of an increment of load but the equivalent load factor would be the capacity factor of the replaced resource.

Therefore, if a resource is very small and its capacity factor is similar to the system load factor then the avoided cost of the resource should be similar to the marginal cost of the system.

In Chapter 6 the DRR method will be used to estimate the avoided cost of non-dispatchable resources in the Polish power system.

Road Map to the Study



CHAPTER 5: UNCONSTRAINED FINANCIAL ANALYSIS OF THE GENERATION SYSTEM

5.1 OBJECTIVES AND APPROACH

This chapter presents the results of an analysis of the financial performance and future financial revenue requirements of the Polish generating system. The objective of this analysis was to forecast the revenues that must be collected by the generating plants in order to operate according to an acceptable criterion of financial performance. Its results were used to develop bulk transfer prices from generating companies to PPGC based on the long-run marginal cost structure for the entire system (Chapter 7).

It is important to stress here that the financial forecast developed in this chapter corresponds to a scenario of ***unconstrained*** tariff increase and instant asset revaluation. In Chapter 11, these results are subjected to different assumptions in order to arrive at a financial forecast that is constrained by the need to limit the impact of tariff increases and by a feasible extent of and schedule for the revaluation of assets.

The approach to this analysis was first to perform an historical review of the financial data, followed by the adoption of a financial criterion to be met. Last, the forecast revenue requirements were determined.

5.2 HISTORICAL FINANCIAL REVIEW AND ANALYSIS

The financial analysis of the generating system is based on a detailed analysis of 17 individual plants consisting of Poland's four largest lignite-fired conventional grid plants and 13 of the largest coal-fired conventional and collector grid plants. This sample covers 96 percent of all the energy generated by grid plants.

A considerable effort was made by PPGC, at the consultants' request, to gather the historical financial data for each of the generating plants. These data were used to develop a financial spreadsheet model for each generating plant for the years 1990 and 1991. The purpose of this exercise was to provide a valid starting position for future projections, as well as to attempt to identify any underlying trends and ratios that might be expected to continue into the future.

While distortions in data due to high inflation (600 percent for 1990 and over 50 percent in 1991) cannot be entirely eliminated from the analysis, a number of clear conclusions emerge from the historical data. These relate to the valuation of assets, debt-to-equity ratios, and expenses of the generating plants.

5.2.1 Asset Valuation

The valuation of gross fixed assets as of December 31, 1991 was based on a revaluation undertaken by the Polish Statistical Office in 1990. This revaluation, as will be discussed later in greater detail, still leaves the assets significantly undervalued with respect to their probable replacement cost. It thus exaggerates the stated rate of return as well as the stated debt-to-equity ratio.

5.2.2 Debt-to-Equity Ratio

As of December 31, 1991, the long-term debt of the Polish generation system amounted to 2,654 B.Zl (1 B.Zl = 1 billion Zlotys = 1,000,000,000 Zlotys), most of which is associated with the relatively new Belchatow lignite plant. This debt is 7.3 percent of the stated (and greatly undervalued) equity of 36,567 B.Zl.

5.2.3 Expenses

It is apparent that significant efforts have already been made to maintain (or even increase in real terms) powerplant revenues in line with inflation. In particular, revenues have been well adjusted for rising variable energy costs (coal and lignite purchase costs, and environmental penalties).

On the other hand, overhead costs have not been fully passed through. This would be even more apparent if the assets (and hence, depreciation expense) had been revalued in line with inflation.

5.3 ADOPTED CRITERIA, ASSUMPTIONS AND DATA SOURCES

5.3.1 Financial Criteria

Based on the Polish Government's stated policy to establish power generation as a viable commercial enterprise, a profit-driven financial criterion has been adopted: the generating plants must achieve an annual rate of return of 6.0 percent on their net assets employed. (The 6.0% criterion represents a judgment which relates to industry risk and country risk, and which compares for example, to a 4.0% return for electricity generation in the UK, 6.0% in Egypt and 8.0% in certain African countries).

For this purpose, the rate of return is defined as "operating income after depreciation expense and before financial expense and income tax," as a ratio of "revalued net fixed assets plus accounts receivable and inventories (taken as an average for the year)."

The revalued net assets are based on 1992 price levels. Accumulated depreciation is also adjusted to 1992 price levels and based on the remaining useful life of the assets (assuming a total 30-year economic life).

While other financial performance criteria would normally be relevant, the financial strength of the Polish generating system and its relatively limited projected capital expenditure requirements, render other ratios of little significance if the target 6.0 percent rate of return on revalued net assets is achieved.

5.3.2 Assumptions

The key assumptions used in the financial analysis are listed below:

- All values are projected at mid-1992 price levels and the corresponding exchange rate of 13,400 Zl equals US $1.00.

- Fuel cost (including transportation) is projected at the economic prices for coal and lignite discussed in Chapter 3, equivalent to 29.970 Zl/KJ (Zloty per kilojoule) of coal.

- The gross value (before depreciation) of the system generating assets is assumed to be out of date by a factor of 6.0. This assumption results from the ratio between the estimated 1992 international price of comparable coal-fired plants[1] and the average 1991 gross book value of the generating assets.

- The net value of each asset is based on applying the uniform index of 6.0 to its gross book value and calculating the accumulated depreciation from its commissioning date, assuming an economic life of 30 years.

- It is assumed that 15 percent of the target rate of return is achieved through energy sales and 85 percent of the target rate of return is collected through capacity sales. This assumption has been made in order to provide a profit-incentive to each generating plant to actually produce electricity, rather than being able to earn all its net income solely by being available for dispatch.

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[1] Based on $870/kW for a coal-fired plant without emission control equipment and before interest during construction.

5.3.3 Sources of Data

Income Statement

The sources for the historical data for each plant's income statement were the "F-02" annual accounting returns for each plant, the Energy Statistics reports from CEI, and energy purchase analyses provided by PPGC.

For 1992 and future years, the sources used for each plant are briefly outlined as follows:

- Physical energy sales and production were developed for each plant using the simulation discussed in Chapter 4 (details are reported in Appendix 4.2).

- Environmental charges were based on the PPGC energy purchase summary by plant for January-August 1992.

- Operation and maintenance costs were considered as fixed costs and several sources of data were used:

  -- 1991 actual costs adjusted by inflation to 1992 and 1993

  -- estimates for 1992 established by Energoprojekt's detailed cost analysis

  -- international comparisons and trends for plants of various sizes as used in the economic analysis presented in Chapter 4.

  In general, the approach taken was to base personnel costs for 1992 and 1993 on the 1991 actual increased by inflation, and to use Energoprojekt's assessment for maintenance and other overhead. Then, if the resulting O&M level exceeded the economic standard, the total O&M estimate was reduced by 10 percent per year until it reached the economic standard, which was usually met by 1995.

- Interest expense (income) was assumed to be earned on net cash balances. The only plant with significant interest expense is Belchatow.

- Corporate tax was assumed to continue at the current rate of 40 percent.

Balance Sheet

The sources for the historical data for each plant's balance sheet were the "F-02" annual accounting returns for each plant, together with the 1991 fixed-asset valuations contained in the May/June 1992 cost analysis prepared by the Tariffs and Economics Department of PPGC.

The historical data provided information with respect to historical working capital requirements (for example, days' sales in accounts receivable, or days' supply of fuel on hand), which were then used to project future working capital requirements.

The critical balance sheet item, however, is fixed assets - gross and net. In addition to the revaluation and amortization assumptions discussed above, provision has been made for additions to fixed assets resulting from rehabilitation and investment in environmental protection over the 1993-1997 period. The level of investment for each plant is based on the review discussed in Chapter 3.

5.4 RESULTS

The results presented below are those for the unconstrained tariff increase and instant asset revaluation scenario. See Chapter 11 for results under the financial forecast constrained by the need to limit the impact of tariff increases and the feasible extent of and schedule for the revaluation of assets.

5.4.1 Results for the Consolidated Generating System

The revenue requirement in 1994 for the consolidated generating system, expressed at 1992 price levels, is 489 Zl/kWh. This results from an average fixed charge of 97,709,000 Zl/kW-M (Zloty per kW per month) and an average variable charge of 307 Zl/kWh. The income statement, balance sheet, and operating and financial ratios for the consolidated system are shown in Exhibits 5.1a, 5.1b and 5.1c, respectively.

On the basis of a 6.0 percent return on net assets revalued to 1992 levels -- which (after an average 40 percent tax rate) is equivalent to about 4.5 percent after tax on revalued equity -- the total system (as now constituted) should generate approximately 30,000 B.Zl in surplus cash by 1997. This cash balance includes the projected rehabilitation and modernization of existing plants, but it does not include financing for the Opole powerplant, which is under construction. Financing for this plant is assumed to be paid by Government equity contributions.

Exhibit 5–1a
INCOME STATEMENT – CONSOLIDATED GENERATION SYSTEM

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
		97,847	Energy Sales -- Gwh	97,011	96,337	99,676	102,424	105,582	107,948
		20,773	Capacity -- MW	20,476	20,366	20,180	20,390	20,189	21,316
			% Capacity Sold						
		73,135	Hours of Production/Year	73,626	73,626	74,765	75,904	66,791	60,630
		195,312	Capacity Sales – Mw/m	185,803	182,381	184,205	184,127	172,483	173,497
			Max Capacity Sales @1994 Installation	208,851	207,732	202,166	200,636	191,242	195,389
		115.499	Energy Sales Price -- Zl/Kwh	196.754	300.222	306.771	313.057	326.149	338.126
		45,459	Capacity Price -- '000 Zl/Mw/m	53,884	103,053	98,580	96,867	100,644	103,333
			Adjusted 1994 Capacity Price						
			Sales Revenue						
		11,301	Energy	19,087	28,922	30,578	32,064	34,435	36,500
		8,879	Capacity	10,012	18,795	18,159	17,836	17,359	17,928
282	3,698	20,199	Sub–total Electricity Sales	29,099	47,717	48,737	49,900	51,795	54,428
18	320	412	Others	1,012	885	875	875	875	855
300	**4,018**	**20,611**	**Total Sales/Revenues**	**30,111**	**48,602**	**49,611**	**50,775**	**52,669**	**55,283**
			Variable Cost						
170	2,087	10,738	Fuel	11,592	25,295	26,245	27,016	28,018	28,757
	88		Transport	1,694					
	49	601	Environmental Penalty	2,719	2,687	2,742	2,798	2,850	2,871
3	28	4	Others						
173	2,253	11,343	Total Variable Cost @ 1992 Prices	16,004	27,982	28,987	29,815	30,868	31,628
			Plus: Inflation						
172	**2,236**	**11,343**	**Total Variable Cost**	**16,004**	**27,982**	**28,987**	**29,815**	**30,868**	**31,628**
			Fixed/ Capacity Costs						
95	951	5,865	Existing Plant	6,398	5,778	5,342	4,956	4,695	4,501
			New Plant			72	145	289	434
95	951	5,865	Total Fixed Cost (ex.Dep'n)@1992	6,398	5,778	5,415	5,101	4,984	4,935
			Plus: Inflation						
95	**951**	**5,865**	**Total Fixed Cost before Dep'n.**	**6,398**	**5,778**	**5,415**	**5,101**	**4,984**	**4,935**
7	141	1,947	Depreciation Expense	8,953	8,953	8,801	9,434	9,719	11,027
274	3,344	19,155	Total Operating Expense	31,355	42,714	43,203	44,349	45,571	47,590
27	691	1,456	Operating Income	(1,244)	5,888	6,408	6,426	7,099	7,693
4	31	65	Financial/Interest Expense (Net)	(557)	(1,199)	(1,761)	(2,347)	(2,980)	(3,699)
0	(67)	421	Extraordinary Income (Loss)						
22	588	1,799	Income Before Tax	(687)	7,087	8,169	8,772	10,079	11,392
5	279	980	Corporate Tax	(275)	2,835	3,268	3,509	4,031	4,557
17	309	820	Net Income After Tax	(412)	4,252	4,901	5,263	6,047	6,835

Billions Zloty at Base Year Prices

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Exhibit 5-1b

BALANCE SHEET - CONSOLIDATED GENERATION SYSTEM

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			ASSETS						
	544	723	Cash	879	1,288	1,304	1,292	1,282	1,274
	374	1,378	Accounts Receivable	1,613	2,480	2,602	2,732	2,958	3,180
	797	1,614	Inventories -- Fuel	1,694	3,171	3,334	3,414	3,547	3,630
	12	20	Others						
	468	224	Others		450	850	1,300	1,700	2,000
	2,196	**3,959**	**Total Current Assets**	**4,186**	**7,390**	**8,090**	**8,736**	**9,488**	**10,084**
	35,125	36,835	Gross Fixed Assets	219,816	219,832	238,904	247,856	267,422	297,728
	16,435	18,295	Less: Acc. Depreciation	122,397	131,351	140,152	149,585	159,304	170,331
	18,690	18,539	Net Fixed Assets	97,418	88,481	98,752	98,270	108,118	127,397
	1,413	18,735	Capital Work-in-Progress	23,133	33,446	27,611	30,368	26,257	9,738
	22,299	**41,233**	**TOTAL ASSETS EMPLOYED**	**124,737**	**129,317**	**134,453**	**137,376**	**143,862**	**147,219**
			LIABILITIES						
	602	1,329	Accounts Payable						
	556	920	Other Liabilities						
			LTD due within 1 year - existing	170	170	170	170	170	170
	10	18	LTD due within 1 year - new local						
			LTD due within 1 year - new FX						
			Cash Deficiency (Surplus)	(5,911)	(9,397)	(13,159)	(18,739)	(23,671)	(30,489)
	1,168	**2,268**	**Total Current Liabilities**	**(5,741)**	**(9,227)**	**(12,989)**	**(18,569)**	**(23,502)**	**(30,319)**
	(50)		Other Liabilities	704	1,970	3,342	4,112	6,934	7,725
	1,447	2,492	Long Term Debt - existing	3,068	2,899	2,729	2,559	2,390	2,220
		162	Long Term Debt - new local	704	1,970	3,342	4,112	6,934	7,725
			Long Term Debt - new FX						
			Total Long Term Debt	**3,772**	**4,869**	**6,071**	**6,671**	**9,323**	**9,945**
			Equity Balance:						
	14,657	15,642	Assumed Opening Position	32,770	32,770	32,770	32,770	32,770	32,770
	1,199	16,751	Additional Paid in Capital	2,718	5,436	8,230	10,870	13,589	16,306
	482	378	Revaluation of Fixed Assets	87,832	87,832	87,832	87,832	87,832	87,832
	2 833	3,103	Retained Earnings -- Prior Years	3,797	3,385	7,637	12,539	17,802	23,849
	507	694	Current Year's Net Income	(412)	4,252	4,901	5,263	6,047	6,835
	19,678	**36,567**	**Total Equity**	**126,706**	**133,676**	**141,371**	**149,275**	**158,041**	**167,593**
	22,299	**41,233**	**TOTAL LIABILITIES & EQUITY**	**124,737**	**129,317**	**134,453**	**137,376**	**143,862**	**147,219**

Billions Zloty at Base Year Prices

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Exhibit 5–1c
OPERATING AND FINANCIAL RATIOS – CONSOLIDATED GENEARATION SYSTEM

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End – – December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES						
			Energy Sales(Gwh) – Annual Growth – %	–0.9%	–0.7%	3.5%	2.8%	3.1%	2.2%
	1209.5%	446.2%	Sales Revenue(Zl) – Annual Growth – %	44.1%	64.0%	2.1%	2.4%	3.8%	5.1%
		206.433	Average Tariff – – Zlotys/kwh	299.957	495.317	488.951	487.195	490.566	504.206
			OPERATING RATIOS						
		115.929	Variable Cost / kwh	164.969	290.460	290.815	291.091	292.358	292.992
		174.048	Total Operating Cost/ kwh	289.863	398.883	394.636	396.005	391.496	409.362
		174.715	Total Cost/ kwh (excl. ROE)	284.118	386.439	376.969	373.094	363.271	375.094
		30,027	Fixed Cost/ Mw/m	34,434	31,684	29,395	27,702	28,898	28,445
		39,994	Fixed Cost plus Dep'n/ Mw/m	82,621	80,775	77,175	78,937	85,243	92,000
		40,328	Fixed Cost plus Dep'n & Int./Mw/m	79,622	74,202	67,615	66,192	67,966	70,679
	17.2%	7.1%	Operating Income to Sales – %	–4.1%	12.1%	12.9%	12.7%	13.5%	13.9%
			Operating Income to Gross Assets in Service (Average) – %:						
		14.9%	–historical						
	3.9%	4.0%	–revalued	–1.0%	2.7%	2.8%	2.6%	2.8%	2.7%
	7.4%	7.8%	Operating Income/ Net Assets – %	–2.1%	6.3%	6.8%	6.5%	6.9%	6.5%
			BALANCE SHEET RATIOS						
		1.7	Current Ratio	–0.7	–0.8	–0.6	–0.5	–0.4	–0.3
		0.4	Cash at Bank to Sales – months	0.4	0.3	0.3	0.3	0.3	0.3
		24	Accts.Receivable to Sales – days	20	19	19	20	21	21
			Debt to Equity Ratio – %						
			–historical						
		0.0%	–revalued	3.0%	3.6%	4.3%	4.5%	5.9%	5.9%

Billions Zloty at Base Year Prices

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It is relevant to observe that total expenditure on Opole (in 1992 prices) will amount to approximately 30,000 B.Zl, which is almost equal to the system's total cash surplus. Thus, under the unconstrained analysis, the Opole project could in effect be financed from within the system.

In summary, given the present combination of circumstances (a low-growth scenario, present surplus capacity, and an extremely favorable debt-to-equity ratio of about 3.0 percent) and assuming no constraints in the instant revaluation of assets, a real increase in revenues of 63 percent above current levels would be required to finance the generation system if no additional long-term debt were assumed.

5.4.2 Results by Generating Company

Coal Plants

The table in Exhibit 5-2 is a summary of the results for each individual plant. Using the results for the individual plants, the financial forecasts for each of the five generating companies (four companies with coal-fired plants and one company with all of the lignite plants) were consolidated. The assumed composition of each generating group is as follows:

Group 1	Jaworzno 3, Laziska, Siersza
Group 2	Rybnick, Dolna Odra, Blacjownia, Halemba
Group 3	Kozienice, Ostroleka, Stalowa Wola
Group 4	Polaniec, Lagisza, Skawina

The most relevant characteristics of each of these groups are compared in Exhibit 5-3. This exhibit shows that the range of revenue requirements is from 498 Zl/kWh for Group 2 to 574 Zl/kWh for Group 1 (that is, a variance of approximately 7 percent about the mean requirements of all coal-fired grid plants).

The results for the generating companies are presented in Exhibits 5-4 to 5-7 and include the income statement, balance sheet, and financial and operating ratios for each of them.

The Rybnik powerplant is the primary reason for the low revenue requirements of Group 2, and the Jaworzno 3 powerplant is the primary reason for the high revenue requirements of Group 1. If the objective is to make revenue requirements as uniform as possible, then one option would be to move Jaworzno 3 to Group 2 in exchange for Dolna Odra.

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Exhibit 5–2
SUMMARY OF RESULTS FOR INDIVIDIAL PLANTS

				ENERGY			CAPACITY			REVENUE
PLANT'S NAME	TYPE	AGE IN 1992	CAPACITY (MW)	SALES (Gwh/Year)	COST (ZI/Kwh)	PRICE (ZI/Kwh)	SALES Mw–m	COST K ZI/Mw–m	PRICE K ZI/Mw–m	REQUIREMENTS (ZI/Kwh)
Adamow	Lignite	28	480	2,472	250.711	253.000	5,355	62,605	65,000	383.277
Belchatow	Lignite	6	4,320	25,902	262.403	275.000	43,217	57,568	127,000	486.893
Blachownia	Coal	30	164	377	463.707	469.000	1,082	94,127	106,000	746.755
Dolma	Coal	6	1,600	5,583	291.108	327.000	14,971	67,445	94,000	579.067
Halemba	Coal	29	200	462	400.718	405.000	1,322	90,189	104,000	675.701
Jaworzno 3	Coal	13	893	3,799	323.830	339.000	7,519	133,967	185,000	675.441
Koznieci	Coal	18	2,600	8,000	298.181	299.000	24,237	71,238	98,000	595.888
Lagisza	Coal	23	721	2,144	375.485	384.000	4,541	60,518	87,000	552.945
Laziska	Coal	23	920	5,473	337.396	341.000	10,608	74,607	85,000	505.743
Opole	Coal		360	2,289	340.583	628.000				628.000
Ostroleka B	Coal	18	600	1,967	361.754	368.000	3,651	118,999	73,000	503.483
Patnow	Lignite	28	1,200	8,897	238.456	243.000	12,240	30,607	49,000	310.415
Polaniec	Coal	8	1,600	7,888	296.387	310.000	16,320	59,354	114,000	545.865
Rybnik	Coal	13	1,600	10,058	299.998	307.000	16,320	32,242	79,000	435.182
Siersza	Coal	23	630	1,712	374.195	382.000	3,735	67,925	92,000	567.080
Skawina	Coal	33	141	450	422.210	430.000	1,389	135,464		807.743
Stalowa	Coal	23	311	1,951	280.761	282.000	3,172	97,759	0	282.000
Turow	Lignite	23	1,600	10,050	290.655	295.000	16,146	70,665	80,000	423.531
TOTAL/AVERAGE		345	19,940	99,476	290.896	306.879	185,855			489.433

Notes:

1/ Based on 6.0% return on partially revalued net assets employed in 1994 (at Mid–1992 Prices).

2/ Prices are at June, 1992 levels; Exchange Rate is US$1.00 = ZI 13,400.

3/ Energy Cost includes Fuel at 1992 "ECONOMIC" Coal Price; Transport included in Coal Price; Environmental Penalty Coal Price is 29.970 ZI/Kj; Lignite price is 22.277 ZI/Kj.

4/ Capacity Cost includes Operation & Maintenance; Depreciation; Plus (Minus) Interest Expense (Income).

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EXHIBIT 5–3
COMPARATIVE RESULTS FOR GENERATING COMPANIES

	GROUP 1		GROUP 2		GROUP 3		GROUP 4	
No. of Plants	3		4		3		3	
Energy Sales in 1994(Gwh)	10,985		16,480		11,919		10,482	
Average Tariff ZE/Kwh	574		498		529		559	
Total Revenue Billions ZE	6,305		8,204		7,102		5,935	
Operating Income	637		392		678		873	
Gross Fixed Assets	31,020		38,626		34,276		30,668	
Accumulated Depreciation	21,994	70.9%	25,561	66.2%	26,372	76.9%	18,102	59.0%
Net Fixed Assets	9,027		13,065		7,904		12,566	
Shareholders Equity	12,902		20,150		14,740		17,143	

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Exhibit 5–4a

INCOME STATEMENT – GROUP 1

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End – – December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
		12,564	Energy Sales – – Gwh	10,570	10,754	10,985	10,788	9,980	9,115
		2,563	Capacity – – MW	2,563	2,563	2,563	2,563	2,563	2,563
			% Capacity Sold						
		20,815	Hours of Production/Year	20,814	20,814	20,814	20,814	20,814	20,814
		24,586	Capacity Sales – Mw/m	20,331	20,426	20,963	21,142	19,727	17,876
			Max Capacity Sales @1994 Installation	26,141	26,141	26,141	26,141	26,141	26,141
		109.203	Energy Sales Price – – Zl/Kwh	242.702	346.445	346.700	346.693	346.508	346.549
		65,719	Capacity Price – – '000 Zl/Mw/m	69,366	130,303	119,112	109,823	110,766	116,764
			Adjusted 1994 Capacity Price						
			Sales Revenue						
		1,372	Energy	2,565	3,726	3,809	3,740	3,458	3,159
		1,616	Capacity	1,410	2,662	2,497	2,322	2 183	2,087
180	1,537	3,007	Sub–total Electricity Sales	3,976	6,387	6,305	6,062	5,643	5,246
3	162	136	Others						
183	**1,698**	**3,142**	**Total Sales/Revenues**	**3,976**	**6,387**	**6,305**	**6,062**	**5,643**	**5,246**
			Variable Cost						
113	978	1,453	Fuel	1,532	3,215	3,284	3,222	2,969	2,703
			Transport	77					
			Environmental Penalty	416	423	433	427	398	367
3	22	(1)	Others						
116	1,000	1,452	Total Variable Cost @ 1992 Prices	2,024	3,638	3,718	3,649	3,367	3,070
			Plus: Inflation						
115	**983**	**1,452**	**Total Variable Cost**	**2,024**	**3,638**	**3,718**	**3,649**	**3,367**	**3,070**
			Fixed/ Capacity Costs						
48	353	1,132	Existing Plant	1,232	1,108	985	869	793	749
			New Plant						
48	353	1,132	Total Fixed Cost (ex.Dep'n)@1992	1,232	1,108	985	869	793	749
			Plus: Inflation						
48	**353**	**1,132**	**Total Fixed Cost before Dep'n.**	**1,232**	**1,108**	**985**	**869**	**793**	**749**
4	76	252	Depreciation Expense	966	966	966	966	966	966
167	1,413	2,836	Total Operating Expense	4,222	5,712	5,669	5,483	5,125	4,785
16	286	307	Operating Income	(246)	675	637	579	517	461
4	31		Financial/Interest Expense (Net)						
1	29	31	Extraordinary Income (Loss)						
13	283	337	Income Before Tax	(246)	675	637	579	517	461
3	136	215	Corporate Tax	(98)	270	255	231	207	184
10	147	123	Net Income After Tax	(148)	405	382	347	310	277

Billions Zloty at Base Year Prices

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Exhibit 5–4b
BALANCE SHEET GROUP 1

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End – – December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			ASSETS						
	113	255	Cash	238	345	341	327	301	274
	62	65	Accounts Receivable	87	149	148	143	136	129
	155	313	Inventories – – Fuel	298	605	617	603	547	492
			Others						
	100	(140)	Others						
	431	**493**	**Total Current Assets**	**623**	**1,100**	**1,106**	**1,073**	**984**	**895**
	5,214	5,622	Gross Fixed Assets	31,020	31,020	31,020	31,020	31,020	31,020
	3,078	3,421	Less: Acc. Depreciation	20,061	21,028	21,994	22,960	23,926	24,892
	2,137	2,201	Net Fixed Assets	10,959	9,993	9,027	8,061	7,095	6,129
	45	193	Capital Work–in–Progress	193	193	193	193	193	193
	2,612	**2,886**	**TOTAL ASSETS EMPLOYED**	**11,775**	**11,285**	**10,326**	**9,327**	**8,271**	**7,216**
			LIABILITIES						
	116	214	Accounts Payable						
	191	134	Other Liabilities						
			LTD due within 1 year – existing						
			LTD due within 1 year – new local						
			LTD due within 1 year – new FX						
			Cash Deficiency (Surplus)	(340)	(1,235)	(2,576)	(3,922)	(5,288)	(6,620)
	307	**348**	**Total Current Liabilities**	**(340)**	**(1,235)**	**(2,576)**	**(3,922)**	**(5,288)**	**(6,620)**
			Other Liabilities						
			Long Term Debt – existing						
			Long Term Debt – new local						
			Long Term Debt – new FX						
			Total Long Term Debt						
			Equity Balance:						
	2,215	2,329	Assumed Opening Position	2,329	2,329	2,329	2,329	2,329	2,329
			Additional Paid in Capital						
			Revaluation of Fixed Assets	9,724	9,724	9,724	9,724	9,724	9,724
		91	Retained Earnings – – Prior Years	209	62	466	848	1,196	1,506
	91	118	Current Year's Net Income	(148)	405	382	347	310	277
	2,306	**2,538**	**Total Equity**	**12,115**	**12,520**	**12,902**	**13,249**	**13,560**	**13,836**
	2,612	**2,886**	**TOTAL LIABILITIES & EQUITY**	**11,775**	**11,285**	**10,326**	**9,327**	**8,271**	**7,216**

Billions Zloty at Base Year Prices
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Exhibit 5–4c
OPERATING AND FINANCIAL RATIOS FOR GROUP 1

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End – – December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES						
			Energy Sales(Gwh) – Annual Growth – %	–15.9%	1.7%	2.2%	–1.8%	–7.5%	–8.7%
	755.1%	95.6%	Sales Revenue(Zl) – Annual Growth – %	32.2%	60.7%	–1.3%	–3.9%	–6.9%	–7.0%
		239.316	Average Tariff – – Zlotys/kwh	376.122	593.942	573.998	561.933	567.461	575.542
			OPERATING RATIOS						
		115.551	Variable Cost / kwh	191.502	338.318	338.441	338.224	337.376	336.822
		225.692	Total Operating Cost/ kwh	399.405	531.187	516.052	508.288	513.608	524.965
		225.692	Total Cost/ kwh (excl. ROE)	399.405	531.187	516.052	508.288	513.608	524.965
		46,028	Fixed Cost/ Mw/m	60,573	54,245	46,989	41,078	40,183	41,889
		56,284	Fixed Cost plus Dep'n/ Mw/m	108,090	101,543	93,075	86,772	89,154	95,934
		56,284	Fixed Cost plus Dep'n & Int./Mw/m	108,090	101,543	93,075	86,772	89,154	95,934
	16.8%	9.8%	Operating Income to Sales – %	–6.2%	10.6%	10.1%	9.5%	9.2%	8.8%
			Operating Income to Gross Assets in Service (Average) – %:						
		14.9%	–historical						
	11.0%	5.7%	–revalued	–1.3%	2.2%	2.1%	1.9%	1.7%	1.5%
	22.3%	11.7%	Operating Income/ Net Assets – %	–3.4%	6.0%	6.0%	6.0%	6.0%	6.1%
			BALANCE SHEET RATIOS						
		1.4	Current Ratio	–1.8	–0.9	–0.4	–0.3	–0.2	–0.1
		1.0	Cash at Bank to Sales – months	0.7	0.6	0.6	0.6	0.6	0.6
		8	Accts.Receivable to Sales – days	8	9	9	9	9	9
			Debt to Equity Ratio – %						
			–historical						
		0.0%	–revalued						

Billions Zloty at Base Year Prices
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Exhibit 5–5a

INCOME STATEMENT – GROUP 2

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End – – December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
		16,393	Energy Sales – – Gwh	16,244	16,134	16,480	16,698	17,057	16,907
		3,644	Capacity – – MW	3,644	3,605	3,564	3,56[illegible]	3,523	3,441
			% Capacity Sold						
		11,917	Hours of Production/Year	11,917	11,917	11,917	11,917	11,917	11,917
		36,584	Capacity Sales – Mw/m	32,848	32,551	33,481	34,065	34,446	33,938
			Max Capacity Sales @1994 Installation	37,169	36,771	36,353	36,353	35,935	35,098
		124,576	Energy Sales Price – – Zl/Kwh	235,516	320,443	320,226	320,236	319,364	317,723
		42,526	Capacity Price – – '000 Zl/Mw/m	52,498	94,804	87,401	80,844	75,318	72,952
			Adjusted 1994 Capacity Price						
			Sales Revenue						
		2,042	Energy	3,826	5,170	5,277	5,347	5,447	5,372
		1,556	Capacity	1,724	3,086	2,926	2,754	2,594	2,476
29	324	3,598	Sub–total Electricity Sales	5,550	8,256	8,204	8,101	8,042	7,848
7	78	(1,049)	Others						
36	**402**	**2,549**	**Total Sales/Revenues**	**5,550**	**8,256**	**8,204**	**8,101**	**8,042**	**7,848**
			Variable Cost						
16	113	1,082	Fuel	2,026	4,497	4,583	4,640	4,715	4,642
			Transport	564					
		97	Environmental Penalty	413	411	419	424	432	429
			Others						
16	113	1,179	Total Variable Cost @ 1992 Prices	3,003	4,908	5,003	5,064	5,147	5,071
			Plus: Inflation						
16	**113**	**1,179**	**Total Variable Cost**	**3,003**	**4,908**	**5,003**	**5,064**	**5,147**	**5,071**
			Fixed/ Capacity Costs						
16	149	964	Existing Plant	760	684	613	547	485	472
			New Plant						
16	149	964	Total Fixed Cost (ex.Dep'n)@1992	760	684	613	547	485	472
			Plus: Inflation						
16	**149**	**964**	**Total Fixed Cost before Dep'n.**	**760**	**684**	**613**	**547**	**485**	**472**
1	7	211	Depreciation Expense	1,696	1,696	1,696	1,696	1,696	1,696
33	269	2,354	Total Operating Expense	5,459	7,288	7,311	7,307	7,328	7,239
3	133	195	Operating Income	92	968	892	794	714	609
		48	Financial/Interest Expense (Net)	(118)	(295)	(493)	(698)	(907)	(1,127)
(2)	(99)	35	Extraordinary Income (Loss)						
2	34	182	Income Before Tax	210	1,262	1,385	1,492	1,621	1,736
	18	137	Corporate Tax	84	505	554	597	648	694
1	16	45	Net Income After Tax	126	757	831	895	973	1,041

Billions Zloty at Base Year Prices

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Exhibit 5–5b
BALANCE SHEET – GROUP 2

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			ASSETS						
	54	51	Cash	107	143	143	138	132	126
	38	216	Accounts Receivable	202	322	323	320	321	310
	119	226	Inventories -- Fuel	216	364	381	393	407	390
			Others						
	50	35	Others						
	261	**528**	**Total Current Assets**	**526**	**830**	**847**	**851**	**860**	**825**
	4,310	4,389	Gross Fixed Assets	38,626	38,626	38,626	38,626	38,626	38,626
	2,633	2,840	Less: Acc Depreciation	22,170	23,865	25,561	27,257	28,953	30,649
	1,677	1,549	Net Fixed Assets	16,457	14,761	13,065	11,369	9,673	7,977
	70	160	Capital Work-in-Progress	160	160	160	160	160	160
	2,008	**2,237**	**TOTAL ASSETS EMPLOYED**	**17,142**	**15,750**	**14,072**	**12,380**	**10,694**	**8,963**
			LIABILITIES						
	87	115	Accounts Payable						
	109	224	Other Liabilities						
			LTD due within 1 year – existing						
			LTD due within 1 year – new local						
			LTD due within 1 year – new FX						
			Cash Deficiency (Surplus)	(1,418)	(3,568)	(6,077)	(8,665)	(11,324)	(14,096)
	196	**339**	**Total Current Liabilities**	**(1,418)**	**(3,568)**	**(6,077)**	**(8,665)**	**(11,324)**	**(14,096)**
			Other Liabilities						
	11	67	Long Term Debt – existing						
			Long Term Debt – new local						
			Long Term Debt – new FX						
			Total Long Term Debt						
			Equity Balance:						
	325	328	Assumed Opening Position	328	328	328	328	328	328
			Additional Paid in Capital						
	77		Revaluation of Fixed Assets	16,603	16,603	16,603	16,603	16,603	16,603
	1,384	1,459	Retained Earnings -- Prior Years	1,504	1,630	2,387	3,218	4,114	5,086
	16	45	Current Year's Net Income	126	757	831	895	973	1,041
	1,801	**1,832**	**Total Equity**	**18,561**	**19,318**	**20,150**	**21,045**	**22,018**	**23,059**
	2,008	**2,237**	**TOTAL LIABILITIES & EQUITY**	**17,142**	**15,750**	**14,072**	**12,380**	**10,694**	**8,963**

Billions Zloty at Base Year Prices
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Exhibit 5–5c
OPERATING AND FINANCIAL RATIOS FOR GROUP 2

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End – – December 31	ESTIMATE 1992	1993	FORECAST 1994	1995	1996	1997
			SALES						
			Energy Sales(Gwh) – Annual Growth – %	–0.9%	–0.7%	2.1%	1.3%	2.2%	–0.9%
	1010.7%	1008.9%	Sales Revenue(Zl) – Annual Growth – %	54.3%	48.7%	–0.6%	–1.2%	–0.7%	–2.4%
		219.481	Average Tariff – – Zlotys/kwh	341.674	511.720	497.793	485.168	471.469	464.159
			OPERATING RATIOS						
		71.897	Variable Cost / kwh	184.856	304.230	303.553	303.289	301.775	299.944
		143.584	Total Operating Cost/ kwh	336.033	451.727	443.651	437.593	429.608	428.151
		146.536	Total Cost/ kwh (excl. ROE)	328.751	433.470	413.729	395.792	376.427	361.510
		26.344	Fixed Cost/ Mw/m	23,134	21,007	18,308	16,049	14,067	13,902
		32.122	Fixed Cost plus Dep'n/ Mw/m	74,761	73,105	68,959	65,831	63,299	63,871
		33.445	Fixed Cost plus Dep'n & Int./Mw/m	71,160	64,056	54,231	45,341	36,965	30,671
	33.0%	7.7%	Operating Income to Sales – %	1.7%	11.7%	10.9%	9.8%	8.9%	7.8%
			Operating Income to Gross Assets in Service (Average) – %:						
		14.9%	–historical						
	6.2%	4.5%	–revalued	0.4%	2.5%	2.3%	2.1%	1.8%	1.6%
	13.7%	9.7%	Operating Income/ Net Assets – %	1.0%	5.9%	5.0%	6.1%	6.3%	6.3%
			BALANCE SHEET RATIOS						
		1.6	Current Ratio	–0.4	–0.2	–0.1	–0.1	–0.1	–0.1
		0.2	Cash at Bank to Sales – months	0.2	0.2	0.2	0.2	0.2	0.2
		31	Accts Receivable to Sales – days	13	14	14	14	15	14
			Debt to Equity Ratio – %						
			–historical						
			–revalued						

Billions Zloty at Base Year Prices
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Exhibit 5-6a

INCOME STATEMENT - GROUP 3

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
		11,226	Energy Sales -- Gwh	11,426	11,484	11,919	12,102	12,228	11,902
		3,545	Capacity -- MW	3,545	3,545	3,511	3,511	3,511	3,511
			% Capacity Sold						
			Hours of Production/Year						
		30,300	Capacity Sales - Mw/m	29,509	29,628	31,060	31,613	32,091	31,241
			Max Capacity Sales @1994 Installation	36,159	36,159	35,812	35,812	35,812	35,812
		132.304	Energy Sales Price -- Zl/Kwh	230.474	306.729	307.605	307.490	306.942	306.472
		42,614	Capacity Price -- '000 Zl/Mw/m	54,596	91,983	85,052	80,224	76,052	71,877
			Adjusted 1994 Capacity Price						
			Sales Revenue						
		1,485	Energy	2,633	3,522	3,666	3,721	3,753	3,648
		1,291	Capacity	1,611	2,725	2,642	2,536	2,441	2,246
		2,776	Sub-total Electricity Sales	4,244	6,248	6,308	6,257	6,194	5,893
		909	Others	912	795	795	795	795	795
		3,686	**Total Sales/Revenues**	**5,156**	**7,042**	**7,102**	**7,052**	**6,989**	**6,688**
			Variable Cost						
		1,598	Fuel	1,285	3,239	3,371	3,422	3,451	3,354
			Transport	606					
		119	Environmental Penalty	262	263	274	278	281	273
			Others						
		1,717	Total Variable Cost @ 1992 Prices	2,153	3,502	3,645	3,700	3,732	3,627
			Plus: Inflation						
		1,717	**Total Variable Cost**	**2,153**	**3,502**	**3,645**	**3,700**	**3,732**	**3,627**
			Fixed/ Capacity Costs						
		1,141	Existing Plant	1,039	998	982	967	967	967
			New Plant						
		1,141	Total Fixed Cost (ex.Dep'n)@1992	1,039	998	982	967	967	967
			Plus: Inflation						
		1,141	**Total Fixed Cost before Dep'n.**	**1,039**	**998**	**982**	**967**	**967**	**967**
		377	Depreciation Expense	1,797	1,797	1,797	1,797	1,797	1,848
		3,235	Total Operating Expense	4,989	6,297	6,424	6,464	6,497	6,442
		450	Operating Income	167	745	678	588	492	246
		147	Financial/Interest Expense (Net)	(81)	(167)	(253)	(327)	(437)	(598)
		45	Extraordinary Income (Loss)						
		348	Income Before Tax	248	912	931	915	929	843
		152	Corporate Tax	99	365	372	366	372	337
		196	Net Income After Tax	149	547	559	549	557	506

Billions Zloty at Base Year Prices

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Exhibit 5–6b
BALANCE SHEET – GROUP 3

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End – – December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			ASSETS						
	50	95	Cash	113	160	166	163	170	166
	97	467	Accounts Receivable	493	562	557	554	551	533
	172	380	Inventories – – Fuel	440	756	788	801	810	788
	3	2	Others						
	66	48	Others		450	850	1,300	1,700	2,000
	388	**992**	**Total Current Assets**	**1,046**	**1,927**	**2,362**	**2,823**	**3,230**	**3,487**
	2,325	2,409	Gross Fixed Assets	34,259	34,276	34,276	34,276	35,529	36,480
	1,404	1,502	Less: Acc. Depreciation	22,778	24,574	26,372	28,169	29,967	31,814
	920	907	Net Fixed Assets	11,481	9,701	7,904	6,106	5,562	4,666
	31	98	Capital Work – in – Progress	98	462	1,318	2,270	1,587	731
	1,339	**1,996**	**TOTAL ASSETS EMPLOYED**	**12,625**	**12,090**	**11,583**	**11,199**	**10,380**	**8,884**
			LIABILITIES						
	104	270	Accounts Payable						
	(79)	286	Other Liabilities						
			LTD due within 1 year – existing						
			LTD due within 1 year – new local						
			LTD due within 1 year – new FX						
			Cash Deficiency (Surplus)	(1,009)	(2,091)	(3,157)	(4,090)	(5,467)	(7,469)
	25	**556**	**Total Current Liabilities**	**(1,009)**	**(2,091)**	**(3,157)**	**(4,090)**	**(5,467)**	**(7,469)**
			Other Liabilities						
	270	326	Long Term Debt – existing						
			Long Term Debt – new local						
			Long Term Debt – new FX						
			Total Long Term Debt						
			Equity Balance:						
			Assumed Opening Position						
			Additional Paid in Capital						
	17		Revaluation of Fixed Assets	12,371	12,371	12,371	12,371	12,371	12,371
	947	1,035	Retained Earnings – – Prior Years	1,114	1,263	1,811	2,369	2,918	3,476
	80	80	Current Year's Net Income	149	547	559	549	557	506
	1,045	**1,114**	**Total Equity**	**13,634**	**14,182**	**14,740**	**15,289**	**15,847**	**16,353**
	1,339	**1,996**	**TOTAL LIABILITIES & EQUITY**	**12,625**	**12,090**	**11,583**	**11,199**	**10,380**	**8,884**

Billions Zloty at Base Year Prices
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Exhibit 5–6c
OPERATING AND FINANCIAL RATIOS FOR GROUP 3

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End –– December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES						
			Energy Sales(Gwh) – Annual Growth – %	1.8%	0.5%	3.8%	1.5%	1.0%	–2.7%
			Sales Revenue(Zl) – Annual Growth – %	52.9%	47.2%	1.0%	–0.8%	–1.0%	–4.9%
		247.326	Average Tariff –– Zlotys/kwh	371.479	544.045	529.251	517.047	506.524	495.140
			OPERATING RATIOS						
		152.929	Variable Cost / kwh	188.442	304.972	305.822	305.720	305.218	304.778
		288.207	Total Operating Cost/ kwh	436.654	548.340	538.994	534.147	531.285	541.259
		301.339	Total Cost/ kwh (excl. ROE)	429.590	533.770	517.805	507.109	495.519	491.056
		37.670	Fixed Cost/ Mw/m	35.219	33.685	31.606	30.590	30.134	30.954
		50.117	Fixed Cost plus Dep'n/ Mw/m	96.106	94.328	89.476	87.448	86.144	90.092
		54.983	Fixed Cost plus Dep'n & Int./Mw/m	93.371	88.681	81.344	77.097	72.515	70.967
		12.2%	Operating Income to Sales – %	3.2%	10.6%	9.6%	8.3%	7.0%	3.7%
			Operating Income to Gross Assets in Service (Average) – %:						
		14.9%	–historical						
		19.0%	–revalued	0.9%	2.2%	2.0%	[illegible]%	1.4%	0.7%
		28.1%	Operating Income/ Net Assets – %	2.3%	6.2%	6.2%	6.1%	5.5%	2.9%
			BALANCE SHEET RATIOS						
		1.8	Current Ratio	–1.0	–0.9	–0.7	–0.7	–0.6	–0.5
		0.3	Cash at Bank to Sales – months	0.3	0.3	0.3	0.3	0.3	0.3
		46	Accts.Receivable to Sales – days	35	29	29	29	29	29
			Debt to Equity Ratio – %						
			–historical						
			–revalued						

Billions Zloty at Base Year Prices
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Exhibit 5-7a

INCOME STATEMENT - GROUP 4

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
		11,495	Energy Sales -- Gwh	10,008	10,994	10,482	9,466	8,368	7,497
		2,901	Capacity -- MW	2,604	2,533	2,462	2,462	2,462	2,321
			% Capacity Sold						
		12,077	Hours of Production/Year	12,077	12,077	12,077	12,077	12,077	5,916
		27,144	Capacity Sales - Mw/m	22,215	21,966	21,744	21,704	19,592	17,391
			Max Capacity Sales @1994 Installation	26,559	25,838	25,116	25,116	25,116	23,674
		117.484	Energy Sales Price -- Zl/Kwh	223.040	330.164	330.291	332.351	333.577	328.318
		47,872	Capacity Price -- '000 Zl/Mw/m	54,040	112,933	110,046	105,698	112,433	115,441
			Adjusted 1994 Capacity Price						
			Sales Revenue						
		1,350	Energy	2,232	3,630	3,462	3,146	2,791	2,461
		1,299	Capacity	1,201	2,481	2,393	2,294	2,203	2,008
73	699	2,650	Sub-total Electricity Sales	3,433	6,110	5,855	5,440	4,994	4,469
7	78	236	Others	100	90	80	80	80	60
81	**777**	**2,885**	**Total Sales/Revenues**	**3,533**	**6,200**	**5,935**	**5,520**	**5,074**	**4,529**
			Variable Cost						
41	379	1,246	Fuel	1,206	3,196	3,045	2,764	2,451	2,162
			Transport	446					
		89	Environmental Penalty	281	300	288	267	239	206
			Others						
41	379	1,335	Total Variable Cost @ 1992 Prices	1,932	3,496	3,333	3,030	2,690	2,369
			Plus: Inflation						
41	**379**	**1,335**	**Total Variable Cost**	**1,932**	**3,496**	**3,333**	**3,030**	**2,690**	**2,369**
			Fixed/ Capacity Costs						
31	237	1,000	Existing Plant	892	788	721	675	647	575
			New Plant						
31	237	1,000	Total Fixed Cost (ex.Dep'n)@1992	892	788	721	675	647	575
			Plus: Inflation						
31	**237**	**1,000**	**Total Fixed Cost before Dep'n.**	**892**	**788**	**721**	**675**	**647**	**575**
2	32	349	Depreciation Expense	1,009	1,009	1,009	1,009	1,009	974
73	648	2,684	Total Operating Expense	3,833	5,292	5,062	4,714	4,346	3,918
8	129	201	Operating Income	(300)	908	873	807	728	612
			Financial/Interest Expense (Net)	(51)	(136)	(265)	(403)	(543)	(679)
1	1	45	Extraordinary Income (Loss)						
7	126	233	Income Before Tax	(249)	1,044	1,138	1,209	1,271	1,291
1	60	174	Corporate Tax	(100)	418	455	484	508	516
5	66	60	Net Income After Tax	(150)	626	683	726	763	774

Billions Zloty at Base Year Prices

Case: gencobas\system_v\group4

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Exhibit 5–7b
BALANCE SHEET – GROUP 4

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End – – December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			ASSETS						
	96	100	Cash	140	219	207	185	165	149
	48	171	Accounts Receivable	193	340	330	309	286	262
	141	366	Inventories – – Fuel	407	789	754	684	606	541
	1	6	Others						
	8	1	Others						
	294	**645**	**Total Current Assets**	**739**	**1,349**	**1,291**	**1,179**	**1,057**	**952**
	7,422	7,582	Gross Fixed Assets	30,668	30,668	30,668	30,668	30,668	30,668
	3,143	3,493	Less: Acc. Depreciation	16,085	17,094	18,102	19,111	20,120	21,094
	4,279	4,089	Net Fixed Assets	14,583	13,575	12,566	11,557	10,549	9,575
	78	137	Capital Work–in–Progress	137	137	137	137	137	137
	4,651	**4,871**	**TOTAL ASSETS EMPLOYED**	**15,460**	**15,060**	**13,994**	**12,873**	**11,743**	**10,664**
			LIABILITIES						
	50	238	Accounts Payable						
	116	136	Other Liabilities						
			LTD due within 1 year – existing						
	10	18	LTD due within 1 year – new local						
			LTD due within 1 year – new FX						
			Cash Deficiency (Surplus)	(374)	(1,400)	(3,149)	(4,995)	(6,888)	(8,742)
	176	**391**	**Total Current Liabilities**	**(374)**	**(1,400)**	**(3,149)**	**(4,995)**	**(6,888)**	**(8,742)**
			Other Liabilities						
	1		Long Term Debt – existing						
			Long Term Debt – new local						
			Long Term Debt – new FX						
			Total Long Term Debt						
			Equity Balance:						
	4,375	4,421	Assumed Opening Position	4,421	4,421	4,421	4,421	4,421	4,421
			Additional Paid in Capital						
			Revaluation of Fixed Assets	11,503	11,503	11,503	11,503	11,503	11,503
			Retained Earnings – – Prior Years	59	(91)	536	1,219	1,944	2,707
	99	59	Current Year's Net Income	(150)	626	683	726	763	774
	4,474	**4,480**	**Total Equity**	**15,834**	**16,460**	**17,143**	**17,868**	**18,631**	**19,405**
	4,651	**4,871**	**TOTAL LIABILITIES & EQUITY**	**15,460**	**15,060**	**13,994**	**12,873**	**11,743**	**10,664**

Billions Zloty at Base Year Prices
Case: gencobas\system_v\group4

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Exhibit 5–7c
OPERATING AND FINANCIAL RATIOS FOR GROUP 4

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES						
			Energy Sales(Gwh) -Annual Growth -%	-12.9%	9.9%	-4.7%	-9.7%	-11.6%	-10.4%
	851.6%	279.0%	Sales Revenue(Zl) -Annual Growth -%	29.5%	78.0%	-4.2%	-7.1%	-8.2%	-10.5%
		230.533	Average Tariff -- Zlotys/kwh	342.993	555.797	558.560	574.697	596.820	596.109
			OPERATING RATIOS						
		116.165	Variable Cost / kwh	193.063	317.984	317.971	320.113	321.468	315.967
		233.508	Total Operating Cost/ kwh	382.990	481.379	482.948	497.939	519.335	522.544
		233.544	Total Cost/ kwh (excl. ROE)	377.893	469.021	457.644	455.407	454.501	431.935
		36.840	Fixed Cost/ Mw/m	40.160	35.862	33.145	31.086	33.027	33.046
		49.690	Fixed Cost plus Dep'n/ Mw/m	85.564	81.782	79.533	77.558	84.510	89.053
		49.706	Fixed Cost plus Dep'n & Int./Mw/m	83.268	75.596	67.335	59.008	56.819	49.992
	16.6%	7.0%	Operating Income to Sales - %	-8.5%	14.6%	14.7%	14.6%	14.4%	13.5%
			Operating Income to Gross Assets						
			in Service (Average) - %:						
		14.9%	-historical						
	3.5%	2.7%	-revalued	-1.6%	3.0%	2.8%	2.6%	2.4%	2.0%
	5.7%	4.3%	Operating Income/ Net Assets - %	-3.0%	6.0%	6.1%	6.1%	6.0%	5.5%
			BALANCE SHEET RATIOS						
		1.6	Current Ratio	-2.0	-1.0	-0.4	-0.2	-0.2	-0.1
		0.4	Cash at Bank to Sales - months	0.5	0.4	0.4	0.4	0.4	0.4
		22	Accts.Receivable to Sales -days	20	20	20	20	21	21
			Debt to Equity Ratio - %						
			-historical						
			-revalued						

Billions Zloty ... Base Year Prices
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Lignite Plants

The group of lignite plants has approximately the same amount of sales as all four generating companies with coal plants. It is projected that the revenue requirement for the lignite group will be 434 Zl/kWh in 1994, or about 19 percent lower than for coal plants. The financial statements for the lignite group are shown in Exhibit 5-8.

In contrast to the coal plants, a rate of return of 6 percent on net assets of the lignite group is not sufficient to cover all cash requirements. This is largely due to work planned in the Patnow and Turow plants.

Therefore, some debt increase is necessary. The total cash deficiency is projected to increase to 10,837 B.Zl by 1997, while long-term debt will increase from 3,772 B.Zl in 1992 to 9,945 B.Zl in 1997. Nevertheless, the total debt-to-equity ratio is projected to increase to a very reasonable 16.6 percent by 1997.

Exhibit 5–8a

INCOME STATEMENT – LIGNITE GROUP

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
		46,170	Energy Sales -- Gwh	48,762	46,972	47,521	48,792	48,792	48,792
		8,120	Capacity -- MW	8,120	8,120	7,720	7,570	6,690	7,320
			% Capacity Sold						
		28,327	Hours of Production/Year	28,818	28,818	29,957	31,096	21,983	21,983
		76,698	Capacity Sales – Mw/m	80,900	77,810	76,958	75,602	66,626	73,052
			Max Capacity Sales @1994 Installation	82,824	82,824	78,744	77,214	68,238	74,664
		109,409	Energy Sales Price -- Zl/Kwh	160,585	274,095	272,002	271,246	271,246	271,246
		40,633	Capacity Price -- '000 Zl/Mw/m	50,253	100,776	100,071	104,888	119,120	124,731
			Adjusted 1994 Capacity Price						
			Sales Revenue						
		5,051	Energy	7,830	12,875	12,926	13,235	13,235	13,235
		3,116	Capacity	4,065	7,841	7,701	7,930	7,936	9,112
	1,137	8,168	Sub–total Electricity Sales	11,896	20,716	20,627	21,164	21,171	22,346
	3	181	Others						
	1,141	**8,349**	**Total Sales/Revenues**	**11,896**	**20,716**	**20,627**	**21,164**	**21,171**	**22,346**
			Variable Cost						
	618	5,358	Fuel	5,544	11,147	11,230	11,506	11,506	11,506
	88		Transport	1					
	49	297	Environmental Penalty	1,347	1,290	1,279	1,306	1,306	1,306
	6	6	Others						
	761	5,661	Total Variable Cost @ 1992 Prices	6,891	12,437	12,509	12,812	12,812	12,812
			Plus: Inflation						
	761	**5,661**	**Total Variable Cost**	**6,891**	**12,437**	**12,509**	**12,812**	**12,812**	**12,812**
			Fixed/ Capacity Costs						
	211	1,628	Existing Plant	2,475	2,201	2,042	1,899	1,804	1,739
			New Plant						
		1,093	Total Fixed Cost (ex.Dep'n)@1992	1,773	1,595	1,520	1,448	1,414	1,402
			Plus: Inflation						
	211	**1,628**	**Total Fixed Cost before Dep'n.**	**2,475**	**2,201**	**2,042**	**1,899**	**1,804**	**1,739**
	25	757	Depreciation Expense	3,486	3,486	3,333	3,436	3,721	3,955
	143	5,921	Total Operating Expense	9,617	13,838	14,017	14,359	14,101	15,106
	143	303	Operating Income	(956)	2,592	2,742	3,017	2,834	3,841
		(131)	Financial/Interest Expense (Net)	(307)	(601)	(736)	(856)	(936)	(944)
	2	265	Extraordinary Income (Loss)						
	145	699	Income Before Tax	(649)	3,193	3,479	3,873	3,770	4,785
	65	302	Corporate Tax	(260)	1,277	1,391	1,549	1,508	1,914
	79	396	Net Income After Tax	(390)	1,916	2,087	2,324	2,262	2,871

Billions Zloty at Base Year Prices

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Exhibit 5–8b
BALANCE SHEET – LIGNITE GROUP

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End – – December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			ASSETS						
	231	223	Cash	281	421	427	431	430	430
	129	458	Accounts Receivable	637	1,107	1,124	1,165	1,18-	1,227
	210	328	Inventories – – Fuel	333	657	671	689	689	689
	8	12	Others						
	244	280	Others						
	822	**1,302**	**Total Current Assets**	**1,251**	**2,184**	**2,222**	**2,285**	**2,304**	**2,346**
	15,855	16,832	Gross Fixed Assets	85,242	85,242	93,723	102,675	110,398	129,161
	6,178	7,039	Less: Acc. Depreciation	41,303	44,789	48,123	51,559	55,280	59,235
	9,678	9,793	Net Fixed Assets	43,938	40,452	45,600	51,116	55,118	69,927
	1,189	2,682	Capital Work–in–Progress	4,363	11,594	12,775	11,864	16,307	8,517
	11,689	**13,777**	**TOTAL ASSETS EMPLOYED**	**49,552**	**54,230**	**60,597**	**65,265**	**73,728**	**80,790**
			LIABILITIES						
	245	493	Accounts Payable						
	220	141	Other Liabilities						
			LTD due within 1 year – existing	170	170	170	170	170	170
			LTD due within 1 year – new local						
			LTD due within 1 year – new FX						
			Cash Deficiency (Surplus)	(2,769)	(1,103)	1,974	3,718	7,268	10,837
	465	**634**	**Total Current Liabilities**	**(2,599)**	**(933)**	**2,144**	**3,888**	**7,437**	**11,006**
	(50)		Other Liabilities	704	1,970	3,342	4,112	6,934	7,725
	1,166	2,100	Long Term Debt – existing	3,068	2,899	2,729	2,559	2,390	2,220
		162	Long Term Debt – new local	704	1,970	3,342	4,112	6,934	7,725
			Long Term Debt – new FX						
			Total Long Term Debt	**3,772**	**4,869**	**6,071**	**6,671**	**9,323**	**9,945**
			Equity Balance:						
	7,743	8,563	Assumed Opening Position	10,227	10,227	10,227	10,227	10,227	10,227
	1,199	1,286	Additional Paid in Capital						
	388	378	Revaluation of Fixed Assets	37,631	37,631	37,631	37,631	37,631	37,631
	502	519	Retained Earnings – – Prior Years	911	522	2,437	4,524	6,848	9,110
	220	393	Current Year's Net Income	(390)	1,916	2,087	2,324	2,262	2,871
	10,052	**11,138**	**Total Equity**	**48,379**	**50,295**	**52,382**	**54,706**	**56,968**	**59,839**
	11,689	**13,777**	**TOTAL LIABILITIES & EQUITY**	**49,552**	**54,230**	**60,597**	**65,265**	**73,728**	**80,790**

Billions Zloty at Base Year Prices
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Exhibit 5–8c
OPERATING AND FINANCIAL RATIOS FOR LIGNITE GROUP

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End – – December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES						
			Energy Sales(Gwh) – Annual Growth – %	5.6%	–3.7%	1.2%	2.7%	0.0%	0.0%
		618.1%	Sales Revenue(Zl) – Annual Growth – %	45.6%	74.1%	–0.4%	2.6%	0.0%	5.6%
		176.909	Average Tariff – – Zlotys/kwh	243.958	441.035	434.064	433.769	433.907	457.997
			OPERATING RATIOS						
		122.610	Variable Cost / kwh	141.326	264.784	263.237	262.592	262.592	262.592
		128.253	Total Operating Cost/ kwh	197.227	294.594	294.965	294.288	289.007	309.598
		125.416	Total Cost/ kwh (excl. ROE)	190.926	281.799	279.472	276.737	269.829	290.248
		21.225	Fixed Cost/ Mw/m	30.593	28.286	26.534	25.120	27.070	23.799
		31.096	Fixed Cost plus Dep'n/ Mw/m	73.684	73.087	69.847	70.571	82.921	77.934
		29.389	Fixed Cost plus Dep'n & Int./Mw/m	69.886	65.363	60.280	59.244	68.876	65.011
	12.5%	3.6%	Operating Income to Sales – %	–8.0%	12.5%	13.3%	14.3%	13.4%	17.2%
			Operating Income to Gross Assets in Service (Average) – %:						
		14.9%	–historical						
	1.8%	1.9%	–revalued	–1.9%	3.0%	3.1%	3.1%	2.7%	3.2%
	3.0%	3.1%	Operating Income/ Net Assets – %	–3.6%	6.1%	6.4%	6.2%	5.3%	6.1%
			BALANCE SHEET RATIOS						
		2.1	Current Ratio	–0.5	–2.3	1.0	0.6	0.3	0.2
		0.3	Cash at Bank to Sales – months	0.3	0.2	0.2	0.2	0.2	0.2
		20	Accts.Receivable to Sales – days	20	20	20	20	20	20
			Debt to Equity Ratio – %						
			–historical						
			–revalued	7.8%	9.7%	11.6%	12.2%	16.4%	16.6%

Billions Zloty at Base Year Prices

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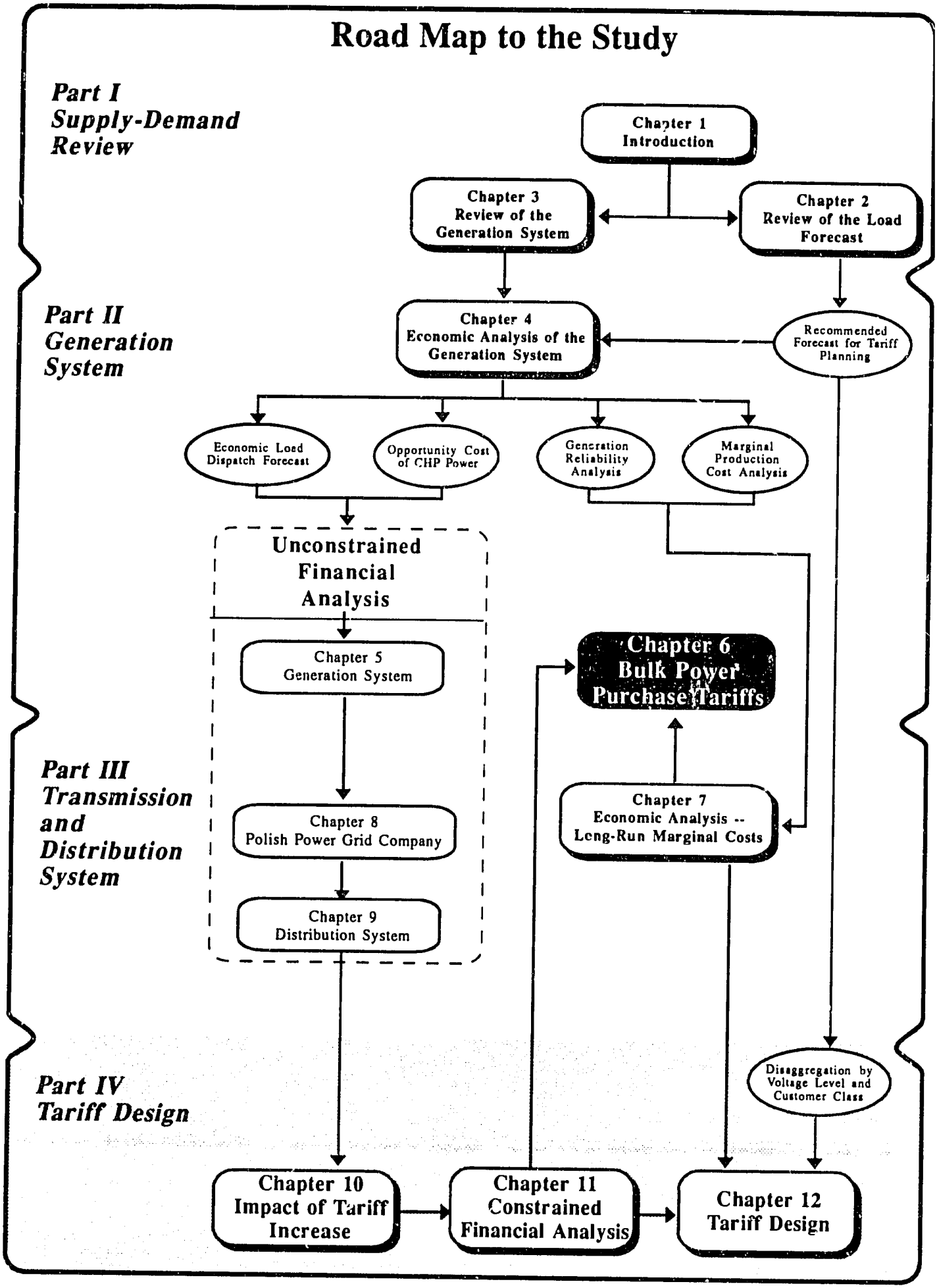
Road Map to the Study



CHAPTER 6: BULK POWER PURCHASE TARIFFS

The revenue requirements for the generation system were developed in Chapter 5 based on the pricing principles discussed during the review of the generation system (Chapter 3) and the forecast of production costs and investments (Chapter 4). The objective of this chapter is to provide more detailed recommendations about how the required revenues could be collected.

6.1 CLASSIFICATION OF BULK PURCHASE TARIFFS

Existing Thermal Plants

As discussed in Section 3.7 the pricing system recommended for 1994 consists on a *cost based* tariff for all existing powerplants and a *value based* tariff for other resources are not directly controlled by the grid. These other resources include CHP plants, other cogeneration facilities and, eventually, independent power producers (IPP).

Projects under Construction

The Opole plant, which is not yet in operation, is considered as an existing conventional grid plant for the purposes of this analysis. Beyond Opole, any new thermal capacity should be value based except when such capacity is added through the rehabilitation or repowering of an existing unit. In this case, the principles governing the purchases from the existing plant will apply.

Pumped Storage Hydroelectric Plants

It is assumed that pumped storage plants remain under the ownership of PPGC during 1994, and probably thereafter, since these plants are intimately linked to the system dispatch and control operations. Therefore, pricing for these plants should not be an issue because pumping energy will come from the aggregated bulk power purchases of PPGC and there will be no sale of power from pumped storage plants to PPGC.

6.2 COST-BASED PRICING

It is recommended that cost based pricing apply to all existing conventional power plants that are dedicated primarily to power production. This would include plants involved in minor sales of heat, as described earlier.

The compensation should be based on a two-part tariff. Fixed costs would be recovered through capacity sales and variable costs through energy sales. In addition, profit, calculated as a return on net assets, should be included in the tariff. It is recommended that most of this return (85 percent) be collected through capacity sales with a small part (15 percent) collected through energy sales.

6.2.1 Standard Cost Phase-In

Standard costs should be established for both fixed and variable cost components. Fixed-cost standards should cover the wages of plant personnel, administrative costs, and plant maintenance. Variable-cost standards should apply to fuel, variable operating costs, and costs for use of the environment.

To facilitate the transition to standard costs, a phase-in period can be established. During this period, partial recovery will be allowed of costs incurred above standards and, similarly, a partial withholding of an equal fraction of any the windfall profits of power plants that operate at costs below standard. The need for this adjustment may be eliminated by revised grouping of thermal plants into generating utilities as discussed in Chapter 5.

The actual selection of standard costs for each component should be the subject of a detailed analysis, but we offer recommendations on the principles for the treatment of fixed costs of non-essential capacity and basic principles for determining standard costs for fuel and the use of the environment.

6.2.2 Non-Essential Capacity

While the current excess generating capacity is not the result of poor planning by the power sector, it is nonetheless its responsibility. Therefore, generating utilities should be allowed to recover the fixed costs of such capacity from the ratepayers. On the other hand, it is necessary to provide a signal to the generating utilities that such capacity is not of value to the system at present and that it is within their managerial responsibility to decide whether to retire excess capacity or maintain it for future capacity sales.

One option is to allow the recovery of standard fixed costs while not providing any return on assets for non-ordered capacity. This option will not provide a significant saving since the capacity in question generally is installed in the older plants and their return on net revalued assets is very small.

A second option is to reduce the standard fixed cost allowance by application of a factor that is uniform for all non-essential capacity and related to the period of time until such capacity will become essential. This is being done at present except that the factor is not uniform (it is related to the specific plant).

A third option is to compute the value of the current capacity by performing a differential revenue requirements analysis. (A similar option is discussed later in this chapter with respect to CHP plants.)

6.2.3 Standard Fuel Cost

We recommended that fuel costs for coal-fired conventional grid plants be recovered on the basis of the border price of coal of a standard quality burned at the efficiency declared by the plant to the central dispatch. The standard cost of lignite should be pegged to the border price of coal through a formula that includes the estimated additional cost of burning lignite at the same level of emissions as that of standard-quality coal.

It is reasonable to use the heat rate declared by each powerplant in the formula that relates the actual energy purchases to the fuel cost compensation at standard fuel price. In this situation, the order of merit dispatch will be strictly based on increasing heat rate for each type of fuel. Any increment in the declared heat rate above its actual value would simply result in lower energy purchases and therefore lower profit. Hence, it could be economically sound to allow powerplants to compete against each other in the declaration of heat rate to the central dispatch.

6.2.4 Allowance for Environmental Tax Recovery

In principle, we would prefer that no environmental tax be levied against plants that meet target emission levels set by the Polish Government and that, eventually, only plants meeting these targets be allowed to sell power. However, since this policy may not be within the control of the power sector, a system needs to be established to allow the recovery of these costs in a way that would promote fair internal prices for fuels of different qualities and reduce overall emissions.

It is recommended that recovery of environmental costs be allowed up to the amount that would be levied if the plant were burning fuel of the standard quality used as a reference for setting border price of coal. Any additional costs would not be recoverable. Thus, a system of internal fuel prices would develop in the coal market to offset the environmental costs which can not be recovered when lower quality fuel is burned. Furthermore, any emissions reduced below the standard will result in additional profit to the generating company thereby giving further incentives for clean air production.

Two important issues must be addressed in the allowance for recovery of environmental tax: 1) the recovery of the cost of environmental control equipment and 2) the effect of environmental tax on the order of merit dispatch.

Recovery of the Cost of Environmental Control

Accepting that emission standards are a matter of Government policy, it is entirely reasonable to allow for recovery of any capital and operating costs incurred to meet those standards and to allow a return on the additional value of net assets. It is also reasonable to develop a different operating cost standard to cover the cost of chemicals and other operating expenses associated with emission control equipment.

In general, it should be attractive for any powerplant to eliminate non-recoverable emissions costs if requisite investments are fully recoverable and even profitable. It is important to establish that, once the environmental control equipment is in operation, then the equivalent level of emissions for fuel of standard quality also drops. Thus switching to a cheaper (and dirtier) fuel will not be very attractive. In other words, the ratepayers should pay for investments and costs that result in actual improvement to the quality of the environment and not for investments that increase profit to the plants at the same environmental quality level.

Dispatch Order

As a general rule, environmental taxes should not be included as economic costs when calculating order of merit dispatch. Taxes are transfer payments within society, and as such they are not treated as economic costs.

Environmental costs should be included as economic costs if they represent quantified measures of impact to society. Specifically, these charges should be directly related to: 1) the quantity of pollutants emitted, and 2) the cost to society of either reducing emissions or of living with them.

Including environmental taxes in the dispatch could cause lignite-fired plants to move above the base in the merit dispatch, significantly distorting the intended use of these plants and increasing the total cost of power generation. Therefore, we recommend that environmental costs should be included only to the extent that they represent explicit costs to society.

6.2.5 Heat Sales by Power Plants

The sale of heat by plants primarily dedicated to power production is economically efficient to both the heat and the power subsectors and this activity must therefore be encouraged. These plants will be compensated according to the cost based principles discussed above, including the recovery of the additional cost of producing heat for sale. However, the revenues from the sale of heat should be applied against costs to be recovered. In order to provide an incentive for sales of heat from powerplants, these plants may be allowed a regulated rate of return on such sales so long as the regulator is satisfied that revenues from heat sales offset the additional costs.

6.3 VALUE-BASED PRICING

There are many resources in the system that are not entirely under the control of central dispatch or that have constraints that prevent their dispatch on an economic basis. Resources that may have this characteristics are combined heat and power plants, small hydroelectric plants and surplus power from autoproducers. Many of these resources may sell their power directly to distribution companies at negotiated prices but in some cases power will be sold to the grid and thus the price should be determined either through bidding or negotiated not to exceed the minimum cost that would be incurred to secure such power supply from an alternative source. This approach to evaluating power is known as the "avoided cost principle" and there are many methods and techniques applied all over the world to compute avoided costs.

As discussed in Chapter 4, the computation of avoided cost may in some cases yield similar results to that of marginal costs but the former takes into account the characteristics of the power being supplied (i.e. capacity and capacity factor) whereas the later assumes that power is supplied at load factor and very small increments.

6.4 COMPUTATION OF AVOIDED COSTS FOR CHP, SMALL HYDRO AND AUTOPRODUCERS

While the joint production of heat and power is economically efficient and should be encouraged, a cost based compensation for power is not recommended for plants that are not primarily operated for power production as is the case of CHP plants in Poland.

Due to the relatively small share of CHP in total power production and the social priority placed on adequate and economic heat supply, it is preferable to transfer to district heating customers the full benefit of the cogeneration process as recommended in the district heating tariff study (DBDH, August 1992). Purchase of electricity from CHP plants based on the principle of avoided costs eliminates the need to allocate costs between the joint products of heat and electricity.

Small hydro plants and autoproducers are mostly outside the control of central dispatch and, at any rate, produce to little power to engage in individual pricing formulas based on their production cost. It is therefore preferable to apply avoided cost principles to these resources.

Since different resources have different characteristics the computation of avoided cost should be done individually for each resource under negotiation. However, in order to provide a reference value, it is illustrative to present a computation of the combined avoided cost of all CHP, small hydro and autoproducers.

6.4.1 Least-Cost Expansion Plans

The GPT model described before and used for the long term simulation of the system has a very convenient feature that is particularly useful to estimate the approximate least cost of expanding the system. Faced with a situation when capacity reserve is below a target level GPT will choose from a selection of different resources those that will minimize the capital and operating costs for each year.

This method generally results in expansion plans that are not continuously feasible and are slightly lower in cost than that of the true feasible least cost plan but the difference in cost between two approximate plans is very close to the difference in cost between two true lest cost plans and thus the method is well suited for avoided cost calculations.

In this case GPT was allowed to choose resources from three possible candidates. A 360 MW lignite fired steam turbine unit, a 600 MW coal fired steam turbine unit and a 120 MW gas turbine fired with natural gas. These candidate resources were also used by PPGC in the analysis of the expansion plan and the same characteristics and costs were adopted. The

need for capacity is defined by a target of zero effective capacity reserve which results in adequate installed capacity reserve levels.

The model was run twice under identical conditions for the period 1992-2010 with the only difference being that in the second run (evaluation case) all CHP, small hydro and autoproducers are eliminated from the planned system (base case). A summary of the capacity additions chosen for some spot years follows:

Capacity Additions in MW

Year	Base Case			Evaluation Case		
	Lignite	Coal	Gas Turbine	Lignite	Coal	Gas Turbine
1995	0	0	720	0	0	4,560
2000	0	0	120	0	0	6,840
2005	0	0	1,680	1,440	6,960	2,400
2010	360	1,200	1,200	2,880	4,800	6,600

It is stressed that the additions shown for the two plans are only meaningful in the context of an analysis of differential costs and not at all in absolute terms. For instance, the addition of 720 MW of gas turbines in 1995 is to compensate for capacity undergoing rehabilitation. Similarly, the drop in peaking capacity (gas turbines) through time in favor of base load capacity (lignite and coal) is not really feasible. On the other hand, the reliability of these ideal sequences is much closer than can normally be expected of truly feasible sequences and thus their costs are more readily comparable.

6.4.2 Annual Avoided Costs

In Exhibit 6-1 it is shown, for each of these two cases, the annual capacity and production of all CHP, hydro and autoproducers and the fixed cost (capital and operation) and variable cost (fuel) of the entire generation system. The capacity and production of hydro in the evaluation case corresponds to resources not being evaluated such as pumped storage hydroelectric.

EXHIBIT 6–1

COMBINED AVOIDED COST OF CHP, SMALL HYDRO AND AUTOPRODUCERS

YEAR	BASE CASE EXPANSION ANNUAL VALUES				EVALUATION CASE EXPANSION ANNUAL VALUES				GENERATION AVOIDED COSTS ANNUAL UNIT VALUES			
	CHP+H+AP CAPACITY MW	CHP+H+AP PRODUCTION GWH	FIXED COSTS M$	VARIABLE COSTS M$	CHP+H+AP CAPACITY MW	CHP+H+AP PRODUCTION GWH	FIXED COSTS M$	VARIABLE COSTS M$	CAPACITY $/kW–Y	CAPACITY CTS/kWh	ENERGY CTS/kWh	TOTAL CTS/kWh
1992	7041	14630.2	473.4	2044.8	1330	326.7	729.3	2465.8	44.81	1.79	2.94	4.73
1993	7091	16477.8	499.8	2085.3	1330	1844.4	771.6	2539.6	47.18	1.86	3.10	4.96
1994	7191	15658.3	514.0	2168.3	1330	358.9	801.6	2665.2	49.07	1.88	3.25	5.13
1995	7341	16494.7	514.8	2218.3	1330	208.4	810.4	2747.6	49.18	1.82	3.25	5.06
1996	7531	17786.9	484.0	2206.4	1330	204.8	787.6	2777.6	48.96	1.73	3.25	4.98
1997	7871	20024.4	480.7	2223.7	1330	173.9	808.1	2864.5	50.05	1.65	3.23	4.88
1998	9061	23892.4	614.2	2218.4	2080	1124	941.5	2987.7	46.88	1.44	3.38	4.82
1999	9161	24516.8	627.1	2296.9	2080	1088.3	986.2	3136.7	50.71	1.53	3.58	5.12
2000	9681	27952.1	618.2	2300.2	2080	1050.4	1017.0	3293.1	52.47	1.48	3.69	5.17
2001	9981	29954.9	611.9	2217.9	2080	1023.9	1034.5	3276.2	53.49	1.46	3.66	5.12
2002	10281	31906.4	638.0	2307.8	2080	986.1	1092.3	3493.2	55.40	1.47	3.83	5.30
2003	10581	33884.4	660.0	2391.6	2080	960.3	1258.7	3603.5	70.43	1.82	3.68	5.50
2004	10881	35785.4	695.5	2509.4	2080	914.5	1559.9	3594.7	98.22	2.48	3.11	5.59
2005	11181	37808.7	713.1	2592.1	2080	879.3	1807.5	3605.0	120.25	2.96	2.74	5.71
2006	11481	39720.3	744.8	2717.9	2080	823.8	1997.4	3680.5	133.24	3.22	2.47	5.70
2007	11781	41688.6	800.1	2695.5	2080	777.8	2028.1	3821.4	126.58	3.00	2.75	5.75
2008	12081	43608.6	754.2	2828.4	2080	710.7	2148.2	3910.7	139.39	3.25	2.52	5.77
2009	12381	45539.2	863.9	2875.2	2080	681.2	2402.3	3933.4	149.34	3.43	2.36	5.79
2010	12851	48822	1071.2	2816.2	2080	629.6	2600.0	4018.7	141.94	3.17	2.50	5.67

The difference in fixed costs divided by the difference in capacity is the fixed avoided cost per unit of capacity of each year and the difference in variable costs divided by the difference in production is the variable avoided cost per unit of energy of each year. The total avoided cost per unit of energy is the difference between all costs divided by the difference in production. The fixed avoided cost can, of course, also be expressed per unit of energy.

6.4.3 Levelized Avoided Costs

The unit annual avoided costs are rather unstable because they react to short term system circumstances. It is normally preferable to use levelized values over a period of time, generally corresponding to contract term, as a basis for a power purchase agreement. Sometimes part of the price is levelized while another part, usually the fuel component, remains annually variable.

In Exhibit 6-2 the results of the two cases are shown in the form of accumulated discounted values for each year and the computation of unit levelized values of avoided costs is done using these accumulated discounted values exactly in the same way that the unit annual values were used in Exhibit 6-1. This is the correct method of obtaining levelized unit avoided costs (or any levelized unit cost for that matter) and is not the same as levelizing the annual unit avoided costs.

The tendency for avoided costs to increase is due to several factors. The avoided fixed costs per unit of capacity increase as the excess reserve in the system disappears towards 1997/98. After 2000 it continues to increase as the replacement generation becomes more mixed between base load and peaking plants. The variable costs vary very little and only as a result of different generation mix through the years and the small but constant increase in the price of gas.

6.4.4 Proxy Plant Methods

It is often considered advantageous to define avoided cost in terms of an alternative or "proxy" resource. Thus, any changes in fuel prices or other costs can be captured directly by the response of the proxy resource to the new cost inputs.

The most likely proxy plant for compensating CHP power in Poland is a conventional coal fired steam plant. A reasonable agreement would involve energy payments based on the equivalent cost of energy produced by a coal fired steam turbine and capacity payments based on the unit capacity cost of a coal fired steam turbine plant applied to the alternative capacity that the CHP system is actually avoiding. The amount of "avoided capacity" can again be

EXHIBIT 6–2

COMBINED AVOIDED COST OF CHP, SMALL HYDRO AND AUTOPRODUCERS

YEAR	BASE CASE EXPANSION ACCUMULATED PRESENT VALUES				EVALUATION CASE EXPANSION ACCUMULATED PRESENT VALUES				GENERATION AVOIDED COSTS LEVELIZED UNIT VALUES (1992-YEAR)			
	CHP+H+AP CAPACITY MW	CHP+H+AP PRODUCTION GWH	FIXED COSTS M$	VARIABLE COSTS M$	CHP+H+AP CAPACITY MW	CHP+H+AP PRODUCTION GWH	FIXED COSTS M$	VARIABLE COSTS M$	CAPACITY $/kW-Y	CAPACITY CTS/kWh	ENERGY CTS/kWh	TOTAL CTS/kWh
1992	7041.0	14630.2	473.4	2044.8	1330.0	326.7	729.3	2465.8	44.81	1.79	2.94	4.73
1993	13372.3	29342.5	919.7	3906.7	2517.5	1973.5	1418.2	4733.3	45.93	1.82	3.02	4.84
1994	19104.9	41825.2	1329.4	5635.2	3577.8	2259.6	2057.3	6858.0	46.88	1.84	3.09	4.93
1995	24330.0	53565.8	1695.8	7214.2	4524.4	2407.9	2634.1	8813.7	47.37	1.83	3.13	4.96
1996	29116.1	64869.7	2003.4	8616.4	5369.7	2538.1	3134.6	10578.9	47.64	1.81	3.15	4.96
1997	33582.4	76232.1	2276.2	9878.2	6124.4	2636.8	3593.2	12204.3	47.96	1.79	3.16	4.95
1998	38172.9	88336.7	2587.4	11002.1	7178.1	3206.2	4070.2	13717.9	47.84	1.74	3.19	4.93
1999	42316.9	99426.9	2871.0	12041.1	8119.0	3698.5	4516.3	15136.8	48.11	1.72	3.23	4.95
2000	46226.9	110716.3	3120.7	12970.1	8959.1	4122.7	4927.0	16466.9	48.47	1.69	3.28	4.98
2001	49826.2	121518.3	3341.4	13769.9	9709.2	4492.0	5300.1	17648.3	48.82	1.67	3.31	4.99
2002	53136.4	131791.3	3546.8	14512.9	10378.9	4809.5	5651.7	18773.0	49.23	1.66	3.35	5.01
2003	56178.1	141532.3	3736.5	15200.5	10976.8	5085.5	6013.6	19808.9	50.38	1.67	3.38	5.05
2004	58971.0	150717.5	3915.0	15844.6	11510.7	5320.3	6414.0	20731.6	52.65	1.72	3.36	5.08
2005	61533.4	159382.3	4078.5	16438.6	11987.4	5521.8	6828.2	21557.8	55.50	1.79	3.33	5.11
2006	63882.7	167509.8	4230.9	16994.7	12413.0	5690.3	7236.9	22310.9	58.40	1.86	3.29	5.14
2007	66035.0	175126.2	4377.0	17487.2	12793.0	5832.4	7607.4	23009.0	60.67	1.91	3.26	5.17
2008	68005.7	182239.7	4500.1	17948.6	13132.3	5948.4	7957.9	23646.9	63.01	1.96	3.23	5.19
2009	69808.9	188872.2	4625.9	18367.3	13435.2	6047.6	8307.7	24219.8	65.31	2.01	3.20	5.22
2010	71480.0	195221.0	4765.2	18733.5	13705.7	6129.5	8645.9	24742.4	67.17	2.05	3.18	5.23

BASE YEAR 1992 DISCOUNT RATE: 12.00%

determined directly from system expansion plans with and without the CHP component or more simply from the capacity needed to maintain adequate capacity reserve margin if the CHP component were not there.

Alternative proxy plant methods can be used to provide an incentive for generation at times of highest system cost. For instance, energy sold at peak can be compensated at the cost of gas turbine generation while energy sold off-peak can be compensated at the cost of steam turbine generation. This mode may be interesting for new resources entering the system beyond 1997 but the additional complexity is not justified for existing resources.

6.5 BULK PURCHASE POWER STRUCTURE

It is important to maintain the LRMC structure at the retail and perhaps at the bulk sales tariff level in order to give consumers correct signals about the cost of supplying electricity. At the power purchase level these signals are only relevant to value based compensation system since the economic dispatch will assure the efficient utilization of the cost based resources.

Time-of-Day Tariff for CHP

There could be economic advantages for PPGC to structure its bulk purchase tariff in line with its bulk sales tariff. For instance, when time-of-day tariffs are offered to distribution companies it makes sense to offer CHP plants a time-of-day compensation on the variable portion of avoided costs.

This can be structured on the basis of the hourly short run marginal costs (SRMC) discussed in Chapter 4 but the differential SRMC between peak and off-peak up to 1997 is fairly small, only 8 percent. Thus it is unlikely that a time-of-day tariff for CHP would be justified in the next few years. Once gas turbines exist in the system the differential SRMC could be much greater and a time-of-day tariff will certainly be advantageous. This time-of-day tariff may be agreed on the basis of the SRMC structure or by developing a two part energy proxy plant as discussed in 6.4.2 above.

One-Part or Two-Part Tariff

At the generation level the issue of one-part or two-part tariff has more to do with project financing and risk management than with economics and is therefore a matter of negotiation. For instance, while a one part tariff based on energy delivered may be simpler for PPGC to

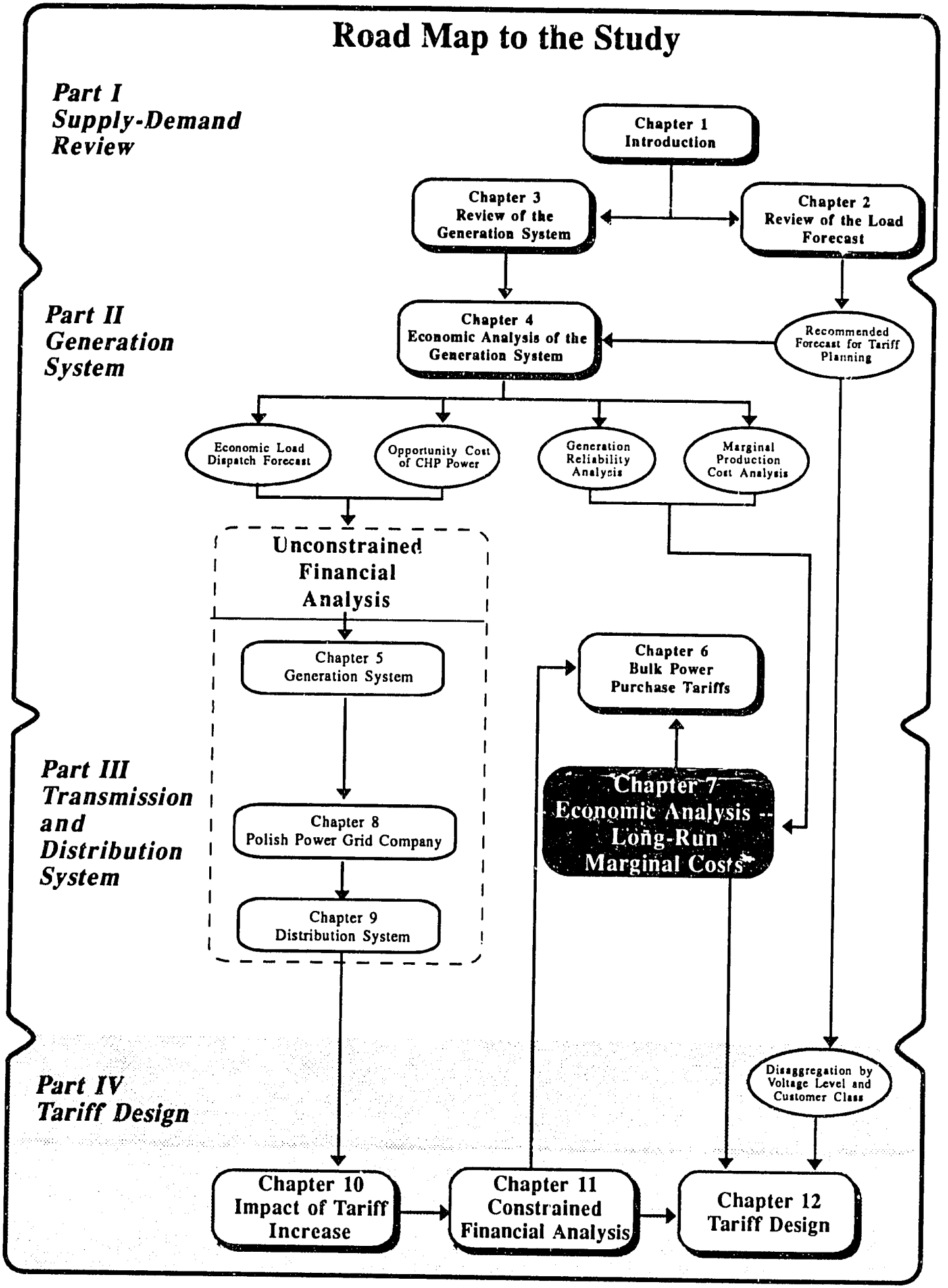
administer, it is possible that a better total power price from a generator could result if a two-part tariff would facilitate better financing terms for the plant.

Dispatch Flexibility

The total avoided cost of energy should be the ceiling of the willingness of PPGC to pay for power that would be entirely under its control. Less control or flexibility in the dispatch of that power should result in a lower price.

In the computation of DRR assumptions must be made regarding the split of CHP power between base and peak. That is, some of the energy from CHP is assumed to be associated with a constant power output, while some can be flexibly dispatched and therefore generated during the peak hours. To the extent that CHP plants are willing to accept more flexibility in the dispatch, these assumptions could be changed and the resulting avoided costs would be slightly higher.

Road Map to the Study



CHAPTER 7: ECONOMIC ANALYSIS - LONG-RUN MARGINAL COSTS

This chapter describes the methodology employed and the analysis undertaken to estimate long-run marginal costs (LRMCs) for the Polish power system. These estimates provide the necessary economic benchmark and establish the point of departure in tariff design that are required to accommodate financial and equity objectives. Specifically, average tariff yield is governed by the financial revenue requirement, whereas the allocation of this revenue responsibility by customer class and the individual customer class tariff structure are affected by the LRMC structure.

The chapter is organized as follows. Section 7.1 describes the overall marginal cost methodology. Section 7.2 illustrates the application of this methodology through the use of an LRMC computer model tailored specifically to Poland. This section contains actual model printouts and results. Section 7.3 discusses the sensitivity of the results to alternative modeling assumptions.

7.1 OBJECTIVES AND APPROACH

The efficiency pricing objective in electricity tariff planning is embedded in the economic theory of efficient allocation of resources and can be theoretically linked to the marginal cost structure of the supply system. These costs typically vary by service voltage level and by time of day, and spatial characteristics in cost structure may exist due to differential losses.

Put very simply, the marginal cost of electricity represents the cost of an increment of demand. While there are different interpretations of marginal cost, the alternative definitions are similar in that they are all forward looking. They consider only future costs related to future output, as opposed to embedded cost-of-service methods.

The rationale for marginal cost pricing emanates from the economic theory of efficient allocation of resources in competitive markets. Prices that are equal to marginal cost provide the correct signals to decision-makers -- producers and consumers -- and should result in a market equilibrium at a level and pattern of electricity supply that provide for the most efficient allocation of scarce resources.

Long-run marginal cost can be defined as the incremental costs of all adjustments in the system development plan and system operations that are attributable to an incremental increase in demand that is sustained indefinitely into the future. LRMC pricing emphasizes the trade-off between the need to give correct signals and the importance of prices that are

relatively stable over time. While short-run marginal costs (SRMC)[1] might provide even greater allocative efficiency at any given time, tariff policy-makers, producers, and consumers generally prefer a reasonable degree of price predictability and stability in order to facilitate long-term planning. A long-run perspective also reflects the long-term effects of the changing costs of electricity supply. Ignoring such effects can result in consumers making sub-optimal decisions with regard to long-term investments.

7.2 LONG-RUN MARGINAL COST PRICING MODEL AND RESULTS

For this study, a PC-based model was developed and adapted to estimate marginal costs for the Polish power system. Illustrative model results and their implications are discussed in detail in the following sections. Briefly, the model's structure embodies the theoretical considerations outlined in the preceding discussion and facilitates the calculation of marginal energy costs for up to three rating periods (peak, mid-peak, and off-peak). In addition, the model incorporates the calculations necessary to estimate marginal generation capacity cost utilizing the peaker method, and as a user option affords the same calculation using the next-plant method.[2] Also contained in the model are calculations of long-run average incremental costs (LRAIC) for various network voltage levels selected by the user.

It should be noted that the model calculates long-run marginal costs in "border prices." These are the world market prices of the goods and services (delivered to the Polish border) needed to provide marginal energy and capacity. Border prices exclude the effects of taxes, duties and subsidies that distort the prices of these goods in the domestic market.

A standard conversion factor (SCF) is used to adjust the costs of local goods to border prices in the model. This factor has been approximated as 1.0 (i.e., no adjustment).[3] A foreign conversion factor is included in the model in order to account for the average duties/taxes on imported equipment; this factor is assumed to be 1.00 because taxes and duties are excluded from all cost streams. A local labor conversion factor is also included in the model to adjust for cases in which the opportunity cost of domestic labor employed on power projects diverges from its market wage. We have not applied this factor in Poland because local labor was not separated in the cost streams. After LRMCs are calculated at border prices,

[1] Short-run marginal cost can be defined as the variable fuel and O&M cost ("system lambda") of the generating unit providing marginal energy, plus outage costs (also known as "congestion costs").

[2] Estimates from the second approach serve as a useful point of comparison. As noted later in this chapter, the next-plant method is less relevant for the current Polish situation of excess baseload capacity.

[3] The SCF is defined as the official exchange rate divided by the shadow exchange rate (OER/SER); an SCF of 1.0 implies a shadow exchange rate equal to the market exchange rate of 13,400 Zl/US dollar (mid-1992).

they are finally restated at domestic prices (using the same SCF) to derive appropriate LRMCs at market efficiency prices. Of course, with an SCF of 1.0, there is no adjustment.

Cash flows in future years are discounted back to the study year by applying a 12 percent real discount rate. The discount rate level was defined in discussions with international agencies and Polish planning authorities; it represents the opportunity cost of capital for the economy as a whole as presumed that the weighted average return on all the possible sources to finance for future investment in Poland. This choice is justified on the basis that capital markets reflect all we need to know about the productivity of capital and the preferences of consumers, whose utilities in turn ought to form the basis for social choice. Just as a private firm seeks to maximize profits, the national economy's goal is to maximize growth of net output. It should not, therefore, undertake any project which does not at least achieve its weighted average opportunity cost of capital.

In order to parallel the logical flow of the LRMC model, the remainder of this section is organized into four subsections:

- marginal energy cost
- marginal generation capacity cost
- marginal network capacity cost
- results.

The first three sections demonstrate how the model uses basic assumptions about the system to calculate energy (Zl/kWh) and capacity (Zl/kW) costs. The results section presents the additional calculations required to integrate these component costs into the model's estimation of the long-run marginal cost of electricity delivered to different voltages and tariff classes.

Marginal Energy Cost

The first component is essentially the variable cost (fuel and variable O&M) of the most expensive generating unit that is running for the purpose of "picking up incremental load at the margin." Once this plant is identified, the marginal energy cost at that instant can be calculated directly given the unit fuel price, heat content of the fuel, and the incremental heat rate of the generating unit.

Exhibit 7-1 helps to illustrate the concept of marginal energy cost and its variation by time-of-day (TOD). The exhibit depicts a schematic of a typical winter daily load curve for the Polish power grid. Also shown in the exhibit is a 1997 merit order stacking of generating units classified into seven homogeneous groups, ranked from the cheapest to the most expensive fuel group. At the bottom (i.e., the first to be dispatched) is the base hydro

energy. The variable cost of operation for this group is essentially any non-fuel variable O&M expense. Therefore, the total variable cost for this group is close to zero.

Stacked immediately above the base hydro are the combined heat and power (CHP) units expected to be in the system by 1997. These units are not stacked in "merit order" due to lower cost, but rather because the system is obligated to purchase the energy produced as part of the nation's district heating system. Next in the stack come the lignite units. The variable cost of lignite-fired energy is estimated to be 218.7 Zl/kWh. As one goes higher up in the stacking order, the variable (fuel plus other O&M) costs become progressively higher.

Stacked immediately above the lignite units are the coal units. We have divided these into two groups. "Coal-1" includes the majority of coal-fired capacity; the variable cost of energy of these more efficient units is estimated to be 272.5 Zl/kWh. "Coal-2" generally includes the oldest, smallest, and least-efficient coal-fired units, with an estimated variable cost of 302.9 Zl/kWh. Following the coal units in the stacking order is the peaking energy from combustion turbines, with an estimated variable cost of 591.5 Zl/kWh.

A production simulation model (GPT) was utilized to determine the optimal stacking presented in Exhibit 7-1, and a short-marginal cost model was used to determine, *on a probabilistic basis*, the units that can be expected to be at the margin at different hours of the day in summer and winter. These models are described in Chapter 4. Surprisingly, the 240 MW of combustion turbine capacity installed by 1997 are not expected to provide marginal energy, even during peak winter hours; these units are part of the least-cost expansion plan to provide reliability support, as highlighted by the very low capacity utilization of combustion turbines shown in Exhibit 7-1. Rather, marginal energy during both seasons and during all hours of the day is provided by coal-fired steam generating units.

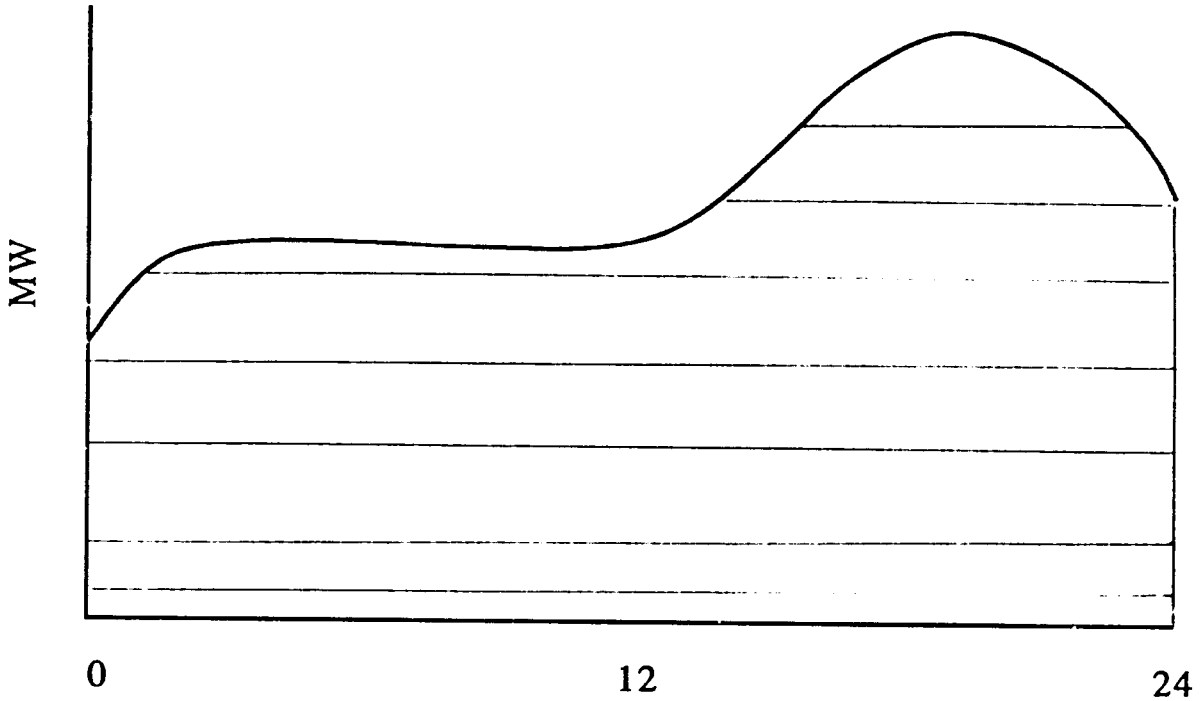
For the purposes of estimating long-run marginal energy costs by season and time of day, the following data were reviewed:

- projected load resource balances (MW) through the year 2006
- system dispatch (GWh generation by fuel type) at present and projected for the future
- production costing simulations for the next 15 years, focusing on the year 1997,[4] estimating the capacity utilization and average energy production by generating unit

[4] We selected the year 1997 as a representative snapshot of system characteristics and conditions for the purpose of estimating long-run marginal costs.

Exhibit 7-1

Typical Day Winter Load Curve and 1997 "Merit Order" Stacking of Marginal Plants



Variable Cost (Z/kWh) by Plant Group	
Pumped Storage	--
Combined Turbines	591.5
Coal -2	302.9
Coal -1	272.5
Lignite	218.7
CHP	--
Base Hydro	--

- system hourly load data for the last several years.

In addition, a separate analysis was conducted to identify those hours of each day that contribute most towards the annual loss-of-load probability (LOLP). Based on LOLP, the peak, mid-peak, and off-peak periods have been identified.

These analyses, detailed in Chapter 4, are the basis for the following assumptions applied to estimate marginal energy costs:

- distinct seasonal difference in both supply and demand distinguish summer (May through October) and winter (November through April) periods

- Time of day rating periods:

  -- Winter: A peak period of 4:00 p.m. to 9:00 p.m. on weekdays, and a mid-peak period of 7:00 a.m. to 1:00 p.m. on weekdays, with all other times off-peak

  -- Summer: A peak period of 7:00 p.m. to 10:00 p.m. on weekdays, and a mid-peak period of 7:00 a.m. to 1:00 p.m. on weekdays, with all other times off-peak

- Fuel costs used in the marginal energy cost analysis are summarized below. (Fuel price issues are elaborated in Chapter 3 and in Appendix 3.2.)

Fuel Cost	$/GJ	TysZl/GJ
Coal	2.01	26.940
Lignite	1.53	20.470
Mazout	2.07	27.610
Gas/Distillate	3.65	49.050

- The following table summarizes the marginal costs derived from the production simulation analysis for 1997. The table identifies "proxy" coal-fired units whose variable costs closely approximate the calculated marginal costs. These proxies have been applied in the LRMC model to define marginal energy costs.

- Note that marginal energy costs are higher in the Summer than during the Winter for mid-peak and off-peak rating periods. As discussed in Chapter 4, this surprising result follows from the fact that less capacity is available during

the Summer months (e.g., shutdown of CHP units) and maintenance scheduling requires utilization of older, less efficient generating units.

Season/ Time of Day	Marginal Energy Cost ($/kWh)	Proxy Unit (MW)
Summer		
Peak	4.64	Gas Turbine
Mid-Peak	3.97	-[5]
Off-Peak	2.12	Jaworzno 3 (200)
Winter		
Peak	4.64	Gas Turbine
Mid-Peak	2.80	Jaworzno 1 (19)
Off-Peak	2.07	Rybnik (200)

Exhibit 7-2, taken from the LRMC model, summarizes the results and specific assumptions used in calculating marginal energy costs: heat rate, fuel types, heat content, variable O&M expenses, etc. for the marginal plants during on-peak and off-peak hours. The exhibit indicates that marginal energy costs are determined as fuel and O&M costs (per kWh) for operating the proxy gas turbine and coal-fired steam plants identified in the preceding table. The on-peak energy cost is taken as the operating cost of a combustion turbine; the mid-peak (morning peak) and off-peak marginal energy costs are taken as that of the coal-fired steam units identified above.

By way of illustration, the border price long-run marginal costs of energy at generation (before losses) for peak energy (summer) and off-peak energy (winter) are given as:

$$\textit{Summer Peak Energy} = \left(\frac{12000 Btu}{kWh} \times \frac{\$3.65}{GJ} + \frac{\$1.056 GJ}{MMBtu} \right) \times \frac{Zl13400}{\$} = 620\ Zl/kWh$$

[5] As a practical matter, due to operational constraints in the system, Summer mid-peak marginal energy cost falls between the operation costs of a small coal plant and a gas turbine (see Chapter 4). In the model, a "dummy" heat rate was assigned to simulate the marginal cost defined through a production cost simulation of the system in 1997.

EXHIBIT 7-2
MARGINAL ENERGY COSTS

Assumptions for Marginal Energy Cost Calculations:	SUMMER SEASON 8/ PEAK-1	PEAK-2	MID-PK	OFF-PK	WINTER SEASON 8/ PEAK-1	PEAK-2	MID-PK	OFF-PK
Marginal Plant	C-TURB		COAL	COAL	C-TURB		COAL 9/	COAL
Heat Rate (BTU/kWh)	12000		13289	9984	12000		18700	9734
Fuel Used	Gas		Coal	Coal	Gas		Coal	Coal
Fuel Cost (US$/unit) 7/	3.86		2.12	2.12	3.86		2.12	2.12
Heat Content (MMBtu/unit)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Variable O&M ($/MMBtu)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Utilization of Plant on Peak (%)	100%	0%			100%	0%		

MARGINAL ENERGY COST (tysZl/KWh): 1/

	SUMMER SEASON 2/ PEAK	MID-PK	OFF-PK	WINTER SEASON 2/ PEAK	MID-PK	OFF-PK	ANNUAL AVERAGE 2/ PEAK	MID-PK	OFF-PK
GEN	0.670	0.407	0.306	0.670	0.573	0.298	0.670	0.490	0.302
(adjusted to local prices and for station losses)									
VHV	0.682	0.415	0.310	0.682	0.584	0.303	0.682	0.499	0.306
HV	0.713	0.433	0.321	0.713	0.610	0.313	0.713	0.522	0.317
MV	0.736	0.448	0.329	0.736	0.630	0.321	0.736	0.539	0.325
LV	0.832	0.506	0.361	0.832	0.712	0.352	0.832	0.609	0.356

1/ Energy Costs derived directly from basic assumptions regarding marginal plant, heat rate, fuel cost, fuel heat content, and variable O&M.

$$\textit{Winter Off-Peak Energy} = \left(\frac{9{,}734Btu}{kWh} \times \frac{\$2.01}{GJ} + \frac{\$1.056GJ}{MMBtu}\right) \times \frac{Zl\ 13400}{\$} = 276.5\ Zl/kW$$

Subsequently, these estimates are further adjusted to local prices for our estimate of the LRMC of energy at generation by season and time of day,as shown in the lower panel of Exhibit 7-2.[6]

Marginal Generation Capacity Cost

In contrast to the marginal energy cost calculation, there is no universally accepted method for estimating the LRMC for generation capacity. Whereas there is general agreement at a conceptual level, when it comes to estimation, a consensus is lacking. Several methods have been proposed. Three methods frequently mentioned are:

- peaker method
- next-plant method
- incremental revenue requirements method.

It is beyond the scope of this report to provide a detailed description of these methods, the subtleties involved, and their relative merits and disadvantages. Briefly, however, long-run marginal generational capacity cost is defined as the changes in total future costs associated with a 1 kW increase in peak demand, sustained indefinitely into the future. The methods noted above differ in what they *assume* to be hypothetical system response to the hypothetical increment in peak load.

The peaker method is rationalized on the basis that the least-cost means of securing capacity is a peaking unit, and the reason any other type of generation is built is to derive the energy savings. The annualized cost of such a unit -- adjusted for reserve margin and losses, and appropriately discounted to today from the year it is needed -- is the marginal cost of generation capacity. The following equation captures this calculation:

$$\textit{Marginal Generation Capacity Cost (Zl/coincidentKW/year)} = K \times \left(\frac{1+RM}{1-SL}\right)$$

[6] These marginal energy costs must also be adjusted for losses if the energy is not sold at the busbar.

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where,

K = annualized cost of peaking unit (Zl/kW/yr)
RM = planning reserve margin (%)
SL = station losses (%).

This cost (in constant prices) is subsequently discounted from the first year in the future when the reserve margin constraint (or the loss-of-load probability criterion) is binding, and adjusted upwards for incremental fixed O&M expenses, as well as any downstream losses up to the point of delivery. Finally, this cost can be allocated to different rating periods in the study (e.g., peak, mid-peak, and off-peak) using a number of different methods. A common allocation method is on the basis of the contribution of each rating period to the annual loss-of-load probability (LOLP).

Under the next-plant method, it is assumed that the 1 kW load increment (decrement) will be met by appropriately advancing forward (delaying) whichever power plant is planned to come on-line next. For example, if the next plant called for in the system plan is a baseload lignite unit planned for 2001,[7] then its annualized cost can be used to establish the LRMC, after assigning credit for any fuel savings as a result of having a more fuel-efficient plant.

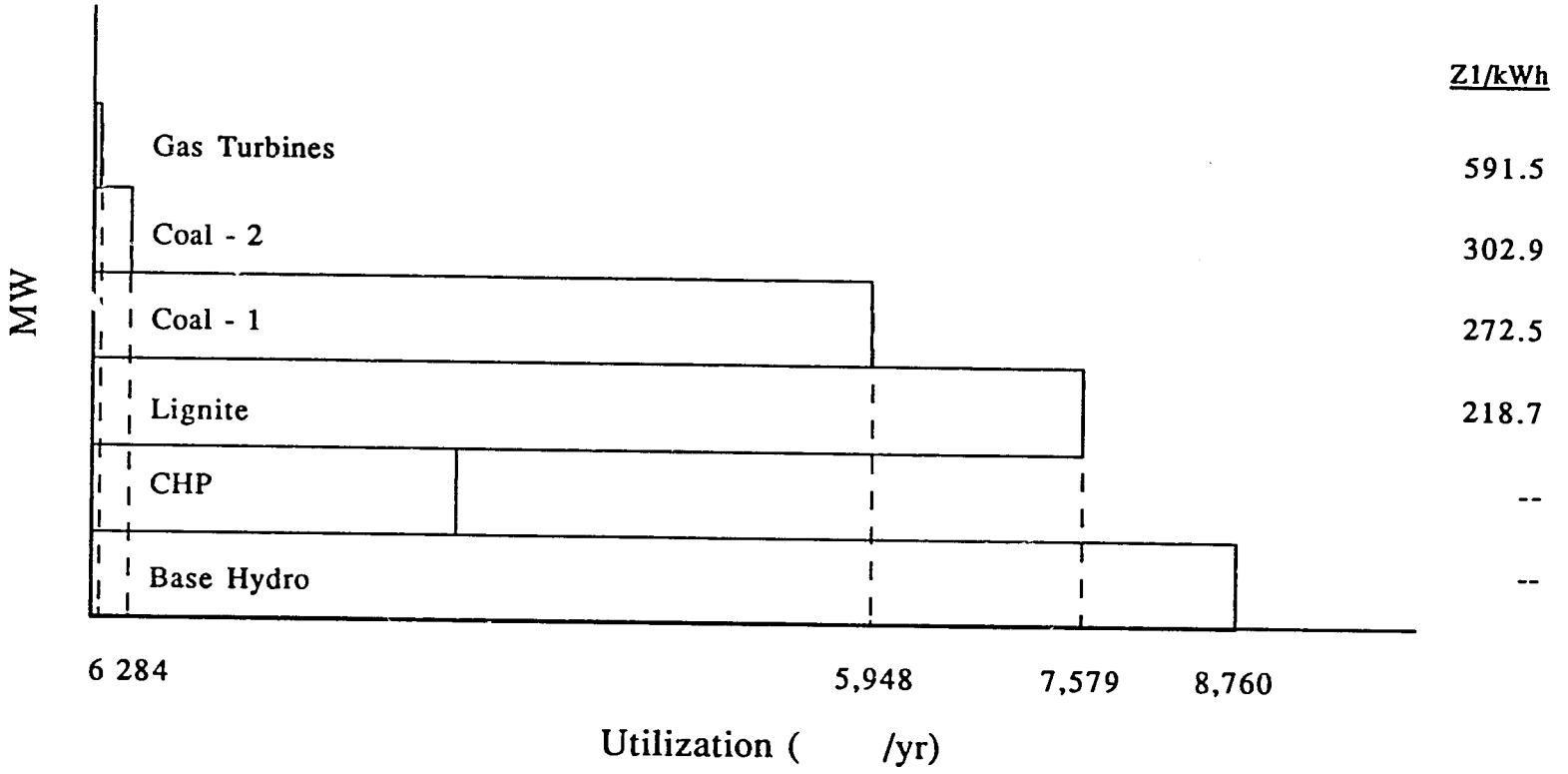
Exhibit 7-3 helps to illustrate the fuel savings adjustment that is required when using the next-plant method to estimate marginal generation capacity cost. The exhibit shows a schematic annual load duration curve with a merit order stacking of generating plants. If the "next plant" in the least-cost expansion program is a baseload lignite unit, then 1 kW of additional capacity from such a unit will have the effect of displacing generation of all more expensive units, i.e., units higher up in the stacking order. In the illustration in Exhibit 7-3, this is depicted as reducing 1 kW of "Coal-1" generation for 5,948 hours, 1 kW of "Coal-2" for 284 hours, and 1 kW of gas turbine generation for 6 hours. Thus, the annual fuel savings that should be credited against the annualized capital cost of the lignite plant are given by the calculation [5948 x (272.5 - 218.7) + 284 x (302.9 - 272.5) + 6 x (591.5 - 302.9)] Zl/kW/year. Therefore, the marginal generation capacity cost under the next-plant method is inferred as the annualized capital cost of the lignite plant (expressed in Zl/kW/year) less the fuel savings estimated as above.

In contrast to the two methods described above, the incremental revenue requirements method re-optimizes the entire expansion plan and estimates the incremental difference in the present value of two expenditure streams. Reoptimization of the expansion plan requires the

[7] Excluding combustion turbines (already reflected in the peaker method) and pumped hydro (whose benefits exceed pure capacity), such a lignite plant is the "next plant" in the least-cost development plan.

Exhibit 7-3

Marginal Generation Capacity Costs Using "Next Plant" Method



Marginal capacity cost = Annualized cost of lignite plant minus fuel savings

Fuel savings = [5948 x (272.5 - 218.7)] + [284 x (302.9 - 272.5)] + [6 x (59.5 - 302.9)] (Z1/kWh)

use of sophisticated optimization system expansion planning models.[8] We have employed a variation of this methodology to calculate the "avoided cost" of the CHP generation supplied to the system (see Chapter 4).

Implementing the incremental revenue requirements method requires a substantial commitment of resources. More fundamentally, however, the incremental revenue requirements method is characterized by a conceptual flaw. Estimates of "marginal cost" developed by this method are weighted averages of capacity costs of a diverse mix of marginal as well as inframarginal plant types: peaking, intermediate, and baseload. Such a basis is contrary to the notion of marginal capacity cost, i.e., the cost of meeting a marginal increment of demand on-peak.

As a practical matter, the three methods should yield similar estimates of LRMC under conditions where the utility's generating mix is not substantially different from the least-cost mix and the reserve margin is just adequate. Under such conditions, the "next unit" for capacity purposes will indeed be a peaker and the system reoptimization method should also elect to advance the peaker.

In practice, the peaker method is by far the most frequently used method, providing a close approximation of the pure value of an increment of capacity. Use of the incremental revenue requirements method is less frequent but is probably the best when a firm expansion plan is available. Because the method provides the most complex system response to meet an increment of new load, it is more commonly utilized in the context of estimating "avoided costs" for calculating payments for power purchases. The "next plant" method, while providing only an imperfect measure of the system response to a capacity addition, has been applied in some regulatory environments as an alternative to the peaker method, particularly when new peeking capacity is not part of the system expansion plan. This method is less reliable than the others two.

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[8] For example, the International Atomic Energy Agency's WASP model for optimal generation expansion planning, or the GPT model described in Chapter 4. Specifically, three model runs are required as follows. Run 1 corresponds to optimizing the system generation expansion plan to the baseload forecast. Model Run 2 reoptimizes the system expansion plan with the peak load forecast used in Run 1 incremented by the equivalent of one year's load growth. Finally, Run 3 is a production simulation (e.g., WASP in a "pre-specified pathway" mode) to estimate the fuel costs associated with the load forecast used in Run 1, but unit staging determined in Run 2. Thus, LRMC for generation capacity can be estimated by calculating the following quantity and levelizing it:

$$[(CR_1 - CR_2) + (FC_3 - FC_1)]/DMW$$

where CR_i is the capital investment associated with model run i (i = 1, 2, 3), FC_i is the fuel (production) cost associated with the expansion plan model run i, and DMW is the megawatt incremental difference in peak load between Runs 1 and 2.

Based upon our review of the expansion plan, we believe that the peaker method is appropriate for estimating the marginal cost of generation capacity. However, for the purposes of comparison, we have also estimated generation capacity cost using the next-plant method. For this purpose, the first baseload plant added to the system in the least-cost expansion plan (a lignite plant in the year 2001) provides the only reasonable proxy. As noted above, the results of this method are not reliable and are only provided as an illustration.

Exhibit 7-4 depicts key input assumptions and results for the LRMC model for the marginal generation capacity cost calculation. At an exchange rate of Zl 13,400 to US $1.00 and a standard conversion factor of 1.0, the border prices discounted back from the year the capacity is required, are 3,073 TysZl/kW for a peaker plant[9] and 8,551 TysZl/kW[10] less associated fuel savings of 330 TysZl/kW/year for the lignite plant. These costs are subsequently annualized over the respective plant lifetimes, adjusted to local prices and for reserve margin, station losses, and incremental O&M expense.

Marginal Network Capacity Cost

The transmission and distribution (T&D) network's capacity is designed to accommodate peak demand power flows from generation to end users. Further, in a growing system, such network capacity is sized and sequenced recognizing future growth potential as well. Generally, all investment costs for T&D are allocated to incremental capacity since the designs of these facilities are determined principally by the peak kilowatts that they carry rather than by kilowatt-hours. The most frequently used approach for estimating marginal T&D capacity cost, and the one which we have also used, is the long-run average incremental cost (LRAIC) method.

The LRAIC represents the present value of all T&D investments over the planning horizon divided by the present value of the corresponding annual increments in peak load. This value, expressed in Zl per incremental kW, is then annuitized over the life of the facilities, resulting in the annuitized capacity cost, expressed in Zl/kW/year.

Separate LRAICs must be estimated for each major voltage level of the grid -- very high voltage (VHV), high voltage (HV), medium voltage (MV), and low voltage (LV) -- as depicted schematically in Exhibit 7-5.

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[9] i.e., $(4033 + 1083 \times 1.0) \times (1/(1.12)^5)$.

[10] i.e., $(3557 + 20155 \times 1.0) \times (1/(1.12)^9)$.

EXHIBIT 7-4
GENERATION CAPACITY COST - PEAKER AND "NEXT PLANT" METHODS (tysZl/KW)

ASSUMPTIONS	PEAKER METHOD	"NEXT PLANT"
Marginal Plant	C-TURB	LIGNITE
Life (years)	20	30
O&M and A&G (% of capital cost)	4.50%	1.87%
Year Generation Required	1997	2001
Capital Cost:		
Foreign (tysZl/KW)	4332.7	3556.8
Local Materials	1083.2	20155.4
Local Labor 4/	0.0	0.0
CAPACITY COST (discounted to study year)		
Market Price	3073.09	8550.86
Border Price	3073.09	8550.86

PSE/POLISH POWER GRID
RANKING OF GENERATING PLANTS BY VARIABLE COST - 1997

GENERATING PLANT GROUPS	TYPE	MEGA-WATTS (MW) 1/	ANNUAL USE Hrs/Yr	VARIABLE COST $/KWh	VARIABLE COST tysZl/KWh	HEAT RATE Btu/KWh	FUEL COST $/MMBtu	VAR. O&M (% FUEL COST)
BASE HYDRO	HYDRO	80	8760	-	-	-	-	-
COMB. HEAT AND POWER 2/	CHP	5901	2597	-	-	-	-	-
LIGNITE-FIRED	LIGNITE	8791	7579	0.0163	0.2187	10118	1.61	0.0%
COAL-FIRED STEAM 1	COAL-1	11652	5948	0.0203	0.2725	9582	2.12	0.0%
COAL-FIRED STEAM 2	COAL-2	2292	284	0.0226	0.3029	10652	2.12	0.0%
COMBUSTION TURBINES	C-TURB	240	6	0.0441	0.5915	12000	3.68	0.0%
PUMPED STORAGE	P-STOR	1890	1420	-	-	-	-	-

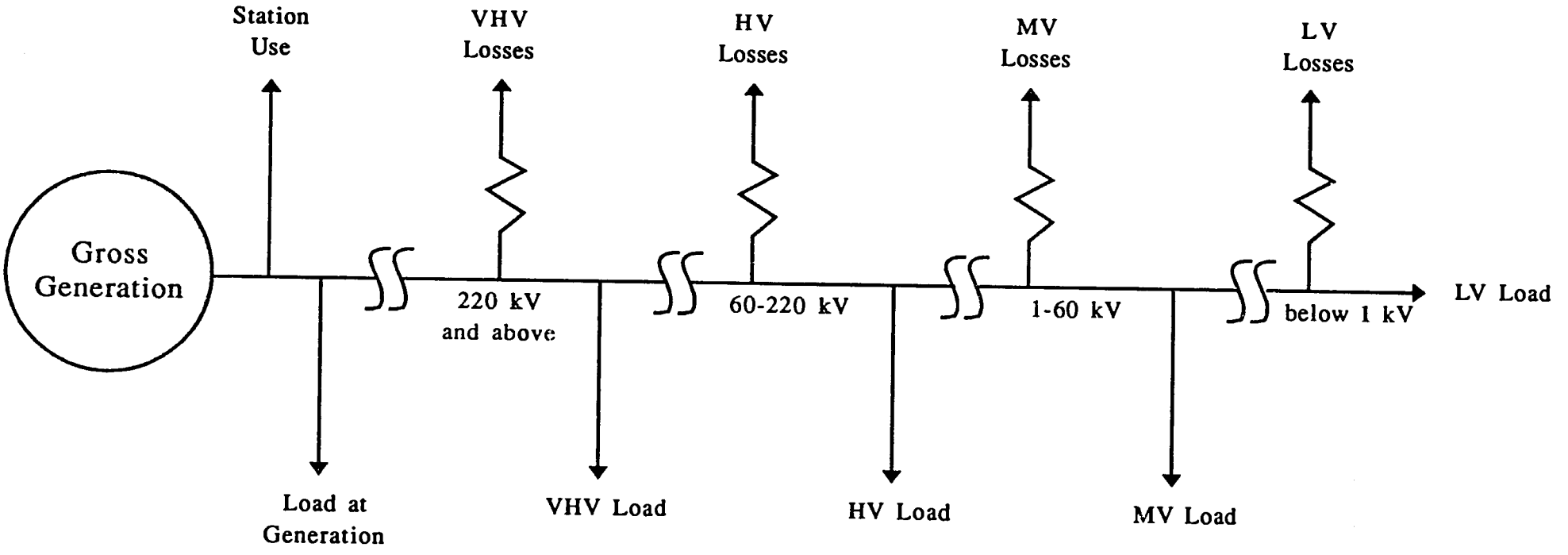
1/ Installed capacity.
2/ Megawatt capacity includes 1290 MW autogeneration.
3/ Based on PSE practice, all O&M is treated as a fixed cost.

ASSOCIATED FUEL SAVINGS - "NEXT PLANT" METHOD

---UNIT TYPE--- NEW	DISPL	COST (tysZl/KWh) NEW	DISPL	HRS/YR	SAVINGS (tysZl/KW)
LIGNITE	COAL-1	0.2187	0.2725	5948	320.01
COAL-1	COAL-2	0.2725	0.3029	284	8.64
COAL-2	C-TURB	0.3029	0.5915	6	1.73
TOTAL FUEL SAVINGS (tysZl/KW/Yr)					330.38

Exhibit 7-5

Schematic Representation of the Polish Power Grid



The schematic representation is a simplification adopted to facilitate more coherent modeling. Of course, electricity is generated at many points in the network, and more detailed power flows can be used to determine specific point to point tariff structures.

To estimate separate LRAICs for each voltage, capital expenditures, lines, and loads must be estimated for each voltage level. Exhibit 7-6 displays the incremental investments by voltage. These were derived from the most recent investment program of PPGC, and from a planning study of distribution network investment needs prepared by the Institute of Power Engineering.[11] The details of these programs are presented in Appendix 7.1.

Forecasts of energy consumption by voltage level are shown in Exhibit 7-7. These allocations were derived from PPGC's forecast of sales and peak demand for the national grid (see Chapter 2). System peak loads are derived from total sales by applying a system load factor because peak load forecasts are not available by voltage.

The model also requires estimates of peak and average loss coefficients at each voltage level as a percent of incoming load. Based upon discussions with PPGC's transmission planning staff, average network losses in 1991 were allocated by voltage level as 1.5 percent for VHV, 3.4 percent for HV, 1.8 percent for MV, and 4.3 percent for LV (for a total of 11.1 percent). For subsequent years, these values were scaled to match PPGC's total network loss forecast.

Peak loss calculations in the model are determined according to the following empirical formula, which has been developed based upon experience in many countries:

$$\textit{Peak Losses} = \frac{\textit{Average Losses}}{.3 + (.7 \times \textit{Load Factor})}$$

Estimates of average and peak loss factors by voltage level are shown in Exhibit 7-8.

Estimates of incoming peak load, losses, and consumption in MW at each voltage level as calculated by the model are shown in Exhibit 7-9. The exhibit displays the predicted coincident power balance under each voltage for the years 1992 through 2001. To illustrate, in the year 1993, the gross peak level of 22,224 MW, after adjusting for 1,596 MW of station use (based upon application of the peak station use factors in Exhibit 7-8), and after

[11] A consolidated investment program by voltage level for the distribution companies is not available. Since the best available investment program for the distribution companies is a "requirements" plan, there is some concern that it may *overstate* a realistic investment program. The impact of a lower investment program on estimated LRMCs is considered in the sensitivity analysis of Section 7.3.

EXHIBIT 7–6
NETWORK CAPACITY COSTS (tysZl MILLION)

YEAR ENDING	VHV COSTS TOTAL	VHV COSTS FOREIGN	VHV COSTS LOC Mat.	VHV COSTS LOC Labor	HV COSTS TOTAL	HV COSTS FOREIGN	HV COSTS LOC Mat.	HV COSTS LOC Labor
1992	331.00	264.80	66.20	0.00	430.15	141.96	288.19	0.00
1993	158.00	126.40	31.60	0.00	696.64	243.18	453.46	0.00
1994	1079.00	750.70	328.30	0.00	752.02	259.45	492.57	0.00
1995	1694.00	1241.05	452.95	0.00	844.50	282.20	562.30	0.00
1996	1610.00	1183.00	427.00	0.00	790.79	254.66	536.12	0.00
1997	206.00	164.80	41.20	0.00	633.89	150.01	483.88	0.00
1998	200.00	160.00	40.00	0.00	586.38	114.24	472.14	0.00
1999	1161.00	823.80	337.20	0.00	684.75	175.96	508.80	0.00
2000	1243.00	888.20	354.80	0.00	794.75	247.46	547.30	0.00
2001	1160.00	823.00	337.00	0.00	482.01	164.26	317.75	0.00

YEAR ENDING	MV COSTS TOTAL	MV COSTS FOREIGN	MV COSTS LOC Mat.	MV COSTS LOC Labor	LV COSTS TOTAL	LV COSTS FOREIGN	LV COSTS LOC Mat.	LV COSTS LOC Labor
1992	1354.40	181.72	1172.68	0.00	1497.32	200.90	1296.42	0.00
1993	1385.93	185.95	1199.98	0.00	1519.00	203.81	1315.19	0.00
1994	1374.08	184.36	1189.72	0.00	1529.70	205.24	1324.46	0.00
1995	1452.66	194.91	1257.75	0.00	1575.09	211.33	1363.75	0.00
1996	1738.85	233.31	1505.55	0.00	1541.22	206.79	1334.43	0.00
1997	1835.04	246.21	1588.83	0.00	1565.58	210.06	1355.52	0.00
1998	1835.04	246.21	1588.83	0.00	1585.09	212.68	1372.41	0.00
1999	1868.57	250.71	1617.86	0.00	1604.59	215.29	1389.30	0.00
2000	1897.70	254.62	1643.08	0.00	1628.95	218.56	1410.39	0.00
2001	1897.70	254.62	1643.08	0.00	1628.95	218.56	1410.39	0.00

EXHIBIT 7 – 7
GRID SALES AND LOSS FORECAST

YEAR ENDING	PEAK (MW)	GROSS GEN (GWh)	LOAD FACTOR	CONSUMPTION BY VOLTAGE LEVEL (GWh) 1,2						AVERAGE LOSSES BY VOLTAGE LEVEL (GWh) 3/					
				TOTAL	GEN	VHV	HV	MV	LV	STN USE	VHV	HV	MV	LV	TOTAL
1992	22024	125100	64 8	102625	4352	3200	28229	24943	41901	8986	1840	4179	2241	5229	22475
1993	22224	127100	65 3	105175	4400	3200	28158	25471	43945	9129	1745	3965	2126	4960	21925
1994	22528	129700	65 7	108191	4450	3300	28146	26102	46193	9315	1663	3778	2026	4727	21509
1995	22978	133200	66 2	112300	4500	3300	28410	27051	49040	9565	1546	3512	1883	4394	20900
1996	22989	135300	67 2	113658	4539	1900	29049	27665	50506	9736	1624	3689	1978	4615	21642
1997	23570	138900	67 3	116633	4578	1900	29742	28329	52084	10016	1671	3796	2035	4749	22267
1998	24077	142600	67 6	119689	4618	1900	30451	29010	53711	10304	1720	3906	2094	4887	22911
1999	24660	146500	67 7	122742	4659	1900	31153	29684	55347	10593	1768	4017	2154	5025	23557
2000	25173	148600	67 4	125000	4700	1900	31637	30151	56613	10781	1749	3972	2129	4969	23600
2001	25279	150400	67 9	126187	4719	0	32373	30906	58188	10900	1816	4125	2212	5160	24213

1/ Consumption at generation includes pumping in hydro plants plus heat generation auxiliary use minus self-producer supply to grid, consumption at VHV includes net exports
2/ Flows are subsequently converted in the model as consumption demand by applying the system load factor
3/ Average network losses by voltage level have been estimated based on the following allocation of total losses at a percent of net generation

EXHIBIT 7-8
AVERAGE AND PEAK LOSS FACTORS (FRACTION OF INCOMING)

YEAR	STATION USE		VHV		HV		MV		LV	
ENDING	AVERAGE	PEAK	AVERAGE	PEAK	AVERAGE	PEAK	AVERAGE	PEAK	AVERAGE	PEAK
1992	0.072	0.072	0.016	0.022	0.039	0.052	0.030	0.040	0.111	0.147
1993	0.072	0.072	0.015	0.020	0.037	0.048	0.028	0.037	0.101	0.134
1994	0.072	0.072	0.014	0.019	0.034	0.045	0.026	0.034	0.093	0.122
1995	0.072	0.072	0.013	0.017	0.031	0.040	0.023	0.030	0.082	0.108
1996	0.072	0.072	0.013	0.017	0.031	0.041	0.023	0.030	0.084	0.109
1997	0.072	0.072	0.013	0.017	0.031	0.041	0.023	0.030	0.084	0.108
1998	0.072	0.072	0.013	0.017	0.031	0.041	0.023	0.030	0.083	0.108
1999	0.072	0.072	0.013	0.017	0.032	0.041	0.023	0.030	0.083	0.108
2000	0.073	0.073	0.013	0.017	0.031	0.040	0.023	0.029	0.081	0.105
2001	0.072	0.072	0.013	0.017	0.031	0.040	0.023	0.030	0.081	0.105
Average	0.072	0.072	0.014	0.018	0.033	0.043	0.025	0.032	0.088	0.115

EXHIBIT 7-9
DEMAND AND LOSS FORECAST AT TIME OF SYSTEM PEAK (MW)

YEAR	PEAK	STATION	GEN	VHV			HV			MV			LV	
ENDING		USE	CONSUM	LOSS	PEAK	CONSUM	LOSS	PEAK	CONSUM	LOSS	PEAK	CONSUM	LOSS	PEAK
1992	22024	1582.0	766.2	429.7	19246.1	563.4	970.5	17712.3	4969.8	509.7	12232.8	4391.2	1153.9	6687.7
1993	22224	1596.2	769.4	403.2	19454.9	559.5	911.1	17984.3	4923.6	479.4	12581.3	4453.7	1089.0	7038.7
1994	22528	1617.9	772.9	380.1	19757.2	573.2	859.4	18324.6	4388.8	453.0	12982.8	4533.8	1031.9	7417.1
1995	22978	1650.0	776.3	349.5	20201.9	569.3	790.5	18842.2	4900.8	417.6	13523.8	4666.4	954.3	7903.1
1996	22989	1654.2	771.2	358.2	20205.1	322.8	810.4	19071.9	4935.7	428.2	13708.0	4700.5	979.1	8028.5
1997	23570	1699.6	776.9	367.9	20726.2	322.4	832.2	19571.6	5047.0	439.8	14084.8	4807.3	1005.6	8271.9
1998	24077	1739.7	779.7	375.5	21182.4	320.8	849.5	20012.1	5141.5	449.0	14421.6	4898.1	1027.1	8496.4
1999	24660	1785.5	785.2	385.1	21703.9	320.3	871.2	20512.5	5251.0	460.5	14801.0	5003.4	1053.6	8743.9
2000	25173	1826.4	796.2	383.8	22166.5	321.9	868.4	20976.3	5359.2	459.1	15157.9	5107.5	1050.8	8999.5
2001	25279	1832.1	793.2	393.6	22259.7	0.0	890.6	21369.1	5441.2	470.9	15457.0	5194.5	1078.1	9184.4

adjusting for generation consumption (heat generation auxiliary use and hydro pumping) of 769 MW and VHV network losses of 403 MW, results in a VHV peak of 19,455 MW. Of this amount, 560 MW of load is supplied at this voltage (net exports), with the remaining power transmitted to the HV network. The HV peak is estimated to be 17,984 MW, after adjusting for losses of 911 MW. In this manner, the power balance is sequentially derived to arrive at an estimated LV network peak of 7,038 MW.

Exhibit 7-10 shows the calculation of separate LRAICs for the four voltage levels. Incremental peak loads are calculated from Exhibit 7-9, whereas incremental expenditures are calculated from Exhibit 7-6. These costs are subsequently annualized over their respective lifetimes, and then adjusted to local prices and for incremental O&M expense as shown in Exhibit 7-11.

Results

Estimates of marginal generation capacity cost and network capacity cost (expressed as Zl/coincident kW) are summarized in Exhibit 7-11. In the model and the foregoing discussion, both capacity and energy costs are calculated at border prices. In order to estimate the long-run marginal cost as seen by the customer, these border prices must be re-expressed in terms of local prices (i.e., divided by the SCF). The capital cost of generation capacity must also be adjusted to account for the desired reserve margin and station losses at peak. The "summary of capacity costs" in Exhibit 7-11 makes these adjustments, annualizes investment costs, adds in an appropriate factor for annual O&M (including administrative and general expenses), and estimates a capacity cost per month for generation and network at each voltage level. To illustrate, the marginal generation capacity cost (peaker method) is 59.26 TysZl/coincident kW/month.

Similarly, Exhibit 7-11 derives the marginal cost of network capacity (Zl/coincident kW/month) at each voltage level. These costs range from 27.70 TysZl/kW/month at HV to 74.65 TysZl/kW/month at LV.

Exhibit 7-12 presents estimates of strict long-run marginal costs by voltage level. To illustrate, marginal capacity costs (generation plus network) using the peaker method range from 93.21 TysZl/coincident kW/month for load served at VHV to 285.69 TysZl/coincident kW/month for LV load. Similarly, average annual marginal energy costs at LV are 428 Zl/kWh during the peak hours and 356 Zl/kWh during off-peak hours. These costs are progressively lower (reflecting reduced losses) as service is taken at higher voltages.

In order to apply the strict marginal cost estimates discussed above to each tariff class, additional factors must be considered. These are: the coincidence of peak for each class in relation to the system peak, the load factor for each type of customer, and the split of total

EXHIBIT 7-10
AVERAGE INCREMENTAL NETWORK CAPACITY COSTS BY VOLTAGE LEVEL (tysZl MILLION)

YEAR ENDING	VHV NETWORK PEAK MW TOTAL	PEAK MW DISCOUNTED	INVESTMENT COST MARKET	INVESTMENT COST BORDER	INVESTMENT COST DISCOUNTED
1992	0.00	0.00	331.00	331.00	331.00
1993	208.79	186.42	158.00	158.00	141.07
1994	302.26	240.96	1079.00	1079.00	860.17
1995	444.75	316.57	1694.00	1694.00	1205.76
1996	3.18	2.02	1610.00	1610.00	1023.18
1997	521.05	295.66	206.00	206.00	116.89
1998	456.24	231.15	200.00	200.00	101.33
1999	521.50	235.90	1161.00	1161.00	525.18
2000	462.58	186.83	1243.00	1243.00	502.03
2001	93.22	33.62	1160.00	1160.00	418.31
Lagged Total		1542.70 (1994-2001)			4304.58 (1992-99)
AVERAGE INCREMENTAL VHV CAPACITY COST/KW =					2790.29

YEAR ENDING	HV NETWORK PEAK MW TOTAL	PEAK MW DISCOUNTED	INVESTMENT COST MARKET	INVESTMENT COST BORDER	INVESTMENT COST DISCOUNTED
1992	0.00	0.00	430.15	430.15	430.15
1993	272.02	242.88	696.64	696.64	622.00
1994	340.32	271.30	752.02	752.02	599.51
1995	517.58	368.40	844.50	844.50	601.10
1996	229.73	146.00	790.79	790.79	502.56
1997	499.64	283.51	633.89	633.89	359.69
1998	440.53	223.19	586.38	586.38	297.08
1999	500.38	226.35	684.75	684.75	309.75
2000	463.79	187.32	794.75	794.75	320.99
2001	392.89	141.68	482.01	482.01	173.82
		1847.73 (1994-2001)			3721.82 (1992-99)
AVERAGE INCREMENTAL HV CAPACITY COST/KW =					2014.26

YEAR ENDING	MV NETWORK PEAK MW TOTAL	PEAK MW DISCOUNTED	INVESTMENT COST MARKET	INVESTMENT COST BORDER	INVESTMENT COST DISCOUNTED
1992	0.00	0.00	1354.40	1354.40	1354.40
1993	348.51	311.17	1385.93	1385.93	1237.44
1994	401.45	320.03	1374.08	1374.08	1095.41
1995	541.05	385.11	1452.66	1452.66	1033.97
1996	184.19	117.05	1738.85	1738.85	1105.07
1997	376.79	213.80	1835.04	1835.04	1041.25
1998	336.83	170.65	1835.04	1835.04	929.69
1999	379.35	171.60	1868.57	1868.57	845.25
2000	356.93	144.15	1897.70	1897.70	766.45
2001	299.13	107.87	1897.70	1897.70	684.33
Lagged Total		1941.44 (1993-2001)			9408.93 (1992-00)
AVERAGE INCREMENTAL MV CAPACITY COST/KW =					4846.36

YEAR ENDING	LV NETWORK PEAK MW TOTAL	PEAK MW DISCOUNTED	INVESTMENT COST MARKET	INVESTMENT COST BORDER	INVESTMENT COST DISCOUNTED
1992	0.00	0.00	1497.32	1497.32	1497.32
1993	351.02	313.41	1519.00	1519.00	1356.25
1994	378.38	301.64	1529.70	1529.70	1219.47
1995	486.05	345.96	1575.09	1575.09	1121.12
1996	125.35	79.66	1541.22	1541.22	979.47
1997	243.39	138.10	1565.58	1565.58	888.35
1998	224.48	113.73	1585.09	1585.09	803.05
1999	247.59	112.00	1604.59	1604.59	725.84
2000	255.59	103.23	1628.95	1628.95	657.91
2001	184.88	66.67	1628.95	1628.95	587.42
		1574.41 (1993-2001)			9248.77 (1992-00)
AVERAGE INCREMENTAL LV CAPACITY COST/KW =					5874.43

EXHIBIT 7–11
SUMMARY OF CAPACITY COSTS

GENERATION:	PEAKER METHOD	"NEXT PLANT"
CAPITAL COST (tysZl/KW) (adjusted to local prices and for reserve margin and station losses at peak)	3974.27	11058.38
CAPITAL COST PER YEAR (tysZl/KW/Yr)	532.07	1372.83
ASSOCIATED FUEL SAVINGS (tysZl/KW/Yr) (adjusted to local prices and for station losses)	–	356.06
CAPITAL COST NET OF FUEL SAVINGS (tysZl/KW/Yr)	532.07	1016.77
O&M COST PER YEAR (tysZl/KW/Yr)	179.04	206.36
TOTAL CAPITAL COST PER YEAR (tysZl/KW/Yr)	711.11	1223.13
CAPACITY COST PER MONTH	59.26	101.93

TRANSMISSION & DISTRIBUTION:	VHV	HV	MV	LV
CAPITAL COST (tysZl/KW) (adjusted to local prices)	2790.29	2014.26	4846.36	5874.43
CAPITAL COST PER YEAR (tysZl/KW/Yr)	338.47	244.34	617.91	748.99
O&M COST PER YEAR (tysZl/KW/Yr)	55.81	40.29	121.16	146.86
TOTAL CAPITAL COST PER YEAR (tysZl/KW/Yr)	394.28	284.62	739.07	895.85
CAPACITY COST PER MONTH	32.86	23.72	61.59	74.65

EXHIBIT 7 – 12
STRICT LONG RUN MARGINAL COST BASED TARIFF BY VOLTAGE LEVEL

MARGINAL CAPACITY COST (tysZl/COINCIDENT KW/MONTH):

	GENERATION		TRANSMISSION & DISTRIBUTION					TOTAL MARGINAL CAPACITY COST	
	PEAKER METHOD	"NEXT PLANT"	VHV	HV	MV	LV	TOTAL	PEAKER METHOD	"NEXT PLANT"
VHV	60.36	103.82	32.86				32.86	93.21	136.68
HV	63.06	108.46	34.33	23.72			58.04	121.10	166.50
MV	65.14	112.05	35.46	24.50	61.59		121.55	186.70	233.60
LV	73.63	126.65	40.08	27.70	69.62	74.65	212.05	285.69	338.70

energy between peak and off-peak. Applying the coincidence factors results in an estimate of total marginal capacity cost per month for each customer class.[12] These results are shown for PPGC's sales to distribution companies in Exhibit 7-13, and for distribution company final sales in Exhibit 7-14. In these exhibits, marginal energy cost is a weighted average of peak, mid-peak and off-peak costs. The class load factors are used to express capacity costs in terms of kWh.[13] The final line of each exhibit derives average system-wide strict LRMC estimates for PPGC and the consolidated distribution companies, respectively.

The strict LRMC values by tariff class shown in Exhibits 7-13 and 7-14 establish an economic benchmark for the purpose of evaluating the extent of distortions in the present tariffs. In the case of PPGC, the average[14] LRMC is 708.5 Zl/kWh in comparison with an estimated current average tariff yield (mid-1992 prices) of 339.8 Zl/kWh. For the distribution companies, the average LRMC is 987.9 Zl/kWh in comparison with an average tariff yield of 542.1 Zl/kWh.

Strict LRMC is a pure economic cost and as such does not represent what must be collected from electricity customers. Rather, tariffs must collect the financial revenue requirement (see Chapter 8), which is generally less than the strict long-run marginal cost.

7.3 SENSITIVITY ANALYSIS

It is useful to test the sensitivity of results to key input variables. This exercise helps to identify those assumptions with a significant impact on final LRMC calculations. We have analyzed the sensitivity of PPGC and distribution company average LRMC tariff to changes in the following variables:

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[12] In arriving at these assumptions, the study team members first reviewed and analyzed the load research data derived from surveys conducted by the Institute of Power Engineering (JEN/Katovica) and consolidated tariff class billing data compiled by PPGC for the past two years. We identified class load factors and coincidence factors from seasonal hourly load shapes estimated for each tariff class. Further, the billing records provided an independent estimate of class load factors. Where available data were insufficient, the assumptions made are also conditioned upon the team members' experience and judgment. In the absence of comprehensive national load research data, our estimates of coincidence factors are intentionally conservative; underestimation of coincidence factors would translate directly into undercollection of revenues for customers not metered on a coincident demand basis.

[13] To avoid unnecessary confusion, the printed table shows strict LRMCs for the peaker method. For comparative purposes, parallel results for the "next-plant" method appear in the model spreadsheet to the right of these printed data. A complete printout of the LRMC model results is contained in Appendix 5.2.

[14] Weighted by billed sales by tariff class recorded for the first half of 1992.

Exhibit 7–13
STRICT LONG RUN MARGINAL COST BASED TARIFF BY TARIFF CLASS – BULK

TARIFF CLASS	SERVICE VOLTAGE	COINCI-DENCE	LOAD FACTOR	ENERGY SHARES PEAK	MID-PEAK	TOTAL MARGINAL COST/MONTH CAPACITY tysZl/KW	ENERGY tysZl/KWh	TOTAL tysZl/KWh	DEMAND CHARGE SHARE	H1/1992 SALES GWh	CURRENT YIELD tysZl/KWh
DISTRIBUTION COS.	HV	1.00	0.65	0.20	0.28	121.10	0.4533	0.7085	36%	50434	0.3398
BULK SYSTEM AVERAGE				0.20	0.28	121.10	0.4533	0.7085		50434	0.3398
Equivalent tysZl/KWh						0.2552	0.4533	0.7085			
% of System Average						36%	64%	100%			

Exhibit 7–14
STRICT LONG RUN MARGINAL COST BASED TARIFF BY TARIFF CLASS – RETAIL

TARIFF CLASS	SERVICE VOLTAGE	COINCI-DENCE	LOAD FACTOR	ENERGY SHARES PEAK	MID-PEAK	TOTAL MARGINAL COST/MONTH CAPACITY tysZl/KW	ENERGY tysZl/KWh	TOTAL tysZl/KWh	DEMAND CHARGE SHARE	H1/1992 SALES GWh	CURRENT YIELD tysZl/KWh
INDUSTRIAL	HV	0.81	0.60	0.16	0.27	98.09	0.4354	0.6594	34%	14090	0.3874
	MV	0.63	0.42	0.18	0.31	117.62	0.4652	0.8488	45%	8884	0.4995
	LV	0.54	0.31	0.18	0.31	154.27	0.5203	1.2020	57%	1334	0.7828
TRACTION	HV	0.93	0.48	0.19	0.30	112.62	0.4534	0.7748	41%	67	0.4606
	MV	0.93	0.48	0.19	0.30	173.63	0.4671	0.9627	51%	2178	0.4715
COMMERCIAL	MV	0.63	0.49	0.20	0.32	117.62	0.4755	0.8044	41%	641	0.4934
	LV	0.55	0.30	0.20	0.32	157.13	0.5323	1.2498	57%	4464	0.7745
AGRICULTURAL	MV	0.54	0.38	0.20	0.32	100.82	0.4755	0.8390	43%	320	0.5287
RETAIL	LV	0.49	0.25	0.27	0.25	139.99	0.5479	1.3150	58%	13616	0.6310
ST. LIGHTING	LV	1.00	0.50	0.21	0.04	285.69	0.4659	1.2486	63%	742	0.7884
DISTRIBUTION COMPANY AVERAGE				0.20	0.28	128.31	0.4888	0.9879		46336	0.5421
Equivalent tysZl/KWh						0.4991	0.4888	0.9879			
% of System Average						51%	49%	100%			

Variable	Sensitivity Range
Discount Rate	8% - 14%
Standard Conversion Factor	0.85 - 1.0
Foreign Exchange Rate	13000 - 19000 Zl/US$
Planning Reserve Margin	15% - 25%
Year Generation Required	1996 - 1999
Economic Price of Coal	$1.50 - $2.50/MMBtu
Size of T&D Investment Program	0.6 - 1.0 times the Base Case

Exhibit 7-15 summarizes the results of these sensitivities. The top row of each sensitivity test shows the LRMC -- PPGC bulk and distribution company retail -- with the base case value for that variable. Subsequent rows show how alternative values would alter the final result.

The average LRMC is most sensitive to changes in the foreign exchange rate, and to the T&D investment program. The exhibit graphs the sensitivity of these results. As the exchange rate moves from 13,400 Zl/$ (mid-1992) to 19,000 Zl/kWh, the retail (distribution company) LRMC increases from 988 to 1,302 Zl/kWh. Alternatively, a reduction in the total T&D investment program by 20 percent would reduce the retail LRMC from 988 to 919 Zl/kWh.

The LRMC is also sensitive to changes in the discount rate and the price of coal. A 2 percent increase (decrease) in the discount rate used in project analysis effectively increases (decreases) the retail LRMC by about 6 percent. A coal price rise from $2.12 to $2.50 per MMBtu ($2.01 to $2.37 per GJ) increases the average retail LRMC from 988 to 1,047 Zl/kWh.

Surprisingly, LRMC is relatively insensitive to differing reserve margin assumptions. At planning reserve margins in the range of 15 to 25 percent, the retail LRMC varies by less than 2 percent. It is also quite insensitive to expediting or delaying the year in which new generation is first required.

We did not calculate the sensitivity of LRMC to changes in projected load growth that might occur as a result of required electricity tariff increases. There are two major reasons *not* to do so. First, no reliable Poland-specific price elasticity data are available from which to estimate demand response. Second, any demand response will require a revised investment program in order to calculate the LRAIC of network capacity. In the absence of this information, tariff planning should continue based on the PPGC Scenario II ("low") load forecast.

Exhibit 7-15
LRMC SENSITIVITY ANALYSIS (tysZl/KWh)

DISCOUNT RATE	Bulk LRMC	Retail LRMC
12%	0.7085	0.9879
8%	0.6538	0.8768
10%	0.6807	0.9311
12%	0.7085	0.9879
14%	0.7370	1.0468

EXCHANGE RATE	Bulk LRMC	Retail LRMC
13.400	0.7085	0.9879
13.000	0.6890	0.9655
15.000	0.7867	1.0778
17.000	0.8844	1.1900
19.000	0.9821	1.3023

COAL PRICE	Bulk LRMC	Retail LRMC
2.12	0.7085	0.9879
1.50	0.6174	0.8913
1.75	0.6540	0.9301
2.00	0.6906	0.9690
2.25	0.7272	1.0078
2.50	0.7639	1.0467

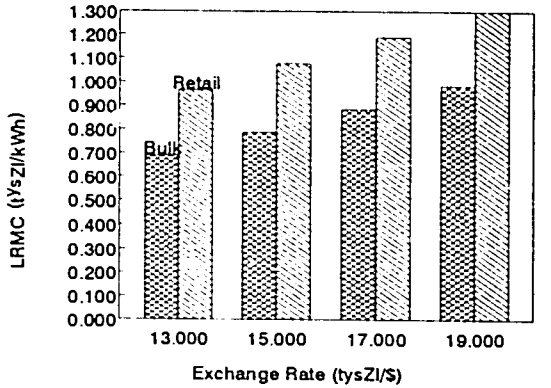
T&D INVSTMNT	Bulk LRMC	Retail LRMC	T&D % of Capac Csts
1.00	0.7085	0.9879	74%
0.90	0.6963	0.9536	72%
0.80	0.6840	0.9193	70%
0.70	0.6718	0.8850	67%
0.60	0.6596	0.8507	63%

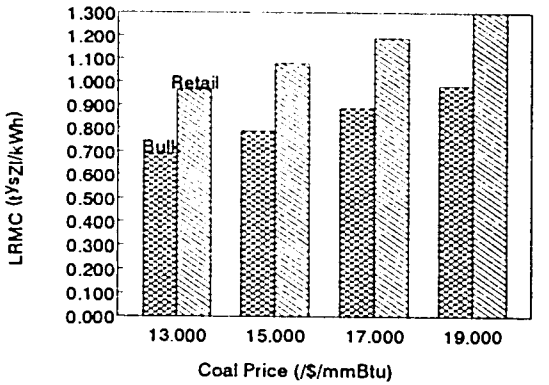
SCF	Bulk LRMC	Retail LRMC
1.00	0.7085	0.9879
0.85	0.8193	1.1152
0.90	0.7783	1.0680
0.95	0.7416	1.0259
1.00	0.7085	0.9879

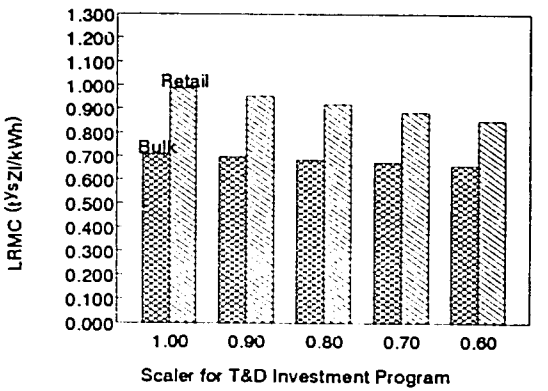
YEAR GEN NEEDED	Bulk LRMC	Retail LRMC
1997	0.7085	0.9879
1996	0.7244	1.0067
1997	0.7085	0.9879
1998	0.6943	0.9712
1999	0.6816	0.9563

RESERVE MARGIN	Bulk LRMC	Retail LRMC
20.0%	0.7085	0.9879
15.0%	0.7030	0.9814
17.5%	0.7057	0.9847
20.0%	0.7085	0.9879
22.5%	0.7113	0.9912
25.0%	0.7140	0.9944

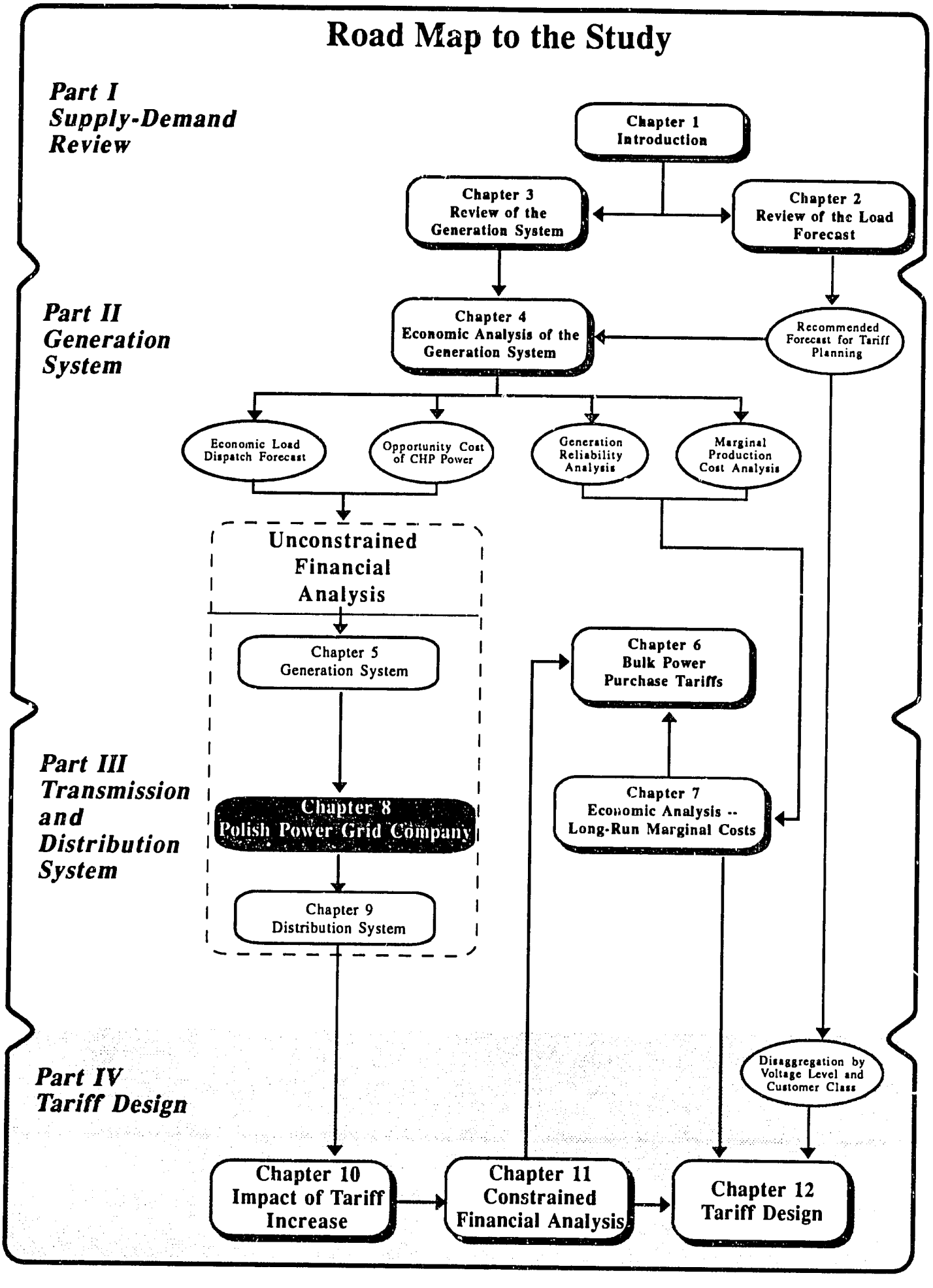
Note: Program must be "RUN" to update sensitivity analysis.







Road Map to the Study



CHAPTER 8: UNCONSTRAINED FINANCIAL ANALYSIS OF THE POLISH POWER GRID COMPANY

8.1 OBJECTIVES AND APPROACH

The analysis of transmission costs and the required financial revenues is essentially a financial analysis of the Polish Power Grid Company. Following up on the financial analysis of the generating system's revenue requirements presented in Chapter 5, the objective of the financial analysis of PPGC is to determine the revenue requirements the company needs to operate as a viable commercial entity.

As in Chapter 5, the financial forecast of Chapter 8 corresponds to a scenario of *unconstrained* tariff increase and instant asset revaluation. In Chapter 11, these results are subjected to different assumptions in order to arrive at a financial forecast that is constrained by the need to limit the impacts of tariff increases and by the feasible extend of and schedule for the revaluation of assets.

PPGC was formed in October 1990. Therefore, only one full year of historical data are available for the 12 months ending December 31, 1991. Furthermore, financial performance ratios have been distorted because the bulk of the transmission assets plus the pumped storage plant and associated operation and maintenance costs were not transferred to PPGC until January 1993.

PPGC is the balancing point between bulk power purchases and sales. It was thus necessary to derive the overall electric energy balance and relate it to the energy purchases and sales, as well as the transmission losses, of PPGC.

8.2 HISTORICAL REVIEW

The historical information for 1991 was obtained from PPGC's "F-02" annual accounting report and from statistical information provided by PPGC.

Because the bulk of the transmission assets and related costs had not been transferred to PPGC as of 1992, yet PPGC was allowed a margin related to those assets, its published results for 1991 indicate a return of 145.7 percent operating income to net assets, with operating income to sales of 1.1 percent. However, after the transfer of assets and costs from the distribution companies to PPGC, these ratios would deteriorate significantly to 7.2 percent and 0.1 percent, respectively.

8.3 FINANCIAL REVENUE REQUIREMENTS OF PPGC

8.3.1 Transfer of Assets

In projecting the results for 1993-1997, PPGC's fixed assets were revalued and increased effective January 1, 1993 by 57,207 billion zloties, representing the 1992 valuation of distribution assets transferred from the distribution companies to PPGC. The gross book value of the assets transferred can be summarized as follows:

	Billion Zloties	
Asset	At 1990 Book Value	At 1992 Revaluation
Lines > 100 kV	4,163	24,644
Substations	3,002	13,007
Subtotal	7,165	37,651
Pumped Storage Plants	3,339	19,556
Total	10,504	57,207

The revalued depreciation amounted to 52 percent of the revalued gross book value. It was assumed that the asset transfer represented an *equity* contribution to PPGC.

8.3.2 Financial Criteria to be Met

The key financial target to be achieved by PPGC was assumed to be the same as for the generating companies: 6.0 percent return on net assets employed (i.e., working capital plus fixed assets valued at depreciated replacement cost).

8.3.3 Assumptions and Data Sources

Assumptions similar to those for the generating companies were adopted for PPGE.

- The financial forecast was developed at mid-1992 price levels and exchange rate of 13,400 Zl to the US dollar.

- The financial forecast was developed at mid-1992 price levels and exchange rate of 13,400 Zl to the US dollar.

- The purchase price of electricity is the weighted average of the selling price by the system power plants -- i.e., 489 Zl/kWh in 1994 and the "avoided cost" that would be paid to the CHP plants, assumed to be 603 Zl/kWh, or 4.5 US cents/kWh, as discussed in Chapter 4.

- The PPGC capital investment program is the program provided by the PPGC Investment Planning Department.

- PPGC's 1992 cost estimate is based on the revised budget prepared by the PPGC Finance Department in November 1992.

- The costs for 1993 and future years are based on the 1992 budget plus costs associated with the transferred assets, as developed by Energoprojekt.

- System losses overall are assumed to be approximately 2.5 percent, which comprises approximately 1.8 percent in the transmission network and approximately 0.7 percent in pumped storage.

8.4 RESULTS

The results presented in this section are those for the unconstrained tariff increase and instant asset revaluation scenario. See Chapter 11 for results under the financial forecast constrained by the need to limit the impact of tariff increases and the feasible extent of and schedule for the revaluation of assets.

In Exhibit 8-1 the forecast energy balance of PPGC is presented for the period 1992-1997; Exhibit 8-2 contains a forecast of revenues and revenues from sales and the cost of energy sold. In Exhibits 8-3a, 8-3b, and 8-3c, the income statement, balance sheet and financial performance ratios of PPGC are shown.

Based on the average purchase price to the generating companies of 489 Zl/kWh forecast for 1994 and the avoided cost to CHP plants estimated at 603 Zl/kWh, the revenue requirement that PPGC needs to provide a return of 6.0 percent on its revalued net assets is 563 Zl/kWh. All these are expressed at 1992 price levels.

Considering the mid-1992 average bulk purchase sale price of 337 Zl/kWh, this represents a real increase of 67 percent.

Exhibit 8-1
ENERGY BALANCE OF PPGC

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLSKIE SIECI ELEKTROENERGETYCZNE Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			Total Energy Sales by Distrbn Cos						
65,405	57,312	51,052	Industry	48,988	48,864	48,843	49,300	50,410	51,612
5,875	5,346	4,915	Railways	5,160	5,631	6,158	6,800	6,940	7,092
9,386	8,218	9,821	Commercial	9,192	9,676	10,206	10,871	11,201	11,556
8,633	8,124	8,394	Agriculture	8,422	8,865	9,351	9,960	10,262	10,587
20,267	22,183	20,829	Residential	21,937	23,091	24,356	25,943	26,731	27,578
28,900	30,307	29,223	Sub-total - Agricult & Resid'l	30,359	31,956	33,707	35,903	36,993	38,165
1,506	1,325	1,372	Street Lighting	1,375	1,448	1,527	1,627	1,676	1,729
111,072	**102,508**	**96,383**	**TOTAL FINAL CONSUMPTION**	**95,074**	**97,575**	**100,441**	**104,501**	**107,220**	**110,154**
			Distribution System Losses -- %						
13,345	9,235	14,597	Distribution System Losses	11,237	10,659	10,156	9,579	9,919	10,207
		1,891	Distribution Co's Own Generation						
			Total Distribution Co. Purchases:						
124,013	111,235	108,733	From Grid (PSE)	105,911	107,834	110,197	113,680	116,739	119,961
396	495	339	From Self Producers	400	400	400	400	400	400
8	13	17	From Small Hydro						
124,417	111,743	109,089	Total Purchases	106,311	108,234	110,597	114,080	117,139	120,361
			Total Energy Sales by Grid:						
124,013	111,235	108,733	Distribution Companies	105,911	107,834	110,197	113,680	116,739	119,961
10,268	11,477	9,326	Exports						
134,281	**122,712**	**118,059**	**TOTAL PSE SALES**	**105,911**	**107,834**	**110,197**	**113,680**	**116,739**	**119,961**
777	717	785	Pumped Storage Usage (Net)	750	750	750	750	750	750
0	0	0	Transmission Losses -- %	0	0	0	0	0	0
2,145	4,025	3,642	Transmission Losses	2,253	2,137	2,036	1,921	1,988	2,046
137,203	**127,454**	**122,486**	**TOTAL PSE PURCHASES**	**108,914**	**110,721**	**112,983**	**116,351**	**119,477**	**122,757**
12,059	10,437	6,708	Imports						
125,144	117,017	115,778	Domestic Purchases:	108,914	110,721	112,983	116,351	119,477	122,757
123,540	115,614	114,347	System Thermal Plants	94,913	96,387	97,983	100,352	102,208	103,219
			CHP & Collector Plants	12,570	12,903	13,569	14,568	15,838	18,107
1,604	1,403	1,431	Hydro - generation	1,431	1,431	1,431	1,431	1,431	1,431
			Unexplained Diffference						

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Exhibit 8-2
REVENUE AND COST OF SALES OF PPGC

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLSKIE SIECI ELEKTROENERGETYCZNI Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			REVENUE AND COST OF SALES						
			Domestic Demand -- MW						
124,013	111,235	108,733	Domestic Energy Sales -- GWH	105,911	107,834	110,197	113,680	116,739	119,961
(1,791)	1,040	2,618	Net Export Energy Sales -- GWH						
2.33%	4.05%	3.82%	System Losses -- %	2.76%	2.61%	2.47%	2.30%	2.29%	2.28%
125,144	117,017	115,778	Domestic Energy Purchases -- GWh	108,914	110,721	112,983	116,351	119,477	122,757
		235,072.8	Capacity Purchases -- MW	231,828.4	231,828.4				
		769	No. of Employees						
			Domestic Tariff -- 000 Zl / MW						
		218.230	-- 000 Zl / kwh	336.716	337.000	563.000	557.000	559.000	571.000
		333.290	Export Tariff(Av.Net) -- 000 Zl/kwh						
			Revenues from Sales:						
		23,729	Domestic	35,662	36,340	62,041	63,320	65,257	68,497
			Demand						
		23,729	Energy	35,662	36,340	62,041	63,320	65,257	68,497
		873	Net Export Revenue						
			Demand						
		873	Energy						
		52	Other (Services, Domestic/Export)						
		24,653	**Total Sales**	**35,662**	**36,340**	**62,041**	**63,320**	**65,257**	**68,497**
			Purchase Tariffs from Generators						
		46.848	Capacity Payment -- 000 Zl / MW	57.590	57.590				
		110.211	Energy Payment -- system Zl / kwh	186.000	186.000	488.951	487.195	490.566	504.206
			Energy Payment -- CHP Zl / kwh	186.000	186.000	603.000	603.000	603.000	603.000
			Energy Payment -- hydro Zl / kwh	336.716	337.000	653.000	447.000	559.000	571.000
			Cost of Sales:						
		11,013	Capacity payments	13,351	13,351	0	0	0	0
		12,760	Energy Purchases - system plants	17,654	17,928	47,909	48,891	50,140	52,043
			Energy Purchases - CHP plants	2,338	2,400	8,182	8,785	9,550	10,919
			Energy Purchases - hydro plants	482	482	806	797	800	817
		(98)	Penalty to GenCos for Shortfall						
		341	System Control Costs						
		24,015	**Total Cost of Sales**	**34,329**	**34,161**	**56,897**	**58,473**	**60,490**	**63,779**

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Exhibit 8-3a
INCOME STATEMENT – PPGC

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLSKIE SIECI ELEKTROENERGETYCZNE Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			INCOME STATEMENT						
		24,653	Total Sales	35,662	36,340	62,041	63,320	65,257	68,497
		24,015	Total Cost of Sales	34,329	34,161	56,897	58,473	60,490	63,797
		638	Net Revenue from Energy Sales	1,333	2,179	5,144	4,847	4,767	4,718
		141	Materials & Energy	166					
		147	Outside Services	94					
		35	Salaries / Payroll	62					
		22	Payroll Taxes, etc.	30					
		2	Business Travel	2					
		7	Other						
		354	**Total Overhead Costs @1992 Prices**	354					
			Inflation						
			Total @ Current Prices	354					
			Plus. Transfers from Distribution Cos:						
		9	Materials & Energy	12					
		54	Outside Services	75					
		39	Salaries / Payroll	54					
			Payroll Taxes, etc.						
			Business Travel						
		56	Pumped Storage Costs	69					
		143	Other	198					
		301	Total O'head Costs Transf'd @1992 Prices	407					
			Inflation						
			Total O'head Costs Transferred	407					
			Adjusted Total Overhead Costs:						
		150	Materials & Energy	178	178	178	178	178	178
		201	Outside Services	169	169	169	169	169	169
		74	Salaries / Payroll	116	116	116	116	116	116
		22	Payroll Taxes, etc.	30	30	30	30	30	30
		2	Business Travel	2	2	2	2	2	2
		64	Pumped Storage Costs	69	69	69	69	69	69
		151	Other	198	198	198	198	198	198
		662	**Total Adjusted O'head Costs @1992**	761	761	761	761	761	761
			Inflation						
			Total @ Current Prices	761	761	761	761	761	761
		13	Other Costs						
		271	Net Revenue from Production	979					

Exhibit 8-3a
INCOME STATEMENT - PPGC

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLSKIE SIECI ELEKTROENERGETYCZNI Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			(BEFORE TRANSFERRED COSTS)						
			Net Revenue from Production		1,418	4,383	4,086	4,006	3,957
			(AFTER TRANSFERRED COSTS)						
		10	Interest from loans to Others						
		130	Interest on Deposits at Bank	2	51	258	569	857	1,139
		2	Gain on Currency Exchange						
		142	**Financial Income/ Interest Income**	2	51	258	569	857	1,139
		1	Other Revenues	17					
		414	Operating Income	998					
			(BEFORE TRANSFERRED COSTS)						
			Operating Income		1,469	4,641	4,655	4,863	5,096
			(AFTER TRANSFERRED COSTS)						
		11	Depreciation - per Statement	15	22	59	147	309	509
			Plus Dep'n on Revaluation						
			Total Dep'n @ Current Prices	15	22	59	147	309	509
		469	Depreciation - - Transferred from DCs		525	525	525	525	525
			Plus: Dep'n on Revaluation		2,329	2,337	2,337	2,337	2,337
			Total Dep'n @ Current Prices		2,854	2,863	2,863	2,863	2,863
		480	Total Adjusted Depreciation @1992	15	547	584	672	834	1,034
			Plus Dep'n on Revaluation		2,329	2,337	2,337	2,337	2,337
			Total Dep'n @ Current Prices	15	2,875	2,922	3,009	3,172	3,372
			Operating Income after Deprec'n	983	(1,406)	1,719	1,646	1,692	1,724
			Financial Charges:						
		6	Lease Payments						
		27	Long Term Loan Interest	59	107	286	619	949	1,128
			Less: Interest during Construction		77	148	330	520	538
			Net Interest	59	30	138	289	429	589
		371	Income Before Tax	925	(1,437)	1,581	1,357	1,262	1,135
		148	Income Tax	370	(575)	632	543	505	454
			Capital Tax						
		1	Other Taxes						
		221	**NET INCOME (BEFORE TRANSFERS)**	555	(862)	949	814	757	681

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Exhibit 8-3b
BALANCE SHEET - PPGC

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLSKIE SIECI ELEKTROENERGETYCZNI Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			ASSETS						
			Fixed Assets:						
			Capital Assets						
	179	180	Gross Fixed Assets	180	680	1,680	4,180	8,180	12,180
			Plus: Transfers of Grid from DCs	7,165	7,165	7,165	7,165	7,165	7,165
			Plus: Transfers of Pumped Storage	3,339	3,339	3,339	3,339	3,339	3,339
			Total Adjusted Gross Fixed Assets	**10,685**	**11,185**	**12,185**	**14,685**	**18,685**	**22,685**
			Plus: Revaluation to 1992	46,397	46,746	46,746	46,746	46,746	46,746
			Plus: Revaluation after 1992						
			Revalued Gross Fixed Assets	57,082	57,931	58,931	61,431	65,431	69,431
	91	95	Less: Accumulated Depreciat'n	110	132	191	337	646	1,155
			Depreciation on Transfers	5,483	6,008	6,533	7,059	7,584	8,109
			Revalued Depreciation	24,217	26,545	28,883	31,220	33,557	35,894
			Depreciation on Revaluation						
			Total Accumulated Depreciationn	**29,810**	**32,685**	**35,607**	**38,816**	**41,787**	**45,159**
	88	85	Net Fixed Assets	27,272	25,246	23,324	22,815	23,644	24,272
	3	130	Capital Work-in-Progress	699	1,344	3,000	4,723	4,895	2,627
	1	185	Advance Payments	197	197	197	197	197	197
		1	Patents & Licenses	1	1	1	1	1	1
			Financial Investments:						
		0	Shares in other Companies						
	221	193	Long Term Accounts Receivable	193	193	193	193	193	193
			Current Assets:						
	0	0	Inventories						
	247	1,905	Accounts Receivable	2,736	2,788	4,759	4,857	5,006	5,255
	24	0	Income Tax Receivable						
	5	5	Other Accounts Receivable						
	590	25	Cash at Bank and on Deposit	15	917	3,769	6,578	9,007	11,697
	868	**1,936**	**Total Current Assets**	**2,751**	**3,704**	**8,529**	**11,435**	**14,013**	**16,952**
	1,180	**2,530**	**TOTAL ASSETS**	**31,114**	**30,686**	**35,245**	**39,365**	**42,944**	**44,243**

Exhibit 8-3b
BALANCE SHEET - PPGC

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLSKIE SIECI ELEKTROENERGETYCZNI Year End -- December 31	ESTIMATE 1992	1993	1994	FORECAST 1995	1996	1997
			LIABILITIES						
			Equity Capital:						
	515	515	Equity	515	515	515	515	515	515
	71	389	Reserve Capital	610	1,165	303	1,252	2,066	2,823
			Transfers of Grid from DCs	7,165	7,165	7,165	7,165	7,165	7,165
			Transfer of Pumped Storage	3,339	3,339	3,339	3,339	3,339	3,339
			Less Accum. dep'n on Transfers	5,483	5,483	5,483	5,483	5,483	5,483
	1		Asset Revaluation	22,180	22,180	22,180	22,180	22,180	22,180
	321	221	Current Year's Net Income	555	(862)	949	814	757	681
	908	**1,125**	**Total Equity**	**28,882**	**28,020**	**28,968**	**29,783**	**30,540**	**31,221**
		315	Long Term Debt	750	1,200	4,000	7,250	10,000	10,500
			Current Liabilities:						
	231	841	Accounts Payable	1,232	1,217	2,026	2,083	2,154	2,272
	6	112	Other Accounts Payable	110	110	110	110	110	110
			Short Term Loans						
	35	138	Other Liabilities	140	140	140	140	140	140
			Owing to Bank						
	271	**1,091**	**Total Current Liabilities**	**1,482**	**1,467**	**2,276**	**2,333**	**2,404**	**2,522**
	1,180	**2,531**	**TOTAL LIABILITIES**	**31,114**	**30,686**	**35,245**	**39,365**	**42,944**	**44,243**
	179	180	Gross Fixed Assets	180	680	1,680	4,180	8,180	12,180
	6,903	6,903	Plus: Transfers of Grid from DCs	7,165	7,165	7,165	7,165	7,165	7,165
		3,252	Plus: Transfers of Pumped Storage	3,339	3,339	3,339	3,339	3,339	3,339
	7,082	**7,084**	**Total Adjusted Gross Fixed Assets**	**10,685**	**11,185**	**12,185**	**14,685**	**18,685**	**22,685**

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Exhibit 8-3c

FINANCIAL PERFORMANCE RATIOS – PPGC

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLSKIE SIECI ELEKTROENERGETYCZNE Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			DOMESTIC SALES:						
		-2.2%	Energy Sales(Gwh) - Annual Growth - %	-2.6%	1.8%	2.2%	3.2%	2.7%	2.8%
			Sales Revenue(Zl) - Annual Growth - %	50.3%	1.9%	70.7%	2.1%	3.1%	5.0%
		218.2	**Average Tariff -- Zl/kwh**	336.7	337.0	563.0	557.0	559.0	571.0
		218.2	Average Energy Tariff -- Zl/kwh	336.7	337.0	563.0	557.0	559.0	571.0
			Av.Capac. Tariff - '000 Zl/MW/mo						
			INCOME RATIOS:						
			Op. Income/ Net Assets %						
		145.7%	BEFORE Transfer of Assets/Costs	200.0%					
		-7.2%	**AFTER Transfer of Assets/Costs**	6.1%	-4.8%	6.1%	5.9%	6.0%	5.9%
			Op. Income after Dep'n/ Sales %						
		1.1%	BEFORE Transfer of Assets/Costs	2.8%					
		-0.1%	**AFTER Transfer of Assets/Costs**	1.7%	-3.9%	2.8%	2.6%	2.6%	2.5%
			Net Income/ Total Equity %						
		21.7%	BEFORE Transfer of Assets/Costs	1.8%					
		-23.6%	AFTER Transfer of Assets/Costs	2.1%	-3.0%	3.3%	2.8%	2.5%	2.2%
			CASH FLOW RATIOS:						
			Debt Service Ratio						
		8.10	BEFORE Transfer of Assets/Costs	10.73	-26.69	8.29	4.33	3.48	3.02
			Self-Financing Ratio						
		64.4%	BEFORE Transfer of Assets/Costs	98.0%	-78.7%	40.2%	24.7%	29.2%	99.8%
			BALANCE SHEET RATIOS:						
		1.78	Current Ratio	1.86	2.53	3.75	4.90	5.83	6.72
		0.01	Cash at Bank to Sales - months	0.01	0.30	0.73	1.25	1.66	2.05
		0.93	Accts.Receivable to Sales -months	0.92	0.92	0.92	0.92	0.92	0.92
			Debt to Equity Ratio - %						
		28.0%	BEFORE Transfer of Assets/Costs	2.6%					
			AFTER Transfer of Assets/Costs		4.3%	13.8%	24.3%	32.7%	33.6%

Projected

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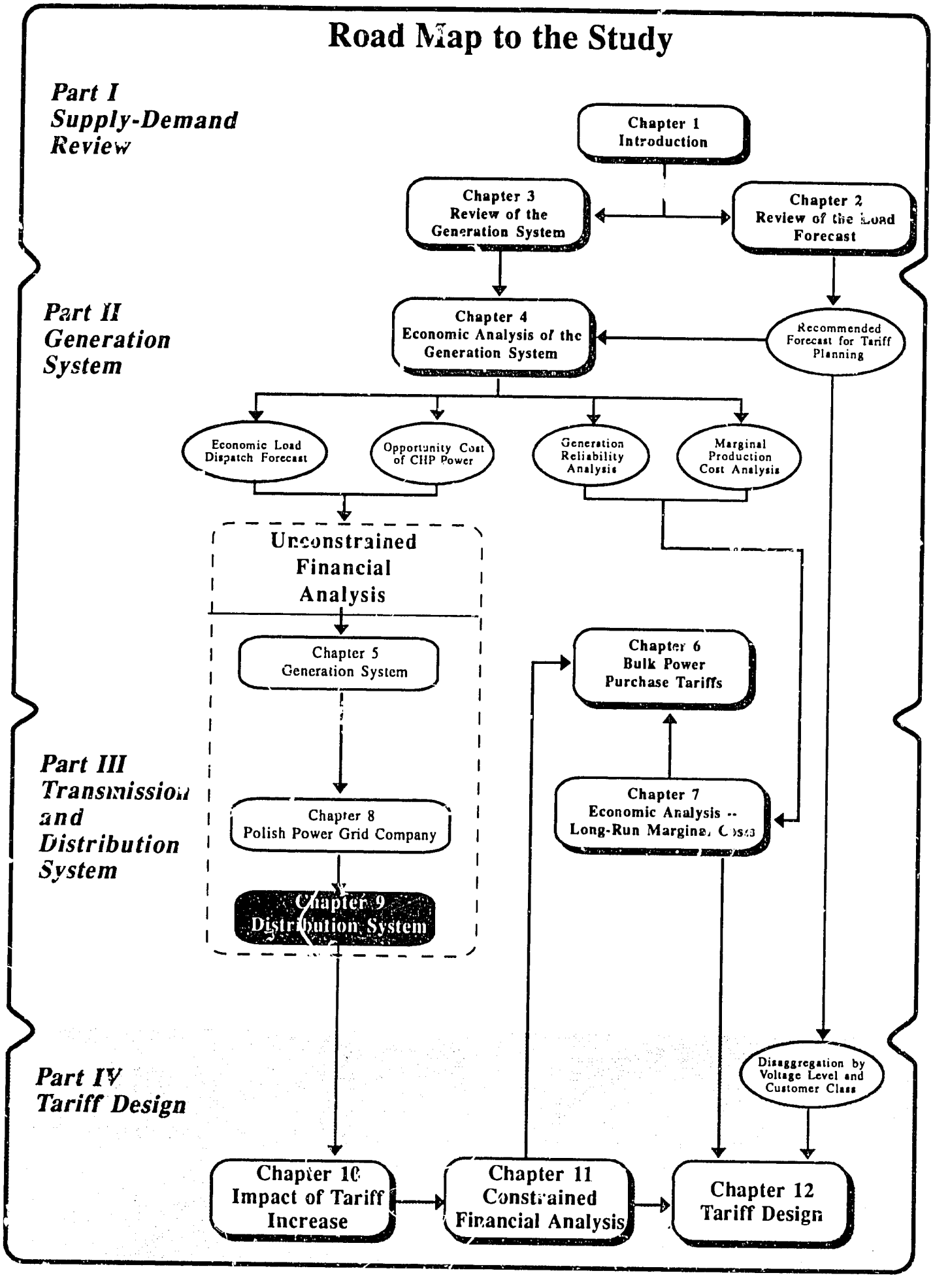
Road Map to the Study



CHAPTER 9: UNCONSTRAINED FINANCIAL ANALYSIS OF THE DISTRIBUTION SYSTEM

9.1 OBJECTIVES AND APPROACH

In this chapter, the financial requirements for the total distribution system and the resulting average system-wide tariff at the distribution level are developed with an emphasis on 1994. As was done with the generating system in Chapter 5 and the transmission grid in Chapter 8, the objective was to determine the revenue requirements of the distribution system so that this system can become a viable commercial activity.

As in Chapter 5, the financial forecast of Chapter 9 corresponds to a scenario of *unconstrained* tariff increase and instant asset revaluation. In Chapter 11, these results are subjected to different assumptions in order to arrive at a financial forecast that is constrained by the need to limit the impacts of tariff increases and by the feasible extent of and schedule for the revaluation of assets.

It is the Polish Government's policy to adopt uniform bulk sales tariffs for all distribution companies and allow each company to set its retail tariffs based on a regulated profit but according to the specific cost structure of each company. It is relevant to the objectives of this study to determine the variability that can be expected among the average retail tariffs of different distribution companies. Therefore, in addition to the consolidated case, three individual distribution companies were analyzed -- namely Warsaw, Gliwice and Bialystok -- which represent major urban, mid-size urban, and rural distribution companies.

The analysis of distribution costs and the required financial revenues and *average* tariff at the level of the distribution company customers was based on a consolidation or aggregation of key income statement and balance sheet data for the 33 distribution companies.

The consolidation was prepared by the Economics Department of PPGC from the "F-02" accounting returns from the individual distribution companies.

The analysis of 1989-1992 includes high-voltage lines and substations that were carried on the books of the distribution companies before being transferred to PPGC in January 1993.

9.2 HISTORICAL FINANCIAL REVIEW AND ANALYSIS

It should be noted that the 1989-1992 analysis includes high-voltage transmission assets. Thus, in 1991, distribution losses shown at 11.65 percent include losses attributable to transmission, which are estimated at approximately 2.0 percent.

9.2.1 Income Ratios

The ratios between the average selling tariff of the distribution companies and their average purchase cost from PPGC are as follows:

	1989	1990	1991	1992 (est.)
Average Selling Tariff (Zl/kWh)	19.9	213.4	354.0	542.1
Average Purchase Cost (Zl/kWh)	n.a.	135.3	221.7	339.1
Ratio (percent)	n.a.	157.7	159.7	159.9

In 1990 and 1991, the ratios of operating income to sales (after allowing for depreciation based upon the 1990 PSO (Polish Statistical Office) asset revaluation were 10.4 percent and 8.4 percent, respectively. This, in turn, amounted to an operating income to net assets return of 3.4 percent and 3.9 percent, respectively.

It is worth noting that consistency has been maintained in these ratios despite the massive inflation that has occurred between 1989 and 1992.

9.2.2 Balance Sheet Ratios

The total net assets employed in the Polish distribution system in 1991 amounted to approximately 42,272 billion Zlotys (based on the 1990 PSO revaluation). Long-term debt totalled 1,309 billion Zlotys. This amounted to a debt-to-equity ratio of about 4 percent.

At least three different financial criteria are possible for the distribution system. They correspond to different levels of risk and different possibilities of financing, and result in different revenue requirements.

Criterion A - No Net Increase in Overall Debt

This criterion requires that there be no net change in borrowing or indebtedness over the 1993-1997 period (a four-year period), although short-term borrowing to smooth out fluctuations is allowed in the intervening years. This criterion means that all capital expenditures plus all working capital increases must be paid for from cash flow, taking the four years in total. The distribution system must thus be capable of financing its equipment replacement and extending its service coverage from its revenues.

This is unquestionably the most prudent policy because it assumes that distribution utilities will not borrow on a long-term basis. Because of the stringency of this criterion, it will tend to result in a higher tariff than the other two criteria.

Criterion B - 6 Percent Return on Net Assets

A 6 percent return on net assets for distribution companies was considered only because this would provide a consistent criterion throughout the power system, from generation to distribution. However, this criterion could result in highly volatile tariffs because the effects of capital expenditures in distribution are magnified by the effect of a 60 percent tax rate on the pre-tax profits of distribution companies.

Criterion C - 100 Percent Self-Financing Ratio

The self-financing ratio is defined here as the net cash generation (i.e., depreciation plus net profit after taxes) divided by the average of three years of capital expenditure in the previous, current, and following years.

This definition, however, ignores any requirement to finance *working* capital (that is, increases in accounts receivable and inventories). In other words, a self-financing ratio of 100 percent would mean that only the cost of fixed *capital* expenditure is paid for from internal cash flow. Increases in working capital could still be financed by increased bank borrowing.

9.3.3 Assumptions and Sources of Data

The following are the major assumptions and sources of data used in the analysis of distribution companies:

- The historical data for the income statement and balance sheet were entered from a consolidation of the "F-02" statements for the distribution companies.

- The forecast energy sales were developed by Hagler, Bailly in conjunction with PPGC. They are described in Chapter 2.

- All projections of costs are in constant, mid-1992 price levels (equivalent to US $1.00 equals 13,400 Zlotys).

- Energy purchase costs were input from the results of the financial analysis of the transmission grid in Chapter 8.

- Operating costs for 1992 and subsequent years were based on 1991 costs (adjusted for the transfer of transmission assets) plus an inflation provision of 38 percent from 1991 to 1992. Given the companies' flat or modestly increasing sales, the real operating costs were projected to remain unchanged from 1992 levels.

- Annual depreciation expense was computed at 5.0 percent of average gross fixed assets in service.

- Interest expense (net of inflation) was computed at 11.0 percent per annum, based on average outstanding debt.

- From 1993 onwards, capital expenditure was assumed to be the sum of two components: 1) a component proportional to sales growth and the existing gross fixed assets in service and 2) replacement and modernization at 3.33 percent of existing gross assets. Assets were assumed, on average, to be placed in service 12 months after initial expenditure.

- Working capital is based on 2.0 months' sales in accounts receivable. This is higher than in the past; however, as the economy becomes increasingly privatized, it is likely that the trend will be towards an increase in average outstanding receivables (which were just under 1 month in 1991).

To avoid fluctuations over the period 1994-1997 due to annual changes in the revenue requirements of the generation system and the transmission grid, the average retail tariff was levelized by short-term borrowing rather than maintaining a uniform ratio with the bulk tariff.

9.4 RESULTS FOR THE CONSOLIDATED DISTRIBUTION SYSTEM

Exhibit 9-1 shows a balance of energy sales and purchases for the consolidated distribution companies. Exhibits 9-2a and 9-2b correspond to the income statement and balance sheet, respectively, for the consolidated distribution system, using the financial criterion of no net increase in overall debt (criterion A), as discussed above.

The application of the financial criterion of no net increase in debt to the forecast costs and capital expenditures results in revenue requirements of 785 Zl/kWh for the period 1994-1995. This represents the required average retail tariff at price levels of 1992 and is equivalent to 5.9 US cents/kWh. Compared with the mid-1992 average retail tariff, this represents a real increase of 45 percent. Using this criterion, the operating and financial ratios for the consolidated system are shown in Exhibit 9-2c.

The operating and financial ratios of the consolidated distribution companies using the 6 percent return on net assets criterion are presented in Exhibit 9-2d. Using this criterion, the forecast revenue requirements at the retail level would be 847 Zl/kWh in 1994, or a 56 percent increase from mid-1992 levels.

The operating and financial ratios of the consolidated distribution companies using the 100 percent self-financing ratio criterion are presented in Exhibit 9-2e. Using this criterion, the forecast revenue requirements at the retail level would be 739 Zl/kWh in 1994 or a 36 percent increase from mid-1992 levels.

The results presented below are those for the unconstrained tariff increase and instant asset revaluation scenario. See Chapter 11 for results under the financial forecast constrained by the need to limit the impact of tariff increases and the feasible extent of and schedule for the revaluation of assets.

Exhibit 9–1
BALANCE OF ENERGY PURCHASES AND SALES
CONSOLIDATED DISTRIBUTION SYSTEM

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLSKIE SIECI ELEKTROENERGETYCZNE Year End –– December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES SUMMARY GWh						
65,405	57,312	51,052	Industry	48,988	48,864	48,843	49,300	50,410	51,612
5,875	5,346	4,915	Railways	5,160	5,631	6,158	6,800	6,940	7,092
9,386	8,218	9,821	Commercial	9,192	9,676	10,206	10,871	11,201	11,556
8,633	8,124	8,394	Agriculture	8,422	8,865	9,351	9,960	10,262	10,587
20,267	22,183	20,829	Residential	21,937	23,091	24,356	25,943	26,731	27,578
28,900	30,307	29,223	Sub–total – Agricult & Resid'l	30,359	31,956	33,707	35,903	36,933	38,165
1,506	1,325	1,372	Street Lighting	1,375	1,448	1,527	1,627	1,676	1,729
111,072	**102,508**	**96,383**	**TOTAL ENERGY SALES**	**95,074**	**97,575**	**100,441**	**104,501**	**107,220**	**110,154**
			AVERAGE TARIFF						
0.0	241.1	341.7	Industry						
0.0	264.7	352.6	Railways						
0.0	340.6	502.1	Commercial						
0.0	119.2	317.4	Agriculture						
0.0	99.6	304.0	Residential						
0.0	104.9	307.8	Sub–total – Agricult & Resid'l						
0.0	506.5	741.3	Street Lighting						
19.9	**213.4**	**354.0**	**OVERALL AVERAGE TARIFF**	**542.1**	**542.1**	**785.0**	**785.0**	**795.0**	**805.0**
			TOTAL SALES REVENUE						
	13,815	17,443	Industry						
	1,415	1,733	Railways						
	2,799	4,931	Commercial						
	969	2,664	Agriculture						
	2,210	6,331	Residential						
	3,179	8,995	Sub–total – Agricult & Resid'l						
	671	1,017	Street Lighting						
2,215	**21,885**	**34,119**	**GRAND TOTAL SALES –– ELECTRICITY**	**51,540**	**52,895**	**78,846**	**82,033**	**85,240**	**88,674**

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Exhibit 9–2a

INCOME STATEMENT – CONSOLIDATED DISTRIBUTION SYSTEM

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH DISTRIBUTION COMPANIES Year End –– December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
111,072	102,508	96,383	Energy Sales –– GWh	95,074	97,575	100,441	104,501	107,220	110,154
19.9	213.4	354.0	Average Tariff –– Zl/kWh	542.1	542.1	785.0	785.0	795.0	805.0
2,215	21,880	34,119	Total Energy Sales Revenue	51,540	52,895	78,846	82,033	85,240	88,674
16	332	676	Other Revenues (Net)	773	793	1,183	1,230	1,279	1,330
2,231	**22,212**	**34,795**	**Total Revenue**	**52,313**	**53,689**	**80,029**	**83,264**	**86,518**	**90,004**
			Energy Costs						
		130	Own Thermal						
		248	Own Hydro						
		50	Auto producer	58	58	58	58	58	58
		7	Small Hydro						
1,530	15,122	23,715	PSE	35,989	36,341	62,039	63,322	65,259	68,497
1,530	**15,114**	**24,149**	**Total Energy Costs**	**36,047**	**36,399**	**62,097**	**63,380**	**65,317**	**68,556**
			Transmission and Customer Service						
25	216	317	Materials						
137	1,422	1,593	Repairs						
243	1,275	2,090	Salaries and Payroll Taxes						
61	1,192	3,418	Amortization						
115	688	299	Administration Overhhead						
			Other Costs						
581	**4,793**	**7,717**	**TOTAL FIXED OPERATING COSTS**	**0**	**0**	**0**	**0**	**0**	**0**
			Less: High Voltage Network Costs						
	4	9	Materials						
	44	54	Repairs						
	26	39	Salaries and Taxes						
	146	469	Amortization						
	53	87	Administration Overhhead						
	30	56	Other Costs						
	303	**714**	**Total High Voltage Network Costs**	**0**	**0**	**0**	**0**	**0**	**0**

Exhibit 9–2a
INCOME STATEMENT – CONSOLIDATED DISTRIBUTION SYSTEM

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH DISTRIBUTION COMPANIES Year End - – December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			Net Distribution Network Costs						
	212	308	Materials	425	425	425	425	425	425
	1,378	1,539	Repairs	2,123	2,123	2,123	2,123	2,123	2,123
	1,249	2,051	Salaries and Taxes	1,732	1,732	1,732	1,732	1,732	1,732
	1,047	2,949	Amortization	12,239	12,239	12,384	12,703	13,237	14,017
	635	212	Administration Overhhead	1,391	1,391	1,391	1,391	1,391	1,391
	(30)	(56)	Other Costs	(78)	(78)	(78)	(78)	(78)	(78)
	4,490	**7,002**	**Total Distribution Costs @1992**	**17,832**	**17,832**	**17,977**	**18,297**	**18,830**	**19,610**
			Plus: Inflation	0	0	0	0	0	0
			Total Distribution Costs	17,832	17,832	17,977	18,297	18,830	19,610
2,111	**19,907**	**31,866**	**TOTAL COSTS**	**53,879**	**54,232**	**80,075**	**81,677**	**84,148**	**88,166**
110	**2,305**	**2,929**	**OPERATING INCOME**	**(1,567)**	**(543)**	**(46)**	**1,587**	**2,371**	**1,838**
21	**947**	**1,375**	**OTHER INCOME**	**1,581**	**1,597**	**2,724**	**2,780**	**2,865**	**3,007**
2	5	260	Interest Expense	(192)	(554)	(711)	(1,064)	(1,041)	(1,064)
139	**2,647**	**4,044**	**INCOME BEFORE TAX**	**207**	**1,608**	**3,389**	**5,430**	**6,277**	**5,908**
39	1,716	2,874	Less: Income & Corporate Tax	142	643	1,355	2,172	2,511	2,363
100	**931**	**1,170**	**NET INCOME**	**65**	**965**	**2,033**	**3,258**	**3,766**	**3,545**

Billions Zloty at Base Year Prices
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Exhibit 9–2b
BALANCE SHEET – CONSOLIDATED DISTRIBUTION SYSTEM

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH DISTRIBUTION COMPANIES Year End – – December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			ASSETS						
	1,116	1,226	Cash	1,692	1,692	1,692	1,692	1,692	1,692
	895	3,716	Accounts Receivable	8,719	8,948	13,338	13,877	14,420	15,001
	318	532	Inventories	735	735	735	735	735	735
0	2,329	5,474	**Total Current Assets**	11,145	11,375	15,765	16,304	16,846	17,427
		66,711							
			Gross Fixed Assets:						
		6,903	Transmission (>110kv)& S/stations						
		44,206	Distribution Lines						
		14,803	Substations						
		4,930	Other Fixed & Tangible Assets						
	65,818	70,842	Gross Fixed & Tangible Assets	244,775	247,678	254,063	264,737	280,337	296,564
	33,859	36,976	Less: Acc. Depreciation	140,000	152,239	164,623	177,326	190,563	204,579
	31,959	33,866	Net Fixed & Tangible Assets	104,775	95,439	89,440	87,412	89,774	91,985
	1,190	2,903	Capital Work–in–Progress	2,903	6,385	10,674	15,600	16,227	16,389
	6	30	Goodwill						
0	34,927	42,272	**TOTAL ASSETS EMPLOYED**	118,823	113,199	115,880	119,315	122,848	125,801
			LIABILITIES						
	891	2,671	Accounts Payable						
	633	3,799	Other Liabilities						
		0	Cash Deficiency (Surplus)	(3,492)	(10,081)	(9,434)	(9,256)	(9,489)	(10,081)
0	1,784	6,470	**Total Current Liabilities**	(3,492)	(10,081)	(9,434)	(9,256)	(9,489)	(10,081)
	575	1,309	Long Term Debt	1,309	1,309	1,309	1,309	1,309	1,309
			Equity Balance:						
	31,645	32,578	Assumed Opening Position	32,578	32,578	32,578	32,578	32,578	32,578
			Reserve for Asset Revaluation	86,448	86,448	86,448	86,448	86,448	86,448
		923	Retained Earnings – – Prior Years	1,915	1,979	2,944	4,978	8,236	12,002
	923	991	Current Year's Net Income	65	965	2,033	3,258	3,766	3,545
	32,568	34,492	**Total Equity**	121,005	121,970	124,004	127,262	131,028	134,573
	34,927	42,272	**TOTAL LIABILITIES & EQUITY**	118,823	113,199	115,880	119,315	122,848	125,801

Billions Zloty at Base Year Prices
Case: DISCOBAS\disor011

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Exhibit 9–2c
OPERATING AND FINANCIAL RATIOS – CONSOLIDATED DISTRIBUTION SYSTEM
Criterion = Zero Debt Increase

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH DISTRIBUTION COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES RATIOS						
19.942	213.444	353.994	Average Sales Tariff -- Zl/ kWh	542.100	542.100	785.000	785.000	795.000	805.000
	135.258	221.677	Average Purchase Cost -- Zl/ kWh	339.071	336.295	561.492	555.559	557.590	569.588
	–7.7%	–6.0%	Annual Sales Growth (kWh) -- %	–1.4%	2.6%	2.9%	4.0%	2.6%	2.7%
	887.8%	55.9%	Annual Sales Growth (Zl) -- %	51.1%	2.6%	49.1%	4.0%	3.9%	4.0%
			OPERATING RATIOS						
	8.3%	11.6%	Distribution Losses – %	10.6%	9.9%	9.2%	8.4%	8.5%	8.5%
	63.4%	62.6%	Energy Purchase/ Sales -- %	62.5%	62.0%	71.5%	70.8%	70.1%	70.8%
5.4%	10.4%	8.4%	Operating Income/ Sales -- %	–3.0%	–1.0%	–0.1%	1.9%	2.7%	2.0%
	3.4%	3.9%	Operating Income/ Net Assets -- %	–2.1%	–0.5%	–0.0%	1.5%	2.3%	1.7%
	2.9%	3.4%	Net Income after Tax/ Equity -- %	0.1%	0.8%	1.6%	2.6%	2.9%	2.6%
			FINANCIAL RATIOS						
	1.3	0.8	Current Ratio	–3.2	–1.1	–1.7	–1.8	–1.8	–1.7
	7.2%	22.6%	Total Debt/ Equity -- %	–1.8%	–7.2%	–6.6%	–6.2%	–6.2%	–6.5%
			Self–Financing Ratio -- %		232.2%	132.4%	112.7%	105.8%	107.9%

Case: DISCOBAS\disor011

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Exhibit 9–2d
OPERATING AND FINANCIAL RATIOS – CONSOLIDATED DISTRIBUTION SYSTEM
Criterion = 6% Return on Assets

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH DISTRIBUTION COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES RATIOS						
19.942	213.444	353.994	Average Sales Tariff -- Zl/ kWh	542.100	542.100	847.000	829.000	831.000	846.000
	135.258	221.677	Average Purchase Cost -- Zl/ kWh	339.071	336.295	561.492	555.559	557.590	569.588
	-7.7%	-6.0%	Annual Sales Growth (kWh) -- %	-1.4%	2.6%	2.9%	4.0%	2.6%	2.7%
	887.8%	55.9%	Annual Sales Growth (Zl) -- %	51.1%	2.6%	60.8%	1.8%	2.8%	4.6%
			OPERATING RATIOS						
	8.3%	11.6%	Distribution Losses -- %	10.6%	9.9%	9.2%	8.4%	8.5%	8.5%
	63.4%	62.6%	Energy Purchase/ Sales -- %	62.5%	62.0%	66.3%	67.0%	67.1%	67.3%
5.4%	10.4%	8.4%	Operating Income/ Sales -- %	-3.0%	-1.0%	7.3%	7.1%	7.0%	6.8%
	3.4%	3.9%	Operating Income/ Net Assets -- %	-2.1%	-0.5%	6.0%	6.0%	6.0%	6.0%
	2.9%	3.4%	Net Income after Tax/ Equity -- %	0.1%	0.8%	4.5%	4.7%	4.6%	4.7%
			FINANCIAL RATIOS						
	1.3	0.8	Current Ratio	-3.2	-1.1	-1.4	-1.1	-0.9	-0.8
	7.2%	22.6%	Total Debt/ Equity -- %	-1.8%	-7.2%	-8.6%	-10.5%	-12.2%	-14.2%
			Self–Financing Ratio -- %		232.2%	168.1%	133.9%	122.8%	128.5%

Case: DISCOBAS\disor012

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Exhibit 9–2e
OPERATING AND FINANCIAL RATIOS – CONSOLIDATED DISTRIBUTION SYSTEM
Criterion = 100% Self Financing

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH DISTRIBUTION COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES RATIOS						
19.942	213.444	353.994	Average Sales Tariff -- Zl/ kWh	542.100	542.100	739.000	760.000	786.000	792.000
	135.258	221.677	Average Purchase Cost -- Zl/ kWh	339.071	336.295	561.492	555.559	557.590	569.588
	-7.7%	-6.0%	Annual Sales Growth (kWh) -- %	-1.4%	2.6%	2.9%	4.0%	2.6%	2.7%
	887.8%	55.9%	Annual Sales Growth (Zl) -- %	51.1%	2.6%	40.3%	7.0%	6.1%	3.5%
			OPERATING RATIOS						
	8.3%	11.6%	Distribution Losses – %	10.6%	9.9%	9.2%	8.4%	8.5%	8.5%
	63.4%	62.6%	Energy Purchase/ Sales -- %	62.5%	62.0%	76.0%	73.1%	70.9%	71.9%
5.4%	10.4%	8.4%	Operating Income/ Sales -- %	-3.0%	-1.0%	-6.3%	-1.3%	1.6%	0.4%
	3.4%	3.9%	Operating Income/ Net Assets -- %	-2.1%	-0.5%	-4.6%	-1.0%	1.3%	0.4%
	2.9%	3.4%	Net Income after Tax/ Equity -- %	0.1%	0.8%	-1.2%	1.2%	2.3%	1.8%
			FINANCIAL RATIOS						
	1.3	0.8	Current Ratio	-3.2	-1.1	-2.2	-3.6	-4.7	-5.8
	7.2%	22.6%	Total Debt/ Equity -- %	-1.8%	-7.2%	-4.5%	-2.6%	-1.8%	-1.3%
			Self–Financing Ratio -- %		232.2%	100.4%	100.3%	100.4%	100.1%

Case: DISCOBAS\disor013

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9.5 SUMMARY OF RESULTS OF THE UNCONSTRAINED FINANCIAL ANALYSIS OF THE CONSOLIDATED SYSTEM

Exhibit 9-2f shows a summary of the results of the financial revenue requirements analyses for the consolidated generation, transmission and distribution system. For the distribution system, the most strongly recommended financial criterion was used: that is, no increase in overall debt.

9.6 CASE STUDIES FOR DISTRIBUTION COMPANIES

In order to study the effect of uniform bulk sales tariffs on individual distribution utilities, the financial outlook of three companies was examined. The financial and operating ratios for the distribution company Bialystok are shown in Exhibit 9-3a,b, and c corresponding to the three financial criteria discussed above for the consolidated system. The same information is shown for the Gliwice Distribution Company in Exhibit 9-4 and for the Warsaw Distribution Company in Exhibit 9-5.

The resulting 1994 revenue requirements for each company and according to the different criteria are shown in Exhibit 9-6. Because the capital investment forecasts for each of these companies were not available, they were estimated on a basis that is not directly comparable to the forecast available for the consolidated distribution system. Thus, the results for these companies are only valid to establish relative differences among them and not in relation to the entire system. Nevertheless, the following conclusions are possible:

- The spreads among the average retail tariffs of these companies are 60.0 percent, 50.2 percent, and 48.92 percent corresponding to criteria A, B and C above.

- As might be expected, tariffs for Bialystok (rural area) are consistently the highest while tariffs for the heaviest industrial area Gliwice are consistently the lowest.

EXHIBIT 9-2F

SUMMARY OF REVENUE
REQUIREMENTS THROUGH THE SYSTEM

	1992	1994	1995	1996	1997	FINANCIAL CRITERION
GENERATING COMPANIES	300.296	488.951	487.195	490.566	504.206	6% Return on Net Assets
PPGC	336.716	563.000	557.000	559.000	571.000	6% Return on Net Assets
DISTRIBUTION COMPANIES Criterion A	542.100	785.000	785.000	795.000	805.000	No increase in Overall Borrowing 1993-1997
DISTRIBUTION COMPANIES Criterion C	542.100	739.000	760.000	786.000	792.000	100% Self Financing Ratio

Exhibit 9–3a
OPERATING AND FINANCIAL RATIOS – BIALYSTOK DISTRIBUTION COMPANY
Criterion = Zero Debt Increase

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH DISTRIBUTION COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES RATIOS						
0.000	211.112	393.081	Average Sales Tariff -- Zl/ kWh	542.100	542.100	1245.000	1245.000	1245.000	1245.000
	104.089	181.800	Average Purchase Cost -- Zl/ kWh	339.071	336.295	563.000	557.000	559.000	571.000
		–3.7%	Annual Sales Growth (kWh) -- %	15.8%	3.5%	3.5%	5.2%	2.8%	2.9%
	931.7%	79.3%	Annual Sales Growth (Zl) -- %	59.7%	3.5%	137.5%	5.2%	2.8%	2.9%
			OPERATING RATIOS						
	1.2%	19.6%	Distribution Losses – %	9.8%	9.0%	8.3%	7.5%	7.5%	7.5%
	49.3%	46.2%	Energy Purchase/ Sales -- %	62.5%	62.0%	45.2%	44.7%	44.9%	45.9%
8.7%	10.7%	11.0%	Operating Income/ Sales -- %	6.1%	–20.9%	28.4%	29.4%	28.9%	27.2%
	10.2%	8.8%	Operating Income/ Net Assets -- %	1.6%	–3.3%	10.9%	11.7%	11.4%	10.8%
	1.6%	5.7%	Net Income after Tax/ Equity -- %	1.4%	–2.9%	6.8%	7.2%	7.0%	6.7%
			FINANCIAL RATIOS						
	1.0	0.8	Current Ratio	–0.4	0.1	0.1	0.1	0.1	0.1
	8.8%	17.3%	Total Debt/ Equity	–1.5%	8.2%	8.2%	9.7%	8.2%	7.3%
			Self Financing Ratio -- %	100.6%	56.9%	142.1%	152.2%	151.7%	252.3%

Case: DISCOBAS\bialr001

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Exhibit 9–3b
OPERATING AND FINANCIAL RATIOS – BIALYSTOK DISTRIBUTION COMPANY
Criterion = 6% Return on Assets

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH DISTRIBUTION COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES RATIOS						
0.000	211.112	393.081	Average Sales Tariff -- Zl/kWh	542.100	542.100	1,086.000	1,068.000	1,073.000	1,093.000
	104.089	181.800	Average Purchase Cost -- Zl/ kWh	339.071	336.295	563.000	557.000	559.000	571.000
		–3.7%	Annual Sales Growth (kWh) -- %	15.8%	3.5%	3.5%	5.2%	2.8%	2.9%
	931.7%	79.3%	Annual Sales Growth (Zl) -- %	59.7%	3.5%	107.3%	3.5%	3.3%	4.8%
			OPERATING RATIOS						
	1.2%	19.6%	Distribution Losses – %	9.3%	9.0%	8.3%	7.5%	7.5%	7.5%
	49.3%	46.2%	Energy Purchase/ Sales -- %	62.5%	62.0%	51.8%	52.2%	52.1%	52.2%
8.7%	10.7%	11.0%	Operating Income/ Sales -- %	6.1%	–20.9%	17.9%	17.7%	17.5%	17.1%
	10.2%	8.8%	Operating Income/ Net Assets -- %	1.6%	–3.3%	6.0%	6.0%	6.0%	6.0%
	1.6%	5.7%	Net Income after Tax/ Equity -- %	1.4%	–2.9%	4.0%	4.1%	4.2%	4.3%
			FINANCIAL RATIOS						
	1.0	0.8	Current Ratio	–0.4	0.1	0.1	0.1	0.0	0.0
	8.8%	17.3%	Total Debt/ Equity	–1.5%	8.2%	11.4%	16.8%	19.1%	21.6%
			Self Financing Ratio -- %	100.6%	56.9%	108.5%	114.3%	115.1%	198.2%

Case: DISCOBAS\bialr002

RCG/HAGLER, BAILLY, Inc.
File Name g:\pol\report\exhibit\e9_3.wk1
29–Jun–93

Exhibit 9–3c
OPERATING AND FINANCIAL RATIOS – BIALYSTOK DISTRIBUTION COMPANY
Criterion = 100% Self Financing Ratio

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH DISTRIBUTION COMPANIES Year End –– December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES RATIOS						
0.000	211.112	393.081	Average Sales Tariff –– Zl/ kWh	542.100	542.100	1,042.000	1,005.000	1,005.000	825.000
	104.089	181.800	Average Purchase Cost –– Zl/ kWh	339.071	336.295	563.000	557.000	559.000	571.000
		–3.7%	Annual Sales Growth (kWh) –– %	15.8%	3.5%	3.5%	5.2%	2.8%	2.9%
	921.7%	79.3%	Annual Sales Growth (Zl) –– %	59.7%	3.5%	98.9%	1.5%	2.8%	–15.5%
			OPERATING RATIOS						
	1.2%	19.6%	Distribution Losses – %	9.8%	9.0%	8.3%	7.5%	7.5%	7.5%
	49.3%	46.2%	Energy Purchase/ Sales –– %	62.5%	62.0%	54.0%	55.4%	55.6%	69.2%
8.7%	10.7%	11.0%	Operating Income/ Sales –– %	6.1%	–20.9%	14.5%	12.6%	11.9%	–9.8%
	10.2%	8.8%	Operating Income/ Net Assets –– %	1.6%	–3.3%	4.6%	4.0%	3.8%	–2.6%
	1.6%	5.7%	Net Income after Tax/ Equity –– %	1.4%	–2.9%	3.2%	2.9%	2.9%	–1.5%
			FINANCIAL RATIOS						
	1.0	0.8	Current Ratio	–0.4	0.1	0.1	0.0	0.0	0.0
	8.8%	17.3%	Total Debt/ Equity	–1.5%	8.2%	12.4%	19.3%	23.4%	34.0%
			Self Financing Ratio –– %	100.6%	56.9%	100.5%	100.7%	100.7%	102.8%

Case: DISCOBAS\bialr003

RCG/HAGLER, BAILLY, Inc.
File Name g:\pol\report\exhibit\e9_3.wk1
29–Jun–93

Exhibit 9–4a
OPERATING AND FINANCIAL RATIOS – GLIWICE DISTRIBUTION COMPANY
Criterion = Zero Debt Increase

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH DISTRIBUTION COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES RATIOS						
0.000	204.291	322.284	Average Sales Tariff -- Zl/ kWh	542.100	542.100	776.940	768.660	771.420	787.980
	164.983	247.583	Average Purchase Cost -- Zl/ kWh	339.071	336.295	563.000	557.000	559.000	571.000
		–8.0%	Annual Sales Growth (kWh) -- %	–0.1%	1.3%	1.6%	2.7%	2.5%	2.6%
	855.1%	45.1%	Annual Sales Growth (Zl) -- %	68.1%	1.3%	45.6%	1.6%	2.8%	4.8%
			OPERATING RATIOS						
	3.8%	7.9%	Distribution Losses – %	9.8%	9.0%	8.3%	7.5%	7.5%	7.5%
	80.8%	76.8%	Energy Purchase/ Sales -- %	62.5%	62.0%	72.5%	72.5%	72.5%	72.5%
2.5%	7.8%	6.1%	Operating Income/ Sales -- %	21.4%	16.1%	10.1%	10.6%	10.6%	10.7%
	5.5%	5.5%	Operating Income/ Net Assets -- %	30.2%	30.4%	13.1%	13.6%	12.7%	12.7%
	4.5%	2.6%	Net Income after Tax/ Equity -- %	6.6%	4.8%	7.9%	7.8%	7.4%	7.3%
			FINANCIAL RATIOS						
	0.9	0.7	Current Ratio	1.5	1.4	1.4	1.4	1.5	1.6
	11.6%	33.0%	Total Debt/ Equity	13.1%	13.6%	17.9%	16.1%	14.4%	13.1%
			Self Financing Ratio -- %	319.6%	235.2%	181.8%	172.7%	161.5%	252.4%

Case: DISCOBAS\gliwr001

RCG/HAGLER, BAILLY, Inc.
File Name g:\pol\report\exhibit\e9_3.wk1
29–Jun–93

Exhibit 9–4b
OPERATING AND FINANCIAL RATIOS – GLIWICE DISTRIBUTION COMPANY
Criterion = 6% Return on Assets

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH DISTRIBUTION COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES RATIOS						
0.000	204.291	322.284	Average Sales Tariff -- Zl/kWh	542.100	542.100	735.000	723.000	728.000	743.000
	164.983	247.583	Average Purchase Cost -- Zl/ kWh	339.071	336.295	563.000	557.000	559.000	571.000
		–8.0%	Annual Sales Growth (kWh) -- %	–0.1%	1.3%	1.6%	2.7%	2.5%	2.6%
	855.1%	45.1%	Annual Sales Growth (Zl) -- %	68.1%	1.3%	37.8%	1.0%	3.2%	4.7%
			OPERATING RATIOS						
	3.8%	7.9%	Distribution Losses – %	9.8%	9.0%	8.3%	7.5%	7.5%	7.5%
	80.8%	76.8%	Energy Purchase/ Sales -- %	62.5%	62.0%	76.6%	77.0%	76.8%	76.9%
2.5%	7.8%	6.1%	Operating Income/ Sales -- %	21.4%	16.1%	5.0%	5.0%	5.3%	5.3%
	5.5%	5.5%	Operating Income/ Net Assets -- %	30.2%	30.4%	6.1%	6.0%	6.1%	6.0%
	4.5%	2.6%	Net Income after Tax/ Equity -- %	6.6%	4.8%	3.9%	3.8%	3.9%	4.0%
			FINANCIAL RATIOS						
	0.9	0.7	Current Ratio	1.5	1.4	1.1	1.0	0.8	0.8
	11.6%	33.0%	Total Debt/ Equity	13.1%	13.6%	21.8%	25.1%	28.0%	31.0%
			Self Financing Ratio -- %	319.6%	235.2%	135.5%	126.2%	120.6%	188.3%

Case: DISCOBAS\gliwr002

RCG/HAGLER, BAILLY, Inc.
File Name g:\pol\report\exhibit\e9_3.wk1
29–Jun–93

Exhibit 9–4c
OPERATING AND FINANCIAL RATIOS – GLIWICE DISTRIBUTION COMPANY
Criterion = 100% Self Financing Ratio

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH DISTRIBUTION COMPANIES Year End –– December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES RATIOS						
0.000	204.291	322.284	Average Sales Tariff –– Zl/kWh	542.100	542.100	703.000	698.000	707.000	681.000
	164.983	247.503	Average Purchase Cost –– Zl/ kWh	339.071	336.295	563.000	557.000	559.000	571.000
		–8.0%	Annual Sales Growth (kWh) –– %	–0.1%	1.3%	1.6%	2.7%	2.5%	2.6%
	855.1%	45.1%	Annual Sales Growth (Zl) –– %	68.1%	1.3%	31.8%	1.9%	3.8%	–1.2%
			OPERATING RATIOS						
	3.8%	7.9%	Distribution Losses – %	9.8%	9.0%	8.3%	7.5%	7.5%	7.5%
	80.8%	76.8%	Energy Purchase/ Sales –– %	62.5%	62.0%	80.[illegible]%	79.8%	79.1%	83.8%
2.5%	7.8%	6.1%	Operating Income/ Sales –– %	21.4%	16.1%	0.7%	1.6%	2.5%	–3.3%
	5.5%	5.5%	Operating Income/ Net Assets –– %	30.2%	30.4%	0.8%	1.9%	2.8%	–3.4%
	4.5%	2.6%	Net Income after Tax/ Equity –– %	6.6%	4.8%	0.5%	1.2%	1.9%	–2.6%
			FINANCIAL RATIOS						
	0.9	0.7	Current Ratio	1.5	1.4	1.0	0.8	0.7	0.5
	11.6%	33.0%	Total Debt/ Equity	13.1%	13.6%	24.9%	32.0%	38.0%	49.6%
			Self Financing Ratio –– %	319.6%	235.2%	100.2%	100.7%	100.9%	99.9%

Case: DISCOBAS\gliwr003

RCG/HAGLER, BAILLY, Inc.
File Name g:\pol\report\exhibit\e9_3.wk1
29–Jun–93

Exhibit 9–5a
OPERATING AND FINANCIAL RATIOS – WARSAWA DISTRIBUTION COMPANY
Criterion = Zero Debt Increase

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH DISTRIBUTION COMPANIES Year End –– December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES RATIOS						
	228.113	378.867	Average Sales Tariff –– Zl/ kWh	542.100	542.100	906.430	896.770	899.090	919.310
	145.019	238.353	Average Purchase Cost –– Zl/ kWh	339.071	336.295	563.000	557.000	559.000	571.000
		–9.6%	Annual Sales Growth (kWh) –– %	9.3%	3.3%	3.6%	4.7%	2.7%	2.8%
		50.2%	Annual Sales Growth (Zl) –– %	56.3%	3.3%	73.3%	3.6%	3.0%	5.0%
			OPERATING RATIOS						
	9.9%	13.2%	Distribution Losses – %	9.8%	9.0%	8.3%	7.5%	7.5%	7.5%
	63.6%	62.9%	Energy Purchase/ Sales –– %	62.5%	62.0%	62.1%	62.1%	62.1%	62.1%
4.9%	8.5%	3.6%	Operating Income/ Sales –– %	9.2%	1.9%	14.9%	15.6%	15.6%	15.8%
43.1%	16.7%	4.7%	Operating Income/ Net Assets –– %	9.6%	1.5%	17.8%	16.9%	15.8%	15.5%
	3.0%	0.5%	Net Income after Tax/ Equity –– %	2.4%	0.5%	11.3%	10.9%	10.1%	9.7%
			FINANCIAL RATIOS						
	1.1	0.7	Current Ratio	1.2	0.7	0.8	0.8	0.9	1.0
	8.9%	34.5%	Total Debt/ Equity	13.6%	24.5%	30.3%	28.6%	23.4%	19.1%
			Self Financing Ratio –– %	124.3%	114.4%	143.7%	152.4%	155.6%	174.7%

Case: DISCOBAS\warsr001

RCG/HAGLER, BAILLY, Inc.
File Name g:\pol\report\exhibit\e9_3.wk1
29–Jun–93

Exhibit 9-5b
OPERATING AND FINANCIAL RATIOS – WARSAWA DISTRIBUTION COMPANY
Criterion = 6% Return on Assets

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH DISTRIBUTION COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES RATIOS						
	228.113	378.867	Average Sales Tariff -- Zl/ kWh	542.100	542.100	817.000	807.000	813.000	830.000
	145.019	238.353	Average Purchase Cost -- Zl/ kWh	339.071	335.295	563.000	557.000	559.000	571.000
		-9.6%	Annual Sales Growth (kWh) -- %	9.3%	3.3%	3.6%	4.7%	2.7%	2.8%
		50.2%	Annual Sales Growth (Zl) -- %	56.3%	3.3%	56.2%	3.4%	3.4%	5.0%
			OPERATING RATIOS						
	9.9%	13.2%	Distribution Losses – %	9.8%	9.0%	8.3%	7.5%	7.5%	7.5%
	63.6%	62.9%	Energy Purchase/ Sales -- %	62.5%	62.0%	68.9%	69.0%	68.8%	68.8%
4.9%	8.5%	3.6%	Operating Income/ Sales -- %	9.2%	1.9%	5.6%	6.2%	6.5%	6.7%
43.1%	16.7%	4.7%	Operating Income/ Net Assets -- %	9.6%	1.5%	6.1%	6.1%	6.1%	6.1%
	3.0%	0.5%	Net Income after Tax/ Equity -- %	2.4%	0.5%	4.1%	4.5%	4.7%	4.8%
			FINANCIAL RATIOS						
	1.1	0.7	Current Ratio	1.2	0.7	0.6	0.5	0.5	0.4
	8.9%	34.5%	Total Debt/ Equity	13.6%	24.5%	38.6%	46.7%	49.2%	51.9%
			Self Financing Ratio -- %	124.3%	114.4%	93.6%	100.4%	105.1%	118.8%

Case: DISCOBAS\warsr002

RCG/HAGLER, BAILLY, Inc.
File Name g:\pol\report\exhibit\e9_3.wk1
29-Jun-93

Exhibit 9–5c
OPERATING AND FINANCIAL RATIOS – WARSAWA DISTRIBUTION COMPANY
Criterion = 100% Self Financing Ratio

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH DISTRIBUTION COMPANIES Year End –– December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES RATIOS						
	228.113	378.867	Average Sales Tariff –– Zl/ kWh	542.100	542.100	829.000	807.000	805.000	800.000
	145.019	238.353	Average Purchase Cost –– Zl/ kWh	339.071	336.295	563.000	557.000	559.000	571.000
		–9.6%	Annual Sales Growth (kWh) –– %	9.3%	3.3%	3.6%	4.7%	2.7%	2.8%
		50.2%	Annual Sales Growth (Zl) –– %	56.3%	3.3%	58.5%	1.9%	2.4%	2.2%
			OPERATING RATIOS						
	9.9%	13.2%	Distribution Losses – %	9.8%	9.0%	8.3%	7.5%	7.5%	7.5%
	63.6%	62.9%	Energy Purchase/ Sales –– %	62.5%	62.0%	67.9%	69.0%	69.4%	71.4%
4.9%	8.5%	3.6%	Operating Income/ Sales –– %	9.2%	1.9%	7.0%	6.2%	5.6%	3.2%
43.1%	16.7%	4.7%	Operating Income/ Net Assets –– %	9.6%	1.5%	7.7%	6.1%	5.2%	2.8%
	3.0%	0.5%	Net Income after Tax/ Equity –– %	2.4%	0.5%	5.1%	4.4%	4.0%	2.3%
			FINANCIAL RATIOS						
	1.1	0.7	Current Ratio	1.2	0.7	0.6	0.5	0.5	0.4
	8.9%	34.5%	Total Debt/ Equity	13.6%	24.5%	37.4%	45.2%	48.6%	54.8%
			Self Financing Ratio –– %	124.3%	114.4%	100.3%	100.4%	100.5%	100.0%

Case: DISCOBAS\warsr003

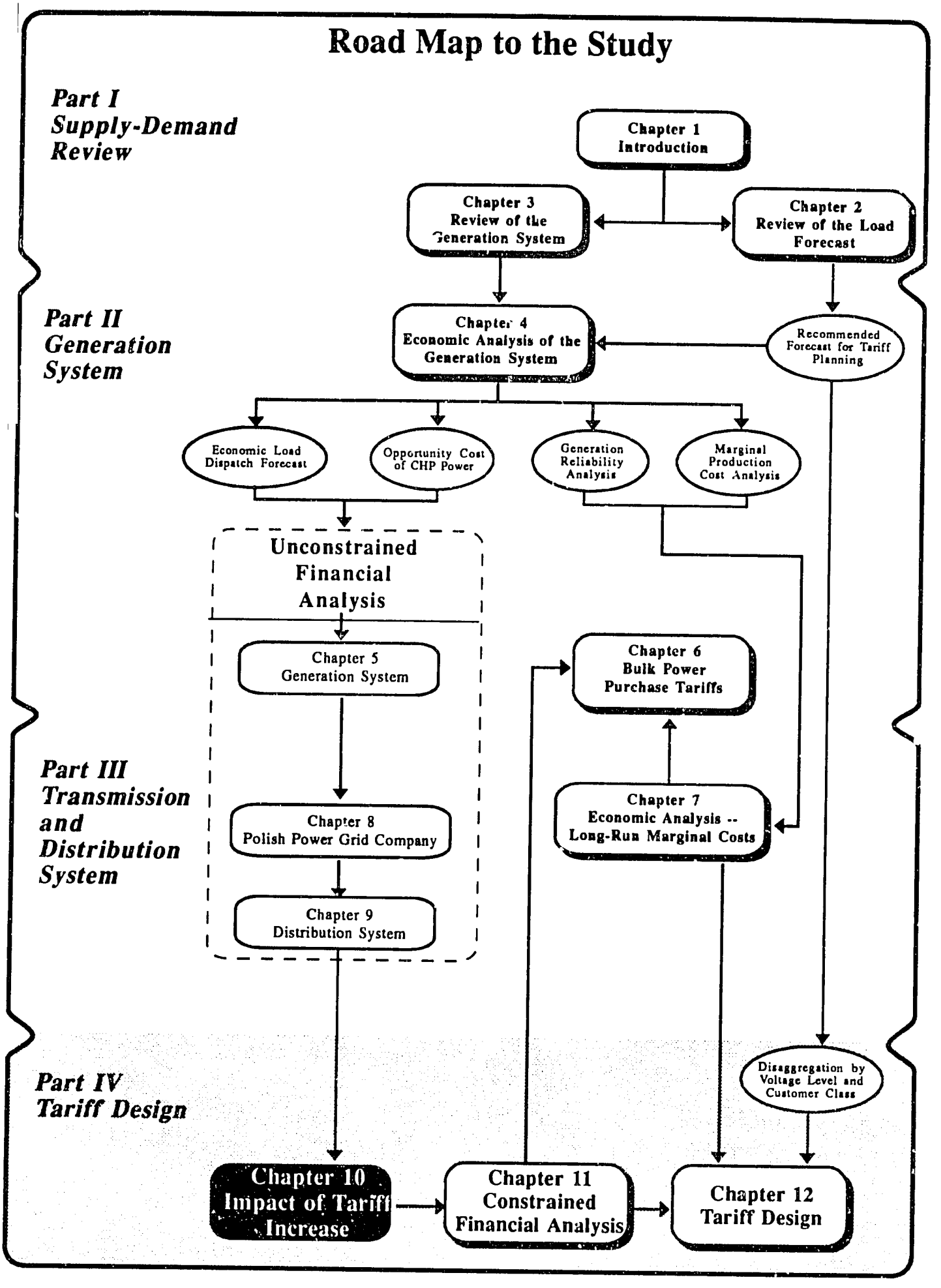
RCG/HAGLER, BAILLY, Inc.
File Name g:\pol\report\exhibit\e9_3.wk1
29–Jun–93

EXHIBIT 9-6

REVENUE REQUIREMENTS OF THREE DISTRIBUTION COMPANIES (ZI/kWh)

DISTRIBUTION COMPANY	FINANCIAL CRITERION		
	A ZERO DEBT INCREASE	B 6% RETURN	C 100% SELF FINANCING
BIALYSTOK	1245.0	1086.0	1042.0
GLIWICE	776.9	735.0	703.0
WARSAW	906.4	817.0	829.0

Road Map to the Study



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CHAPTER 10: IMPACT OF TARIFF INCREASES

This chapter assesses the impact of electricity tariff increases on Poland's end-users in order to adjust from current levels to full cost-based pricing. If the payment of new tariffs for electricity were extremely damaging to economic output or to the welfare of households, it might be desirable to design tariff phase-in periods, continued subsidies, or other mitigating measures.

This chapter focuses primarily on Polish industry and households, although agriculture and transportation are also discussed. For several reasons, it is not possible to rely fully on the information that is currently available on these end-users. First, where data exist, they are poor and may not reflect the values that are of most interest. Thus, data on past expenditures usually do not reflect the amounts spent now. Second, all end-users are experiencing markets in great disequilibrium. Even if precise data were available on variables of interest, it is likely that those values will change rapidly in the near future. Third, abrupt changes in the Polish incentive system imply significant changes in consumer and productive behavior over the relatively short run. Again, precise data on the current situation may not reveal much about the near future.

As a result of these conditions, we used empirical data where possible, and made judgments where good data were not available. For each end-user, we attempted to determine the amounts of money that are likely to be spent on electricity now. We then asked whether it would make a difference if tariffs were much higher. Polish decision-makers must ultimately judge whether or not the differences identified are significant in the Polish context.

10.1 THE IMPACTS ON INDUSTRY

A number of factors complicate the analysis of the impact of tariff increases on Poland's industries. First, the historical data available on Polish industry reflect many factors that were arbitrarily determined by state planners. Second, the disequilibrium faced by Polish industry now is so overpowering that it is difficult to predict what cost/price structures will be when "normal" conditions return. Third, prior to 1990, internal incentives for Polish industry were perverse, and in many cases, cost reductions resulted in reduced profit.[1]

Also, because electricity shortages were common, managers would take steps to reduce the potential damage to production that results from input shortages. If they incurred extra costs

[1] For an elaboration on the incentives embedded in socialized industry in Poland, see Kharas (1991).

to avoid shortages, they protected their ability to meet production targets and were rewarded with increased profits. In addition, it was common to contract for much more capacity than was actually needed (however, capacity was seldom drawn upon). Therefore, in calculating the cost of electricity to an enterprise, the cost per kWh may appear to be very high. This is not necessarily due to having used a great deal of energy, but to spreading the capacity charge over the energy that was used. A more rational contract for capacity would have shown reduced energy costs even if the amount of energy, production and all prices (including the prices of demand and energy) had remained the same.

Last, there were no standard electricity rates prior to 1990. Firms had their own individual rates, even if they operated under circumstances similar to those of other firms in the same industry.[2] Similar problems with other inputs make most cost/price data prior to 1991 irrelevant.

Since 1990, Polish industry has been in disequilibrium, making it difficult to determine "normal" cost/price relationships. Some of the dimensions of the disequilibrium include:

- Many industries, particularly heavy industry, are still state-owned. Many are still affected by state decisions, subsidies, financing, etc. Even those facing privatization do not yet have firmly established operating rules, nor are their managers operating under private incentives. Furthermore, industry lags other sectors in privatization. As of September 1992, private employment was 58 percent of total employment and some sectors, such as retail businesses, were over 80 percent private. Meanwhile, only 24 percent of industrial output was from private industry.

- Proper revaluation of industrial assets has not been completed. Thus, actual capital costs cannot be determined.

- International trade has been liberalized, and many firms are responding to international prices for the first time. However, most are only beginning to adjust their production to compete in freer markets and full adjustment will take time.

[2] To illustrate the range of electricity rates facing Polish industry, consider the average cost per kWh, as experienced in 1990-91, as reported by GUS, *Fuels and Energy Statistics* (October 1992). Table 2(67) reports the costs per kWh for 22 industries. The average cost was 441 Zl/kWh, but the standard deviation was 83 Zl. Therefore, 95 percent of industrial electrical energy costs would have fallen in the 293 Zl to 547 Zl range.

For political reasons, firms that are suffering losses have been kept operating to protect employment levels. Some firms have maintained employment by cutting work hours. Others maintain "over employment" by keeping more workers than are necessary for current production levels. Wages are kept under control by an "excess wage tax," which applies to all employment in public enterprises and government. In general, as production has been cut back, labor forces have been reduced by much less.

This last point probably affects the pattern of recorded electricity in production. If firms respond to reduced demand by cutting back production but not employment, then the use of resources that support employees may be reduced by less than output is reduced. Excess employment wastes not only labor, but it also wastes the resources that support labor. In the case of electricity, as the same number of employees go through a scaled-back or slowed-down set of activities to produce less output, the amount of electricity consumed is not likely to drop by as much as output. Electrical devices will still be operated simply to keep the excessive number of workers "working." Under these circumstances, it is likely that as output drops, the electricity input per unit of output increases.

Exhibit 10-1 illustrates this phenomenon using data for 23 industrial branches over the period 1987-1991. For each industry it shows kWh per million zlotys of value added, in constant 1990 zlotys. It also shows real value-added per employee for the same period. Using the above reasoning, as output slowed between 1987-89 and 1990-91, the ratio of kWh to value-added should rise, which in general it does. Furthermore, those industries where value-added per employee has fallen most are those that are suffering from the most "over employment." Thus, the kWh to value-added ratio should rise most where value-added per employee has fallen most, which also appears to be the case. For example, in coal mining and fuels production, the ratio has risen about 60 percent and 100 percent, respectively. At the same time, value-added per employee in coal (the most notorious case of maintaining employment despite demand conditions) has fallen by about 40 percent and in fuels by 60 percent. In industry branches where demand has held up (e.g., wood, construction materials) or where workers have been laid off (e.g., clothing) the kWh/value-added ratio has not risen.

This examination reveals three important points. First, what appears to be increasingly electricity-intensive industrial production probably is not. It is merely a reflection of unique conditions facing Polish industry. Second, the level of electricity intensity in Polish industry

EXHIBIT 10-1

ELECTRICITY AND EMPLOYMENT IN POLISH INDUSTRY

kWh/VA = kWh per million zlotys of valve added
VA/Empl. = Valve-added per employee, in million Zl.
All figures are in zlotys of 1990

	1987	1988	1989	1990	1991
INDUSTRY OVERALL					
kWh/VA	302	293	296	344	385
VA/Empl.	na	na	na	na	na
COAL					
kWh/VA	605	667	744	1070	1064
VA/Empl.	39.6	36.5	32.1	21.7	22.2
FUEL					
kWh/VA	84	89	98	155	181
VA/Empl.	589.2	566.4	543.0	315.1	228.8
ELECTRIC ENERGY					
kWh/VA	581	598	783	1076	1635
VA/Empl.	238.3	228.2	178.6	122.1	75.0
IRON & STEEL					
kWh/VA	366	393	438	454	566
VA/Empl.	172.6	165.0	146.9	140.7	95.4
NON FERROUS METALS					
kWh/VA	288	283	305	425	817
VA/Empl.	305.2	320.0	297.5	199.3	107.3
METALS					
KwH/VA	232	226	201	198	188
VA/Empl.	37.3	41.3	47.7	42.9	34.6
MACHINERY					
kWh/VA	197	183	146	130	137
VA/Empl.	34.2	38.3	47.8	49.4	39.6
PRECISION INSTRUMENTS					
kWh/VA	104	91	78	74	76
VA/Empl.	26.1	30.7	36.6	37.8	31.2
TRANSPORTATION EQUIPMENT					
kWH/VA	137	128	144	138	301
VA/Empl.	53.4	58.7	51.8	41.9	21.4

EXHIBIT 10-1, page 2

ELECTRICITY AND EMPLOYMENT IN POLISH INDUSTRY (cont.)

	1987	1988	1989	1990	1991
ELECTRICAL & ELECTRICAL MACHINERY					
kWH/VA	154	138	131	124	119
VA/Empl.	34.6	40.5	41.9	42.7	39.8
CHEMICALS					
kWh/VA	446	425	495	571	590
VA/Empl.	106.5	115.9	103.0	82.0	62.6
CONSTRUCTION MATERIALS					
kWh/VA	624	610	549	486	541
VA/Empl.	38.9	41.0	49.7	45.9	38.8
GLASS					
kWh/VA	215	200	245	329	350
VA/Empl	52.4	57.1	50.3	37.5	34.9
CERAMICS					
kWh/VA	144	149	156	189	228
VA/Empl.	43.7	49.2	49.4	38.5	31.5
WOOD					
kWh/VA	265	248	207	296	251
VA/Empl.	31.7	35.6	46.5	33.4	25.4
PAPER					
kWh/VA	438	429	417	695	720
VA/Empl.	115.1	124.0	128.9	73.5	71.0
TEXTILES					
kWh/VA	176	162	154	222	203
VA/Empl.	44.3	50.7	52.7	31.4	30.3
CLOTHING					
kWh/VA	53	47	32	39	47
VA/Empl.	16.2	18.7	24.4	21.4	17.0
LEATHER GOODS					
kWh/VA	54	50	55	68	61
VA/Empl.	31.4	34.8	30.1	24.3	23.5

EXHIBIT 10-1, page 3

ELECTRICITY AND EMPLOYMENT IN POLISH INDUSTRY (cont.)

	1987	1988	1989	1990	1991
FOOD					
kWh/VA	54	57	72	85	79
VA/Empl.	165.8	160.0	127.2	101.0	90.5
PRINTING					
kWh/VA	96	91	71	77	116
VA/Empl.	23.6	26.7	31.3	30.9	20.1
OTHER					
kWh/VA	207	197	143	207	210
VA/Empl.	34.7	37.6	39.6	32.2	18.5

SOURCE: Ministry of Industry and Trade, Energy Information Center, CHARAKTERYS TYKI ENERGO-EKONOMICZNE GALEZI I BRANZ PRZEMYSLM (1992)

under "normal" conditions is probably somewhat less than recent data may indicate. Third, in many areas of Polish industry, production is not particularly electricity intensive, although heavy industry appears to be so.

The data in Exhibit 10-2 can be used to indicate the importance of electricity in total industry costs. Column 1 shows the number of kWh per million zlotys of output sold in 1991 for main industries. Because data on the actual electricity rates paid by each industry are not available, the average price paid by the industrial sector in 1991 (342 Zl/kWh) was used. If all industries paid the average price, then electricity cost as a percentage of sales is the figure shown in column 2. If all industries had exactly zero profit in 1991, then costs and sales would be equal and column 2 would approximate the percentage of electricity cost to total cost. For industries that were not profitable (a common event in 1991), the figures in column 2 overstate the importance of electricity in total cost, and vice versa. Also, if it is correct to assume that electricity intensity increases in the process of keeping employment artificially high, then the figures in column 2 would again over-state electricity costs as a percentage of the total.[3]

The data in Exhibit 10-2 indicate that electricity accounts for about 3.4 percent of industrial costs on average. There are some industries, notably heavy industries, where the proportion is higher. The non-ferrous metal industry includes aluminum which is highly electricity intensive.[4] Some chemicals are particularly electricity (and energy) intensive, and among construction materials, the main cement production techniques used in Poland are very electricity intensive. Nevertheless, electricity costs as a percentage of total costs are not high for the most part. The range is generally from about 1 percent to 5 percent of the total, but some industries exceed this.

Partial corroboration of these figures comes from a survey of selected industries based on 1990 conditions (column 3). These figures are generally higher than the first set, but they include cogeneration. The food industry is of particular concern when assessing the welfare of households (see below). Separate information on the food processing industry for 1992

[3] An additional factor may cause these figures to overstate electricity as a percentage of total cost. The original source obtains its data from firms that are relatively large (over 50 employees). If smaller firms are less electricity-intensive in their production technology and if these smaller firms were included in the data, the figures in column 2 would be lower.

[4] The only aluminum firm has a relatively constant demand of 120 MW. Electricity costs account for about 26 percent of total costs according to a representative of the firm.

EXHIBIT 10-2

ELECTRICITY COST IN TOTAL COST

	kWh/Product Sold in million ZI. 1991	Electricity Cost as % of Product sold 1991	Electricity as % of Total Cost (A)
INDUSTRY OVERALL	100	3.4	
Coal	189	6.5	
Fuel	42	1.4	
Electric Energy	269	9.2	
Iron & Steel	162	5.5	4.9
Non-Ferrous Metals	226	7.7	7.3
Metal	58	2.0	4.4
Machinery	49	1.7	4.6
Precision Instruments	29	1.0	3.6
Transportation Equipment	48	1.6	4.4
Electrical Machinery	7	1.3	3.3
Chemicals	151	5.2	6.7
Construction Materials	158	5.4	
Glass	97	2.8	
Ceramics	78	2.7	
Wood	53	1.8	4.3
Paper	237	8.1	
Textiles	65	2.2	
Clothing	15	0.5	
Leather Goods	17	0.6	
Food	23	0.8	2.1
Feed	28	1.0	
Printing	21	0.7	
Other	67	2.2	3.6

Source: Some as Table 12.1 except A, Which is the results of a questionaire administered by GUS for the Ministry of Industry and Trade, 1990

reveals that the overall energy costs (which include electricity) for the first 6 months of 1992 averaged only 2.6 percent.

Summary

Electricity costs are probably not the largest problem facing Polish industry at this time. The problems associated with privatization, changing product prices, changing technology, shifts in product choice, depressed aggregate demand, and the installation of normal market incentives tend to make the problem of rising real electricity prices seem rather slight.

World Bank (1992) studies illustrate the institutional problems remaining and the incentives still lacking before industrial firms can operate on a market basis. State-owned industries (the majority) have been slow to adjust and their output still appears to be in decline. Mining, some chemicals, cement and aluminum production are intensive in the use of electricity. For them, electricity pricing is a major concern, but in these cases, opportunities for energy conservation can be easily identified (Pasierb, 1992). Of greater concern to most firms is whether they will continue to exist under any circumstances in a free market environment. Industrial net profits were negative for the first eight months of 1992 (World Bank, *Economic Update*, October 1992), despite a slight increase in real output. The fact that the real price of electricity to industry declined between 1991 and 1992 seems consistent with the notion that factors other than electricity prices predominate.

Conclusions

Electricity prices are not a factor that will make or break Polish industry. More important factors are easily identified. However, industrial customers should be given greater flexibility in striking contracts with the entities that offer them the most favorable price and delivery conditions. Currently, industrial enterprises do not have many options in terms of service and rates.

10.2 THE IMPACTS ON AGRICULTURE AND TRANSPORTATION

Agriculture and transportation are of particular interest to the assessment of household budgets. Food occupies a relatively large part of most household budgets in Poland. The transportation system is usually a key factor in people's ability to work, and in Poland a large part of the transportation system is by electric tram or train. Therefore, interviews

were held with several specialists in various aspects of agricultural and food production. Also, several representatives of the railroad (PKP) were interviewed.

Agriculture

Although specific data were not available on electricity as an input to farm production, there is a consensus that production is not very electricity-intensive. Furthermore, PPGC and distribution company data confirm that little electricity is used for production on most Polish farms. Most farms have only one meter, serving both the home and farm operations. Average annual use (in the F1 rate class) is only 2,000 kWh. Distribution company representatives and agricultural specialists estimate that only 20 percent of that goes toward farm production; the remainder is used in the home. Therefore, it is not likely that non-farm households' budgets will be affected much by electricity price increases to farmers.

It is interesting to note that everyone interviewed indicated an unmet demand for increased electrical service on farms. Most farms are served by a very weak distribution system that was installed shortly after World War II.[5] Many farms would like to install increased numbers of electrically-driven devices, but overly loaded distribution systems do not permit it. Distribution companies receive many requests for increased service, but are unable to respond under current conditions.

Transportation

The transportation system in Poland relies heavily on electric trains and trams. Of the 23,000 km of track in Poland, 11,000 are electrified. Most freight and almost all passengers are moved by electric power.

Currently, there is no clear transportation policy. The rail company (the PKP) is heavily subsidized. Rates for service are set without regard to cost, and rates for passenger service appear to be far below actual costs. Budget constraints have cut the subsidy flowing to the PKP in recent years, but allowed rate increases have fallen well short of inflation. As a result, the PKP system is probably deteriorating physically and service is being reduced.

[5] The system installed then was a first effort at rural electrification. Some rural distribution systems were upgraded in the 1970s, but those improvements were aimed mainly at serving state farms. Most state farms are now bankrupt. About 80 percent of all farms are private and are still served by the distribution system installed almost fifty years ago.

Meanwhile, PKP has fallen into arrears in its payments to electric distribution companies and to other suppliers. The distribution company surrounding Warsaw alone is owed over 20 billion Zl by PKP, and PKP has no obvious solution available to it for making payment.

It is difficult to estimate how transportation rates would behave should the price of electricity paid by PKP rise. PKP estimates that only 5.6 percent of its total costs are associated with electricity purchases. However, because transportation rates are not cost-based, how they would be affected by electric tariff increases is not clear.

Conclusions

Electric pricing for Polish agriculture appears to be a minor problem. No special treatment seems justified for agricultural customers, except insofar as they reflect differences in the cost of service.

There is an apparent unmet demand for power in the agricultural sector. Special attention should be directed toward developing a distribution system upgrade and expansion plan in rural areas.

The transportation system appears to be in some disarray due to a lack of clear policy. The PKP is one of the electric system's largest customers, yet it has been put in a position where it cannot recover its own costs and cannot rely on subsidies to make up for losses. PKP arrears with the distribution companies that serve it are almost assured until PKP is put on a self-sustaining basis.

10.3 THE IMPACTS ON HOUSEHOLDS

Household budget information is available from the Government Statistical Office (GUS).[6] Because data are available for all of 1991 and for the first three quarters of 1992,[7] the

[6] Three sources were used here. GUS (1992a) is a statistical yearbook for general data through 1991. GUS (1992b) provides detailed household information, including data on income and expenditures, through 1991. GUS (1993) provides abbreviated data, similar in coverage to GUS (1992b), but reported quarterly, through the third quarter of 1992. Data from GUS documents are consistent across documents.

[7] To abbreviate, the notation "year:quarter" will be used (e.g., the first quarter of 1992 is 1992:1).

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analysis focuses first on 1991, and then qualified estimates are made of budgets as of the end of 1992 and early 1993. The estimates for early 1993 are only general approximations.

GUS regularly collects data from a large, stratified sample of Polish households.[8] The stratification separates households into four categories:

- **Employees.** Where the head of household works in business and trades, including work in state organizations. About 42 percent of all households surveyed fall in this category. This group is divided into two classes: wage earners and salaried workers.

- **Employees/farmers.** Where the household head is an "employee" (as above) but also where part of the family income comes from farming. Eleven percent of households are in this group.

- **Farmers.** Where the household's primary income is from farming. Eleven percent of households are farmers.

- **Retirees and pensioners.** Households in this group receive the largest part of their income from pensions, although they may also work in one of the other categories. Thirty-six percent of households fall in this group. Retired persons fall in the other categories if their income from work exceeds their income from retirement.

Exhibit 10-3 shows a summary of data on households and their 1991 incomes from the GUS documents. All data on incomes and expenditures are stated in thousand zlotys, or kilo-zlotys (kZ) unless otherwise specified. Households averaged 3.1 persons; households of retirees were smaller than average (1.9 people) and those on farms were larger. All income figures shown are net of taxes and include social benefits. While there was some variation in average household income across the groups, the variation is largely a function of the number of people in the household. Per-household monthly net income averaged 2,929 kZ,[9] but ranged from 1,816 kZ for retirees to 4,391 kZ for employee/farmers.

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[8] For a description of the survey and sampling technique, see GUS (1992b), pages xxiii - xxx.

[9] About $266, given average exchange rates for the period. Average per capita net income was about $1,130 per year.

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EXHIBIT 10-3

HOUSEHOLD CHARACTERISTICS, 1991

	AVERAGES: HH SIZE	HH INCOME Z(000)	INCOME PER PERSON	% OF HH (A)
ALL HOUSEHOLDS	3.1	2929.4	945.1	100.0
EMPLOYEE HH	3.5	3466.7	979.0	41.8
WAGE	3.7	3200.0	857.9	25.8
SALARY	3.3	3836.4	1176.5	16.1
EMPLOYEE/FARM	4.7	4390.5	930.2	11.0
FARM	3.8	3106.1	823.9	10.9
RETIRED/PENSIONERS	1.9	1816.0	945.9	36.3

SOURCE. GUS (1992) p. 216. table 8(321).
except A. which is p. 213. table 3(316)

Very little variation in income exists in per capita terms. Per capita incomes on farms seem lowest, but are probably under-stated due to the consumption of food items produced at home, and the fact that few farm households pay rent. Incomes of retirees, which seem low on a per household basis, are about average in per capita terms. Some inequality exists within categories. Within employee households, GUS distinguishes between wage and salary earners. Average per capita incomes within salaried households (1,177 kZ per month) exceeded those of wage-earning households (858 kZ) by about 37 percent. However, this per capita inequality is offset by the fact that wage-employee households are larger. Thus, there is less inequality in terms of household income than first appears.

Exhibit 10-4 shows expenditures per household. These are sorted out by broad category of expenditure.[10] Electricity is separated from other energy, where the latter includes heat, natural gas, and other fuels. Transportation fuels are included in the "transportation" category. As percentages of household income, expenditures on energy overall are moderate, ranging from 5.3 percent of income for the employee and employee/farmer categories to 9.7 percent for retirees. While both farmers and retirees spend more on energy than other households, most of the difference is accounted for by non-electrical energy. Farmers are not likely to have access to district heating and must therefore heat with other fuels. While retirees' households often have access to district heating, these households are smaller. For them, the cost of heating a dwelling is spread over fewer people and a smaller income, causing the proportion of income spent on "other energy" to appear extraordinarily high. In money terms, retiree households spend about the same amount on "other energy" as other households and spend less on electricity.

These observations indicate that as a proportion of household expenditures, electricity expenditures are not very great. The proportion of income spent on electricity is generally about 2 percent, although it may range up to 2.8 percent for households of retired persons.

Similar conclusions are reached if utility data are used instead of expenditure survey data. PPGC data are available for all rate classes for calendar year 1992. These data show the total numbers of customers, energy sales to rate classes, and average revenue from each. The rate class that is most commonly occupied by "employee households" (G1) applies to

[10] This exhibit identifies "savings," which are defined as income minus the expenditures that have been specified. Some families have debts, and debt service must come out of "savings." In other cases, inter-household transfers or gifts are made, which would affect the savings category. These cases are labelled "savings" but are not savings as normally calculated. Rather, they represent an amount of income left over after normal expenditures that may be used for other purposes, some of which may include saving. It may also be possible that households have not recorded all expenditures (a common occurrence with surveys of this type).

EXHIBIT 10-4

HOUSEHOLD EXPENDITURE PATTERNS, 1991

PART A: PER CAPITA IN Z(000), MONTHLY

	EMPLOYEE HH	EMPLOYEE/ FARM	FARM	RETIRED/ PENSIONED	AVERAGE WAGE-EARNER
FOOD	369.8	344.3	381.7	445.0	348.5
ALCO+TOBAC	29.6	25.1	27.6	24.8	28.7
CLOTHING	91.8	75.2	67.0	74.5	77.9
HOUSING	80.4	77.5	60.1	96.0	74.5
HEALTH	36.6	21.6	22.6	43.3	29.3
ENTERTAINM'T	100.1	46.4	41.4	60.5	75.0
TRANSPORT	76.2	64.5	59.2	49.9	52.1
ELECTRICITY	19.2	16.6	20.8	26.5	17.4
OTHER ENERGY	32.3	32.4	35.0	65.8	30.5
OTHER	34.7	30.6	42.9	37.5	3.1
TOTAL	879.7	734.2	758.2	923.9	737.0

PART B: TOTAL AVERAGE EXPENDITURES PER HH MONTHLY

	EMPLOYEE HH	EMPLOYEE/ FARM	FARM	RETIRED/ PENSIONED	AVERAGE WAGE-EARNER
FOOD	1309.1	1625.1	1439.0	845.5	1299.9
ALCO+TOBAC	104.8	118.5	104.1	47.1	107.1
CLOTHING	325.0	354.9	252.6	141.8	290.6
HOUSING	316.5	365.8	226.6	182.4	277.9
HEALTH	129.6	102.0	85.2	82.3	109.3
ENTERTAINM'T	354.4	219.0	156.1	115.0	279.6
TRANSPORT	269.7	304.4	223.2	94.8	194.3
ELECTRICITY	68.0	78.4	78.4	50.4	64.9
OTHER ENERGY	114.3	152.9	132.0	125.0	113.7
OTHER	122.8	144.4	161.7	71.3	11.6
TOTAL	3114.1	3465.4	2858.8	1755.2	2749.0
INCOME	3465.7	4390.5	3106.1	1816.0	3200.0
SAVINGS	351.6	925.1	247.3	60.8	451.0
AS % OF INCOME					
ELECTRICITY	2.0	1.8	2.5	2.8	2.0
OTHER ENERGY	3.3	3.5	4.2	8.9	3.6

SOURCE. Previous table: GUS(1992a), pp216-219, table 9(322)

GUS(1992b) p.25 table 9, p.112 table 7(24),
p.176 table 6(35), p.242 table 7(47).
Electricity seperated by Energy Information Center

about 9.7 million customers. Within that rate class, 1992 average energy consumption was 1,675 kWh per customer. Average revenue per kWh in that class was Zl 619. Thus, the average annual expenditure per customer was about 1 million zlotys, and the average monthly expenditure was about 87 kZ per month. GUS (1993) data indicate that household income for "employees" was about 4,400 kZ per month for the same period.[11] Thus, average expenditures on electricity account for about 2 percent of the total average incomes of households of "employees." If the same calculations were performed for 1991, electricity would have amounted to about 1.4 percent of employees' household incomes.

Similar calculations for the rate class most often applicable to farms (F1) indicate that farm customers spent about 100 kZ per month. GUS data indicate that farm household incomes were around Zl 4 million per month. Electricity would have occupied about 2.5 percent of farm household income.[12] In 1991, by the same calculation, electricity took about 2 percent of farm household income. On farms, one should separate electricity used for normal household functions from that used for agricultural production. Most farms have only one meter, so an exact separation is not possible. However, people knowledgeable about farm production conditions in Poland estimate that only about 20 percent of electricity used on farms is used to support production. The remainder is for household use. If this is the case, then Polish farm households are much like urban households in that about 2 percent of the household budget goes to purchase electricity for household uses.

In both cases, where household types can be associated with a rate class (as in the case of employees with G1 and farmers with F1), average electric energy consumption for the rate class declined between 1991 and 1992. In the residential rate class (G1), average energy consumption declined by about 3.6 percent, while among farm customers (in rate class F1), average energy consumption dropped by 7 percent. In both rate classes, average revenue per kWh increased by almost 30 percent in real terms, although real monthly household income remained unchanged during the period. While these declines in energy consumption may be a continued response to the economically depressed conditions in Poland, they are consistent with normal expectations about short-run price elasticities.

[11] The GUS data do not cover 1992:4. The income referred to here is for the period 1991:4 through 1992:3. Thus, the utility data and the GUS data almost match up, but not quite.

[12] It is not very clear where "employee/farmer" or "retired/pensioner" households fall within electric rate classes.

The far right-hand column of Exhibit 10-4 displays data for an average household, where the household head is a wage earner. This is meant to represent a lower-middle income family.

Expenditures on electricity for this kind of family are slightly less than they are for other households, but the proportion of household income spent on electricity is about the same: 2 percent.

Exhibit 10-5 depicts more recent household budgets. Because there is very little variation in budgets across household types, only "employee" and "pensioner" households are reported; together these two groups represent about 78 percent of all households. Exhibit 10-5 represents an "average" monthly budget, given conditions as of the end of 1992:3, where the average accounts for seasonal variation. GUS (1993) reports household incomes and expenditures quarterly for 1991 and 1992, but only through 1992:3. The GUS data are expressed in current zlotys of the quarter in which they occur. Unfortunately, quarter-to-quarter inflation is high enough that simply adding the last four quarters together gives an under-estimate of expenditures in zlotys at the end of period. Simple quarter-to-quarter addition adds inflated zlotys to some with less inflation. Fortunately, the GUS data provide category-specific price changes for each of the expenditure types. To place these figures in zlotys as of the end of 1992:3, each quarter's expenditure, and each category within, has been adjusted upward to represent the inflation that occurred between the time it was recorded and 1992:3.[13]

As of 1992:3, "employee" household energy expenditures had reached an average of about 7.2 percent of income, up from about 5.3 percent in 1991 and from as low as about 3 percent in the late 1980s. Energy expenditures required an even greater share of pensioner income, about 11.8 percent in 1992:3 up from 9.8 percent in 1991. Further, it is worth noting that average total expenditures of pensioners actually exceeded their household income in late 1992.

Because these data do not separate expenditures on electricity from those on other energy resources, the price increases that have occurred in each kind of energy were used to infer the proportion of electricity in the energy budget (Exhibit 10-6). All energy forms shown are sold at regulated prices, except for "coal and other fuels"; thus, price increases are known. For coal and other fuels we assumed that prices increased about in line with

[13] For example, food expenditures for the 1991:4 quarter are adjusted upward by the amount of inflation occurring in food items during each of the subsequent quarters, 1992:1-3.

Exhibit 10-5

Monthly Average Household Budgets, 1992:3
('000 Zl of 1992:3)

A. Employees' Households

	Per Capita	Household	% of Income
Total Expenditure	1221.8	4325.2	86.4
Food	513.5	1817.8	36.3
Alcohol,Tobacco	37.0	131.0	2.6
Clothing	88.0	311.5	6.2
Housing	139.5	493.8	9.9
Health	57.2	202.5	4.0
Entertainmt/Educ.	125.5	444.3	8.9
Transp,Commun.	94.6	334.9	6.7
Energy	102.4	362.5	7.2
Other	64.1	226.9	4.5
Savings	191.8	679.0	13.6
Total Income	1413.6	5004.2	100.0

B. Retired Persons and Pensioners Households

	Per Capita	Household	% of Income
Total Expenditure	1313.9	2525.3	100.9
Food	646.8	1243.1	49.7
Alcohol,Tobacco	35.0	67.3	2.7
Clothing	64.6	124.2	5.0
Housing	148.3	285.0	11.4
Health	77.6	149.1	6.0
Entertainmt/Educ.	70.2	134.9	5.4
Transp,Commun.	65.6	126.1	5.0
Energy	154.1	296.2	11.8
Other	51.7	99.4	4.0
Savings	−11.8	−22.7	−0.9
Total Income	1302.1	2502.6	100.0

Source: GUS (1993).

inflation, i.e., by 40 percent. During 1992, the cost of heat and hot water to households was increased in nominal terms by about 169 percent. Heat prices increased by 158 percent and hot water by 180 percent, while electricity and gas prices rose by 42.5 percent and 89.6 percent, respectively.

Meanwhile, household incomes were increasing in nominal terms about in line with inflation (44 percent). Thus, as the price of electricity was rising, its proportion of energy expenditures was falling[14] slightly since electricity price increases kept pace with the general inflation rate, while other energy forms had price increases exceeding inflation. By the third quarter of 1992, electricity probably represented about 30 percent of the "employee" household energy budget expenditures and about 2.2 percent of household income. For the pensioner household, electricity may have represented only about 22 percent of energy expenditures, but about 2.6 percent of the total household budget.

After 1992:3, GUS data are not available, but the scheduled 1993 price increases for electricity, gas, and heat & hot water are known. (In the absence of more detailed data, we again assume that coal and other fuel prices keep pace with inflation.) These data, also reported in Exhibit 10-6, permit us to approximate the contribution of electricity and other types of energy to the household budget as of the end of 1993. While other fuels (notably heat & hot water) will experience even greater price increases, retail electricity prices will increase more rapidly than inflation through 1993. Electricity is expected to consume a rising share of the total budget, in the range of 2.5 to 3.1 percent. Further, the statistics suggest that total energy expenditures will increase by about 25 percent in real terms, representing about 9 percent of the "employee" household budget and almost 15 percent of the pensioner budget.

Two reasonable interpretations of this data are possible. They can be summarized briefly as follows:

(1) Because households spend only 2.5 to 3 percent of their total income on electricity, a large real price increase would have only a small effect on household well being. For example, a 75 percent increase in the real price of electricity, in the first quarter of 1994, would cause households to spend an additional 2 to 2.25 percent of income on electricity (assuming no conservation). In isolation, this increase would not appear to be disruptive.

[14] This discussion assumes that the households in question have district heating and hot water. Both "employee" and "pensioner" households are likely to be in cities and therefore likely to be district heating customers.

Exhibit 10-6

Energy Price Increases, 1991–93
(all values in percent)

A. Employees' Households

Fuel	Share of Household Expenditure 1991 1/		Price Increaase 1991–92:3 2/	Inferred Share of Household Expenditure 1992:3		Price Increaase 92:3–93:4 3/	Inferred Share of Household Expenditure 1993:4	
	Energy Budget	Total Budget		Energy Budget	Total Budget		Energy Budget	Total Budget
Electricity	38	2.0	43	30	2.2	67	29	2.6
Gas	21	1.1	90	22	1.6	51	19	1.7
Heat, Hot Water	23	1.2	169	34	2.5	101	40	3.5
Coal & Other	19	1.0	40	15	1.1	54	13	1.2
Total	100	5.3	81	100	7.2	74	100	9.0

B. Retired Persons and Pensioners Households

Fuel	Share of Household Expenditure 1991 1/		Price Increaase 1991–92:3 2/	Inferred Share of Household Expenditure 1992:3		Price Increaase 92:3–93:4 3/	Inferred Share of Household Expenditure 1993:4	
	Energy Budget	Total Budget		Energy Budget	Total Budget		Energy Budget	Total Budget
Electricity	29	2.8	43	22	2.6	67	21	3.1
Gas	24	2.3	90	24	2.9	51	21	3.1
Heat, Hot Water	26	2.5	169	36	4.4	101	43	6.4
Coal & Other	21	2.1	40	16	1.9	54	14	2.1
Total	100	9.8	86	100	11.8	74	100	14.7

1/ Based on 1991 annual average energy budget.
2/ Source: GUS (1993).
3/ From Department Polityki Finansoweji i Analiz for 1993 forecast; 1992:4 assumed price increases – electricity (4.9%), gas (5%), heat & hot water (5%), other (10%).

(2) A 2 to 2.25 percent increase in electricity's demand on household expenditures might be "the straw that broke the camel's back". Prices of most other energy sources have been increasing more rapidly than inflation, and the share of energy in the total household budget has more than doubled since 1990. As noted above, energy will represent nearly 15 percent of a pensioner household budget by 1994. Of course, households must also adjust to some dramatic price increases outside the energy sector.

Households would also be affected indirectly if electricity price increases were passed on to producers of the other things that households consume. Most important in the household budget is food. Fortunately, food production in Poland is not particularly electricity intensive (see the discussion above on industry). About 2.2 percent of the costs of food are attributable to electricity inputs. If real electricity prices to food producers increased by 75 percent as well, given that food occupies about 35 percent of the household budget, expenditures on food would increase by about 0.6 percent.

Transportation may also be important since most people commute to work on electric trains. Evidence suggests that only a very small part of a typical household budget is spent on electrically driven, public transportation. According to GUS data only about 1 percent of the budget is spent on passenger transport and about another 1 percent on freight. Since only 5.6 percent of the rail system's costs are for electricity, the impact of electricity price increases on households, acting through the rail system, would be negligible.

Summary

As of late 1992, a 75 percent real increase in electricity prices could increase household expenditures by about 2.5 to 3 percent of incomes. Of this, 2 to 2.25 percent would be through the direct use of electricity and 0.6 percent through higher food prices. Other consumption items would have very small effects. These estimates must be considered very approximate, for the data upon which they are based are very weak. Furthermore, much depends upon what happens to household incomes as electricity prices rise, and on how households reallocate their expenditures.

The impact of a large electricity tariff increase on household budgets may at first appear negligible. Taken in the context of a rapidly rising prices in all sources of energy and in other sectors of the economy, the adjustments appear more burdensome. Further, even a 3

percent increase in expenses in the household budget is dramatic if resources are strained.[15,16]

Consumer Responses

In most cases where prices increase, reduced consumption can be expected. Although there are no recent studies of the price elasticity for electricity in Poland, there are two main reasons to think that the reduction in consumption among residential customers is likely to be slight. First, electrical energy consumption, on average, is already very low (1,675 kWh per year). Furthermore, about one-third of residential customers consume less than 1,000 kWh per year. Among many of these customers, it is not likely that significant reductions will occur for many uses of electricity other than basic lighting.

A second reason relates to the way residential customers are billed. All residential customers receive a payment book, with payments to be sent in bi-monthly. Books are issued once per year and are based upon forecast consumption. At the end of each year, adjustments are made for consumption that was different than the forecast and for rate changes that occurred during the year.[17] For most customers, this implies modest payments during the year and a very large payment at the end. Even in cases where kWh consumption has declined, the settlement at year-end can give the impression that conservation doesn't pay.

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[15] In 1992:3, GUS data indicate that the household budget of retired persons and pensioners (representing 36 percent of all households) exceeded monthly income by almost 1 percent.

[16] In light of the political nature of electric tariff increases and the difficult economic position of many low-income families in Poland, one option to consider is a residential tariff with two or three rate blocks. Given the pattern of residential electric consumption in Poland, such a step may give relief to lower-income families without affecting average families very much. The amount of electric energy consumed by the lowest consumption group is so small that the revenue loss associated with a lower-priced first block is not very large, and total electric bills for average consumers may not be affected much when revenue is recuperated in higher blocks. This option is discussed in more detail in Chapter 10.

[17] This creates a financial problem for the entire utility system. Currently, generators bill PPGC every five days, but settle accounts monthly. PPGC does the same for distribution companies. However, distribution companies experience a lag in receiving revenue, since they collect from end-users based on forecasts, with a large adjustment in the bill at the end of the year. Payment booklets are issued year round, so some catch-up payments are received at all times. However, when tariffs are increasing rapidly, the resulting revenue increases trickle into the distribution companies over the course of a year. Yet the distribution companies must settle accounts with PPGC monthly.

Furthermore, customers may not know how much they are consuming month to month because their bi-monthly payment gives them no guidance. Finally, even the utility may not be able to tell them what their consumption is because of meter reading problems. Normally, meters are read only once per year, in order to settle the account from the preceding year and prepare a forecast for the next. Meters are normally inside each customer's home, especially in older homes (i.e., over ten years old), so someone must be at home to have the meter read. Thus, meter reading may require repeated visits until someone is found at home.[18] Under these circumstances it is not likely that people even know how much they are spending on electricity service.[19] Without this information, it is not likely that rational decisions can be made about electricity consumption.

Conclusions

Electricity expenditures represent a small portion of the average household budget in percentage terms. Expenditures related to all energy requirements, however, represent a more significant share of income. Statistical data suggest that if electricity were the only good needing a significant real price increase, this increase could be passed to final consumers without damaging household welfare. Unfortunately, electricity is only one of many goods in need of real price adjustments. Therefore it is reasonable that policy-makers call for gradual real price adjustments as the electric sector moves steadily toward tariffs which provide for full financial cost-recovery.

Based on discussions with PPGC management, which in turn reflect PPGC discussions with the Government, we believe that real tariff increases on the order of 10 to 15 percent per year represent the maximum acceptable average annual upward adjustment of prices in today's economic environment. Thus, although the pure financial evaluation presented in Chapters 8 and 9 identifies the need for greater tariff increases, it is recommended that financial leverage be employed to "phase in" tariff adjustments gradually over several years.

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[18] It is not uncommon for meters to be unread for as long as two years.

[19] Recently, a Polish research foundation attempted to solicit information about energy consumption from individuals in focus group settings. People were asked about how much they were spending on electricity. Responses were over twice what one would have expected from other information. This exercise revealed that people could only guess what they spent on electricity.

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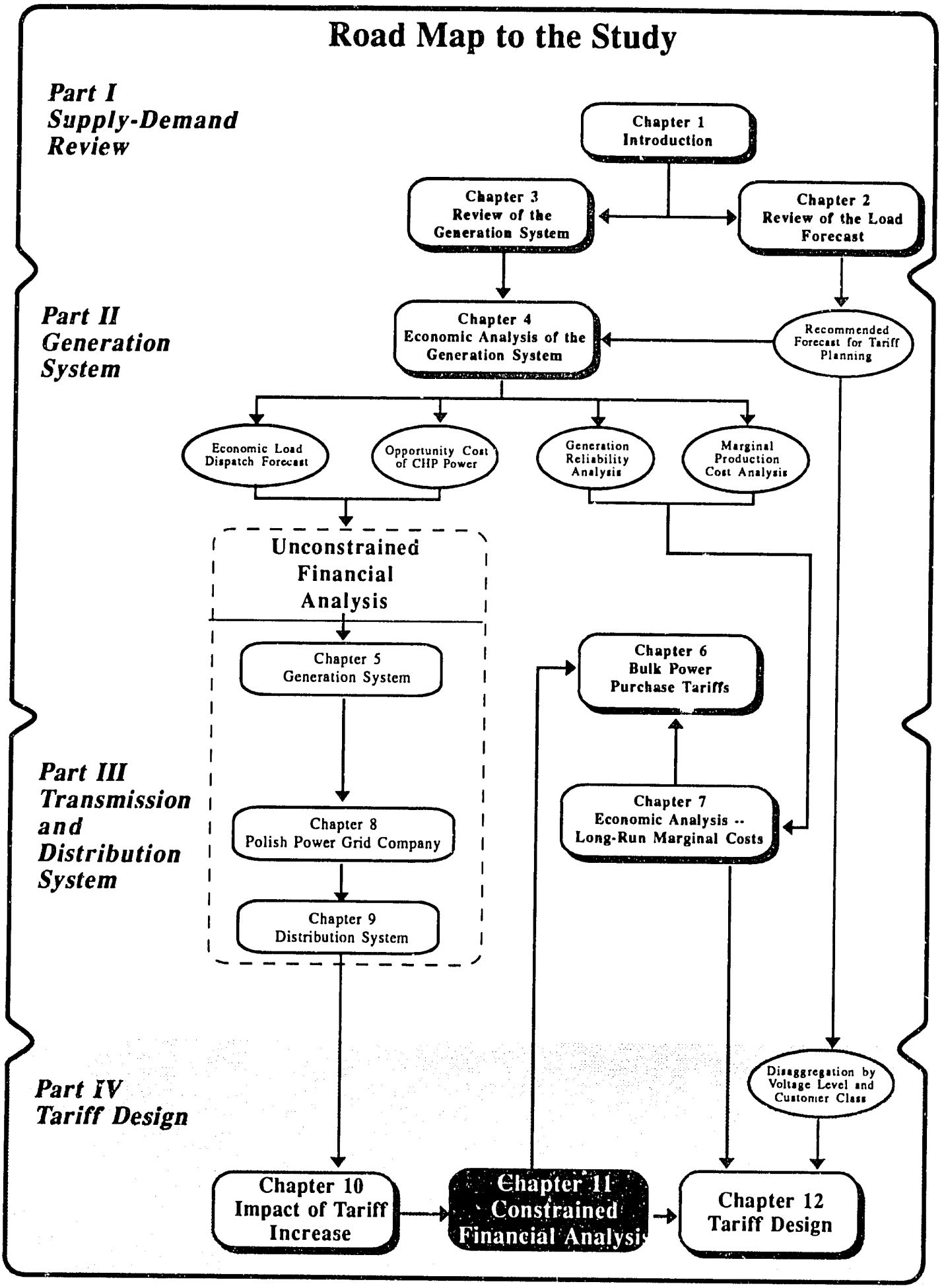
Road Map to the Study



CHAPTER 11: CONSTRAINED FINANCIAL ANALYSIS

In Chapter 9 it was concluded that if revenues at retail level for 1994 could be, in real terms, 45 percent higher than in 1992, then a full adjustment of the pricing system for the power sector would be possible providing the resources needed to maintain and expand the system while providing acceptable rates of return on a realistic value of the assets. However, in Chapter 10 it was concluded that, it may not be possible for real retail tariffs to increase at more than 15 percent per year.

In addition to these constraints on tariff increases the decisions regarding asset revaluation do not rest entirely within the power sector and there is a real possibility that asset revaluation may need to proceed gradually if at all, in order to avoid sudden increases on depreciation allowances for tax purposes. Also, it is likely that by the end of 1993 there would be hardly any real growth in electricity prices with respect to mid-1992.

The objective of this Chapter 11 is to examine the effect of these constraints on the financial outlook of the power sector to arrive at a realistic level of revenues for the period 1994-1997. At the same time, the major uncertainties affecting the analysis are examined to develop a perception of the range of results that can be expected.

11.1 CONSTRAINED CASES

It is appropriate to refer to the financial analysis completed in Chapter 9 as the unconstrained analysis in the sense that is not affected by limitations external to the power sector. The cases to be studied in this chapter are all constrained by combinations of the following:

- a ceiling on the real annual growth of average tariffs at retail level
- a ceiling on the annual rate of revaluation of assets
- a ceiling on the depreciation allowance for tax purposes

Three cases are being considered:

Case 1 - Tariff Increase Restriction Only

Based on the conclusions of Chapter 10 it appears that a 15 percent real increase in average retail tariffs is the maximum that can be applied from one year to the next without serious negative public reaction. Since little progress is expected in real revenue increases from calendar years 1992 to 1993 it will be assumed that average 1994 revenues at retail level can be only 15 percent higher, in real terms, than 1992 increasing at a maximum of 15 percent per year thereafter until other financial performance criteria become binding.

Case 2 - Tariff Increase Restriction and No Asset Revaluation

Keeping the ceiling on tariff increases as described for Case 1, this case simply assumes that no revaluation of assets is possible.

Case 3 - Tariff Increase Restriction and Gradual Asset Revaluation

Based on discussion with PSE it appears that a gradual revaluation is possible and it has been assumed that, by 1997, gross assets could be valued at 100 percent of their replacement cost while depreciation allowance may be limited to only 70 percent of revalued gross assets.

Case 3 is considered to be the most likely scenario and therefore sensitivity analysis with respect to major uncertainties are made keeping the same constraints. Two cases were considered:

Case 3a - High Capital Investments in the Generation System

The analysis described so far estimates that the system will need approximately six billion US dollars in capital investments during 1994-1997. There is a great deal of uncertainty about this figure and currently studies are being conducted to better forecast these needs. To examine the impact of higher investment Case 3a considers a 50 percent increase in the level of required investment to approximately nine billion dollars during 1994-1997.

Case 3b - High Operating Costs in the Generation System

It has been assumed that operating costs would decrease from current levels as the system becomes modernized and operating efficiency is rewarded. While this is certainly likely at a very high level of investments it is less likely at more modest levels since some capital investments may continue to be shown as operating expense. To examine this possibility Case 3b considers no drop in operating expense from current levels.

11.2 APPROACH TO THE ANALYSIS OF FINANCIAL CONSTRAINTS

In order to analyze these different cases it was necessary to simplify the process followed through the detailed financial analyses of the generation, transmission and distribution systems described in Chapters 5, 8 and 9 respectively. Essentially, the analysis of financial constraints is performed on the basis of aggregated generation instead of the plant by plant analyses carried

out in Chapter 5. Therefore, the financial forecasts for 1994-1997 presented in this section are less accurate than those presented for the unconstrained case.

However, in order to allow for clear comparison against the unconstrained case, completed in Chapter 9 the results for this case are first presented, in Exhibit 11.1 in the same form as that will be used for the constrained cases.

11.3 RESULTS OF THE ANALYSIS OF FINANCIAL CONSTRAINTS

Case 1 - Tariff Increase Restriction Only

The results of this analysis are shown in Exhibit 11.2 where it can be observed that average retail tariffs in 1994 are 15 percent higher than 1992 levels and increase an additional 15 percent by 1995. After 1995 only a 10.9 percent increase is required to bring the system to the recommended level.

Since it is reasonable to maintain a no net borrowing criterion for the distribution companies the burden of a lower tariff yield in the short term is assigned to the generation system reducing its average tariff yield from 488.9 Zl/kWh to 351.0 Zl/kWh. This results in a significant loss for the generating system (given border prices for coal) at the operating income and net income levels, leading to a significant increase in the cash deficiency or net borrowing requirement for the generating system. Even so, with a borrowing requirement of about zl 15,000 billion in 1994, the projected debt-to-equity for the generating system is about 5.0%.

Case 2 - Tariff Increase Restriction and No Asset Revaluation

In this case shown in Exhibit 11-3, not only is the retail tariff constrained, but the elimination of revaluation reduces the depreciation expense which can be claimed as a deduction for tax purposes, thereby reducing annual cash flow to the distribution system. To offset this effect, it is necessary to reduce the bulk purchase price paid to PSE.

Thus the PSE selling prices are reduced in 1994 and 1995, in turn forcing a reduction in the price paid to the generating system.

By 1996 generating companies are able to approach a 6.0% rate of return, however, because the assets are not revalued this return is insufficient to cover the financing costs on the ever-increasing cash deficiency.

Exhibit 11-1
NON-CONSTRAINED CASE

Assumptions:
Retail tariff increase: No constraint
Asset Revaluation: 100% of replacement cost by January 1994
Tax allowance from Depreciation: 100% of replacement cost by January 1994
Investments in generation 1993 - 1997: US$ 5.8 billion
Fixed Operation Costs: decreasing
Financial criteria for DCs: no borrowing

	ESTIMATE	FORECAST			
	1992	1994	1995	1996	1997
AVERAGE TARIFFS - Zl/kWh (at mid 1992 price levels)					
Distribution Companies	542.1	785.0	785.0	795.0	805.0
PSE	336.7	563.0	557.0	559.0	571.0
Generation System	300.0	488.9	487.2	490.6	504.2
AVERAGE TARIFFS - US cents/kWh (at mid 1992 price levels)					
Distribution Companies	3.99	5.77	5.77	5.85	5.92
PSE	2.48	4.14	4.10	4.11	4.20
Generation System	2.21	3.59	3.58	3.61	3.71
NET BORROWING / CASH DEFICIENCY (SURPLUS) (billions zloty)					
Distribution Companies		(9,434)	(9,256)	(9,489)	(10,081)
PSE -- Programmed LTD		4,000	7,250	10,000	10,500
Cash		(3,769)	(6,578)	(9,007)	(11,697)
Generation System		782	(2,387)	(4,604)	(7,995)
SELF-FINANCING RATIO - %					
Distribution Companies		132.4	112.7	105.8	107.9
PSE		40.2	24.7	29.2	99.8
DEBT-TO-EQUITY (revalued) RATIO - %					
Distribution Companies		0.0	0.0	0.0	0.0
PSE		13.8	24.3	32.7	33.6
Generation System		4.7	2.8	3.0	1.2
RETURN ON NET ASSETS (revalued) - %					
Distribution Companies		0.0	1.5	2.3	1.7
PSE		6.1	5.9	6.0	5.9
Generation System		7.2	6.8	7.0	7.1
INCOME TAX FOR YEAR - billions Zl.					
Distribution Companies		1355	2,172	2,511	2,363
PSE		632	543	505	454
Generation System		2895	2,945	3,255	3,803
Total		4,882	5,660	6,271	6,620

NOTE: Income tax and cash position differ from the Base case in chapters 1 - 11.
This is because chapters 1 - 11 had assumed asset revaluation at December, 1992.

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Exhibit 11-2
CONSTRAINED CASE 1
Tariff Increase Restriction only

Assumptions:

Retail tariff increase: from mid-1992 to mid-1994, 15%; then 15% per year in real terms

Asset Revaluation: 100% of replacement cost by January 1994

Tax allowance from Depreciation: 100% of replacement cost by January 1994

Investments in generation 1993 - 1997: US$ 5.8 billion

Fixed Operation Costs: decreasing

Financial criteria for DCs: no borrowing

	ESTIMATE	FORECAST			
	1992	1994	1995	1996	1997
AVERAGE TARIFFS - Zl/kWh (at mid 1992 price levels)					
Distribution Companies	542.1	623.4	716.9	795.0	795.0
PSE	336.7	438.0	465.0	545.0	571.0
Generation System	300.0	351.0	385.0	475.0	504.2
AVERAGE TARIFFS - US cents/kWh (at mid 1992 price levels)					
Distribution Companies	3.99	4.58	5.27	5.85	5.85
PSE	2.48	3.22	3.42	4.01	4.20
Generation System	2.21	2.58	2.83	3.49	3.71
NET BORROWING / CASH DEFICIENCY (SURPLUS) (billions zloty)					
Distribution Companies		(10,223)	(10,203)	(10,220)	(10,368)
PSE -- Programmed LTD		4,000	7,250	10,000	10,250
Cash		(4,039)	(6,968)	(9,033)	(11,654)
Generation System		14,750	18,582	18,780	16,041
SELF-FINANCING RATIO - %					
Distribution Companies		114.5	124.7	111.9	104.0
PSE		39.0	24.4	29.2	99.7
DEBT-TO-EQUITY (revalued) RATIO - %					
Distribution Companies		(7.3)	(7.0)	(6.8)	(6.7)
PSE		13.8	24.4	32.8	33.7
Generation System		4.7	5.3	7.1	7.3
RETURN ON NET ASSETS (revalued) - %					
Distribution Companies		(2.7)	4.8	3.9	0.7
PSE		6.1	6.0	6.1	5.9
Generation System		(6.7)	(3.5)	4.6	5.8
INCOME TAX FOR YEAR - billions Zl.					
Distribution Companies		52	3,305	1,169	1,943
PSE		613	535	505	453
Generation System		(3,655)	(2,607)	1,037	1,922
Total		(2,990)	1,233	4,711	4,318

NOTE: Income tax and cash position differ from the Base case in chapters 1 - 11.
This is because chapters 1 - 11 had assumed asset revaluation at December, 1992.

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Exhibit 11–3
CONSTRAINED CASE 2
Tariff Increase Restriction and no Asset Revaluation

Assumptions:

Retail tariff increase: from mid–1992 to mid–1994, 15% ; then 15% per year in real terms

Asset Revaluation: 0% of replacement cost by January 1997

Tax allowance from Depreciation: 0% of replacement cost by January 1997

Investments in generation 1993 – 1997: US$ 5.8 billion

Fixed Operation Costs: decreasing

Financial criteria for DCs: no borrowing

	ESTIMATE	FORECAST			
	1992	1994	1995	1996	1997
AVERAGE TARIFFS – Zl/kWh (at mid 1992 price levels)					
Distribution Companies	542.1	623.4	716.9	735.0	743.0
PSE	336.7	375.0	398.0	439.0	458.0
Generation System	300.0	314.0	338.0	379.0	393.0
AVERAGE TARIFFS – US cents/kWh (at mid 1992 price levels)					
Distribution Companies	3.99	4.58	5.27	5.40	5.46
PSE	2.48	2.76	2.93	3.23	3.37
Generation System	2.21	2.31	2.49	2.79	2.89
NET BORROWING / CASH DEFICIENCY (SURPLUS) (billions zloty)					
Distribution Companies		231	180	199	189
PSE --- Programmed LTD		4,000	7,250	10,000	10,250
Cash					
Generation System		19,542	29,431	39,026	48,018
SELF–FINANCING RATIO – %					
Distribution Companies		112.7	125.2	104.9	103.9
PSE		10.4	9.2	14.4	64.3
DEBT–TO–EQUITY (revalued) RATIO – %					
Distribution Companies		2.9	2.2	1.9	1.6
PSE		53.9	95.0	127.4	129.5
Generation System		61.0	86.3	111.0	128.3
RETURN ON NET ASSETS (revalued) – %					
Distribution Companies		33.9	46.7	33.4	25.6
PSE		5.8	6.6	6.3	6.4
Generation System		(13.9)	(3.4)	5.8	5.4
INCOME TAX FOR YEAR – billions Zl.					
Distribution Companies		5,955	9,300	8,448	7,958
PSE		135	141	145	172
Generation System		(2,200)	(1,843)	(669)	(731)
Total		3,890	7,592	7,920	7,372

NOTE: Income tax and cash position differ from the Base case in chapters 1 – 11.
This is because chapters 1 – 11 had assumed asset revaluation at December, 1992.

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Exhibit 11-4
CONSTRAINED CASE 3
Tariff Increase Restriction and Gradual Asset Revaluation
("most likely case")

Assumptions:

Retail tariff increase: from mid-1992 to mid-1994, 15% ; then 15% per year in real terms

Asset Revaluation: 100% of replacement cost by January 1997

Tax allowance from Depreciation: 70% of replacement cost by January 1997

Investments in generation 1993 - 1997: US$ 5.8 billion

Fixed Operation Costs: decreasing

Financial criteria for DCs: no borrowing

	ESTIMATE	FORECAST			
	1992	1994	1995	1996	1997
AVERAGE TARIFFS - Zl/kWh (at mid 1992 price levels)					
Distribution Companies	542.1	623.4	716.9	814.0	814.0
PSE	336.7	378.0	411.0	517.0	567.0
Generation System	300.0	307.0	337.0	446.0	494.0
AVERAGE TARIFFS - US cents/kWh (at mid 1992 price levels)					
Distribution Companies	3.99	4.58	5.27	5.99	5.99
PSE	2.48	2.78	3.02	3.80	4.17
Generation System	2.21	2.26	2.48	3.28	3.63
NET BORROWING / CASH DEFICIENCY (SURPLUS) (billions zloty)					
Distribution Companies		165	203	199	219
PSE -- Programmed LTD		4,000	7,250	10,000	10,250
Cash		(1,738)	(2,597)	(3,429)	(5,520)
Generation System		19,942	29,399	34,032	34,356
SELF-FINANCING RATIO - %					
Distribution Companies		113.3	124.5	114.0	103.0
PSE		11.8	9.5	18.8	87.0
DEBT- TO-EQUITY (revalued) RATIO - %					
Distribution Companies		1.8	1.4	1.1	1.0
PSE		24.8	34.8	38.9	34.2
Generation System		28.6	34.3	34.7	34.2
RETURN ON NET ASSETS (revalued) - %					
Distribution Companies		15.1	18.0	10.8	2.8
PSE		6.4	6.0	6.1	5.9
Generation System		(9.9)	(5.4)	4.3	6.0
INCOME TAX FOR YEAR - billions Zl.					
Distribution Companies		5,576	8,055	6,886	3,646
PSE		543	656	771	773
Generation System		(2,664)	(2,409)	1,245	2,338
Total		3,455	6,302	8,902	6,757

NOTE: Income tax and cash position differ from the Base case in chapters 1 - 11.
This is because chapters 1 - 11 had assumed asset revaluation at December, 1992.

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This case results in significantly lower retail tariffs than any of the other cases. However, it is not deemed viable because it results in persistent annual net losses at the generating company level, as well as significant distortions in the financial ratios and financial relationships within the industry.

Case 3 - Tariff Increase Restriction and Gradual Asset Revaluation

This is considered to be the ***most likely*** case and the results are shown in Exhibit 11-4.

In the initial years 1994 and 1995, the limited asset revaluation and consequent limited deduction of depreciation expense result in higher income tax and reduced annual cash flow. In turn this necessitates a reduced bulk purchase tariff from PSE in order to maintain the annual cash flow in the retail system.

Insofar as the PSE system is permitted a 6.0% rate of return, the burden of constrained tariffs is borne primarily by the generating system.

In 1994, the generating system incurs operating losses and net losses. A similar result occurs in 1995, leading to net borrowing by 1995 of approximately zl 30,000 billion. This is equivalent to a debt-to-equity ratio of about 34%.

A tariff of 814 zl/kwh is required to achieve a 6.0% return on net assets in 1997.

Case 3a - High Capital Investments in the Generation System

The results of a sensitivity analysis of the results of Case 3 to higher investments in the generation system are shown in Exhibit 11-5.

All of the additional investment will require to be borrowed -- leading to an increase in net borrowing by the generating system. Net borrowing by 1997 would amount to zl 73,223 billion -- or about U.S.$5.5 billion -- equivalent to a debt-to-equity ratio of 66.8%.

As the increased investment will eventually increase the assets-in-service, the tariff charged by the generating system will increase in 1996 and 1997 to reflect a 6.0% return on net assets in service. Thus this case will result in the highest tariff in 1997 -- i.e. 846 zl/kwh, as well as the highest debt for the generating system.

Exhibit 11-5
CONSTRAINED CASE 3a
Sensitivity Analysis to High Generation Investment

Assumptions:
Retail tariff increase: from mid-1992 to mid-1994, 15%; then 15% per year in real terms
Asset Revaluation: 100% of replacement cost by January 1997
Tax allowance from Depreciation: 70% of replacement cost by January 1997
Investments in generation 1993 - 1997: US$ 9.0 billion
Fixed Operation Costs: decreasing
Financial criteria for DCs: no borrowing

	ESTIMATE	FORECAST			
	1992	1994	1995	1996	1997
AVERAGE TARIFFS - Zl/kWh (at mid 1992 price levels)					
Distribution Companies	542.1	623.4	716.9	824.5	846.0
PSE	336.7	378.0	411.0	524.0	591.0
Generation System	300.0	307.0	337.0	454.0	520.0
AVERAGE TARIFFS - US cents/kWh (at mid 1992 price levels)					
Distribution Companies	3.99	4.58	5.27	6.06	6.22
PSE	2.48	2.78	3.02	3.85	4.35
Generation System	2.21	2.26	2.48	3.34	3.82
NET BORROWING / CASH DEFICIENCY (SURPLUS) (billions zloty)					
Distribution Companies		165	203	173	173
PSE -- Programmed LTD		4,000	7,250	10,000	10,250
Cash		(1,738)	(2,597)	(3,389)	(5,483)
Generation System		33,790	50,709	64,911	73,223
SELF-FINANCING RATIO - %					
Distribution Companies		113.3	124.5	115.3	105.6
PSE		12.0	10.0	20.2	95.0
DEBT-TO-EQUITY (revalued) RATIO - %					
Distribution Companies		1.8	1.4	1.1	1.0
PSE		24.8	34.8	38.9	34.1
Generation System		44.3	55.8	61.2	66.8
RETURN ON NET ASSETS (revalued) - %					
Distribution Companies		15.1	18.0	11.1	3.2
PSE		6.4	6.0	6.1	6.3
Generation System		(9.2)	(5.1)	3.9	6.0
INCOME TAX FOR YEAR - billions Zl.					
Distribution Companies		5,576	8,055	7,030	3,931
PSE		543	656	766	836
Generation System		(3,098)	(3,323)	229	1,579
Total		3,021	5,388	8,025	6,346

NOTE: Income tax and cash position differ from the Base case in chapters 1 - 11.
This is because chapters 1 - 11 had assumed asset revaluation at December, 1992.

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Exhibit 11-6
CONSTRAINED CASE 3b
Sensitivity Analysis to Constant Operating Costs

Assumptions:
Retail tariff increase: from mid-1992 to mid-1994, 15%; then 15% per year in real terms
Asset Revaluation: 100% of replacement cost by January 1997
Tax allowance from Depreciation: 70% of replacement cost by January 1997
Investments in generation 1993 - 1997: US$ 5.8 billion
Fixed Operation Costs: constant
Financial criteria for DCs: no borrowing

	ESTIMATE	FORECAST			
	1992	1994	1995	1996	1997
AVERAGE TARIFFS - Zl/kWh (at mid 1992 price levels)					
Distribution Companies	542.1	623.4	716.9	824.5	835.0
PSE	336.7	378.0	411.0	524.0	583.0
Generation System	300.0	307.0	337.0	454.0	511.0
AVERAGE TARIFFS - US cents/kWh (at mid 1992 price levels)					
Distribution Companies	3.99	4.58	5.27	6.06	6.14
PSE	2.48	2.78	3.02	3.85	4.29
Generation System	2.21	2.26	2.48	3.34	3.76
NET BORROWING / CASH DEFICIENCY (SURPLUS) (billions zloty)					
Distribution Companies		165	203	173	154
PSE -- Programmed LTD		4,000	7,250	10,000	10,250
Cash		(1,738)	(2,597)	(3,389)	(5,512)
Generation System		21,007	31,422	36,770	37,370
SELF-FINANCING RATIO - %					
Distribution Companies		113.3	124.5	115.3	104.5
PSE		11.8	9.5	18.6	94.0
DEBT-TO-EQUITY (revalued) RATIO - %					
Distribution Companies		1.8	1.4	1.1	1.0
PSE		24.8	34.8	38.9	34.1
Generation System		30.2	37.0	37.7	37.4
RETURN ON NET ASSETS (revalued) - %					
Distribution Companies		15.1	18.0	11.1	3.0
PSE		6.4	6.0	6.1	6.3
Generation System		(11.5)	(6.9)	3.5	6.0
INCOME TAX FOR YEAR - billions Zl.					
Distribution Companies		5,576	8,055	7,030	3,806
PSE		543	656	766	829
Generation System		(3,118)	(3,054)	798	2,188
Total		3,001	5,657	8,594	6,823

NOTE: Income tax and cash position differ from the Base case in chapters 1 - 11.
This is because chapters 1 - 11 had assumed asset revaluation at December, 1992.

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Case 3b - High Operating Costs in the Generation System

In Exhibit 11-6 are shown the results of Case 3 modified to reflect fixed costs being maintained at 1992 levels, rather than decreasing.

The result is a retail tariff of 835 zl/kwh in 1997 -- or about 2.5% higher than in Case 3.

11.4 CONCLUSIONS OF THE CONSTRAINED FINANCIAL ANALYSIS

11.4.1 Tariffs at retail level

With the exception of Case 2, which is essentially not financially viable, it can be seen in Exhibit 11-7 that by 1997 the retail tariff falls in the range 795 to 846 zl/kwh, or within -2.5% to +3.5% of the 814 zl/kwh in the recommended Case 3.

EXHIBIT 11-7

AVERAGE RETAIL TARIFFS -- ZL/KWH AT MID-1992 PRICE LEVEL

	1992	1994	1995	1996	1997
Non-constrained	542.1	785.0	785.0	795.0	805.0
Case 1		623.4	716.9	795.0	795.0
2		623.4	716.9	735.0	743.0
3		**623.4**	**716.9**	**814.0**	**814.0**
3A		623.4	716.9	824.5	846.0
3B		623.4	716.9	824.5	835.0

11.4.2 Debt

Except for Case 2, none of the alternatives results in an unacceptable debt-to-equity ratio. Even so, it should be recognized that the debt to be incurred is the result of not implementing the tariff increases recommended in the unconstrained case.

It should also be noted that the net cash deficiency of zl 73,223 billion in Case 3A would be likely to require further future tariff increases in order to amortise the principal.

11.4.3 Income tax

The total income tax payable in each case is summarized in Exhibit 11-8.

EXHIBIT 11-8

INCOME TAX PAYABLE (b1.Z1. at mid 1992 price levels).

	1994	1995	1996	1997	TOTAL
Non-constrained	4,882	5,660	6,271	6,620	23,433
Case 1	(2,990)	1,233	4,711	4,318	7,272
2	3,890	7,592	7,920	7,372	26,774
3	**3,445**	**6,302**	**8,902**	**6,757**	**25,406**
3A	3,021	5,388	8,025	6,346	22,780
3B	3,001	5,657	8,594	6,823	24,075

With the exception of Case 1 which combines restricted tariff increases with the maximum depreciation allowance for tax, all other cases result in similar tax yields.

However, it should be noted that Case 2, which yields the highest tax revenue, is also not viable financially. It is the reverse of Case 1, in that it combines the lowest tariffs with the highest taxes (resulting from the lowest depreciation allowance due to the assets not being revalued).

Thus the overall conclusion is that allowing the industry to operate on an economic base with properly valued assets and appropriate tariffs is unlikely to materially affect the total income tax yield from the industry.

11.4.4 Consolidated Financial Statements

The consolidated financial statements of the generating companies, PSE and the distribution companies corresponding to the most likely scenario, Case 3, are shown in Exhibits 11-9 to 11-17. These can be compared to the consolidated financial statements corresponding to the unconstrained case for generation companies, PSE and distribution companies included in Chapters 5, 8 and 9 respectively.

Exhibit 11 – 9
Case 3
CONSOLIDATED BALANCE SHEET – GENERATING COMPANIES

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			ASSETS						
	538	929	Cash	1,583	745	787	885	1,199	1,355
	374	1,378	Accounts Receivable	1,594	1,584	1,677	1,891	2,580	2,922
	797	1,614	Inventories -- Fuel	1,694	3,171	3,334	3,414	3,547	3,630
	12	20	Others						
	468	224	Others		450	850	1,300	1,700	2,000
	2,190	**4,165**	**Total Current Assets**	**4,871**	**5,950**	**6,647**	**7,490**	**9,027**	**9,907**
	35,125	36,835	Gross Fixed Assets	73,272	109,924	165,632	211,220	267,422	297,728
	16,435	18,295	Less: Acc. Depreciation	38,553	60,025	82,719	107,270	133,340	142,254
	18,690	18,539	Net Fixed Assets	34,719	49,899	82,914	103,950	134,082	155,474
	1,413	18,735	Capital Work-in-Progress	23,133	33,446	27,611	30,368	26,257	9,738
	22,293	**41,439**	**TOTAL ASSETS EMPLOYED**	**62,724**	**89,295**	**117,171**	**141,809**	**169,366**	**175,118**
			LIABILITIES						
	602	1,329	Accounts Payable						
	556	920	Other Liabilities						
			LTD due within 1 year – existing	170	170	170	170	170	170
	10	18	LTD due within 1 year – new local						
			LTD due within 1 year – new FX						
			Cash Deficiency (Surplus)	(2,135)	7,782	19,942	29,399	34,032	34,356
	1,168	**2,268**	**Total Current Liabilities**	**(1,965)**	**7,952**	**20,236**	**30,022**	**35,050**	**35,774**
		(50)	Other Liabilities						
	1,447	2,492	Long Term Debt – existing	3,068	2,899	2,729	2,559	2,390	2,220
		162	Long Term Debt – new local	704	1,970	3,342	4,112	6,934	7,725
			Long Term Debt – new FX						
	1,447	**2,654**	**Total Long Term Debt**	**3,772**	**4,869**	**6,071**	**6,671**	**9,323**	**9,945**
			Equity Balance:						
	14,657	15,642	Assumed Opening Position	32,770	32,770	32,770	32,770	32,770	32,770
	1,199	16,751	Additional Paid in Capital	2,718	5,436	8,230	10,870	13,589	16,306
	482	378	Revaluation of Fixed Assets	17,408	35,014	52,620	70,226	87,832	87,832
	2,833	3,103	Retained Earnings -- Prior Years	3,797	8,021	3,255	(2,756)	(8,751)	(9,204)
	507	694	Current Year's Net Income	4,223	(4,766)	(6,011)	(5,995)	(453)	1,675
	19,678	**36,567**	**Total Equity**	**60,916**	**76,475**	**90,864**	**105,115**	**124,987**	**129,379**
	22,293	**41,439**	**TOTAL LIABILITIES & EQUITY**	**62,724**	**89,295**	**117,171**	**141,809**	**169,366**	**175,118**

Billions Zloty at Base Year Prices

RCG/HAGLER, BAILLY, Inc.
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Exhibit 11-10
Case 3
CONSOLIDATED BALANCE SHEET – POLSKIE SIECI ELEKTROENERGETYCZNE

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLSKIE SIECI ELEKTROENERGETYCZNE Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			ASSETS						
			Fixed Assets:						
			Capital Assets						
	179	180	Gross Fixed Assets	180	680	1,680	4,180	8,180	12,180
			Plus: Transfers of Grid from DCs	7,165	7,165	7,165	7,165	7,165	7,165
			Plus: Transfers of Pumped Storage	3,339	3,339	3,339	3,339	3,339	3,339
			Total Adjusted Gross Fixed Assets	**10,685**	**11,185**	**12,185**	**14,685**	**18,685**	**22,685**
			Plus: Revaluation to 1992		9,349	18,698	28,048	37,397	46,746
			Plus: Revaluation after 1992						
			Revalued Gross Fixed Assets	10,685	20,534	30,883	42,733	56,082	69,431
	91	95	Less: Accumulated Depreciat'n	110	132	191	337	646	1,155
			Depreciation on Transfers	5,483	6,008	6,533	7,059	7,584	8,109
			Revalued Depreciation		4,880	9,760	14,639	19,519	24,399
			Depreciation on Revaluation		234	935	2,104	3,740	5,843
			Total Accumulated Depreciation	**29,810**	**32,685**	**35,607**	**38,616**	**41,787**	**45,159**
	88	85	Net Fixed Assets	5,092	9,281	13,465	18,594	24,593	29,924
	3	130	Capital Work-in-Progress	699	1,344	3,000	4,723	4,895	2,627
	1	185	Advance Payments	197	197	197	197	197	197
		1	Patents & Licenses	1	1	1	1	1	1
			Financial Investments:						
		0	Shares in other Companies						
	221	193	Long Term Accounts Receivable	193	193	193	193	193	193
			Current Assets:						
	0	0	Inventories						
	247	1,905	Accounts Receivable	2,736	2,788	3,195	3,584	4,630	5,218
	24	0	Income Tax Receivable						
	5	5	Other Accounts Receivable						
	590	25	Cash at Bank and on Deposit	15	315	1,738	2,597	3,429	5,520
	868	**1,936**	**Total Current Assets**	**2,751**	**3,103**	**4,933**	**6,181**	**8,059**	**10,738**
	1,180	**2,530**	**TOTAL ASSETS**	**8,934**	**14,119**	**21,790**	**29,889**	**37,939**	**43,681**

Exhibit 11-10
Case 3
CONSOLIDATED BALANCE SHEET – POLSKIE SIECI ELEKTROENERGETYCZNE

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLSKIE SIECI ELEKTROENERGETYCZNE Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			LIABILITIES						
			Equity Capital:						
	515	515	Equity	515	515	515	515	515	515
	71	389	Reserve Capital	610	1,165	1,447	1,682	1,906	2,285
			Transfers of Grid from DCs	7,165	7,165	7,165	7,165	7,165	7,165
			Transfer of Pumped Storage	3,339	3,339	3,339	3,339	3,339	3,339
			Less: Accum. dep'n on Transfers	5,483	5,483	5,483	5,483	5,483	5,483
	1		Asset Revaluation	0	4,469	8,939	13,408	17,878	22,347
	321	221	Current Year's Net Income	555	281	236	224	379	529
	908	**1,125**	**Total Equity**	**6,702**	**11,453**	**16,158**	**20,851**	**25,699**	**30,697**
		315	Long Term Debt	750	1,200	4,000	7,250	10,000	10,500
			Current Liabilities:						
	231	841	Accounts Payable	1,232	1,217	1,382	1,538	1,990	2,234
	6	112	Other Accounts Payable	110	110	110	110	110	110
			Short Term Loans						
	35	138	Other Liabilities	140	140	140	140	140	140
			Owing to Bank						
	271	**1,091**	**Total Current Liabilities**	**1,482**	**1,467**	**1,632**	**1,788**	**2,240**	**2,484**
	1,180	**2,531**	**TOTAL LIABILITIES**	**8,934**	**14,119**	**21,790**	**29,889**	**37,939**	**43,681**
	179	180	Gross Fixed Assets	180	680	1,680	4,180	8,180	12,180
	6,903	6,903	Plus: Transfers of Grid from DCs	7,165	7,165	7,165	7,165	7,165	7,165
		3,252	Plus: Transfers of Pumped Storage	3,339	3,339	3,339	3,339	3,339	3,339
	7,082	**7,084**	**Total Adjusted Gross Fixed Assets**	**10,685**	**11,185**	**12,185**	**14,685**	**18,685**	**22,685**

Billions Zloty at Base Year Prices

RCG/HAGLER, BAILLY, Inc.
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Exhibit 11-11
Case 3
CONSOLIDATED BALANCE SHEET – DISTRIBUTION COMPANIES

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH DISTRIBUTION COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			ASSETS						
	1,116	1,226	Cash	1,692	1,692	1,692	1,692	1,692	1,692
	895	3,716	Accounts Receivable	8,719	8,948	10,593	12,674	14,764	15,168
	318	532	Inventories -- Fuel	735	735	735	735	735	735
	2,329	**5,474**	**Total Current Assets**	**11,145**	**11,375**	**13,019**	**15,101**	**17,191**	**17,595**
			Gross Fixed Assets:	73,272	109,924	165,632	211,220	267,422	297,728
		6,903	Transmission (>110kv)& S/stations						
		44,206	Distribution Lines						
		14,803	Substations						
		4,930	Other Fixed & Tangible Assets						
	65,818	70,842	Gross Fixed & Tangible Assets	63,939	103,009	145,561	192,403	244,170	296,564
	33,859	36,976	Less: Acc. Depreciation	38,553	60,025	82,719	107,270	133,340	142,254
	31,959	33,866	Net Fixed & Tangible Assets	27,369	42,556	59,272	78,149	99,610	119,110
	1,190	2,903	Capital Work-in-Progress	2,903	6,385	10,674	15,600	16,227	16,389
	6	30	Goodwill						
	34,927	**42,272**	**TOTAL ASSETS EMPLOYED**	**41,417**	**60,316**	**82,965**	**108,049**	**133,028**	**153,094**
			LIABILITIES						
	891	2,671	Accounts Payable						
	633	3,799	Other Liabilities						
			Cash Deficiency (Surplus)	2,820	186	165	203	199	219
	1,784	**6,470**	**Total Current Liabilities**	**2,820**	**186**	**165**	**203**	**199**	**219**
	575	1,309	Long Term Debt	1,309	1,309	1,309	1,309	1,309	1,309
	575	**1,309**	**Total Long Term Debt**	**1,309**	**1,309**	**1,309**	**1,309**	**1,309**	**1,309**
			Equity Balance:						
	31,645	32,578	Assumed Opening Position	32,578	32,578	32,578	32,578	32,578	32,578
			Reserve for Asset Revaluation	0	17,290	34,579	51,869	69,159	86,448
		923	Retained Earnings -- Prior Years	1,915	4,710	8,953	14,334	22,890	29,784
	923	991	Current Year's Net Income	2,795	4,243	5,381	8,556	6,894	2,756
	32,568	**34,492**	**Total Equity**	**37,288**	**58,820**	**81,491**	**107,337**	**131,520**	**151,565**
	34,927	**42,272**	**TOTAL LIABILITIES & EQUITY**	**41,417**	**60,316**	**82,965**	**108,849**	**133,028**	**153,094**

Billions Zloty at Base Year Prices

RCG/HAGLER, BAILLY, Inc.
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Exhibit 11-12
Case 3
INCOME STATEMENT – GENERATING COMPANIES

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
		97,847	Energy Sales -- GWh	97,011	96,337	99,676	102,424	105,582	107,948
		20,773	Capacity -- MW	20,476	20,366	20,180	20,390	20,189	21,316
			% Capacity Sold						
		73,135	Hours of Production/Year	73,626	73,626	74,765	75,904	66,791	60,630
		195,312	Capacity Sales – MW/m	185,803	182,381	184,205	184,127	172,483	173,497
			Max Capacity Sales @1994 Installation	208,851	207,732	202,156	200,636	191,242	195,389
		115.489	Energy Sales Price -- Zl/kWh	196.754	300.222	306.771	313.057	326.149	338.126
		45,459	Capacity Price -- '000 Zl/MW/m	53,884	103,053	98,580	96,867	100,644	103,333
			Adjusted 1994 Capacity Price						
			Sales Revenue						
		11,301	Energy	19,087	28,922	30,578	32,064	34,435	36,500
		8,879	Capacity	10,012	18,795	18,159	17,836	17,359	17,928
282	3,698	20,180	Sub-total Electricity Sales	29,099	28,901	30,601	34,517	47,089	53,327
18	320	412	Others	1,012	885	875	875	875	855
300	**4,018**	**20,592**	**Total Sales/Revenues**	**30,111**	**29,786**	**31,475**	**35,391**	**47,964**	**54,181**
			Variable Cost						
170	2,087	10,738	Fuel	11,592	25,295	26,245	27,016	28,018	28,757
	88		Transport	1,694					
	49	601	Environmental Penalty	2,719	2,687	2,742	2,798	2,850	2,871
3	28	4	Others						
173	2,253	11,343	Total Variable Cost @ 1992 Prices	16,004	27,982	28,987	29,015	30,868	31,628
			Plus: Inflation						
173	**2,253**	**11,343**	**Total Variable Cost**	**16,004**	**27,982**	**28,987**	**29,815**	**30,868**	**31,628**
			Fixed/ Capacity Costs						
95	951	5,865	Existing Plant	6,398	5,778	5,342	4,956	4,695	4,501
			New Plant			72	145	289	434
95	951	5,865	Total Fixed Cost (ex.Dep'n)@1992	6,398	5,778	5,415	5,101	4,984	4,935
			Plus: Inflation						
95	**951**	**5,865**	**Total Fixed Cost before Dep'n.**	**6,398**	**5,778**	**5,415**	**5,101**	**4,984**	**4,935**
7	141	1,947	Depreciation Expense	1,228	2,442	3,664	5,521	7,041	8,914
274	3,344	19,155	Total Operating Expense	23,629	36,203	38,066	40,437	42,893	45,477
26	674	1,438	Operating Income	6,482	(6,417)	(6,591)	(5,045)	5,071	8,704
4	31	65	Financial/Interest Expense (Net)	(557)	711	2,084	3,359	4,279	4,691
0	(67)	421	Extraordinary Income (Loss)						
23	575	1,794	Income Before Tax	7,039	(7,129)	(8,675)	(8,405)	792	4,013
5	279	980	Corporate Tax	2,816	(2,363)	(2,664)	(2,409)	1,245	2,338
18	296	814	Net Income After Tax	4,223	(4,766)	(6,011)	(5,995)	(453)	1,675

Billions Zloty at Base Year Prices

RCG/HAGLER, BAILLY, Inc.
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30-Jun-93

Exhibit 11-13
Case 3
INCOME STATEMENT – POLSKIE SIECI ELEKTROENERGETYCZNE

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLSKIE SIECI ELEKTROENERGETYCZNE Year End --- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			INCOME STATEMENT						
		24,653	Total Sales	35,662	36,340	41,655	46,723	60,354	68,018
		24,015	Total Cost of Sales	34,329	34,161	38,804	43,191	55,875	62,720
		638	Net Revenue from Energy Sales	1,333	2,179	2,851	3,531	4,479	5,298
		141	Materials & Energy	166					
		147	Outside Services	94					
		35	Salaries / Payroll	62					
		22	Payroll Taxes, etc.	30					
		2	Business Travel	2					
		7	Other						
		354	**Total Overhead Costs @1992 Prices**	**354**					
			Inflation						
			Total @ Current Prices	354					
			Plus: Transfers from Distribution Companies:						
		9	Materials & Energy	12					
		54	Outside Services	75					
		39	Salaries / Payroll	54					
			Payroll Taxes, etc.						
			Business Travel						
		56	Pumped Storage Costs	69					
		143	Other	198					
		301	Total O'head Costs Transf'd @1992 Prices	407					
			Inflation						
			Total O'head Costs Transferred	**407**					
			Adjusted Total Overhead Costs:						
		150	Materials & Energy	178	178	178	178	178	178
		201	Outside Services	169	169	169	169	169	169
		74	Salaries / Payroll	116	116	116	116	116	116
		22	Payroll Taxes, etc.	30	30	30	30	30	30
		2	Business Travel	2	2	2	2	2	2
		64	Pumped Storage Costs	69	69	69	69	69	69
		151	Other	198	198	198	198	198	198
		662	**Total Adjusted O'head Costs @1992**	**761**	**761**	**761**	**761**	**761**	**761**
			Inflation						
			Total @ Current Prices	**761**	**761**	**761**	**761**	**761**	**761**
		13	Other Costs						
		271	Net Revenue from Production	979					

Exhibit 11-13

Case 3

INCOME STATEMENT – POLSKIE SIECI ELEKTROENERGETYCZNE (cont.)

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLSKIE SIECI ELEKTROENERGETYCZNE Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			(BEFORE TRANSFERRED COSTS)						
			Net Revenue from Production		1,418	2,089	2,770	3,718	4,537
			(AFTER TRANSFERRED COSTS)						
		10	Interest from loans to Others						
		130	Interest on Deposits at Bank	2	18	113	238	331	492
		2	Gain on Currency Exchange						
		142	**Financial Income/ Interest Income**	**2**	**18**	**113**	**238**	**331**	**492**
		1	Other Revenues	17					
		414	Operating Income	998					
			(BEFORE TRANSFERRED COSTS)						
			Operating Income		1,436	2,202	3,008	4,049	5,029
			(AFTER TRANSFERRED COSTS)						
		11	Depreciation -- per Statement	15	22	59	147	309	509
			Plus: Dep'n on Revaluation						
			Total Dep'n @ Current Prices	**15**	**22**	**59**	**147**	**309**	**509**
		469	Depreciation -- Transferred from DCs		525	525	525	525	525
			Plus: Dep'n on Revaluation		234	701	1,169	1,636	2,104
			Total Dep'n @ Current Prices		**759**	**1,226**	**1,694**	**2,161**	**2,629**
		480	Total Adjusted Depreciation @1992	15	547	584	672	834	1,034
			Plus: Dep'n on Revaluation		234	701	1,169	1,636	2,104
			Total Dep'n @ Current Prices	**15**	**780**	**1,285**	**1,840**	**2,470**	**3,138**
			Operating Income after Deprec'n	933	655	917	1,168	1,579	1,891
			Financial Charges:						
		6	Lease Payments						
		27	Long Term Loan Interest	59	107	286	619	949	1,128
			Less: Interest during Construction		77	148	330	520	538
			Net Interest	59	30	138	289	429	589
		371	Income before Tax	925	625	779	879	1,150	1,302
		148	Income Tax	370	343	543	656	771	773
			Capital Tax						
		1	Other Taxes						
		221	**NET INCOME (BEFORE TRANSFERS)**	**555**	**281**	**236**	**224**	**379**	**529**

Billions Zloty at Base Year Prices

RCG/HAGLER, BAILLY, Inc.

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30-Jun-93

Exhibit 11 – 14
Case 3
INCOME STATEMENT – DISTRIBUTION COMPANIES

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH DISTRIBUTION COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
111,072	102,508	96,383	Energy Sales -- GWh	95,074	97,575	100,441	104,501	107,220	110,154
19.9	213.4	354.0	Average Tariff -- Zl/kWh	542.1	542.1	717.0	824.5	948.2	1090.4
2,215	21,880	34,119	Total Energy Sales Revenue	51,540	52,895	62,616	74,920	87,277	89,565
16	332	676	Other Revenues (Net)	773	793	939	1,124	1,309	1,345
2,231	**22,212**	**34,795**	**Total Sales/Revenues**	**52,313**	**53,689**	**63,556**	**76,043**	**88,586**	**91,010**
			Energy Costs						
		130	Own Thermal						
		248	Own Hydro						
		50	Auto producer	58	58	58	58	58	58
		7	Small Hydro						
1,530	15,122	23,715	PSE	35,989	36,341	41,653	46,724	60,356	67,898
1,530	**15,114**	**24,149**	**Total Energy Costs**	**36,047**	**36,399**	**41,712**	**46,783**	**60,414**	**67,956**
			Transmission and Customer Service						
25	216	317	Materials						
137	1,422	1,593	Repairs						
243	1,275	2,090	Salaries and Payroll Taxes						
61	1,192	3,418	Amortization						
115	688	299	Administration Overhhead						
			Other Costs						
581	**4,793**	**7,717**	**Total Fixed Operating Costs**						
			Less: High Voltage Network Costs						
	4	9	Materials						
	44	54	Repairs						
	26	39	Salaries and Taxes						
	146	469	Amortization						
	53	87	Administration Overhhead						
	30	56	Other Costs						
	303	**714**	**Total High Voltage Network Costs**						
			Net Distribution Network Costs						
	212	308	Materials	425	425	425	425	425	425
	1,378	1,539	Repairs	2,123	2,123	2,123	2,123	2,123	2,123
	1,249	2,051	Salaries and Taxes	1,732	1,732	1,732	1,732	1,732	1,732
	1,047	2,949	Amortization	3,197	5,005	6,959	9,086	11,429	14,017
	635	212	Administration Overhhead	1,391	1,391	1,391	1,391	1,391	1,391
	(30)	(56)	Other Costs	(78)	(78)	(78)	(78)	(78)	(78)
	4,490	**7,002**	**Total Distribution Costs @1992**	**8,790**	**10,599**	**12,552**	**14,680**	**17,022**	**19,610**
			Plus: Inflation	0	0	0	0	0	0
			Total Distribution Costs	**8,790**	**10,599**	**12,552**	**14,680**	**17,022**	**19,610**
2,111	**19,907**	**31,866**	**TOTAL COSTS**	**44,838**	**46,998**	**54,264**	**61,463**	**77,436**	**87,567**
119	**2,305**	**2,929**	**OPERATING INCOME**	**7,475**	**6,691**	**9,292**	**14,581**	**11,150**	**3,444**
21	**347**	**1,375**	**OTHER INCOME**	**1,581**	**1,597**	**1,830**	**2,052**	**2,650**	**2,981**
2	5	260	Interest Expense	155	10	164	21	20	23
139	**2,647**	**4,044**	**INCOME BEFORE TAX**	**8,901**	**8,277**	**10,957**	**16,611**	**13,780**	**6,401**
39	1,716	2,874	Less: Income & Corporate Tax	6,106	4,034	5,576	8,055	6,886	3,646
100	**931**	**1,170**	**NET INCOME**	**2,795**	**4,243**	**5,381**	**8,556**	**6,894**	**2,756**

Billions Zloty at Base Year Prices

RCG/HAGLER, BAILLY, Inc.
File Name g:\pol\report\exhibit\e11-12.wk1
30-Jun-93

Exhibit 11-15
CASE 3
OPERATING AND FINANCIAL RATIOS – GENERATION COMPANIES

PRO-FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH GENERATING COMPANIES Year End -- December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES						
			Energy Sales(Gwh)-Annual Growth -%	-0.9%	-0.7%	3.5%	2.6%	3.1%	2.2%
	1209.5%	445.7%	Sales Revenue(Zl)-Annual Growth -%	44.2%	-0.7%	5.9%	12.8%	36.4%	13.2%
		206.239	Average Tariff -- Zlotys/kWh	299.957	300.000	307.000	337.000	446.000	494.000
			OPERATING RATIOS						
		115.929	Variable Cost / kWh	164.969	290.460	290.815	291.091	292.358	292.992
		195.761	Total Operating Cost/ kWh	243.575	375.795	381.899	394.796	406.252	421.283
		196.428	Total Cost/ kwh (excl. ROE)	237.831	375.795	381.899	394.796	406.252	421.286
		30,027	Fixed Cost/ Mw/m	34,434	31,684	29,395	27,702	28,898	28,445
		39,994	Fixed Cost plus Dep'n/ Mw/m	41,042	45,075	49,287	57,688	69,717	79,824
		40,328	Fixed Cost plus Dep'n & Int./Mw/m	38,042	45,075	49,287	57,688	69,717	79,824
	16.8%	7.0%	Operating Income to Sales -- %	21.5%	-21.5%	-20.9%	-14.3%	10.6%	16.1%
			Operating Income to Gross Assets						
			in Service (Average) - %:						
		14.9%	-historical						
	3.8%	4.0%	-revalued	11.8%	-7.0%	-4.8%	-2.7%	2.1%	3.1%
	7.2%	7.7%	Operating Income/ Net Assets - %	24.3%	-15.2%	-9.9%	-5.4%	4.3%	6.0%
			BALANCE SHEET RATIOS						
		1.8	Current Ratio	-2.5	0.7	0.3	0.2	0.3	0.3
		0.5	Cash at Bank to Sales - months	0.3	0.3	0.3	0.3	0.3	0.3
		24	Accts.Receivable to Sales -days	19	19	19	20	20	20
			Debt to Equity Ratio - %						
			-historical						
		7.3%	-revalued	6.2%	16.5%	28.6%	34.3%	34.7%	34.2%

Billions Zloty at Base Year Prices

RCG/HAGLER, BAILLY, Inc.
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Exhibit 11–16
CASE 3
OPERATING AND FINANCIAL RATIOS – PSE

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	PSE Year End –– December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES						
		–2.2%	Energy Sales(Gwh)–Annual Growth –%	–2.6%	1.8%	2.2%	3.2%	2.7%	2.8%
			Sales Revenue(Zl)–Annual Growth –%	50.3%	1.9%	14.6%	12.2%	29.2%	12.7%
		218.2	Average Tariff –– Zlotys/kWh	336.7	337.0	378.0	411.0	517.0	567.0
		218.2	Average Energy Tariff –– Zlotys/kWh	336.7	337.0	378.0	411.0	517.0	567.0
			Average Capacity Tariff '000 Zlotys/ MW/mo						
			INCOME RATIOS:						
			Operating Income/ Net Assets – %						
		145.7%	BEFORE Transfer of Assets/Costs	200.0%					
		–7.2%	AFTER Transfer of Assets/Costs	20.0%	6.6%	6.4%	6.0%	6.1%	5.9%
			Operating Income after Dep'n/ Sales – %						
		1.1%	BEFORE Transfer of Assets/Costs	2.8%					
		–0.1%	AFTER Transfer of Assets/Costs	1.7%	1.8%	2.2%	2.5%	2.6%	2.8%
			Net Income/ Total Equity – %						
		21.7%	BEFORE Transfer of Assets/Costs	7.1%					
		–23.6%	AFTER Transfer of Assets/Costs	8.2%	3.1%	1.7%	1.2%	1.6%	1.9%
			CASH FLOW RATIOS:						
			Debt Service Ratio						
		8.10	BEFORE Transfer of Assets/Costs	10.73	10.98	3.13	2.28	2.60	2.76
			Self–Financing Ratio						
		64.4%	BEFORE Transfer of Assets/Costs	98.0%	28.4%	11.8%	9.5%	18.8%	87.0%
			BALANCE SHEET RATIOS:						
		1.78	Current Ratio	1.86	2.12	3.02	3.46	3.60	4.32
		0.01	Cash at Bank to Sales – months	0.01	0.10	0.50	0.67	0.68	0.97
		0.93	Accts.Receivable to Sales – months	0.92	0.92	0.92	0.92	0.92	0.92
			Debt to Equity Ratio – %						
		28.0%	BEFORE Transfer of Assets/Costs	11.2%					
			AFTER Transfer of Assets/Costs		10.5%	24.8%	34.8%	38.9%	34.2%

Billions Zloty at Base Year Prices

RCG/HAGLER, BAILLY, Inc.
File Name g:\pol\report\exhibit\e11_15.wk1
30–Jun–93

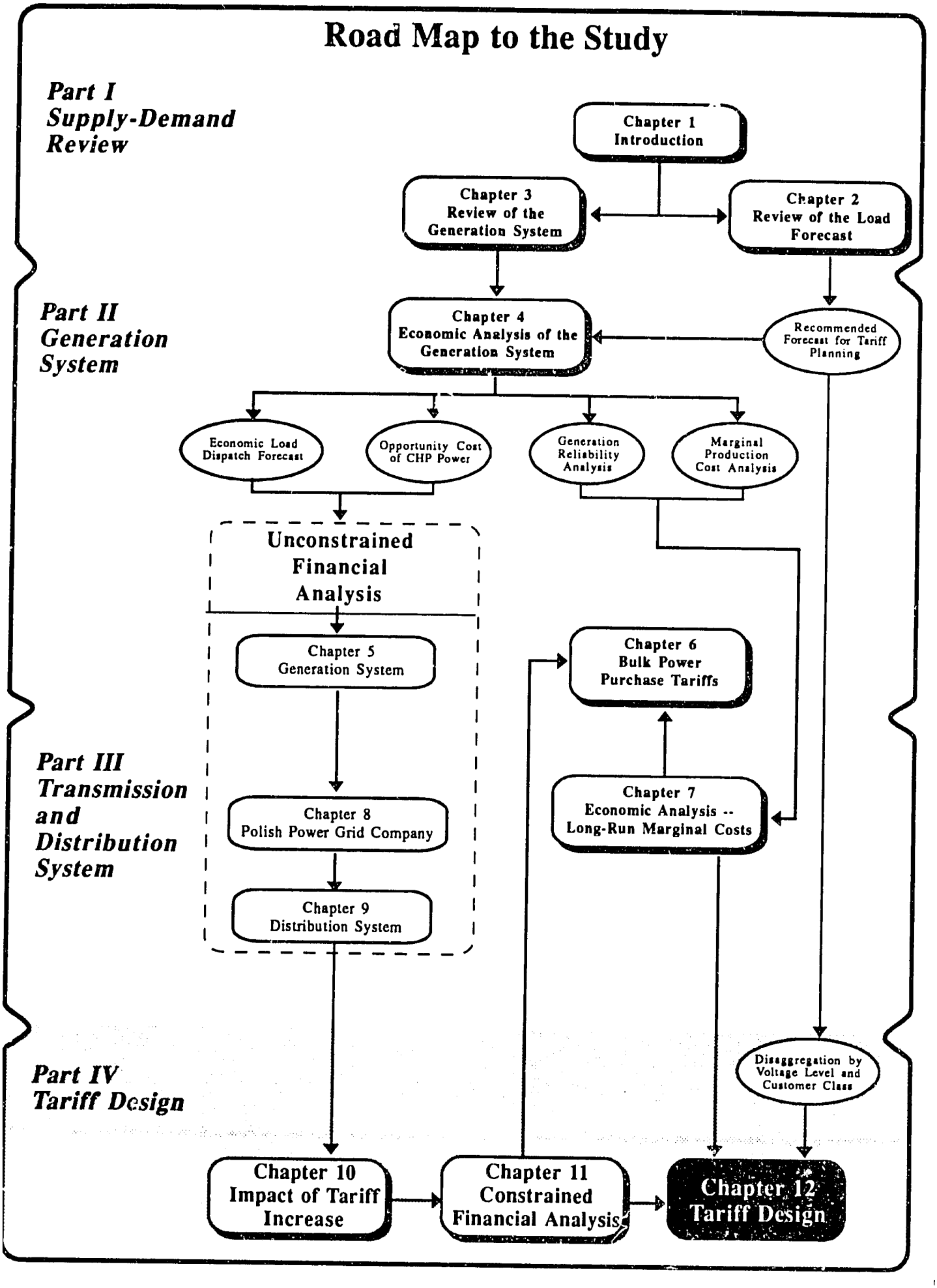
Exhibit 11–17
CASE 3
OPERATING AND FINANCIAL RATIOS – DISTRIBUTION COMPANIES

PRO–FORMA 1989	ACTUAL 1990	ACTUAL 1991	POLISH DISTRIBUTION COMPANIES Year End –– December 31	ESTIMATE 1992	FORECAST 1993	1994	1995	1996	1997
			SALES RATIOS						
19.942	213.444	353.994	Average Sales Tariff –– Zl/ Kwh	542.100	542.100	623.415	716.927	814.000	814.000
	135.258	221.677	Average Purchase Cost –– Zl/ Kwh	339.071	336.295	377.161	410.071	515.734	564.605
	–7.7%	–6.0%	Annual Sales Growth (Kwh) –– %	–1.4%	2.6%	2.9%	4.0%	2.6%	2.7%
	887.8%	55.9%	Annual Sales Growth (Zl) –– %	51.1%	2.6%	18.4%	19.6%	16.5%	2.7%
			OPERATING RATIOS						
	8.3%	11.6%	Distribution Losses – %	10.6%	9.9%	9.2%	8.4%	8.5%	8.5%
	63.4%	62.6%	Energy Purchase/ Sales –– %	62.5%	62.0%	60.5%	57.2%	63.4%	69.4%
5.4%	10.4%	8.4%	Operating Income/ Sales –– %	14.3%	12.5%	14.6%	19.2%	12.6%	3.8%
	3.4%	3.9%	Operating Income/ Net Assets –– %	20.0%	15.0%	15.1%	18.0%	10.8%	2.8%
	2.9%	3.4%	Net Income after Tax/ Equity –– %	7.5%	7.2%	6.6%	8.0%	5.2%	1.8%
			FINANCIAL RATIOS						
	1.3	0.8	Current Ratio	4.0	61.1	78.8	74.3	86.4	80.2
	7.2%	22.6%	Total Debt/ Equity –– %	11.1%	2.5%	1.8%	1.4%	1.1%	1.0%
			Self–Financing Ratio –– %		162.6%	113.3%	124.5%	114.0%	103.0%

Billions Zloty at Base Year Prices

RCG/HAGLER, BAILLY, Inc.
File Name g:\pol\report\exhibit\e11_15.wk1
30–Jun–93

Road Map to the Study



CHAPTER 12: TARIFF DESIGN

This chapter develops our recommendations for tariff restructuring. Section 12.1 presents a review and evaluation of existing tariffs in light of information on the long-run marginal cost (LRMC) structure and financial revenue requirements as determined in Chapters 7 through 9, respectively.

The tariff restructuring begins with a determination of individual tariff class revenue responsibilities in Section 12.2. This is followed by a presentation of the tariff structures for bulk electricity sales by PPGC to the distribution companies. Section 12.3 presents the uniform bulk sales tariff and Section 12.4 outlines illustrative bulk sales tariffs for tariffs differentiated for individual distribution companies. Section 12.5 presents "final sales" (retail) tariffs that recover class-specific revenue responsibility. Section 12.6 discusses optional tariffs recommended to PPGC and the distribution companies. Finally, Section 12.7 outlines other tariff clauses/provisions.

Throughout this chapter, we compare "current" tariff yields (i.e., based on price list No. 7-Z/92) with financial and economic costs of supply expressed in mid-1992 prices. To facilitate this comparison, the current yields are also restated at the levels of mid-1992.

12.1 REVIEW OF EXISTING TARIFF STRUCTURE AND LEVELS

All of PPGC's domestic bulk sales are to 33 independent distribution companies (DCs), which in turn resell electricity to final consumers. Tariffs to each company are adjusted to permit uniform national tariffs to these end-users. PPGC's average yield on bulk sales was 334.6 Zl/kWh in October 1992, and is estimated to be 381.4 Zl/kWh as of February 1993 (339.8 Zl/kWh at mid-1992 prices).

Exhibit 12-1 summarizes the retail tariff structure that came into effect on January 1, 1993 (No. 7-Z/92). The tariffs are based strictly on consumer service voltage, with time-of-day rate options offered for each class. Based on billed sales data for the first half of 1992, tariff "A" (High Voltage, 60 to 220 kV) represents approximately 31 percent of total sales. Tariff "B" (Medium Voltage, 1 to 60 kV) customers account for about 26 percent of total sales. All of these customers pay both demand and energy charges.

Tariff "C" (Low Voltage, below 1 kV) is divided into two classes. The first is customers with maximum demand above 40 kW or consumption over 80 MWh/year (tariff "C2"), which account for about 3 percent of total sales. The second is non-residential customers consuming

EXHIBIT 12-1

MAPPING OF CURRENT (No. 7 – Z/92) AND PREVIOUS (No. 7 – Z/91) TARIFF CLASSES

CURRENT RETAIL TARIFF (No. 7–Z/92)			equivalent to –>	PREVIOUS RETAIL TARIFF (No. 7–Z/92)		
Tariff	Customer Segment	% of Sales 1/		Tariff	Customer Segment	% of Sales 1/
A21	HV – All non–residential (demand, flat energy)	0.1%		A9 (3%)	HV Rail Transport	0.1%
A22	HV – All non–residential (demand, energy – 2 TOD)	1%		A2	HV Industry	1%
A23	HV – All non–residential (demand, energy – 3 TOD)	29%		A3	HV Industry	29%
B21	MV – All non–residential (demand, flat energy)	9%		A11	MV Industry	3%
				A9 (97%)	MV Rail Transport	5%
				E11	MV Commercial	1%
				F11	MV Large Farms	0.5%
B22	MV – All non–residential (demand, energy – 2 TOD)	10%		A21	MV Industry	9%
				E21	MV Commercial	0.3%
				F21	MV Large Farms	0.2%
B23	MV – All non–residential (demand, energy – 3 TOD)	7%		A31	MV Industry	7%
C21	LV – All non–residential (demand, flat energy)	2%		B1	LV Industry	2%
C22a,b	LV – All non–residential (demand, energy – 2 TOD)	1%		B2	LV Industry	1%
C11	LV – All non–residential (flat energy only)	10%		D	Street Lights	2%
				E1	LV Commercial	9%
C12a,b	LV – All non–residential (energy only – 2 TOD)	1%		E2	LV Commercial	1%
G11	LV – Residential/Small Farm (flat energy only)	23%		F1	Small Farms	5%
				G1	Residential	18%
G12	LV – Residential/Small Farm (energy only – 2 TOD)	6%		F2	Small Farms	3%
				G2	Residential	3%

1/ Based on sales data for the first half of 1992.

less than 40 kW or 80 MWh/year (tariff "C1"), which comprise approximately 11 percent of total sales. Only the former group is assessed a demand charge.

Residential and small farm customers (tariff "G") account for the remaining 29 percent of system retail sales.

Although the current tariff classes do not follow traditional customer classifications (industrial, commercial, residential, street lights, etc.), we know the composition of the current classes from the tariff structure that was in effect throughout 1992 (No. 7-Z/91). For comparison, these tariff groups are also shown in Exhibit 12-1. The current HV sales (tariff "A") are almost exclusively to industry, with a very small rail transport component. The MV sales (tariff "B") are also dominated by industry (19 percent of total sales), with lesser shares attributable to rail transport (5 percent), commerce (1 percent) and large farms (1 percent). LV sales above 40 kW (or 80 MWh/year) all also all industrial, accounting for 3 percent of final sales. LV sales below 40 kW are commercial (10 percent) and street lights (about 2 percent). Finally, LV residential sales (tariff "G") are predominantly to households (21 percent of total sales), with a significant small farm component (8 percent of total sales).

The data reveal the dominance of industry in the Polish economy. Approximately 52 percent of total final sales go to the industrial sector. Surprisingly, only 17 percent of all final sales are consumed by rail transport, commerce, and large agricultural consumers combined.

Exhibits 12-2 and 12-3 present the essential features of the retail electricity tariffs in effect today (No. 7-Z/92) and during the last quarter of 1992 (No. 7-Z/91).

12.1.1 Overall Assessment of Tariff Levels

From a resource allocation and purely economic efficiency point of view, tariffs should be set at parity to the economic cost of supply. In practice, other considerations must also be balanced. This means that any restructuring of tariffs should strive to bring tariffs at each voltage level in closer alignment with the true cost of supply. Therefore, as a starting point, it is useful to examine the efficiency implications of existing tariff levels vis-a-vis the marginal cost, as defined earlier in Chapter 7 and reproduced here in Exhibit 12-4.

At the PPGC level, the data highlight the fact that the estimated current yield (i.e., as of the February 1993 tariff increase) is 381.4 Zl/kWh (339.8 Zl/kWh at mid-1992 prices). By comparison, the economic cost of supply is 708.5 Zl/kWh (mid-1992 prices) and the 1994 financial revenue requirement (also at mid-1992 prices) has been estimated in Chapter 8 to be

EXHIBIT 12-2

Retail Tariffs Effective 10/1/1992 (No. 7 – Z/91)

Tariff Class	Service Voltage	Customer Segments	DEMAND CHARGE (Zl/KW/Month) Contract	Measured	Excess	ENERGY CHARGE (Zl/KWh) Flat	Peak	Off–Peak	Day	Night
A11	MV	Industry	15.970	30.030	159.700	440	–	–	–	–
A2	HV/MV	Industry	15.810	28.470	158.100	–	670	230	–	–
A21	HV/MV	Industry	15.970	30.030	159.700	–	620	210	–	–
A3	HV/MV	Industry	15.810	28.470	158.100	–	490	–	300	170
A31	HV/MV	Industry	15.970	30.030	159.700	–	490	–	270	150
A9	HV/MV	Transport	15.970	30.030	159.700	240	–	–	–	–
	HV/MV	Transport	15.970	–	159.700	330	–	–	–	–
B1	LV	Industry	17.390	39.530	173.900	470	–	–	–	–
B2	LV	Industry	17.390	39.530	173.900	–	940	290	–	–
D	LV	Street Lights	–	–	–	1180	–	–	–	–
	LV	Street Lights	–	–	–	830	–	–	–	–
E1	LV	Commercial	–	–	–	830	–	–	–	–
	LV	Commercial	–	–	–	770	–	–	–	–
E2	LV	Commercial	–	–	–	–	1140	410	–	–
E11	HV/MV	Commercial	17.390	39.530	173.900	400	–	–	–	–
E21	HV/MV	Commercial	17.390	39.530	173.900	–	650	210	–	–
F11	LV	Farms	13.279	27.100	132.800	400	–	–	–	–
F21	LV	Farms	13.279	27.100	132.800	–	480	210	–	–
R		Temporary	–	–	–	1130	–	–	–	–
F1, G1	LV	Residential/Sm Farms	–	–	–	700	–	–	–	–
F2, G2	LV	Residential/Sm Farms	–	–	–	–	–	–	810	320

EXHIBIT 12-3

Retail Tariffs Effective 1/1993 (No. 7 – Z/92)

Tariff Class	Service Voltage	Customer Segments	DEMAND CHARGE (Zl/KW/Month) Contract	Measured	Excess	Flat	ENERGY CHARGE (Zl/KWh) Peak	Off–Peak	Day	Night
A21	HV	All Non–Residential	10.000	29.000	50.000	410	–	–	–	–
A22	HV	All Non–Residential	10.000	29.000	50.000	–	655	350	–	–
A23	HV	All Non–Residential	10.000	29.000	50.000	–	655	–	355	180
B11	MV	All Non–Residential	–	–	–	650	–	–	–	–
B21	MV	All Non–Residential	11.000	30.000	55.000	415	–	–	–	–
B22	MV	All Non–Residential	11.000	30.000	55.000	–	705	350	–	–
B23	MV	All Non–Residential	11.000	30.000	55.000	–	705	–	385	200
C21	LV>40kW	All Non–Residential	12.100	40.000	60.500	640	–	–	–	–
C22a	LV>40kW	All Non–Residential	12.100	40.000	60.500	–	960	520	–	–
C22b	LV>40kW	All Non–Residential	12.100	40.000	60.500	–	–	–	650	360
C11	LV<40kW	All Non–Residential	–	–	–	930	–	–	–	–
C12a	LV<40kW	All Non–Residential	–	–	–	–	1150	530	–	–
C12b	LV<40kW	All Non- Residential	–	–	–	–	–	–	1040	400
R		Temporary Service	–	–	–	1230	–	–	–	–
G11	LV	Residential/Sm Farms	–	–	–	785	–	–	–	–
G12	LV	Residential/Sm Farms	–	–	–	–	–	–	925	340

EXHIBIT 12-4

STRICT LONG RUN MARGINAL COST BASED TARIFF BY TARIFF CLASS – BULK

TARIFF CLASS	SERVICE VOLTAGE	COINCI-DENCE	LOAD FACTOR	ENERGY SHARES PEAK	MID-PEAK	TOTAL MARGINAL COST/MONTH CAPACITY tysZl/KW	ENERGY tysZl/KWh	TOTAL tysZl/KWh	DEMAND CHARGE SHARE	H1/1992 SALES GWh	CURRENT YIELD tysZl/KWh
DISTRIBUTION COS.	HV	1.00	0.65	0.20	0.28	121.10	0.4533	0.7085	36%	50434	0.3398
BULK SYSTEM AVERAGE				0.20	0.28	121.10	0.4533	0.7085		50434	0.3398
Equivalent tysZl/KWh						0.2552	0.4533	0.7085			
% of System Average						36%	64%	100%			

STRICT LONG RUN MARGINAL COST BASED TARIFF BY TARIFF CLASS – RETAIL

TARIFF CLASS	SERVICE VOLTAGE	COINCI-DENCE	LOAD FACTOR	ENERGY SHARES PEAK	MID-PEAK	TOTAL MARGINAL COST/MONTH CAPACITY tysZl/KW	ENERGY tysZl/KWh	TOTAL tysZl/KWh	DEMAND CHARGE SHARE	H1/1992 SALES GWh	CURRENT YIELD tysZl/KWh
INDUSTRIAL	HV	0.81	0.60	0.16	0.27	98.09	0.4354	0.6594	34%	14090	0.3874
	MV	0.63	0.42	0.18	0.31	117.62	0.4652	0.8488	45%	8884	0.4995
	LV	0.54	0.31	0.18	0.31	154.27	0.5203	1.2020	57%	1334	0.7828
TRACTION	HV	0.93	0.48	0.19	0.30	112.62	0.4534	0.7748	41%	67	0.4606
	MV	0.93	0.48	0.19	0.30	173.63	0.4671	0.9627	51%	2178	0.4715
COMMERCIAL	MV	0.63	0.49	0.20	0.32	117.62	0.4755	0.8044	41%	641	0.4934
	LV	0.55	0.30	0.20	0.32	157.13	0.5323	1.2498	57%	4464	0.7745
AGRICULTURAL	MV	0.54	0.38	0.20	0.32	100.82	0.4755	0.8390	43%	320	0.5287
RETAIL	LV	0.49	0.25	0.27	0.25	139.99	0.5479	1.3150	58%	13616	0.6310
ST. LIGHTING	LV	1.00	0.50	0.21	0.04	285.69	0.4659	1.2486	63%	742	0.7884
DISTRIBUTION COMPANY AVERAGE				0.20	0.28	128.31	0.4888	0.9879		46336	0.5421
Equivalent tysZl/KWh						0.4991	0.4888	0.9879			
% of System Average						51%	49%	100%			

367.0 Zl/kWh. At the retail (final sales) level, the estimated current yield (as January 1993) is 621.9 Zl/kWh (542.1 Zl/kWh at mid-1992 prices), the strict economic cost of supply is 987.9 Zl/kWh, and the financial revenue requirement in 1994 (mid-1992 prices) has been estimated to be 623.4 Zl/kWh. These data reveal a financial subsidy for all final sales on the order of Zl 7.5×10^{12} per year, or equivalently, about US $0.6 billion per year at an exchange rate of 13,400 Zl/US$.

The economic subsidy -- measured as the difference between current yield and LRMC -- for all final sales is on the order of Zl 4.1×10^{13} per year, or equivalently, about US $3.0 billion per year. The incidence of these subsidies is widespread, with the most extreme case of distortions to be found among low-voltage customers, in particular tariff class "G" (including residential and small farm users).

Generally speaking, it is not prudent economic policy or financial policy to price electricity -- or for that matter, any other good or service -- such that a very high percentage of customers and sales are subsidized substantially. Any subsidies received by one customer segment must be made up by charging more than otherwise necessary to another customer segment. This distorts the price signals to all customers. Those who are being subsidized will not make efficient consumption decisions because the price they pay is lower than the cost to the nation for providing the service. Additionally, efficiency losses occur because others must pay more. This distorts their consumption levels and patterns as well, and creates the potential for significant distortionary impacts economy-wide due to resource and capital mis-allocation.

12.1.2 Tariff "G" - Residential

The residential tariff includes domestic sales (formerly, tariffs "G1" and "G2") and small farms (formerly served under tariffs "F1" and "F2"). Larger farms (formerly, tariffs "F11" and "F21") are served under a separate low-voltage tariff discussed later. Tariff "G" also includes group accommodation facilities, such as dormitories, schools, etc.

The residential tariff structure is a flat energy charge for all kWh (tariff "G11"). As an option, a day/night time-of day (TOD) tariff ("G12") is available. The estimated average yield (as of January 1993) is 744.4 Zl/kWh (631.0 Zl/kWh at mid-1992 prices), as compared to an economic cost of supply of 1,315.0 Zl/kWh and a revenue-neutral LRMC of 828.9 Zl/kWh. At current sales levels, these numbers imply a financial subsidy of about Zl 5 trillion per year and an economic subsidy of about Zl 18 trillion per year. The tariff represents about 75 percent of the financial cost of supply and about 50 percent of the economic cost.

The TOD tariff option divides the day into high price hours (14 hours/day, to be specified by each distribution company) and low price hours (the remaining 10 hours/day, including two mid-day valley hours). The tariffs for these two rating periods are 925 and 340 Zl/kWh, respectively.

Single-block residential tariff structures as employed in Poland are truly laudatory. Far more common in other countries are increasing block tariffs designed to facilitate cross-subsidies between and among different customer groups. We have specifically not considered such options in the present study because of PPGC's (and the Polish Government's) stated objective to avoid any subsidies in the provision of electricity service.

Chapter 11 argues that electricity costs do not impose (on average) a disproportionate burden on the consuming public. Nevertheless, the concern has been expressed that electricity costs represent a higher share of low-income household budgets. One option for dealing with this concern is to design a multi-block tariff which, in effect, provides a cross-subsidy from rich to poorer residential consumers. While this option is not being recommended at this time, it is discussed briefly in the following analysis of residential bill frequency.

12.1.3 Bill Frequency Analysis of the Residential Tariff

The bill frequency analysis (BFA) utilizes historical customer billing records to develop two summary characteristics.[1] The BFA provides estimates of the distribution of bills by consumption level, e.g., the fraction of all bills rendered that had a billed consumption level of 50 kWh or less per month. The BFA also estimates the distribution of sales, e.g., the fraction of all sales accounted for up to the 50 kWh per month consumption block. This analysis provides useful insights for tariff block sizing and in simulating future revenues from new tariff structures.

The BFA uses a concept called the "consolidated factor." This factor distinguishes between the two components of sales at any particular interval, and is estimated as the sum of all kilowatt-hours in bills rendered from zero consumption up to that interval but only up to that interval. Consider, for example, the sales in kilowatt-hours at 100 kWh per month. A portion of the sales at 100 kWh is made up of the sum of all kilowatt-hours in bills rendered under that

[1] We have not prepared a separate BFA for this study. Rather, we have relied on a study regularly prepared by the Polish Energy Information Center.

amount. The second portion of the consolidated factor is 100 kWh in every bill rendered in excess of the 100 kWh.

The profiles of bills rendered and sales of electrical energy to all residential customers are shown in Exhibit 12-5. The data aggregate sales and bills for tariff 7-Z/91 classifications "G1," "G2," "F1," and "F2."

Exhibit 12-5
Residential Bill Frequency: Tariff Classes G1, G2, F1, F2

Sales Interval (kWh/month)	Cumulative Percent of Bills	Cumulative Percent of Sales (kWh)
0	0.00%	0.00%
83	36.18%	10.77%
167	69.90%	34.49%
250	83.46%	50.08%
333	89.25%	59.57%
417	92.60%	66.63%
667	97.12%	79.80%
833	98.28%	84.61%
1,667	99.69%	93.19%
2,500	99.88%	95.21%
4,167	99.95%	96.58%
8,333	99.99%	97.57%
83,333	100.00%	100.00%

Note: Zero bills not estimated.

The median points of bills rendered to customers (the point at which 50 percent of the bills are rendered over and 50 under) is approximately 115 kWh per month. The median point of sales in kilowatt-hours per month is about 250 kWh per month. The significance of the chart can be further understood by reviewing the characteristics of sales to residential customers at several intervals.

The billing data indicate that there are about 10,000 bills rendered over 2,500 kWh per month. This is a high number, even after considering that group accommodation facilities are included within this tariff. We suggest that an exception report should be prepared identifying these very large accounts to ensure that they are not misclassified commercial accounts.

Under the present tariff structure, the price of electricity in the residential tariff is much lower than in tariff "C1" (LV < 40 kW). Thus, it is more advantageous for low-voltage commercial customers to be classified as residential. While we do not know the extent (if any) of such misclassification, it is a common problem in other countries. Ultimately, any incentive for strategic misclassification on the part of a large customer can be eliminated by making the price for non-residential customers less than or equal to that of the residential customers. The economic cost structure supports this realignment of tariff levels.

As noted above, it would be possible to "soften" the shock of required residential tariff increases by developing a three-block tariff. The first, subsidized block, would include only electricity consumption associated with basic needs. To illustrate, this block might be set at 83 kWh/month (1,000 kWh/year). The BFA indicates that approximately 36 percent of all bills are rendered at or below this level, and that approximately 11 percent of all sales are billed at this level (including customers that consume more than 83 kWh/month). A second block, including the largest share of sales and bills, would be billed at the revenue-neutral LRMC. Finally, a tail block of high-consumption customers (e.g., over 667 kWh/month, or 8,000 kWh/year, representing only about 1.6 percent of all bills, but nearly 15 percent of all sales) would be charged strict LRMC, cross-subsidizing the low-income consumers. Of course, the structuring of such an option would require more detailed revenue analysis, but in our opinion, the option is far better than a more broadly based residential subsidy.

The argument for this tariff structure is, of course, that high subsidy levels place an unfair burden on other consuming sectors of the economy. Electricity is an expensive good in that it requires substantial commitments of the nation's productive resources. Thus, subsidies, if necessary, should be confined solely to the poorest of the poor.

The disadvantage of a three-block tariff is that, once established, utilities in other countries have found it very hard to eliminate. Thus, we would only consider this option if the burden

imposed by an "unblocked" structure is considered "unfair" or politically unacceptable. Based on the analysis in Chapter 11, we do not recommend a blocked residential tariff.

The policy of providing free electricity to employees at all levels of the power system (the so-called "Energy Worker's" tariff) is inconsistent with the goal of economic efficiency pricing. This practice should be eliminated. The subsidy is significant in financial as well as economic terms; the average current yield (based on today's tariffs (7-Z/92) applied to sales data for the first half of 1992) for the residential class is 744.4 Zl/kWh without the subsidy and 723.2 Zl/kWh when the energy workers' consumption is included, nearly a 3 percent decrease.

Of course, the subsidy cannot simply be eliminated, since "free" electricity is a component of current income for these workers. Rather, a special wage/salary increase should be provided to every worker based on an equitable estimate of the "market value" of this subsidy. Then, the subsidy should be eliminated. Workers will then have the option of continuing to consume energy at their present rate (i.e., no change in current electricity consumption or net income), or they may choose to reduce consumption and apply the increased income to other needs.

12.1.4 Tariff "A" - High Voltage

This new class includes all high-voltage customers, formerly served under HV industrial classes "A2" and "A3." It also includes a very small portion of traction consumption (3 percent of former class "A9"). The class accounts for approximately 30 percent of total sales. The structure of current tariffs parallels that of classes "B" and "C2" discussed above (see Exhibit 12-1).

The current yield (January 1993) from this tariff is estimated to be 457.4 Zl/kWh, (387.7 Zl/kWh at mid-1992 prices) as compared to the economic cost of 659.9 Zl/kWh and a revenue-neutral LRMC of 416.4 Zl/kWh.

Customers pay both a demand charge and energy charge. The basic demand charge has three components -- a contract charge, a measured demand charge, and a penalty of five times the contract rate if measured demand exceeds the contracted demand level. Effective January 1993, the demand charges are 10,000 Zl/kW/month for contract demand and 29,000 Zl/kW/month for measured demand. The basic tariff offers a flat energy charge, currently 640 Zl/kWh. As with other non-residential tariff classes, two optional and three time-of-day energy structures are offered (peak/off-peak, and peak/off-peak(day)/off-peak(night). These tariffs are summarized in Exhibit 12-3.

12.1.5 Tariff "B" - Medium Voltage

This new class includes all medium-voltage customers, formerly served under separate MV classes for industry ("A11," "A21," "A31"), traction (97 percent of "A9"), commercial ("E11," "E21," "F11," "F21"). The class accounts for approximately 26 percent of total sales.

In terms of structure, tariff "B" rates largely parallel the class "A" tariffs described above. They incorporate slightly higher demand charges and energy charges. Optional TOD rates are offered. The actual tariffs are summarized in Exhibit 12-1. The current yield (January 1993) from this tariff is estimated to be 583.8 Zl/kWh (494.9 Zl/kWh at mid-1992 prices), as compared to the economic cost of 866.8 Zl/kWh and a revenue-neutral LRMC of 547.0 Zl/kWh.

12.1.6 Tariff "C2" - Low Voltage > 40 kW

This class includes all non-residential low-voltage customers with maximum demand greater than 40 kW and annual consumption above 80 MWh. This new tariff class is composed predominantly of smaller-sized industrial customers formerly served under tariffs "B1" and "B2."

In terms of structure, tariff "C2" rates parallel the class "A" tariffs described above, albeit at higher rate levels. The basic demand charge (effective January 1993) is 12,100 Zl/kW/month for contract demand and 30,000 Zl/kW/month for measured demand. The basic tariff offers a flat energy charge, currently 640 Zl/kWh. As with tariff "C1," two optional TOD structures are also available for the energy charge (see Exhibit 12-1).

The current yield (January 1993) from this tariff is estimated to be 923.5 Zl/kWh (782.8 Zl/kWh at mid-1992 prices), as compared to the economic cost of 1,202.0 Zl/kWh and a revenue-neutral LRMC of 758.5 Zl/kWh. At current sales levels, these numbers imply no financial subsidy, but they suggest an economic subsidy on the ordr of Zl 1,100 billion per year.

The economic and financial costs of supply are high due to a very low observed load factor among these smaller industries. For example, the load factor for October 1992 was 0.30, and for all of 1991 it was only 0.29. For a customer on this rate with a monthly load factor of 0.30, the demand charge currently represents about 30 percent of his average monthly bill. By contrast, the economic cost structure indicates that this share should be over 60 percent.

It is sometimes suggested that preferential treatment to industrial customers may be justified in order to stimulate industrial growth. Government interventions of this nature -- even though they may be well intentioned and welcome as far as the beneficiaries are concerned -- ultimately distort the tariff for all customers and lead, on net, to more efficiency losses than can be offset by any gains to the recipients of the subsidy.

12.1.7 Tariff "C1" - Low Voltage < 40 kW

This class includes all non-residential low-voltage customers with maximum demand of less than 40 kW and annual consumption below 80 MWh. As noted in Exhibit 12-1, this new tariff class is composed predominantly of small to medium-sized commercial customers formerly served under tariffs "E1" and "E2." It also includes street lighting (formerly tariff "D").

The basic tariff is a flat energy charge, currently 930 Zl/kWh. Two optional structures are also available, charging either different peak/off-peak or day/night rates.

The current yield (January 1993) from this tariff is estimated to be 913.6 Zl/kWh (774.5 Zl/kWh at mid-1992 prices), as compared to the economic cost of 1,249.8 Zl/kWh and a revenue-neutral LRMC of 788.6 Zl/kWh. At current sales levels, these numbers imply only a modest financial subsidy, but they indicate an economic subsidy of Zl 4.2 trillion per year.

12.2 REVENUE RESPONSIBILITY BY TARIFF CLASS

The financial analysis in Chapters 8 and 9 (and subsequent sensitivity analyses) specify the average revenue requirements for PPGC, the distribution companies, and for all final system sales. These requirements for 1994 and the corresponding implications for percentage increases that could be required are summarized in the following table.

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	1994 Financial Revenue Requirement		
	1994 Target Yield (mid-92 Zl/kWh)*	Est. Current Yield (mid-92 Zl/kWh)	Increase Required (%)
PPGC	376.0	339.8	11%
DCs	623.4	542.1	15%

* based on the most likely "constrained" financial scenario developed in Chapter 12.

The class revenue responsibility analysis as well as the subsequent tariff design described in the remainder of this chapter are carried out in real terms (at mid-1992 prices). Although tariffs are being designed for 1994, uncertainty regarding domestic inflation and the Zloty:US$ exchange rate make it appropriate to conduct the analysis in constant prices.

The above data show that on a total final sales basis, the financial revenue requirement of 623.4 Zl/kWh for 1994 implies an average ***real*** tariff increase of approximately 15 percent. The procedure employed for tariff design is to allocate this revenue requirement to each tariff class, thereby defining the revenue responsibility for each class, and then to design specific tariffs for each class to match the revenue responsibility.

Exhibit 12-6 summarizes revenue responsibility by tariff class -- bulk and final sales -- based strictly upon the relative LRMC structure. The table shows current yield, strict LRMC, and revenue neutral LRMC, and finally, revenue responsibility for each tariff class. The "revenue neutral" LRMC is simply the strict LRMC scaled (on a class sales-weighted basis) to exactly collect the financial revenue requirement.

For PPGC sales, the revenue-neutral LRMC implies, for example, that the average price (yield) from PPGC sales to all distribution companies must be increased from 339.8 Zl/kWh (mid-1992 prices) to 376.0 Zl/kWh, an 11 percent increase. At the retail level, the revenue-neutral LRMC implies a ***real*** average price (yield) increase of 31 percent for residential customers (from 631 0 Zl/kWh today to 829.8 Zl/kWh), and considerably smaller increases for all other tariff classes. On a total final sales basis, the average increase required is about 15 percent.

The class revenue responsibilities in Exhibit 12-6 (the last two columns) are designed to incorporate adjustments to the class revenue-neutral LRMCs, if necessary. Possible

EXHIBIT 12-6

REVENUE RESPONSIBILITY BY CUSTOMER/TARIFF CLASS – BULK

BILLING YEAR	1994
TOTAL GRID SALES (GWh)	109072
REVENUE REQUIREMENT	
TOTAL (tysZl MILLION)	41011
AVERAGE (tysZl/KWh) 1/	0.3760

CUSTOMER/ TARIFF CLASS	H1/1992 SALES GWh	CURRENT YIELD2/ tysZl/KWh	STRICT LRMC3/ tysZl/KWh	REVENUE NEUTRAL STRICT LRMC tysZl/KWh	% CHNG	REVENUE RESPONSIBILITY tysZl/KWh	% CHNG
DISTRIBUTION COS.	50434	0.3398	0.7085	0.3760	11%	0.3760	11%
TOTAL BULK	50434	0.3398	0.7085	0.3760	11%	0.3760	11%

1/ Approximate revenue target for 1994.
2/ Estimated average current yield after tariff increase of Q1/1993, in mid – 1992 prices.
3/ Escalated to 1994 prices, a 0.00% increase.

REVENUE RESPONSIBILITY BY CUSTOMER/TARIFF CLASS – RETAIL

BILLING YEAR	1994
TOTAL GRID SALES (GWh)	100441
REVENUE REQUIREMENT	
TOTAL (tysZl MILLION)	62615
AVERAGE (tysZl/KWh) 1/	0.6234

CUSTOMER/ TARIFF CLASS		H1/1992 SALES GWh	CURRENT YIELD2/ tysZl/KWh	STRICT LRMC3/ tysZl/KWh	REVENUE NEUTRAL STRICT LRMC tysZl/KWh	% CHNG	REVENUE RESPONSIBILITY tysZl/KWh	% CHNG
"A"	HV	14157	0.3877	0.6599	0.4164	7%	0.4164	7%
"B"	MV	12023	0.4949	0.8668	0.5470	11%	0.5470	11%
"C" (>40 kW)	LV	1334	0.7828	1.2020	0.7585	–3%	0.7585	–3%
"C" (<40 kW)	LV	4464	0.7745	1.2498	0.7886	2%	0.7896	2%
RETAIL	LV	13616	0.6310	1.3150	0.8298	31%	0.8298	31%
ST. LIGHTING	LV	742	0.7884	1.2486	0.7879	0%	0.7879	0%
TOTAL DC RETAIL		46336	0.5421	0.9879	0.6234	15%	0.6234	15%

1/ Approximate revenue target for 1994.
2/ Estimated average current yield after tariff increase of Q1/1993, in mid – 1992 prices.
3/ Escalated to 1994 prices, a 0.00% increase.

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adjustments might include, for example, 1) moderating to the extent possible a burdensome rate increase to the residential tariff, or 2) avoiding any bill increases that may be perceived as "unfair" in an intra-class comparison (e.g., no class should receive a tariff decrease when others are facing large increases).

In our analysis, we have concluded that the revenue-neutral LRMCs do not place an unfair burden on any particular class, and therefore no special adjustments have been made. The class revenue responsibilities shown in Exhibit 12-6 imply average yield adjustments ranging from a slight decrease for large commercial customers (tariff "C2") to the 31 percent increase for residential customers (tariff "G") noted above.

12.3 BULK/PPGC TARIFF DESIGN

This section develops the proposed tariff structures and levels for bulk sales-for-resale by PPGC to the distribution companies.

Revenue requirement targets for this analysis were developed as described in the financial analysis of Chapters 8 and 9, and the sensitivity analyses of Chapter 11. Economic efficiency considerations in developing the proposed tariff revision were based on: 1) estimates of LRMC obtained as described in Chapter 7, and 2) insights obtained from the analysis of existing tariffs as described in the preceding section.

At present, PPGC sells electricity to each distribution company based on a two-component energy tariff. Distributors are charged for (i) electrical energy ordered and (ii) electrical energy consumed. The former charge approximates a capacity charge (i.e., it is related to the fixed costs of producers providing capacity to supply ordered energy). The payment for ordered energy includes a penalty factor to encourage the "exactness" of the order, much like a penalty for exceeding contracted demand. The latter charge recovers the variable cost of energy actually consumed in the system; this charge is the same for all kWh sold to distributors. Optional settlement procedures based on coincident demand and TOD energy sales are also available for distributors that have the appropriate measuring equipment.

The sale price is set such that a company can recover its costs (including any permitted return) while re-selling electricity to final customers in its service territory at fixed national tariffs. The current (as of February 1993) average bulk tariff for all distribution company sales is 381.4 Zl/kWh (339.8 Zl/kWh at mid-1992 prices), as shown in Exhibit 12-6. As of 1994, PPGC plans to sell to all distribution companies on the basis of the two-component energy tariff or an optional coincident demand/TOD tariff, and permit end-user tariffs to be set by

each company subject to regulatory approval. Section 12.4 explores the implications of this change to three different types of distribution companies.

PPGC's objective should be to sell every kWh on a mandatory time-of-day (TOD) tariff. This tariff might include a separate demand charge, or the capacity costs may be incorporated into TOD energy tariffs. Due to the large number of delivery points, it will take some time to alter the current structure. Nevertheless, it should be possible to proceed in a phased manner to procure and install TOD meters at each delivery point within the next three years, i.e., by year-end 1996.

Section 12.5 describes the philosophy behind the recommended TOD tariff design with regard to retail tariffs; these assumptions are not repeated here. The following table presents a menu of acceptable options for bulk tariffs, based on the marginal cost structure and scaled to the current PPGC revenue requirement of 376 Zl/kWh (see Exhibit 12-6).

PPGC Bulk Sales Tariff		Demand (Z/kW/mo)	Energy (Zl/kWh)		
Option	Season		Peak	Mid-Peak	Off-Peak
Bulk-23	Winter	32.840	681	337	188
	Summer	29.870	503	441	199
Bulk-22	Winter	32.840	446		188
	Summer	29.870	438		199
Bulk-21	Winter	32.840	307		
	Summer	29.870	313		
Bulk-13	Winter	-	842	498	188
	Summer	-	649	587	199
Bulk-12	Winter	-	586		188
	Summer	-	569		199
Bulk-11	Winter	-	376		
	Summer	-	376		

Note: Tariffs based on coincident demand.

The two-part tariff (i.e., both demand and energy charges) designs recover network capacity costs through demand, while generation capacity costs are incorporated in the energy rates.

(The rationale for this breakdown is discussed in Section 12.5.) The pure energy tariffs, of course, recover all capacity costs through TOD energy.

One problem with the tariff structures proposed is that they violate a basic tenet of marginal cost pricing, i.e., that the charge during any hour of the day should not fall below the strict marginal cost of off-peak energy. This result follows from the very low consolidated revenue requirement ("constrained" scenario 3) of PPGC in relation to the level of strict marginal costs. When strict marginal costs are allocated to appropriate rating periods and then scaled to the revenue requirement (376 Zl/kWh), off-peak energy charges fall below their desired minimum. On the other hand, if they are maintained at the value of off-peak energy, the differential between peak and off-peak energy diminishes significantly to prevent over-collection of revenue. On balance, we chose to preserve the appropriate peak/off-peak signals; the strict marginal energy cost is collected during both peak and mid-peak rating periods.

Having noted our strong preference for coincident demand metering or TOD rates which incorporate capacity costs, we recognize that metering constraints may delay the adoption of the proposed tariff structures. In the interim, it is proposed to maintain the present tariff design -- i.e., a pure energy tariff with its capacity (ordered energy) and energy components -- but adjust the levels upwards to ensure that designated revenue responsibilities are attained. Further, it would be unfair to impose TOD tariffs on distribution company purchases until the companies have the right to bill end-users on the same basis.

12.4 EFFECT OF UNIFORM BULK TARIFFS ON DISTRIBUTION COMPANIES

In order to evaluate the effect of uniform bulk sales tariffs on individual distribution companies and, in general terms, on retail tariffs, we studied three very different distribution companies. ZE Glivice serves a heavily industrialized area, with approximately two-thirds of final sales at high or medium voltage. ZE Warszawa covers a more balanced territory, with a mix of customer groups. Finally, ZE Bialystok serves a relatively rural area, with nearly half of all the company's customers in the residential tariff class (including small farms). These three companies currently account for about 13 percent, 5 percent, and 2.5 percent of all distribution company final sales, respectively. Relative sales by tariff class are shown in the following table:

Tariff Class	Percent of Sales by Tariff Class *			
	All Distributors	ZE Glivice	ZE Warszawa	ZE Bialystok
"A"	31%	58%	19%	1%
"B"	26%	19%	29%	29%
"C2" > 40 kW	3%	2%	4%	4%
"C1" < 40 kW	10%	5%	16%	14%
Street Lights	2%	1%	-	3%
"G"	29%	15%	32%	49%
TOTAL	100%	100%	100%	100%

* Based on sales data for January through May, 1992

The national long run marginal cost structure (see Chapter 5) was applied to each company based on the above sales shares by tariff class and company-specific revenue requirements for 1994. Average strict LRMC and revenue neutral requirements vary widely among the three companies:

	Retail Strict LRMC (Zl/kWh)	Revenue Requirement * (Zl/kWh)
ZE Glivice	842	777
ZE Warszawa	1044	906
ZE Bialystok	1160	1245
All Distributors	988	785

* Based on "no increase in net borrowing" criterion. The revenue requirements are taken from the financial analysis of distribution companies presented in Chapter 9, i.e., the unconstrained financial analysis, which tends to magnify the dispersion of revenue requirements across companies.

On a tariff class basis, revenue-neutral strict LRMC's are reasonably close to the consolidated average for two of the three companies, as reported in the following summary:

Tariff Class	Revenue-Neutral Strict LRMC by Tariff Class			
	All Distributors	ZE Glivice	ZE Warszawa	ZE Bialystok
"A"	524	609	573	714
"B"	689	795	749	918
"C2" > 40k	955	1109	1043	1291
W	993	1153	1085	1342
"C1" < 40k	1045	1213	1141	1412
W	992	1152	1084	1341
"G"				
St. Lights	785	777	906	1245
Average				

For ZE Glivice and ZE Warszawa, revenue-neutral LRMCs by class are within 10 to 15 percent of the consolidated average. The class LRMCs are much higher for ZE Bialystok, but this result is not surprising given this rural distributor's extremely high revenue requirement in comparison with the consolidated system. The data suggest that the effect of a uniform bulk tariff on final consumers will be relatively small in most cases.

Of course, these results could be revised (higher or lower) if detailed company-specific data were considered (e.g., more accurate distribution investment program, load research detailing class coincidence factors, load factors, and TOD energy shares. We do not believe, however, that these revisions would significantly alter our conclusion.

12.4.1 Implications Final Sales Tariff-Setting

Since it is planned that distribution companies purchase electricity based on uniform bulk tariffs by 1994, these companies may be faced with the need to develop their own end-use tariffs to recover company-specific revenue requirements. While the electricity sector wants to establish free and competitive markets, it also wants to encourage pricing based on

principles of economic efficiency. How will distribution companies be able to achieve both goals, given no experience and limited staff expertise regarding marginal cost pricing?

We propose that each distributor should be given two options for end-user tariff-setting:

1) Distributors will be permitted to adopt the national structure of marginal costs by class (defined in Section 12.5 and in Exhibits 12-4 and 12-6), appropriately adjusted by company-specific weights (i.e., sales by class) and scaled to the company's own financial revenue requirements. The preliminary analysis reported above suggests that end-user tariffs in different distribution companies would (in general) vary within an acceptable range if this method were applied. At the same time, required revenues would be collected based on a Poland-specific estimate of marginal cost structure. While a clear simplification, the argument for employing this approximation of class tariffs is that it is fast, low cost, and based (at the national level) or an accepted methodology.

2) If, however, the results of the foregoing calculation are not acceptable to a distributor, or the results derived differ from national average class tariffs by more than ± 20 percent, the company should be required to prepare (or have prepared) its own marginal cost analysis as a basis for setting tariffs. Given the probable lack of expertise within the company, one option would be to train one or two Polish consulting teams (e.g., at Energoproject and/or the Institute of Power Engineering) to conduct these studies based on a standardized methodology. This approach would help to assure consistency of results among studies for different distributors.

12.5 FINAL SALES TARIFF DESIGN

This section discusses the proposed restructuring of tariffs for all sales made by distribution companies, given the individual class revenue responsibilities developed in Section 12.2. The discussion proposes many separate time-of-day (TOD) tariff options. The general philosophy employed in setting these rates is discussed first, followed by the specific tariff designs.

12.5.1 TOD Rate Design Philosophy

Specific seasonal and weekly rating periods identified for this study are:

Summer (May - October):

peak (7pm-10pm weekdays), mid-peak (7am-1pm weekdays), off-peak (all other hours)

Winter (November - April):

peak (4pm-9pm weekdays), mid-peak (7am-1pm weekdays), off-peak (all other hours)

Our basic approach for developing a TOD tariff is summarized in Exhibit 12-7. (For the purposes of this exhibit and the subsequent discussion, "peak hours" refers to both the peak and mid-peak periods of the week). This approach is appropriate for a power system such as that in Poland, where there is a relatively broad peak period and with relatively small seasonal variations in the cost structure.

12.5.2 Basis for Peak and Off-Peak Energy Charges

The strict marginal cost of energy in the peak and off-peak periods is obviously the basis for the energy charge. Other charges (capacity costs) may also be incorporated into the energy price, and these costs must be adjusted to reflect the class revenue responsibility. In no case, however, should a customer be charged less than the off-peak cost of energy, since it represents a minimum variable cost.

In addition, the portion of the marginal cost of generation capacity allocated by LOLP to the off-peak period must be spread across all kWh in that period.

Whether other capacity costs should be collected through a demand charge or TOD energy charges depends on whether 1) a coincident demand charge (i.e., one that is measured only in

Exhibit 12-7
Allocation of Marginal Cost Components for TOD Rate Design

Marginal Cost Component	Demand Charge	Peak Energy Price	Off-Peak Energy Price
A. 2-part tariff (demand and energy)			
1. Strict marginal energy cost (not to be adjusted)	--	X	X
2. Coincident demand charge (i.e., on maximum kW in peak hours only)			
a. marginal cost of generation capacity	LOLP-based allocation to peak period. Recovered through energy or demand charge.		LOLP-based
b. marginal cost of network capacity - transmission (VHV, HV) cost	100% recovery through energy charge or demand charge		--
- distribution (MV, LV) cost	--	X	X
3. Simple maximum demand charge (i.e., on maximum kW in all hours)			
a. marginal cost of generation capacity	--	LOLP-based	LOLP-based
b. marginal cost of network capacity - transmission (VHV, HV) cost	100% recovery, preferably through energy charge		--
- distribution (MV, LV) cost	Either 100% in demand charge or recovered fully through peak and off-peak energy charge.		
B. Pure energy tariff (no demand charge)			
1. Marginal energy cost	--	On-peak strict marginal energy cost	Off-peak strict marginal energy cost
2. Marginal capacity costs a. marginal cost of generation capacity	--	LOLP-based share of generation capacity cost	LOLP-based share of generation capacity cost
b. marginal cost of network capacity - transmission (VHV, HV) cost	--	100% recovery through energy charge	
- distribution (MV,LV) cost	--	Recovery spread equally across all kWh in peak and off peak periods	

the peak period), or 2) a simple maximum demand charge (i.e., one that is based on the maximum kW in any hour of the month) is used.

If a ***coincident demand charge*** is applied:

a) the portion of the marginal cost of generation capacity allocated to the peak hours can be recovered through a separate demand charge or through the energy charge. On a system with a broad peak period, recovering these costs through the separate demand charge may be preferable. Often, however, the use of an energy charge is understood better than the use of a demand charge.

b) the marginal cost of network capacity associated with transmission (VHV and/or HV) can be properly recovered through either the peak energy charge or the demand charge. It is assumed that these costs are related to serving peak, and should not be borne by off-peak use.

c) it is desirable that the marginal cost of network capacity related to distribution (MV and/or LV) should be spread equally over all kWh (both peak and off-peak). This prevents a customer from avoiding all costs associated with the local distribution system, by limiting his usage to only the off-peak hours. Other costs further up the system (i.e., transmission and generation capacity costs) avoided by limiting usage to the off-peak hours are freed to serve new load. However, local facilities not used during peak hours are of little or no use to serve other load. These costs could be avoided if they were to be included in a peak period demand charge.

Alternatively, if a ***simple maximum demand charge*** is applied:

a) the portion of the marginal cost of generation capacity allocated by LOLP to the peak period should be spread across all kWh in that period.

b) the marginal cost of network capacity related to transmission (VHV and/or HV) should be recovered through the peak period energy price.

c) the local facilities cost (MV and/or LV) can be recovered through either the demand charge or spread equally across all kWh in the year. With a simple maximum demand charge, these costs would not be avoided by peaking during the off-peak hours. While recovering these costs through the demand charge is desirable, this cost component alone may not be sufficient to justify the additional complication and expense of a separate demand charge.

In theory, a simple maximum demand charge-based tariff design is totally contrary to the philosophy underlying TOD tariffs. From a practical standpoint as well, this option is largely irrelevant in today's metering environment, where TOD metering of energy and demand can be accomplished with one meter and at a cost that is not significantly different than the cost of TOD energy-only metering.

We recommend a phased program of transition that replaces all simple maximum demand to coincident demand billing with coincident demand billing within the next three years. We have included simple maximum demand tariff designs in this report to cover the period of transition.

12.5.3 Basis for Demand Charge

A discussion of the appropriate use of a separate demand charge has been incorporated into the explanation of the peak and off-peak energy price. However, an additional discussion may be helpful.

As is often the case when incorporating cost analysis into rate design, there is an inherent conflict between short-run and long-run considerations. In the case of generation capacity cost, recovering this cost through a separate demand charge may result in a more appropriate short-run price signal, while recovering these costs through the energy charge may give a more appropriate long-run price signal. (In the short run, a large portion of cost is fixed, while in the long run, all costs are variable.)

Other factors to be considered when making the decision on the use of a demand charge include:

- seasonal load variations
- duration of daily peak period
- metering cost
- customer understanding and acceptance
- probability of shifting peak or off-peak period rather than reducing peak
- probability of creating an even higher "needle" peak in the peak period (if the probability is high, use a separate demand charge)
- variation of load and cost between peak and off-peak periods.

These and other factors must be carefully weighed when rates are designed. A delicate balance between economic efficiency, fairness and practicality must be achieved.

It is current Polish practice to divide the demand charge into two components -- contract demand and measured (recorded) demand. A contract component places slightly more emphasis on revenue stability (i.e., the distribution company knows that this revenue is coming) while a single demand charge (particularly a coincident one) places more emphasis on load management objectives. While there is excess system capacity, emphasis on revenue stability is reasonable. We therefore recommend preserving this two-part demand charge in the 1994 tariffs.

The rationale behind the contract demand charge component applied here is called "minimum network cost." The concept is that there are "fixed" and "variable" components to marginal network capacity costs. The former costs (e.g., costs of primary feeders to customers, associated substation transformer capacity) should be collected even if the facilities are not used by the customers for which they are intended, while the latter costs are for facilities that can be utilized to serve other load.[2]

The advantage of the two-component demand charge is that it is already understood by customers. Further, during the current period of industrial restructuring, the "fixed" contract component helps to stabilize revenues. In the near term, however, PPGC should consider rolling all capacity costs into a single measured demand charge. This "pay as you go" approach provides large customers with greater incentive to manage their load. The single demand charge can easily be derived from the tariff structures presented in the following pages. If revenue stability remains a concern, a "ratchet" clause in the demand charge, which relates minimum billing demand to peak-month demand, may be applied.

The level of the contract demand charge is taken as 50 percent of the cost of network capacity on the customer's own-voltage. Thus, for example, a customer served at HV (tariff "A") would pay half of the HV network capacity cost (after it is adjusted to the class revenue responsibility) as a contract charge.

The contract charge is further adjusted downward from strict marginal capacity cost to reflect empirical data indicating that declared contract demand has historically exceeded measured demand, as summarized in the following table.

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[2] Unfortunately, the precise share of costs that are "fixed" is location-specific. For typical customers, we know that these costs are certainly less than 100 percent of own-voltage capacity cost, but we do not know exactly how much less. We have estimated that 50 percent of own-voltage capacity cost should not be avoided. Note that the rationale for the contract demand charge is the same as discussed above with respect to distribution network (MV and/or LV) capacity costs, i.e., that certain investments in the network are user-specific local facilities that should not be avoided even if a customer's peak is not within the peak period.

Tariff Class	Historical Ratio of Contract to Measured Demand			Ratio Assumed in this Study
	1991	Jan-Jun 1992	October 1992	
"A" (HV)	1.28	1.23	1.20	1.10
"B" (MV)	1.86	1.80	1.68	1.50
"C2" (LV)	2.03	1.98	1.97	1.60

12.5.4 Proposed Tariff Design Structure

The foregoing TOD tariff-setting philosophy has been applied in the following manner. First, all tariff classes have been allocated TOD energy charges based on strict long-run marginal cost. Then, marginal capacity costs have then been scaled downward until total charges match class revenue requirements. Finally, these capacity costs have been allocated as demand or energy charges according to the considerations outlined above.

Tariff "G" - Residential

The most important issue with regard to the residential tariff is to reduce the magnitude of the subsidy involved at present. Two options are proposed, paralleling current tariffs "G11" (flat energy charge) and "G12" (TOD energy charge). Each option collects the class revenue target yield of 828.9 Zl/kWh (mid-1992 prices), assuming an average load factor of .25 and a coincidence factor of 0.49. These options are summarized in Exhibit 12-8 and representative bill impacts are presented in Exhibit 12-9.

This tariff is applicable to all residential and small farm households. It is presumed that most households will continue to be billed on a flat-rate energy charge. For the optional two-period TOD rate, the peak period includes all peak and mid-peak hours of the week; the mid-day valley and all other hours are off-peak.

Given the fact that an overall real yield increase of 15 percent is required to achieve revenue responsibility (see Exhibit 12-6), it is considered reasonable to expect that the historically low residential tariff accept a somewhat higher increase. Therefore, it was decided not to use cross-subsidies from other classes as a means to moderate the proposed

Exhibit 12-8
Proposed Tariff "G" (Residential) Structure

Tariff "G"		Energy (Zl/kWh)		
Option	Season	Peak	Mid-Peak	Off-Peak
G12	Winter	1.149		484
	Summer	1.106		531
G11	Winter	830		
	Summer	830		

Exhibit 12-9
Typical Bill Impacts: Tariff "G" (Residential)

Consumption kWh/kW/mo	TOD Energy Shares		Bill Impact (tysZl/kW/month)		
	Peak	Mid-Peak	Present	Proposed	% Change
200	0.27	0.25	126.200	165.936	31%
200	0.32	0.30	126.200	177.823	41%
200	0.22	0.20	126.200	154.049	22%
100	0.27	0.25	63.100	82.968	31%
100	0.32	0.30	63.100	88.912	41%
100	0.22	0.20	63.100	77.024	22%
400	0.27	0.25	252.400	331.872	31%
400	0.32	0.30	252.400	355.646	41%
400	0.22	0.20	252.400	308.098	22%

tariff increase to residential users. When comparing the flat-rate tariff with current rates, the proposed real increase is approximately 60 percent (at mid-1992 prices).

As noted in Section 12.2, if it is concluded that this rate increase would impose too great a burden on low-income users, we would suggest a three-block tariff instead. Under this option (not quantified here), the tail block is priced to reflect strict LRMC. Once this is fixed, the prices for the first two blocks would be adjusted until the desired yield (revenue responsibility) is achieved. Under this option, the subsidized block would be charged at a minimum the strict long run marginal cost of off-peak energy.

The residential tariff currently includes group accommodation facilities (e.g., dormitories, schools, orphanages, etc.). As residential tariffs are increased toward marginal costs, other low-voltage tariffs may be more advantageous for these consumers, and they should be encouraged to consider options available in tariff class "C."

A point worth noting here relates to the very small difference in class revenue-neutral LRMC between residential (tariff "G") and other LV classes (tariffs "C1" and "C2"). Since all of these classes are served at low voltage, the differences result from differing assumptions regarding coincidence factor, load factor, and rating period energy shares. The results are based on limited available load research and the judgment of the study team. Uncertainty regarding these fundamental assumptions highlights the importance of and critical need for additional load research on electricity consumption patterns in Poland.

Tariff "A" - High Voltage

This proposed tariff is to be applied for all electricity consumption of customers served at high voltage.

Currently, tariff "A" customers (approximately 400) are given the option, subject to engineering constraints, of a coincident or a maximum demand charge, and a flat or TOD energy charge. As soon as feasible, all of these customers should be on a mandatory two-part time-of-day (TOD) tariff with a coincident demand charge.

Tariff options are summarized in Exhibit 12-10. Assuming an average class load factor of 0.6 and representative TOD energy shares (0.17 peak and 0.27 mid-peak), these tariff structures would meet a class revenue responsibility of 416.4 Zl/kWh. The demand and energy charges have been aligned closely with the economic cost of supply.

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Exhibit 12-10
Proposed Tariff "A" (High Voltage) Structure

Tariff "A"		Demand (tysZl/kW/mo)		Energy (Zl/kWh)		
Option	Season	Contract	Measured	Peak	Mid-Peak	Off-Peak
A23	Winter	6.790	36.580	752	352	210
	Summer	6.790	33.260	542	472	225
A22	Winter	6.790	36.580	508		210
	Summer	6.790	33.260	494		225
A21	Winter	6.790	36.580	335		
	Summer	6.790	33.260	342		

Note: Tariffs based on coincident demand.

Typical bill impacts are illustrated in Exhibit 12-11. Of course, actual bill impacts can vary widely, depending on individual customer characteristics, including load factor, energy shares by rating period, etc. Since the proposed structure is similar to the existing structure, the data do not show a marked difference in impact across a range of load factors and patterns of energy use.

It is probable that obligatory implementation of TOD pricing will require time for various preparatory activities, including meter procurement, testing, calibration, implementation, training of meter readers and testers, altering billing procedures, etc. This process is likely to take up to a year. In the interim, it may be necessary to continue offering a two-part tariff structure based upon a simple maximum demand charge (i.e., a non-coincident demand-based charge) and a flat energy charge. Representative tariff structures are shown in Exhibit 12-10.

Tariff "B" - Medium Voltage

This tariff is to be applied to all customers -- currently about 27,000 -- served at medium voltage.

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Exhibit 12-11
Typical Bill Impacts: Tariff "A" (High Voltage)

Load Factor	Consumption kWh/kW/mo	TOD Energy Shares		Bill Impact (tysZl/kW/month)		
		Peak	Mid-Peak	Present	Proposed	% Change
0.60	438	0.16	0.27	169.827	182.702	8%
0.60	438	0.19	0.32	169.827	193.322	14%
0.60	438	0.13	0.22	169.827	172.082	1%
0.40	292	0.16	0.27	123.318	133.247	8%
0.40	292	0.19	0.32	123.318	140.327	14%
0.40	292	0.13	0.22	123.318	126.166	2%
0.80	584	0.16	0.27	216.335	232.157	7%
0.80	584	0.19	0.32	216.335	246.317	14%
0.80	584	0.13	0.22	216.335	217.997	1%

The recommended tariff design is defined in Exhibit 12-12. Again, a mandatory, two-part TOD tariff based on a coincident demand charge is recommended. Interim tariff structures based on a maximum demand charge are also presented. Based upon an average class load factor of 0.42 and assumed rating period energy shares (0.18 peak and 0.31 mid-peak), these tariff structures are adequate for the desired revenue responsibility of 547 Zl/kWh. Representative bill impacts are shown in Exhibit 12-13.

Tariff "C2" - Low Voltage > 40 kW

This tariff should be applied to all non-residential customers served at low voltage whose maximum demand is over 40 kW or whose consumption exceeds 80 GWh. These customers (estimated to be about 25,000) are predominantly small industries.

Again, two-part tariffs are recommended, with a pure energy tariff option. For low-voltage service, it is reasonable to permit customers flexibility with regard to tariff structure (coincident or maximum demand charge; one, two, or three rating periods for energy

Exhibit 12-12
Proposed Tariff "B" (Medium Voltage) Structure

Tariff "B"		Demand (tysZl/kW/mo)		Energy (Zl/kWh)		
Option	Season	Contract	Measured	Peak	Mid-Peak	Off-Peak
B23	Winter	11.560	33.760	884	457	277
	Summer	11.560	31.780	644	574	303
B22	Winter	11.560	33.760	620		277
	Summer	11.560	31.780	599		303
B21	Winter	11.560	33.760	442		
	Summer	11.560	31.780	448		

Note: Tariffs based on coincident demand.

Exhibit 12-13
Typical Bill Impacts: Tariff "B" (Medium Voltage)

Load Factor	Consumption kWh/kW/mo	TOD Energy Shares		Bill Impact (tysZl/kW/month)		
		Peak	Mid-Peak	Present	Proposed	% Change
0.42	307	0.18	0.31	151.743	168.075	11%
0.42	307	0.22	0.37	151.743	177.594	17%
0.42	307	0.14	0.25	151.743	158.557	4%
0.20	146	0.18	0.31	91.629	96.572	5%
0.20	146	0.22	0.37	91.629	101.105	10%
0.20	146	0.14	0.25	91.629	92.040	0%
0.60	438	0.18	0.31	200.927	226.578	13%
0.60	438	0.22	0.37	200.927	240.176	20%
0.60	438	0.14	0.25	200.927	212.980	6%

charges). Various options pegged to the class revenue responsibility are presented in Exhibit 12-14. Typical bill impacts are shown in Exhibit 12-15.

Tariff "C1" - Low Voltage < 40 kW

This tariff should be applied to all non-residential customers served at low voltage whose maximum demand is under 40 kW or whose consumption is less than 80 GWh. There are more than 1.1 million customers in this class, including commercial and service facilities, entertainment establishments, offices, hotels, etc.

Again, two-part tariffs are recommended, with a pure energy tariff option. Due to the large number of customers and their diversity, it is reasonable to permit customers flexibility with regard to tariff structure (coincident or maximum demand charge; one, two, or three rating periods for energy charges). Various options pegged to the class revenue responsibility are presented in Exhibit 12-16. Typical bill impacts are shown in Exhibit 12-17.

Street Lighting Tariff

Street lighting was eliminated as a separate tariff class in the most recent tariff revision. It is recommended that the class be re-instituted. Whenever a sizeable customer group with a unique and identifiable consumption pattern can be classified, we believe that it should be charged for these characteristics rather than those associated with other customers. There are currently about 100,000 public lighting accounts.

The recommended street lighting tariff is shown in Exhibit 12-18. This tariff is designed to recover class revenue responsibility. It is understood that the capital and O&M costs associated with the installation of street lighting -- poles, fixtures, luminaries, photovoltaic cells, conductors, etc. -- are directly borne by the respective public authorities concerned. Consequently, the tariff is intended to recover only the cost of generation and distribution of electricity.

Exhibit 12-14
Proposed Tariff "C2" (Low Voltage > 40 kW) Structure

Tariff "C2" (>40 kW)		Demand (tysZl/kW/mo)		Energy (Zl/kWh)		
Option	Season	Contract	Measured	Peak	Mid-Peak	Off-Peak
C223	Winter	5.930	17.240	1.152	660	448
	Summer	5.930	16.530	860	787	483
C222	Winter	5.930	17.240	847		448
	Summer	5.930	16.530	813		483
C221	Winter	5.930	17.240	640		
	Summer	5.930	16.530	645		
C213	Winter	-	-	1.365	912	451
	Summer	-	-	1.087	1.020	483

Note: Tariffs based on simple maximum demand.

Exhibit 12-15
Typical Bill Impacts: Tariff "C2" (Low Voltage > 40 kW)

Load Factor	Consumption kWh/kW/mo	TOD Energy Shares		Bill Impact (tysZl/kW/month)		
		Peak	Mid-Peak	Present	Proposed	% Change
0.31	226	0.18	0.31	177.153	171.834	-3%
0.31	226	0.22	0.37	177.153	179.857	2%
0.31	226	0.14	0.25	177.153	163.811	-8%
0.20	146	0.18	0.31	130.922	120.219	-8%
0.20	146	0.22	0.37	130.922	125.396	-4%
0.20	146	0.14	0.25	130.922	115.043	-12%
0.50	365	0.18	0.31	257.005	260.986	2%
0.50	365	0.22	0.37	257.005	273.927	7%
0.50	365	0.14	0.25	257.005	248.045	-3%

Exhibit 12-16
Proposed Tariff "C1" (Low Voltage < 40 kW) Structure

Tariff "C1" (<40 kW)		Demand (tysZl/kW/mo)		Energy (Zl/kWh)		
Option	Season	Contract	Measured	Peak	Mid-Peak	Off-Peak
C123	Winter	6.090	17.680	1.133	673	462
	Summer	6.090	16.970	858	801	501
C122	Winter	6.090	17.680	854		462
	Summer	6.090	16.970	822		501
C121	Winter	6.090	17.680	663		
	Summer	6.090	16.970	669		
C113	Winter	-	-	1.347	922	467
	Summer	-	-	1.084	1.032	503
C112	Winter	-	-	1.088		467
	Summer	-	-	1.051		503
C111	Winter	-	-	789		
	Summer	-	-	789		

Exhibit 12-17
Typical Bill Impacts: Tariff "C1" (Low Voltage < 40 kW)

Load Factor	Consumption kWh/kW/mo	TOD Energy Shares		Bill Impact (tysZl/kW/month)		
		Peak	Mid-Peak	Present	Proposed	% Change
0.31	226	0.20	0.32	175.269	178.447	2%
0.31	226	0.24	0.38	175.269	192.185	10%
0.31	226	0.16	0.26	175.269	164.708	-6%
0.20	146	0.20	0.32	113.077	115.127	2%
0.20	146	0.24	0.38	113.077	123.990	10%
0.20	146	0.16	0.26	113.077	106.263	-6%
0.50	365	0.20	0.32	282.693	287.817	2%
0.50	365	0.24	0.38	282.693	309.976	10%
0.50	365	0.16	0.26	282.693	265.659	-6%

Exhibit 12-18
Proposed Street Lights Tariff

Street Lights Tariff		Energy (Zl/kWh)		
Option	Season	Peak	Mid-Peak	Off-Peak
-	Winter	788		
	Summer	788		

12.6 OPTIONAL INTERRUPTIBLE TARIFFS

At some point in the future after today's excess system capacity is absorbed, distribution companies should consider the introduction of interruptible tariffs on an optional basis. The potential class of such customers -- typically a subset of tariff classes "A" and "B" -- will have to be determined based upon a detailed market survey and the considerations outlined in the following.

Interruptible service (IS) is a demand-side option that is widely used and accepted by electric utilities and utility customers in many countries. Interruptible service allows a utility to interrupt load to a customer in accordance with specified provisions. For this privilege, the utility reduces the customer's bill by a specified amount each month. In regard to the daily operations of generation facilities, IS improves reliability and operating flexibility. In the longer term, IS allows the utility to build less generating capacity. A well designed IS tariff provides substantial benefits to both the utility and the customer.

Under an IS tariff, the customer contracts with the utility for an amount of load the customer is willing to remove from the system when requested to do so. This load is then considered to be non-firm. The IS tariff will specify an advance notice period that may be as long as 24 hours to as little as 15 minutes. While the utility may, in some cases, have direct control over the customer's load, most often the interruption is triggered by a phone call from the utility to the customer. This requires a dedicated phone line which is manned constantly to ensure timely communication. Special metering equipment that records usage on a continuous basis is also required to ensure compliance with the magnitude and time of requested interruption.

As mentioned earlier, IS allows the utility to install less generating capacity while maintaining a target level of reliability. Since IS can be called for a limited number of hours, it displaces peaking capacity in the generation mix. Therefore, the interruptible credit given to the customer should be based on the long-run marginal cost of peaking capacity, generally assumed to be combustion turbines (CT). While the credit should be *based* on this cost, it may *not equal* the LRMC of a CT because the IS capacity may not be of equal value to the utility as the same amount of CT capacity. For example, an IS tariff that allows only 100 hours per year of interruption would not be as valuable to the utility as a CT that can run 2,000 or more hours per year. In this case, the $/kW credit for IS should be less than the same $/kW LRMC of a CT.

The IS tariff should include specification of the interruption period. Generally, a maximum number of hours of interruption per year, week, and day will be given. This provision has a major impact on the value of the IS to the utility.

The IS tariff should include a substantial penalty for non-compliance. The utility has foregone building capacity and paid significant amounts to the customer for the right to interrupt the load. Customers must be discouraged from contracting for non-firm load and receiving credits when they have little intention or ability to interrupt load.

Since the influence of IS has a long-term impact on the utility's generation expansion plan, a three-year notice of contract cancellation on the part of the customer may be appropriate. Specification of the various parameters of an interruptible tariff would begin with the consideration and types of calculations discussed above. Once a preliminary menu of interruptible tariffs is developed on this basis, it is necessary to conduct a survey of the target population to test the concept. Information gathered in this process can be valuable in subsequently "fine tuning" the preliminary menu. Some of this preliminary research is currently in progress as part of the demand side management (DSM) program being conducted for PPGC by Hagler, Bailly.

12.7 OTHER TARIFF CONSIDERATIONS

The objective of this study is to identify appropriate levels and structures for electricity pricing-of power purchases, bulk transactions and retail final sales- at the national level. The study cannot address the myriad of special terms and agreements between and among individual generators, PPGC, distributors, and final consumers. In short, the detailed principles governing the settlement of accounts between entities in the power sector are not superseded. Likewise, specialized billing principles such as outlined in the Price List No.7-Z/92 (e.g., service rates, penalty provisions, and charges for reactive energy, overcurrent protection, and increased service reliability should continue to be applied in the context of revised tariff structures and levels.

Having noted the limit of this study, this section contains a brief discussion of other considerations beyond the basic tariff class structures defined in the foregoing pages.

Reactive Energy

Currently, high and medium voltage (as well as some low voltage) customers can be charged for the consumption of reactive energy when consumed at a sub-optimal level for the system. The charge is billed as a percentage surcharge to the value of the active energy consumed. The result is a progressive scale of payments for power factors below 0.93. While this system

is being implemented successfully, we understand that there have been complaints that it is not a rational fee, possibly due to a misunderstanding of its basis.

One possible alternative to the present system would be to require customers consuming potentially high levels of reactive energy to be billed on the basis of kVa rather than kW. Structuring the demand charge in this manner provides a built-in incentive for power factor improvement. To illustrate, the proposed Winter demand charge for tariff "A" is 36,580 Z1/coincident kW; alternatively, a demand charge of 32,920 Z1/coincident kVa could be offered. A customer who maintains the desired power factor (assumed to be 0.90 for this example), would see no adverse bill impact. On the other hand a customer with a lower power factors would be penalized. Further, any customer who is able to improve power factor beyond the target level will see a bill reduction. Additionally, distributors will benefit through reduction in line losses.

This alternative billing procedure would require additional investment in metering, but it would offer the advantage of a more transparent methodology with positive incentives.

Supply Reliability

Currently customers who request and receive a higher degree of reliability than the standard (which is based on a single independent supply sequence), are charged a multiple of the demand charge specified for their tariff class. The multiple is a factor of 1.5 for two separate supply sequences and 2.0 for three or more independent sequences.

In concept, the current charges appear reasonable, and they offer the clear advantage of customer comprehension. The disadvantage of simple multiples is that they do not incorporate specific customer circumstance, and may therefore over-or under-recover the cost of providing increased supply reliability. For example, the charge should certainly be dependent on the extent to which the customer-supplied equipment is used for improving reliability of supply. In general, while it may be appropriate to offer a standard "factor", we would encourage negotiations with individual customers permitting charges which are more closely linked to the incremental cost of providing additional supply reliability.

Special Agreements with Customers

Special agreements with customers are currently permitted when particular conditions dictate, e.g., when the customer has his own generating units, or when his industrial requirement is especially sensitive to the conditions of supply.

Adapting tariffs to local circumstances is entirely appropriate, so long as the principles underlying negotiations are consistent with the principles of marginal cost pricing which have been employed in setting standard rates by tariff class. Class tariff should be the starting point of these negotiations; subsequent adjustments can then be made to more accurately reflect the marginal cost of providing service under the specific circumstances of the customer.

Load Research

To facilitate future tariff revisions, we suggest that PPGC and the distribution companies expand currently available load research data to develop on-going additional survey data on customer load shapes, coincidence factors, peak energy shares, and load factors for each tariff class, as well as for the typical customer segments within each class.

there is a need to put in place a well designed and on-going load research program. This could be done through a contract with an organization such as the Power Engineering Institute, or through internal staffing. Such a program should be based upon a sample design that can support the development of statistically valid estimates for the types of data noted above, with a degree of precision that conforms to load research norms in the industry today. While useful *ad hoc* load research activities have been conducted, these are not certain to provide an on-going basis for developing estimates of key variables, noted above, that are essential in tariff planning, load forecasting, and system planning.

PN-ARQ 400

ELECTRIC POWER TARIFF STUDY: POLISH POWER GRID COMPANY

Final Report: Appendices

Prepared for:

U.S. AGENCY FOR INTERNATIONAL DEVELOPMENT
Bureau for Europe
Office of Development Resources
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Washington, DC 20523
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HBI Reference No. 93-D060-003

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PDC-0249-1-03-0090-00
Delivery Order No. 03

October 1993

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Appendix 2.1
Review of Electricity Demand Forecasts

APPENDIX 2.1 REVIEW OF ELECTRICITY DEMAND FORECASTS

As discussed in Chapter 2, three forecasting studies developed in Poland since 1990 were reviewed for this analysis. These were prepared by:

- The Polish Academy of Sciences (PAS)
- The Polish Power Grid Company (PPGC), Department of Development
- The Ministry of Industry (MOI), as published by the OECD/IEA.

Each of these forecasts includes its own high and low scenario, for a total of six forecasts. We have divided these forecasts according to their underlying macroeconomic assumptions about future economic conditions in Poland. Scenario 1 (Optimistic Growth) forecasts are summarized in Exhibit 2.1-1 and Scenario 2 (Rapid Recovery to Steady Growth) forecasts are summarized in Exhibit 2.1-2. Each exhibit compares economic and electricity generation forecasts, and calculates implied income elasticities from each source. The individual studies are described briefly below.

POLISH ACADEMY OF SCIENCE

This study was prepared in 1991 based on macroeconomic scenarios developed by working groups of Polish economic experts (e.g., the Central Planning Office, the Institute of Basic Technical Problems of the Polish Academy of Science). Two economic performance scenarios were identified: a "low" case in which GNP falls by 5 percent in real terms from 1990 to 1995, and a "high" case in which GNP is expected to rise by about 17 percent over the same period.

Further, the economic scenarios anticipated a change in the structure of the national economy, away from energy-intensive industries (e.g., ironworks, construction materials, chemicals), transport and agriculture, and toward other sectors (e.g., trade, telecommunications, small industry).

As summarized in Exhibit 2-4 (in Chapter 2), each scenario contained an independent assessment of new apartment construction, which was directly linked to future energy needs. Specifically, the low case estimated 130,000 units per year in the near term, rising to 220,000 units per year in the long term; the high scenario assumed 200,000 units from 1991-1995, rising to 350,000 units per year by 2010. By way of comparison, about 125,000 apartments were constructed in 1990 and an average of 170,000 units per year from 1986-1990. Higher levels are representative of 1970s' construction levels.

Exhibit 2.1-1
Scenario 1: Optimistic Economic Growth

A. POLISH ACADEMY OF SCIENCES – 1990/91

year	Real GNP 1/	(%)	HIGH Electricity Required 2/	(%)	Income Elasticity
1990	535.5	–	135.3	–	–
1995	626.5	3.2%	160.0	3.4%	–
2000	818.8	5.5%	193.0	3.8%	0.69
2010	1223.2	4.1%	265.0	3.2%	0.79

B. POLISH POWER GRID CO. (PSE) – December 1991

year	Real GNP 1/,/3	(%)	VARIANT II (High) Electricity Required 2/	(%)	Income Elasticity
1990	535.5	–	135.3	–	–
1991	492.7	-8.0%	132.0	-2.4%	–
1995	626.5	6.2%	151.0	3.4%	0.55
2000	818.8	5.5%	174.6	2.9%	0.54
2005	1020.0	4.5%	199.9	2.7%	0.61
2010	1223.2	3.7%	228.8	2.7%	0.74

C. POLAND MINISTRY OF INDUSTRY – October 1990

year	Real GNP 4/	(%)	MEDIUM Electricity Required 2/	(%)	Income Elasticity
1990	6320.0	–	141.0	–	–
2000	10400.0	5.1%	203.0	3.7%	0.73
2010	16770.0	4.9%	280.0	3.3%	0.67

1/ Real GNP in trillion Zloty at 1990 prices (reported by PSE).
2/ Electricity production for domestic needs, in billion KWh.
3/ Real GNP for 1991 estimated by PSE; real GNP for 2005 estimated from PSE-supplied elasticities.
4/ Real GNP in billion 1984 Zloty.

Exhibit 2.1-2
Scenario 2: Rapid Recovery to Steady Economic Growth

A. POLISH ACADEMY OF SCIENCES – 1990/91

year	Real GNP 1/	(%)	LOW Electricity Required 2/	(%)	Income Elasticity
1990	535.5	–	135.3	–	–
1995	508.7	-1.0%	144.0	1.3%	–
2000	577.9	2.6%	162.0	2.4%	0.92
2010	793.0	3.2%	208.0	2.5%	0.79

B. POLISH POWER GRID CO. (PSE) – December 1991

year	Real GNP 1,3/	(%)	VARIANT I (Low) Electricity Required 2/	(%)	Income Elasticity
1990	535.5	–	130.5	–	–
1991	492.7	-8.0%	132.0	1.1%	–
1995	508.7	0.8%	138.0	1.1%	1.39
2000	577.9	2.6%	156.4	2.5%	0.98
2005	674.0	3.1%	175.9	2.4%	0.76
2010	793.0	3.3%	197.8	2.4%	0.72

C. POLAND MINISTRY OF INDUSTRY – October 1990

year	Real GNP 4/	(%)	LOW Electricity Required 2/	(%)	Income Elasticity
1990	6320.0	–	138.0	–	–
2000	8810.0	3.4%	180.0	2.7%	0.80
2010	11400.0	2.6%	248.0	3.3%	1.25

1/ Real GNP in trillion Zloty at 1990 prices (reported by PSE).
2/ Electricity production for domestic needs, in billion KWh.
3/ Real GNP for 1991 estimated by PSE; real GNP for 2005 estimated from PSE-supplied elasticities.
4/ Real GNP in billion 1984 Zloty.

PAS applied the PROSK computer model to project the energy implications of these economic scenarios. We understand that the electricity demand projections incorporated:

- assumptions reflecting the official energy policies of the Republic of Poland (as of August 1990)
- projected energy intensity improvements of various sectors of the economy
- expected increases in the costs of delivered electricity.

The high and low PAS cases are summarized in Exhibits 2.1-1 and 2.1-2.

THE POLISH POWER GRID COMPANY

The PPGC Department of Development prepared its own forecast in December 1991. The forecast is based on the PAS economic forecast, but on revised estimates of the income elasticity of demand. In particular, PPGC made these revised forecasts based on the following considerations:

- assumed rationalizing of energy and fuel utilization within the overall economy, including the need to lower electricity consumption per unit of GNP
- assumed substantial adjustments in Polish energy prices to levels at or near world prices.

The summary results in Exhibits 2.1-1 and 2.1-2 confirm that PPGC has assumed more conservative income elasticities for both the Variant I (low) and Variant II (high) cases. These cases have been adopted by PPGC for system planning purposes until more precise projections are available.

POLAND MINISTRY OF INDUSTRY

The MOI prepared economic growth and electricity demand forecasts for a report on energy policies in Poland prepared by the OECD/International Energy Agency in the winter of

1990/91.[1] While dated in comparison to the PAS and PPGC analyses, these forecasts provide an additional estimation of expected income elasticities of electricity demand in Poland.

The MOI economic forecast was prepared at the worst possible time. The country was just beginning its transition to a market economy, facing the need for dramatic structural readjustments, with little basis for projecting the rate of adaptation or the rate of future growth. Hence, the macroeconomic growth forecast consisted of three simple "spreadsheet" scenarios:

- low - 3 percent annual growth (1991-2010)
- medium - 5 percent annual growth (1991-2010)
- high - 8 percent (1991-2000) and 5 percent (2001-2010) annual growth.

As shown in Exhibit 2-4 in Chapter 2, apartment construction was forecast for each scenario independent of the rate of economic growth. The low scenario assumed less construction, averaging 125,000 units until 1995 and 175,000 units from 1995 to 2000. The medium scenario assumed that the level of the recent past could be maintained (175,000 per year, rising to 200,000 from 1995-2000). Finally, the high scenario assumed that levels of the 1970s could be achieved: 205,000 units from 1991-1995 and 260,000 units for the last five years of the decade.

The resulting energy requirements forecasts for the low and medium MOI scenarios are summarized in Exhibits 2.1-1 and 2.1-2. (The high forecast was considered so unlikely that associated energy projections were never developed.) The MOI report concluded that both the low and the medium forecasts of macroeconomic growth and energy needs are optimistic because they assume relatively high and stable growth rates. If, on the other hand, there is social tension, an unfavorable international environment, or any slowdown in economic restructuring, the authors observed that actual growth rates could be expected to be considerably lower.

[1] *Energy Policies - Poland*, 1990 Survey, OECD/IEA, Paris, 1990. A report prepared by the Ministry of Industry, Poland in October 1990, "Status and Assumptions for Future Development of Polish Energy Sector in the Years 1990-2010," appeared as an annex in this publication. The MOI report was compiled in response to an IEA questionnaire.

Appendix 2.2
Scenario 3: End-User Trends Forecast

APPENDIX 2.2: SCENARIO 3: END-USER TRENDS FORECAST

This forecast was developed using a method that was common before widespread computerization facilitated the use of more sophisticated econometric forecasting methods.

End-use forecasts are developed in the same manner that a "chartist" projects stock prices. He uses no outside data, but assumes that everything he needs to know is embedded in historical data. For this analysis, we relied completely on historical performance of sales to different customer classes as a basis for forecasting. We know the number of customers in each class and the average use per customer. Given uncertainties regarding future economic growth rates and appropriate income elasticities, it is possible that a forecast based on sales data is a better guide to the future than far more complex econometric formulations.

Exhibit 2.2-1 reports historical performance disaggregated by three main customer groups.[1] Average growth rates were calculated for the years of dramatic change (1988-91) and for two earlier periods.

Exhibit 2.2-2 represents one forecast developed from the historical series. The results are judgmental, and other forecasters would draw different conclusions. The forecast attempts to draw a balance between the following factors:

- There is a gradual transition between the average performance of the past three years and future trends in use per customer. For example, the decline in average use per customer among industrial customers continues, albeit at a moderated pace.

- The uninterrupted historical growth in the number of customers for each customer group is preserved.

- Market shares of consumption continue their historical transition from industrial dominance toward greater balance across sectors. We used trendline regression (with dummy variables for 1990 and 1991) as a basis for projecting gradual change in class shares of total final sales.

[1] The groups are: industry customer classes A and B; industry class C, traction, and commercial; and farms, residential, and street lights. Industry class C was separated from other industry since it appears that this class was reclassified as commercial in 1991.

Exhibit 2.2-1
Republic of Poland: End-Use Trends

	1982	1985	1986	1987	1988	1989	1990	1991	Average Annual Rate of Change 1982-85	1985-88	1988-91
SALES (GWh)											
Industry Group 1/	53773	60538	62323	64429	65433	63603	55783	51052	4.0%	2.6%	-7.9%
		2.6%	2.9%	3.4%	1.6%	-2.8%	-12.3%	-8.5%			
Commercial Group 2/	13647	15010	15723	16491	16889	17063	15093	14736	3.2%	4.0%	-4.4%
		0.2%	4.8%	4.9%	2.4%	1.0%	-11.5%	-2.4%			
Domestic Group 3/	19336	24672	25953	28112	29256	30406	31633	30595	8.5%	5.8%	1.5%
		13.5%	5.2%	8.3%	4.1%	3.9%	4.0%	-3.3%			
Final Domestic Sales	86755	100220	103998	109032	111578	111073	102509	96384	4.9%	3.6%	-4.8%
		4.7%	3.8%	4.8%	2.3%	-0.5%	-7.7%	-6.0%			
HV Sales	30941	34834	36209	37680	38531	37397	32761	29656	4.0%	3.4%	-6.4%
MV Sales	27365	30757	31338	32201	32519	31700	28070	25936	4.0%	1.9%	-7.3%
LV Sales	28449	34629	36450	39151	40527	41975	41678	40791	6.8%	5.4%	0.2%
CUSTOMERS ('000)											
Industry Group	33	37	38	39	41	43	44	45	3.0%	4.1%	2.9%
		3.5%	4.1%	3.7%	4.4%	3.9%	2.8%	2.0%			
Commercial Group	1385	999	1003	1018	1040	1055	1043	1080	-10.3%	1.3%	1.3%
		-13.0%	0.3%	1.6%	2.1%	1.5%	-1.2%	3.6%			
Domestic Group	11198	12168	12350	12511	12689	12867	13027	13179	2.8%	1.4%	1.3%
		2.8%	1.5%	1.3%	1.4%	1.4%	1.2%	1.2%			
Total	12616	13204	13391	13569	13770	13965	14114	14304	1.5%	1.4%	1.3%
		1.4%	1.4%	1.3%	1.5%	1.4%	1.1%	1.3%			
USE PER CUSTOMER (KWh/month)											
Industry Group	134221	138113	136579	136147	132464	123893	105689	94838	1.0%	-1.4%	-10.5%
		-0.9%	-1.1%	-0.3%	-2.7%	-6.5%	-14.7%	-10.3%			
Commercial Group	821	1252	1307	1349	1354	1347	1206	1137	15.1%	2.6%	-5.6%
		15.1%	4.4%	3.3%	0.3%	-0.5%	-10.5%	-5.7%			
Domestic Group	144	169	175	187	192	197	202	193	5.5%	4.4%	0.2%
		10.4%	3.6%	6.9%	2.6%	2.5%	2.6%	-4.4%			
All Groups	573	633	647	670	675	663	605	562	3.3%	2.2%	-6.0%
		3.2%	2.3%	3.5%	0.8%	-1.8%	-8.7%	-7.2%			
SALES – MARKET SHARES											
Industry Group	0.62	0.60	0.60	0.59	0.59	0.57	0.54	0.53	-0.9%	-1.0%	-3.3%
Commercial Group	0.16	0.15	0.15	0.15	0.15	0.15	0.15	0.15	-1.6%	0.4%	0.3%
Domestic Group	0.22	0.25	0.25	0.26	0.26	0.27	0.31	0.32	3.4%	2.1%	6.6%

Exhibit 2.2-2
Republic of Poland: End-Use Trend Forecast

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Avg Rate of Change 1991-96	Avg Rate of Change 1996-01
SALES (GWh)												
Industry Group 1/	48949	47931	46934	47617	48310	49759	51252	52789	54373	56004	1.1%	3.0%
	-4.1%	-2.1%	-2.1%	1.5%	1.5%	3.0%	3.0%	3.0%	3.0%	3.0%		
Commercial Group 2/	14494	14403	14459	14515	14718	15297	15899	16525	17175	17851	0.0%	3.9%
	-1.6%	-0.6%	0.4%	0.4%	1.4%	3.9%	3.9%	3.9%	3.9%	3.9%		
Domestic Group 3/	31024	31458	32217	33322	34464	36344	38327	40418	42624	44949	2.4%	5.5%
	1.4%	1.4%	2.4%	3.4%	3.4%	5.5%	5.5%	5.5%	5.5%	5.5%		
Final Domestic Sales	94467	93792	93610	95452	97492	101400	105478	109732	114171	118804	0.2%	4.0%
	-2.0%	-0.7%	-0.2%	2.0%	2.1%	4.0%	4.0%	4.0%	4.0%	4.1%		
HV Sales	28434	27843	27264	27661	28063	28905	29772	30665	31585	32533	-1.1%	3.0%
MV Sales	25072	24672	24350	24659	25035	25870	26733	27626	28549	29505	-0.7%	3.3%
LV Sales	40960	41278	41996	43133	44394	46626	48973	51441	54037	56766	1.7%	5.0%
CUSTOMERS ('000)												
Industry Group	46	47	48	49	51	52	54	55	57	59	2.4%	3.0%
	2.0%	2.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%		
Commercial Group	1095	1110	1126	1142	1158	1174	1190	1207	1224	1241	1.4%	1.4%
	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%		
Domestic Group	13363	13550	13740	13932	14128	14325	14526	14729	14935	15145	1.4%	1.4%
	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%		
Total	14504	14708	14914	15123	15336	15551	15770	15991	16216	16444	1.4%	1.4%
	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%		
USE PER CUSTOMER (KWh/month)												
Industry Group	89148	85582	82159	80927	79713	79713	79713	79713	79713	79713	-3.4%	0.0%
	-6.0%	-4.0%	-4.0%	-1.5%	-1.5%	0.0%	0.0%	0.0%	0.0%	0.0%		
Commercial Group	1103	1081	1070	1059	1059	1086	1113	1141	1169	1199	-1.4%	2.5%
	-3.0%	-2.0%	-1.0%	-1.0%	0.0%	2.5%	2.5%	2.5%	2.5%	2.5%		
Domestic Group	193	193	195	199	203	211	220	229	238	247	1.0%	4.0%
	0.0%	0.0%	1.0%	2.0%	2.0%	4.0%	4.0%	4.0%	4.0%	4.0%		
All Groups	543	531	523	526	530	543	557	572	587	602	-1.2%	2.6%
	-3.3%	-2.1%	-1.6%	0.6%	0.7%	2.6%	2.6%	2.6%	2.6%	2.6%		
SALES - MARKET SHARES												
Industry Group	0.52	0.51	0.50	0.50	0.50	0.49	0.49	0.48	0.48	0.47	-1.3%	-1.0%
Commercial Group	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	-0.3%	-0.1%
Domestic Group	0.33	0.34	0.34	0.35	0.35	0.36	0.36	0.37	0.37	0.38	2.2%	1.4%

1/ Industry Group includes Industry tariff classes A and B.
2/ Commercial Group includes Industry tariff class C plus all Traction and Commercial sales.
3/ Domestic Group includes all Farm, Residential and Street Light sales.

The end-use forecast projects final sales by class. We have applied these final sales to the generation and loss forecast assumptions of the PPGC Variant I (Low) forecast as a basis for estimating total generation requirements. The resulting forecast is shown in Exhibit 2.2-3.

Exhibit 2.2-2

Scenario Forecast of Generation and Consumption (GWh)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Avg Annual Rate (%) 1991-96	Avg Annual Rate (%) 1996-01
PUBLIC POWER SYSTEM												
Industry Group	48949	47931	46934	47617	48310	49759	51252	52789	54373	56004	1.1%	3.0%
Commercial Group	14494	14403	14459	14515	14718	15297	15899	16525	17175	17851	0.0%	3.9%
Domestic Group	31024	31458	32217	33322	34464	36344	38327	40418	42624	44949	2.4%	5.5%
Final Domestic Sales	94467	93792	93610	95453	97492	101400	105478	109732	114171	118804	0.2%	4.0%
Exports 1/	3200	3200	3300	3300	1900	1900	1900	1900	1900	0	–	–
Imports (–)	0	0	0	0	0	0	0	0	0	0	–	–
TOTAL SALES	97667	96992	96910	98753	99392	103300	107378	111632	116071	118804	0.1%	3.6%
Network Losses	13407	12326	11408	11500	10866	11313	11895	12442	13000	13199	-5.4%	4.0%
% of incoming	11.84%	11.05%	10.32%	9.6%	9.66%	9.68%	9.71%	9.71%	9.8%	9.72%		
Pumping in Hydro Plants 2/	2600	2600	2600	2600	2600	2600	3667	4200	4200	4200	-1.1%	10.1%
Self-Producer Supply to Grid (–)	400	400	400	400	400	400	400	400	400	400	3.4%	0.0%
NET GENERATION	113274	111519	110518	112453	112457	116813	122540	127874	132871	135803	-0.6%	3.8%
Heat Generation Auxiliary Use	2152	2200	2250	2300	2339	2378	2418	2459	2500	2519	2.1%	1.5%
Station Use	8933	8800	8725	9400	8880	9219	9664	10078	10600	10685	-0.2%	3.8%
% of incoming	7.18%	7.18%	7.18%	7.18%	7.18%	7.18%	7.18%	7.18%	7.18%	7.17%		
GROSS GENERATION (GWh)	124359	122519	121493	124153	123676	128410	134621	140411	145971	149007	-0.5%	3.8%
Load Factor	0.648	0.653	0.657	0.662	0.672	0.673	0.676	0.677	0.681	0.670		
MAXIMUM DEMAND (MW)	21894	21423	21103	21417	21014	21790	22730	23667	24478	25381	–	3.8%
OTHER PRODUCERS												
Self-Producer Factory Use	7200	7200	7200	7200	7200	7200	7200	7200	7200	7200	–	–
Self-Producer Supply to Grid	400	400	400	400	400	400	400	400	400	400	–	–
Other Supply to Grid	–	–	–	–	–	–	–	–	–	–	–	–
NET GENERATION	7600	7600	7600	7600	7600	7600	7600	7600	7600	7600	–	–
Station Use	500	500	500	500	500	500	500	500	500	500	–	–
% of incoming	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%		
GROSS GENERATION (GWh)	8100	8100	8100	8100	8100	8100	8100	8100	8100	8100	–	–
Load Factor	0.648	0.653	0.657	0.662	0.672	0.673	0.676	0.677	0.681	0.670		
MAXIMUM DEMAND (MW)	1426	1416	1407	1397	1376	1375	1368	1365	1358	1380	–	–
TOTAL GROSS GENERATION 3/	132459	130619	129593	132253	131776	136510	142721	148511	154071	157107	-0.4%	3.6%
TOTAL MAXIMUM DEMAND 4/	23320	22839	22509	22814	22390	23165	24098	25032	25836	26760	–	3.6%
Annual Load Factor 5/	0.648	0.653	0.657	0.662	0.672	0.673	0.676	0.677	0.681	0.670		

1/ Includes 300 GWh "fee" for transit. No exports assumed after 2000.
2/ Mloty pumping is included; this load is estimated as 1067 GWh in 1998 and another 533 GWh in 1999.
3/ Includes domestic requirements plus international energy exchange estimated by PSE.
4/ Derived from load factor (see note 5) and total gross generation forecast.
5/ From Exhibit 2-7.

Appendix 3.1
Emissions Control Retrofit Costs for System Compliance

APPENDIX 3.1: EMISIONS CONTROL RETROFIT COSTS ESTIMATE FOR SYSTEM COMPLIANCE

Using in-house information on pollution control equipment and practices and supplementing this information with discussions with industry, EPRI and experts RCG/Hagler, Bailly estimated the costs associated with bringing the Polish power system under environmental compliance. The principal pollutants of concern include SO2, NOx and particulates. Exhibit 1 summarizes the principal pollution control technologies applicable to the Polish power situation.

1. SO_2 Control

Some 70 Unites States electric utilities are currently operating 150 stack gas scrubbers or flue gas desulfurization units (FGD) successfully. The FGD's are installed on almost 61,900 MW of installed electric power capacity. As a result of rapid FGD deployment at some of the nations worst SO_2 offenders, the US Environmental Protection Agency estimates that SO_2 emissions were down by almost 21 percent since 1973, despite a 95 percent increase in coal combustion in power plants. As a result of recent Clean Air Act (CAA) regulations, almost 21,000 MW of installed electric capacity is being retrofitted with scrubbers; a further 21,000 MW is considering either fuel-switching or FGD scrubber retrofitted.

Pollution control systems can account for up to 40 percent of the capital cost and 35 percent of the operating cost of new plants, and costs associated with retrofitting plants with FGD can be considerably higher. Recently, EPRI completed technical and economic evaluations of 28 FGD processes, including both wet and dry FGD processes.

Capital cost estimates for nine conventional high-efficiency FGD processes and six dry injection processes are provided in Exhibit 1. These cost estimates assume a moderately difficult retrofit engineering and construction effort for a 300 MW thermal power plant unit operating using 2.6 percent Sulfur coal. The retrofit FGD includes the absorber module and on spare unit. The cost estimates are provided in ranges and do not account for site-specific conditions at thermal power plants. Most processes offer SO_2 removal process efficiencies of 90 percent. Certain dry processes are not efficient and offer a 50 percent SO_2 removal efficiency. However, the capital costs reflect this performance difference.

Control Type	Select Technology	Range Estimate	Average Cost ($/kW)	Removal Cost ($/ton)	Efficiency (%)	Retrofit Applicability
SOx CONTROLS						
for Coal–fired boiler	limestone/oxidation	--	205	550	>90	yes
steam turbine systems	limestone/gypsum	--	240	555	>90	yes
– Conventional	enhanced lime	--	225	510	>90	yes
	spray drying	--	150	500	>90	yes
– Dry Injection	furnace sorbent	--	80	650	50	yes
	economizer injection	--	80	650	50	yes
	circulating fluid bed	--	140	400	est. 80	yes
NOx CONTROLS						
– Front–end	low NOx burner design	10–30	15	200–500	40–60	yes
	combustion modification	5–10	7.5	unknown	20–25	yes
	reburning	25–45	35	500–1,000	60–65	yes
	reburning+LNB	35–75	50	700–1,500	65–90	yes
– Post–combustion	SCR	60–180	120	2000–4,000	60–90	yes
	SNCR	10–25	17.5	500–1,500	50–80	yes
SOx/NOx CONTROLS						
– Conventional	wet FGD+LNB	300–400	--	--	95/40–60	yes
	dry FGD+SCR	300–350	--	--	70–95/70–85	yes
– Advanced	slagging combustors (w/pulv. coal)	300–500	--	--	45–90/40–60	yes
	retrofit FGD:chelates/wet FGD	5–10	--	--	90+	yes
	retrofit FGD:phosphorus/wet FGD	5–10	--	--	90+	yes
	retrofit FGD:oxidizers/spray FGD	5–10	--	--	90+	yes
	Downstream–sorbent injection	5–10	--	--	70–95/60–80	yes
	electron beam	400–600	--	--	--	yes
– Others	NOXSO, WSA–SNOX, DESONOX	--	--	--	--	yes
– In–boiler	reburning+sorbent injection	375	--	--	--	yes
	integrated SI	--	--	--	90	yes
DUST CONTROLS						
	ESP's	--	55–80		>95	yes
	fabric filters:reverse/air, shake/deflate	--	40–70		>95	yes
	pulse jet	--	40–70		>95	yes
COAL CLEANING						
– Washing/beneficiation	physical	--	20–75		10–30	yes
	advanced physical	--	75–150		20–60	yes
– Advanced	chemical/biological	--	200–250		80–90	yes

Source: based on EPRI, Power Engineering, CEC and communication with professional power engineering firms, 1993.

Major US suppliers of FGD equipment include the following: AIRPOL, Anderson 2000, Babcock and Wilcox, ABB-Combustion Engineering, Davy McKee, Flakt, GE Environmental Systems, M W Kellog, Pure Air, Mikropul, Research Cottrell, Sly, United McGill, Wheelabrator and Otto H. York.

2. NO_x Control

As detailed information on Nox emissions was unavailable for this study, an estimate of $100 per kW for Nox control retrofits.

3. Particulate Control

Primary types of particulate control devices used for coal combustion include multiple cyclones, electrostatic precipitators, fabric filters (baghouses) and scrubbers. Additional measures of control can be achieved by using ash settling in boiler/air heater/economizer dust hoppers, large breeches and wide chimney bases.

Electrostatic precipitators (ESP's) are considered to be the most common high efficiency control devices that are used on pulverized coal boilers, cyclone units and increasingly on stoker systems. Typically, ESP efficiency is defined as the collector surface area per flue gas flow rate through the equipment. ESP's can exhibit removal efficiencies as high as 99.9 weight percent if properly designed, installed and operated.

Recently, fabric filters are gaining in popularity with both utility and industrial applications. This trend is most likely due to the increased trend towards utilizing low sulfur coal which often display high flyash resistivities, which are handled well by fabric filters. ESP's located behind air preheaters, or cold-side precipitators may operate at considerable reduced removal efficiencies when low-sulfur coal is used. Scrubbers are also used to control particulates but their chief application is SO2 control.

Stoker-fired boilers typically utilize mechanical collectors such as an array of cyclones which are used to reduce the flyash burden. These equipment can also achieve high removal efficiencies, in the range of 90 to 95 percent, especially when used with properly designed input flow rates.

Major US suppliers of ESP's include the following: ABB Environmental Systems, Aercology, Andersen 2000, Babcock and Wilcox, Bischoff Environmental Systems, Enviro Elements, GE Environmental Systems, Micropul, Research Cottrell, United Air, United McGill, and Wheelabrator.

Exhibit 2
Capital and Levelized Cost Estimates for 15 FGD processes for Moderately Difficult Retrofit Applications at U.S. utility for a 300 MW, 2.6 Percent Sulfur Coal.

FGD	Capital Costs (US$/kW)	Levelized Costs ($/ton SO_2 removal)
I. Conventional Process (removal efficiencies of > 90%)		
Limestone-forced oxidation	205	550
Limestone/gypsum	240	555
Magnesium enhanced lime	225	510
Limestone/inh. oxidation	205	545
Limestone/DBA	200	545
CT-121	190	480
Lime dual-alkali	180	490
Pure Air/Mitsubishi	190	480
Lime spray drying	150	500
II. Dry Injection Processes (removal efficiencies of typically less than 90%)		
Furnace sorbent injection (50%)	80	650
Economizer injection (50%)	80	650
Duct sorbent injection (50%)	80	700
Duct spray drying (50%)	65	540
Tampella LIFAC (80%)	220	690
Lurgi circulating fluid bed	140	400
Average for wet scrubbing	200	517
Average for dry injection	111	605

Source: FGD Economics, *EPRI Journal*, Palo Alto, CA, September 1992.

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	PLANT NAME	FUEL	1991 SO2 EMISSIONS ('000 tonnes)	1991 SO2 EMISSIONS FACTOR (g/GJ)	MEAN UNIT CAPACITY (MW)	NO. UNITS	NAME-PLATE CAPACITY (MW)	1,991 PROD--CTION (GWh)
1	JAWORZNO III	COAL	103	1,579	200	6	1,200	6,302
2	SIERSZA P	COAL	31	1,503	123	6	738	3,128
3	JAWORZNO II	COAL	20	1,491	50	7	350	904
4	BELCHATOW	LIGNITE	346	1,274	360	12	4,320	27,213
5	OSTROLEKA B	COAL	36	1,256	200	3	600	2,864
6	JAWORZNO I Borsig	COAL	2	1,192				
7	JAWORZNO I skoda	COAL	5	1,185	29	5	145	279
8	TUROW	LIGNITE	158	1,174	200	10	2,000	12,035
9	OSTROLEKA A	COAL	6	1,139				
10	LAGISZA	COAL	43	1,103	120	7	840	3,423
11	POLANIEC	COAL	2	1,030	200	8	1,600	7,173
12	SIERZA F	COAL	14	983				
13	RADOM POLNOC KP	COAL	1	976				
14	PATNOW	LIGNITE	76	971	200	10	2,000	7,628
15	WROCLAW II WP	COAL	2	958	100	2	200	1,089
16	WROCLAW II DP	COAL	16	958				
17	BEDZIN KPiWP	COAL	6	953				
18	LODZ III KPiWP	COAL	9	938				
19	KONIN	LIGNITE	38	933	65	9	583	3,148
20	BLACHOWNIA	COAL	4	930	47	6	282	781
21	KIELCE	COAL	2	898				
22	ZIELONA GORA	COAL	3	886				
23	KATOWICE	COAL	3	875				
24	SKAWINA	COAL	21	871	79	7	550	1,919
	TOTAL --->		945	1,086		98	15,408	

Source: Polish Power Grid Company, October, 1992.

15,500 MW of capacity is in non-compliance as of 1992
At $200 per kW it would cost US$ 3.1 billion to retrofit this stock to be in full compliance by 1997/98
Levelized control costs to remove approx. 945,000 tons of SO2 are estimated to be US$ 491 million
(cost estiamtes are derived from EPRI estimates in 1990 dollars)

Exhibit 3. Dust emissions: non-compliance power plants in the Polish power grid, October 1992.

	PLANT NAME	1991 DUST EMISSIONS ('000 tonnes)	1991 DUST EMISSIONS FACTOR (g/GJ)	NAME-PLATE CAPACITY (MW)	FUEL
1	ADAMOW	14	436	480	COAL
2	BEDZIN 28	0	0	55	COAL
3	BEDZIN KPiWP	4	619		COAL
4	BELCHATOW	26	96	4320	LIGNITE
5	BIALYSTOK	5	485	118	COAL
6	BIELSKO BIALA	3	279	100	COAL
7	BLACHOWNIA	16	2213	287	COAL
8	BLACHOWNIA III	2	408		COAL
9	BYDGOSZCZ I	1	193	14	COAL
10	BYDGOSZCZ II	5	303	169	COAL
11	BYDGOSZSZ III	2	2007	33	COAL
12	CHORZOW EF.P	4	750	100	COAL
13	CHORZOW MECH	0	983		COAL
14	CHORZOW WP	0	187		COAL
15	CIESZYN	0	121		COAL
16	CZECHNICA	4	764		COAL
17	CZESTOCHOWA	1	1225		COAL
18	DOLNA ODRA	25	365	1600	COAL
19	ELBAG KP	7	1867		COAL
20	ELBAG MAZ	0	0		COAL
21	ELBANG WP	0	113		COAL
22	GDANSK II	5	342	188	COAL
23	GDYNIA I	2	1577	20	COAL
24	GDYNIA II	2	934	23	COAL
25	GDYNIA III	2	222	150	COAL
26	GORZOW I	9	3382		COAL
27	GORZOW II	4	757		COAL
28	GRUDZIADZ	0	150		COAL
29	HALEMBA	1	107	200	COAL
30	JAWARNO I Borsig	2	1288		COAL
31	JAWARNO I Skoda	4	892	146	COAL
32	JAWARZNO II	9	662	350	COAL
33	JAWORZNO III	9	138	1200	COAL
34	KAGISZA	9	218		COAL
35	KALISZ	1	351	8	COAL
36	KATOWICE	0	91		COAL
37	KAWECZYN	1	171		COAL
38	KAZISKA 126	2	232		COAL
39	KAZISKA 129	6	153		COAL
40	KIELCE	1	421		COAL

Exhibit 3. Dust emissions: non–compliance power plants in the Polish power grid, October 1992.

	PLANT NAME	1991 DUST EMISSIONS ('000 tonnes)	1991 DUST EMISSIONS FACTOR (g/GJ)	NAME–PLATE CAPACITY (MW)	FUEL
41	KOMOROWICE MAZ	0	0		COAL
42	KOMOROWICE WEG	1	265		COAL
43	KONIN	20	491	523	LIGNITE
44	KOZIENICE 200	11	169	2600	COAL
45	KOZIENICE 500	11	686		COAL
46	KRAKOW LEG BC	8	334	460	COAL
47	KRAKOW LEG WP	2	825		COAL
48	LODZ IV	3	238	110	COAL
49	LODZ I	2	2107		COAL
50	LODZ I KR	1	292	36	COAL
51	LODZ II KP	17	1463	179	COAL
52	LODZ II PTWM	0	0		COAL
53	LODZ III KPiWP	3	324	198	COAL
54	LODZ III PTWM	0	0		COAL
55	LUBLIN I	0	918		COAL
56	LUBLIN WROTKOW	1	115		COAL
57	MIECHOWITZ	4	675	110	COAL
58	OLOWIANKA KP	1	1638		COAL
59	OLOWIANKA KR	0	376		COAL
60	OSTROLEKA A	2	249		COAL
61	OSTROLEKA B	7	241	600	COAL
62	PATNOW MAZ	0	0		COAL
63	PATNOW WEG	17	219	1600	LIGNITE
64	POLANIEC	13	181	1600	COAL
65	POMORZANY KP	4	840	120	COAL
66	POMORZANY WP	0	377		COAL
67	POWISLE	1	176	42	COAL
68	POZNAN GARBARY	0	224		COAL
69	POZNAN GARBARY KP	3	1837		COAL
70	POZNAN KAROLIN KM	0	0		COAL
71	POZNAN KAROLIN KW	4	449		COAL
72	PRUSZKOW	0	152		COAL
73	RADOM POLANC KR	1	320		COAL
74	RADOM POLNOC KP	0	54		COAL
75	RYBNIK	9	92	1600	COAL
76	RZESZOW ZALEZA WR	0	195		COAL
77	RZESZOW ZALEZE WP	1	261		COAL
78	SIEKIERKI 90	5	459		COAL
79	SIEKIERKI PTWM	0	0		COAL
80	SIEKIERKI WPI	7	296	622	COAL

Exhibit 3. Dust emissions: non–compliance power plants in the Polish power grid, October 1992.

	PLANT NAME	1991 DUST EMISSIONS ('000 tonnes)	1991 DUST EMISSIONS FACTOR (g/GJ)	NAME–PLATE CAPACITY (MW)	FUEL
81	SIERSZA F	3	192	740	COAL
82	SIERSZA P	3	149		COAL
83	SKAWINA	6	251	550	COAL
84	STALOWA WOLA	3	893	385	COAL
85	STALOWA WOLA 126	1	104		COAL
86	STALOWA WOLA 13	0	501		COAL
87	STALOWA WOLA 80	2	188		COAL
88	STALOWA WOLA WP	2	329		COAL
89	SZCZECIN I	2	766		COAL
90	SZCZECIN II	0	167		COAL
91	SZOBIERKI K16	0	756	44	COAL
92	SZOMBIERKI La Mon	2	699		COAL
93	SZOMBIERSKI WR	0	173		COAL
94	TORUN GREBOCIN	1	241		COAL
95	TUROW	66	487	2000	LIGNITE
96	TYCHY I	1	274		COAL
97	TYCHY II	1	229		COAL
98	WOLA	0	0		COAL
99	WROCLAW I	0	1398		COAL
100	WROCLAW II OP	4	233		COAL
101	WROCLAW II WP	1	682	200	COAL
102	ZABARZE I	5	733		COAL
103	ZABRZE II	0	114		COAL
104	ZAMOSC SZOPINEK	0	412		COAL
105	ZERAN KP	20	765	250	COAL
106	ZERAN WP	2	373		COAL
107	ZIELONA GORA	1	262	10	COAL
	TOTAL --->	465		24,140	

Source: Polish Power Grid Company, October, 1992.

Market Estimate:
24,140 MW of capacity is in dust emission non–compliance as of 1992
At $45–70 per kW for the installation of Pulse–jet fabric filters, fabric filters or ESP's, would cost US$ 1.1 to 1.7 billion to retrofit this stock to be in full compliance by 1997/98
Levelized control costs to control approx. 465,000 tons of dust/year with a >90% efficiency.
(cost estimates are derived from EPRI and industry estimates)

4. Market Estimate

The cost for retrofitting the Polish power utility industry is estimated to be $6.1 billion. The estiamte has been made based on average costs for technologies which have been successfully operated at United States and European utility systems. The cost for environmental control equipment is estiamted as follows: SO2 control is estimated to be $3.1 billion; NOx control is estimated at $1.5 billion and dust control at about $1.5 billion.

Appendix 4.1
Generation Reliability Analysis for Determining Tariff Periods

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GENERATION RELIABILITY ANALYSIS FOR DETERMINING TARIFF PERIODS

1. INTRODUCTION AND SUMMARY

The marginal cost of electricity generation fluctuates with the hourly demand, because (1) generating units typically are dispatched in order of increasing energy cost, and (2) the higher the load, the more likely that it cannot be met by *all* available generating units, resulting in "loss of load." Thus the marginal cost of electricity generation can be divided into two components: energy and capacity, or reliability. Prices that reflect variations in marginal costs are economically desirable, because they tend to shift demand to the lower-cost periods and thereby reduce supply costs. Therefore this chapter develops tariff periods—within the day, weekday vs. weekend, and seasonal—to summarize these variations in a simple, practical way. The capacity component generally is much more sensitive to the demand level than the energy component, so the tariff periods are based on a generation reliability analysis reflecting the capacity component only. A factor is derived for each tariff period to allow allocation of the capacity component of marginal generation cost across the periods. The marginal energy component will be allocated separately.

The marginal cost of electricity generation (both capacity and energy components) is probabilistic, primarily because the generating units are subject to random failures (forced outages). Therefore *expectations* over possible outcomes are calculated in probabilistic analyses (expectation is defined in Appendix A). The generation reliability analysis determines the probability of loss of load—that is, demand in excess of available capacity—for each hour of a forecast year (see Appendix A). This probability is called "loss-of-load probability" or LOLP. LOLP is proportional to the marginal generation capacity cost for an increment of demand, because it is the probability that this increment would go unserved. This is the same as the marginal capacity benefit of an increment of perfectly reliable generation capacity, and LOLP is also the probability that this increment would be needed to meet demand.

The average LOLP over a period is called the period LOLP, and it can be interpreted as the probability of loss of load at a random time in the period. The analysis described here determines period LOLPs for selected tariff periods, for allocating annual marginal generation capacity costs. The tariff period LOLPs can be interpreted as relative marginal generation capacity costs.

The variation of LOLP over a forecast year is due primarily to the variation of the hourly loads, though it results also from changes in the generation system (typically assumed to occur at most monthly), such as seasonal changes in supply and removals of units for their annual maintenance. Within each day, LOLP is related directly to the loads, after they are adjusted for energy-limited generation such as pumped storage. The relation between LOLP and load shows increasing sensitivity as the load increases, as Exhibit 1 shows. The result is that to a large extent the choice of tariff periods is determined by daily load shapes and seasonal variations, such as the historical 1991 shapes of Exhibit 2.

The base case reliability analysis for this study used forecast year 1997, with the forecast load shape based on the historical 1991 data summarized in Exhibit 2. Recent (1989-

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1991) historical load shapes show a morning peak period of about 7 am to 1 pm and an evening peak period that gradually becomes later in the day and shorter toward the middle of the year. Weekend loads are significantly lower than weekday loads, as shown in Exhibit 3. The LOLP results confirmed these observations and led to the recommended tariff periods shown in Exhibit 4. This exhibit also shows recommended LOLP factors, which are rounded base-case results.

The recommended tariff periods divide the year into winter and summer seasons. These serve to reflect changes in the evening on-peak periods rather than changes in overall reliability, because the monthly LOLPs are approximately equal across the year (due to the maintenance allocation, modeled as described in the next section). Exhibit 4 also shows LOLP factors for the combined morning and evening peak periods, to provide an alternative, simpler tariff structure.

The morning and evening peak periods in Exhibit 4 comprise the hours that have the highest average LOLP, as shown in Figure 1. The periods are similar to those used for the one-part and two-part tariff classes in a recent price list (7-Z/92, Electricity SWW 0311, Warsaw 1992). However, the on-peak periods of Exhibit 4 exclude weekends and are somewhat broader. Also, minor monthly variations among evening on-peak periods within each season are ignored for simplicity.

Nine sensitivity cases show that the LOLP factors are fairly insensitive to changes in assumptions, except for those concerning pumped storage operation and hourly load shapes. A detailed analysis of feasible hourly pumped storage operation with reliability and other objectives would be desirable in the future. Forecasting and analysis of possible changes in hourly load shapes were beyond the scope of this study. A gradual deepening of the afternoon valley has been suggested, but this would not clearly affect the choice of morning and evening peak periods. Every few years, as the load shapes and generation system evolve (especially with the addition of the Mloty pumped storage plant), the choice of tariff periods and the allocation of costs to them should be reviewed. The computer software tailored for this analysis (see the end of the next section) can simplify such reviews.

The next section describes the reliability analysis procedure, including the load forecasting, pumped storage modeling, and maintenance allocation. The third section describes the input data, and the final section gives the results and describes the sensitivity analyses.

2. PROCEDURE

Exhibit 5 flowcharts the procedure for calculating hourly and tariff-period LOLPs for a forecast year. Note that the calculations do not use any cost data. The first part of the procedure is to prepare the hourly load forecast. This requires scaling the recorded hourly demand for a historical year, so as to obtain a desired annual peak and load factor. This scaling was done by the following formula, where d denotes hourly demand, p denotes annual peak demand, LF denotes load factor, and each ' symbol denotes forecast:

$$d' = \frac{p'}{p}\left[d + \frac{LF' - LF}{1 - LF}(p - d)\right]$$

If the second term in the brackets were omitted, the scaling would provide the desired peak p' but not the desired load factor LF'. The second term increases off-peak demands in a simple way to achieve the desired load factor.

Recorded pumping loads were subtracted from the initial recorded loads before the scaling and were restored after the scaling, together with subtraction of hourly estimated pumping generation. A sophisticated pumped storage model would account for reservoir sizes and reliability vs. economic objectives, but was beyond the scope of this analysis. One simple alternative would be to use a historical year's pumping and generation in forecast years. However, this could miss the potentially increased generation from the pumped storage units if they are needed to avoid loss of load—an assumption appropriate for reliability evaluation. Therefore, the following simple "peak-flattening" model was used.

The pumped storage units were assumed to generate whenever the forecast load is within the total pumped storage capacity (derated for forced outages) of the daily peak load. The modeled generation was such that the net load after generation was the daily peak load minus the derated pumped storage capacity. The resulting annual energy generation in the base case (189 average MW) was not far from the actual 1991 energy generation (224 average MW), so the actual 1991 pumping loads were used (see Exhibit 6 for a summary of the actual pumping and generation). This model may underuse the pumped storage somewhat, but after testing with two sensitivity cases (see the last section) it was felt to be adequate for the current analysis.

The second part of the procedure calculates LOLPs for each hour of the forecast year and averages these over the tariff periods. The LOLP for a given load is found by looking up the probability that the available system capacity is less than the given load. This requires the probability distribution of available system capacity, which is calculated from the capacities and forced outage rates of the generating units (see Appendix A). Exhibit 7 illustrates the results of this calculation. For a large system such as Poland's, the distribution is very smooth.

Planned maintenance for the generating units was modeled by allocating an annual total maintenance capacity to the months of the year, so as to levelize monthly LOLP. The annual total maintenance capacity was calculated by adding the capacity of each unit, derated by its forced outage rate and multiplied by its maintenance duration as a fraction of a year. The monthly allocated maintenance capacities were subtracted from the available system capacities before the LOLPs were looked up.

The iteration shown in Exhibit 5 is needed to find the maintenance allocation that levelizes LOLP; typically about four iterations are required. The result is approximately equal monthly LOLPs for all months with maintenance, and higher LOLPs for any months with no maintenance. This maintenance model is simpler than schedulers which remove individual units each month or week of the year. However, such scheduling imposes a large computational burden and can result in arbitrary jumps in reliability from period to period, and the simpler model is reasonably accurate for long-term analyses.

After the hourly LOLPs are calculated, they are averaged to determine monthly, annual, and tariff-period LOLPs. Since the hourly loads represent instantaneous readings (starting at 1am each day), the LOLPs at both the start and the end of the morning and evening tariff periods were included, each weighted one half.

The REM (Reliability Evaluation Model) microcomputer model was used for all these calculations (see the *REM User's Manual*, Version 1.3). It consists of two Lotus 1-2-3® spreadsheets and a Fortran subroutine for the probability calculations, which is called automatically from one of the spreadsheets. REM also produces plots of the available capacity distribution, loads, and LOLPs similar to those in the exhibits here.

3. INPUT DATA

The base-case input data was a subset of the input data used for the production and marginal energy cost analyses, with a few exceptions as noted below. The demand inputs consisted of 1991 recorded hourly loads and pumping loads, and a forecast 1997 peak of 23,700 MW and load factor of 67.3%. The recorded loads included autoproducer self-loads, whereas the autoproducer generation data excluded the generation serving this load, so the 1991 autoproducer self-loads were subtracted from the recorded loads (as monthly average MW; see Exhibit 8, footnote 3).

Exhibit 8 shows the generation input data for year 1997. The derated pumped storage capacity was pre-dispatched hourly as described in the previous section. Combined heat and power (CHP) generation was allowed to vary monthly, rather than in two seasons as in the production cost analysis. The production cost analysis represented CHP, autoproducers, and hydroelectric generation with energy limitations, but the reliability model used 6-hour-per-day capacity estimates for CHP and average capacities (energy production divided by period length) for autoproducers and hydro, because the independent calculations for each hour prevent direct modeling of energy limitations. The average-capacity representation may be conservative, especially for dispatchable hydro, but relatively little generation is involved.

An alternate set of forced outage rates, shown in the last column of Exhibit 8, was used in a sensitivity case (see the next section). In this as well as the base case, the forced outage rate for Belchatow was lowered from the production analysis assumption, based on updated information.

4. RESULTS AND SENSITIVITY ANALYSES

Using the tariff periods of Exhibit 4, the base case and nine sensitivity cases were analyzed, giving the results summarized in Exhibit 9. A brief discussion of each case follows.

Base Case

In this case as in most of the sensitivity cases, all 12 monthly LOLPs were equalized by the maintenance allocation, which assigned some maintenance to every month. However, the flatter summer load shape results in a lower evening-peak LOLP and a higher off-peak LOLP (closer to the annual average of 100%) in the summer than in the winter.

Year 1992 Case

This case used forecast 1992 loads and resources. The tariff-period LOLPs were almost identical to the base case, despite a higher annual LOLP.

325

500 MW Added Case and 500 MW Removed Case
These cases added and removed, respectively, 500 perfectly reliable MW from the system. Alternatively, these cases can be thought of as base-load decrement and base-load increment cases respectively. The results suggest that as capacity is added, the relative contributions of the peak periods to annual LOLP increases, and the opposite as demand increases.

Load Uncertainty Case
This case used the load uncertainty feature of the REM model (see the *REM User's Manual*), which has effects similar to weighting the results of the base case and the two cases above. Possible errors in the forecast demand are represented by a bell-shaped (Gaussian) probability distribution (which is represented as 11 cases). The spread of this distribution was such that there is a 90% probability that the demand is within plus or minus 500 MW of the forecast in every hour. The results are intermediate between those of the +500 MW and -500 MW cases.

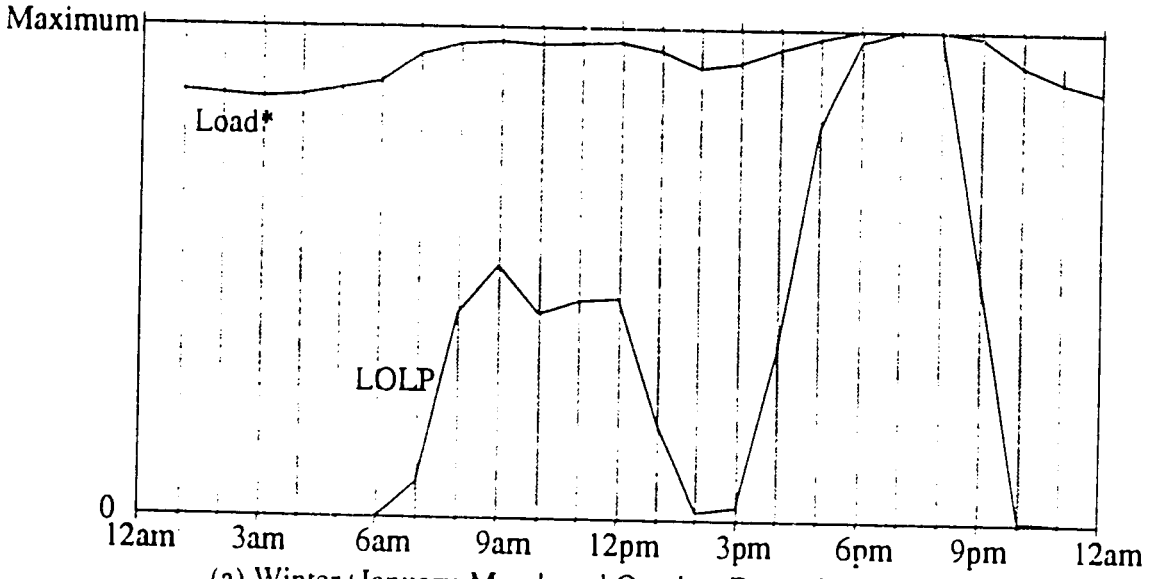
Alternate FORs Case
This case used the alternate forced outage rates shown in the last column of Exhibit 8, obtained more recently than the base case data. Results are fairly insensitive to this change.

1990 Load Shape and 1989 Load Shape Cases
These cases started with 1990 and 1989 recorded loads instead of 1991 recorded loads in the load forecasting. In the base case, autoproducer self-loads were removed from the recorded loads, and pumping loads were removed until after the scaling that produced the forecast peak and load factor. These steps were skipped here because the 1990 and 1989 self-loads and pumping loads were not readily available; however, the scaling provided the same peak and load factor as in the base case. The results are similar to the base case except that in the winter, the evening peak period contributes more, and the morning peak period less, to the annual LOLP. Whether or not these results suggest a trend of flattening winter load shapes could be investigated in the future.

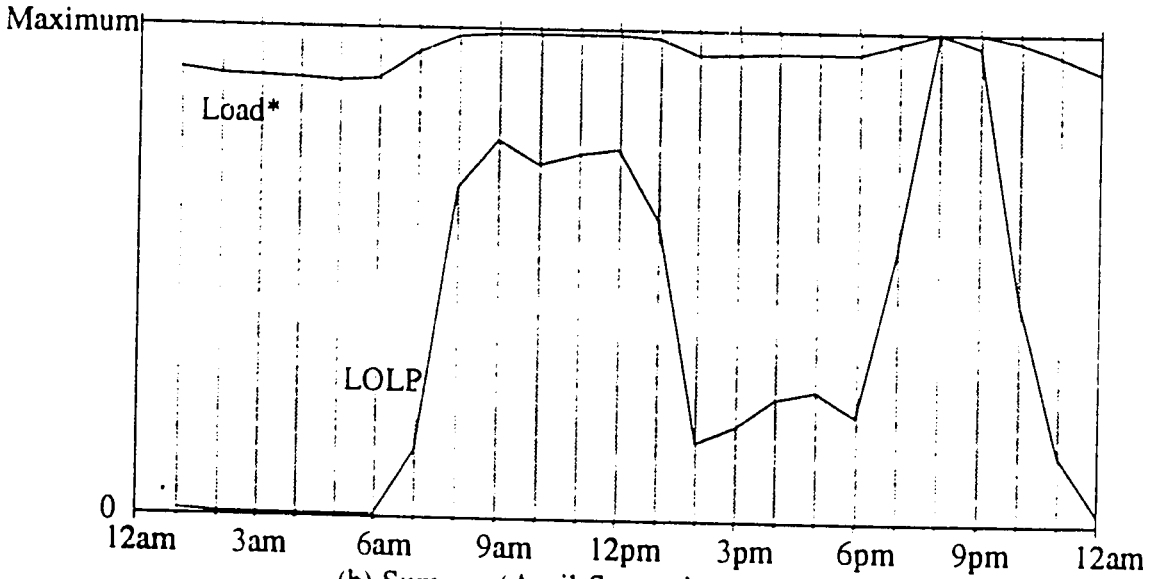
Pumping Load Ignored Case
This case modeled pumping generation as described, but included no pumping load. The similarity of the results to the base case suggests that accurate modeling of the pumping load is not critical.

Historical Pumped Storage Case
This case used historical 1991 pumping generation, rather than the model described, together with historical pumping load. Annual LOLP is lower because the actual generation (224 average MW) was higher than the modeled level (189 average MW). The weekday evenings contribute relatively more, and the weekday mornings contribute relatively less, to the annual LOLP compared to the base case. Whether this reflects operational objectives other than reliability or limitations of the pumped storage model used here could be investigated in the future.

Exhibit 1
Average Load and LOLP by Time of Day (TOD) for 1997



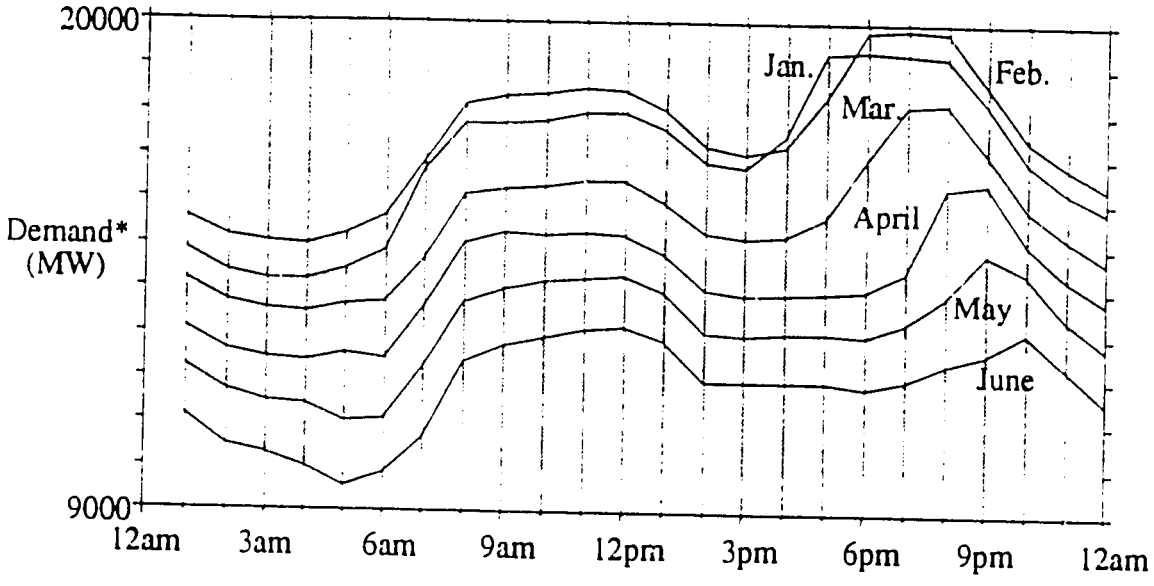
(a) Winter (January-March and October-December)



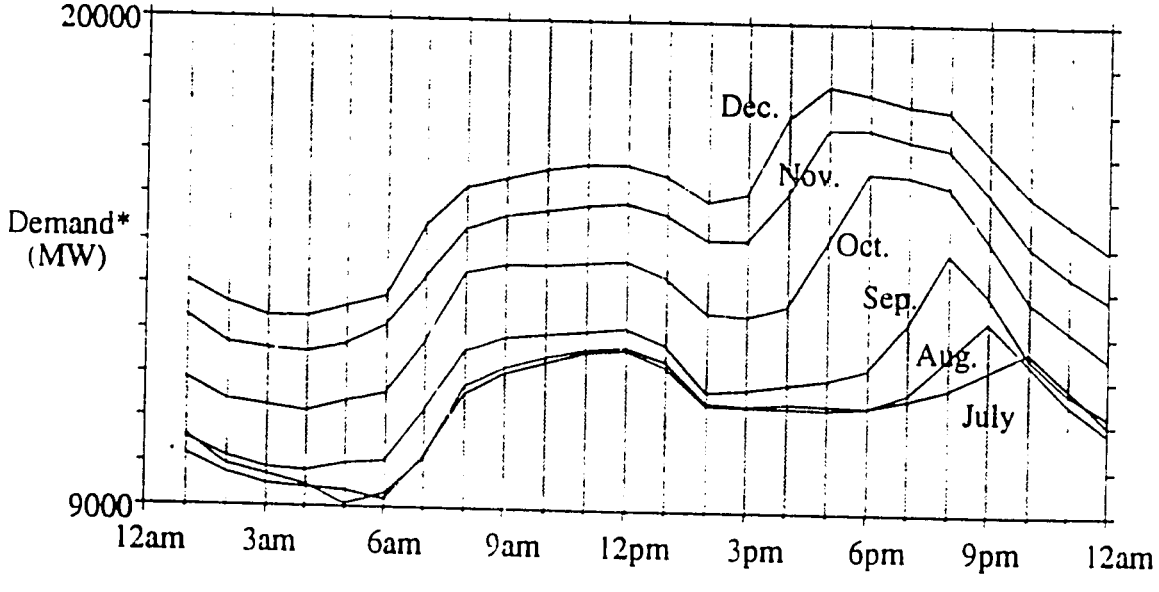
(b) Summer (April-September)

* Load is after modeled pumped storage load and generation.

Exhibit 2
Average Demand by TOD for each Month of 1991



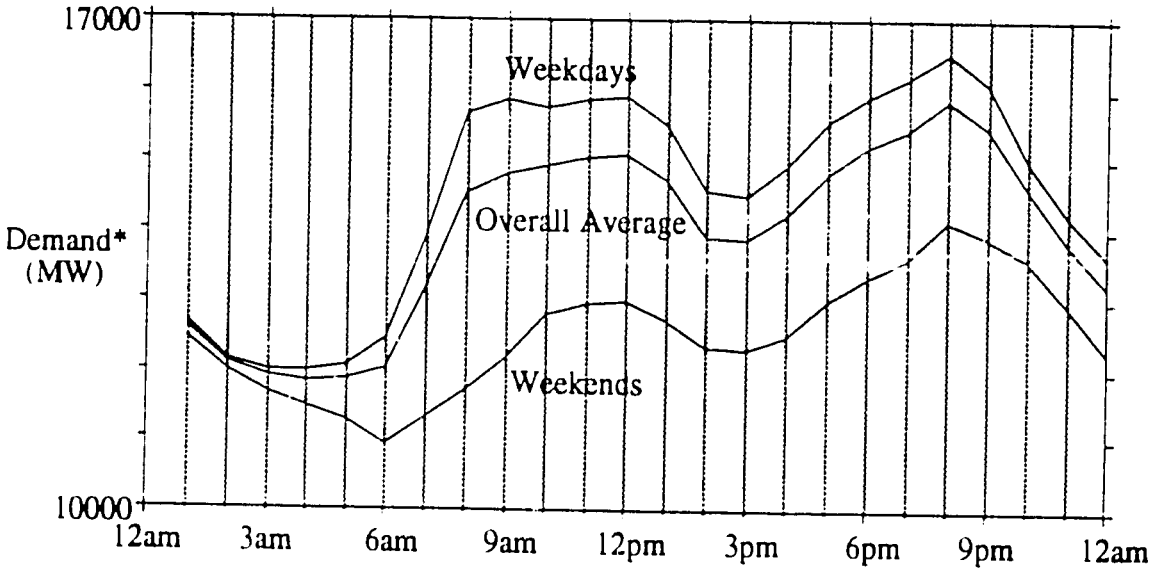
(a) January-June



(b) July-December

* Demand excludes pumping load and autoproducer self-load.

Exhibit 3
Average Demand by TOD for Weekdays vs. Weekends in 1991



* Demand excludes pumping load and autoproducer self-load.

Exhibit 4
Recommended Rating Periods and Their LOLPs

Season	Morning Peak	Evening Peak	Combined Peak	Off-Peak
Winter = October-March	7am-1pm weekdays: 190%	4pm-9pm weekdays: 400%	Morning + evening periods: 280%	Remainder of week: 10%
Summer = April-September	7am-1pm weekdays: 260%	7pm-10pm weekdays: 320%	Morning + evening periods: 280%	Remainder of week: 30%

Note: percentages are period LOLPs as a percentage of annual average LOLP, and their weighted average using period lengths as weights equals 100%, except for rounding error.

Exhibit 5
Annual Calculation Flowchart

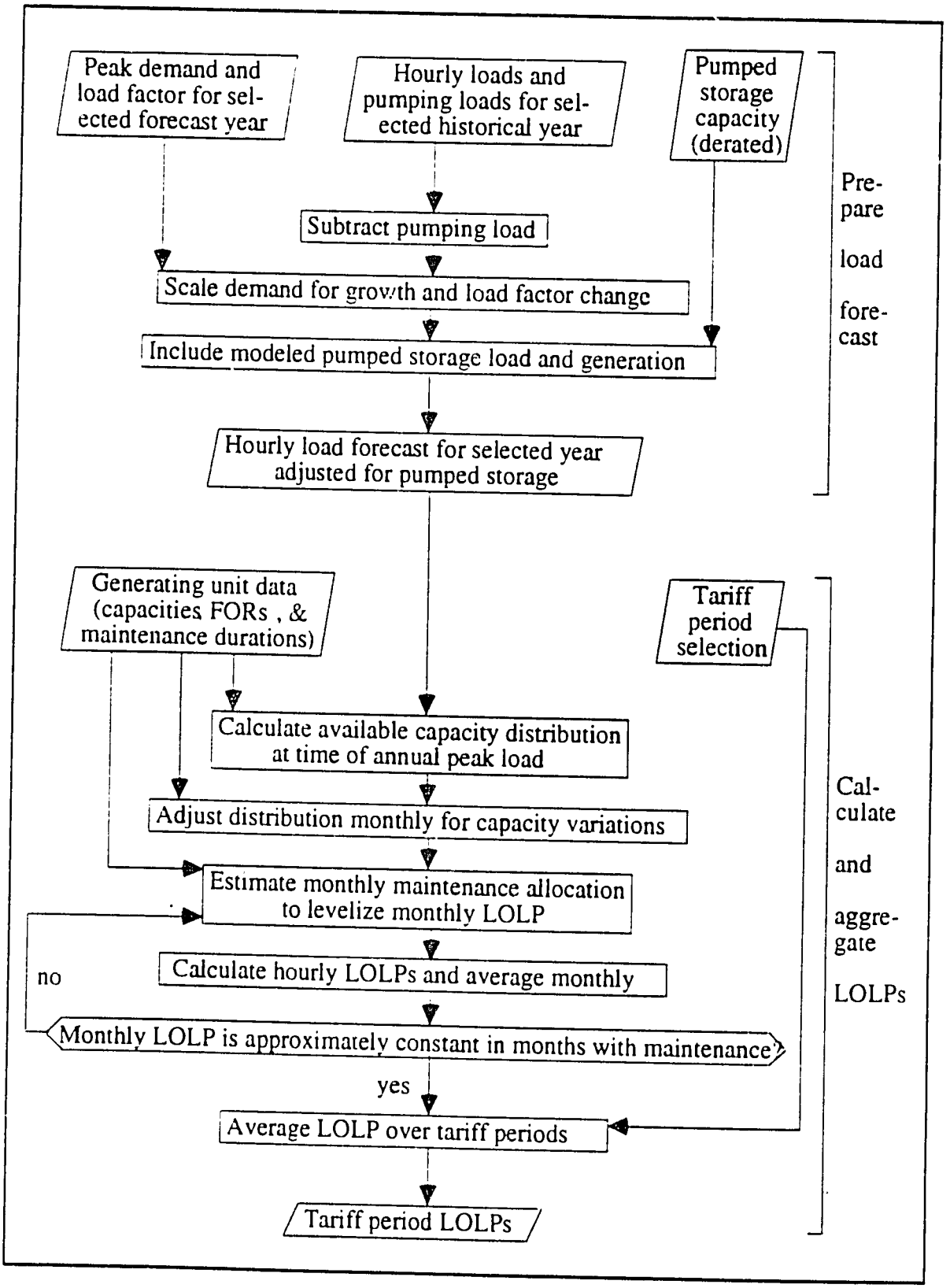


Exhibit 6
Average 1991 Pumping Load and Generation by TOD

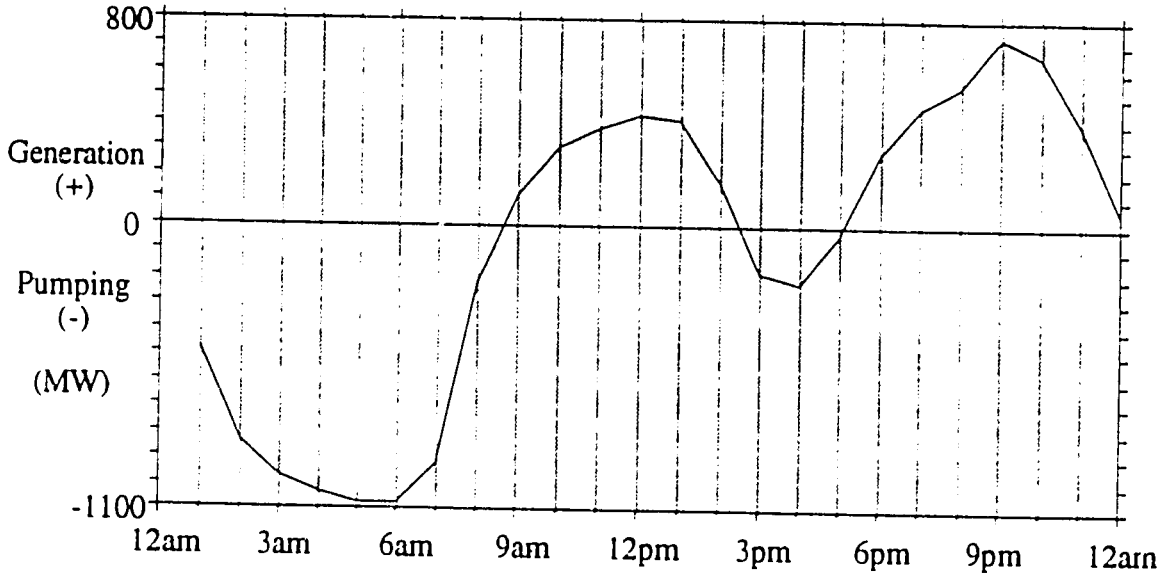
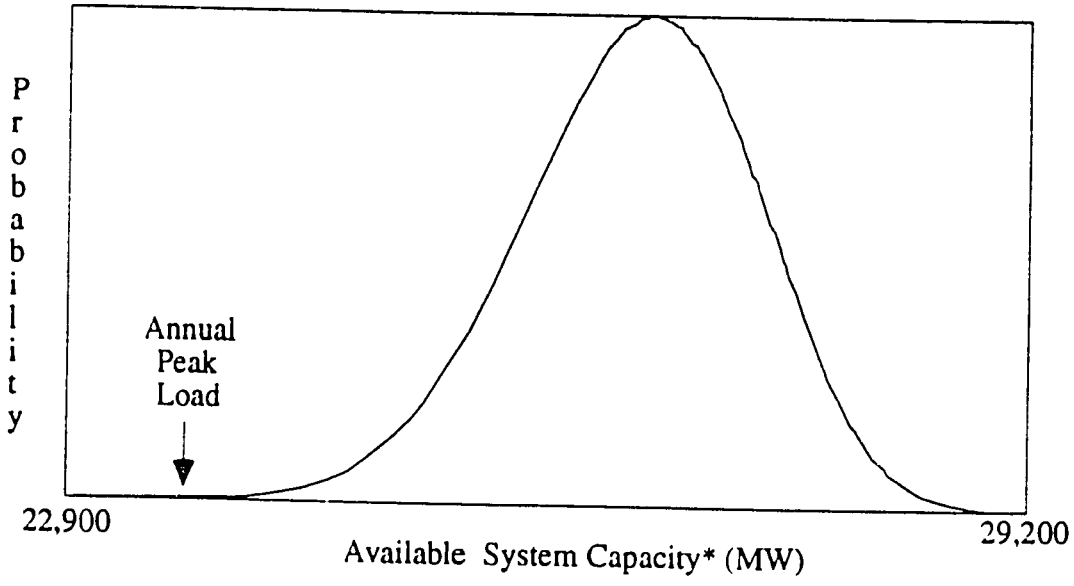


Exhibit 7
Probability Distribution of Available System Capacity in 1997



* In month of forecast peak load (February), before subtracting maintenance.

Exhibit 8
1997 Generation System Data for Reliability Analysis

Plant	Units	F.O.R.	Unit Cap. (MW)	Maint. (days/y)	Alternate F.O.R.s (Sensitivity Case)
Pumped Storage (derated)	1	0[1]	1264[2]	22	0[1]
Hydro (avg. energy)	1	0[1]	163	0	0[1]
Autoproducers (avg. en.)	1	0[1]	59[3]	0	0[1]
CHP (6 h/day capacity)	1	0[1]	4249[3]	0	0[1]
Belchatow 360	12	0.1	360	45	0.1
Patnow 200	8	0.106	200	45	0.1
Turow 200	8	0.105	200	45	0.1
Konin 100	2	0.121	120	45	0.11
Adamow 100	5	0.158	96	88	0.117
Konin small	6	0.13	40	45	0.13
Kozienice 500	2	0.3	500	60	0.249
Opole 360	6	0.108	360	45	0.1
Ostroleka 200	3	0.116	200	45	0.123
Kozienice 200	8	0.117	200	45	0.1
Polaniec 200	8	0.071	200	45	0.1
Rybnik 200	8	0.108	200	45	0.1
Jaworzno 3 200	6	0.107	190	45	0.1
Laziska 200	4	0.134	180	45	0.141
Dolna Odra 200	8	0.095	200	45	0.1
Laziska 100	2	0.162	100	45	0.138
Stalowa Wola 100	2	0.112	106	45	0.112
Lagisza 100	7	0.119	103	45	0.117
Siersza 100	6	0.116	105	45	0.1
Stalowa Wola small	3	0.1	33	45	0.1
Skawina small	3	0.104	45	45	0.13
Jaworzno 2 small	7	0.104	43	45	0.13
Blachownia small	1	0.107	41	45	0.14
Halemba small	4	0.118	50	45	0.12
Jaworzno 1 small	6	0.157	19	45	0.14
Miechowice small	3	0.118	50	45	0.12
Pomorzany small	1	0.123	56	45	0.12
Gas turbine 120	2	0.12	120	45	0.12

[1] Forced outage rate = 0 because capacity has been derated for forced outages or is an average based on energy production.

[2] Pumped storage available capacity is modeled with a maximum of 1330 MW - 5% for forced outages, and varies hourly as described in the text.

[3] CHP capacity, based on average monthly energies, and net autoproducer capacity after serving self-load vary monthly as shown below. 1991 monthly-average autoproducer self-loads, which were subtracted from the recorded 1991 hourly loads, are shown too.

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
CHP Cap. (MW)	4249	4249	4249	2974	2549	1700	1700	1700	2549	3824	4249	4249
Aut. Cap. (MW)	59	59	59	20	20	20	20	20	20	59	59	59
Aut. Self-Load (MW)	1097	1186	1027	897	722	650	562	598	660	934	1199	1214

Exhibit 9
Base and Sensitivity Case Results

Case	.....Tariff Period LOLP (% of Annual Average).....								Annual LOLE* (hours)
	.....Winter On-Peak.....			Winter	....Summer On-Peak....			Summer	
	Morn.	Eve.	Both	Off-Pk	Morn.	Eve.	Both	Off-Pk	
Base (Year 1997)	186	395	281	12.7	258	318	278	34.2	16
Year 1992	185	395	281	12.5	259	319	279	33.9	25
500 MW Added	174	411	282	11.6	262	330	284	32.4	3.3
500 MW Removed	197	374	277	14.0	256	305	273	36.4	59
Load Uncertainty	195	381	280	13.8	255	306	255	35.9	26
Alternate FORs	182	399	280	12.3	260	321	280	33.8	11
1990 Load Shape	151	427	277	13.6	256	323	279	34.5	7.9
1989 Load Shape	91	515	284	10.6	250	367	289	31.6	40
Pumping Ld. Ignored	188	400	284	11.2	269	331	290	29.7	15
Historical Pumped Storage	90	537	293	6.3	243	536	341	11.4	9.9

* LOLE = sum of hourly LOLPs = expected cumulative duration of loss of load.

Note: average of period LOLPs weighted by period lengths = 100%.

APPENDIX A: PROBABILITY AND GENERATION RELIABILITY MEASURES

REVIEW OF PROBABILITY AND EXPECTATION

The probability of an event A, P(A), can be interpreted as the long-run average frequency that A would occur in a repeated experiment. Some properties of probability are:

- It must be between 0 and 1.
- If events A, ..., Z include all possibilities (are "collectively exhaustive") and do not overlap (are "mutually exclusive"), then P(A) + ... + P(Z) = 1.
- P(A and B) = P(A) P(B given A) = P(B) P(A given B). If A and B are independent, the "given ..." conditions can be dropped, so that P(A and B) = P(A) P(B). If A and B are mutually exclusive, P(A and B) = 0.
- P(A or B) = P(A) + P(B) – P(A and B). The last term is 0 if A and B are mutually exclusive.

Expectation, or expected value, applies to a "random variable," which is a variable that can take on different numerical values with associated probabilities. The expectation of random variable X, E(X), is the average of possible values of X weighted by their probabilities. Some distinctions between expectation and probability are:

- Probability applies to an event, but expectation applies to a random variable.
- A probability must be between 0 and 1, but an expectation can be any value between the smallest and largest possible values of the random variable (depending on the probabilities for the possible values).
- P(A or B) can be less than P(A) + P(B), but E(X + Y) = E(X) + E(Y).

These distinctions are illustrated below.

GENERATION RELIABILITY MEASURES

In generation reliability evaluation, loss-of-load (LOL) events at each hour of the year are considered. Let $LOLP_t$ = P(LOL at hour t). This is called the instantaneous (or hourly) loss-of-load probability. Any probability of an event can be expressed as an expectation: the expected number of events (either 0 or 1) that occur. Thus

$$LOLP_t = P(\text{LOL at } t) = E(\text{number of LOL events at } t)$$

Let the random variable X equal the number of LOL events over a year (or other specified period). Then the loss-of-load expectation, or LOLE, for this period is E(X). This can be calculated as

$$LOLE = \text{sum over } t \text{ of } LOLP_t$$

because of the property given above that expectations sum. LOLE can be interpreted as the expected cumulative duration of LOL over the period.

LOLE can be expressed in fractional units by dividing by the period length. This gives the "period LOLP":

$$\text{period LOLP} = \frac{\text{LOLE for period}}{\text{length of period}}$$

Period LOLP can be interpreted as the probability of LOL at a time selected at random from the period. But it is easier and safer to think of period LOLP as LOLE in different

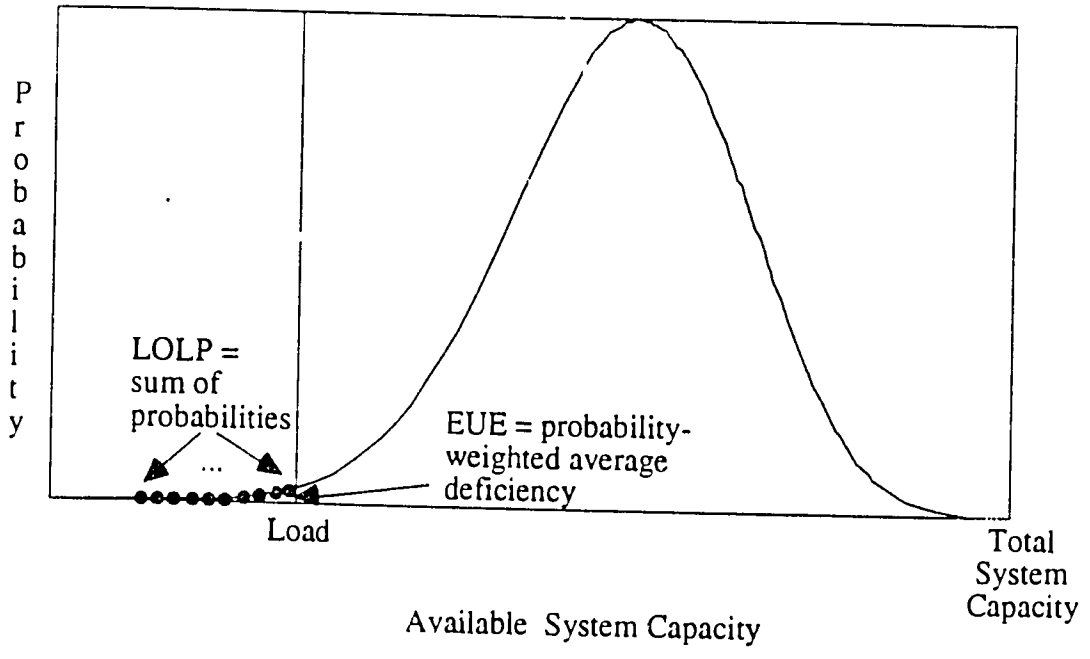
units—an expectation rather than a probability. This avoids confusion with the probability of *one or more* LOL events in the period, which is difficult to calculate (because P(A or B) can be less than P(A) + P(B)).

Another generation reliability measure is expected unserved energy (EUE), the expected energy demanded but not supplied due to LOL. Unlike LOLP, it incorporates the possible magnitudes of LOL. All these measures can be calculated from the forecast loads and the probability distribution of available system capacity, as described below.

CALCULATING THE AVAILABLE SYSTEM CAPACITY DISTRIBUTION AND RELIABILITY MEASURES

The available system capacity is the sum of the available capacities of each generating unit. The available system capacity is uncertain (that is, a random variable), because the available capacity of each generating unit is uncertain, equaling either the rated capacity, with probability one minus the forced outage rate, or zero, with probability equal to the forced outage rate. (Partial capacities and probabilities could be included too.) The probability distribution of available system capacity can be calculated from the probability distributions of available capacity for each generating unit. One approach to this calculation is to consider every possible combination of outcomes for all generating units in a "probability tree." This method is impractical for large systems, so a more efficient method called convolution is used in models like REM (see Chapter 3 of the *REM User's Manual*). Convolution, unlike the probability tree, assumes that the available capacities of the generating units are independent.

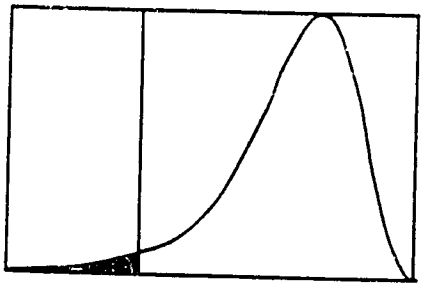
For a large system, the probability distribution of available system capacity typically is a smooth curve, as illustrated below. LOLP and EUE for any hour can be calculated from this curve as shown. Alternatively, these measures can be calculated in a simple way from the *cumulative* probability distribution of available system capacity. LOLE and EUE for a period are the sums of these results over the hours of the period.



REM

User's Manual

Reliability Evaluation Model
Version 1.3, December 1992



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Chapter 1 Features

REM is a flexible electric generation reliability model with a Lotus 1-2-3® user interface. Table 1 summarizes the model features.

Reliability Outputs	Loss-of-load expectation or probability (LOLE/LOLP), expected unserved energy (EUE), capacity adjustment to meet reliability criterion, available reserve distribution and optional plot.
Analysis Periods	User-specified (e.g., annual or monthly); number is limited by available memory – up to 126 periods fit in the spreadsheet.
Maximum Number of Generating Unit Forced Outage States	Unlimited except by the spreadsheet size.[1]
Maximum Number of Loads Per Period	2000.[2]
Accuracy	User controllable; no approximation required.[2]
Method	Discrete convolution of units and loads (treated as a single, multi-state negative-capacity unit), with compensated rounding to a user-specified step size.
Computer Environment	IBM-compatible microcomputer with Lotus 1-2-3 Release 2.2 or compatible version; 512K or more bytes of memory preferable.
Model Languages	Lotus 1-2-3 macros, Fortran 77.
Benchmark Speed	50 seconds to run the 32-unit IEEE Reliability Test System with 364 loads on an IBM AT microcomputer (see Appendix B).[3]

Table 1. Main Features

[1] The data for each unit are written as a single string, which 1-2-3 limits to a maximum of 240 characters. The advanced user can bypass this constraint by a small modification to the 1-2-3 code.

[2] The Fortran part of REM allows no more than 2000 states for generating units, loads, and the available reserve distribution, but the code may be recompiled with this parameter increased. Because 1-2-3 spreadsheets have 8192 rows and REM takes loads by row, REM cannot read all hourly loads of a year directly. The companion spreadsheet *LAGG* (Load/LOLE Aggregator – see Appendix C) allows an hourly load file for a year to be converted to hourly LOLEs.

[3] The version of the Fortran code exploiting the math coprocessor was used. The *LAGG* spreadsheet converts 8760 hourly loads to LOLE/LOLP in about 2 minutes with this computer.

REM has some special features that set it apart from standard reliability models:

- A customizable spreadsheet interface, convenient for input preparation, input and output reports, and plotting.
- A load uncertainty model.
- Separate peak-load-only reliability results.
- A two-parameter approximation of relative LOLE or EUE vs. load around zero available reserve (for the peak load as well as the full period).
- Quick (three keystroke) plotting of the available reserve distribution.
- A monthly reserve margin adjustment in the companion *LAGG* spreadsheet, for representing monthly-varying capacity and maintenance.
- A monthly maintenance adjustment worksheet, which levelizes monthly reserve margins, in the companion *LAGG* spreadsheet.

Features found in some reliability models but not in *REM* Version 1.3 include:

- Automatic maintenance scheduling levelizing a probabilistic measure of reliability across months or weeks of each year.
- Conversion of chronological loads to load duration curves (typically simplified, with greater accuracy near the peak load,
- Energy limitation modeling (e.g., peak shaving for hydro generation).

Chapter 2 A Guided Tour

REM is designed to be largely self-explanatory, and hands-on practice is the quickest way to learn how to use it. All you need is some familiarity with Lotus 1-2-3, DOS (IBM's Disk Operating System), and electric generation reliability. 1-2-3 skills that are assumed include inserting and deleting rows in the spreadsheet, copying ranges, using the GOTO and CALC keys, and invoking macros. The necessary reliability concepts are reviewed in Appendix A.

Starting the Spreadsheet

To set up the model, copy the *REM* files below from your master disk into a DOS directory:

- REM.WK1 – the 1-2-3 model and data spreadsheet, containing a small example,
- SREL.EXE – the compiled Fortran part of the model, and
- SRELBAT.BAT – a small batch file to run the Fortran program.

The additional file SREL-COP.EXE is equivalent to SREL.EXE except that it requires a math coprocessor in the computer. If your computer has this, you may want to first rename SREL.EXE to SREL-NOC.EXE (indicating that it is the no-coprocessor version), rename SREL-COP.EXE to SREL.EXE, and copy this file instead. This will reduce the Fortran run time substantially.

It's simplest to keep these files in the same directory and start 1-2-3 from this directory, so that 1-2-3 will find the batch and Fortran files in its default directory when running *REM*. Additional files you should copy are:

- REM-IEEE.WK1 – like REM.WK1, but with benchmark data used for Appendix B, and
- LAGG.WK1 – the 1-2-3 spreadsheet for hourly load-to-LOLE conversion and aggregation, described in Appendix C.

Before starting *REM*, change to the *REM* directory if you are not there already. This is necessary because *REM* will look for the SREL files in the current directory. To load the *REM* spreadsheet, type as a DOS command:

```
123 -wrem
```

(This starts 1-2-3 and immediately loads REM.WK1 .) You'll see the example spreadsheet of Figure 1. Try the on-line help, which is reproduced in Figure 2.

Figure 1. Initial Spreadsheet

REM (Copyright (c) RCG/Hagler Bailly, Inc., 1991-2) Version 1.3, 12/92
User's Manual Example
(For help, press F5 and type 'help'.)

PERIOD:			.....Year 1.....		.....Year 2.....	
INPUT SECTION						
Plant	Units	F.O.R.	Partial Cap.(MW)	Unit Cap.(MW)	Partial Cap.(MW)	Unit Cap.(MW)
Plant 1	12	0.1		10		10
Plant 2	1	0.1		0		10
Plant 3	1	0.05		20		24
partial state		0.02	5		6	
partial state		0.05	10		12	
partial state		0.03	15		18	
Total (to update current pds., press Alt-t)				140		154
Expected Peak Load (MW)				100		120
Reserve Margin (%)				40.00%		28.33%
Load Uncertainty Model:						
90% Confidence Increase (%)				0.00%		0.00%

Load Duration Curve:

% of Peak	Cum. % of Time	% of Peak	Cum. % of Time
100.00%	1.00%	100.00%	100.00%
99.00%	2.00%		
98.00%	4.00%		
95.00%	10.00%		
90.00%	20.00%		
80.00%	50.00%		
60.00%	100.00%		

Figure 1. Initial Spreadsheet (continued)

CONTROLS SECTION

Start with period number:	1	A positive integer. Allows skipping first period(s).
End with period number:	126	Allows skipping last period(s). A blank PERIOD name (e.g. in col. D) also stops the run.
Measure (LOLE or EUE):	LOLE	LOLE = loss-of-load expectation (frac); EUE = Expected Unserved Energy (MWh/h in pd.)
Reliability Criterion (-1 for none):	0.002739	Same units as measure. Used to find "Perfect Capacity Over Criterion".
# of System Reserve Probs. to Show:	2000	An integer between 0 and 2000 (the maximum number calculated).
Step Size for System Reserve (MW):	10	A positive integer. Smaller values are more accurate but slower.
Cutoff Prob. for Reserve Dist.:	1.00E-08	Between 0 and 1. Smaller values are more accurate but slower.

RESULTS SECTION (to run model & update results, press Alt-r)

PERIOD:	.....Year 1.....			
Period Reliability (units of measure)	0.004313		0.058365	
Perfect Capacity Over Criterion (MW)	-1		-27	
Exponential Approx. Parameters (MW)	NA	NA	NA	NA
Peak Reliability (units of measure)	0.047371		0.058365	
Exponential Approx. Parameters (MW)	NA	NA	NA	NA

Available Reserve Distribution:
(set graph ranges with Alt-g)

Rsv.(MW)	Prob.	Rsv.(MW)	Prob.
-51	0.000000	-77	0.000000
-41	0.000001	-67	0.000000
-31	0.000016	-57	0.000005
-21	0.000122	-47	0.000054
-11	0.000726	-37	0.000414
-1	0.003446	-27	0.002495
9	0.013051	-17	0.011800
19	0.039059	-7	0.043595
29	0.090451	3	0.123247
39	0.157136	13	0.253810
49	0.200083	23	0.340892
59	0.196058	33	0.223684
69	0.175577		
79	0.124268		

Figure 2. On-Line Help

REM (Reliability Evaluation Model) Quick Help

To move quickly around the spreadsheet, use the range names, such as "inputs", "loads", "controls", and "results" (press F5, F3, and F3 again, and select a name). The macro Alt-r (hold down the Alt key and press "r") runs REM. REM works one period at a time, by running (1) a data writer, which writes out the data in the Input and Controls sections to a DOS file ("TEMPIN.DAT"), (2) a Fortran reliability program (SREL, or Single-period RELiability program), and (3) a data reader, which reads the results from another DOS file ("TEMPOUT.DAT"). Warning: the Fortran program requires a math coprocessor in your computer; you can check if it has one with /Worksheet Status. To run the Fortran program separately, e.g. for debugging invalid inputs, use /System and type "srel < tempin.dat".

Within some constraints, you may tailor the spreadsheet without interfering with REM's operation. Be careful not to delete rows with named cells. If you put many formulas in the spreadsheet, set recalculation to Manual (/Worksheet Global Recalculation Manual), or else REM (in particular, the data writer) will be slowed down.

In the input section, unit partial capacities and load "Cum. % of Time" values should be in ascending order, and "% of Peak" values should be in descending order. The data writer looks for a blank F.O.R. (forced outage rate) to signal the end of the plants (it does not look at the plant name field), and a blank "% of Peak" to signal the end of the load duration curve points. Therefore, don't leave blank rows within these subsections. The data writer also looks for the Expected Peak Load and Load Uncertainty data, but you may modify other rows such as the total capacity.

In the Results section, you may insert rows above the Available Reserve Distribution subsection, e.g. to provide LOLE in hours per year by multiplying by 8760. The exponential approximation parameters are fitted from the reserve distribution in the neighborhood of 0 reserve, if possible, and are set to NA otherwise. The two parameters, m and s respectively, are those of the cumulative reserve distribution approximation:

LOLE exp(r/m - (r/s)**2)

which may be interpreted as LOLE as a function of constant load increment r; or if the EUE measure is selected,

EUE exp(r/m - (r/s)**2).

If you get a "Memory Full" error during a REM run, you can reset the mode indicator at the top right of the screen by pressing Alt-c. Turning off UNDO will free up a lot of memory.

Exploring the Spreadsheet

The *REM* spreadsheet has sections for inputs, controls (which are special inputs), and results, as well as macros for running the model. A 1-2-3 range name labels the start of each section, so you can move to it quickly no matter how large the spreadsheet becomes. Explore these labels by pressing the GOTO key followed by the NAME key twice, and selecting from the resulting list. The most useful labels are `INPUTS`, `LOADS`, `CONTROLS`, and `RESULTS`. (The names beginning with a special character are for use by *REM*'s macros.)

Analysis Periods

The spreadsheet uses two columns per period, starting with the fourth column (D). This allows up to 126 periods within the width of a 1-2-3 spreadsheet. The example analysis covers two periods, labeled `Year 1` and `Year 2`. *REM* analyzes periods sequentially until it finds an empty cell in the first of a pair of period columns, in the row labeled "`PERIOD:`" (near the top of Figure 1). (You can also limit the analysis periods with controls shown below). Therefore, your periods must be labeled in sequential even-numbered columns (D, F, etc.), as in the example.

Plants and Peak Load

The example shows three plants, of which the first has 12 units, for a total of 14 units. *REM* assumes that all units at a plant have the same capacity and forced outage data. In year 1, Plant 3 has a full forced outage rate (FOR) of .05, and three partial FORs: .02 at 5 MW, .05 at 10 MW, and .03 at 15 MW. Therefore its full capacity of 20 MW is available .85 of the time (1-.05-.02-.05-.03). *REM*'s reliability calculations assume that partial capacities are in ascending order, as illustrated.

Plant 2 is not in operation in year 1, indicated by its 0 capacity. In year 2, both the full and the partial capacities of Plant 3 increase by 20%. The total capacity in Year 1 is 140 megawatts (MW), giving a reserve margin of 40% (reserve margin is defined as capacity over load, minus 1, expressed in percent). The total capacity for the current periods (set in the Controls section of the spreadsheet) is totaled for you by the macro Alt-t. To test it, erase the total capacity for either year and press [Alt]-[t]; the total should be restored after a moment. (Note that the CMD status indicator at the bottom of the screen is on while any macro is running.) Next, press the CALC key to ensure up-to-date reserve margins, which depend through formulas on the total capacities and the expected peak loads.

You may enter non-integer capacities and peak loads, but *REM* will use rounded, integer copies of them for the reliability calculations. Capacities should be non-negative, with one exception allowed: you may put in a negative-capacity unit with a zero FOR (and no partial FORs). This is useful for quickly simulating a base (constant) load increase.

To add or remove plants, it's easiest to use /Worksheet Insert Row or /Worksheet Delete Row. A blank row, or more precisely a blank FOR, signals the end of the plant data to *REM* (the plant name column is ignored). Therefore you mustn't leave any blank rows between plants. Also, a blank partial capacity cell under a filled cell indicates the end of a list of partial capacities. (Note that the first row for any plant has a blank partial capacity.)

Example 1: Adding a Plant

Suppose a new plant, "Plant 4", is to be added to the system shown in Figure 1. It consists of a single unit with a 10% forced outage rate and a capacity of 20 MW, in both Year 1 and Year 2. Using 1-2-3 commands, go to the blank row underneath the last plant (above the row labeled "Total"), and insert a new row. (Note that 1-2-3 inserts rows *above* the current row.) On the new row, enter in columns A through C the data: `Plant 4`, `1`, and `.01`, then skip a column, enter `20` in column E, skip another column and enter `20` again in column G. The skipped columns are for partial capacities, which are not needed here, and the second `20` is for the second period, Year 2.

Now update the total system capacity by pressing [Alt]-[t]. The totals should increase by 20 MW in each year.

Example 2: Adding a Partial Forced Outage Rate

Suppose Plant 2 is to be given a partial forced outage rate of 5% at 2 MW partial capacity, while retaining its 10% full forced outage rate. This means that on the average, 10% of the time Plant 2 is fully forced out, an additional 5% of the time only 2 MW are available, and the remaining 85% of the time all 10 MW are available. First, go to the row *below* the row labeled "Plant 2" and insert a row. In the first column, enter `'partial state` if you like (this is not required). Skip a column, and enter `.05` in column C. Enter `2` in column D, and again in column F (skipping column E). You may want to check now that the total system capacity is unchanged, by pressing [Alt]-[t] and watching the total system capacity.

Load Duration Curve

Move down to the "`Load Duration Curve`" data and note that in Year 1 the curve has seven points, most of which are near the peak, where accuracy is needed the most in reliability analysis. Of course, a realistic annual or monthly load duration curve would have many more points. In Year 2, only the 100% point is used because only peak-load reliability is desired.

Just as partial capacities must be in ascending order, the load duration curve values (modeled as negative capacities) must be in descending order. The "`Cum. % of Time`" data must be in ascending order ending at 100%, since these are cumulative. *REM* looks for a blank "`% of Peak`" to signal the end of the loads.

Load Uncertainty Model

Above the load duration curve, you can specify a simple load uncertainty model which gives a Gaussian (normal, or bell-shaped) distribution about the given loads. The distribution has zero expected value (mean), so that the loads you provide represent expected values. You specify only the "`90% Confidence Increase`": the load increase such that there is a 90% probability of a smaller load and a 10% probability of a higher one. (The 90% point is about 1.3 standard deviations above the mean for a Gaussian distribution. The 10% point is the same distance below the mean.) You enter this increase as a percent of the period expected peak load, and all loads in the period are assumed to have the same standard deviation, in megawatt rather than percentage terms. (Though a standard deviation that varies with the load might be somewhat more realistic, it would make *REM* run much more slowly.) As an example, an expected peak load of 100 MW and a 90% Confidence Increase of 5% imply a 90% probability that each load is no more than 5 MW higher than the value given.

REM accepts only discrete data, whereas the Gaussian distribution is continuous. Therefore *REM* discretizes the load uncertainty distribution into 11 points, by a "moment matching" technique.[4]

Controls

The next section, CONTROLS, contains explanations to the right of each control (see Figure 1). The initial values in the spreadsheet make good starting points. These values make *REM* calculate

[4] A reference for moment-matching discretization is A.C. Miller and T. R. Rice, "Discrete Approximations of Probability Distributions," *Management Science*, Vol. 29, No. 3, March 1983.

LOLE and apply a criterion of 1 day in 1 year (1/365). Figure B-1 in Appendix B illustrates how the `Step Size` control trades off speed and accuracy.

Results

Having reviewed all inputs, you're ready to run the model. Doing so updates the next section of the spreadsheet, RESULTS. To ensure that your run changes some results from those already there, you may want to change a control such as "`Reliability Criterion`," which affects the "`Perfect Capacity over Criterion`" results.

Press [Alt]-[r] to run *REM*. The mode indicator at the top of the screen tells you what's happening. Assuming all goes well, you will see the new results for both periods after a few seconds. To see a graph of the available reserve distribution for the last period analyzed (year 2), press [Alt]-[g] followed by Enter. LOLE is the sum of the probabilities (really, the sum of expectations, as explained in Appendix A) to the left of 0 reserve, and the Perfect Capacity over Criterion is the reserve where the cumulative probability just equals the criterion (positive or negative). You can verify the Perfect Capacity over Criterion by adding a plant with the negative of this amount of capacity and with zero FOR, i.e., perfect capacity. The resulting Perfect Capacity over Criterion should be 0.

Returning to the RESULTS section, note that the peak reliability (reliability at the peak load) is worse than the period reliability, which is an average for all loads provided. The exponential approximation parameters are NA (not available), because the approximation is valid only when the number of states is large enough and the available reserve distribution is smooth enough. When available, the parameters provide an approximation of the cumulative of the reserve distribution, which you graphed, in the neighborhood of zero reserve. This is useful for sensitivity analyses. Appendix A has more information about the approximation and the reliability measures.

Tailoring the Spreadsheet

You may tailor the spreadsheet for input preparation, reporting, or other purposes, as long as you don't move or delete the range names that *REM* looks for (which you saw in "Exploring the Spreadsheet"), and don't put extra rows or columns within input data ranges. *REM* assumes that plant data start two rows below the "`Plant`" header and end when a row has a blank FOR cell; and the load duration curve data start three rows below the "`Load Duration Curve:`" label and end

Figure C-3. SREL Fortran Program

```
C  Single-period electric generation reliability program.
C  Language: (almost) ANSI Fortran 77.
C  The simple I/O is intended for interfacing with other programs.
C  Change Log:
C  11/90    Bill Poland     First version.
C  12/90    Bill Poland     Added m & s parameter outputs for exponential
C                           approx., added switch for LOLE vs. EUE calcs.,
C                           refined COC calculation for EUE criterion.
C   1/91    Bill Poland     Added DELTA to control m & s estimation.

      program SREL
C  This single-period electric generation reliability program calculates
C  LOLE/LOLP (loss-of-load expectation/loss-of-load probability)
C  or EUE (expected unserved energy), and excess capacity over a
C  criterion, as well as the two parameters of an exponential approximation
C  of relative reliability as a function of available reserve.  The program
C  reads data from standard input device, calculates reliability, and
C  writes results to standard output device.  After an echoed title
C  line, the input is "list-directed," as follows.  It consists of a
C  base case group and one or more sensitivity case groups.  A group
C  consists of 6 controls, any number of unit/load descriptions, and a
C  terminating 0.  The controls are: step size, cutoff probability, type
C  of reliability measure, criterion, approximation step size, and output
C  control (see code comments below).  (Since changing the step size for
C  the sensitivities would be illegal, the step size is ignored after being
C  read for each sensitivity.)  A unit/load description consists of
C  a number of states, say n, followed by n integer capacities in ascending
C  order, and n-1 corresponding probabilities; the last one is computed
C  for you. You can model loads as a negative-capacity unit.  After
C  each input group is read, an output group, consisting of reliability
C  measures and an optional reserve probability distribution, is
C  written.
C  All calculations are done in double precision (but note that capacities
C  including capacity over criterion are integer on input & output).
C  Note the comment about the "sPrbMx" parameter below.  If it's set too
C  small, you'll get warnings written to unit 0.


C  Make declarations and initialize system
C  sPrbMx is maximum system probability array size: *** UPDATE AS NEEDED***
      integer sPrbMx
      parameter (sPrbMx = 2000)
      integer show
      double precision sum
      integer stepSz, capSz, cap(sPrbMx), sPrbSz, sPrbS0, type, delta,
     *        COC
      double precision cutOff, crit, rel, mParam, sParam, prob(sPrbMx),
     *                 prfRsv, prfRs0, sProb(sPrbMx), sProb0(sPrbMx)
      data prfRsv /0d0/, sPrbSz /1/, sProb(1) /1d0/
C     reserve for state i, rounded:
      iRsv(i) = idnint(prfRsv) + stepSz*(i-1)
      iRsv0(i) = idnint(prfRs0) + stepSz*(i-1)

C  Read base controls, and base data while building base system
      read (*,*)  stepSz, cutOff, type, crit, delta, show
```

```
1     read (*,*) capSz, (cap(i), i=1,capSz), (prob(i), i=1,capSz-1)
      if (capSz .ne. 0) then
         sum = 0d0
         do 2 i=1,capSz-1
2             sum = sum + prob(i)
         prob(capSz) = 1d0 - sum
         call ADDU(stepSz,cutOff,capSz,cap,prob,prfRsv,sPrbSz,sProb,
                   sPrbMx)
         goto 1
      end if

C  Find & write base results (including up to output lines of the
C  reserve distribution)
      call CALCR(stepSz,prfRsv,sPrbSz,sProb,type,crit,delta,rel,
     *           mParam,sParam,COC)
      if (crit .lt. 0d0) then
           write (*,91) rel, mParam, sParam
      else
         write (*,91) rel, mParam, sParam, COC
      end if
91    format( 3(1x,e22.15),1x,i10 )
      if (show .gt. 0)
     *   write (*,93) ( iRsv(i), sProb(i), i=1, min(show,sPrbSz) )
93    format(1x,i10,1x,e22.15)

C  Do the same for any sensitivity cases, after retrieving the base case
C  (note stepSz is effectively skipped in the read below, by use of i)
3     read (*,*,end=7) i, cutOff, type, crit, delta, show
      prfRs0 = prfRsv
      sPrbS0 = sPrbSz
      do 4 i=1,sPrbS0
4        sProb0(i) = sProb(i)
5     read (*,*) capSz, (cap(i), i=1,capSz), (prob(i), i=1,capSz-1)
      if (capSz .ne. 0) then
         sum = 0d0
         do 6 i=1,capSz-1
6             sum = sum + prob(i)
         prob(capSz) = 1d0 - sum
         call ADDU(stepSz,cutOff,capSz,cap,prob,prfRs0,sPrbS0,sProb0,
     *           sPrbMx)
         goto 5
      end if
      call CALCR(stepSz,prfRs0,sPrbS0,sProb0,type,crit,delta,rel,
     *           mParam,sParam,COC)
      if (crit .lt. 0d0) then
         write (*,91) rel, mParam, sParam
      else
         write (*,91) rel, mParam, sParam, COC
      end if
      if (show .gt. 0)
     *   write (*,93) ( iRsv0(i), sProb0(i), i=1,min(show,sPrbS0) )
      goto 3
7     end
```

Figure C-3. SREL Fortran Program (continued)

```
      subroutine ADDU( stepSz, cutOff, capSz, cap, prob,
     *                 prfRsv, sPrbSz, sProb, sPrbMx )
C  (first arguments)   in      in    in/ch in/ch in/ch ('ch' means changed)
C  (remg. arguments)    in/out in/out in/out    in

C  Does convolution: adds the probability distribution of the capacity
C  of a generating unit (or a load) to that of the system.

C  stepSz = step size for rounding unit probability distributions
C  cutOff = minimum system probability to be represented.
C           If set to 0 or very small, you might get a Fortran underflow
C           error.
C  capSz  = current size of cap and prob arrays.
C  cap    = array of unit capacities, in non-decreasing order.
C  prob   = array of corresponding probabilities.
C  prfRsv = perfect system reserves, i.e. minimum rsv. represented.
C  sPrbSz = current size of sProb array.
C  sProb  = array of system reserve probabilities.
C  sPrbMx = maximum size of sProb array, i.e. its dimension size.

...
      return
      end


      subroutine CALCR( stepSz, prfRsv, sPrbSz, sProb, type, crit,
     *                  delta, rel, mParam, sParam, COC )
C  (first arguments)     in      in      in      in      in      in
C  (remaining arguments) in    out    out     out     out

C  Calculates system reliability measures based on loss-of-load expec-
C  tation (LOLE) or expected unserved energy (EUE).  If type is 0, LOLE
C  is used; otherwise EUE is used.  If crit is nonnegative, COC is
C  calculated.

C  stepSz, prfRsv, sPrbSz, sProb: see documentation in ADDU.
C  type   = 0 for LOLE calculations, or any other integer for EUE.
C  crit   = LOLE criterion, i.e. minimum acceptable value, as a
C           fraction, or EUE criterion in units of capacity times
C           period length -- or a negative # to inhibit COC calculation.
C  rel    = LOLE or EUE for the period (for units, see above).
C  delta  = integer multiple (e.g. 5) of stepSz to use in estimating
C           mParam and sParam, or a nonpositive integer to skip
C           calculating them.
C  mParam = m parameter for exponential approximation of reliability fn.
C           (based on a range of 2 delta x stepSz starting at about 0 reserve)
C           i.e. F(r) = exp( r/m - (r/s)**2 ).  Note that this approx.
C           can be valid only for r << (s/2)(s/m), the r giving maximum
C           approximated F(r), because F(r) cannot decrease.
C  sParam = s parameter for exponential approximation of reliability fn.
C           (based on a range of 2 delta x stepSz starting at about 0 reserve)
C  COC    = perfect capacity in excess of the criterion (if calculated).
...
      return
      end
```

Appendix 4.2
Long-Term Simulation

APPENDIX 4.2.1
INPUT FILE

```
*****************************************************************************************
************************** GENERATION PLANNING TOOL - GPT ***********************************
**************************          INPUT DATA FILE   ***********************************
*****************************************************************************************
** INSTRUCTIONS FOR USING AND MODIFYING THIS FILE
** ---------------------------------------------
** 1) All lines in this file are 95 columns long
** 2) All lines starting with * are for comments and are not executable
** 3) All lines starting with F define fields under which data must be placed as follows:
** Fields shown as rrrr must have real numbers (with decimal point) anywhere under the field
** Fields shown as iiii must have integers right justified under the field
** Fields shown as aaaa must have alphanumeric characters
*****************************************************************************************
** The file is divided into three large parts: Part I contains only annual values.
** Part II contains only information on how annual values are to be distributed over periods
** in which the year may be subdivided. Part III contains only load duration curve patterns to
** be used as specified in Parts I and II.
** Each part contains several sections corresponding to specific types of data.
*****************************************************************************************
** To be recognized by GPT as an input file, this file must be stored under a name ending in
** ".gpt". Before execution the model will eliminate all comments and change the name to end in
** ".gpd". To save storage space, only ".gpd" files need to be kept and can then be renamed
** as ".gpt" in order to make them recognizable by the model prior to execution.
*****************************************************************************************
```

```
**
*****************************************************************************************
*****************************************************************************************
**
**              *******  ******  *******  *********        ****
**              **   **  **  **  **   **  *********         **
**              *******  **  **  **  ***     ***            **
**              **       ******  ******      ***            **
**              **       **  **  **  ***     ***            **
**              **       **  **  **   **     ***           ****
**
**                                ANNUAL DATA
*****************************************************************************************
*****************************************************************************************
**
*****************************************************************************************
**                                SECTION A
**                   PROGRAM CONTROL AND BASIC CHARACTERISTICS
*****************************************************************************************
** The following values will determine the basic characteristics of the model:
**
** OPTION          Select 0 if you are running in batch mode and you want the model to carry
** BATCH OR        on unattended. Select 1 if you want to be given the option to modify the
** INTERACTIVE     the ammount of screen output or interact with input data, including other
**                 program controls, during execution. Select -1 to monitor data entry.
**
** NUMBER OF       Indicate here how many hydroelectric plants will be considered including
** HYDROELECTRIC   existing and planned plants. Maximum 100 plants.
** PLANTS
**
** NUMBER OF       Indicate here how many types of different thermal units will be considered.
** THERMAL UNIT    A unit type is a particular combination of technology (steam, internal
** TYPES           combustion, diesel), fuel, size and even site. In short, anything that
**                 can differentiate one unit from another other than its commissioning date.
**                 Normally existing units require one type each because they have different
**                 operating records. Up to 200 types can be defined and there is no limit
**                 in the number of units that can be included in each type.
**
** NUMBER OF       Select 1 if the file will not contain data for subannual periods.
** SUBANNUAL       Select 2 or more if you want to use PART II containing the allocation of
** PERIODS         annual values to 2 or more subperiods within the year. Note: this last
**                 option will not be operational if any optimization of generation mix
**                 must take place.
**                 Select -n if data for n subperiods is present but you do not want to use
**                 it in this run even if there is no optimization involved.
**
** NUMBER OF       Indicate here how many water conditions will be defined. The number is the
** WATER           the same for all hydro plants and can be as high as 50.  Thus, for most
** CONDITIONS      it is possible to define one condition for each year of record.  However,
**                 this will make execution very slow and it is better to define only two
**                 (normal and dry), three (wet, normal and dry) or at the most four (wet,
**                 normal, dry and critical) water conditions.
**
** MODE OF         Select 0 if you want that all different hydroconditions be dispatched
** HYDRO           before any thermal dispatch takes place and 1 if you want that a particular
** DISPATCH        hydrocondition be randomly selected according to the relative probabilities
**                 of each.
**
** MODE OF         Select 0 if you want a deterministic dispatch in which thermal unit
** THERMAL         capacity is derated by its equivalent availability.  Select 1 if you
** DISPATCH        want a probabilistic (Booth-Baleriaux) dispatch. Note: this last option
**                 will not be operational if any optimization of generation mix must take
**                 place.
**
** LOAD            Select 0 if you want the model to use maximum accuracy (determined as a
** RESOLUTION      function of load, number of units and mode of dispatch) or enter a number
** STEP            in MW corresponding to the smallest interval of load to be resolved.
**                 Note: if you use this last option and you selected a number that is too
**                 small the model may exceed available computer memory and fail. If you
**                 select 0 (automatic) the model may take longer than necessary without
**                 appreciable change in results.  The best is to try 0 and note the value
**                 determined by the model, if it takes too long a larger value can be
```

```
**                  tried verifying that results remain largely constant.
**
** SCALE FACTOR     For small systems in which a load resolution of 1 MW could be tolerated
**                  by available memory, the model may give inaccurate results as it will round
**                  units to the nearest MW and some units may be too small for this.  In this
**                  case a scaling factor may need to be used.  As a general rule, the following
**                  formula should be used:
**
**                       peak load + peak load * (1+reserve)
**                       ---------------------------------- less than 5,000
**                            (scale/step)
**
** DATA PERIOD      The first and last of a series of consecutive years for which data is made
** YEAR START       available. Data Start must be always smaller than or equal to Simul.Start
** YEAR END         however, if the data period does not fully cover the simulation period
**                  simulation will continue using an input load growth rate and the fuel price
**                  escalation rate from the last year for which data is available.
**
** EXECUTION        The first and last years for which a simulation is desired.  Note that
** PERIOD           it is only required that the simulation starts at or after ther first
** SIMUL.START      year for which data is available. However it is not necessary that data
** & SIMUL.END      is available for the entire simulation period.
**
** EXECUTION        After the simulation period is completed the model can assume that the
** PERIOD           load and the production of each unit remains constant but fuel prices
** EXTRAP.END       continue escalating. This variable controls the end of that extrapolation.
**
*****************************************************************************************
**OPTION*NUMBER*NUMBER *NUMBER *NUMBER *HYDRO*THER.*LOAD*SCALE *    EXECUTION PERIOD      *
**BATCH *OF    *OF     *OF     *OF     *DISP.*DISP.*RES.*FACTOR*****************************
**  OR  *HYDRO *THERMAL*SUBAN. *WATER  *MODE *MODE *STEP*      *FIRST* DISCRETE YEARS  * LAST *
**INTER.*PLANTS*TYPES  *PERIODS*COND.  *     *     *(MW)*      *YEAR *   1     2     3 * YEAR *
**
F  i     iii     iii     ii      ii      i      i    rrrr rrrrr   iiii  iiii  iiii  iiii  iiii
   0     24      31      2       1       1      1    20.    1.    1992    0     0     0  2000
*****************************************************************************************
** NUMBER *DETAILED * RESOURCE  * RESOURCE  * RESOURCE  * RESOURCE  * RESOURCE  * RESOURCE    *
** OF     *OUTPUT   * MONITORED * MONITORED * MONITORED * MONITORED * MONITORED * MONITORED   *
** RANDOM *0 = NO   * IN SCREEN * IN SCREEN * IN SCREEN * IN SCREEN * IN SCREEN * IN SCREEN   *
** PASSES *1 = YES  *           *           *           *           *           *            *
**
F  iiii    iiii        iiii        iiii        iiii        iiii        iiii        iiii
     1      1           30          31          30          31          30          31
*****************************************************************************************
**
**                                SECTION B
                                   TITLE
*****************************************************************************************
** Following the last comment line there will be 23 executable lines.  Each line contains an
** alphanumeric field 75 columns long.  The contents of these 23 fields will be printed in
** every output produced using this data file.
**
F aaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaaa
 T   POLAND  -  ELECTRICTY PRICING STUDY - 1992
 T   POLISH POWER GRID COMPANY - POLSKIE SIECI ELEKTROENERGETYCZNE
 T   PSE1200 ANALYSIS - 13.Jan.93 - Arlington
 T   1200 series
 T   Same as 1100 series but rerun on probabilistic subannual mode for
 T   use by gpt-m. 1200 series is compatible with new GPT version that
 T   uses scale factor when necessary for small systems
 T
 T   Codes for thermal categories:  TF-II-SSS
 T   T: plant type:  T=s  dispatchable steam turbine
 T                    d  dispatchable steam turbine used in dh cogeneration
 T                    c  combustion turbine
 T   F: fuel type    F=l  lignite
 T                    c  hard coal
 T                    r  residual oil (bunker, #6)
 T                    d  distillate oil (gas oil, #2)
 T                    g  natural gas
 T   II: plant identification (see codes for plant names in section E)
 T                   xx  new capacity
 T   SSS: unit size class
```

```
  1                    000  denotes units under 100 mw
  2
  3
 **
 ******************************************************************************************
 **                                  SECTION C
 **                             BASE ECONOMIC PARAMETERS
 ******************************************************************************************
 ** This section contains economic parameters that are constant from year to year or the values
 ** at the first year of data (which is also the origin for discounting purposes) of those
 ** values which can change from year to year.
 ******************************************************************************************
 ** DISCOUNT  EFFECTIVE THERMAL  BASE  BASE YEAR          BASE  YEAR FUEL COST  ($/MMBTU)
 **  RATE     CAPACITY RESERVE   YEAR  PEAK LOAD        Lignite  Coal    Oil#6   Oil#2   Gas
 **   (%)      (% above peak)            (MW)          ($/Mbtu)($/Mbtu)($/Mbtu)($/Mbtu)($/Mbtu)
 **
 F  rrrrr  r  rrrrrrrrrrrrrrrr   iiii   rrrrrrrr        rrrrrrr rrrrrrr rrrrrrr rrrrrrr rrrrrrr
     12.00            0.0        1992   22024.0         1.6100  2.1220  2.1750  4.0600  3.50000
 *c dr/ as agreed
 *c ecr/ check correl. with lolp to define ecr if optimizing
 *c bypl/ excludes selfsupplied load
 *c byfc/ coal based on 30,000 zl/gj delivered at plant from comparison of WB coal prices cif
 *c byfc/ Gdansk plus 12.6% inland transport and PSE's values for current price w/o subsidies
 *c byfc/ of coal delivered at polish plants.
 *c byfc/ lignite based on comparison of actual price w/o subsidies of coal and lignite at
 *c byfc/ polish plants resulting on lignite price = 0.76 coal price
 *c byfc/ crude at 17.4 $/bbl (World Bank); oil#6 assumed at 75% and 6 mbtu
 *c byfc/ gas assumed to be an average of 75% of crude
 ******************************************************************************************
 **                                  SECTION D
 **                   ANNUALLY VARIABLE LOAD CHARACTERISTICS AND FUEL PRICE DATA
 ******************************************************************************************
 F          iii iii iii iii iii iii iii iii iii iii iii iii iii iii iii iii iii iii iii iii
 ******************************************************************************************
 **   ANNUAL LOAD FACTOR (1/1000) AND LOAD SHAPE NUMBER
 **   YEAR   92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
  L.F. (pth)648 653 657 662 672 673 676 677 681 670 673 677 680 683 686 689 692 694 696 698 700
 *c l.f. includes mloty pumping loads after commissioning in 1998
 *c l.f. includes end of exports after 2001
  SHAPE NO.   1   1   1   1   1   1   1   1   1   1   1   1   1   1   1   1   1   1   1   1   1
 ******************************************************************************************
 **   RANGE OF ANNUAL LOAD GROWTH RATE (1/1000)
 **   YEAR   92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
   MAX      000 009 014 021 005 025 022 024 021 003 023 023 023 023 023 023 023 023 023
   MIN      000 009 014 021 005 025 022 024 021 003 023 023 023 023 023 023 023 023 023
 *c base case with mloty from b.v.
 *c must include mloty pumping loads after commiss.
 ******************************************************************************************
 **   RANGE OF ANNUAL ESCALATION IN FUEL TYPE 1  (1/1000) - (or associated fuel type and cost ratio)
 **   YEAR   92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
   MAX        0 000 000 000 000 000 000 000 000 000 000 000 000 000 000 000 000 000 000
   MIN        0 000 000 000 000 000 000 000 000 000 000 000 000 000 000 000 000 000 000
 *c lignite 0.0% real escalation - assumes parallel with hard coal
 *c era of cheap lignite to end. apply escal. after 2000 to reflect depletion
 ******************************************************************************************
 **   RANGE OF ANNUAL ESCALATION IN FUEL TYPE 2  (1/1000) - (or associated fuel type and cost ratio)
 **   YEAR   92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
   MAX        0 000 000 000 000 000 000 000 000 000 000 000 000 000 000 000 000 000 000
   MIN        0 000 000 000 000 000 000 000 000 000 000 000 000 000 000 000 000 000 000
 *c coal prices dropping since 1990 assume constant
 ******************************************************************************************
 **   RANGE OF ANNUAL ESCALATION IN FUEL TYPE 3  (1/1000) - (or associated fuel type and cost ratio)
 **   YEAR   92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
   MAX        0 010 010 010 010 010 010 010 010 010 010 010 010 010 010 010 010 010 010
   MIN        0 010 010 010 010 010 010 010 010 010 010 010 010 010 010 010 010 010 010
 *c residual oil (1% real for oil & gas)
 ******************************************************************************************
 **   RANGE OF ANNUAL ESCALATION IN FUEL TYPE 4  (1/1000) - (or associated fuel type and cost ratio)
 **   YEAR   92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
   MAX        0 010 010 010 010 010 010 010 010 010 010 010 010 010 010 010 010 010 010
   MIN        0 010 010 010 010 010 010 010 010 010 010 010 010 010 010 010 010 010 010
 *c distillate oil (1% real for oil & gas)
```

```
*****************************************************************************************
**   RANGE OF ANNUAL ESCALATION IN FUEL TYPE 5  (1/1000) - (or associated fuel type and cost ratio)
**   YEAR   92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
  MAX        0 020 020 020 020 020 020 020 020 020 020 020 020 020 020 020 020 020 020
  MIN        0 020 020 020 020 020 020 020 020 020 020 020 020 020 020 020 020 020 020
*c natural gas (2% real)
**
*****************************************************************************************
**
**                                  SECTION  E
**                         ECONOMIC DATA ON THE GENERATING SYSTEM
*****************************************************************************************
** In this section the capital and operating cost for each generating resource are specified
** as follows:
**
** TYPE            Use H for hydro plants and T for thermal generation.
**
** NUMBER          A consecutive number for hydro plants and a consecutive number for thermal
**                 plants. These numbers for hydro and thermal will associate eachl plant
**                 with additional data in this file.
**
** IDENTITY        A 10 character word identifying the plant. For hydro and existing thermal
**                 plants this will typically be a proper name.  For alternative thermal
**                 plants it can have a code denoting the type of plant (example: GCC for
**                 gas-fired-combined-cycle) and a number denoting unit size.
**
** NAMEPLATE       The nameplate capacity of the generator in MW
**
** CAPITAL COST    This is the cost in dollars per nameplate MW at the price levels of the
**                 first year of data and including everything except interest during
**                 construction. Include spare parts inventory and fuel stock in this value.
**
** FIXED COST      This is the annual fixed operating cost in $ per nameplate MW, largely
**                 salaries and fixed maintenance contracts.
**
** VARIABLE COST   Include any non-fuel cost that vary as a function of power production such
**                 as lubricants and interim replacements.
**
** LIFE            This value is used to determine the capital annuity only and has no impact
**                 on the availability of the plant after commissioning.
**
** CASH FLOW       The negative numbers denote years prior to plant start up. Under each of
**                 these years go the percent of capital disbursed and assumed concentrated at
**                 the middle of the year. Year 0 is when start up occurs and can also carry
**                 a share of capital disbursements.
**
*****************************************************************************************
**T NO IDENTITY NAMEPLATE CAPITAL FIXED VARIABLE LIFE   CASH FLOW BEFORE AND AFTER COMMISSSIONING
**              CAPACITY COST    COST   COST  (YRS) EXPRESSED IN ROUNDED PERCENT OF CAPITAL COST
**                (MW)  ($/MW)($/MW-Y)($/MWH)    -0 -1 -2 -3 -4 -5 -6 -7 -8 -9-10-11-12-13-14
**
*c nc/ from pse statistics
*c cc/from wasp assumptions, verified by intl. prices
*c fc/for thermal is based on homogeneized historical data
*c fc/as a function of plant capacity: <500 MW fc=30$/kw
*c fc/ 500-1000MW fc=25$/kw; >1000MW fc=15$/kw
*c vc/for thermal corresponds to plant specific fuel transport
* a ii aaaaaaaaaa rrrrrrr rrrrrr rrrrrr rrrrrr ii ii ii ii ii ii ii ii ii ii ii ii ii ii ii ii
  H  1 PH-92-PUMP    1330.       0  10800    0.00
*c exstg. ps hydro zarnowiec (680) + zydowo (150) + porabka (500)
*c treated as a peaking hydro with pumping added to load forecast
  H  2 PH-MLOTY       750. 633000  10800    0.00  50  5 15 30 20 20
*c mloty pumped storage hydro treated like exs-ps-hyd
*c cc/harza 684-exstg. inv., net=633000
*c fc/use 1% of total cc
  H  3 CH-92-HYDR     640.       0  10800    0.00
*c solina (136) + dychow (75) + small hydros
  H  4 CH-VISTULA     170.1730000  10800    0.00 50  5 15 20 20 20 20
*c lower vistula hydro not relevant for oper. since commisioned late
  H  5 AC-92-AUTO    1290.       0  30000   21.1
*c nc/dispatcher's maximum available capacity from autoprod.
*c vc/assumed at 10000 Btu/kwh and economic coal price
  H  6 DC-92-CHP     3781.       0  .0000    .000
```

```
*c all chp plants defined as plants with high cogeneration coefficient
  H  7 DC-93-CHP      50.      0  .0000   .000
  H  8 DC-94-CHP     100.      0  .0000   .000
  H  9 DC-95-CHP     150.      0  .0000   .000
  H 10 DC-96-CHP     190.      0  .0000   .000
  H 11 DC-97-CHP     340.      0  .0000   .000
  H 12 DC-98-CHP     440.      0  .0000   .000
  H 13 DC-99-CHP     100.      0  .0000   .000
  H 14 DC-00-CHP     520.      0  .0000   .000
  H 15 DC-01-CHP     300.      0  .0000   .000
  H 16 DC-02-CHP     300.      0  .0000   .000
  H 17 DC-03-CHP     300.      0  .0000   .000
  H 18 DC-04-CHP     300.      0  .0000   .000
  H 19 DC-05-CHP     300.      0  .0000   .000
  H 20 DC-06-CHP     300.      0  .0000   .000
  H 21 DC-07-CHP     300.      0  .0000   .000
  H 22 DC-08-CHP     300.      0  .0000   .000
  H 23 DC-09-CHP     300.      0  .0000   .000
  H 24 DC-10-CHP     300.      0  .0000   .000
*c chp additions as per expansion plan table 6.1
  T  1 SL-BE-360     360.      0  15000   0.00
*c belchatow 360
  T  2 SL-PA-200     200.      0  15000   0.00
*c patnow 200
  T  3 SL-TU-200     200.      0  15000   0.00
*c turow 200
  T  4 SL-KO-100     120.      0  25000   0.00
*c konin 100
  T  5 SL-AD-100     120.      0  30000   0.00
*c adamow 100
  T  6 SL-KO-000      49.      0  25000   0.00
*c konin small
  T  7 SC-KO-500     500.      0  25000   0.00
*c kozienice 500
  T  8 SC-OP-360     360.      0  15000   0.00
*c opole 360 plant under construction / check with Harry about including cc
  T  9 SC-OS-200     200.      0  25000   0.00
*c ostroleka 200
  T 10 SC-KO-200     200.      0  15000   0.00
*c kozienice 200
  T 11 SC-PO-200     200.      0  15000   0.00
*c polaniec 200
  T 12 SC-RY-200     200.      0  15000   0.00
*c rybnik 200
  T 13 SC-J3-200     200.      0  15000   0.00
*c jaworzno 3 200
  T 14 SC-LZ-200     200.      0  25000   0.00
*c laziska 200
  T 15 SC-DO-200     200.      0  15000   0.00
*c dolna odra 200
  T 16 SC-LZ-100     120.      0  25000   0.00
*c laziska 100
  T 17 SC-ST-100     120.      0  30000   0.00
*c stalowa wola 100
  T 18 SC-LG-100     120.      0  25000   0.00
*c lagisza 100
  T 19 SC-SI-100     123.      0  25000   0.00
*c siersza 100
  T 20 SC-SK-100     100.      0  30000   0.00
*c skawina 100
  T 21 SC-ST-000      36.      0  30000   0.00
*c stalowa wola small
  T 22 SC-SK-000      50.      0  30000   0.00
*c skawina small
  T 23 SC-J2-000      50.      0  30000   0.00
*c jaworzno 2 small
  T 24 SC-BL-000      47.      0  30000   0.00
*c blachownia small
  T 25 SC-HA-000      50.      0  30000   0.00
*c halemba small
  T 26 SC-J1-000      29.      0  30000   0.00
*c jaworzno 1 small
```

```
  T 27 SC-MI-000       55.       0  30000   0.00
*c miechowice small
  T 28 SC-PO-000       60.       0  30000   0.00
*c pomorzany small
  T 29 SR-PA-200      200.       0  15000   0.00
*c patnow oil 200
  T 30 SL-XX-360      360.1330000  15000   0.00 30  5 15 30 30 20
*c new baseload assumed lignite from wasp solution
  T 31 CG-XX-120      120. 340000  15000   0.00 20  5 45 45  5
*c new peak load assumed 120 mw ng fired gas turbine.
**
*****************************************************************************************
**                                  SECTION F
**              AVAILABILITY AND DETERMINISTIC ANNUAL DATA FOR HYDRO PLANTS
*****************************************************************************************
** Hydroelectric plants are special components of the generating system because each can be
** considered unique in cost and power potential but also because their power potential is not
** known except in the form of probabilities. Section F includes the characteristics of the
** hydro plants that do not need to be expressed by probabilities.
**
** NO. & IDENTITY  Should correspond to the values defined in Section E
**
** YEAR IN & OUT   First and last year of the plant in the system.
**
** INSTALLED       The total generator rating in the plant regardless of head limitations or
** CAPACITY        firm energy availability. Expressed in MW. Do not include plant service or
**                 transmission losses in this number.
**
** AVERAGE ENERGY  Total average long term annual energy production. Expressed in average MW.
**                 Do not include plant service or transmission losses in this number.
**
** MUST RUN ENERGY Average long term annual energy that is generated to meet riparian flow or
**                 other non-power requirements.  Expressed in average MW.
**
** LOSSES          Percent of capacity and percent of energy used in plant service and
**                 transmission losses.
**
*****************************************************************************************
** NO. IDENTITY   YEAR YEAR PEAKING   AVERAGY  MUST RUN  LOSS FACTORS
**                IN  OUT CAPABILITY ENERGY    ENERGY   CAPAC. ENERGY
**                            (MW)   (av.MW)   (av.MW)   (%)    (%)
**  ii aaaaaaaaaa iiii iiii rrrrrrrr rrrrrrrr rrrrrrrr     rrrr rrrr
**-----------------------------------------------------------------------------------------
* capacity losses included in lieu of f.o.r.
* all station and network losses included in load
  H  1 PH-92-PUMP 1950 3000      1330      224        0      0.99 0.00
* pc/notes ref.1 ae/pse statistics - peaking energy of ps hydro
  H  2 PH-MLOTY   1998 3000       750      113        0      0.99 0.00
* e/15% c.f. from Harza study use 867 mw pumping load and 76% eff.(lf=17%)
  H  3 CH-92-HYDR 1950 3000       640      163       80      0.99 0.00
* pc/ae/from pse statistics assumed 50% peaking
  H  4 CH-VISTULA 2010 3000       170      150      150      0.99 0.00
* e/assumed
  H  5 AC-92-AUTO 1992 3000      1220       39       20      0.88 0.00
* pc/based on autoproducers cont. to peak on peak load month
* ae/from pse statistics (339 gwh) assumed 50 % peaking
* autoproducers deleted from load and resources
  H  6 DC-92-CHP  1992 3000      3498     1435     1250      0.88 0.00
* pc/ae/pse 1991 prod. 12569 gwh/8.76
* includes all plants with high cogeneration coefficient (>20) except stalowa-wola
  H  7 DC-93-CHP  1993 3000        50       38       33      0.88 0.00
  H  8 DC-94-CHP  1994 3000       100       76       66      0.88 0.00
  H  9 DC-95-CHP  1995 3000       150      114       99      0.88 0.00
  H 10 DC-96-CHP  1996 3000       190      145      126      0.88 0.00
  H 11 DC-97-CHP  1997 3000       340      259      225      0.88 0.00
  H 12 DC-98-CHP  1998 3000       440      335      294      0.88 0.00
  H 13 DC-99-CHP  1999 3000       100       76       66      0.88 0.00
  H 14 DC-00-CHP  2000 3000       520      396      345      0.88 0.00
  H 15 DC-01-CHP  2001 3000       300      228      199      0.88 0.00
  H 16 DC-02-CHP  2002 3000       300      228      199      0.88 0.00
  H 17 DC-03-CHP  2003 3000       300      228      199      0.88 0.00
```

```
  H 18 DC-04-CHP  2004 3000      300      228      199      0.88 0.00
  H 19 DC-05-CHP  2005 3000      300      228      199      0.88 0.00
  H 20 DC-06-CHP  2006 3000      300      228      199      0.88 0.00
  H 21 DC-07-CHP  2007 3000      300      228      199      0.88 0.00
  H 22 DC-08-CHP  2008 3000      300      228      199      0.88 0.00
  H 23 DC-09-CHP  2009 3000      300      228      199      0.88 0.00
  H 24 DC-10-CHP  2010 3000      300      228      199      0.88 0.00
**
*****************************************************************************************
**                                   SECTION G
**                   PROBABILISTIC ANNUAL DATA FOR HYDROELECTRIC PLANTS
*****************************************************************************************
** All    oelectric plants are assumed to belong to the same hydrologic regime and thus
** to experience all the same water conditions.  For each water condition three parameters
** are provided:
**
** PROBABILITY          The probability that the hydroelctric system will experience the
**                      particular water condition. Note that the sum of the probabilities
**                      of all water conditions must be 1.00
**
** CAPABILITY           The fraction of rated capacity that can be counted on during this
** RATIO                water condition due to limitations in head. Note: A wet condition can
**                      often reduce capability due to tailwater increase. This value cannot
**                      be larger than 1.00 since the generator capacity cannot be exceeded.
**
** TOTAL ENERGY         The fraction of total average annual energy that will be produced
** RATIO                during the water condition. This number may be higher and lower than
**                      one but the average of all water condition weighted by their
**                      respective probabilities must be 1.00 since the average energy under
**                      all water conditions should yield the average annual energy.
**
** DESCRIPTION          This is a non executable part of the field and is only for recording
**                      in the data file the nature of the hydrologic condition.
**
** Note: GPT will assume that must-run constraints remain constant for all water conditions.
**       However, if the total energy in a dry condition drops below the value of must run
**       energy requirements then must-run energy will be reduced to equal total available
**       energy.
**
*****************************************************************************************
**  HYDROLOGIC  PROBABILITY    CAPABILITY   TOTAL ENERGY          DESCRIPTION
**  CONDITION   OF CONDITION     RATIO       RATIO
****.........*---------------*----------*----------*****************************************
       1            1.0         1.00        1.00
*c conventional hydro resource too small to warrant hydrologic conditions
**
*****************************************************************************************
**                                   SECTION H
**                   OPERATING CHARACTERISTICS OF THERMAL UNIT TYPES
*****************************************************************************************
** In this section the characteristics of each thermal unit type are provided:
**
** NUMBER & IDENTITY    These values must be consistent with those used in Section E
**
** GROSS RATING         The maximum continues rating of the generator before any losses. In MW.
**
** FUEL TYPE            The fule type number consistent with fuels defined in Section C
**
** NET AVERAGE HEAT     The average heat rate at maximum continuous rating expressed in
** RATE AT MCR          BTU/KWH.
**
** SCHEDULED MAINT.     The number of days per year of scheduled maintenance outage.
**
** EQUIVALENT FORCED    Percent of the time that the unit is expected to be unavailable for
** OUTAGE RATE          service and is not in scheduled maintenance. This value must include
**                      the equivalent time of full outage obtained by multiplying the time
**                      under partial outage (derating) by the fraction of capacity lost.
**
** STATION SERVICE AND  Percent of capacity and energy lost between the generator and the
** TRANSMISSION LOSSES  point where the load is being measured.
**
*****************************************************************************************
```

** NO.	IDENTITY	GROSS RATING (MW)	FUEL TYPE	NET AV. HEAT RATE AT MCR (BTU/KWH)	SCHEDULED MAINTENANCE (d/YR)	FORCED OUTAGE	STATION SERVICE AND TRANSMISSION LOSSES (%)
F	iii aaaaaaaaaa	rrrrrrrr	i	rrrrrrrrrrrr	iii	rrrrrr	rrrrrrrrr

```
*c gr/based on psa statistic sheet 1987-1991
*c fo/based on historic data from harza's mloty study;
*c hr/based on energoprojet data / mr.skonieczny
*c ss + tl are included in load
*c sm set to us experience
```

1	SL-BE-360	360	1	9766	45	16.3	0.00
*c belchatow 360							
2	SL-PA-200	200	1	9694	45	10.6	0.00
*c patnow 200							
3	SL-TU-200	200	1	10595	45	10.5	0.00
*c turow 200							
4	SL-KO-100	120	1	10662	45	12.1	0.00
*c konin 100							
5	SL-AD-100	96	1	11175	88	15.8	0.00
*c adamow 100							
6	SL-KO-000	40	1	11920	45	13.0	0.00
*c konin small							
7	SC-KO-500	500	2	9400	60	30.0	0.00
*c kozienice 500 - very poor reliability in these units / enrgoprojet							
8	SC-OP-360	360	2	9400	45	10.8	0.00
*c opole 360							
9	SC-OS-200	200	2	9949	45	11.6	0.00
*c ostroleka 200							
10	SC-KO-200	200	2	9949	45	11.7	0.00
*c kozienice 200							
11	SC-PO-200	200	2	9413	45	7.1	0.00
*c polaniec 200							
12	SC-RY-200	200	2	9734	45	10.8	0.00
*c rybnik 200							
13	SC-J3-200	190	2	9984	45	10.7	0.00
*c jaworzno 3 200							
14	SC-LZ-200	180	2	9925	45	13.4	0.00
*c laziska 200							
15	SC-DO-200	200	2	9369	45	9.5	0.00
*c dolna odra 200							
16	SC-LZ-100	100	2	9925	45	16.2	0.00
*c laziska 100							
17	SC-ST-100	106	2	8397	45	11.2	0.00
*c stalowa wola 100							
18	SC-LG-100	103	2	10567	45	11.9	0.00
*c lagisza 100							
19	SC-SI-100	105	2	10671	45	11.6	0.00
*c siersza 100							
20	SC-SK-100	90	2	11420	45	10.4	0.00
*c skawina 100							
21	SC-ST-000	33	2	8397	45	10.0	0.00
*c stalowa wola small							
22	SC-SK-000	45	2	11420	45	10.4	0.00
*c skawina small							
23	SC-J2-000	43	2	12647	45	10.4	0.00
*c jaworzno 2 small							
24	SC-BL-000	41	2	11857	45	10.7	0.00
*c blachownia small							
25	SC-HA-000	50	2	11933	45	11.8	0.00
*c halemba small							
26	SC-J1-000	19	2	13289	45	15.7	0.00
*c jaworzno 1 small							
27	SC-MI-000	50	2	13000	45	11.8	0.00
*c miechowice small							
28	SC-PO-000	56	2	9091	45	12.3	0.00
*c pomorzany small							
29	SR-PA-200	200	3	9500	45	2.3	0.00
*c patnow oil 200							
30	SL-XX-360	360	1	9766	45	16.0	0.00
*c new lignite 360							
31	CG-XX-120	120	5	12000	20	12.0	0.00
*c new gas turbine 120							

```
**
*****************************************************************************************
**                                  SECTION I
**                             THERMAL SYSTEM CONFIGURATION
*****************************************************************************************
** In this section the maximum and minimum number of units for each thermal type defined in
** Sections E and G must be specified for each year of the simulation period. If the minimum
** and maximum number of each unit type is the same the system will be rigidly constrained and
** the model will not attempt to modify it.  If the limits in all or some of the units offer
** some flexibility then GPT will add or substract units from the system to come as closely as
** possible to the effective capacity reserve margin specified in Section D, selecting the mix
** of generating units likely to result in least system cost.
**
** Three lines of data are used for each unit. The first line contains the unit type identity
** followed by the identification of the years for which unit numbers are being defined. The
** first year must coincide with the first year of the data period. The second and third
** lines contain the upper and lower bounds of the number of units for each year.  The first
** 10 columns of the second and third lines are ignored by the model.
** Note: GPT will continue to read upper and lower bounds of unit types even if the period of
** data is shorter than the period of simulation.
**
*****************************************************************************************
*IDENTITY       MAXIMUM (TOP) AND MINIMUM (BOTTOM) NUMBER OF UNITS ALLOWED EACH YEAR
*-----------------------------------------------------------------------------------------
Faaaaaaaa  iii iii iii iii iii iii iii iii iii iii iii iii iii iii iii iii iii iii iii iii iii
 SL-BE-360  92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
   1   MAX  12  12  12  12  12  12  12  12  12  12  12  12  12  12  12  12  12  12  12
       MIN  12  12  12  12  12  12  12  12  12  12  12  12  12  12  12  12  12  12  12
 SL-PA-200  92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
   2   MAX   6   6   7   8   8   8   8   8   8   8   6   4   4   6   6   6   6   6   6
       MIN   6   6   7   8   8   8   8   8   8   8   6   4   4   6   6   6   6   6   6
*c add.conv.                   1   1
*c ret.rehab.
*c add.rehab.                                                   2   2
*c two units of sr-pa-200 converted to lignite commissioned as sc-pa-200 in 94 and 95
*c neglect 2 x 15 mw  due to lignite conversion                                   2
*c neglect 2 x 15 mw due to rehabs 2003-2005
 SL-TU-200  92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
   3   MAX  10   9   8   8   8   8   8   9  10  10  10  10  10  10  10  10  10  10  10
       MIN  10   9   8   8   8   8   8   9  10  10  10  10  10  10  10  10  10  10  10
*c ret.rehab.      1   1                                                                   10
*c add.rehab.                                   1   1
*c neglect 6 x 30 mw due to rehabs 1993-2000
 SL-KO-100  92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
   4   MAX   2   2   2   2   2   2   2   2   1   0   1   2   2   2   2   2   2   2   2
       MIN   2   2   2   2   2   2   2   2   1   0   1   2   2   2   2   2   2   2   2
*c ret.rehab.                                   1   1
*c add.rehab.                                                   1   1
 SL-AD-100  92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
   5   MAX   5   4   5   5   5   5   5   4   3   3   4   5   5   5   5   5   5   5   5
       MIN   5   4   5   5   5   5   5   4   3   3   4   5   5   5   5   5   5   5   5
*c ret.rehab.      1                            1   1
*c add.rehab.          1                                                                   1
 SL-KO-000  92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
   6   MAX   7   5   3   5   6   6   5   5   5   5   5   5   5   5   5   5   5   5   5
       MIN   7   5   3   5   6   6   5   5   5   5   5   5   5   5   5   5   5   5   5
*c retire                          1       1
*c ret.rehab.      3   2
*c add.rehab.      1       2   2
*c retirement 55 mw unit in 96 and 28 mw unit in 98
 SC-KO-500  92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
   7   MAX   2   2   2   2   2   2   2   2   2   2   2   2   2   2   2   2   2   2   2
       MIN   2   2   2   2   2   2   2   2   2   2   2   2   2   2   2   2   2   2   2
 SC-OP-360  92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
   8   MAX   0   0   1   2   4   6   6   6   6   6   6   6   6   6   6   6   6   6   6
       MIN   0   0   1   2   4   6   6   6   6   6   6   6   6   6   6   6   6   6   6
*c additions           1   1   2   2
*c exp. plan modified to start in 94 and catch up to 6 units by 1997
 SC-OS-200  92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
   9   MAX   3   3   3   3   3   3   3   3   3   3   3   3   3   3   3   3   3   3   3
       MIN   3   3   3   3   3   3   3   3   3   3   3   3   3   3   3   3   3   3   3
 SC-KO-200  92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
```

```
 10   MAX  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8
      MIN  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8
SC-PO-200 92 93 94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12
 11   MAX  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8
      MIN  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8
SC-RY-200 92 93 94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12
 12   MAX  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8
      MIN  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8
SC-J3-200 92 93 94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12
 13   MAX  6  6  6  6  6  6  6  6  6  6  6  6  6  6  6  6  6  6  6
      MIN  6  6  6  6  6  6  6  6  6  6  6  6  6  6  6  6  6  6  6
SC-LZ-200 92 93 94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12
 14   MAX  4  4  4  4  4  4  4  4  4  4  4  4  4  3  3  4  4  4  4
      MIN  4  4  4  4  4  4  4  4  4  4  4  4  4  3  3  4  4  4  4
*c ret.rehab                                                   1
*c assumed add.rehab.
SC-DO-200 92 93 94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12
 15   MAX  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8
      MIN  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8  8
SC-LZ-100 92 93 94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12
 16   MAX  2  2  2  2  2  2  2  2  2  2  0  0  2  2  2  2  2  2  2
      MIN  2  2  2  2  2  2  2  2  2  2  0  0  2  2  2  2  2  2  2
*c ret.rehab                                   2
*c add.rehab                                                2
SC-ST-100 92 93 94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12
 17   MAX  2  2  2  2  2  2  2  2  1  0  1  2  2  2  2  2  2  2  2
      MIN  2  2  2  2  2  2  2  2  1  0  1  2  2  2  2  2  2  2  2
*c ret.rehab.                          1  1
*c add.rehab.                                1  1
SC-LG-100 92 93 94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12
 18   MAX  7  7  7  7  7  7  6  5  6  7  7  6  4  3  3  5  7  7  7
      MIN  7  7  7  7  7  7  6  5  6  7  7  6  4  3  3  5  7  7  7
*c ret.rehab.                          1  1                 1  2  2
*c add.rehab.                                1  1                 2  2
SC-SI-100 92 93 94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12
 19   MAX  6  6  6  6  6  6  4  4  6  6  6  6  4  2  2  4  6  6  6
      MIN  6  6  6  6  6  6  4  4  6  6  6  6  4  2  2  4  6  6  6
*c retire                              2                 2  2
*c ret.rehab.                                2  2
*c add.rehab.                                2
SC-SK-100 92 93 94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12
 20   MAX  4  3  2  2  2  0  1  2  3  4  4  4  4  4  4  4  4  4  4
      MIN  4  3  2  2  2  0  1  2  3  4  4  4  4  4  4  4  4  4  4
*ret.rehab       1  1     1  2
*add.rehab                1     1  1  1  1
SC-ST-000 92 93 94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12
 21   MAX  4  4  3  3  3  3  4  4  4  4  4  4  4  4  4  4  4  4  4
      MIN  4  4  3  3  3  3  4  4  4  4  4  4  4  4  4  4  4  4  4
*c retire              1     1
*c retirement of 35 mw in 1994 and 10 mw in 1997
*c additions                  1  1
*c 55 mw additions
SC-SK-000 92 93 94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12
 22   MAX  3  3  3  3  3  3  1  0  0  0  0  0  0  0  0  0  0  0  0
      MIN  3  3  3  3  3  3  1  0  0  0  0  0  0  0  0  0  0  0  0
*c retire                      2  1
SC-J2-000 92 93 94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12
 23   MAX  7  7  7  7  7  7  6  5  4  3  4  6  7  7  7  7  7  7  7
      MIN  7  7  7  7  7  7  6  5  4  3  4  6  7  7  7  7  7  7  7
*c ret.rehab.                          1  1  2  2  1
*c add.rehab.                                1  1  2  2  1
SC-BL-000 92 93 94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12
 24   MAX  6  5  4  4  3  1  0  0  0  0  0  0  0  0  0  0  0  0  0
      MIN  6  5  4  4  3  1  0  0  0  0  0  0  0  0  0  0  0  0  0
SC-HA-000 92 93 94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12
 25   MAX  4  4  4  4  4  4  4  4  2  0  2  4  4  4  4  4  4  4  4
      MIN  4  4  4  4  4  4  4  4  2  0  2  4  4  4  4  4  4  4  4
*c ret.rehab.                                2  2
*c add.rehab.                                      2  2
SC-J1-000 92 93 94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12
 26   MAX  6  6  6  6  6  6  5  4  2  0  0  0  0  0  0  0  0  0  0
      MIN  6  6  6  6  6  6  5  4  2  0  0  0  0  0  0  0  0  0  0
```

```
*c check unit capacity as it had been assumed that only 5 units
 SC-MI-000  92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
  27   MAX   2   3   3   3   3   3   3   3   3   3   3   3   3   3   3   3   3   3   3
       MIN   2   3   3   3   3   3   3   3   3   3   3   3   3   3   3   3   3   3   3
*c addition 55mw 1
 SC-PO-000  92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
  28   MAX   2   2   2   1   0   1   2   2   2   2   2   2   2   2   2   2   2   2   2
       MIN   2   2   2   1   0   1   2   2   2   2   2   2   2   2   2   2   2   2   2
*c ret.rehab.                1   1
*c add.rehab.                        1   1
 SR-PA-200  92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
  29   MAX   2   1   0   0   0   0   0   0   0   0   0   0   0   0   0   0   0   0   0
       MIN   2   1   0   0   0   0   0   0   0   0   0   0   0   0   0   0   0   0   0
*c ret.conv.     1   1
*c conversion to lignite after 94  sec sl-pa-200
 SL-XX-360  92  93  94  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
  30   MAX   0   0   0   0   0   0   0   0   0   0   2   3   5   6   6   6   6   6   6
       MIN   0   0   0   0   0   0   0   0   0   0   2   3   5   6   6   6   6   6   6
*c add                                               2   1   2   1
*c wasp case lw (Table 7.2b)  Belchatow II
 CG-XX-120  92  93  9.  95  96  97  98  99  00  01  02  03  04  05  06  07  08  09  10  11  12
  31   MAX   0   0   0   0   1   2   2   2   3   4   6   7   8   8   8   8   8   8   8
       MIN   0   0   0   0   1   2   2   2   3   4   6   7   8   8   8   8   8   8   8
*c add                       1   1           1   1   2   1   1
*c wasp case lw (table 7.2 b) modified for 120 Mw only
```

```
**
*****************************************************************************************
*****************************************************************************************
**
**          *******  ******  *******  *********        **** ****
**          **   **  **  **  **   **  *********         **   **
**          *******  **  **  **  ***     ***            **   **
**          **       ******  ******     ***            **   **
**          **       **  **  **  ***    ***            **   **
**          **       **  **  **   **    ***           **** ****
**
**                        SUBANNUAL PERIOD DATA
*****************************************************************************************
*****************************************************************************************
**
** A subannual period can represent any period within one year, consecutive or not. Examples
** of possible subannual periods are as follows:
** - each of the twelve months of the year
** - all weekdays, all saturdays and all sundays of the year
** - two or four seasons
** - four seasons each divided into weekdays, saturdays and sundays.
**
** This Part II of the data file will only be used if the number of subannual periods defined
** in section B of Part I is 2 or more.  Most values in this part are dimensionless fractions
** of values in Part I.  GPT will execute one subannual period at a time and for each of them
** it will multiply the value in Part I by the fraction in Part II corresponding to that value
** for a specific subannual period.
**
*****************************************************************************************
**  LOAD DATA - MULTIPLIERS FOR VALUES IN SECTION D OF PART I (1/1000)
*****************************************************************************************
*                                PERIOD:   1    2    3    4    5    6    7    8    9   10   11   12
*c period 1 = summer defined as apr-may-jun-jul-aug-sep
*c period 2 = winter defined as oct-nov-dec-jan-feb-mar
F                                         iiii iiii iiii iiii iiii iiii iiii iiii iiii iiii iiii iiii
 SUBANNUAL LOAD DURATION CURVE              2    3
*c assumed that period differences in ldc are not significantly affected by new pumping loads
F                                         rrrr rrrr rrrr rrrr rrrr rrrr rrrr rrrr rrrr rrrr rrrr rrrr
 FRACTION OF ANNUAL DURATION              .500 .500
 FRACTION OF ANNUAL PEAK LOAD             .770 1.00
 FRACTION OF ANNUAL MEAN LOAD             .870 1.13
**
*****************************************************************************************
**  HYDRO PLANT DATA - MULTIPLIERS FOR VALUES IN SECTION F OF PART I
*****************************************************************************************
*                                PERIOD:   1    2    3    4    5    6    7    8    9   10   11   12
F iii aaaaaaaaaa                          rrrr rrrr rrrr rrrr rrrr rrrr rrrr rrrr rrrr rrrr rrrr rrrr
    1 PH-92-PUMP   CAPABILITY             1.00 1.00
    1 PH-92-PUMP   TOTAL ENERGY           1.00 1.00
    1 PH-92-PUMP   MUST RUN ENERGY        1.00 1.00
    2 PH-MLOTY     CAPABILITY             1.00 1.00
    2 PH-MLOTY     TOTAL ENERGY           1.00 1.00
    2 PH-MLOTY     MUST RUN ENERGY        1.00 1.00
    3 CH-92-HYDR   CARABILITY             1.00 1.00
    3 CH-92-HYDR   TOTAL ENERGY           1.00 1.00
    3 CH-92-HYDR   MUST RUN ENERGY        1.00 1.00
    4 CH-VISTULA   CAPABILITY             1.00 1.00
    4 CH-VISTULA   TOTAL ENERGY           1.00 1.00
    4 CH-VISTULA   MUST RUN ENERGY        1.00 1.00
    5 AC-92-AUTO   CAPABILITY             0.54 0.88
    5 AC-92-AUTO   TOTAL ENERGY           0.50 1.25
    5 AC-92-AUTO   MUST RUN ENERGY        0.50 1.25
    6 DC-92-CHP    CAPABILITY             0.54 0.85
    6 DC-92-CHP    TOTAL ENERGY           0.30 1.36
    6 DC-92-CHP    MUST RUN ENERGY        0.30 1.36
    7 DC-93-CHP    CAPABILITY             0.54 0.85
    7 DC-93-CHP    TOTAL ENERGY           0.30 1.36
    7 DC-93-CHP    MUST RUN ENERGY        0.30 1.36
    8 DC-94-CHP    CAPABILITY             0.54 0.85
    8 DC-94-CHP    TOTAL ENERGY           0.30 1.36
    8 DC-94-CHP    MUST RUN ENERGY        0.30 1.36
    9 DC-95-CHP    CAPABILITY             0.54 0.85
```

when a row has a blank "% of Peak" cell. *REM* puts the output reserve distributions two rows below the "Available Reserve Distribution:" label.

REM's reliability calculation ignores data such as plant names, total capacity, and reserve margin; you can modify or remove these without harm. *REM* looks for the row for writing each result by means of a range name. Therefore, for example, you can insert rows labeled "LOLE (hours/year)" with formulas converting *REM*'s fractional LOLEs into hours/year, above or below the rows with the *REM* results.

Saving Your Work

The *REM* spreadsheet contains the spreadsheet part of the model as well as your data. For your convenience in tailoring the spreadsheet, none of the cells is protected. In case you accidentally damage the model (e.g. by deleting a cell with a needed range name), be careful not to overwrite the master copy of the spreadsheet. It's advisable to save your modified spreadsheets under different names than REM.WK1.

Some Tips When There's an Error

REM Version 1.3 doesn't check its inputs for validity, so it's up to you to do so. For example, if partial capacities for a plant are not in ascending order, *REM* will calculate invalid results. (A check for this kind of problem is that the sum of the available reserve distribution probabilities is 1, as it should be.)

One of the more common errors is "Memory Full". *REM* tries to report any error in the indicator message at the top right of the screen and then restore the indicator, but in the case of the Memory Full error, it cannot do so. To restore the indicator, press [Alt]-[c] ("c" stands for "clean"). Turning off the UNDO feature often removes the memory deficiency. Though UNDO is very convenient for most spreadsheet work, foregoing it is not a loss during *REM* runs because UNDO can't undo a *REM* run (due to 1-2-3 limitation when a call to DOS is made, in this case to run the Fortran reliability program). Another, more sophisticated technique for catching errors is to review the file that the spreadsheet macros write for input to the Fortran program, as discussed in the next chapter.

Chapter 3 Operation and Suggestions for the Advanced User

As the run-time indicator messages suggest, *REM* loops over the periods, with three main steps per period:

1. Prepare an input file for the Fortran reliability program, SREL.
2. Run SREL.
3. Read the file of results from SREL.

Figure 3 shows these steps as well as the relationships of the programs and files.

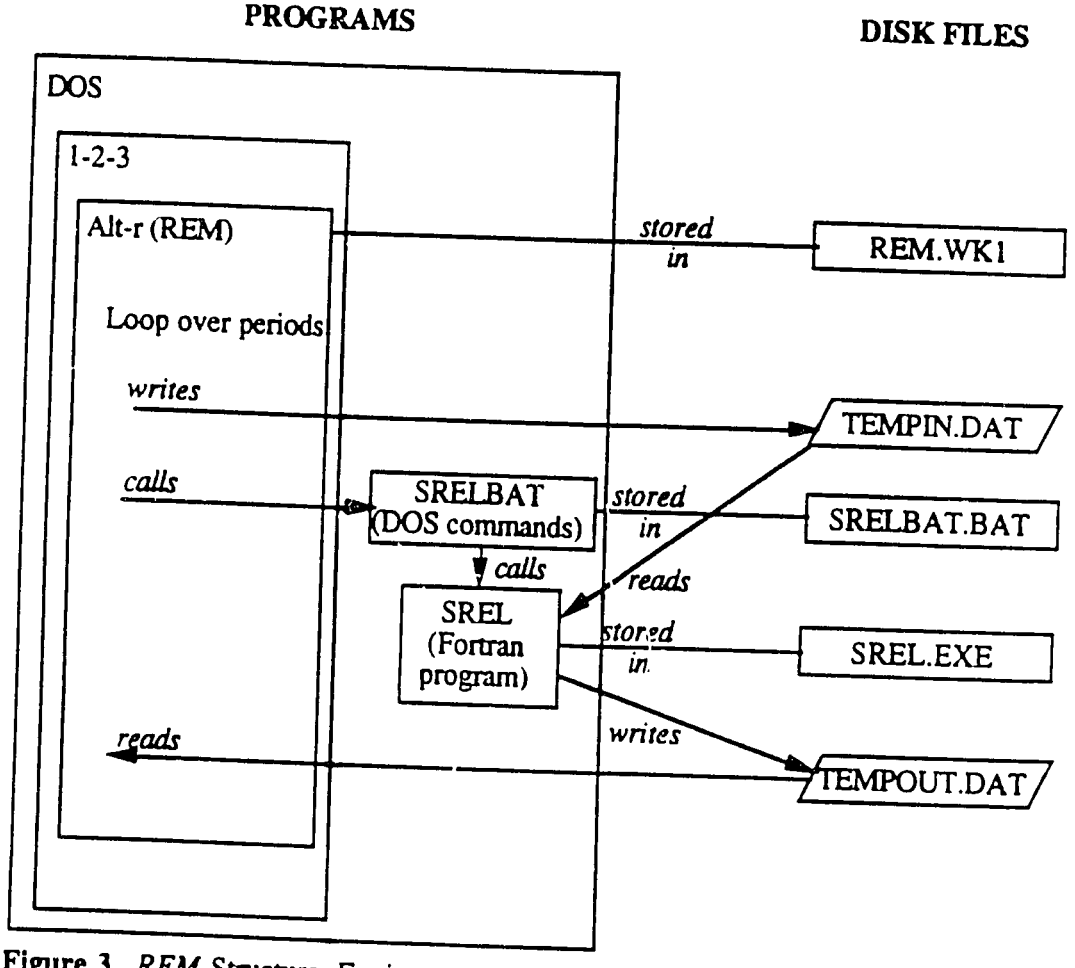


Figure 3. *REM* Structure, Environment, and Files

The spreadsheet data writer and data reader macros (listed in Appendix D) may be edited by the advanced user for special purposes. In addition, with the help of the SREL documentation in Appendix D, the TEMPIN.DAT FORTRAN input file may be tailored and SREL may be run directly. SREL is a general-purpose, single-period reliability program with some capabilities not exploited by *REM*. The 1-2-3 command to exit to DOS temporarily is /System. The DOS command to run SREL, with input from TEMPIN.DAT and output directed to TEMPOUT.DAT, is:

```
srel < tempin.dat > tempout.dat
```

To return to 1-2-3, type

```
exit
```

The main operation of SREL is to construct the distribution of available system reserve, i.e. available system capacity minus load (first for the peak load only, and then for all loads in the period). Reliability measures are easy to calculate from this distribution (see Appendix A). The distribution is built by iteratively combining the probability distributions for the capacity of each generating unit. The combination process, which is the probabilistic equivalent of addition, is called convolution. The negative of the load distribution is then convolved with the system capacity distribution.

The essence of convolution is the following conditional probability expansion: the probability of a system reserve level r after an addition is the sum over the addition's states of the state probability times the former system reserve level which would result in level r. Symbolically, if the addition has states c_i with probabilities p_i,

$$P(r \text{ given addition}) = \sum_i p_i \, P(r - c_i)$$

Textbooks detailing reliability evaluation methods are available.[5]

---

[5] One of several references is J. Endrenyi, *Reliability Modeling in Power Systems* (Chichester, U.K., Wiley, 1978).

Before convolving capacity and load distributions, SREL rounds each state to a multiple of the step size control (initially 10 MW), and adjusts a total "perfect" (deterministic) reserve for the roundoff error. The step size can be set as small as 1 MW, which eliminates the rounding. However, the Fortran memory limits may be exceeded and the Fortran run time may become unacceptably high. Figure B-1 illustrates the speed vs. accuracy tradeoff provided by the step size.

Chapter 4 Hourly Load Analysis with the *LAGG* Spreadsheet

The *LAGG* (Load/LOLE Aggregator) spreadsheet may be used in conjunction with *REM* to calculate LOLEs by hour and to aggregate these in ways you define. *LAGG* also allows monthly reserve margin adjustments, which can represent maintenance and seasonal capacity fluctuations. A worksheet within *LAGG* re-distributes an average monthly maintenance capacity so as to levelize monthly reserve margins. Applications of *LAGG* include accurately calculating total annual loss-of-load expectation, and comparing alternative time-of-day electricity pricing periods.

LAGG is intended to be tailored by you. Because it leaves you direct control over the way hourly reliability is aggregated, you must be more proficient in 1-2-3 than *REM* alone requires. An example with hour-of-day, weekday vs. weekend, and monthly aggregations is provided in the initial spreadsheet, with pre-defined graphs of these aggregations. *LAGG*'s documentation is stored in the spreadsheet; the basic documentation is reproduced in Figure C-1.

Before using *LAGG*, first calculate a system reserve distribution with *REM*. *LAGG* will determine loss-of-load expectation at each hourly load of the year. Therefore, *REM* should be run with the annual peak load only; *LAGG* will apply the remaining loads later. In the *REM* spreadsheet, put the desired peak load on the row "`Expected Peak Load`" and then provide a one-point load duration curve: set the first "`% of Peak`" and "`Cum. % of Time`" both to 100%, and ensure the cells directly underneath these two cells are blank.

Example

The example in Figure 1 illustrates in Year 2 a one-point load duration curve, for the peak load only. However, Year 1 in the example has several points in the load duration curve, so this period cannot be used with *LAGG* as it stands. Therefore, to use the example spreadsheet with *LAGG*, move down to the controls section and change the start period number from 1 to 2, before running *REM*.

LAGG requires a system available reserve distribution in order to calculate LOLE for each hourly load. Therefore, be sure the control for "`# of System Reserve Probs. to Show`" is set to a

large number, such as the default of 2000. Then run *REM* (press [Alt]-[r]), and note the range of the peak-load reserve distribution. This range contains two columns: the columns for the year you are analyzing. For example, the range for period 2 in the example of Figure 1 is F59..G70.

Now save your *REM* spreadsheet, retrieve the *LAGG* spreadsheet, and follow the instructions here.

```
      Hourly Load & LOLE Aggregation Spreadsheet (V1.3, 12/92)

This spreadsheet converts hourly loads to hourly LOLEs and aggregates
them various ways, which you can tailor.  It has four main sections of
data and a macro section, each labeled for quick access with the F5 key:

Label      Section
-----      -------
HOURLY     8760 or 8784 hourly loads or LOLEs.  Use Alt-i to import
           (combine) hourly loads from another 1-2-3 spreadsheet (see
           notes on format).  You can aggregate loads just like LOLEs
           (see below).  Use Alt-s to scale loads with an input peak and
           load factor.  Use Alt-c to convert each load to an LOLE.
RESERVE    Monthly reserve adjustments (if any) and cumulative distri-
           bution of available system reserve at the annual peak.  Needed
           for converting loads to LOLEs.  To prepare it, first calculate
           a peak (not period) reserve distribution by running REM (Reli-
           ability Evaluation Model), noting the 2-column range of the
           reserve distribution.  Then use Alt-d to import it.
WEEKENDS   Copy of hourly data (LOLEs or loads) for weekends only (you
           should tailor this for your needs).  Update with Alt-w.
AGGS       Various aggregations of LOLE or loads, using formulas which
           you may edit.  Update aggregations with F9 (CALC).  You can
           use Alt-a to do Alt-c, Alt-w, F9, and go to the AGGS label.
MACROS     The macros referred to above, such as Alt-i.
```

Figure 4. *LAGG* Basic Help

Appendix A Electric Generation Reliability: Review and Approximations

Probability and its Properties

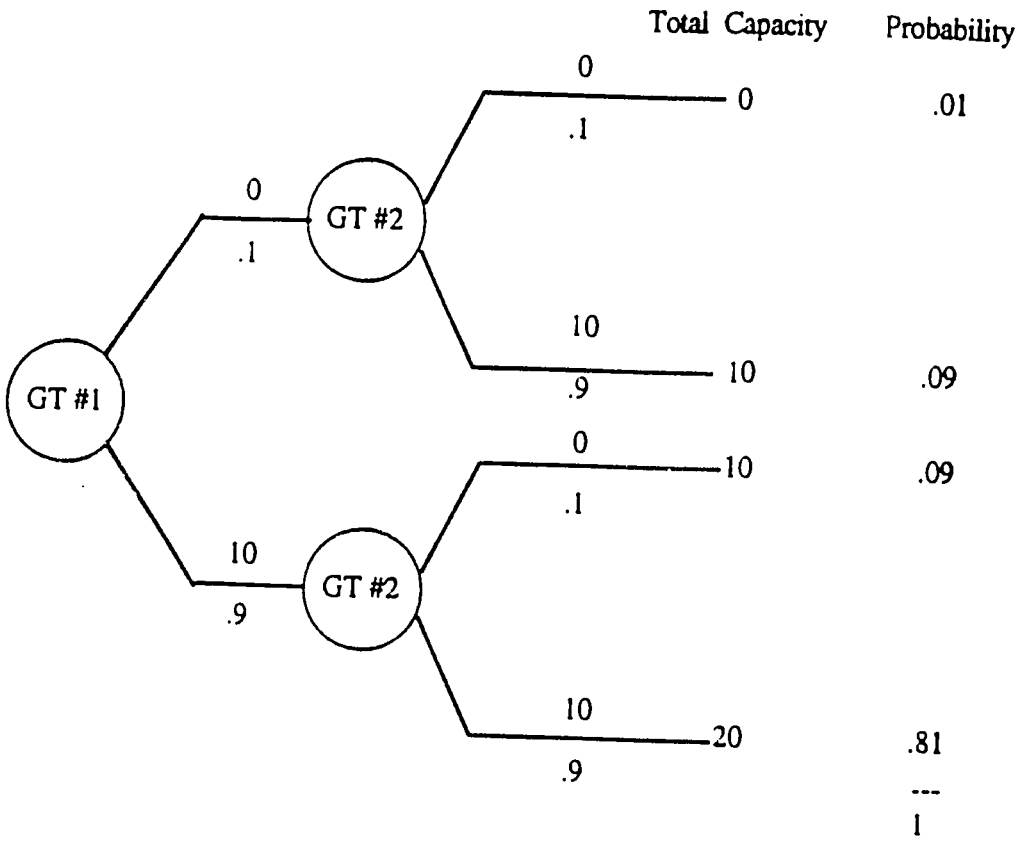
The *probability* of an event A, P(A), may be thought of as the long-run average frequency that A would occur, in an experiment repeated an infinite number of times. Properties of probability include:

- Its range is 0 to 1 inclusive.
- The sum of the probabilities over any set of "mutually exclusive" (not overlapping) and "collectively exhaustive" (covering all possibilities) events is 1.
- P(A or B) = P(A) + P(B) - P(A and B). Note that if A and B are mutually exclusive (not to be confused with "independent"), then the last term is 0 and P(A or B) is just P(A) + P(B).
- P(A and B) = P(A) P(B given A) = P(B) P(A given B). Note that if A and B are independent, the "givens" can be dropped so that P(A and B) is just P(A) P(B).

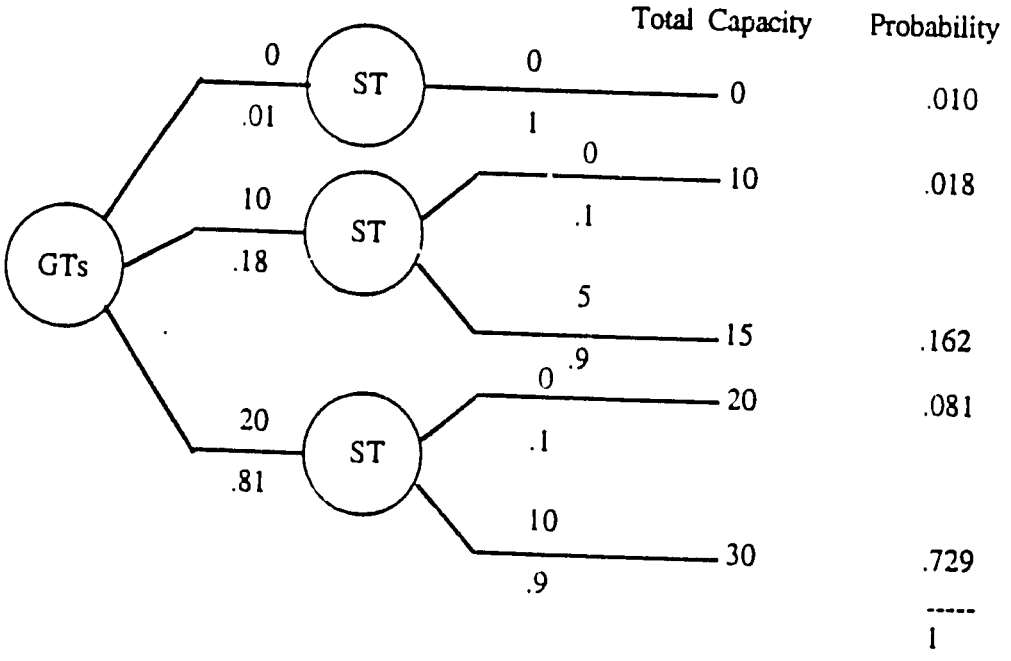
Example: Reliability of a Combined Cycle Power Plant

A particular combined cycle power plant consists of two gas turbines (GTs) and a steam turbine (ST). The GTs each provide 10 MW of power, with independent forced outage rates (FORs), or failure probabilities, of .1. The ST also provides 10 MW with a .1 FOR, but since it is powered by steam heated by the GTs' exhaust, its output falls to 5 MW if one of the GTs is forced out, and 0 MW if both are forced out. What is the probability distribution of the total plant capacity?

First, find the capacity distribution for the GTs together, using a probability tree (for each branch, the associated capacity is shown above the branch and the probability is shown below it):



Then, make a probability tree for the ST capacity given the capacity of the GTs together:



Therefore the plant has a full FOR of .01 and three partial FORs, as shown above. Note that if all three component units had independent capacities, the full FOR would have been only .001 (.1 x .1 x .1).

Expectation vs. Probability

A *random variable* is a variable that can take on different values with associated probabilities. The possible values constitute mutually exclusive, collectively exhaustive events. The *expectation*, or expected value, of a random variable X, E(X), is the sum (or integral) of these values weighted by their respective probabilities. Properties of expectation include:

- Its range is not restricted in general. (However, if the random variable is always between 0 and 1; e.g., if it is a fraction of time, then expectation must also be between 0 and 1.)

- E(X + Y) = E(X) + E(Y). Compare P(A or B), which may be less than P(A) + P(B).

Any probability can be interpreted as an expectation: the expected number of events, 0 or 1, that would occur in a single trial. For example, P(head on next coin flip) = E(number of heads on next coin flip) = 1/2. But an expectation cannot in general be interpreted as a probability, e.g. if it is not between 0 and 1.

Loss-of-Load Probability (LOLP) vs. Loss-of-Load Expectation (LOLE)

"Loss of load" (LOL) means load in excess of available capacity, resulting in a negative reserve. For one point in time, t:

LOLP = P(LOL at t),

LOLE = E(number of LOL events, 0 or 1, at t).

Over a year (for example):

LOLE = LOLE in hour 1 + ... + LOLE in hour 8760
= LOLP at hour 1 + ... + LOLP at hour 8760.

What about LOLP over a year? Probabilities such as P(1 or more LOL events over a year) and P(exactly 1 LOL event in a year) are very difficult to calculate, because they require information indicating how long LOL events might last. Unfortunately, the term "LOLP" is often used to refer to annual LOLE, in hours, divided by 8760 hours (resulting in a quantity between 0 and 1). It is possible to interpret this quantity as P(LOL at a randomly selected hour of the year), but it is a good idea to think of this quantity as a scaled LOLE rather than as a probability. Similarly, think of a criterion such as 1 day (24 hours) per year or per 10 years as an LOLE criterion, not an LOLP criterion.

Example Calculation of Loss-of-Load Probability (LOLP), Loss-of-Load Expectation (LOLE), and Expected Unserved Energy (EUE)

Period:	1 year with 8760 hours.
Generation System:	2 10 MW units, each with a 10% FOR.
Loads:	15 MW in all hours.

First, calculate the distribution of available reserve, by adding each unit to an initialized empty system, and then adding the negative of the loads, treated like a negative-capacity generating unit:

Initialized empty system = 0 MW with probability 1.

+ first unit = $\begin{cases} 0 \text{ MW with probability } .1 \\ 10 \text{ MW with probability } .9 \end{cases}$

+ second unit = $\begin{cases} 0 \text{ MW with probability } .01 \\ 10 \text{ MW with probability } .18 \\ 20 \text{ MW with probability } .81 \end{cases}$

+ negative of loads = $\begin{cases} -15 \text{ MW with probability } .01 \\ -5 \text{ MW with probability } .18 \\ 5 \text{ MW with probability } .81 \end{cases}$

Next, calculate reliability measures from this distribution:

LOLE = expected duration of negative reserve
= .01 + .18 = .19 year/year
= .19 x 8760 hours/year = 1664.4 hours/year.

LOLP = probability of negative reserve

= .19

EUE = expected negative reserve x period length
= [(.01) 15 MW + (.18) 5 MW] x 8760 hours/year
= 9198 MWh/year.

Approximations of Reliability vs. Reserve Function

For a generating system with a large number of units, the probability distribution of available reserve typically is somewhat bell-shaped, and the curve around 0 reserve rises almost exponentially (see Figure A-1). This property of the curve allows a simple approximation of LOLE and EUE as a function of added load or capacity. LOLE as a function of added load is the same function as the cumulative distribution of reserve, F(r), because both represent the expected fraction of time that the reserve is less than a given value. A simple approximation of this function in the region around 0 reserve is:

$$F(r) = \text{LOLE} \exp(r/m)$$

where m is a system characteristic, with capacity units such as MW. EUE can be approximated similarly, because it is an integral of LOLE (see Figure A-1), and the integral of an exponential function is still exponential. The parameter m can be estimated from:

$$m = \frac{1}{\ln F(r)'}$$

where the prime denotes derivative, as you can verify by taking the derivative of ln F(r).

A more accurate approximation of F(r) uses a second system characteristic, "s", in addition to "m" to recognize that F(r) grows slower than exponentially:

$$F(r) = \text{LOLE} \exp\left[\frac{r}{m} - \left(\frac{r}{s}\right)^2\right]$$

Like m, s has capacity units. This approximation can be valid only for:

$$r \ll \frac{s^2}{2m}$$

because $\frac{s^2}{2m}$ maximizes this approximation, whereas F(r) must be nondecreasing with r. The parameter s can be estimated from

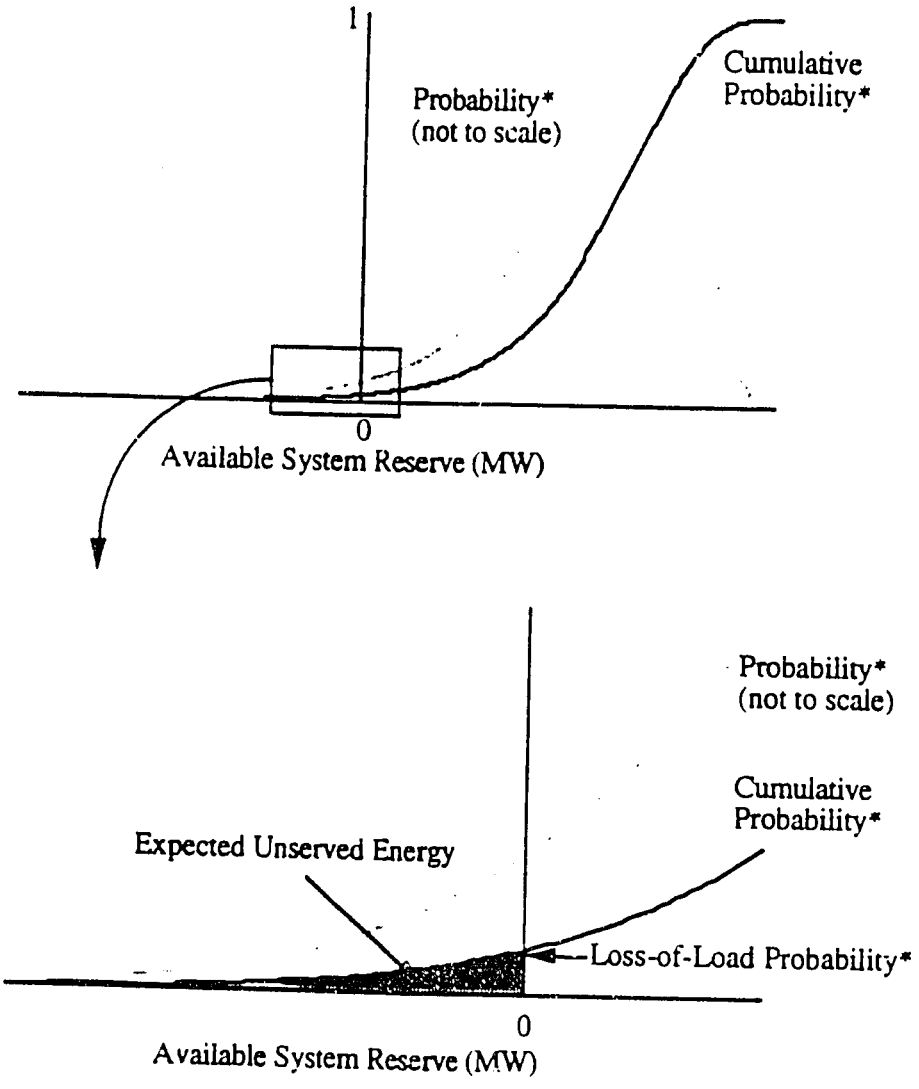
$$s = \sqrt{\frac{-2}{\ln F(r)''}}$$

and m can be estimated as before near r = 0, as you can verify by taking the first two derivatives of ln F(r).

Applications of Approximations

These approximations can be used to estimate quickly, without a reliability model analysis, quantities such as the load-carrying capability of a generating unit (not discussed here) and the hourly contributions of demand or generation to the total period reliability. Applications of the latter are time-of-use electricity pricing and evaluating time-dependent generation such as solar and wind power. Though the first approximation is adequate for estimating load-carrying capability, the greater accuracy of the second is worthwhile for estimating hourly LOLE. An example comparison is shown below, for m = 100 MW and s = 500 MW.

		.....LOLE Relative to Peak LOLE.....	
Load	r = Load-Peak	Simple Approx.	Improved Approx.
5000	0	1	1
4900	-100	.368	.353
4500	-500	.00674	.00248



* For a period rather than a point in time, "probability" becomes "expected fraction of time" and "loss-of-load probability" becomes "loss-of-load expectation".

Figure A-1. Available Reserve Distribution and Definition of Generation Reliability Measures

Appendix B IEEE Benchmark Analysis

The spreadsheet REM-IEEE.WK1 contains an analysis of the 32-unit IEEE Reliability Test System with 364 daily peak loads.[6] Except for the step size, default values were used for the controls. The "exact" LOLE according to the second reference differs slightly from that of a *REM* run with a one MW step size, probably because of a difference in the rounding of small probabilities to 0. Figure B-1 shows both "exact" results and *REM*'s results for varying step size settings, and corresponding run times on an IBM AT Model 339 microcomputer (8 Mhz) with a math coprocessor. The Fortran part of *REM* typically takes a small fraction of the total run time.

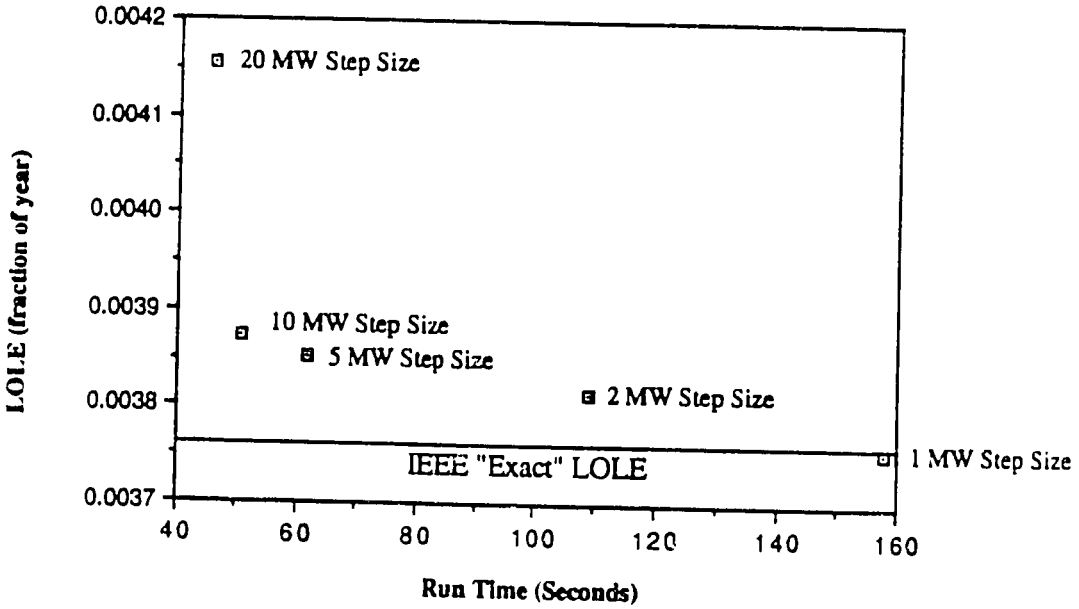


Figure B-1. *REM*'s Speed vs. Accuracy Tradeoff for IEEE System

---

[6] See:

Reliability Test System Task Force, "IEEE Reliability Test System." *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-98, No. 6, Nov./Dec. 1979.

R.N. Allan, R. Billinton, and N.M.K. Abdel-Gawad, "The IEEE Reliability Test System – Extensions to and Evaluation of the Generating System." *IEEE Transactions on Power Systems*, Vol. PWRS-1, No. 4, November 1986.

Appendix C Model Code

REM's code consists of 1-2-3 macros, which are shown in Figure C-1; a small batch file, shown in Figure C-2; and the Fortran SREL program, which is shown except for some subroutine code in Figure C-3. The comments in SREL will help the advanced user to run it as a stand-alone program.

Figure C-1. 1-2-3 Macros for *REM*

```
MACROS

\r        {onerror _cleanerr,%temp}  *** RUNS REM ***
          {paneloff}{windowsoff}
          {let %pd,startpd}          (start here for debugging)
__dopds   {goto}periods~{r 2*%pd+1}
          {if @cellpointer("type")="b"}{let %pd,%pd-1}{goto}results~{r
             2*%pd+1}{branch __done}
          {_write1}                  write data for one period
          {_run1}                    find reliability for period
          {_read1}                   read results for period
          {if %pd<endpd}{let %pd,%pd+1}{branch __dopds}
__done    {beep 3}{calc}             remove CALC message

_write1   {indicate +"REM: Preparing Inputs for Period "&@string(%pd,0)}
          {open "tempin.dat",w}{beep}
          {contents %temp,cutoff}
          {writeln @string(stepsz,0)&" "&%temp&@if(measure="LOLE"," 0 -1 5
             0","1 -1 5 0")}
          {goto}plants~{d 2}{r 2}    to first "F.O.R." field
          {_writeus}                 write data for all units
          {goto}peaks~{r 2*%pd+2}
          {let %pk,@cellpointer("contents")}
          {writeln +"1 "&@string(-%pk,0)}     write (neg.) peak load only
          {_writelu}{writeln "0"}
          {contents %temp,cutoff}{contents %temp2,crit}
          {writeln +"0 "&%temp&@if(measure="LOLE"," 0 ","1 ")&%temp2&" 5
             "&@string(show,0)}
          {_writels}{writeln "0"}          write (neg.) lds. as sens'y
          {close}
          {indicate}

_run1     {system +"srelbat tempin.dat tempout.dat Finding Reliability for
             Period "&@string(%pd,0)&" ..."}
```

Figure C-1. 1-2-3 Macros for *REM* (continued)

```
_read1    {indicate +"REM: Preparing Results for Period "&@string(%pd,0)}
          {goto}%pkrel~/re{end}{d}{r 3}~
          /fintempout.dat~
          {if @cell("type",%coc)<>"v"}{let %temp,"Error in Fortran--output will
             be shown"}/re{end}{d}{r 3}~/fittempout.dat~{_cleanerr}{quit}
          {goto}pkrels~{r 2*%pd+2}{let @cellpointer("address"),%pkrel}
          {goto}pkparms~{r 2*%pd+1}/c%pkparms~~          (2 cells)
          {if @cellpointer("contents")=0}{let
             @cellpointer("address"),@na}{r}{let @cellpointer("address"),@na}
          {goto}rels~{r 2*%pd+2}{let @cellpointer("address"),%rel}
          {goto}parms~{r 2*%pd+1}/c%parms~~              (2 cells)
          {if @cellpointer("contents")=0}{let
             @cellpointer("address"),@na}{r}{let @cellpointer("address"),@na}
          {goto}cocs~{r 2*%pd+2}{let @cellpointer("address"),%coc}
          {goto}dists~{d 2}{r 2*%pd+1}
          {if @cellpointer("type")<>"b"}/re{end}{d}{r}~
          {if show=0}{branch __donepd}
          {let %where,@cellpointer("address")}
          {goto}%rel~{d}/m{end}{d}{r}~{%where}  (moving dist. is faster than
             copying)
__donepd  {goto}results~{r 2*%pd+1}{beep 3}{windowson}{windowsoff}
          {indicate}

_writeus  {if @cellpointer("type")="b"}{return}          start at "F.O.R." field
          {r 2*%pd}          to full cap. field
          {if @cellpointer("contents")=0}{l}{_to0}{l 2*%pd-1}{branch _writeus}
          {l}                to partial cap. field
          {let %temp,l}
__ploop   {let %temp,l+%temp}
          {d}
          {if @cellpointer("contents")<>0}{branch __ploop}
          {let %string,@string(%temp,0)&" 0"}
          {u %temp-2}        to first partial cap. if any
          {for %count,2,%temp-1,1,_appld0}
          {u %temp-1}{r}                to full capacity field
          {let %string,%string&" "&@string(@cellpointer("contents"),0)}
          {l 2*%pd}          to FOR field.  Next line allows neg. cap. w/0 FOR.
          {if @cellpointer("contents")=0#and#%temp=2}{let
             %string,@replace(%string,0,3,"1")}{branch __tou}
          {for %count,1,%temp-1,1,_appld}{u %temp-1}
__tou     {l}                to #units field
          {for %unit,1,@cellpointer("contents"),1,_writeu}
          {r}{d}             to next unit's FOR field
          {branch _writeus}

_appld    {let %temp2,@cellpointer("contents")}
          {contents %temp2,%temp2}
          {let %string,%string&" "&%temp2}
          {d}

_appld0   {let %string,%string&" "&@string(@cellpointer("contents"),0)}
          {d}
```

Figure C-1. 1-2-3 Macros for *REM* (continued)

```
_writeu   {writeln %string}
          {return}

_writels  {goto}loads~{d 4}{r 2*%pd+1}          to 2nd % load
          {if @cellpointer("type")="b"}{return}        peak-only case
          {u}{let %count,@cellpointer("row")}
          {end}{d}{let %count,@cellpointer("row")-%count+1}
          {writeln @string(%count,0)}
          {goto}loads~{d 3}{r 2*%pd+1}          to first % load
          {for %temp,1,%count,1,_writel}
          {goto}loads~{d 3}{r 2*%pd+2}          to first prob.
          {let %prob,0}
          {for %temp,1,%count-1,1,_writep}      {omit last prob.}
          {return}
_writel   {writeln @string((1-@cellpointer("contents"))*%pk,0)}
          {d}
          {return}
_writep   {let %prob,@cellpointer("contents")-%prob}
          {contents %prob,%prob}{writeln %prob}
          {let %prob,@cellpointer("contents")}
          {d}

_writelu  {goto}loaduncs~{r 2*%pd+2}            uses 11-pt moment-matching
             approx. of Gaussian w/given 90% pt
          {if @cellpointer("contents")=0}{return}
          {let %temp,@cellpointer("contents")*%pk/1.2818456}
          {writeln +"11 "&@string(-5.188001*%temp,0)&" "&@string(-
             3.936167*%temp,0)&" "&@string(-2.865123*%temp,0)&" "&@string(-
             1.876035*%temp,0)&" "&@string(-0.928869*%temp,0)}
          {writeln +"   0 "&@string(0.928869*%temp,0)&"
             "&@string(1.876035*%temp,0)&" "&@string(2.865123*%temp,0)&"
             "&@string(3.936167*%temp,0)&" "&@string(5.188001*%temp,0)}
          {writeln "   .812185e-6 .195672e-3 .672028e-2 .0661387 .242240
             .369409 .242240 .0661387 .672028e-2 .195672e-3 .812185e-6"}

_to0      {d}
          {if @cellpointer("contents")<>0}{branch _to0}


_cleanerr{beep}{indicate +%temp&" (press Enter)"}{?}
\c        {indicate}          *** REMOVES ANY LEFTOVER MODE INDICATOR ***
```

Figure C-1. 1-2-3 Macros for *REM* (continued)

```
\t        {paneloff}{windowsoff}      *** TOTALS CAP. FOR CURRENT PDS. ***
          {let %pd,startpd}           (start here for debugging)
          {goto}plants~{d 2}{r 2}{end}{d}     down F.O.R. col.
          {let %count,@cellpointer("row")-@cell("row",plants)-1}
__sumpds  {goto}periods~{r 2*%pd+1}
          {if @cellpointer("type")="b"}{goto}{%where}~{return}
          {goto}totals~{r 2*%pd+2}{let %where,@cellpointer("address")}
          {let +%where,0}
          {goto}plants~{d 2}{r}       to #units field
          {for %temp,1,%count,1,__inctot}
          {goto}totals~{r 2*%pd+2}{beep 3}{windowson}{windowsoff}
          {let %pd,%pd+1}~{if %pd<=endpd}{branch __sumpds}
          {return}
__inctot  {if @cellpointer("type")="b"}{d}{return}
          {let %unit,@cellpointer("contents")}          # units
          {r 2*%pd+1}
          {let +%where,@@(%where)+%unit*@cellpointer("contents")}
          {l 2*%pd+1}
          {d}


\g        {goto}dists~{r 2*%pd+1}{d 2}        *** SETS UP FOR DIST. GRAPH ***
          {if @cellpointer("type")="b"}{let %temp,"Reserve distribution not
             found"}{_cleanerr}{quit}
          /gg{bs}.{r}{end}{d}~c{l 4} leave ready to View
```

```
%pd              1
%temp          364
%temp2    0.002739
%count         364
%string  2 0 400      0.12
%unit            3
%pk           2850
%prob     0.997252
%where    $D$419
(blank)                %pkparms,%parms    ---,%coc
%pkrel    0.096132          0         0
%rel      0.003873          0         0       -44
(%dist)
```

Figure C-2. SRELBAT.BAT Batch File for Running SREL

```
@echo off
rem     Example use:
rem     srelbat tempin.dat tempout.dat Finding Reliability for Period 1
cls
echo %3 %4 %5 %6 %7 %8 %9
srel < %1 > %2
```

```
    9 DC-95-CHP    TOTAL ENERGY       0.30 1.36
    9 DC-95-CHP    MUST RUN ENERGY    0.30 1.36
   10 DC-96-CHP    CAPABILITY         0.54 0.85
   10 DC-96-CHP    TOTAL ENERGY       0.30 1.36
   10 DC-96-CHP    MUST RUN ENERGY    0.30 1.36
   11 DC-97-CHP    CAPABILITY         0.54 0.85
   11 DC-97-CHP    TOTAL ENERGY       0.30 1.36
   11 DC-97-CHP    MUST RUN ENERGY    0.30 1.36
   12 DC-98-CHP    CAPABILITY         0.54 0.85
   12 DC-98-CHP    TOTAL ENERGY       0.30 1.36
   12 DC-98-CHP    MUST RUN ENERGY    0.30 1.36
   13 DC-99-CHP    CAPABILITY         0.54 0.85
   13 DC-99-CHP    TOTAL ENERGY       0.30 1.36
   13 DC-99-CHP    MUST RUN ENERGY    0.30 1.36
   14 DC-00-CHP    CAPABILITY         0.54 0.85
   14 DC-00-CHP    TOTAL ENERGY       0.30 1.36
   14 DC-00-CHP    MUST RUN ENERGY    0.30 1.36
   15 DC-01-CHP    CAPABILITY         0.54 0.85
   15 DC-01-CHP    TOTAL ENERGY       0.30 1.36
   15 DC-01-CHP    MUST RUN ENERGY    0.30 1.36
   16 DC-02-CHP    CAPABILITY         0.54 0.85
   16 DC-02-CHP    TOTAL ENERGY       0.30 1.36
   16 DC-02-CHP    MUST RUN ENERGY    0.30 1.36
   17 DC-03-CHP    CAPABILITY         0.54 0.85
   17 DC-03-CHP    TOTAL ENERGY       0.30 1.36
   17 DC-03-CHP    MUST RUN ENERGY    0.30 1.36
   18 DC-04-CHP    CAPABILITY         0.54 0.85
   18 DC-04-CHP    TOTAL ENERGY       0.30 1.36
   18 DC-04-CHP    MUST RUN ENERGY    0.30 1.36
   19 DC-05-CHP    CAPABILITY         0.54 0.85
   19 DC-05-CHP    TOTAL ENERGY       0.30 1.36
   19 DC-05-CHP    MUST RUN ENERGY    0.30 1.36
   20 DC-06-CHP    CAPABILITY         0.54 0.85
   20 DC-06-CHP    TOTAL ENERGY       0.30 1.36
   20 DC-06-CHP    MUST RUN ENERGY    0.30 1.36
   21 DC-07-CHP    CAPABILITY         0.54 0.85
   21 DC-07-CHP    TOTAL ENERGY       0.30 1.36
   21 DC-07-CHP    MUST RUN ENERGY    0.30 1.36
   22 DC-08-CHP    CAPABILITY         0.54 0.85
   22 DC-08-CHP    TOTAL ENERGY       0.30 1.36
   22 DC-08-CHP    MUST RUN ENERGY    0.30 1.36
   23 DC-09-CHP    CAPABILITY         0.54 0.85
   23 DC-09-CHP    TOTAL ENERGY       0.30 1.36
   23 DC-09-CHP    MUST RUN ENERGY    0.30 1.36
   24 DC-10-CHP    CAPABILITY         0.54 0.85
   24 DC-10-CHP    TOTAL ENERGY       0.30 1.36
   24 DC-10-CHP    MUST RUN ENERGY    0.30 1.36
*c dc summer energy = 0; winter energy (av.mw.) = 365/242 = 1.508 of annual
*
*****************************************************************************
**  THERMAL PLANT DATA - MULTIPLIERS FOR VALUES IN SECTION H OF PART I
*****************************************************************************
*                                PERIOD:  1    2    3    4    5    6    7    8    9   10   11   12
F iii aaaaaaaaaa                         rrrr rrrr rrrr rrrr rrrr rrrr rrrr rrrr rrrr rrrr rrrr rrrr
    1 SL-BE-360    RATING               1.00 1.00
                   SCHEDULED OUTAGE     .800 .200
    2 SL-PA-200    RATING               1.00 1.00
                   SCHEDULED OUTAGE     .300 .200
    3 SL-TU-200    RATING               1.00 1.00
                   SCHEDULED OUTAGE     .800 .200
    4 SL-KO-100    RATING               1.00 1.00
                   SCHEDULED OUTAGE     .800 .200
    5 SL-AD-100    RATING               1.00 1.00
                   SCHEDULED OUTAGE     .800 .200
    6 SL-KO-000    RATING               1.00 1.00
                   SCHEDULED OUTAGE     .800 .200
    7 SC-KO-500    RATING               1.00 1.00
                   SCHEDULED OUTAGE     .800 .200
    8 SC-OP-360    RATING               1.00 1.00
                   SCHEDULED OUTAGE     .800 .200
    9 SC-OS-200    RATING               1.00 1.00
                   SCHEDULED OUTAGE     .800 .200
```

10	SC-KO-200	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
11	SC-PO-200	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
12	SC-RY-200	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
13	SC-J3-200	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
14	SC-LZ-200	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
15	SC-DO-200	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
16	SC-LZ-100	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
17	SC-ST-100	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
18	SC-LG-100	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
19	SC-SI-100	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
20	SC-SK-100	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
21	SC-ST-000	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
22	SC-SK-000	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
23	SC-J2-000	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
24	SC-BL-000	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
25	SC-HA-000	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
26	SC-J1-000	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
27	SC-MI-000	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
28	SC-PO-000	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
29	SR-PA-200	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
30	SL-XX-360	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200
31	CG-XX-120	RATING	1.00	1.00
		SCHEDULED OUTAGE	.800	.200

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*****************************************************************************************
*****************************************************************************************
**
**        *******  ******  *******  *********        **** **** ****
**        **   **  **  **  **   **  *********         **   **   **
**        *******  **  **  **  ***     ***            **   **   **
**        **       ******  ******     ***            **   **   **
**        **       **  **  **  ***    ***            **   **   **
**        **       **  **  **   **    ***            **** **** ****
**
**                        LOAD DURATION CURVE PATTERNS
*****************************************************************************************
*****************************************************************************************
** PATTERN 1  PATTERN 2  PATTERN 3  PATTERN 4  PATTERN 5  PATTERN 6  PATTERN 7  PATTERN 8
*****************************************************************************************
** Next data values are the number of points for each pattern
*****************************************************************************************
F    iii       iii       iii       iii       iii       iii       iii       iii
      20        20        20
*****************************************************************************************
** Next data values are the fraction of peak and the fraction of duration at each point.
** The first point is the base with 0.000 fraction of peak and 1.000 fraction of time. The
** second point is the "knee" of the curve, the fraction of peak would be the minimum load and
** the fraction of time must remain 1.000.  The last value must be 1.000 for fraction of peak.
*****************************************************************************************
*PT FRACTION   FRACTION   FRACTION   FRACTION   FRACTION   FRACTION   FRACTION   FRACTION
*   LOAD TIME  LOAD TIME  LOAD TIME  LOAD TIME  LOAD TIME  LOAD TIME  LOAD TIME  LOAD TIME
*****************************************************************************************
Fii ffff ffff  ffff ffff  ffff ffff  ffff ffff  ffff ffff  ffff ffff  ffff ffff  ffff ffff
*****************************************************************************************
  1    .0 1.00   .000 1.00   .000 1.00
  2 .432 1.00   .531 1.00   .499 1.00
  3 .464 .833   .557 .886   .527 .857
  4 .495 .547   .583 .839   .555 .773
  5 .527 .506   .609 .756   .583 .553
  6 .558 .506   .635 .601   .610 .506
  7 .590 .506   .661 .500   .638 .506
  8 .621 .506   .687 .500   .666 .506
  9 .653 .506   .713 .458   .694 .506
 10 .684 .482   .739 .398   .722 .506
 11 .716 .434   .765 .375   .749 .440
 12 .747 .381   .791 .315   .777 .416
 13 .779 .321   .817 .238   .805 .339
 14 .810 .291   .843 .202   .833 .315
 15 .842 .250   .869 .148   .861 .261
 16 .873 .202   .895 .131   .888 .214
 17 .905 .136   .922 .077   .916 .136
 18 .937 .077   .948 .041   .944 .089
 19 .968 .041   .974 .006   .972 .047
 20 1.00 .000   1.00 .000   1.00 .000
*c
*c results from analysis of the 1991 hourly loads using gpt-l
*c period 1 summer
*c PEAK LOAD (MW) =          17878.00
*c BASE LOAD (MW) =           9505.80
*c WEEKLY ENERGY (MWH) = 2141339.00
*c LOAD FACTOR (%) =            71.29
*c period 2 winter
*c PEAK LOAD (MW) =          23219.00
*c BASE LOAD (MW) =          11603.40
*c WEEKLY ENERGY (MWH) = 2759205.00
*c LOAD FACTOR (%) =            70.73
*c annual average energy = (123*2141339/(7*24) + 242*2759205/(7*24))/365 = 15184.48 av.mw.
*c period energy ratios = 12746.07/15184.48 = 0.839  & 16423.84/15184 = 1.0816
*c *100 series was modified for 183/183 days and 0.436/0.564 mean loads.
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APPENDIX 4.2.2
DETAILED OUTPUT

```
**************************************************
**        GPT - GENERATION PLANING TOOL         **
** C Copyright HYDROSCIENCE -   1986            **
** C.Yermoli (703) 351-0337 Fax (703) 351-0342  **
**************************************************
** VERSION: POLISH POWER GRID - UNLICENSED      **
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T   POLAND  -  ELECTRICTY PRICING STUDY - 1992
T   POLISH POWER GRID COMPANY - POLSKIE SIECI ELEKTROENERGETYCZNE
T   PSE1200 ANALYSIS - 13.Jan.93 - Arlington
T   1200 series
T   Same as 1100 series but rerun on probabilistic subannual mode for
T   use by gpt-m. 1200 series is compatible with new GPT version that
T   uses scale factor when necessary for small systems
T
T   Codes for thermal categories:  TF-II-SSS
T   T: plant type:  T=s  dispatchable steam turbine
T                    d  dispatchable steam turbine used in dh cogeneration
T                    c  comoustion turbine
T   F: fuel type    F=l  lignite
T                    c  hard coal
T                    r  residual oil (bunker, #6)
T                    d  distillate oil (gas oil, #2)
T                    g  natural gas
T   II: plant identification (see codes for plant names in section E)
T                   xx  new capacity
T   SSS: unit size class
1                  000  denotes units under 100 mw
2
3
```

YEAR 1993 PERIOD 1

SELECTION AND ADJUSTMENT OF LOAD DURATION CURVE

E = ALL MW AND GWH MUST BE DIVIDED BY 1.00

QUIRED PEAK=	17111.11	MW
QUIRED ENERGY=	55296.02	GWH
QUIRED L.F.=	.7378	
TTERN L.F.=	.7123	
TTERN ENERGY=	53388.24	GWH
Q.ADJUSTMENT=	3.57	PCT
JUSTED ENERGY=	55247.58	GWH
CURACY=	.09	PCT
AD RESOLUTION=	20.00	MW
ALING FACTOR=	1.00	

PRODUCTION AND COST OF HYDROELECTRIC RESOURCES

PLANT NAME	INSTALLED CAPACITY (MW)	PLANT CAPABILITY (MW)	AVERAGE ENERGY (aMW)	BASE ENERGY (aMW)	CAPITAL ANNUITY (M$)	O & M COST (M$)	TOTAL COST (M$)
92-PUMP	1330.0	1316.8	224.00	.00	.00	7.18	7.18
2-HYDR	640.0	633.7	163.00	80.00	.00	3.46	3.46
-92-AUTO	1290.0	653.0	19.50	10.00	.00	21.15	21.15
-92-CHP	3781.0	1872.3	430.50	375.00	.00	.00	.00
-93-CHP	50.0	26.8	11.40	9.90	.00	.00	.00
	7091.0	4502.6	848.40	474.90	.00	31.79	31.79

DROELECTRIC CONDITION 1

PUT DATA

DRO CAPABILITY=	4502.56	MW
DRO MUST RUN=	474.90	MW
DRO ENERGY=	3715.99	GWH
AKING CAPABILITY ABOVE BASE LOAD=	4042	MW
AKING ENERGY AVAILABLE=	1701.19	GWH

TPUT DATA

SE ENERGY DISPATCHED=	2014.80	GWH
SE ENERGY LOST=	.00	GWH
AK ENERGY DISPATCHED=	1701.19	GWH
AK ENERGY LOST=	.00	GWH
AK DEPENDABLE CAPACITY=	3160	MW
TAL DEPENDABLE CAPACITY=	3620	MW

IGHTED AVERAGE HYDROELECTRIC PRODUCTION (GWH)= 3467.64

DROELECTRIC DEPENDABLE CAPACITY (MW) = 3620.00

********* PRODUCTION AND COST OF THERMAL RESOURCES **********

ROBABILISTIC PRODUCTION COST ANALYSIS OF THE THERMAL SYSTEM

TACK	LOAD POINT MW	GENERATOR TYPE & NAME	NET RATED MW	P.MAIN. DERATED MW	FORCED OUTAGE %	EFFECTIVE CAPACITY MW	ENERGY OUTPUT GWH	CAPAC. FACTOR %	CAPITAL ANNUITY M$	FIXED O & M M$	VARIABLE O & M M$	FUEL COST M$	TOTAL COST M$	FIXED CHARGE $/KW	VARIABLE CHARGE cts/KWH
	160	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
2	320	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
3	480	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
4	640	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
5	800	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
6	960	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
7	1248	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
8	1536	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
9	1824	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
0	2112	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
1	2400	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
2	2688	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
3	2976	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
4	3264	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
5	3552	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
6	3840	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
7	4128	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
8	4416	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
9	4576	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
0	4736	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
1	4896	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
2	5056	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
3	5216	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
4	5376	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
5	5536	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
6	5696	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
7	5856	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
8	5952	4 SL-KO-100	120.0	96.3	12.10	84.7	385.00	73.25	.00	1.50	.00	6.61	8.11	12.500	1.717
9	6048	4 SL-KO-100	120.0	96.3	12.10	84.7	385.00	73.25	.00	1.50	.00	6.61	8.11	12.500	1.717
0	6133	17 SC-ST-100	106.0	85.1	11.20	75.6	311.16	67.02	.00	1.59	.00	5.54	7.13	15.000	1.782
1	6218	17 SC-ST-100	106.0	85.1	11.20	75.6	311.16	67.02	.00	1.59	.00	5.54	7.13	15.000	1.782
2	6244	21 SC-ST-000	33.0	26.5	10.00	23.8	78.84	54.55	.00	.50	.00	1.40	1.90	15.000	1.782
3	6270	21 SC-ST-000	33.0	26.5	10.00	23.8	78.84	54.55	.00	.50	.00	1.40	1.90	15.000	1.782
4	6296	21 SC-ST-000	33.0	26.5	10.00	23.8	78.84	54.55	.00	.50	.00	1.40	1.90	15.000	1.782
5	6322	21 SC-ST-000	33.0	26.5	10.00	23.8	78.84	54.55	.00	.50	.00	1.40	1.90	15.000	1.782
36	6380	5 SL-AD-100	96.0	59.0	15.80	49.7	221.28	52.63	.00	1.44	.00	3.98	5.42	15.000	1.799
37	6438	5 SL-AD-100	96.0	59.0	15.80	49.7	221.28	52.63	.00	1.44	.00	3.98	5.42	15.000	1.799
38	6496	5 SL-AD-100	96.0	59.0	15.80	49.7	221.28	52.63	.00	1.44	.00	3.98	5.42	15.000	1.799
39	6554	5 SL-AD-100	96.0	59.0	15.80	49.7	221.28	52.63	.00	1.44	.00	3.98	5.42	15.000	1.799
40	6586	6 SL-KO-000	40.0	32.1	13.00	27.9	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
41	6618	6 SL-KO-000	40.0	32.1	13.00	27.9	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
42	6650	6 SL-KO-000	40.0	32.1	13.00	27.9	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
43	6682	6 SL-KO-000	40.0	32.1	13.00	27.9	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
44	6714	6 SL-KO-000	40.0	32.1	13.00	27.9	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
45	6758	28 SC-PO-000	56.0	45.0	12.30	39.4	153.65	62.64	.00	.84	.00	2.96	3.80	15.000	1.929
46	6802	28 SC-PO-000	56.0	45.0	12.30	39.4	153.65	62.64	.00	.84	.00	2.96	3.80	15.000	1.929
47	6962	15 SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
48	7122	15 SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
49	7282	15 SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
50	7442	15 SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
51	7602	15 SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
52	7762	15 SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
53	7922	15 SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
54	8082	15 SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
55	8450	7 SC-KO-500	500.0	368.5	30.00	257.9	1103.76	50.40	.00	6.25	.00	22.02	28.27	12.500	1.995
56	8818	7 SC-KO-500	500.0	368.5	30.00	257.9	1103.76	50.40	.00	6.25	.00	22.02	28.27	12.500	1.995
57	8978	11 SC-PO-200	200.0	160.5	7.10	149.1	650.99	74.31	.00	1.50	.00	13.00	14.50	7.500	1.997
8	9138	11 SC-PO-200	200.0	160.5	7.10	149.1	650.77	74.29	.00	1.50	.00	13.00	14.50	7.500	1.997
9	9298	11 SC-PO-200	200.0	160.5	7.10	149.1	650.15	74.22	.00	1.50	.00	12.99	14.49	7.500	1.997
0	9458	11 SC-PO-200	200.0	160.5	7.10	149.1	648.78	74.06	.00	1.50	.00	12.96	14.46	7.500	1.997
1	9618	11 SC-PO-200	200.0	160.5	7.10	149.1	646.31	73.78	.00	1.50	.00	12.91	14.41	7.500	1.997
2	9778	11 SC-PO-200	200.0	160.5	7.10	149.1	642.46	73.34	.00	1.50	.00	12.83	14.33	7.500	1.997

3	9938	11	SC-PO-200	200.0	160.5	7.10	149.1	637.08	72.73	.00	1.50	.00	12.73	14.23	7.500	1.997
4	10098	11	SC-PO-200	200.0	160.5	7.10	149.1	630.22	71.94	.00	1.50	.00	12.59	14.09	7.500	1.997
5	10258	12	SC-RY-200	200.0	160.5	10.80	143.2	597.31	68.19	.00	1.50	.00	12.34	13.84	7.500	2.066
6	10418	12	SC-RY-200	200.0	160.5	10.80	143.2	588.83	67.22	.00	1.50	.00	12.16	13.66	7.500	2.066
7	10578	12	SC-RY-200	200.0	160.5	10.80	143.2	579.55	66.16	.00	1.50	.00	11.97	13.47	7.500	2.066
8	10738	12	SC-RY-200	200.0	160.5	10.80	143.2	569.49	65.01	.00	1.50	.00	11.76	13.26	7.500	2.066
9	10898	12	SC-RY-200	200.0	160.5	10.80	143.2	558.55	63.76	.00	1.50	.00	11.54	13.04	7.500	2.066
0	11058	12	SC-RY-200	200.0	160.5	10.80	143.2	546.56	62.39	.00	1.50	.00	11.29	12.79	7.500	2.066
1	11218	12	SC-RY-200	200.0	160.5	10.80	143.2	533.38	60.89	.00	1.50	.00	11.02	12.52	7.500	2.066
2	11378	[illegible]	SC-RY-200	200.0	160.5	10.80	143.2	519.00	59.25	.00	1.50	.00	10.72	12.22	7.500	2.066
3	11538	[illegible]	-PA-200	200.0	160.5	2.30	156.9	551.61	62.97	.00	1.50	.00	11.51	13.01	7.500	2.087
4	11682	[illegible]	-LZ-200	180.0	144.5	13.40	125.1	413.89	52.50	.00	2.25	.00	8.72	10.97	12.500	2.106
5	11826	14	[illegible] LZ-200	180.0	144.5	13.40	125.1	402.25	51.02	.00	2.25	.00	8.47	10.72	12.500	2.106
6	11970	14	SC-LZ-200	180.0	144.5	13.40	125.1	390.92	49.58	.00	2.25	.00	8.23	10.48	12.500	2.106
7	12114	14	SC-LZ-200	180.0	144.5	13.40	125.1	380.20	48.22	.00	2.25	.00	8.01	10.26	12.500	2.106
8	12194	16	SC-LZ-100	100.0	80.3	16.20	67.3	206.08	47.05	.00	1.25	.00	4.34	5.59	12.500	2.106
9	12274	16	SC-LZ-100	100.0	80.3	16.20	67.3	203.22	46.40	.00	1.25	.00	4.28	5.53	12.500	2.106
0	12434	9	SC-OS-200	200.0	160.5	11.60	141.9	419.96	47.94	.00	2.50	.00	8.87	11.37	12.500	2.111
1	12594	9	SC-OS-200	200.0	160.5	11.60	141.9	409.81	46.78	.00	2.50	.00	8.65	11.15	12.500	2.111
2	12754	9	SC-OS-200	200.0	160.5	11.60	141.9	401.17	45.80	.00	2.50	.00	8.47	10.97	12.500	2.111
3	12914	10	SC-KO-200	200.0	160.5	11.70	141.8	393.26	44.89	.00	1.50	.00	8.30	9.80	7.500	2.111
[illegible]	13074	10	SC-KO-200	200.0	160.5	11.70	141.8	386.50	44.12	.00	1.50	.00	8.16	9.66	7.500	2.111
[illegible]	13234	10	SC-KO-200	200.0	160.5	11.70	141.8	379.97	43.38	.00	1.50	.00	8.02	9.52	7.500	2.111
[illegible]	13394	10	SC-KO-200	200.0	160.5	11.70	141.8	373.24	42.61	.00	1.50	.00	7.88	9.38	7.500	2.111
[illegible]	13500	10	SC-KO-200	200.0	160.5	11.70	141.8	366.02	41.78	.00	1.50	.00	7.73	9.23	7.500	2.111
[illegible]	13500	10	SC-KO-200	200.0	160.5	11.70	141.8	358.08	40.88	.00	1.50	.00	7.56	9.06	7.500	2.111
[illegible]	13500	10	SC-KO-200	200.0	160.5	11.70	141.8	349.29	39.87	.00	1.50	.00	7.37	8.87	7.500	2.111
[illegible]	13500	10	SC-KO-200	200.0	160.5	11.70	141.8	339.48	38.75	.00	1.50	.00	7.17	8.67	7.500	2.111
[illegible]	13500	13	SC-J3-200	190.0	152.5	10.70	136.2	332.10	39.91	.00	1.42	.00	7.04	8.46	7.500	2.119
[illegible]	13500	13	SC-J3-200	190.0	152.5	10.70	136.2	319.03	38.34	.00	1.42	.00	6.76	8.18	7.500	2.119
[illegible]	13500	13	SC-J3-200	190.0	152.5	10.70	136.2	303.69	36.49	.00	1.42	.00	6.43	7.86	7.500	2.119
94	13500	13	SC-J3-200	190.0	152.5	10.70	136.2	285.56	34.31	.00	1.42	.00	6.05	7.47	7.500	2.119
95	13500	13	SC-J3-200	190.0	152.5	10.70	136.2	264.32	31.76	.00	1.42	.00	5.60	7.02	7.500	2.119
96	13500	13	SC-J3-200	190.0	152.5	10.70	136.2	239.99	28.84	.00	1.42	.00	5.08	6.51	7.500	2.119
97	13500	18	SC-LG-100	103.0	82.7	11.90	72.8	108.95	24.15	.00	1.29	.00	2.44	3.73	12.500	2.242
98	13500	18	SC-LG-100	103.0	82.7	11.90	72.8	102.17	22.65	.00	1.29	.00	2.29	3.58	12.500	2.242
99	13500	18	SC-LG-100	103.0	82.7	11.90	72.8	95.21	21.10	.00	1.29	.00	2.13	3.42	12.500	2.242
00	13500	18	SC-LG-100	103.0	82.7	11.90	72.8	88.14	19.54	.00	1.29	.00	1.98	3.26	12.500	2.242
01	13500	18	SC-LG-100	103.0	82.7	11.90	72.8	81.04	17.96	.00	1.29	.00	1.82	3.10	12.500	2.242
02	13500	18	SC-LG-100	103.0	82.7	11.90	72.8	73.99	16.40	.00	1.29	.00	1.66	2.95	12.500	2.242
03	13500	18	SC-LG-100	103.0	82.7	11.90	72.8	67.05	14.86	.00	1.29	.00	1.50	2.79	12.500	2.242
04	13500	19	SC-SI-100	105.0	84.3	11.60	74.5	60.53	13.16	.00	1.31	.00	1.37	2.68	12.500	2.264
05	13500	19	SC-SI-100	105.0	84.3	11.60	74.5	54.02	11.75	.00	1.31	.00	1.22	2.54	12.500	2.264
06	13500	19	SC-SI-100	105.0	84.3	11.60	74.5	47.83	10.40	.00	1.31	.00	1.08	2.40	12.500	2.264
07	13500	19	SC-SI-100	105.0	84.3	11.60	74.5	42.03	9.14	.00	1.31	.00	.95	2.26	12.500	2.264
08	13500	19	SC-SI-100	105.0	84.3	11.60	74.5	36.63	7.97	.00	1.31	.00	.83	2.14	12.500	2.264
09	13500	19	SC-SI-100	105.0	84.3	11.60	74.5	31.68	6.89	.00	1.31	.00	.72	2.03	12.500	2.264
10	13500	20	SC-SK-100	90.0	72.2	10.40	64.7	27.55	6.99	.00	1.35	.00	.67	2.02	15.000	2.423
11	13500	20	SC-SK-100	90.0	72.2	10.40	64.7	23.39	5.93	.00	1.35	.00	.57	1.92	15.000	2.423
12	13500	20	SC-SK-100	90.0	72.2	10.40	64.7	19.69	4.99	.00	1.35	.00	.48	1.83	15.000	2.423
13	13500	22	SC-SK-000	45.0	36.1	10.40	32.4	8.65	4.39	.00	.68	.00	.21	.88	15.000	2.423
14	13500	22	SC-SK-000	45.0	36.1	10.40	32.4	7.88	4.00	.00	.68	.00	.19	.87	15.000	2.423
15	13500	22	SC-SK-000	45.0	36.1	10.40	32.4	7.17	3.64	.00	.68	.00	.17	.85	15.000	2.423
16	13500	24	SC-BL-000	41.0	32.9	10.70	29.4	6.49	3.61	.00	.62	.00	.16	.78	15.000	2.516
17	13500	24	SC-BL-000	41.0	32.9	10.70	29.4	5.88	3.27	.00	.62	.00	.15	.76	15.000	2.516
18	13500	24	SC-BL-000	41.0	32.9	10.70	29.4	5.31	2.96	.00	.62	.00	.13	.75	15.000	2.516
19	13500	24	SC-BL-000	41.0	32.9	10.70	29.4	4.79	2.67	.00	.62	.00	.12	.74	15.000	2.516
20	13500	24	SC-BL-000	41.0	32.9	10.70	29.4	4.32	2.40	.00	.62	.00	.11	.72	15.000	2.516
21	13500	25	SC-HA-000	50.0	40.1	11.80	35.4	3.83	1.75	.00	.75	.00	.10	.85	15.000	2.532
22	13500	25	SC-HA-000	50.0	40.1	11.80	35.4	3.44	1.57	.00	.75	.00	.09	.84	15.000	2.532
23	13500	25	SC-HA-000	50.0	40.1	11.80	35.4	3.08	1.41	.00	.75	.00	.08	.83	15.000	2.532
24	13500	25	SC-HA-000	50.0	40.1	11.80	35.4	2.76	1.26	.00	.75	.00	.07	.82	15.000	2.532
25	13500	23	SC-J2-000	43.0	34.5	10.40	30.9	2.50	1.33	.00	.64	.00	.07	.71	15.000	2.684
26	13500	23	SC-J2-000	43.0	34.5	10.40	30.9	2.22	1.18	.00	.64	.00	.06	.70	15.000	2.684
27	13500	23	SC-J2-000	43.0	34.5	10.40	30.9	1.97	1.05	.00	.64	.00	.05	.70	15.000	2.684
28	13500	23	SC-J2-000	43.0	34.5	10.40	30.9	1.74	.93	.00	.64	.00	.05	.69	15.000	2.684
29	13500	23	SC-J2-000	43.0	34.5	10.40	30.9	1.54	.82	.00	.64	.00	.04	.69	15.000	2.684
30	13500	23	SC-J2-000	43.0	34.5	10.40	30.9	1.36	.72	.00	.64	.00	.04	.68	15.000	2.684
31	13500	23	SC-J2-000	43.0	34.5	10.40	30.9	1.19	.63	.00	.64	.00	.03	.68	15.000	2.684
32	13500	27	SC-MI-000	50.0	40.1	11.80	35.4	1.03	.47	.00	.75	.00	.03	.78	15.000	2.759
33	13500	27	SC-MI-000	50.0	40.1	11.80	35.4	.90	.41	.00	.75	.00	.02	.77	15.000	2.759
34	13500	27	SC-MI-000	50.0	40.1	11.80	35.4	.79	.36	.00	.75	.00	.02	.77	15.000	2.759

135	13500	26	SC-J1-000	19.0	15.3	15.70	12.9	.34	.41	.00	.28	.00	.01	.29	15.000	2.820
136	13500	26	SC-J1-000	19.0	15.3	15.70	12.9	.32	.39	.00	.28	.00	.01	.29	15.000	2.820
137	13500	26	SC-J1-000	19.0	15.3	15.70	12.9	.30	.36	.00	.28	.00	.01	.29	15.000	2.820
138	13500	26	SC-J1-000	19.0	15.3	15.70	12.9	.28	.34	.00	.28	.00	.01	.29	15.000	2.820
139	13500	26	SC-J1-000	19.0	15.3	15.70	12.9	.26	.32	.00	.28	.00	.01	.29	15.000	2.820
140	13500	26	SC-J1-000	19.0	15.3	15.70	12.9	.25	.30	.00	.28	.00	.01	.29	15.000	2.820
				21586.017189.8		.00	15012.7	*******	.00	.00	200.06	.00	958.21	1158.27		

POWER SYSTEM RELIABILITY AND COST

OTAL INSTALLED CAPACITY=	28677.00 MW
HERMAL EFFECTIVE CAPACITY=	15012.72 MW
EAK THERMAL LOAD=	.00 MW
RMAL EFFECTIVE CAPACITY RESERVE=	11.28 %
STALLED CAPACITY RESERVE=	67.59 %
OSS OF LOAD PROBABILITY=	13.71HRS
YDROELECTRIC GENERATION=	3467.64 GWH
HERMAL GENERATION=	51825.10 GWH
OTAL GENERATION=	55292.75 GWH
NERGY LOAD=	55296.03 GWH
NSERVED ENERGY=	3.28 GWH
OTAL COST THIS PERIOD=	1188.26 M$

YEAR 1993 PERIOD 2

SELECTION AND ADJUSTMENT OF LOAD DURATION CURVE

)TE = ALL MW AND GWH MUST BE DIVIDED BY	1.00	
:EQUIRED PEAK=	22222.21	MW
EQUIRED ENERGY=	71821.27	GWH
EQUIRED L.F.=	.7379	
ATTERN L.F.=	.7069	
ATTERN ENERGY=	68806.86	GWH
EQ.ADJUSTMENT=	-.38	PCT
DJUSTED ENERGY=	71796.14	GWH
CCURACY=	.04	PCT
OAD RESOLUTION=	20.00	MW
CALING FACTOR=	1.00	

PRODUCTION AND COST OF HYDROELECTRIC RESOURCES

PLANT NAME	INSTALLED CAPACITY (MW)	PLANT CAPABILITY (MW)	AVERAGE ENERGY (aMW)	BASE ENERGY (aMW)	CAPITAL ANNUITY (M$)	O & M COST (M$)	TOTAL COST (M$)
PW-92-PUMP	1330.0	1316.8	224.00	.00	.00	7.18	7.18
CH-92-HYDR	640.0	633.7	163.00	80.00	.00	3.46	3.46
AC-92-AUTO	1290.0	1064.2	48.75	25.00	.00	23.86	23.86
DC-92-CHP	3781.0	2947.1	1951.60	1700.00	.00	.00	.00
DC-93-CHP	50.0	42.1	51.68	44.88	.00	.00	.00
	7091.0	6003.9	2439.03	1849.88	.00	34.49	34.49

HYDROELECTRIC CONDITION 1

INPUT DATA

HYDRO CAPABILITY=	6003.91 MW
HYDRO MUST RUN=	1849.88 MW
HYDRO ENERGY=	10682.95 GWH
PEAKING CAPABILITY ABOVE BASE LOAD=	4163 MW
PEAKING ENERGY AVAILABLE=	2623.75 GWH

OUTPUT DATA

BASE ENERGY DISPATCHED=	8059.20 GWH
BASE ENERGY LOST=	.00 GWH
PEAK ENERGY DISPATCHED=	2623.75 GWH
PEAK ENERGY LOST=	.00 GWH
PEAK DEPENDABLE CAPACITY=	3680 MW
TOTAL DEPENDABLE CAPACITY=	5520 MW

WEIGHTED AVERAGE HYDROELECTRIC PRODUCTION (GWH)= 9865.84

HYDROELECTRIC DEPENDABLE CAPACITY (MW) = 5520.00

********* PRODUCTION AND COST OF THERMAL RESOURCES **********

PROBABILISTIC PRODUCTION COST ANALYSIS OF THE THERMAL SYSTEM

STACK LEVEL MW	LOAD POINT MW	GENERATOR TYPE	& NAME	NET RATED MW	P.MAIN. DERATED MW	FORCED OUTAGE %	EFFECTIVE CAPACITY MW	ENERGY OUTPUT GWH	CAPAC. FACTOR %	CAPITAL ANNUITY M$	FIXED O & M M$	VARIABLE O & M M$	FUEL COST M$	TOTAL COST M$	FIXED CHARGE $/KW	VARIABLE CHARGE cts/KWH
1	190	2	SL-PA-200	200.0	190.1	10.60	170.0	783.14	89.40	.00	1.50	.00	12.22	13.72	7.500	1.561
2	380	2	SL-PA-200	200.0	190.1	10.60	170.0	783.14	89.40	.00	1.50	.00	12.22	13.72	7.500	1.561
3	570	2	SL-PA-200	200.0	190.1	10.60	170.0	783.14	89.40	.00	1.50	.00	12.22	13.72	7.500	1.561
4	760	2	SL-PA-200	200.0	190.1	10.60	170.0	783.14	89.40	.00	1.50	.00	12.22	13.72	7.500	1.561
5	950	2	SL-PA-200	200.0	190.1	10.60	170.0	783.14	89.40	.00	1.50	.00	12.22	13.72	7.500	1.561
6	1140	2	SL-PA-200	200.0	190.1	10.60	170.0	783.14	89.40	.00	1.50	.00	12.22	13.72	7.500	1.561
7	1482	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
8	1824	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
9	2166	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
10	2508	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
11	2850	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
12	3192	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
13	3534	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
14	3876	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
15	4218	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
16	4560	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
17	4902	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
18	5244	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
19	5434	3	SL-TU-200	200.0	190.1	10.50	170.2	784.02	89.50	.00	1.50	.00	13.37	14.87	7.500	1.706
20	5624	3	SL-TU-200	200.0	190.1	10.50	170.2	784.02	89.50	.00	1.50	.00	13.37	14.87	7.500	1.706
21	5814	3	SL-TU-200	200.0	190.1	10.50	170.2	784.02	89.50	.00	1.50	.00	13.37	14.87	7.500	1.706
22	6004	3	SL-TU-200	200.0	190.1	10.50	170.2	784.02	89.50	.00	1.50	.00	13.37	14.87	7.500	1.706
23	6194	3	SL-TU-200	200.0	190.1	10.50	170.2	784.02	89.50	.00	1.50	.00	13.37	14.87	7.500	1.706
24	6384	3	SL-TU-200	200.0	190.1	10.50	170.2	784.02	89.50	.00	1.50	.00	13.37	14.87	7.500	1.706
25	6574	3	SL-TU-200	200.0	190.1	10.50	170.2	784.02	89.50	.00	1.50	.00	13.37	14.87	7.500	1.706
26	6764	3	SL-TU-200	200.0	190.1	10.50	170.2	784.02	89.50	.00	1.50	.00	13.37	14.87	7.500	1.706
27	6954	3	SL-TU-200	200.0	190.1	10.50	170.2	784.02	89.50	.00	1.50	.00	13.37	14.87	7.500	1.706
28	7068	4	SL-KO-100	120.0	114.1	12.10	100.3	462.00	87.90	.00	1.50	.00	7.93	9.43	12.500	1.717
29	7182	4	SL-KO-100	120.0	114.1	12.10	100.3	462.00	87.90	.00	1.50	.00	7.93	9.43	12.500	1.717
30	7282	17	SC-ST-100	106.0	100.8	11.20	89.5	388.94	83.77	.00	1.59	.00	6.93	8.52	15.000	1.782
31	7382	17	SC-ST-100	106.0	100.8	11.20	89.5	388.94	83.77	.00	1.59	.00	6.93	8.52	15.000	1.782
32	7413	21	SC-ST-000	33.0	31.4	10.00	28.2	157.68	109.09	.00	.50	.00	2.81	3.30	15.000	1.782
33	7444	21	SC-ST-000	33.0	31.4	10.00	28.2	157.68	109.09	.00	.50	.00	2.81	3.30	15.000	1.782
34	7475	21	SC-ST-000	33.0	31.4	10.00	28.2	157.68	109.09	.00	.50	.00	2.81	3.30	15.000	1.782
35	7506	21	SC-ST-000	33.0	31.4	10.00	28.2	157.68	109.09	.00	.50	.00	2.81	3.30	15.000	1.782
36	7592	5	SL-AD-100	96.0	86.7	15.80	73.0	295.04	70.17	.00	1.44	.00	5.31	6.75	15.000	1.799
37	7678	5	SL-AD-100	96.0	86.7	15.80	73.0	295.04	70.17	.00	1.44	.00	5.31	6.75	15.000	1.799
38	7764	5	SL-AD-100	96.0	86.7	15.80	73.0	295.04	70.17	.00	1.44	.00	5.31	6.75	15.000	1.799
39	7850	5	SL-AD-100	96.0	86.7	15.80	73.0	295.04	70.17	.00	1.44	.00	5.31	6.75	15.000	1.799
40	7888	6	SL-KO-000	40.0	38.0	13.00	33.1	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
41	7926	6	SL-KO-000	40.0	38.0	13.00	33.1	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
42	7964	6	SL-KO-000	40.0	38.0	13.00	33.1	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
43	8002	6	SL-KO-000	40.0	38.0	13.00	33.1	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
44	8040	6	SL-KO-000	40.0	38.0	13.00	33.1	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
45	8093	28	SC-PO-000	56.0	53.2	12.30	46.7	230.48	93.96	.00	.84	.00	4.45	5.29	15.000	1.929
46	8146	28	SC-PO-000	56.0	53.2	12.30	46.7	230.48	93.96	.00	.84	.00	4.45	5.29	15.000	1.929
47	8336	15	SC-DO-200	200.0	190.1	9.50	172.1	792.78	90.50	.00	1.50	.00	15.76	17.26	7.500	1.988
48	8526	15	SC-DO-200	200.0	190.1	9.50	172.1	792.78	90.50	.00	1.50	.00	15.76	17.26	7.500	1.988
49	8716	15	SC-DO-200	200.0	190.1	9.50	172.1	792.78	90.50	.00	1.50	.00	15.76	17.26	7.500	1.988
50	8906	15	SC-DO-200	200.0	190.1	9.50	172.1	792.78	90.50	.00	1.50	.00	15.76	17.26	7.500	1.988
51	9096	15	SC-DO-200	200.0	190.1	9.50	172.1	792.78	90.50	.00	1.50	.00	15.76	17.26	7.500	1.988
52	9286	15	SC-DO-200	200.0	190.1	9.50	172.1	792.67	90.49	.00	1.50	.00	15.76	17.26	7.500	1.988
53	9476	15	SC-DO-200	200.0	190.1	9.50	172.1	792.13	90.43	.00	1.50	.00	15.75	17.25	7.500	1.988
54	9666	15	SC-DO-200	200.0	190.1	9.50	172.1	790.55	90.24	.00	1.50	.00	15.72	17.22	7.500	1.988
55	10133	7	SC-KO-500	500.0	467.1	30.00	327.0	1392.44	63.58	.00	6.25	.00	27.77	34.02	12.500	1.995
56	10600	7	SC-KO-500	500.0	467.1	30.00	327.0	1361.05	62.15	.00	6.25	.00	27.15	33.40	12.500	1.995
57	10790	11	SC-PO-200	200.0	190.1	7.10	176.6	770.60	87.97	.00	1.50	.00	15.39	16.89	7.500	1.997
58	10980	11	SC-PO-200	200.0	190.1	7.10	176.6	754.84	86.17	.00	1.50	.00	15.08	16.58	7.500	1.997
59	11170	11	SC-PO-200	200.0	190.1	7.10	176.6	736.63	84.09	.00	1.50	.00	14.71	16.21	7.500	1.997
60	11360	11	SC-PO-200	200.0	190.1	7.10	176.6	716.03	81.74	.00	1.50	.00	14.30	15.80	7.500	1.997
61	11550	11	SC-PO-200	200.0	190.1	7.10	176.6	693.24	79.14	.00	1.50	.00	13.85	15.35	7.500	1.997
62	11740	11	SC-PO-200	200.0	190.1	7.10	176.6	668.74	76.34	.00	1.50	.00	13.36	14.86	7.500	1.997

63	11930	11	SC-PO-200	200.0	190.1	7.10	176.6	643.35	73.44	.00	1.50	.00	12.85	14.35	7.500	1.997
64	12120	11	SC-PO-200	200.0	190.1	7.10	176.6	618.21	70.57	.00	1.50	.00	12.35	13.85	7.500	1.997
65	12310	12	SC-RY-200	200.0	190.1	10.80	169.6	570.91	65.17	.00	1.50	.00	11.79	13.29	7.500	2.066
66	12500	12	SC-RY-200	200.0	190.1	10.80	169.6	551.59	62.97	.00	1.50	.00	11.39	12.89	7.500	2.066
67	12690	12	SC-RY-200	200.0	190.1	10.80	169.6	535.43	61.12	.00	1.50	.00	11.06	12.56	7.500	2.066
68	12880	12	SC-RY-200	200.0	190.1	10.80	169.6	522.83	59.68	.00	1.50	.00	10.80	12.30	7.500	2.066
69	13070	12	SC-RY-200	200.0	190.1	10.80	169.6	513.86	58.66	.00	1.50	.00	10.61	12.11	7.500	2.066
70	13260	12	SC-RY-200	200.0	190.1	10.80	169.6	508.29	58.02	.00	1.50	.00	10.50	12.00	7.500	2.066
71	13450	12	SC-RY-200	200.0	190.1	10.80	169.6	505.71	57.73	.00	1.50	.00	10.45	11.95	7.500	2.066
72	13640	12	SC-RY-200	200.0	190.1	10.80	169.6	505.59	57.72	.00	1.50	.00	10.44	11.94	7.500	2.066
73	13830	29	SR-PA-200	200.0	190.1	2.30	185.8	555.71	63.44	.00	1.50	.00	11.60	13.10	7.500	2.087
74	14001	14	SC-LZ-200	180.0	171.1	13.40	148.2	446.10	56.58	.00	2.25	.00	9.40	11.65	12.500	2.106
75	14172	14	SC-LZ-200	180.0	171.1	13.40	148.2	449.07	56.96	.00	2.25	.00	9.46	11.71	12.500	2.106
76	14343	14	SC-LZ-200	180.0	171.1	13.40	148.2	452.20	57.36	.00	2.25	.00	9.52	11.77	12.500	2.106
77	14514	14	SC-LZ-200	180.0	171.1	13.40	148.2	455.16	57.73	.00	2.25	.00	9.59	11.84	12.500	2.106
78	14609	16	SC-LZ-100	100.0	95.1	16.20	79.7	245.72	56.10	.00	1.25	.00	5.18	6.43	12.500	2.106
79	14704	16	SC-LZ-100	100.0	95.1	16.20	79.7	246.33	56.24	.00	1.25	.00	5.19	6.44	12.500	2.106
80	14894	9	SC-OS-200	200.0	190.1	11.60	168.1	521.10	59.49	.00	2.50	.00	11.00	13.50	12.500	2.111
81	15084	9	SC-OS-200	200.0	190.1	11.60	168.1	521.49	59.53	.00	2.50	.00	11.01	13.51	12.500	2.111
82	15274	9	SC-OS-200	200.0	190.1	11.60	168.1	519.86	59.34	.00	2.50	.00	10.98	13.48	12.500	2.111
83	15464	10	SC-KO-200	200.0	190.1	11.70	167.9	515.43	58.84	.00	1.50	.00	10.88	12.38	7.500	2.111
84	15654	10	SC-KO-200	200.0	190.1	11.70	167.9	509.37	58.15	.00	1.50	.00	10.75	12.25	7.500	2.111
85	15844	10	SC-KO-200	200.0	190.1	11.70	167.9	501.20	57.21	.00	1.50	.00	10.58	12.08	7.500	2.111
86	16034	10	SC-KO-200	200.0	190.1	11.70	167.9	491.13	56.06	.00	1.50	.00	10.37	11.87	7.500	2.111
87	16224	10	SC-KO-200	200.0	190.1	11.70	167.9	479.43	54.73	.00	1.50	.00	10.12	11.62	7.500	2.111
88	16414	10	SC-KO-200	200.0	190.1	11.70	167.9	466.34	53.24	.00	1.50	.00	9.85	11.35	7.500	2.111
89	16604	10	SC-KO-200	200.0	190.1	11.70	167.9	451.99	51.60	.00	1.50	.00	9.54	11.04	7.500	2.111
90	16700	10	SC-KO-200	200.0	190.1	11.70	167.9	436.32	49.81	.00	1.50	.00	9.21	10.71	7.500	2.111
91	16700	13	SC-J3-200	190.0	180.6	10.70	161.3	382.31	45.94	.00	1.42	.00	8.10	9.52	7.500	2.119
92	16700	13	SC-J3-200	190.0	180.6	10.70	161.3	366.33	44.02	.00	1.42	.00	7.76	9.19	7.500	2.119
93	16700	13	SC-J3-200	190.0	180.6	10.70	161.3	348.22	41.84	.00	1.42	.00	7.38	8.80	7.500	2.119
94	16700	13	SC-J3-200	190.0	180.6	10.70	161.3	327.53	39.36	.00	1.42	.00	6.94	8.36	7.500	2.119
95	16700	13	SC-J3-200	190.0	180.6	10.70	161.3	304.01	36.53	.00	1.42	.00	6.44	7.87	7.500	2.119
96	16700	13	SC-J3-200	190.0	180.6	10.70	161.3	277.72	33.37	.00	1.42	.00	5.88	7.31	7.500	2.119
97	16700	18	SC-LG-100	103.0	97.9	11.90	86.3	140.54	31.15	.00	1.29	.00	3.15	4.44	12.500	2.242
98	16700	18	SC-LG-100	103.0	97.9	11.90	86.3	131.64	29.18	.00	1.29	.00	2.95	4.24	12.500	2.242
99	16700	18	SC-LG-100	103.0	97.9	11.90	86.3	122.51	27.16	.00	1.29	.00	2.75	4.03	12.500	2.242
100	16700	18	SC-LG-100	103.0	97.9	11.90	86.3	113.25	25.10	.00	1.29	.00	2.54	3.83	12.500	2.242
101	16700	18	SC-LG-100	103.0	97.9	11.90	86.3	103.96	23.04	.00	1.29	.00	2.33	3.62	12.500	2.242
102	16700	18	SC-LG-100	103.0	97.9	11.90	86.3	94.74	21.00	.00	1.29	.00	2.12	3.41	12.500	2.242
103	16700	18	SC-LG-100	103.0	97.9	11.90	86.3	85.70	19.00	.00	1.29	.00	1.92	3.21	12.500	2.242
104	16700	19	SC-SI-100	105.0	99.8	11.60	88.2	77.20	16.79	.00	1.31	.00	1.75	3.06	12.500	2.264
105	16700	19	SC-SI-100	105.0	99.8	11.60	88.2	68.73	14.94	.00	1.31	.00	1.56	2.87	12.500	2.264
106	16700	19	SC-SI-100	105.0	99.8	11.60	88.2	60.71	13.20	.00	1.31	.00	1.37	2.69	12.500	2.264
107	16700	19	SC-SI-100	105.0	99.8	11.60	88.2	53.19	11.57	.00	1.31	.00	1.20	2.52	12.500	2.264
108	16700	19	SC-SI-100	105.0	99.8	11.60	88.2	46.23	10.05	.00	1.31	.00	1.05	2.36	12.500	2.264
109	16700	19	SC-SI-100	105.0	99.8	11.60	88.2	39.85	8.66	.00	1.31	.00	.90	2.21	12.500	2.264
110	16700	20	SC-SK-100	90.0	85.6	10.40	76.7	28.12	7.13	.00	1.35	.00	.68	2.03	15.000	2.423
111	16700	20	SC-SK-100	90.0	85.6	10.40	76.7	24.63	6.25	.00	1.35	.00	.60	1.95	15.000	2.423
112	16700	20	SC-SK-100	90.0	85.6	10.40	76.7	21.45	5.44	.00	1.35	.00	.52	1.87	15.000	2.423
113	16700	22	SC-SK-000	45.0	42.8	10.40	38.3	9.67	4.91	.00	.68	.00	.23	.91	15.000	2.423
114	16700	22	SC-SK-000	45.0	42.8	10.40	38.3	8.98	4.56	.00	.68	.00	.22	.89	15.000	2.423
115	16700	22	SC-SK-000	45.0	42.8	10.40	38.3	8.34	4.23	.00	.68	.00	.20	.88	15.000	2.423
116	16700	24	SC-BL-000	41.0	39.0	10.70	34.8	7.70	4.29	.00	.62	.00	.19	.81	15.000	2.516
117	16700	24	SC-BL-000	41.0	39.0	10.70	34.8	7.12	3.97	.00	.62	.00	.18	.79	15.000	2.516
118	16700	24	SC-BL-000	41.0	39.0	10.70	34.8	6.58	3.67	.00	.62	.00	.17	.78	15.000	2.516
119	16700	24	SC-BL-000	41.0	39.0	10.70	34.8	6.08	3.38	.00	.62	.00	.15	.77	15.000	2.516
120	16700	24	SC-BL-000	41.0	39.0	10.70	34.8	5.60	3.12	.00	.62	.00	.14	.76	15.000	2.516
121	16700	25	SC-HA-000	50.0	47.5	11.80	41.9	5.09	2.32	.00	.75	.00	.13	.88	15.000	2.532
122	16700	25	SC-HA-000	50.0	47.5	11.80	41.9	4.68	2.14	.00	.75	.00	.12	.87	15.000	2.532
123	16700	25	SC-HA-000	50.0	47.5	11.80	41.9	4.30	1.96	.00	.75	.00	.11	.86	15.000	2.532
124	16700	25	SC-HA-000	50.0	47.5	11.80	41.9	3.95	1.80	.00	.75	.00	.10	.85	15.000	2.532
125	16700	23	SC-J2-000	43.0	40.9	10.40	36.6	3.67	1.95	.00	.64	.00	.10	.74	15.000	2.684
126	16700	23	SC-J2-000	43.0	40.9	10.40	36.6	3.36	1.78	.00	.64	.00	.09	.74	15.000	2.684
127	16700	23	SC-J2-000	43.0	40.9	10.40	36.6	3.06	1.63	.00	.64	.00	.08	.73	15.000	2.684
128	16700	23	SC-J2-000	43.0	40.9	10.40	36.6	2.79	1.48	.00	.64	.00	.07	.72	15.000	2.684
129	16700	23	SC-J2-000	43.0	40.9	10.40	36.6	2.54	1.35	.00	.64	.00	.07	.71	15.000	2.684
30	16700	23	SC-J2-000	43.0	40.9	10.40	36.6	2.31	1.22	.00	.64	.00	.06	.71	15.000	2.684
31	16700	23	SC-J2-000	43.0	40.9	10.40	36.6	2.09	1.11	.00	.64	.00	.06	.70	15.000	2.684
32	16700	27	SC-MI-000	50.0	47.5	11.80	41.9	1.87	.85	.00	.75	.00	.05	.80	15.000	2.759
33	16700	27	SC-MI-000	50.0	47.5	11.80	41.9	1.69	.77	.00	.75	.00	.05	.80	15.000	2.759
34	16700	27	SC-MI-000	50.0	47.5	11.80	41.9	1.53	.70	.00	.75	.00	.04	.79	15.000	2.759

135	16700	26	SC-J1-000	19.0	18.1	15.70	15.2	.68	.82	.00	.28	.00	.02	.30	15.000	2.820
136	16700	26	SC-J1-000	19.0	18.1	15.70	15.2	.65	.78	.00	.28	.00	.02	.30	15.000	2.820
137	16700	26	SC-J1-000	19.0	18.1	15.70	15.2	.62	.74	.00	.28	.00	.02	.30	15.000	2.820
138	16700	26	SC-J1-000	19.0	18.1	15.70	15.2	.59	.71	.00	.28	.00	.02	.30	15.000	2.820
139	16700	26	SC-J1-000	19.0	18.1	15.70	15.2	.56	.67	.00	.28	.00	.02	.30	15.000	2.820
140	16700	26	SC-J1-000	19.0	18.1	15.70	15.2	.53	.64	.00	.28	.00	.01	.30	15.000	2.820
				21586.0	20486.9	.00	17879.5	*******	.00	.00	200.06	.00	1141.32	1341.38		

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POWER SYSTEM RELIABILITY AND COST

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TOTAL INSTALLED CAPACITY=	28677.00	MW
THERMAL EFFECTIVE CAPACITY=	17879.52	MW
PEAK THERMAL LOAD=	.00	MW
THERMAL EFFECTIVE CAPACITY RESERVE=	7.05	%
INSTALLED CAPACITY RESERVE=	29.05	%
LOSS OF LOAD PROBABILITY=	29.96	HRS
HYDROELECTRIC GENERATION=	9865.84	GWH
THERMAL GENERATION=	61946.10	GWH
TOTAL GENERATION=	71811.95	GWH
ENERGY LOAD=	71821.27	GWH
UNSERVED ENERGY=	9.33	GWH
TOTAL COST THIS PERIOD=	1371.37	M$

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SUMMARY OF 1993 RESULTS

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PEAK LOAD=	22222.21 MW
EFFECTIVE CAPACITY RESERVE=	.00 %
LOSS OF LOAD PROBABILITY=	43.67HRS
HYDROELECTRIC GENERATION=	13333.49 GWH
THERMAL GENERATION=	113771.20 GWH
TOTAL GENERATION=	127104.70 GWH
ENERGY LOAD=	127117.30 GWH
UNSERVED ENERGY=	12.61 GWH
TOTAL ANNUAL COST=	2559.62 M$

YEAR 1997 PERIOD 1

SELECTION AND ADJUSTMENT OF LOAD DURATION CURVE

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OTE = ALL MW AND GWH MUST BE DIVIDED BY       1.00
REQUIRED PEAK=       18248.69 MW
REQUIRED ENERGY=     60778.41 GWH
REQUIRED L.F.=          .7604
PATTERN L.F.=           .7123
PATTERN ENERGY=      56937.60 GWH
REQ.ADJUSTMENT=          6.75 PCT
ADJUSTED ENERGY=     60758.01 GWH
ACCURACY=                 .03 PCT
LOAD RESOLUTION=        20.00 MW
SCALING FACTOR=          1.00
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PRODUCTION AND COST OF HYDROELECTRIC RESOURCES

PLANT NAME	INSTALLED CAPACITY (MW)	PLANT CAPABILITY (MW)	AVERAGE ENERGY (aMW)	BASE ENERGY (aMW)	CAPITAL ANNUITY (M$)	O & M COST (M$)	TOTAL COST (M$)
PH-92-PUMP	1330.0	1316.8	224.00	.00	.00	7.18	7.18
CH-92-HYDR	640.0	633.7	163.00	80.00	.00	3.46	3.46
AC-92-AUTO	1290.0	653.0	19.50	10.00	.00	21.15	21.15
DC-92-CHP	3781.0	1872.3	430.50	375.00	.00	.00	.00
DC-93-CHP	50.0	26.8	11.40	9.90	.00	.00	.00
DC-94-CHP	100.0	53.5	22.80	19.80	.00	.00	.00
DC-95-CHP	150.0	80.3	34.20	29.70	.00	.00	.00
DC-96-CHP	190.0	101.7	43.50	37.80	.00	.00	.00
DC-97-CHP	340.0	182.0	77.70	67.50	.00	.00	.00
	7871.0	4920.1	1026.60	629.70	.00	31.79	31.79

HYDROELECTRIC CONDITION 1

INPUT DATA

HYDRO CAPABILITY=	4920.05	MW
HYDRO MUST RUN=	629.70	MW
HYDRO ENERGY=	4496.51	GWH
PEAKING CAPABILITY ABOVE BASE LOAD=	4300	MW
PEAKING ENERGY AVAILABLE=	1780.91	GWH

OUTPUT DATA

BASE ENERGY DISPATCHED=	2715.60	GWH
BASE ENERGY LOST=	.00	GWH
PEAK ENERGY DISPATCHED=	1780.91	GWH
PEAK ENERGY LOST=	.00	GWH
PEAK DEPENDABLE CAPACITY=	3200	MW
TOTAL DEPENDABLE CAPACITY=	3820	MW

WEIGHTED AVERAGE HYDROELECTRIC PRODUCTION (GWH)= 4197.82

HYDROELECTRIC DEPENDABLE CAPACITY (MW) = 3820.00

********* PRODUCTION AND COST OF THERMAL RESOURCES **********

PROBABILISTIC PRODUCTION COST ANALYSIS OF THE THERMAL SYSTEM

STACK LEVEL MW	LOAD POINT MW	GENERATOR TYPE & NAME	NET RATED MW	P.MAIN. DERATED MW	FORCED OUTAGE %	EFFECTIVE CAPACITY MW	ENERGY OUTPUT GWH	CAPAC. FACTOR %	CAPITAL ANNUITY M$	FIXED O & M M$	VARIABLE O & M M$	FUEL COST M$	TOTAL COST M$	FIXED CHARGE $/KW	VARIABLE CHARGE cts/KWH
1	160	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
2	320	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
3	480	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
4	640	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
5	800	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
6	960	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
7	1120	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
8	1280	2 SL-PA-200	200.0	160.5	10.60	143.5	626.52	71.52	.00	1.50	.00	9.78	11.28	7.500	1.561
9	1568	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
10	1856	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
11	2144	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
12	2432	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
13	2720	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
14	3008	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
15	3296	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
16	3584	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
17	3872	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
18	4160	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
19	4448	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
20	4736	1 SL-BE-360	360.0	289.0	16.30	241.9	1026.50	65.10	.00	2.70	.00	16.14	18.84	7.500	1.572
21	4896	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
22	5036	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
23	5216	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
24	5376	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
25	5536	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
26	5696	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
27	5856	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
28	6016	3 SL-TU-200	200.0	160.5	10.50	143.7	627.22	71.60	.00	1.50	.00	10.70	12.20	7.500	1.706
29	6112	4 SL-KO-100	120.0	96.3	12.10	84.7	385.00	73.25	.00	1.50	.00	10.70	12.20	7.500	1.706
30	6208	4 SL-KO-100	120.0	96.3	12.10	84.7	385.00	73.25	.00	1.50	.00	10.70	12.20	7.500	1.706
31	6293	17 SC-ST-100	106.0	85.1	11.20	75.6	311.16	67.02	.00	1.50	.00	6.61	8.11	12.500	1.717
32	6378	17 SC-ST-100	106.0	85.1	11.20	75.6	311.16	67.02	.00	1.50	.00	6.61	8.11	12.500	1.717
33	6404	21 SC-ST-000	33.0	26.5	10.00	23.8	78.84	54.55	.00	1.59	.00	5.54	7.13	15.000	1.782
34	6430	21 SC-ST-000	33.0	26.5	10.00	23.8	78.84	54.55	.00	1.59	.00	5.54	7.13	15.000	1.782
35	6456	21 SC-ST-000	33.0	26.5	10.00	23.8	78.84	54.55	.00	.50	.00	1.40	1.90	15.000	1.782
36	6514	5 SL-AD-100	96.0	59.0	15.80	49.7	221.28	52.63	.00	.50	.00	1.40	1.90	15.000	1.782
37	6572	5 SL-AD-100	96.0	59.0	15.80	49.7	221.28	52.63	.00	.50	.00	1.40	1.90	15.000	1.782
38	6630	5 SL-AD-100	96.0	59.0	15.80	49.7	221.28	52.63	.00	1.44	.00	3.98	5.42	15.000	1.799
39	6688	5 SL-AD-100	96.0	59.0	15.80	49.7	221.28	52.63	.00	1.44	.00	3.98	5.42	15.000	1.799
40	6746	5 SL-AD-100	96.0	59.0	15.80	49.7	221.28	52.63	.00	1.44	.00	3.98	5.42	15.000	1.799
41	6778	6 SL-KO-000	40.0	32.1	13.00	27.9	152.42	87.00	.00	1.44	.00	3.98	5.42	15.000	1.799
42	6810	6 SL-KO-000	40.0	32.1	13.00	27.9	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
43	6842	6 SL-KO-000	40.0	32.1	13.00	27.9	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
44	6874	6 SL-KO-000	40.0	32.1	13.00	27.9	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
45	6906	6 SL-KO-000	40.0	32.1	13.00	27.9	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
46	6938	6 SL-KO-000	40.0	32.1	13.00	27.9	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
47	6982	28 SC-PO-000	56.0	45.0	12.30	39.4	153.65	62.64	.00	.84	.00	2.96	3.80	15.000	1.929
48	7142	15 SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
49	7302	15 SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
50	7462	15 SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
51	7622	15 SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
52	7782	15 SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
53	7942	15 SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
54	8102	15 SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
55	8262	15 SC-DO-200	200.0	160.5	9.50	145.3	634.22	72.40	.00	1.50	.00	12.61	14.11	7.500	1.988
56	8630	7 SC-KO-500	500.0	368.5	30.00	257.9	1103.76	50.40	.00	1.50	.00	12.61	14.11	7.500	1.988
57	8998	7 SC-KO-500	500.0	368.5	30.00	257.9	1103.76	50.40	.00	6.25	.00	22.02	28.27	12.500	1.995
58	9286	8 SC-OP-360	360.0	289.0	10.80	257.8	1093.94	69.38	.00	6.25	.00	22.02	28.27	12.500	1.995
59	9574	8 SC-OP-360	360.0	289.0	10.80	257.8	1093.75	69.37	.00	2.70	.00	21.82	24.52	7.500	1.995
60	9862	8 SC-OP-360	360.0	289.0	10.80	257.8	1092.45	69.28	.00	2.70	.00	21.82	24.52	7.500	1.995
61	10150	8 SC-OP-360	360.0	289.0	10.80	257.8	1088.21	69.01	.00	2.70	.00	21.79	24.49	7.500	1.995
62	10438	8 SC-OP-360	360.0	289.0	10.80	257.8	1079.40	68.46	.00	2.70	.00	21.71	24.41	7.500	1.995
									.00	2.70	.00	21.53	24.23	7.500	1.995

63	10726	8	SC-OP-360	360.0	289.0	10.80	257.8	1065.85	67.60	.00	2.70	.00	21.26	23.96	7.500	1.995
64	10886	11	SC-PO-200	200.0	160.5	7.10	149.1	626.79	71.55	.00	1.50	.00	12.52	14.02	7.500	1.997
65	11046	11	SC-PO-200	200.0	160.5	7.10	149.1	620.29	70.81	.00	1.50	.00	12.39	13.89	7.500	1.997
66	11206	11	SC-PO-200	200.0	160.5	7.10	149.1	613.33	70.02	.00	1.50	.00	12.25	13.75	7.500	1.997
67	11366	11	SC-PO-200	200.0	160.5	7.10	149.1	605.87	69.16	.00	1.50	.00	12.10	13.60	7.500	1.997
68	11526	11	SC-PO-200	200.0	160.5	7.10	149.1	597.74	68.24	.00	1.50	.00	11.94	13.44	7.500	1.997
69	11686	11	SC-PO-200	200.0	160.5	7.10	149.1	588.71	67.20	.00	1.50	.00	11.76	13.26	7.500	1.997
70	11846	11	SC-PO-200	200.0	160.5	7.10	149.1	578.61	66.05	.00	1.50	.00	11.56	13.06	7.500	1.997
71	12006	11	SC-PO-200	200.0	160.5	7.10	149.1	567.36	64.77	.00	1.50	.00	11.33	12.83	7.500	1.997
72	12166	12	SC-RY-200	200.0	160.5	10.80	143.2	533.01	60.85	.00	1.50	.00	11.01	12.51	7.500	2.066
73	12326	12	SC-RY-200	200.0	160.5	10.80	143.2	521.13	59.49	.00	1.50	.00	10.76	12.26	7.500	2.066
74	12486	12	SC-RY-200	200.0	160.5	10.80	143.2	509.17	58.12	.00	1.50	.00	10.52	12.02	7.500	2.066
75	12646	12	SC-RY-200	200.0	160.5	10.80	143.2	497.65	56.81	.00	1.50	.00	10.28	11.78	7.500	2.066
76	12806	12	SC-RY-200	200.0	160.5	10.80	143.2	487.09	55.60	.00	1.50	.00	10.06	11.56	7.500	2.066
77	12966	12	SC-RY-200	200.0	160.5	10.80	143.2	477.86	54.55	.00	1.50	.00	9.87	11.37	7.500	2.066
78	13126	12	SC-RY-200	200.0	160.5	10.80	143.2	470.18	53.67	.00	1.50	.00	9.71	11.21	7.500	2.066
79	13286	12	SC-RY-200	200.0	160.5	10.80	143.2	464.01	52.97	.00	1.50	.00	9.58	11.08	7.500	2.066
80	13430	14	SC-LZ-200	180.0	144.5	13.40	125.1	390.27	49.50	.00	2.25	.00	8.22	10.47	12.500	2.106
81	13574	14	SC-LZ-200	180.0	144.5	13.40	125.1	387.29	49.12	.00	2.25	.00	8.16	10.41	12.500	2.106
82	13718	14	SC-LZ-200	180.0	144.5	13.40	125.1	384.59	48.78	.00	2.25	.00	8.10	10.35	12.500	2.106
83	13862	14	SC-LZ-200	180.0	144.5	13.40	125.1	381.89	48.44	.00	2.25	.00	8.04	10.29	12.500	2.106
84	13942	16	SC-LZ-100	100.0	80.3	16.20	67.3	209.96	47.94	.00	1.25	.00	4.42	5.67	12.500	2.106
85	14022	16	SC-LZ-100	100.0	80.3	16.20	67.3	208.98	47.71	.00	1.25	.00	4.40	5.65	12.500	2.106
86	14182	9	SC-OS-200	200.0	160.5	11.60	141.9	437.19	49.91	.00	2.50	.00	9.23	11.73	12.500	2.111
87	14342	9	SC-OS-200	200.0	160.5	11.60	141.9	431.31	49.24	.00	2.50	.00	9.11	11.61	12.500	2.111
88	14420	9	SC-OS-200	200.0	160.5	11.60	141.9	424.15	48.42	.00	2.50	.00	8.95	11.45	12.500	2.111
89	14420	10	SC-KO-200	200.0	160.5	11.70	141.8	415.16	47.39	.00	1.50	.00	8.76	10.26	7.500	2.111
90	14420	10	SC-KO-200	200.0	160.5	11.70	141.8	405.27	46.26	.00	1.50	.00	8.56	10.06	7.500	2.111
91	14420	10	SC-KO-200	200.0	160.5	11.70	141.8	393.94	44.97	.00	1.50	.00	8.32	9.82	7.500	2.111
92	14420	10	SC-KO-200	200.0	160.5	11.70	141.8	381.06	43.50	.00	1.50	.00	8.04	9.54	7.500	2.111
93	14420	10	SC-KO-200	200.0	160.5	11.70	141.8	366.39	41.82	.00	1.50	.00	7.74	9.24	7.500	2.111
94	14420	10	SC-KO-200	200.0	160.5	11.70	141.8	349.56	39.90	.00	1.50	.00	7.38	8.88	7.500	2.111
95	14420	10	SC-KO-200	200.0	160.5	11.70	141.8	330.21	37.70	.00	1.50	.00	6.97	8.47	7.500	2.111
96	14420	10	SC-KO-200	200.0	160.5	11.70	141.8	308.04	35.16	.00	1.50	.00	6.50	8.00	7.500	2.111
97	14420	13	SC-J3-200	190.0	152.5	10.70	136.2	286.21	34.39	.00	1.42	.00	6.06	7.49	7.500	2.119
98	14420	13	SC-J3-200	190.0	152.5	10.70	136.2	257.94	31.00	.00	1.42	.00	5.46	6.89	7.500	2.119
99	14420	13	SC-J3-200	190.0	152.5	10.70	136.2	227.66	27.36	.00	1.42	.00	4.82	6.25	7.500	2.119
100	14420	13	SC-J3-200	190.0	152.5	10.70	136.2	196.36	23.60	.00	1.42	.00	4.16	5.59	7.500	2.119
101	14420	13	SC-J3-200	190.0	152.5	10.70	136.2	165.23	19.85	.00	1.42	.00	3.50	4.93	7.500	2.119
102	14420	13	SC-J3-200	190.0	152.5	10.70	136.2	135.46	16.28	.00	1.42	.00	2.87	4.29	7.500	2.119
103	14420	18	SC-LG-100	103.0	82.7	11.90	72.8	56.93	12.62	.00	1.29	.00	1.28	2.56	12.500	2.242
104	14420	18	SC-LG-100	103.0	82.7	11.90	72.8	50.59	11.21	.00	1.29	.00	1.13	2.42	12.500	2.242
105	14420	18	SC-LG-100	103.0	82.7	11.90	72.8	44.65	9.90	.00	1.29	.00	1.00	2.29	12.500	2.242
106	14420	18	SC-LG-100	103.0	82.7	11.90	72.8	39.14	8.68	.00	1.29	.00	.88	2.17	12.500	2.242
107	14420	18	SC-LG-100	103.0	82.7	11.90	72.8	34.06	7.55	.00	1.29	.00	.76	2.05	12.500	2.242
108	14420	18	SC-LG-100	103.0	82.7	11.90	72.8	29.44	6.53	.00	1.29	.00	.66	1.95	12.500	2.242
109	14420	18	SC-LG-100	103.0	82.7	11.90	72.8	25.27	5.60	.00	1.29	.00	.57	1.85	12.500	2.242
110	14420	19	SC-SI-100	105.0	84.3	11.60	74.5	21.61	4.70	.00	1.31	.00	.49	1.80	12.500	2.264
111	14420	19	SC-SI-100	105.0	84.3	11.60	74.5	18.27	3.97	.00	1.31	.00	.41	1.73	12.500	2.264
112	14420	19	SC-SI-100	105.0	84.3	11.60	74.5	15.34	3.34	.00	1.31	.00	.35	1.66	12.500	2.264
113	14420	19	SC-SI-100	105.0	84.3	11.60	74.5	12.79	2.78	.00	1.31	.00	.29	1.60	12.500	2.264
114	14420	19	SC-SI-100	105.0	84.3	11.60	74.5	10.59	2.30	.00	1.31	.00	.24	1.55	12.500	2.264
115	14420	19	SC-SI-100	105.0	84.3	11.60	74.5	8.71	1.89	.00	1.31	.00	.20	1.51	12.500	2.264
116	14420	22	SC-SK-000	45.0	3 .1	10.40	32.4	3.81	1.94	.00	.68	.00	.09	.77	15.000	2.423
117	14420	22	SC-SK-000	45.0	36.1	10.40	32.4	3.43	1.74	.00	.68	.00	.08	.76	15.000	2.423
118	14420	22	SC-SK-000	45.0	36.1	10.40	32.4	3.08	1.57	.00	.68	.00	.07	.75	15.000	2.423
119	14420	24	SC-BL-000	41.0	32.9	10.70	29.4	2.76	1.54	.00	.62	.00	.07	.68	15.000	2.516
120	14420	25	SC-HA-000	50.0	40.1	11.80	35.4	2.44	1.11	.00	.75	.00	.06	.81	15.000	2.532
121	14420	25	SC-HA-000	50.0	40.1	11.80	35.4	2.18	1.00	.00	.75	.00	.06	.81	15.000	2.532
122	14420	25	SC-HA-000	50.0	40.1	11.80	35.4	1.95	.89	.00	.75	.00	.05	.80	15.000	2.532
123	14420	25	SC-HA-000	50.0	40.1	11.80	35.4	1.74	.79	.00	.75	.00	.04	.79	15.000	2.532
124	14420	23	SC-J2-000	43.0	34.5	10.40	30.9	1.57	.84	.00	.64	.00	.04	.69	15.000	2.684
125	14420	23	SC-J2-000	43.0	34.5	10.40	30.9	1.40	.74	.00	.64	.00	.04	.68	15.000	2.684
126	14420	23	SC-J2-000	43.0	34.5	10.40	30.9	1.24	.66	.00	.64	.00	.03	.68	15.000	2.684
127	14420	23	SC-J2-000	43.0	34.5	10.40	30.9	1.09	.58	.00	.64	.00	.03	.67	15.000	2.684
128	14420	23	SC-J2-000	43.0	34.5	10.40	30.9	.96	.51	.00	.64	.00	.03	.67	15.000	2.684
129	14420	23	SC-J2-000	43.0	34.5	10.40	30.9	.85	.45	.00	.64	.00	.02	.67	15.000	2.684
130	14420	23	SC-J2-000	43.0	34.5	10.40	30.9	.75	.40	.00	.64	.00	.02	.67	15.000	2.684
131	14420	27	SC-MI-000	50.0	40.1	11.80	35.4	.64	.29	.00	.75	.00	.02	.77	15.000	2.759
132	14420	27	SC-MI-000	50.0	40.	11.80	35.4	.56	.26	.00	.75	.00	.02	.77	15.000	2.759
133	14420	27	SC-MI-000	50.0	40.1	11.80	35.4	.50	.23	.00	.75	.00	.01	.76	15.000	2.759
134	14420	26	SC-J1-000	19.0	15.3	15.70	12.9	.21	.26	.00	.28	.00	.01	.29	15.000	2.820

135	14420	26	SC-J1-000	19.0	15.3	15.70	12.9	.20	.24	.00	.28	.00	.01	.29	15.000	2.820
136	14420	26	SC-J1-000	19.0	15.3	15.70	12.9	.19	.23	.00	.28	.00	.01	.29	15.000	2.820
137	14420	26	SC-J1-000	19.0	15.3	15.70	12.9	.18	.21	.00	.28	.00	.00	.29	15.000	2.820
138	14420	26	SC-J1-000	19.0	15.3	15.70	12.9	.17	.20	.00	.28	.00	.00	.29	15.000	2.820
139	14420	26	SC-J1-000	19.0	15.3	15.70	12.9	.15	.19	.00	.28	.00	.00	.29	15.000	2.820
140	14420	31	CG-XX-120	120.0	109.5	12.00	96.3	.65	.12	3.07	.90	.00	.03	4.00	33.064	4.637
141	14420	31	CG-XX-120	120.0	109.5	12.00	96.3	.46	.09	3.07	.90	.00	.02	3.99	33.064	4.637
				23599.0	18813.9	.00	16441.1	*******	.00	6.14	212.16	.00	1045.83	1264.13		

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POWER SYSTEM RELIABILITY AND COST

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TOTAL INSTALLED CAPACITY=	31470.00 MW
THERMAL EFFECTIVE CAPACITY=	16441.13 MW
PEAK THERMAL LOAD=	.00 MW
THERMAL EFFECTIVE CAPACITY RESERVE=	13.95 %
INSTALLED CAPACITY RESERVE=	72.45 %
LOSS OF LOAD PROBABILITY=	4.25HRS
HYDROELECTRIC GENERATION=	4197.82 GWH
THERMAL GENERATION=	56579.62 GWH
TOTAL GENERATION=	60777.44 GWH
ENERGY LOAD=	60778.42 GWH
UNSERVED ENERGY=	.98 GWH
TOTAL COST THIS PERIOD=	1294.11 M$

YEAR 1997 PERIOD 2

SELECTION AND ADJUSTMENT OF LOAD DURATION CURVE

NOTE = ALL MW AND GWH MUST BE DIVIDED BY 1.00

REQUIRED PEAK=	23699.59	MW
REQUIRED ENERGY=	78942.09	GWH
REQUIRED L.F.=	.7605	
PATTERN L.F.=	.7069	
PATTERN ENERGY=	73381.29	GWH
REQ.ADJUSTMENT=	7.58	PCT
ADJUSTED ENERGY=	78906.06	GWH
ACCURACY=	.05	PCT
LOAD RESOLUTION=	20.00	MW
SCALING FACTOR=	1.00	

PRODUCTION AND COST OF HYDROELECTRIC RESOURCES

PLANT NAME	INSTALLED CAPACITY (MW)	PLANT CAPABILITY (MW)	AVERAGE ENERGY (aMW)	BASE ENERGY (aMW)	CAPITAL ANNUITY (M$)	O & M COST (M$)	TOTAL COST (M$)
PH-92-PUMP	1330.0	1316.8	224.00	.00	.00	7.18	7.18
CH-92-HYDR	640.0	633.7	163.00	80.00	.00	3.46	3.46
AC-92-AUTO	1290.0	1065.2	48.75	25.00	.00	23.86	23.86
DC-92-CHP	3781.0	2947.1	1951.60	1700.00	.00	.00	.00
DC-93-CHP	50.0	42.1	51.68	44.88	.00	.00	.00
DC-94-CHP	100.0	84.3	103.36	89.76	.00	.00	.00
DC-95-CHP	150.0	126.4	155.04	134.64	.00	.00	.00
DC-96-CHP	190.0	160.1	197.20	171.36	.00	.00	.00
DC-97-CHP	340.0	286.5	352.24	306.00	.00	.00	.00
	7871.0	6661.1	3246.87	2551.64	.00	34.49	34.49

HYDROELECTRIC CONDITION 1

INPUT DATA

HYDRO CAPABILITY=	6661.08 MW
HYDRO MUST RUN=	2551.64 MW
HYDRO ENERGY=	14221.29 GWH
PEAKING CAPABILITY ABOVE BASE LOAD=	4121 MW
PEAKING ENERGY AVAILABLE=	3096.09 GWH

OUTPUT DATA

BASE ENERGY DISPATCHED=	11125.20 GWH
BASE ENERGY LOST=	.00 GWH
PEAK ENERGY DISPATCHED=	3096.09 GWH
PEAK ENERGY LOST=	.00 GWH
PEAK DEPENDABLE CAPACITY=	4020 MW
TOTAL DEPENDABLE CAPACITY=	6560 MW

WEIGHTED AVERAGE HYDROELECTRIC PRODUCTION (GWH)= 13365.55

HYDROELECTRIC DEPENDABLE CAPACITY (MW) = 6560.00

********* PRODUCTION AND COST OF THERMAL RESOURCES **********

PROBABILISTIC PRODUCTION COST ANALYSIS OF THE THERMAL SYSTEM

STACK LEVEL MW	LOAD POINT MW	GENERATOR TYPE	& NAME	NET RATED MW	P.MAIN. DERATED MW	FORCED OUTAGE %	EFFECTIVE CAPACITY MW	ENERGY OUTPUT GWH	CAPAC. FACTOR %	CAPITAL ANNUITY M$	FIXED O & M M$	VARIABLE O & M M$	FUEL COST M$	TOTAL COST M$	FIXED CHARGE $/KW	VARIABLE CHARGE cts/KWH
1	190	2	SL-PA-200	200.0	190.1	10.60	170.0	783.14	89.40	.00	1.50	.00	12.22	13.72	7.500	1.561
2	380	2	SL-PA-200	200.0	190.1	10.60	170.0	783.14	89.40	.00	1.50	.00	12.22	13.72	7.500	1.561
3	570	2	SL-PA-200	200.0	190.1	10.60	170.0	783.14	89.40	.00	1.50	.00	12.22	13.72	7.500	1.561
4	760	2	SL-PA-200	200.0	190.1	10.60	170.0	783.14	89.40	.00	1.50	.00	12.22	13.72	7.500	1.561
5	950	2	SL-PA-200	200.0	190.1	10.60	170.0	783.14	89.40	.00	1.50	.00	12.22	13.72	7.500	1.561
6	1140	2	SL-PA-200	200.0	190.1	10.60	170.0	783.14	89.40	.00	1.50	.00	12.22	13.72	7.500	1.561
7	1330	2	SL-PA-200	200.0	190.1	10.60	170.0	783.14	89.40	.00	1.50	.00	12.22	13.72	7.500	1.561
8	1520	2	SL-PA-200	200.0	190.1	10.60	170.0	783.14	89.40	.00	1.50	.00	12.22	13.72	7.500	1.561
9	1862	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
10	2204	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
11	2546	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
12	2888	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
13	3230	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
14	3572	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
15	3914	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
16	4256	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
17	4598	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
18	4940	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
19	5282	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
20	5624	1	SL-BE-360	360.0	342.2	16.30	286.5	1246.46	79.05	.00	2.70	.00	19.60	22.30	7.500	1.572
21	5814	3	SL-TU-200	200.0	190.1	10.50	170.2	784.02	89.50	.00	1.50	.00	13.37	14.87	7.500	1.706
22	6004	3	SL-TU-200	200.0	190.1	10.50	170.2	784.02	89.50	.00	1.50	.00	13.37	14.87	7.500	1.706
23	6194	3	SL-TU-200	200.0	190.1	10.50	170.2	784.02	89.50	.00	1.50	.00	13.37	14.87	7.500	1.706
24	6384	3	SL-TU-200	200.0	190.1	10.50	170.2	784.02	89.50	.00	1.50	.00	13.37	14.87	7.500	1.706
25	6574	3	SL-TU-200	200.0	190.1	10.50	170.2	784.02	89.50	.00	1.50	.00	13.37	14.87	7.500	1.706
26	6764	3	SL-TU-200	200.0	190.1	10.50	170.2	784.02	89.50	.00	1.50	.00	13.37	14.87	7.500	1.706
27	6954	3	SL-TU-200	200.0	190.1	10.50	170.2	784.02	89.50	.00	1.50	.00	13.37	14.87	7.500	1.706
28	7144	3	SL-TU-200	200.0	190.1	10.50	170.2	784.02	89.50	.00	1.50	.00	13.37	14.87	7.500	1.706
29	7258	4	SL-KO-100	120.0	114.1	12.10	100.3	462.00	87.90	.00	1.50	.00	7.93	9.43	12.500	1.717
30	7372	4	SL-KO-100	120.0	114.1	12.10	100.3	462.00	87.90	.00	1.50	.00	7.93	9.43	12.500	1.717
31	7472	17	SC-ST-100	106.0	100.8	11.20	89.5	388.94	83.77	.00	1.59	.00	6.93	8.52	15.000	1.782
32	7572	17	SC-ST-100	106.0	100.8	11.20	89.5	388.94	83.77	.00	1.59	.00	6.93	8.52	15.000	1.782
33	7603	21	SC-ST-000	33.0	31.4	10.00	28.2	157.68	109.09	.00	.50	.00	2.81	3.30	15.000	1.782
34	7634	21	SC-ST-000	33.0	31.4	10.00	28.2	157.68	109.09	.00	.50	.00	2.81	3.30	15.000	1.782
35	7665	21	SC-ST-000	33.0	31.4	10.00	28.2	157.68	109.09	.00	.50	.00	2.81	3.30	15.000	1.782
36	7751	5	SL-AD-100	96.0	86.7	15.80	73.0	295.04	70.17	.00	1.44	.00	5.31	6.75	15.000	1.799
37	7837	5	SL-AD-100	96.0	86.7	15.80	73.0	295.04	70.17	.00	1.44	.00	5.31	6.75	15.000	1.799
38	7923	5	SL-AD-100	96.0	86.7	15.80	73.0	295.04	70.17	.00	1.44	.00	5.31	6.75	15.000	1.799
39	8009	5	SL-AD-100	96.0	86.7	15.80	73.0	295.04	70.17	.00	1.44	.00	5.31	6.75	15.000	1.799
40	8095	5	SL-AD-100	96.0	86.7	15.80	73.0	295.04	70.17	.00	1.44	.00	5.31	6.75	15.000	1.799
41	8133	6	SL-KO-000	40.0	38.0	13.00	33.1	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
42	8171	6	SL-KO-000	40.0	38.0	13.00	33.1	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
43	8209	6	SL-KO-000	40.0	38.0	13.00	33.1	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
44	8247	6	SL-KO-000	40.0	38.0	13.00	33.1	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
45	8285	6	SL-KO-000	40.0	38.0	13.00	33.1	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
46	8323	6	SL-KO-000	40.0	38.0	13.00	33.1	152.42	87.00	.00	.50	.00	2.93	3.43	12.500	1.919
47	8376	28	SC-PO-000	56.0	53.2	12.30	46.7	230.48	93.96	.00	.84	.00	4.45	5.29	15.000	1.929
48	8566	15	SC-DO-200	200.0	190.1	9.50	172.1	792.78	90.50	.00	1.50	.00	15.76	17.26	7.500	1.988
49	8756	15	SC-DO-200	200.0	190.1	9.50	172.1	792.78	90.50	.00	1.50	.00	15.76	17.26	7.500	1.988
50	8946	15	SC-DO-200	200.0	190.1	9.50	172.1	792.78	90.50	.00	1.50	.00	15.76	17.26	7.500	1.988
51	9136	15	SC-DO-200	200.0	190.1	9.50	172.1	792.78	90.50	.00	1.50	.00	15.76	17.26	7.500	1.988
52	9326	15	SC-DO-200	200.0	190.1	9.50	172.1	792.71	90.49	.00	1.50	.00	15.76	17.26	7.500	1.988
53	9516	15	SC-DO-200	200.0	190.1	9.50	172.1	792.33	90.45	.00	1.50	.00	15.75	17.25	7.500	1.988
54	9706	15	SC-DO-200	200.0	190.1	9.50	172.1	791.19	90.32	.00	1.50	.00	15.73	17.23	7.500	1.988
55	9896	15	SC-DO-200	200.0	190.1	9.50	172.1	788.66	90.03	.00	1.50	.00	15.68	17.18	7.500	1.988
56	10363	7	SC-KO-500	500.0	467.1	30.00	327.0	1385.99	63.29	.00	6.25	.00	27.65	33.90	12.500	1.995
57	10830	7	SC-KO-500	500.0	467.1	30.00	327.0	1354.96	61.87	.00	6.25	.00	27.03	33.28	12.500	1.995
58	11172	8	SC-OP-360	360.0	342.2	10.80	305.3	1246.16	79.03	.00	2.70	.00	24.86	27.56	7.500	1.995
59	11514	8	SC-OP-360	360.0	342.2	10.80	305.3	1205.65	76.46	.00	2.70	.00	24.05	26.75	7.500	1.995
60	11856	8	SC-OP-360	360.0	342.2	10.80	305.3	1157.34	73.40	.00	2.70	.00	23.09	25.79	7.500	1.995
61	12198	8	SC-OP-360	360.0	342.2	10.80	305.3	1103.22	69.97	.00	2.70	.00	22.01	24.71	7.500	1.995
62	12540	8	SC-OP-360	360.0	342.2	10.80	305.3	1048.94	66.52	.00	2.70	.00	20.92	23.62	7.500	1.995

63	12882	8	SC-OP-360	360.0	342.2	10.80	305.3	1301.98	63.55	.00	2.70	.00	19.99	22.69	7.500	1.995
64	13072	11	SC-PO-200	200.0	190.1	7.10	176.6	596.97	68.15	.00	1.50	.00	11.92	13.42	7.500	1.997
65	13262	11	SC-PO-200	200.0	190.1	7.10	176.6	587.55	67.07	.00	1.50	.00	11.74	13.24	7.500	1.997
66	13452	11	SC-PO-200	200.0	190.1	7.10	176.6	581.80	66.42	.00	1.50	.00	11.62	13.12	7.500	1.997
67	13642	11	SC-PO-200	200.0	190.1	7.10	176.6	579.53	66.16	.00	1.50	.00	11.58	13.08	7.500	1.997
68	13832	11	SC-PO-200	200.0	190.1	7.10	176.6	580.32	66.25	.00	1.50	.00	11.59	13.09	7.500	1.997
69	14022	11	SC-PO-200	200.0	190.1	7.10	176.6	583.65	66.63	.00	1.50	.00	11.66	13.16	7.500	1.997
70	14212	11	SC-PO-200	200.0	190.1	7.10	176.6	588.93	67.23	.00	1.50	.00	11.76	13.26	7.500	1.997
71	14402	11	SC-PO-200	200.0	190.1	7.10	176.6	595.58	67.99	.00	1.50	.00	11.90	13.40	7.500	1.997
72	14592	12	SC-RY-200	200.0	190.1	10.80	169.6	578.98	66.09	.00	1.50	.00	11.96	13.46	7.500	2.066
73	14782	12	SC-RY-200	200.0	190.1	10.80	169.6	585.95	66.89	.00	1.50	.00	12.10	13.60	7.500	2.066
74	14972	12	SC-RY-200	200.0	190.1	10.80	169.6	592.45	67.63	.00	1.50	.00	12.24	13.74	7.500	2.066
75	15162	12	SC-RY-200	200.0	190.1	10.80	169.6	597.90	68.25	.00	1.50	.00	12.35	13.85	7.500	2.066
76	15352	12	SC-RY-200	200.0	190.1	10.80	169.6	601.72	68.69	.00	1.50	.00	12.43	13.93	7.500	2.066
77	15542	12	SC-RY-200	200.0	190.1	10.80	169.6	603.43	68.88	.00	1.50	.00	12.46	13.96	7.500	2.066
78	15732	12	SC-RY-200	200.0	190.1	10.80	169.6	602.63	68.79	.00	1.50	.00	12.45	13.95	7.500	2.066
79	15922	12	SC-RY-200	200.0	190.1	10.80	169.6	599.12	68.39	.00	1.50	.00	12.38	13.88	7.500	2.066
80	16093	14	SC-LZ-200	180.0	171.1	13.40	148.2	518.43	65.76	.00	2.25	.00	10.92	13.17	12.500	2.106
81	16264	14	SC-LZ-200	180.0	171.1	13.40	148.2	511.92	64.93	.00	2.25	.00	10.78	13.03	12.500	2.106
82	16435	14	SC-LZ-200	180.0	171.1	13.40	148.2	503.84	63.91	.00	2.25	.00	10.61	12.86	12.500	2.106
83	16606	14	SC-LZ-200	180.0	171.1	13.40	148.2	494.38	62.71	.00	2.25	.00	10.41	12.66	12.500	2.106
84	16701	16	SC-LZ-100	100.0	95.1	16.20	79.7	261.59	59.72	.00	1.25	.00	5.51	6.76	12.500	2.106
85	16796	16	SC-LZ-100	100.0	95.1	16.20	79.7	258.36	58.99	.00	1.25	.00	5.44	6.69	12.500	2.106
86	16986	9	SC-OS-200	200.0	190.1	11.60	168.1	533.52	60.90	.00	2.50	.00	11.26	13.76	12.500	2.111
87	17140	9	SC-OS-200	200.0	190.1	11.60	168.1	517.05	59.02	.00	2.50	.00	10.92	13.42	12.500	2.111
88	17140	9	SC-OS-200	200.0	190.1	11.60	168.1	499.11	56.98	.00	2.50	.00	10.54	13.04	12.500	2.111
89	17140	10	SC-KO-200	200.0	190.1	11.70	167.9	478.77	54.65	.00	1.50	.00	10.11	11.61	7.500	2.111
90	17140	10	SC-KO-200	200.0	190.1	11.70	167.9	456.55	52.12	.00	1.50	.00	9.64	11.14	7.500	2.111
91	17140	10	SC-KO-200	200.0	190.1	11.70	167.9	431.14	49.22	.00	1.50	.00	9.10	10.60	7.500	2.111
92	17140	10	SC-KO-200	200.0	190.1	11.70	167.9	401.95	45.89	.00	1.50	.00	8.49	9.99	7.500	2.111
93	17140	10	SC-KO-200	200.0	190.1	11.70	167.9	368.78	42.10	.00	1.50	.00	7.79	9.29	7.500	2.111
94	17140	10	SC-KO-200	200.0	190.1	11.70	167.9	331.93	37.89	.00	1.50	.00	7.01	8.51	7.500	2.111
95	17140	10	SC-KO-200	200.0	190.1	11.70	167.9	292.31	33.37	.00	1.50	.00	6.17	7.67	7.500	2.111
96	17140	10	SC-KO-200	200.0	190.1	11.70	167.9	251.30	28.69	.00	1.50	.00	5.31	6.81	7.500	2.111
97	17140	13	SC-J3-200	190.0	180.6	10.70	161.3	193.69	23.27	.00	1.42	.00	4.10	5.53	7.500	2.119
98	17140	13	SC-J3-200	190.0	180.6	10.70	161.3	161.26	19.38	.00	1.42	.00	3.42	4.84	7.500	2.119
99	17140	13	SC-J3-200	190.0	180.6	10.70	161.3	131.18	15.76	.00	1.42	.00	2.78	4.20	7.500	2.119
100	17140	13	SC-J3-200	190.0	180.6	10.70	161.3	104.22	12.52	.00	1.42	.00	2.21	3.63	7.500	2.119
101	17140	13	SC-J3-200	190.0	180.6	10.70	161.3	80.85	9.72	.00	1.42	.00	1.71	3.14	7.500	2.119
102	17140	13	SC-J3-200	190.0	180.6	10.70	161.3	61.24	7.36	.00	1.42	.00	1.30	2.72	7.500	2.119
103	17140	18	SC-LG-100	103.0	97.9	11.90	86.3	26.78	5.94	.00	1.29	.00	.60	1.89	12.500	2.242
104	17140	18	SC-LG-100	103.0	97.9	11.90	86.3	22.51	4.99	.00	1.29	.00	.50	1.79	12.500	2.242
105	17140	18	SC-LG-100	103.0	97.9	11.90	86.3	18.79	4.17	.00	1.29	.00	.42	1.71	12.500	2.242
106	17140	18	SC-LG-100	103.0	97.9	11.90	86.3	15.57	3.45	.00	1.29	.00	.35	1.64	12.500	2.242
107	17140	18	SC-LG-100	103.0	97.9	11.90	86.3	12.80	2.84	.00	1.29	.00	.29	1.57	12.500	2.242
108	17140	18	SC-LG-100	103.0	97.9	11.90	86.3	10.43	2.32	.00	1.29	.00	.23	1.52	12.500	2.242
109	17140	18	SC-LG-100	103.0	97.9	11.90	86.3	8.47	1.88	.00	1.29	.00	.19	1.48	12.500	2.242
110	17140	19	SC-SI-100	105.0	99.8	11.60	88.2	6.84	1.49	.00	1.31	.00	.15	1.47	12.500	2.264
111	17140	19	SC-SI-100	105.0	99.8	11.60	88.2	5.46	1.19	.00	1.31	.00	.12	1.44	12.500	2.264
112	17140	19	SC-SI-100	105.0	99.8	11.60	88.2	4.33	.94	.00	1.31	.00	.10	1.41	12.500	2.264
113	17140	19	SC-SI-100	105.0	99.8	11.60	88.2	3.40	.74	.00	1.31	.00	.08	1.39	12.500	2.264
114	17140	19	SC-SI-100	105.0	99.8	11.60	88.2	2.66	.58	.00	1.31	.00	.06	1.37	12.500	2.264
115	17140	19	SC-SI-100	105.0	99.8	11.60	88.2	2.06	.45	.00	1.31	.00	.05	1.36	12.500	2.264
116	17140	22	SC-SK-000	45.0	42.8	10.40	38.3	.70	.36	.00	.68	.00	.02	.69	15.000	2.423
117	17140	22	SC-SK-000	45.0	42.8	10.40	38.3	.63	.32	.00	.68	.00	.02	.69	15.000	2.423
118	17140	22	SC-SK-000	45.0	42.8	10.40	38.3	.57	.29	.00	.68	.00	.01	.69	15.000	2.423
119	17140	24	SC-BL-000	41.0	39.0	10.70	34.8	.51	.28	.00	.62	.00	.01	.63	15.000	2.516
120	17140	25	SC-HA-000	50.0	47.5	11.80	41.9	.45	.20	.00	.75	.00	.01	.76	15.000	2.532
121	17140	25	SC-HA-000	50.0	47.5	11.80	41.9	.40	.18	.00	.75	.00	.01	.76	15.000	2.532
122	17140	25	SC-HA-000	50.0	47.5	11.80	41.9	.36	.16	.00	.75	.00	.01	.76	15.000	2.532
123	17140	25	SC-HA-000	50.0	47.5	11.80	41.9	.32	.15	.00	.75	.00	.01	.76	15.000	2.532
124	17140	23	SC-J2-000	43.0	40.9	10.40	36.6	.29	.15	.00	.64	.00	.01	.65	15.000	2.684
125	17140	23	SC-J2-000	43.0	40.9	10.40	36.6	.26	.14	.00	.64	.00	.01	.65	15.000	2.684
126	17140	23	SC-J2-000	43.0	40.9	10.40	36.6	.23	.12	.00	.64	.00	.01	.65	15.000	2.684
127	17140	23	SC-J2-000	43.0	40.9	10.40	36.6	.20	.11	.00	.64	.00	.01	.65	15.000	2.684
128	17140	23	SC-J2-000	43.0	40.9	10.40	36.6	.18	.10	.00	.64	.00	.00	.65	15.000	2.684
129	17140	23	SC-J2-000	43.0	40.9	10.40	36.6	.16	.08	.00	.64	.00	.00	.65	15.000	2.684
130	17140	23	SC-J2-000	43.0	40.9	10.40	36.6	.14	.07	.00	.64	.00	.00	.65	15.000	2.684
131	17140	27	SC-MI-000	50.0	47.5	11.80	41.9	.12	.06	.00	.75	.00	.00	.75	15.000	2.759
132	17140	27	SC-MI-000	50.0	47.5	11.80	41.9	.11	.05	.00	.75	.00	.00	.75	15.000	2.759
133	17140	27	SC-MI-000	50.0	47.5	11.80	41.9	.09	.04	.00	.75	.00	.00	.75	15.000	2.759
134	17140	26	SC-J1-000	19.0	18.1	15.70	15.2	.04	.05	.00	.28	.00	.00	.29	15.000	2.820

135	17140	26	SC-J1-000	19.0	18.1	15.70	15.2	.04	.05	.00	.28	.00	.00	.29	15.000	2.820
136	17140	26	SC-J1-000	19.0	18.1	15.70	15.2	.04	.04	.00	.28	.00	.00	.29	15.000	2.820
137	17140	26	SC-J1-000	19.0	18.1	15.70	15.2	.03	.04	.00	.28	.00	.00	.29	15.000	2.820
138	17140	26	SC-J1-000	19.0	18.1	15.70	15.2	.03	.04	.00	.28	.00	.00	.29	15.000	2.820
139	17140	26	SC-J1-000	19.0	18.1	15.70	15.2	.03	.04	.00	.28	.00	.00	.29	15.000	2.820
140	17140	31	CG-XX-120	120.0	117.4	12.00	103.3	.15	.03	3.07	.90	.00	.01	3.97	33.064	4.637
141	17140	31	CG-XX-120	120.0	117.4	12.00	103.3	.10	.02	3.07	.90	.00	.00	3.97	33.064	4.637
				23599.0	22402.7	.00	19563.8	*******	.00	6.14	212.16	.00	1203.14	1421.44		

POWER SYSTEM RELIABILITY AND COST

TOTAL INSTALLED CAPACITY=	31170.00 MW
THERMAL EFFECTIVE CAPACITY=	19563.79 MW
PEAK THERMAL LOAD=	.00 MW
THERMAL EFFECTIVE CAPACITY RESERVE=	14.14 %
INSTALLED CAPACITY RESERVE=	32.79 %
LOSS OF LOAD PROBABILITY=	.78HRS
HYDROELECTRIC GENERATION=	13365.55 GWH
THERMAL GENERATION=	65576.39 GWH
TOTAL GENERATION=	78941.94 GWH
ENERGY LOAD=	78942.09 GWH
UNSERVED ENERGY=	.15 GWH
TOTAL COST THIS PERIOD=	1451.42 M$

SUMMARY OF 1997 RESULTS

PEAK LOAD=	23699.60 MW
EFFECTIVE CAPACITY RESERVE=	.00 %
LOSS OF LOAD PROBABILITY=	5.03HRS
HYDROELECTRIC GENERATION=	17563.37 GWH
THERMAL GENERATION=	122156.00 GWH
TOTAL GENERATION=	139719.40 GWH
ENERGY LOAD=	139720.50 GWH
UNSERVED ENERGY=	1.13 GWH
TOTAL ANNUAL COST=	2745.54 M$

APPENDIX 4.2.3
SUMMARY OUTPUT

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1992	22024.0	125018.8	32.96	13.61	.00	.04

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	7041.	13086.1	.0	60.0	6.3	.0	66.3	.0	56.7	6.0	.0	62.6
ECONOMIC	22243.	111931.7	.0	413.4	.0	2049.6	2463.1	.0	390.7	.0	1936.7	2327.4
TOTAL	29284.	125017.9	.0	473.4	6.3	2049.6	2529.3	.0	447.3	6.0	1936.7	2390.0

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1993	22222.2	127117.3	29.05	9.16	.01	.50

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	7091.	13333.5	.0	60.0	6.3	.0	66.3	.0	107.3	11.3	.0	118.6
ECONOMIC	21586.	113771.2	.0	400.1	.0	2099.5	2499.6	.0	728.2	.0	3708.0	4436.2
TOTAL	28677.	127104.7	.0	460.1	6.3	2099.5	2565.9	.0	835.5	11.3	3708.0	4554.8

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1994	22533.3	129686.5	27.76	7.75	.02	1.08

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	7191.	13908.1	.0	60.0	6.3	.0	66.3	.0	152.5	16.0	.0	168.5
ECONOMIC	21598.	115749.3	.0	398.5	.0	2138.3	2536.8	.0	1028.4	.0	5318.7	6347.2
TOTAL	28789.	129657.4	.0	458.5	6.3	2138.3	2603.1	.0	1180.9	16.0	5318.7	6515.6

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1995	23006.5	133417.6	28.32	8.49	.01	.70

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	7341.	14650.4	.0	60.0	6.3	.0	66.3	.0	192.8	20.3	.0	213.1
ECONOMIC	22182.	118749.6	.0	407.2	.0	2190.1	2597.3	.0	1302.3	.0	6791.8	8094.0
TOTAL	29523.	133399.9	.0	467.2	6.3	2190.1	2663.6	.0	1495.1	20.3	6791.8	8307.1

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1996	23121.6	136110.1	31.89	12.31	.00	.11

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	7531.	15696.0	.0	60.0	6.3	.0	66.3	.0	228.8	24.1	.0	252.9
ECONOMIC	22965.	120411.8	6.1	417.9	.0	2218.3	2642.3	3.7	1553.2	.0	8123.9	9680.8
TOTAL	30496.	136107.8	6.1	477.9	6.3	2218.3	2708.6	3.7	1782.0	24.1	8123.9	9933.7

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1997	23699.6	139720.5	32.79	14.05	.00	.06

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	7871.	17563.4	.0	60.0	6.3	.0	66.3	.0	261.0	27.4	.0	288.4
ECONOMIC	23599.	122156.0	12.3	424.3	.0	2249.0	2685.6	10.3	1780.7	.0	9329.7	11120.7
TOTAL	31470.	139719.4	12.3	484.3	6.3	2249.0	2751.8	10.3	2041.7	27.4	9329.7	11409.1

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1998	24221.0	143430.9	33.33	13.55	.00	.15

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	9061.	20973.2	134.7	68.1	6.3	.0	209.0	64.5	293.6	30.5	.0	388.5
ECONOMIC	23232.	122454.4	12.3	415.1	.0	2254.3	2681.6	16.1	1979.4	.0	10408.9	12404.5
TOTAL	32293.	143427.6	146.9	483.1	6.3	2254.3	2890.7	80.6	2273.0	30.5	10408.9	12792.9

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1999	24802.3	147090.5	30.54	10.83	.01	.59

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	9161.	21508.9	134.7	68.1	6.3	.0	209.0	122.0	322.6	33.2	.0	477.8
ECONOMIC	23216.	125567.2	12.3	412.1	.0	2316.7	2741.0	21.4	2155.6	.0	11399.1	13576.1
TOTAL	32377.	147076.1	146.9	480.2	6.3	2316.7	2950.1	143.4	2478.2	33.2	11399.1	14053.9

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
2000	25323.1	151066.7	30.78	11.41	.01	.77

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	9681.	24346.9	134.7	68.1	6.3	.0	209.0	173.4	348.6	35.6	.0	557.6
ECONOMIC	23436.	126700.2	18.4	412.9	.0	2343.1	2774.5	28.4	2313.2	.0	12293.3	14634.9
TOTAL	33117.	151047.1	153.1	481.0	6.3	2343.1	2983.5	201.8	2661.8	35.6	12293.3	15192.5

Appendix 4.3
Hourly Load Data Preparation

POLISH POWER GRID COMPANY
HOURLY LOAD PREPARATION FOR THE YEAR 1993

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
C.Yermoli/Hagler,Bailly Inc. - Arlington, VA., USA
Release: 930202 Polish Power Grid Company - PPGC - Warsaw
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PATTERN YEAR IS NOT LEAP 1991

WK	1	PEAK=	21298.00	MW MEAN=	17741.20	MW BASE=	13836.00	MW LF=	.833
WK	2	PEAK=	22159.00	MW MEAN=	18860.30	MW BASE=	14999.00	MW LF=	.851
WK	3	PEAK=	21861.00	MW MEAN=	18734.24	MW BASE=	14639.00	MW LF=	.857
WK	4	PEAK=	22903.00	MW MEAN=	19075.71	MW BASE=	15569.00	MW LF=	.833
WK	5	PEAK=	23219.00	MW MEAN=	19668.73	MW BASE=	15474.00	MW LF=	.847
WK	6	PEAK=	22808.00	MW MEAN=	19035.92	MW BASE=	15643.00	MW LF=	.835
WK	7	PEAK=	21923.00	MW MEAN=	18476.80	MW BASE=	14386.00	MW LF=	.843
WK	8	PEAK=	21619.00	MW MEAN=	17900.93	MW BASE=	14218.00	MW LF=	.828
WK	9	PEAK=	21431.00	MW MEAN=	17532.01	MW BASE=	13969.00	MW LF=	.818
WK	10	PEAK=	20633.00	MW MEAN=	16879.20	MW BASE=	12651.00	MW LF=	.818
WK	11	PEAK=	20252.00	MW MEAN=	16441.67	MW BASE=	12209.00	MW LF=	.812
WK	12	PEAK=	20504.00	MW MEAN=	16597.93	MW BASE=	12037.00	MW LF=	.809
WK	13	PEAK=	18966.00	MW MEAN=	14929.10	MW BASE=	11796.00	MW LF=	.787
WK	14	PEAK=	18785.00	MW MEAN=	15465.20	MW BASE=	11648.00	MW LF=	.823
WK	15	PEAK=	18826.00	MW MEAN=	15721.89	MW BASE=	12648.00	MW LF=	.835
WK	16	PEAK=	18669.00	MW MEAN=	15614.51	MW BASE=	11551.00	MW LF=	.836
WK	17	PEAK=	17110.00	MW MEAN=	13197.80	MW BASE=	11034.00	MW LF=	.771
WK	18	PEAK=	17878.00	MW MEAN=	14692.72	MW BASE=	10884.00	MW LF=	.822
WK	19	PEAK=	16548.00	MW MEAN=	14352.34	MW BASE=	11659.00	MW LF=	.867
WK	20	PEAK=	17121.00	MW MEAN=	14591.68	MW BASE=	11373.00	MW LF=	.852
WK	21	PEAK=	16390.00	MW MEAN=	13153.24	MW BASE=	10281.00	MW LF=	.803
WK	22	PEAK=	15608.00	MW MEAN=	13170.22	MW BASE=	9520.00	MW LF=	.844
WK	23	PEAK=	15230.00	MW MEAN=	12861.83	MW BASE=	9239.00	MW LF=	.845
WK	24	PEAK=	15038.00	MW MEAN=	12755.41	MW BASE=	9526.00	MW LF=	.848
WK	25	PEAK=	14595.00	MW MEAN=	12512.13	MW BASE=	9604.00	MW LF=	.857
WK	26	PEAK=	14425.00	MW MEAN=	12172.35	MW BASE=	9404.00	MW LF=	.844
WK	27	PEAK=	14038.00	MW MEAN=	11955.95	MW BASE=	8729.00	MW LF=	.852
WK	28	PEAK=	14155.00	MW MEAN=	11937.92	MW BASE=	9226.00	MW LF=	.843
WK	29	PEAK=	14512.00	MW MEAN=	12089.89	MW BASE=	9362.00	MW LF=	.832
WK	30	PEAK=	14315.00	MW MEAN=	12166.15	MW BASE=	9302.00	MW LF=	.850
WK	31	PEAK=	14521.00	MW MEAN=	12059.45	MW BASE=	8742.00	MW LF=	.830
WK	32	PEAK=	14701.00	MW MEAN=	11404.11	MW BASE=	8652.00	MW LF=	.776
WK	33	PEAK=	15082.00	MW MEAN=	12258.24	MW BASE=	9208.00	MW LF=	.813
WK	34	PEAK=	15348.00	MW MEAN=	12467.11	MW BASE=	9552.00	MW LF=	.812
WK	35	PEAK=	15927.00	MW MEAN=	12574.10	MW BASE=	9710.00	MW LF=	.789
WK	36	PEAK=	16783.00	MW MEAN=	13051.60	MW BASE=	9822.00	MW LF=	.778
WK	37	PEAK=	16712.00	MW MEAN=	13034.74	MW BASE=	9861.00	MW LF=	.780
WK	38	PEAK=	16881.00	MW MEAN=	13108.34	MW BASE=	9570.00	MW LF=	.777
WK	39	PEAK=	17416.00	MW MEAN=	13458.32	MW BASE=	10203.00	MW LF=	.773
WK	40	PEAK=	17553.00	MW MEAN=	13921.70	MW BASE=	11010.00	MW LF=	.793
WK	41	PEAK=	18330.00	MW MEAN=	14432.22	MW BASE=	11196.00	MW LF=	.787
WK	42	PEAK=	19677.00	MW MEAN=	16176.52	MW BASE=	12230.00	MW LF=	.822
WK	43	PEAK=	20530.00	MW MEAN=	16088.59	MW BASE=	12802.00	MW LF=	.784
WK	44	PEAK=	20415.00	MW MEAN=	16543.82	MW BASE=	12576.00	MW LF=	.810
WK	45	PEAK=	20093.00	MW MEAN=	16290.18	MW BASE=	12642.00	MW LF=	.811
WK	46	PEAK=	20481.00	MW MEAN=	17018.14	MW BASE=	13507.00	MW LF=	.831
WK	47	PEAK=	20478.00	MW MEAN=	17023.92	MW BASE=	13308.00	MW LF=	.831
WK	48	PEAK=	21069.00	MW MEAN=	17757.46	MW BASE=	14186.00	MW LF=	.843
WK	49	PEAK=	22611.00	MW MEAN=	19084.60	MW BASE=	14978.00	MW LF=	.844
WK	50	PEAK=	22078.00	MW MEAN=	18355.80	MW BASE=	14543.00	MW LF=	.831
WK	51	PEAK=	20270.00	MW MEAN=	15571.12	MW BASE=	12703.00	MW LF=	.768

GPT-M Generation Plannir Tools-Marginal Cost Analysis Module
C.Yermoli/Hagler,Baill· ,nc. - Arlington, VA., USA
Release: 930202 Polish Power Grid Company - PPGC - Warsaw
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PERIOD= 1	
PERIOD PEAK LOAD (MW)=	18966.00
PERIOD MEAN LOAD (MW)=	13203.43
PERIOD BASE LOAD (MW)=	8652.00
PERIOD LOAD FACTOR=	.6962
TARGET PEAK LOAD (MW)=	17111.11
TARGET MEAN LOAD (MW)=	12590.00
TARGET BASE LOAD (MW)=	7805.83
TARGET LOAD FACTOR=	.7358
PEAK LOAD OF SELECTED WEEK (MW)=	15325.92
MEAN LOAD OF SELECTED WEEK (MW)=	13203.77
BASE LOAD OF SELECTED WEEK (MW)=	10258.85
LOAD FACTOR OF SELECTED WEEK=	.8615
PEAK LOAD AFTER PEAK SCALING (MW)=	17111.11
MEAN LOAD AFTER PEAK SCALING (MW)=	14741.76
BASE LOAD AFTER PEAK SCALING (MW)=	11453.81
LOAD FACTOR AFTER PEAK SCALING=	.8615
PEAK LOAD OF REPRESENTATIVE WEEK=	17111.11
MEAN LOAD OF REPRESENTATIVE WEEK=	12602.26
BASE LOAD OF REPRESENTATIVE WEEK=	9019.29
LOAD FACTOR OF REPRESENTATIVE WEEK=	.7365
MEAN LOAD ACCURACY (PERCENT)=	99.9027

DAILY REPORT

DAY	1 PEAK=	16684.37 MW	MEAN=	13193.41 MW	BASE=	9487.91
DAY	2 PEAK=	17101.74 MW	MEAN=	13943.83 MW	BASE=	10230.97
DAY	3 PEAK=	17111.11 MW	MEAN=	13975.26 MW	BASE=	10310.66
DAY	4 PEAK=	16774.50 MW	MEAN=	13540.16 MW	BASE=	10227.49
DAY	5 PEAK=	16425.07 MW	MEAN=	13523.27 MW	BASE=	,205.91
DAY	6 PEAK=	13833.66 MW	MEAN=	10614.24 MW	BASE=	9628.16
DAY	7 PEAK=	10232.27 MW	MEAN=	9425.66 MW	BASE=	9019.29

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
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****

PERIOD= 2

PERIOD PEAK LOAD (MW)=	23219.00
PERIOD MEAN LOAD (MW)=	17161.02
PERIOD BASE LOAD (MW)=	10203.00
PERIOD LOAD FACTOR=	.7391
TARGET PEAK LOAD (MW)=	22222.21
TARGET MEAN LOAD (MW)=	16442.60
TARGET BASE LOAD (MW)=	9764.99
TARGET LOAD FACTOR=	.7399
PEAK LOAD OF SELECTED WEEK (MW)=	20659.10
MEAN LOAD OF SELECTED WEEK (MW)=	17152.16
BASE LOAD OF SELECTED WEEK (MW)=	13793.69
LOAD FACTOR OF SELECTED WEEK=	.8302
PEAK LOAD AFTER PEAK SCALING (MW)=	22222.21
MEAN LOAD AFTER PEAK SCALING (MW)=	18449.94
BASE LOAD AFTER PEAK SCALING (MW)=	14837.36
LOAD FACTOR AFTER PEAK SCALING=	.8302
PEAK LOAD OF REPRESENTATIVE WEEK=	22222.21
MEAN LOAD OF REPRESENTATIVE WEEK=	16456.50
BASE LOAD OF REPRESENTATIVE WEEK=	12425.68
LOAD FACTOR OF REPRESENTATIVE WEEK=	.7405
MEAN LOAD ACCURACY (PERCENT)=	99.9155

DAILY REPORT

DAY	1	PEAK=	22033.24 MW	MEAN=	17684.89 MW	BASE=	13043.37
DAY	2	PEAK=	22222.21 MW	MEAN=	18105.23 MW	BASE=	14130.57
DAY	3	PEAK=	21353.11 MW	MEAN=	17396.53 MW	BASE=	13757.37
DAY	4	PEAK=	21411.84 MW	MEAN=	17451.02 MW	BASE=	13838.16
DAY	5	PEAK=	20734.62 MW	MEAN=	17044.54 MW	BASE=	13834.62
DAY	6	PEAK=	17961.34 MW	MEAN=	14573.34 MW	BASE=	13128.28
DAY	7	PEAK=	14359.62 MW	MEAN=	12939.98 MW	BASE=	12425.68

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LOAD DURATION CURVE FOR PERIOD 1

WEEK	POINT	% PEAK	% TIME
1	1	.0000	100.0000
1	2	.5271	100.0000
1	3	.5534	.9048
1	4	.5796	.8155
1	5	.6059	.6488
1	6	.6322	.5238
1	7	.6585	.5238
1	8	.6847	.5238
1	9	.7110	.5238
1	10	.7373	.5238
1	11	.7636	.5179
1	12	.7898	.4524
1	13	.8161	.3571
1	14	.8424	.2917
1	15	.8686	.2798
1	16	.8949	.2500
1	17	.9212	.1964
1	18	.9475	.0952
1	19	.9737	.0655
1	20	1.0000	.0000

PEAK LOAD (MW) = 17111.10
BASE LOAD (MW) = 9019.30
WEEKLY ENERGY (MWH) = 2,17180.00
LOAD FACTOR (%) = 73.65

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LOAD DURATION CURVE FOR PERIOD 2

WEEK	POINT	% PEAK	% TIME
2	1	.0000	100.0000
2	2	.5592	100.0000
2	3	.5836	.8988
2	4	.6081	.8393
2	5	.6326	.6786
2	6	.6571	.5238
2	7	.6816	.4940
2	8	.7061	.4940
2	9	.7306	.4940
2	10	.7551	.4940
2	11	.7796	.4524
2	12	.8041	.3988
2	13	.8286	.3512
2	14	.8531	.2976
2	15	.8775	.1845
2	16	.9020	.1429
2	17	.9265	.0893
2	18	.9510	.0595
2	19	.9755	.0357
2	20	1.0000	.0000

PEAK LOAD (MW) = 22222.20
BASE LOAD (MW) = 12425.70
WEEKLY ENERGY (MWH) = 2764692.00
LOAD FACTOR (%) = 74.05

POLISH POWER GRID COMPANY
HOURLY LOAD PREPARATION FOR 1997

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PATTERN YEAR IS NOT LEAP 1991

WK	1	PEAK=	21298.00	MW MEAN=	17741.20	MW BASE=	13836.00	MW LF=	.833
WK	2	PEAK=	22159.00	MW MEAN=	18860.30	MW BASE=	14999.00	MW LF=	.851
WK	3	PEAK=	21861.00	MW MEAN=	18734.24	MW BASE=	14639.00	MW LF=	.857
WK	4	PEAK=	22903.00	MW MEAN=	19075.71	MW BASE=	15569.00	MW LF=	.833
WK	5	PEAK=	23219.00	MW MEAN=	19668.73	MW BASE=	15474.00	MW LF=	.847
WK	6	PEAK=	22808.00	MW MEAN=	19035.92	MW BASE=	15643.00	MW LF=	.835
WK	7	PEAK=	21923.00	MW MEAN=	18476.80	MW BASE=	14386.00	MW LF=	.843
WK	8	PEAK=	21619.00	MW MEAN=	17900.93	MW BASE=	14218.00	MW LF=	.828
WK	9	PEAK=	21431.00	MW MEAN=	17532.01	MW BASE=	13969.00	MW LF=	.818
WK	10	PEAK=	20633.00	MW MEAN=	16879.20	MW BASE=	12651.00	MW LF=	.818
WK	11	PEAK=	20252.00	MW MEAN=	16441.67	MW BASE=	12209.00	MW LF=	.812
WK	12	PEAK=	20504.00	MW MEAN=	16597.93	MW BASE=	12037.00	MW LF=	.809
WK	13	PEAK=	18966.00	MW MEAN=	14929.10	MW BASE=	11796.00	MW LF=	.787
WK	14	PEAK=	18785.00	MW MEAN=	15465.20	MW BASE=	11648.00	MW LF=	.823
WK	15	PEAK=	18826.00	MW MEAN=	15721.89	MW BASE=	12648.00	MW LF=	.835
WK	16	PEAK=	18669.00	MW MEAN=	15614.51	MW BASE=	11551.00	MW LF=	.836
WK	17	PEAK=	17110.00	MW MEAN=	13197.80	MW BASE=	11034.00	MW LF=	.771
WK	18	PEAK=	17878.00	MW MEAN=	14092.72	MW BASE=	10884.00	MW LF=	.822
WK	19	PEAK=	16548.00	MW MEAN=	14352.34	MW BASE=	11659.00	MW LF=	.867
WK	20	PEAK=	17121.00	MW MEAN=	14591.68	MW BASE=	11373.00	MW LF=	.852
WK	21	PEAK=	16390.00	MW MEAN=	13153.24	MW BASE=	10281.00	MW LF=	.803
WK	22	PEAK=	15608.00	MW MEAN=	13170.22	MW BASE=	9520.00	MW LF=	.844
WK	23	PEAK=	15230.00	MW MEAN=	12861.83	MW BASE=	9239.00	MW LF=	.845
WK	24	PEAK=	15038.00	MW MEAN=	12755.41	MW BASE=	9526.00	MW LF=	.848
WK	25	PEAK=	14595.00	MW MEAN=	12512.13	MW BASE=	9604.00	MW LF=	.857
WK	26	PEAK=	14425.00	MW MEAN=	12172.35	MW BASE=	9404.00	MW LF=	.844
WK	27	PEAK=	14038.00	MW MEAN=	11955.95	MW BASE=	8729.00	MW LF=	.852
WK	28	PEAK=	14155.00	MW MEAN=	11937.92	MW BASE=	9226.00	MW LF=	.843
WK	29	PEAK=	14512.00	MW MEAN=	12089.89	MW BASE=	9362.00	MW LF=	.833
WK	30	PEAK=	14315.00	MW MEAN=	12166.15	MW BASE=	9302.00	MW LF=	.850
WK	31	PEAK=	14521.00	MW MEAN=	12059.45	MW BASE=	8742.00	MW LF=	.830
WK	32	PEAK=	14701.00	MW MEAN=	11404.11	MW BASE=	8652.00	MW LF=	.776
WK	33	PEAK=	15082.00	MW MEAN=	12258.24	MW BASE=	9208.00	MW LF=	.813
WK	34	PEAK=	15348.00	MW MEAN=	12467.11	MW BASE=	9552.00	MW LF=	.812
WK	35	PEAK=	15927.00	MW MEAN=	12574.10	MW BASE=	9710.00	MW LF=	.789
WK	36	PEAK=	16783.00	MW MEAN=	13051.60	MW BASE=	9822.00	MW LF=	.778
WK	37	PEAK=	16712.00	MW MEAN=	13034.74	MW BASE=	9861.00	MW LF=	.780
WK	38	PEAK=	16881.00	MW MEAN=	13108.34	MW BASE=	9570.00	MW LF=	.777
WK	39	PEAK=	17416.00	MW MEAN=	13458.32	MW BASE=	10203.00	MW LF=	.773
WK	40	PEAK=	17553.00	MW MEAN=	13921.70	MW BASE=	11010.00	MW LF=	.793
WK	41	PEAK=	18330.00	MW MEAN=	14432.22	MW BASE=	11196.00	MW LF=	.787
WK	42	PEAK=	19677.00	MW MEAN=	16176.52	MW BASE=	12230.00	MW LF=	.822
WK	43	PEAK=	20530.00	MW MEAN=	16088.59	MW BASE=	12602.00	MW LF=	.784
WK	44	PEAK=	20415.00	MW MEAN=	16543.82	MW BASE=	12576.00	MW LF=	.810
WK	45	PEAK=	20093.00	MW MEAN=	16290.18	MW BASE=	12642.00	MW LF=	.811
WK	46	PEAK=	20481.00	MW MEAN=	17018.14	MW BASE=	13507.00	MW LF=	.831
WK	47	PEAK=	20478.00	MW MEAN=	17023.92	MW BASE=	13308.00	MW LF=	.831
WK	48	PEAK=	21069.00	MW MEAN=	17757.46	MW BASE=	14186.00	MW LF=	.843
WK	49	PEAK=	22611.00	MW MEAN=	19084.60	MW BASE=	14978.00	MW LF=	.844
WK	50	PEAK=	22078.00	MW MEAN=	18355.80	MW BASE=	14543.00	MW LF=	.831
WK	51	PEAK=	20270.00	MW MEAN=	15571.12	MW BASE=	12708.00	MW LF=	.768

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PERIOD= 1	
PERIOD PEAK LOAD (MW)=	18966.00
PERIOD MEAN LOAD (MW)=	13203.43
PERIOD BASE LOAD (MW)=	8652.00
PERIOD LOAD FACTOR=	.6962
TARGET PEAK LOAD (MW)=	18248.69
TARGET MEAN LOAD (MW)=	13838.44
TARGET BASE LOAD (MW)=	8324.77
TARGET LOAD FACTOR=	.7583
PEAK LOAD OF SELECTED WEEK (MW)=	15325.92
MEAN LOAD OF SELECTED WEEK (MW)=	13203.77
BASE LOAD OF SELECTED WEEK (MW)=	10258.85
LOAD FACTOR OF SELECTED WEEK=	.8615
PEAK LOAD AFTER PEAK SCALING (MW)=	18248.69
MEAN LOAD AFTER PEAK SCALING (MW)=	15721.83
BASE LOAD AFTER PEAK SCALING (MW)=	12215.28
LOAD FACTOR AFTER PEAK SCALING=	.8615
PEAK LOAD OF REPRESENTATIVE WEEK=	18248.69
MEAN LOAD OF REPRESENTATIVE WEEK=	13850.23
BASE LOAD OF REPRESENTATIVE WEEK=	9993.54
LOAD FACTOR OF REPRESENTATIVE WEEK=	.7590
MEAN LOAD ACCURACY (PERCENT)=	99 9149

DAILY REPORT

DAY	1	PEAK=	17845.13 MW	MEAN=	14437.00 MW	BASE= 10601.04
DAY	2	PEAK=	18239.83 MW	MEAN=	15208.04 MW	BASE= 11538.63
DAY	3	PEAK=	18248.69 MW	MEAN=	15244.98 MW	BASE= 11637.66
DAY	4	PEAK=	17930.36 MW	MEAN=	14826.55 MW	BASE= 11534.30
DAY	5	PEAK=	17599.91 MW	MEAN=	14804.35 MW	BASE= 11507.45
DAY	6	PEAK=	15149.28 MW	MEAN=	11912.29 MW	BASE= 10780.19
DAY	7	PEAK=	11540.25 MW	MEAN=	10518.43 MW	BASE= 9993.54

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PERIOD= 2

PERIOD PEAK LOAD (MW)=	23219.00
PERIOD MEAN LOAD (MW)=	17161.02
PERIOD BASE LOAD (MW)=	10203.00
PERIOD LOAD FACTOR=	.7391
TARGET PEAK LOAD (MW)=	23699.59
TARGET MEAN LOAD (MW)=	18072.82
TARGET BASE LOAD (MW)=	10414.18
TARGET LOAD FACTOR=	.7626
PEAK LOAD OF SELECTED WEEK (MW)=	20707.42
MEAN LOAD OF SELECTED WEEK (MW)=	17200.16
BASE LOAD OF SELECTED WEEK (MW)=	13833.05
LOAD FACTOR OF SELECTED WEEK=	.8306
PEAK LOAD AFTER PEAK SCALING (MW)=	23699.59
MEAN LOAD AFTER PEAK SCALING (MW)=	19685.54
BASE LOAD AFTER PEAK SCALING (MW)=	15831.89
LOAD FACTOR AFTER PEAK SCALING=	.8306
PEAK LOAD OF REPRESENTATIVE WEEK=	23699.59
MEAN LOAD OF REPRESENTATIVE WEEK=	18087.43
BASE LOAD OF REPRESENTATIVE WEEK=	13838.88
LOAD FACTOR OF REPRESENTATIVE WEEK=	.7632
MEAN LOAD ACCURACY (PERCENT)=	99.9192

DAILY REPORT

DAY 1	PEAK=	23519.24 MW	MEAN=	19285.22 MW	BASE=	14591.26
DAY 2	PEAK=	23699.59 MW	MEAN=	19745.92 MW	BASE=	15894.90
DAY 3	PEAK=	22860.79 MW	MEAN=	19035.97 MW	BASE=	15453.80
DAY 4	PEAK=	22919.33 MW	MEAN=	19093.84 MW	BASE=	15549.53
DAY 5	PEAK=	22265.53 MW	MEAN=	18701.76 MW	BASE=	15544.79
DAY 6	PEAK=	19591.18 MW	MEAN=	16287.49 MW	BASE=	14696.94
DAY 7	PEAK=	16161.54 MW	MEAN=	14461.82 MW	BASE=	13838.88

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
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Release: 930202 Polish Power Grid Company - PPGC - Warsaw
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LOAD DURATION CURVE FOR PERIOD 1

WEEK	POINT	% PEAK	% TIME
1	1	.0000	100.0000
1	2	.5476	100.0000
1	3	.5728	.9226
1	4	.5979	.8452
1	5	.6230	.7798
1	6	.6482	.6012
1	7	.6733	.5238
1	8	.6984	.5238
1	9	.7236	.5238
1	10	.7487	.5238
1	11	.7738	.5238
1	12	.7989	.5060
1	13	.8241	.3869
1	14	.8492	.3155
1	15	.8743	.2798
1	16	.8995	.2560
1	17	.9246	.2024
1	18	.9497	.1250
1	19	.9749	.0714
1	20	1.0000	.0000

PEAK LOAD (MW) = 18248.70
BASE LOAD (MW) = 9993.50
WEEKLY ENERGY (MWH) = 2326839.00
LOAD FACTOR (%) = 75.90

C>T-M Generation Planning Tools-Marginal Cost Analysis Module
C.Yermoli/Hagler,Bailly Inc. - Arlington, VA., USA
Release: 930202 Polish Power Grid Company - PPGC - Warsaw
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LOAD DURATION CURVE FOR PERIOD 2

WEEK	POINT	% PEAK	% TIME
2	1	.0000	100.0000
2	2	.5839	100.0000
2	3	.6070	.9048
2	4	.6302	.8631
2	5	.6533	.7917
2	6	.6764	.6190
2	7	.6995	.5179
2	8	.7226	.4940
2	9	.7457	.4940
2	10	.7688	.4940
2	11	.7920	.4643
2	12	.8151	.4345
2	13	.8382	.3571
2	14	.8613	.3036
2	15	.8844	.1964
2	16	.9075	.1488
2	17	.9307	.0952
2	18	.9538	.0655
2	19	.9769	.0357
2	20	1.0000	.0000

PEAK LOAD (MW) = 23699.60
BASE LOAD (MW) = 13838.90
WEEKLY ENERGY (MWH) = 3038688.00
LOAD FACTOR (%) = 76.32

Appendix 4.4
Theoretical Base of Expected Marginal Production Cost

APPENDIX 4.4: THEORY OF EXPECTED MARGINAL AND PRODUCTION COSTS

ALGORITHM AND DERIVATION

Consider a system of generating units numbered 1 to N in order of increasing variable cost. For unit j, call the rated capacity R_j, the probability of failure (forced outage rate) F_j, and the variable cost C_j. Partial unit failures are ignored here for simplicity, but they lead to a straightforward generalization of the algorithm. The following notation will be useful also:

MC	=	marginal cost of energy generation
LOL	=	loss of load (load exceeding available capacity)
$\overline{\text{LOL}}$	=	no loss of load
$_j$ subscript for a marginal cost of loss of load	=	for a system including only the first j units
(L) argument for a marginal cost or probability	=	as a function of load L
P[LOL]	=	probability of LOL, often written LOLP (implicitly a function of L)
E[X|Y]	=	expected value of X given (conditional on) Y.

Note that we consider *instantaneous* LOLP and MC here, not period quantities, which are averages over the hours in a period.

Because of uncertainty in the availability of each unit, it is uncertain which unit would be at the margin for any given load.
Indeed, it is possible that no unit would be at the margin because the load is too great to be met. Rather than include this case in the expected marginal cost by means of a cost of unserved energy, we exclude it by defining the quantity of interest as a conditional marginal cost:

$$CMC_N(L) = E[MC_N(L) \mid \overline{LOL_N}].$$

The corresponding conditional marginal cost for the first j units is

$$CMC_j(L) = E[MC_j(L) \mid \overline{LOL_j}].$$

$CMC_j(L)$ is undefined for L high enough that $LOLP_j(L) = 1$, because then the condition that load is met is impossible.

For recursion, we would like an expression for $CMC_j(L)$ in terms of $CMC_{j-1}(L)$. Any expectation can be expanded by conditioning on whether or not an event occurs [*reference such as Sheldon Ross's intro. probability text*]. Let us expand $CMC_j(L)$ by conditioning on whether or not the event LOL_{j-1} occurs, and temporarily supress notation of dependences on L for simplicity:

$$CMC_j = E[MC_j \mid \overline{LOL_j}] = P[LOL_{j-1} \mid \overline{LOL_j}]\, E[MC_j \mid LOL_{j-1}, \overline{LOL_j}] + (1 - P[LOL_{j-1} \mid \overline{LOL_j}])\, E[MC_j \mid \overline{LOL_{j-1}}, \overline{LOL_j}] \quad (1)$$

If LOL_{j-1} occurs, unit j is at the margin because we are given that LOL_j does not occur. Therefore the first expected marginal cost <u>on the</u> right above is just C_j.
The second is CMC_{j-1},because the condition LOLj is made irrelevant by the condition $\overline{LOL_{j-1}}$.
The first probability above can be found using the definition of conditional probability, as follows:

$$P[LOL_{j-1} \mid \overline{LOL_j}] = P[LOL_{j-1}, \overline{LOL_j}] \,/\, P[\overline{LOL_j}]$$
$$= (P[LOL_{j-1}] - P[LOL_j]) \,/\, (1 - P[LOL_j])$$

because the joint event $[LOL_{j-1}, \overline{LOL_j}]$ is the event that the jth unit is at the margin: it is needed to meet the load and succeeds in meeting it. The probability of this event is the reduction in LOLP when the jth unit is added. Defining $\Delta LOLP_j$ as this reduction:

$$\Delta LOLP_j = P[LOL_{j-1}] - P[LOL_j],$$

equation (1) gives

$$CMC_j = \frac{\Delta LOLP_j}{1 - P(LOL_j)} C_j + \left(1 - \frac{\Delta LOLP_j}{1 - P(LOL_j)}\right) CMC_{j-1}$$
$$= [\Delta LOLP_j\, C_j + (1 - LOLP_{j-1})\, CMC_{j-1}] \,/\, (1 - P[LOL_j]).$$

Defining further

$$MCO_j = (1 - P[LOL_j])\, CMC_j \qquad \textit{(also implicitly a function of L)},$$

gives the simple recursive formula

$$MCO_j = MCO_{j-1} + \Delta LOLP_j\, C_j. \qquad (2)$$

$MC0_j$ may be interpreted as the marginal cost of the first-j-units system, if the unserved energy cost were zero (at load L, not conditional on this load being met). This can be seen by conditioning $MC0_j$ on the three possible events that unit j is above the margin (load is met by a previous unit), at the margin, and below the margin (load is lost). The resulting conditional-expectation expansion gives the two terms of equation (2), with the term for the zero-cost third event dropping out.

The initial, empty-system condition for $MC0_j(L)$ is

$$MCO_0\,(L) = 0 \text{ for all } L \qquad (3)$$

because the unserved energy has no cost. From this starting point we can apply equation (2) recursively for j=1...N and finally compute.

$$CMC_N\,(L) = MCO_N\,(L) \;/\; (1 - P[LOL_N\,(L)]). \qquad (4)$$

The recursion requires the LOLPs for a system with j=1,..., N units.
These may be calculated recursively (Baleriaux and Booth 1977) together with $MC0_j$. This recursion uses the conditional probability expansion resulting from conditioning on whether or not unit j is available (giving the first and second terms below respectively):

$$P[LOL_j(L)] = (1-F_j)\ P[LOL_{j-1}(L-R_j)] + F_j\ P[LOL_{j-1}(L)].$$

The following rearrangement, in terms of the LOLP reduction when unit j is added, is more convenient here:

$$\Delta LOLP_j(L) = (1-F_j)\ [LOLP_{j-1}(L) - LOLP_{j-1}(L-R_j)],$$
$$LOLP_j(L) = LOLP_{j-1}(L) - \Delta LOLP_j(L). \tag{5}$$

The initial, empty-system condition is

$$LOLP_o(L) = \begin{bmatrix} 0 \ \textit{if}\ L \leq 0 \\ 1 \ \textit{else} \end{bmatrix} \tag{6}$$

because any positive load cannot be met. Equations (2) to (6) are the basis for the following algorithm, which is implemented in Fortran in the appendix with a step size for discretizing the functions of load.

Algorithm to find $CMC_N(L)$ for $0 \leq L \leq$ System Capacity

Initialize empty generation system:
cumcap ← 0
LOLP (0) ← 0, MC0(0) ← 0
Loop over units to build system:
For units j=1 to N:
    Read R_j, F_j, C_j.
    Initialize new states needed:
    For load levels L such that cumcap < l ≤ cumcap + cap_j:
        LOLP(L) ← 1, MC0(L) ← 0
    cumcap ← cumcap + cap_j
Loop backward over load levels to update LOLP(L) and MC0(L):
    For load levels L = cumcap down to 0
    ΔLOLP ← $(1-F_j)$ [LOLP(L) - LOLP(max(0,L-R_j))]
    LOLP(L) ← LOLP(L) - ΔLOLP
    MCO(L) ← MCO(L) + ΔLOLP C_j
Scale MC0(L) to CMC(L) and return it:
    { MC0(L) / [1-LOLP(L) if LOLP(L) ≠ 1
Return { undefined else for 0 ≤ L ≤ cumcap

Appendix 4.5
Short-Run Marginal Cost Analysis

APPENDIX 4.5.1
YEAR 1993

POLISH POWER GRID COMPANY
HOURLY MARGINAL COST AND RELIABILITY ANALYSIS FOR 1993

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
C.Yermoli/Hagler,Bailly Inc. - Arlington, VA., USA
Release: 930201 Polish Power Grid Company - PPGC - Warsaw
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UNIT	AVAILABLE CAPACITY MW	FAILURE RATE %	VARIABLE COST Cents/Kwh
1	160.50	10.60	1.56
2	160.50	10.60	1.56
3	160.50	10.60	1.56
4	160.50	10.60	1.56
5	160.50	10.60	1.56
6	160.50	10.60	1.56
7	289.00	16.30	1.57
8	289.00	16.30	1.57
9	289.00	16.30	1.57
10	289.00	16.30	1.57
11	289.00	16.30	1.57
12	289.00	16.30	1.57
13	289.00	16.30	1.57
14	289.00	16.30	1.57
15	289.00	16.30	1.57
16	289.00	16.30	1.57
17	289.00	16.30	1.57
18	289.00	16.30	1.57
19	160.50	10.50	1.71
20	160.50	10.50	1.71
21	160.50	10.50	1.71
22	160.50	10.50	1.71
23	160.50	10.50	1.71
24	160.50	10.50	1.71
25	160.50	10.50	1.71
26	160.50	10.50	1.71
27	160.50	10.50	1.71
28	96.30	12.10	1.72
29	96.30	12.10	1.72
30	85.10	11.20	1.78
31	85.10	11.20	1.78
32	26.50	10.00	1.78
33	26.50	10.00	1.78
34	26.50	10.00	1.78
35	26.50	10.00	1.78
36	59.00	15.80	1.80
37	59.00	15.80	1.80
38	59.00	15.80	1.80
39	59.00	15.80	1.80
40	32.10	13.00	1.92
41	32.10	13.00	1.92
42	32.10	13.00	1.92
43	32.10	13.00	1.92
44	32.10	13.00	1.92
45	45.00	12.30	1.93
46	45.00	12.30	1.93
47	160.50	9.50	1.99
48	160.50	9.50	1.99
49	160.50	9.50	1.99
50	160.50	9.50	1.99
51	160.50	9.50	1.99
52	160.50	9.50	1.99
53	160.50	9.50	1.99
54	160.50	9.50	1.99
55	368.50	30.00	2.00
56	368.50	30.00	2.00
57	160.50	7.10	2.00
58	160.50	7.10	2.00
59	160.50	7.10	2.00
60	160.50	7.10	2.00
61	160.50	7.10	2.00
62	160.50	7.10	2.00
63	160.50	7.10	2.00
64	160.50	7.10	2.00
65	160.50	10.80	2.07

66	160.50	10.80	2.07
67	160.50	10.80	2.07
68	160.50	10.80	2.07
69	160.50	10.80	2.07
70	160.50	10.80	2.07
71	160.50	10.80	2.07
72	160.50	10.80	2.07
73	160.50	2.30	2.09
74	144.50	13.40	2.11
75	144.50	13.40	2.11
76	144.50	13.40	2.11
77	144.50	13.40	2.11
78	80.30	16.20	2.11
79	80.30	16.20	2.11
80	160.50	11.60	2.11
81	160.50	11.60	2.11
82	160.50	11.60	2.11
83	160.50	11.70	2.11
84	160.50	11.70	2.11
85	160.50	11.70	2.11
86	160.50	11.70	2.11
87	160.50	11.70	2.11
88	160.50	11.70	2.11
89	160.50	11.70	2.11
90	160.50	11.70	2.11
91	152.50	10.70	2.12
92	152.50	10.70	2.12
93	152.50	10.70	2.12
94	152.50	10.70	2.12
95	152.50	10.70	2.12
96	152.50	10.70	2.12
97	82.70	11.90	2.24
98	82.70	11.90	2.24
99	82.70	11.90	2.24
100	82.70	11.90	2.24
101	82.70	11.90	2.24
102	82.70	11.90	2.24
103	82.70	11.90	2.24
104	84.30	11.60	2.26
105	84.30	11.60	2.26
106	84.30	11.60	2.26
107	84.30	11.60	2.26
108	84.30	11.60	2.26
109	84.30	11.60	2.26
110	72.20	10.40	2.42
111	72.20	10.40	2.42
112	72.20	10.40	2.42
113	36.10	10.40	2.42
114	36.10	10.40	2.42
115	36.10	10.40	2.42
116	32.90	10.70	2.52
117	32.90	10.70	2.52
118	32.90	10.70	2.52
119	32.90	10.70	2.52
120	32.90	10.70	2.52
121	40.10	11.80	2.53
122	40.10	11.80	2.53
123	40.10	11.80	2.53
124	40.10	11.80	2.53
125	34.50	10.40	2.68
126	34.50	10.40	2.68
127	34.50	10.40	2.68
128	34.50	10.40	2.68
129	34.50	10.40	2.68
130	34.50	10.40	2.68
131	34.50	10.40	2.68
132	40.10	11.80	2.76
133	40.10	11.80	2.76
134	40.10	11.80	2.76
135	15.30	15.70	2.82
136	15.30	15.70	2.82
137	15.30	15.70	2.82

138	15.30	15.70	2.82
139	15.30	15.70	2.82
140	15.30	15.70	2.82

LOAD MW	LOSS OF LOAD PROBABILITY	EXPECTED MARGINAL COST Cents/Kwh
0.	.000000E+00	.0000
1000.	.000000E+00	1.5720
2000.	.000000E+00	1.5720
3000.	.000000E+00	1.5779
4000.	.000000E+00	1.6723
5000.	.840779E-44	1.7517
6000.	.111497E-35	1.9465
7000.	.156454E-28	1.9920
8000.	.273742E-22	2.0039
9000.	.702480E-17	2.0503
10000.	.297934E-12	2.0897
11000.	.228393E-08	2.1099
12000.	.334876E-05	2.1208
13000.	.952298E-03	2.1975
14000.	.507525E-01	2.3949
15000.	.480783E+00	2.6187
16000.	.963411E+00	2.7463
17000.	.999997E+00	2.8155
17160.	.100000E+01	2.8200

GPT-H Generation Planning Tools-Marginal Cost Analysis Module
C.Yermoli/Hagler,Bailly Inc. - Arlington, VA., USA
Release: 930201 Polish Power Grid Company - PPGC - Warsaw
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PERIOD 1 HYDROCONDITION 1

HOURLY LOADS IN MW

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	9540.7	10484.8	10605.8	10588.7	10473.6	10131.7	9501.9
2	9520.2	10410.0	10494.5	10435.2	10342.1	10061.6	9333.9
3	9487.9	10346.2	10433.0	10403.5	10306.9	10060.9	9332.3
4	9504.0	10297.1	10389.0	10315.7	10287.8	10011.5	9321.3
5	9582.7	10231.0	10310.7	10227.5	10205.9	9842.9	9225.6
6	9886.0	10365.9	10430.8	10316.6	10312.2	9628.2	9019.3
7	12826.6	13895.8	14035.0	13549.9	13586.5	10002.8	9181.7
8	15125.0	16010.2	16110.4	15435.4	15583.8	10216.0	9297.2
9	15534.7	16567.1	16721.7	15935.9	16156.2	10386.5	9353.6
10	15354.0	16473.4	16752.8	15833.6	15975.3	10562.9	9459.6
11	15850.2	16853.1	16707.9	16155.0	16199.3	10632.8	9492.3
12	16061.0	16911.2	16874.1	16186.9	16229.3	10651.6	9486.9
13	15360.5	16099.3	15951.0	15400.0	15364.9	10458.3	9372.1
14	13264.6	13807.0	13798.8	13483.0	13209.6	10100.9	9179.0
15	13401.8	14108.2	14004.5	13548.7	13443.9	10122.2	9171.9
16	13524.6	14419.6	14201.0	13685.0	13685.8	10117.8	9112.7
17	13540.0	14431.2	14240.6	13636.1	13689.2	10060.7	9130.5
18	13463.3	14191.4	14116.7	13437.5	13663.9	10076.1	9204.6
19	14267.3	14922.5	14867.6	14276.2	14297.2	10335.3	9386.2
20	16131.4	16647.5	16742.9	16144.5	15986.0	13412.5	9905.7
21	16684.4	17101.7	17111.1	16774.5	16425.1	13833.7	10232.3
22	15024.6	15686.8	15776.0	15359.8	15306.9	13682.1	10179.5
23	13212.8	13765.7	14037.5	13342.2	13489.1	10480.9	9773.2
24	10493.5	10625.1	10692.8	10492.3	10338.1	9872.1	9562.5

PERIOD 1 HYDROCONDITION 1

TOTAL HYDRO MW

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	474.9	474.9	474.9	474.9	474.9	474.9	474.9
2	474.9	474.9	474.9	474.9	474.9	474.9	474.9
3	474.9	474.9	474.9	474.9	474.9	474.9	474.9
4	474.9	474.9	474.9	474.9	474.9	474.9	474.9
5	474.9	474.9	474.9	474.9	474.9	474.9	474.9
6	474.9	474.9	474.9	474.9	474.9	474.9	474.9
7	474.9	474.9	474.9	474.9	474.9	474.9	474.9
8	874.9	1774.9	1874.9	1194.9	1334.9	474.9	474.9
9	1294.9	2323.0	2474.9	1694.9	1914.9	474.9	474.9
10	1114.9	2234.9	2514.9	1594.9	1734.9	474.9	474.9
11	1614.9	2614.9	2474.9	1914.9	1954.9	474.9	474.9
12	1814.9	2674.9	2634.9	1934.9	1994.9	474.9	474.9
13	1114.9	1854.9	1714.9	1154.9	1114.9	474.9	474.9
14	474.9	474.9	474.9	474.9	474.9	474.9	474.9
15	474.9	474.9	474.9	474.9	474.9	474.9	474.9
16	474.9	474.9	474.9	474.9	474.9	474.9	474.9
17	474.9	474.9	474.9	474.9	474.9	474.9	474.9
18	474.9	474.9	474.9	474.9	474.9	474.9	474.9
19	474.9	674.9	634.9	474.9	474.9	474.9	474.9
20	1894.9	2414.9	2494.9	1894.9	1734.9	474.9	474.9
21	2434.9	2854.9	2874.9	2534.9	2174.9	474.9	474.9
22	774.9	1434.9	1534.9	1114.9	1054.9	474.9	474.9
23	474.9	474.9	474.9	474.9	474.9	474.9	474.9
24	474.9	474.9	474.9	474.9	474.9	474.9	474.9

TOTAL HYDRO ENERGY AVAILABLE (AV.MW) 848.4000000
TOTAL HYDRO ENERGY DISPATCHED (AV.MW) 848.3997000

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
C.Yermoli/Hagler,Bailly Inc. - Arlington, VA., USA
Release: 930201 Polish Power Grid Company - PPGC - Warsaw
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PERIOD 1 HYDROCONDITION 1
THERMAL LOADS IN MW

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	9065.8	10009.9	10130.9	10113.8	9998.7	9656.8	9027.0
2	9045.3	9935.1	10019.6	9960.3	9867.2	9586.7	8859.0
3	9013.0	9871.3	9958.1	9928.6	9832.0	9586.0	8857.4
4	9029.1	9822.2	9914.1	9840.8	9812.9	9536.6	8846.4
5	9107.8	9756.1	9835.8	9752.6	9731.0	9368.0	8750.7
6	9411.1	9891.0	9955.9	9841.7	9837.3	9153.3	8544.4
7	12351.7	13420.9	13560.1	13075.0	13111.6	9527.9	8706.8
8	14250.1	14235.3	14235.5	14240.5	14248.9	9741.1	8822.3
9	14239.8	14244.1	14246.8	14241.0	14241.3	9911.6	8878.7
10	14239.1	14238.5	14237.9	14238.7	14240.4	10088.0	8984.7
11	14235.3	14238.2	14233.0	14240.1	14244.4	10157.9	9017.4
12	14246.1	14236.3	14239.2	14252.0	14234.4	10176.7	9012.0
13	14245.6	14244.4	14236.1	14245.1	14250.0	9983.4	8897.2
14	12789.7	13332.1	13323.9	13008.1	12734.7	9626.0	8704.1
15	12926.9	13633.3	13529.6	13073.8	12969.0	9647.3	8697.0
16	13049.7	13944.7	13726.1	13210.1	13210.9	9642.9	8637.8
17	13065.1	13956.3	13765.7	13161.2	13214.3	9585.8	8655.6
18	12988.4	13716.5	13641.8	12962.6	13189.0	9601.2	8729.7
19	13792.4	14247.6	14232.7	13801.3	13822.3	9860.4	8911.3
20	14236.5	14232.6	14248.0	14249.6	14251.1	12937.6	9430.8
21	14249.5	14246.8	14236.2	14239.6	14250.2	13358.8	9757.4
22	14249.7	14251.9	14241.1	14244.9	14252.0	13207.2	9704.6
23	12737.9	13290.8	13562.6	12867.3	13014.2	10006.0	9298.3
24	10018.6	10150.2	10217.9	10017.4	9863.2	9397.2	9087.6

PERIOD 1 HYDROCONDITION 1
HOURLY LOLP

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000
2	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000
3	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000
4	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000
5	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000
6	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000
7	.0000482	.0077530	.0131778	.0018177	.0021385	.0000000	.0000000
8	.1278591	.1439558	.1436777	.1350764	.1411073	.0000000	.0000000
9	.1375100	.1479595	.1487132	.1447556	.1464077	.0000000	.0000000
10	.1323400	.1464162	.1461624	.1429441	.1449714	.0000000	.0000000
11	.1422939	.1464442	.1451024	.1460815	.1474152	.0000000	.0000000
12	.1471612	.1459587	.1467009	.1493970	.1449109	.0000000	.0000000
13	.1342631	.1469442	.1436385	.1352970	.1355700	.0000000	.0000000
14	.0004776	.0054415	.0052614	.0013438	.0003638	.0000000	.0000000
15	.0009225	.0172107	.0117688	.0018082	.0011227	.0000000	.0000000
16	.0016230	.0485385	.0238302	.0032763	.0032875	.0000000	.0000000
17	.0017387	.0502946	.0272645	.0026545	.0033351	.0000000	.0000000
18	.0012278	.0230541	.0177364	.0010894	.0029940	.0000000	.0000000
19	.0298156	.1204096	.1147401	.0306995	.0329005	.0000000	.0000000
20	.1450447	.1449892	.1490363	.1485703	.1479237	.0009697	.0000000
21	.1494295	.1487236	.1459340	.1467993	.1494773	.0060587	.0000000
22	.1243644	.1440678	.1427303	.1340550	.1343260	.0032358	.0000000
23	.0003695	.0045949	.0133029	.0006955	.0013817	.0000000	.0000000
24	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
C.Yermoli/Hagler,Bailly Inc. - Arlington, VA., USA
Release: 930201 Polish Power Grid Company - PPGC - Warsaw
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PERIOD 1 HYDROCONDITION 1

HOURLY LOLP AS PERCENT OF THE WEEKLY LOLP OF = .708548E+01

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	.00000	.00000	.00000	.00000	.00000	.00000	.00000
2	.00000	.00000	.00000	.00000	.00000	.00000	.00000
3	.00000	.00000	.00000	.00000	.00000	.00000	.00000
4	.00000	.00000	.00000	.00000	.00000	.00000	.00000
5	.00000	.00000	.00000	.00000	.00000	.00000	.00000
6	.00000	.00000	.00000	.00000	.00000	.00000	.00000
7	.00058	.10942	.18598	.02565	.03018	.00000	.00000
8	1.80452	2.03170	2.04189	1.90638	1.99150	.00000	.00000
9	1.94073	2.08821	2.09884	2.04299	2.06631	.00000	.00000
10	1.86776	2.06643	2.06567	2.01742	2.04604	.00000	.00000
11	2.00825	2.06682	2.04788	2.06170	2.08053	.00000	.00000
12	2.07694	2.05997	2.07044	2.10849	2.04518	.00000	.00000
13	1.89490	2.07388	2.02722	1.90950	1.91335	.00000	.00000
14	.00674	.07680	.07426	.01897	.00513	.00000	.00000
15	.01302	.24290	.16610	.02552	.01584	.00000	.00000
16	.02291	.68504	.33632	.04624	.04640	.00000	.00000
17	.02454	.70983	.38479	.03746	.04707	.00000	.00000
18	.01733	.32537	.25032	.01537	.04225	.00000	.00000
19	.42080	1.69939	1.61937	.43327	.46434	.00000	.00000
20	2.04707	2.04629	2.10340	2.09683	2.08770	.01369	.00000
21	2.10895	2.09899	2.05962	2.07183	2.10963	.08551	.00000
22	1.75520	2.03328	2.01440	1.89197	1.89579	.04567	.00000
23	.00522	.06485	.18775	.00982	.01950	.00000	.00000
24	.00000	.00000	.00000	.00000	.00000	.00000	.00000

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
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PERIOD 1 HYDROCONDITION 1

HOURLY MARGINAL GENERATION COST IN $/MWH

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	2.05	2.09	2.09	2.09	2.09	2.08	2.05
2	2.05	2.09	2.09	2.09	2.09	2.08	2.04
3	2.05	2.09	2.09	2.09	2.09	2.08	2.04
4	2.05	2.08	2.09	2.09	2.08	2.08	2.04
5	2.06	2.08	2.09	2.08	2.08	2.07	2.04
6	2.07	2.09	2.09	2.09	2.09	2.06	2.03
7	2.14	2.27	2.30	2.21	2.22	2.07	2.03
8	2.46	2.47	2.47	2.46	2.47	2.08	2.04
9	2.47	2.47	2.47	2.47	2.47	2.09	2.04
10	2.46	2.47	2.47	2.47	2.47	2.09	2.05
11	2.47	2.47	2.47	2.47	2.47	2.10	2.05
12	2.47	2.47	2.47	2.47	2.47	2.10	2.05
13	2.47	2.47	2.47	2.47	2.47	2.09	2.05
14	2.17	2.26	2.25	2.20	2.17	2.08	2.03
15	2.19	2.32	2.29	2.21	2.20	2.08	2.03
16	2.21	2.39	2.34	2.23	2.23	2.08	2.03
17	2.21	2.39	2.35	2.23	2.24	2.08	2.03
18	2.20	2.33	2.32	2.20	2.23	2.08	2.04
19	2.35	2.46	2.46	2.35	2.36	2.09	2.05
20	2.47	2.47	2.47	2.47	2.47	2.19	2.07
21	2.47	2.47	2.47	2.47	2.47	2.26	2.08
22	2.46	2.47	2.47	2.47	2.47	2.23	2.08
23	2.17	2.25	2.30	2.18	2.20	2.09	2.07
24	2.09	2.09	2.10	2.09	2.09	2.07	2.06

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
C.Yermoli/Hagler,Bailly Inc. - Arlington, VA., USA
Release: 930201 Polish Power Grid Company - PPGC - Warsaw
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SUMMER SEASON - MAY TO OCTOBER
MORNING PEAK PRICING PERIOD

NO. OF WEEKLY HOURS=	30.00
AVERAGE WEEKLY MARGINAL COST (CENTS/KWH)=	2.45

SUMMER SEASON - MAY TO OCTOBER
EVENING PEAK PRICING PERIOD

NO. OF WEEKLY HOURS=	15.00
AVERAGE WEEKLY MARGINAL COST (CENTS/KWH)=	2.46

SUMMER SEASON - MAY TO OCTOBER
OFF PEAK PRICING PERIOD

NO. OF WEEKLY HOURS=	123.00
AVERAGE WEEKLY MARGINAL COST (CENTS/KWH)=	2.14

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
C.Yermoli/Hagler,Bailly Inc. - Arlington, VA., USA
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UNIT	AVAILABLE CAPACITY MW	FAILURE RATE %	VARIABLE COST Cents/Kwh
1	190.10	10.60	1.56
2	190.10	10.60	1.56
3	190.10	10.60	1.56
4	190.10	10.60	1.56
5	190.10	10.60	1.56
6	190.10	10.60	1.56
7	342.20	16.30	1.57
8	342.20	16.30	1.57
9	342.20	16.30	1.57
10	342.20	16.30	1.57
11	342.20	16.30	1.57
12	342.20	16.30	1.57
13	342.20	16.30	1.57
14	342.20	16.30	1.57
15	342.20	16.30	1.57
16	342.20	16.30	1.57
17	342.20	16.30	1.57
18	342.20	16.30	1.57
19	190.10	10.50	1.71
20	190.10	10.50	1.71
21	190.10	10.50	1.71
22	190.10	10.50	1.71
23	190.10	10.50	1.71
24	190.10	10.50	1.71
25	190.10	10.50	1.71
26	190.10	10.50	1.71
27	190.10	10.50	1.71
28	114.10	12.10	1.72
29	114.10	12.10	1.72
30	100.80	11.20	1.78
31	100.80	11.20	1.78
32	31.40	10.00	1.78
33	31.40	10.00	1.78
34	31.40	10.00	1.78
35	31.40	10.00	1.78
36	86.70	15.80	1.80
37	86.70	15.80	1.80
38	86.70	15.80	1.80
39	86.70	15.80	1.80
40	38.00	13.00	1.92
41	38.00	13.00	1.92
42	38.00	13.00	1.92
43	38.00	13.00	1.92
44	38.00	13.00	1.92
45	53.20	12.30	1.93
46	53.20	12.30	1.93
47	190.10	9.50	1.99
48	190.10	9.50	1.99
49	190.10	9.50	1.99
50	190.10	9.50	1.99
51	190.10	9.50	1.99
52	190.10	9.50	1.99
53	190.10	9.50	1.99
54	190.10	9.50	1.99
55	467.10	30.00	2.00
56	467.10	30.00	2.00
57	190.10	7.10	2.00
58	190.10	7.10	2.00
59	190.10	7.10	2.00
60	190.10	7.10	2.00
61	190.10	7.10	2.00
62	190.10	7.10	2.00
63	190.10	7.10	2.00
64	190.10	7.10	2.00
65	190.10	10.80	2.07

66	190.10	10.80	2.07
67	190.10	10.80	2.07
68	190.10	10.80	2.07
69	190.10	10.80	2.07
70	190.10	10.80	2.07
71	190.10	10.80	2.07
72	190.10	10.80	2.07
73	190.10	2.30	2.09
74	171.10	13.40	2.11
75	171.10	13.40	2.11
76	171.10	13.40	2.11
77	171.10	13.40	2.11
78	95.10	16.20	2.11
79	95.10	16.20	2.11
80	190.10	11.60	2.11
81	190.10	11.60	2.11
82	190.10	11.60	2.11
83	190.10	11.70	2.11
84	190.10	11.70	2.11
85	190.10	11.70	2.11
86	190.10	11.70	2.11
87	190.10	11.70	2.11
88	190.10	11.70	2.11
89	190.10	11.70	2.11
90	190.10	11.70	2.11
91	180.60	10.70	2.12
92	180.60	10.70	2.12
93	180.60	10.70	2.12
94	180.60	10.70	2.12
95	180.60	10.70	2.12
96	180.60	10.70	2.12
97	97.90	11.90	2.24
98	97.90	11.90	2.24
99	97.90	11.90	2.24
100	97.90	11.90	2.24
101	97.90	11.90	2.24
102	97.90	11.90	2.24
103	97.90	11.90	2.24
104	99.80	11.60	2.26
105	99.80	11.60	2.26
106	99.80	11.60	2.26
107	99.80	11.60	2.26
108	99.80	11.60	2.26
109	99.80	11.60	2.26
110	85.60	10.40	2.42
111	85.60	10.40	2.42
112	85.60	10.40	2.42
113	42.80	10.40	2.42
114	42.80	10.40	2.42
115	42.80	10.40	2.42
116	39.00	10.70	2.52
117	39.00	10.70	2.52
118	39.00	10.70	2.52
119	39.00	10.70	2.52
120	39.00	10.70	2.52
121	47.50	11.80	2.53
122	47.50	11.80	2.53
123	47.50	11.80	2.53
124	47.50	11.80	2.53
125	40.90	10.40	2.68
126	40.90	10.40	2.68
127	40.90	10.40	2.68
128	40.90	10.40	2.68
129	40.90	10.40	2.68
130	40.90	10.40	2.68
131	40.90	10.40	2.68
132	47.50	11.80	2.76
133	47.50	11.80	2.76
134	47.50	11.80	2.76
135	18.10	15.70	2.82
136	18.10	15.70	2.82
137	18.10	15.70	2.82

138	18.10	15.70	2.82
139	18.10	15.70	2.82
140	18.10	15.70	2.82

LOAD MW	LOSS OF LOAD PROBABILITY	EXPECTED MARGINAL COST Cents/Kwh
0.	.000000E+00	.0000
1000.	.000000E+00	1.5624
2000.	.000000E+00	1.5720
3000.	.000000E+00	1.5723
4000.	.000000E+00	1.5911
5000.	.000000E+00	1.6931
6000.	.700649E-44	1.7352
7000.	.323025E-37	1.8795
8000.	.338450E-31	1.9859
9000.	.860862E-26	1.9941
10000.	.589842E-21	2.0048
11000.	.117532E-16	2.0414
12000.	.722484E-13	2.0780
13000.	.143360E-09	2.1023
14000.	.947417E-07	2.1114
15000.	.211626E-04	2.1236
16000.	.159100E-02	2.1858
17000.	.393454E-01	2.3305
18000.	.311004E+00	2.5189
19000.	.816179E+00	2.6693
20000.	.994827E+00	2.7597
20980.	.100000E+01	2.8200

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
C.Yermoli/Hagler,Bailly Inc. - Arlington, VA., USA
Release: 930201 Polish Power Grid Company - PPGC - Warsaw
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PERIOD 2 HYDROCONDITION 1

HOURLY LOADS IN MW

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	13162.8	14327.8	13945.5	14042.4	14013.8	13698.8	12764.8
2	13064.6	14168.6	13830.2	13889.6	13904.6	13642.6	12553.1
3	13043.4	14136.7	13757.4	13838.2	13841.1	13614.7	12555.1
4	13149.0	14130.6	13792.1	13860.6	13837.8	13542.3	12596.7
5	13490.3	14355.7	13975.9	14060.6	14044.3	13559.1	12685.8
6	14114.2	14689.4	14274.6	14395.6	14304.6	13427.2	12519.7
7	17908.0	18711.6	17791.9	17912.4	17683.3	13729.2	12600.6
8	19348.6	20068.0	19126.5	19185.3	18983.2	13931.4	12561.8
9	19543.7	20201.2	19225.1	19286.2	19025.7	14158.1	12463.1
10	19322.8	19895.4	19119.9	18972.5	18660.3	14353.1	12572.6
11	19695.5	20034.1	19016.1	19184.6	18737.1	14456.5	12624.2
12	19866.9	20080.9	19128.4	19207.6	18668.7	14439.7	12655.6
13	19309.8	19311.6	18498.4	18570.3	17947.3	14161.1	12544.5
14	17844.4	17839.3	17088.4	17252.8	14858.6	13899.0	12425.7
15	18189.8	18258.5	17438.8	17530.2	16993.2	14052.8	12481.0
16	19367.6	19571.9	18442.6	18609.5	18194.4	14413.9	12796.5
17	20995.6	21109.8	20091.8	20110.1	19590.4	16993.0	13408.3
18	22006.2	22040.9	21061.1	21030.5	20581.0	17951.4	13924.7
19	22033.2	22222.2	21353.1	21411.8	20734.6	17775.6	14119.5
20	21942.4	21972.6	21148.8	21181.0	20510.0	17961.3	14359.6
21	20128.5	20126.7	19459.2	19479.8	18881.9	14764.2	13874.6
22	17586.3	17827.7	17183.1	17097.4	16879.1	14359.3	13437.5
23	14819.8	14867.6	14585.5	14512.1	14359.4	13747.6	13140.0
24	14504.0	14576.8	14182.2	14203.4	13834.6	13128.3	12894.6

PERIOD 2 HYDROCONDITION 1

TOTAL HYDRO MW

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9
2	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9
3	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9
4	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9
5	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9
6	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9
7	1849.9	2329.9	1849.9	1849.9	1849.9	1849.9	1849.9
8	2949.9	3669.9	2729.9	2789.9	2589.9	1849.9	1849.9
9	3149.9	3809.9	2829.9	2889.9	2629.9	1849.9	1849.9
10	2929.9	3509.9	2729.9	2589.9	2269.9	1849.9	1849.9
11	3309.9	3649.9	2629.9	2789.9	2349.9	1849.9	1849.9
12	3469.9	3689.9	2729.9	2809.9	2269.9	1849.9	1849.9
13	2909.9	2929.9	2109.9	2187.8	1849.9	1849.9	1849.9
14	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9
15	1849.9	1869.9	1849.9	1849.9	1849.9	1849.9	1849.9
16	2969.9	3189.9	2049.9	2209.9	1849.9	1849.9	1849.9
17	4609.9	4709.9	3709.9	3709.9	3209.9	1849.9	1849.9
18	5609.9	5649.9	4669.9	4649.9	4189.9	1849.9	1849.9
19	5649.9	5829.9	4969.9	5029.9	4349.9	1849.9	1849.9
20	5549.9	5589.9	4749.9	4789.9	4109.9	1849.9	1849.9
21	3729.9	3729.9	3069.9	3089.9	2489.9	1849.9	1849.9
22	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9
23	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9
24	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9	1849.9

TOTAL HYDRO ENERGY AVAILABLE (AV.MW) 2439.0300000
TOTAL HYDRO ENERGY DISPATCHED (AV.MW) 2439.0320000

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
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Release: 930201 Polish Power Grid Company - PPGC - Warsaw
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PERIOD 2 HYDROCONDITION 1

THERMAL LOADS IN MW

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	11312.9	12477.9	12095.6	12192.5	12163.9	11848.9	10914.9
2	11214.7	12318.7	11980.3	12039.7	12054.7	11792.7	10703.2
3	11193.5	12286.8	11907.5	11988.3	11991.2	11764.8	10705.2
4	11299.1	12280.7	11942.2	12010.7	11987.9	11692.4	10746.8
5	11640.4	12505.8	12126.0	12210.7	12194.4	11709.2	10835.9
6	12264.3	12839.5	12424.7	12545.7	12454.7	11577.3	10669.8
7	16058.1	16381.7	15942.0	16062.5	15833.4	11879.3	10750.7
8	16398.7	16398.1	16396.6	16395.4	16393.3	12081.5	10711.9
9	16393.8	16391.3	16395.2	16396.3	16395.8	12308.2	10613.2
10	16392.9	16385.5	16390.0	16382.6	16390.4	12503.2	10722.7
11	16385.6	16384.2	16386.2	16394.7	16387.2	12606.6	10774.3
12	16397.0	16391.0	16398.5	16397.7	16398.8	12589.8	10805.7
13	16399.9	16381.7	16388.5	16382.5	16097.4	12311.2	10694.6
14	15994.5	15989.4	15238.5	15402.9	13008.7	12049.1	10575.8
15	16339.9	16388.6	15588.9	15680.3	15143.3	12202.9	10631.1
16	16397.7	16382.0	16392.7	16399.6	16344.5	12564.0	10946.6
17	16385.7	16399.9	16381.9	16400.2	16380.5	15143.1	11558.4
18	16396.3	16391.0	16391.2	16380.6	16391.1	16101.5	12074.8
19	16383.3	16392.3	16383.2	16381.9	16384.7	15925.7	12269.6
20	16392.5	16382.7	16398.9	16391.1	16400.1	16111.4	12509.7
21	16398.6	16396.8	16389.3	16389.9	16392.0	12914.3	12024.7
22	15736.4	15977.8	15333.2	15247.5	15029.2	12509.4	11587.6
23	12969.9	13017.7	12735.6	12662.2	12509.5	11897.7	11290.1
24	12654.1	12726.9	12332.3	12353.5	11984.7	11278.4	11044.7

PERIOD 2 HYDROCONDITION 1

HOURLY LOLP

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000
2	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000
3	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000
4	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000
5	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000
6	.0000000	.0000002	.0000000	.0000000	.0000000	.0000000	.0000000
7	.0153660	.0401009	.0123287	.0154921	.0099426	.0000000	.0000000
8	.0524496	.0560296	.0492984	.0502163	.0465810	.0000000	.0000000
9	.0541339	.0559927	.0508008	.0516501	.0474688	.0000000	.0000000
10	.0520341	.0555044	.0490555	.0461476	.0389578	.0000000	.0000000
11	.0548470	.0557116	.0470903	.0501915	.0408543	.0000001	.0000000
12	.0556687	.0558998	.0493683	.0505970	.0393445	.0000001	.0000000
13	.0520176	.0516731	.0345888	.0364153	.0165213	.0000000	.0000000
14	.0136359	.0135039	.0025365	.0038295	.0000005	.0000000	.0000000
15	.0253475	.0280677	.0059066	.0072213	.0019727	.0000000	.0000000
16	.0526400	.0540894	.0331486	.0378065	.0255490	.0000001	.0000000
17	.0559558	.0562417	.0557267	.0561114	.0541781	.0019717	.0000000
18	.0561692	.0560626	.0560666	.0558532	.0560616	.0166456	.0000000
19	.0559075	.0560887	.0559055	.0558794	.0559353	.0119441	.0000000
20	.0560928	.0558954	.0562216	.0560646	.0562398	.0169495	.0000000
21	.0560937	.0560561	.0533716	.0535610	.0443938	.0000003	.0000000
22	.0081384	.0132085	.0032264	.0025959	.0014409	.0000000	.0000000
23	.0000004	.0000006	.0000001	.0000001	.0000000	.0000000	.0000000
24	.0000001	.0000001	.0000000	.0000000	.0000000	.0000000	.0000000

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PERIOD 2 HYDROCONDITION 1

HOURLY LOLP AS PERCENT OF THE WEEKLY LOLP OF = .330385E+01

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	.00000	.00000	.00000	.00000	.00000	.00000	.00000
2	.00000	.00000	.00000	.00000	.00000	.00000	.00000
3	.00000	.00000	.00000	.00000	.00000	.00000	.00000
4	.00000	.00000	.00000	.00000	.00000	.00000	.00000
5	.00000	.00000	.00000	.00000	.00000	.00000	.00000
6	.00000	.00001	.00000	.00000	.00000	.00000	.00000
7	.46509	1.21376	.37316	.46891	.30094	.00000	.00000
8	1.58753	1.69589	1.49215	1.51993	1.40990	.00000	.00000
9	1.63851	1.69477	1.53762	1.56333	1.43677	.00000	.00000
10	1.57495	1.67999	1.48480	1.39678	1.17916	.00000	.00000
11	1.66009	1.68626	1.42531	1.51918	1.23657	.00000	.00000
12	1.68496	1.69196	1.49427	1.53145	1.19087	.00000	.00000
13	1.57445	1.56403	1.04692	1.10221	.50006	.00000	.00000
14	.41273	.40873	.07677	.11591	.00002	.00000	.00000
15	.76721	.84954	.17878	.21857	.05971	.00000	.00000
16	1.59329	1.63716	1.00333	1.14432	.77331	.00000	.00000
17	1.69365	1.70231	1.68672	1.69836	1.63985	.05968	.00000
18	1.70011	1.69688	1.69701	1.69055	1.69686	.50382	.00000
19	1.69219	1.69768	1.69213	1.69134	1.69303	.36152	.00000
20	1.69780	1.69183	1.70170	1.69694	1.70225	.51302	.00000
21	1.69703	1.69669	1.61543	1.62117	1.34370	.00001	.00000
22	.24633	.39979	.09766	.07857	.04361	.00000	.00000
23	.00001	.00002	.00000	.00000	.00000	.00000	.00000
24	.00000	.00000	.00000	.00000	.00000	.00000	.00000

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
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PERIOD 2 HYDROCONDITION 1

HOURLY MARGINAL GENERATION COST IN $/MWH

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	2.06	2.09	2.08	2.08	2.08	2.08	2.04
2	2.05	2.09	2.08	2.08	2.08	2.07	2.03
3	2.05	2.09	2.08	2.08	2.08	2.07	2.03
4	2.06	2.09	2.08	2.08	2.08	2.07	2.03
5	2.07	2.09	2.08	2.08	2.08	2.07	2.04
6	2.09	2.10	2.09	2.09	2.09	2.07	2.03
7	2.21	2.25	2.19	2.21	2.18	2.08	2.03
8	2.26	2.26	2.26	2.26	2.26	2.08	2.03
9	2.26	2.26	2.26	2.26	2.26	2.09	2.03
10	2.26	2.26	2.26	2.25	2.25	2.09	2.03
11	2.26	2.26	2.25	2.26	2.25	2.09	2.03
12	2.26	2.26	2.26	2.26	2.25	2.09	2.04
13	2.26	2.26	2.25	2.25	2.21	2.09	2.03
14	2.20	2.20	2.14	2.15	2.10	2.08	2.03
15	2.24	2.25	2.16	2.17	2.14	2.08	2.03
16	2.26	2.26	2.25	2.25	2.24	2.09	2.04
17	2.26	2.26	2.26	2.26	2.26	2.14	2.07
18	2.26	2.26	2.26	2.26	2.26	2.21	2.08
19	2.26	2.26	2.26	2.26	2.26	2.19	2.09
20	2.26	2.26	2.26	2.26	2.26	2.21	2.09
21	2.26	2.26	2.26	2.26	2.25	2.10	2.08
22	2.18	2.20	2.15	2.14	2.13	2.09	2.07
23	2.10	2.10	2.10	2.10	2.09	2.08	2.06
24	2.10	2.10	2.09	2.09	2.08	2.06	2.05

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
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WINTER SEASON - NOVEMBER TO APRIL
MORNING PEAK PRICING PERIOD
NO. OF WEEKLY HOURS= 30.00
AVERAGE WEEKLY MARGINAL COST (CENTS/KWH)= 2.25

WINTER SEASON - NOVEMBER TO APRIL
EVENING PEAK PRICING PERIOD
NO. OF WEEKLY HOURS= 25.00
AVERAGE WEEKLY MARGINAL COST (CENTS/KWH)= 2.26

WINTER SEASON - NOVEMBER TO APRIL
OFF PEAK PRICING PERIOD
NO. OF WEEKLY HOURS= 113.00
AVERAGE WEEKLY MARGINAL COST (CENTS/KWH)= 2.10

APPENDIX 4.5.2
YEAR 1997

POLISH POWER GRID COMPANY
HOURLY MARGINAL COST AND RELIABILITY ANALYSIS FOR 1997

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
C.Yermoli/Hagler,Bailly Inc. - Arlington, VA., USA
Release: 930201 Polish Power Grid Company - PPGC - Warsaw
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UNIT	AVAILABLE CAPACITY MW	FAILURE RATE %	VARIABLE COST Cents/Kwh
1	160.50	10.60	1.56
2	160.50	10.60	1.56
3	160.50	10.60	1.56
4	160.50	10.60	1.56
5	160.50	10.60	1.56
6	160.50	10.60	1.56
7	160.50	10.60	1.56
8	160.50	10.60	1.56
9	289.00	16.30	1.57
10	289.00	16.30	1.57
11	289.00	16.30	1.57
12	289.00	16.30	1.57
13	289.00	16.30	1.57
14	289.00	16.30	1.57
15	289.00	16.30	1.57
16	289.00	16.30	1.57
17	289.00	16.30	1.57
18	289.00	16.30	1.57
19	289.00	16.30	1.57
20	289.00	16.30	1.57
21	160.50	10.50	1.71
22	160.50	10.50	1.71
23	160.50	10.50	1.71
24	160.50	10.50	1.71
25	160.50	10.50	1.71
26	160.50	10.50	1.71
27	160.50	10.50	1.71
28	160.50	10.50	1.71
29	96.30	12.10	1.72
30	96.30	12.10	1.72
31	85.10	11.20	1.78
32	85.10	11.20	1.78
33	26.50	10.00	1.78
34	26.50	10.00	1.78
35	26.50	10.00	1.78
36	59.00	15.80	1.80
37	59.00	15.80	1.80
38	59.00	15.80	1.80
39	59.00	15.80	1.80
40	59.00	15.80	1.80
41	32.10	13.00	1.92
42	32.10	13.00	1.92
43	32.10	13.00	1.92
44	32.10	13.00	1.92
45	32.10	13.00	1.92
46	32.10	13.00	1.92
47	45.00	12.30	1.93
48	160.50	9.50	1.99
49	160.50	9.50	1.99
50	160.50	9.50	1.99
51	160.50	9.50	1.99
52	160.50	9.50	1.99
53	160.50	9.50	1.99
54	160.50	9.50	1.99
55	160.50	9.50	1.99
56	368.50	30.00	2.00
57	368.50	30.00	2.00
58	289.00	10.80	2.00
59	289.00	10.80	2.00
60	289.00	10.80	2.00
61	289.00	10.80	2.00
62	289.00	10.80	2.00
63	289.00	10.80	2.00
64	160.50	7.10	2.00
65	160.50	7.10	2.00

66	160.50	7.10	2.00
67	160.50	7.10	2.00
68	160.50	7.10	2.00
69	160.50	7.10	2.00
70	160.50	7.10	2.00
71	160.50	7.10	2.00
72	160.50	10.80	2.07
73	160.50	10.80	2.07
74	160.50	10.80	2.07
75	160.50	10.80	2.07
76	160.50	10.80	2.07
77	160.50	10.80	2.07
78	160.50	10.80	2.07
79	160.50	10.80	2.07
80	144.50	13.40	2.11
81	144.50	13.40	2.11
82	144.50	13.40	2.11
83	144.50	13.40	2.11
84	80.30	16.20	2.11
85	80.30	16.20	2.11
86	160.50	11.60	2.11
87	160.50	11.60	2.11
88	160.50	11.60	2.11
89	160.50	11.70	2.11
90	160.50	11.70	2.11
91	160.50	11.70	2.11
92	160.50	11.70	2.11
93	160.50	11.70	2.11
94	160.50	11.70	2.11
95	160.50	11.70	2.11
96	160.50	11.70	2.11
97	152.50	10.70	2.12
98	152.50	10.70	2.12
99	152.50	10.70	2.12
100	152.50	10.70	2.12
101	152.50	10.70	2.12
102	152.50	10.70	2.12
103	82.70	11.90	2.24
104	82.70	11.90	2.24
105	82.70	11.90	2.24
106	82.70	11.90	2.24
107	82.70	11.90	2.24
108	82.70	11.90	2.24
109	82.70	11.90	2.24
110	84.30	11.60	2.26
111	84.30	11.60	2.26
112	84.30	11.60	2.26
113	84.30	11.60	2.26
114	84.30	11.60	2.26
115	84.30	11.60	2.26
116	36.10	10.40	2.42
117	36.10	10.40	2.42
118	36.10	10.40	2.42
119	32.90	10.70	2.52
120	40.10	11.80	2.53
121	40.10	11.80	2.53
122	40.10	11.80	2.53
123	40.10	11.80	2.53
124	34.50	10.40	2.63
125	34.50	10.40	2.68
126	34.50	10.40	2.68
127	34.50	10.40	2.68
128	34.50	10.40	2.68
129	34.50	10.40	2.68
130	34.50	10.40	2.68
131	40.10	11.80	2.76
132	40.10	11.80	2.76
133	40.10	11.80	2.76
134	15.30	15.70	2.82
135	15.30	15.70	2.82
136	15.30	15.70	2.82
137	15.30	15.70	2.82

138	15.30	15.70	2.82
139	15.30	15.70	2.82
140	109.50	12.00	4.64
141	109.50	12.00	4.64

LOAD MW	LOSS OF LOAD PROBABILITY	EXPECTED MARGINAL COST Cents/Kwh
0.	.000000E+00	.0000
1000.	.000000E+00	1.5633
2000.	.000000E+00	1.5720
3000.	.000000E+00	1.5737
4000.	.000000E+00	1.6389
5000.	.000000E+00	1.7348
6000.	.698982E-40	1.9166
7000.	.806423E-33	1.9905
8000.	.139853E-26	1.9950
9000.	.439135E-21	1.9967
10000.	.287344E-16	2.0156
11000.	.434628E-12	2.0667
12000.	.162636E-08	2.1009
13000.	.155262E-05	2.1134
14000.	.375056E-03	2.1485
15000.	.218539E-01	2.3331
16000.	.285566E+00	2.8211
17000.	.854229E+00	3.5173
18000.	.998909E+00	4.2893
18680.	.100000E+01	4.6370

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
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PERIOD 1 HYDROCONDITION 1

HOURLY LOADS IN MW

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	10668.6	11853.2	12002.1	11981.2	11839.3	11414.9	10619.0
2	10642.4	11760.8	11865.1	11791.9	11676.7	11327.2	10403.0
3	10601.0	11681.8	11789.1	11752.6	11633.0	11326.4	10400.9
4	10621.7	11620.8	11734.7	11643.9	11609.2	11264.5	10386.7
5	10722.3	11538.6	11637.7	11534.3	11507.4	11052.4	10262.8
6	11[illegible]06.7	11706.2	11786.5	11645.1	11639.6	10780.2	9993.5
7	14196.9	15208.0	15339.7	14881.0	14915.5	11253.6	10205.8
8	16370.5	17207.6	17302.3	16664.1	16804.4	11520.0	10355.5
9	16757.9	17734.3	17880.4	17137.3	17345.7	11731.6	10428.4
10	16587.0	17645.6	17909.8	17040.6	17174.6	11949.4	10564.7
11	17056.3	18004.7	17867.4	17344.5	17386.5	12035.3	10606.7
12	17255.6	18059.6	18024.6	17374.6	17414.8	12058.4	10599.8
13	16593.2	17291.9	17151.6	16630.5	16597.4	11820.4	10452.2
14	14611.1	15124.1	15116.3	14817.7	14559.1	11376.5	10202.3
15	14740.8	15408.9	15310.8	14879.8	14780.7	11403.1	10193.0
16	14857.0	15703.4	15496.7	15008.7	15009.5	11397.5	10115.8
17	14871.6	15714.4	15534.1	14962.5	15012.6	11326.2	10139.1
18	14799.0	15487.6	15416.9	14774.7	14988.8	11345.4	10235.6
19	15559.3	16178.9	16127.0	15567.8	15587.6	11668.2	10470.5
20	17322.2	17810.3	17900.5	17334.6	17184.7	14751.0	11131.6
21	17845.1	18239.8	18248.7	17930.4	17599.9	15149.3	11540.2
22	16275.5	16901.7	16986.1	16592.6	16542.5	15005.9	11474.6
23	14562.2	15085.0	15342.1	14684.6	14823.4	11848.3	10964.3
24	11863.9	12025.9	12109.0	11862.3	11671.7	11089.3	10696.5

PERIOD 1 HYDROCONDITION 1

TOTAL HYDRO MW

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	629.7	629.7	629.7	629.7	629.7	629.7	629.7
2	629.7	629.7	629.7	629.7	629.7	629.7	629.7
3	629.7	629.7	629.7	629.7	629.7	629.7	629.7
4	629.7	629.7	629.7	629.7	629.7	629.7	629.7
5	629.7	629.7	629.7	629.7	629.7	629.7	629.7
6	629.7	629.7	629.7	629.7	629.7	629.7	629.7
7	629.7	629.7	629.7	629.7	629.7	629.7	629.7
8	1169.7	2009.7	2109.7	1469.7	1609.7	629.7	629.7
9	1549.7	2529.7	2689.7	1929.7	2149.7	629.7	629.7
10	1389.7	2449.7	2709.7	1849.7	1969.7	629.7	629.7
11	1849.7	2809.7	2669.7	2149.7	2189.7	629.7	629.7
12	2049.7	2849.7	2829.7	2169.7	2209.7	629.7	629.7
13	1389.7	2089.7	1949.7	1429.7	1389.7	629.7	629.7
14	629.7	629.7	629.7	629.7	629.7	629.7	629.7
15	629.7	629.7	629.7	629.7	629.7	629.7	629.7
16	629.7	629.7	629.7	629.7	629.7	629.7	629.7
17	629.7	629.7	629.7	629.7	629.7	629.7	629.7
18	629.7	629.7	629.7	629.7	629.7	629.7	629.7
19	629.7	969.7	929.7	629.7	629.7	629.7	629.7
20	2129.7	2609.7	2709.7	2129.7	1989.7	629.7	629.7
21	2649.7	3048.7	3049.7	2729.7	2409.7	629.7	629.7
22	1069.7	1709.7	1789.7	1389.7	1349.7	629.7	629.7
23	629.7	629.7	629.7	629.7	629.7	629.7	629.7
24	629.7	629.7	629.7	629.7	629.7	629.7	629.7

TOTAL HYDRO ENERGY AVAILABLE (AV.MW) 1026.6000000
TOTAL HYDRO ENERGY DISPATCHED (AV.MW) 1026.5980000

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PERIOD 1 HYDROCONDITION 1

THERMAL LOADS IN MW

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	10038.9	11223.5	11372.4	11351.5	11209.6	10785.2	9989.3
2	10012.7	11131.1	11235.4	11162.2	11047.0	10697.5	9773.3
3	9971.3	11052.1	11159.4	11122.9	11003.3	10696.7	9771.2
4	9992.0	10991.1	11105.0	11014.2	10979.5	10634.8	9757.0
5	10092.6	10908.9	11008.0	10904.6	10877.7	10422.7	9633.1
6	10477.0	11076.5	11156.8	11015.4	11009.9	10150.5	9363.8
7	13567.2	14578.3	14710.0	14251.3	14285.8	10623.9	9576.1
8	15200.8	15197.9	15192.6	15194.4	15194.7	10890.3	9725.8
9	15208.2	15204.6	15190.7	15207.6	15196.0	11101.9	9798.7
10	15197.3	15195.9	15200.1	15190.9	15204.9	11319.7	9935.0
11	15206.6	15195.0	15197.7	15194.8	15196.8	11405.6	9977.0
12	15205.9	15209.9	15194.9	15204.9	15205.1	11428.7	9970.1
13	15203.5	15202.2	15201.9	15200.8	15207.7	11190.7	9822.5
14	13981.4	14494.4	14486.6	14188.0	13929.4	10746.8	9572.6
15	14111.1	14779.2	14681.1	14250.1	14151.0	10773.4	9563.3
16	14227.3	15073.7	14867.0	14379.0	14379.8	10767.8	9486.1
17	14241.9	15084.7	14904.4	14332.8	14382.9	10696.5	9509.4
18	14169.3	14857.9	14787.2	14145.0	14359.1	10715.7	9605.9
19	14929.6	15209.2	15197.3	14938.1	14957.9	11038.5	9840.8
20	15192.5	15200.6	15190.8	15204.9	15195.0	14121.3	10501.9
21	15195.4	15191.4	15199.0	15200.7	15190.2	14519.6	10910.5
22	15205.8	15192.0	15196.4	15202.9	15192.8	14376.2	10844.9
23	13932.5	14455.3	14712.4	14054.9	14193.7	11218.6	10334.6
24	11234.2	11396.2	11479.3	11232.6	11042.0	10459.6	10066.8

PERIOD 1 HYDROCONDITION 1

HOURLY LOLP

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000
2	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000
3	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000
4	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000
5	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000
6	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000
7	.0000862	.0065832	.0105336	.0018629	.0021420	.0000000	.0000000
8	.0644677	.0851213	.0856226	.0728380	.0767744	.0000000	.0000000
9	.0771456	.0894238	.0879978	.0852834	.0864385	.0000000	.0000000
10	.0708600	.0881627	.0891116	.0816526	.0855083	.0000000	.0000000
11	.0837989	.0885768	.0887952	.0862889	.0868829	.0000000	.0000000
12	.0866817	.0903808	.0885732	.0877519	.0880938	.0000000	.0000000
13	.0717879	.0866368	.0848059	.0725869	.0724279	.0000000	.0000000
14	.0005936	.0048247	.0046852	.0014364	.0004714	.0000000	.0000000
15	.0010402	.0133578	.0095174	.0018538	.0012309	.0000000	.0000000
16	.0016890	.0342510	.0179051	.0030990	.0031085	.0000000	.0000000
17	.0017925	.0353958	.0202185	.0025844	.0031470	.0000000	.0000000
18	.0013289	.0173749	.0137287	.0012003	.0028664	.0000000	.0000000
19	.0219233	.0595840	.0566391	.0225208	.0239790	.0000000	.0000000
20	.0858111	.0890662	.0880272	.0873951	.0844753	.0010859	.0000000
21	.0885048	.0882104	.0890873	.0891999	.0873473	.0053004	.0000000
22	.0620990	.0788644	.0812197	.0716966	.0689661	.0030659	.0000000
23	.0004780	.0041609	.0106219	.0008179	.0014707	.0000000	.0000000
24	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000	.0000000

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PERIOD 1 HYDROCONDITION 1

HOURLY LOLP AS PERCENT OF THE WEEKLY LOLP OF = .416200E+01

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	.00000	.00000	.00000	.00000	.00000	.00000	.00000
2	.00000	.00000	.00000	.00000	.00000	.00000	.00000
3	.00000	.00000	.00000	.00000	.00000	.00000	.00000
4	.00000	.00000	.00000	.00000	.00000	.00000	.00000
5	.00000	.00000	.00000	.00000	.00000	.00000	.00000
6	.00000	.00000	.00000	.00000	.00000	.00000	.00000
7	.00207	.15817	.25309	.04476	.05147	.00000	.00000
8	1.54896	2.04520	2.05724	1.75007	1.84465	.00000	.00000
9	1.85357	2.14858	2.11431	2.04909	2.07685	.00000	.00000
10	1.70255	2.11827	2.14107	1.96186	2.05450	.00000	.00000
11	2.01343	2.12822	2.13347	2.07325	2.08752	.00000	.00000
12	2.08269	2.17157	2.12814	2.10841	2.11662	.00000	.00000
13	1.72484	2.08161	2.03762	1.74404	1.74022	.00000	.00000
14	.01426	.11592	.11257	.03451	.01133	.00000	.00000
15	.02499	.32095	.22867	.04454	.02958	.00000	.00000
16	.04058	.82294	.43020	.07446	.07469	.00000	.00000
17	.04307	.85045	.48579	.06210	.07561	.00000	.00000
18	.03193	.41746	.32986	.02884	.06887	.00000	.00000
19	.52675	1.43162	1.36086	.54110	.57614	.00000	.00000
20	2.06177	2.13998	2.11502	2.09983	2.02968	.02609	.00000
21	2.12649	2.11942	2.14049	2.14319	2.09868	.12735	.00000
22	1.49205	1.89487	1.95146	1.72265	1.65704	.07366	.00000
23	.01148	.09997	.25521	.01965	.03534	.00000	.00000
24	.00000	.00000	.00000	.00000	.00000	.00000	.00000

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PERIOD 1 HYDROCONDITION 1

HOURLY MARGINAL GENERATION COST IN $/MWH

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	2.02	2.08	2.08	2.08	2.08	2.06	2.02
2	2.02	2.07	2.08	2.07	2.07	2.05	2.01
3	2.02	2.07	2.07	2.07	2.07	2.05	2.01
4	2.02	2.07	2.07	2.07	2.07	2.05	2.01
5	2.02	2.06	2.07	2.06	2.06	2.04	2.01
6	2.04	2.07	2.07	2.07	2.07	2.02	2.00
7	2.13	2.23	2.26	2.18	2.18	2.05	2.00
8	2.44	2.47	2.47	2.45	2.45	2.06	2.01
9	2.45	2.49	2.49	2.47	2.47	2.07	2.01
10	2.44	2.48	2.49	2.46	2.47	2.08	2.01
11	2.46	2.50	2.49	2.47	2.47	2.08	2.02
12	2.47	2.50	2.50	2.48	2.48	2.08	2.02
13	2.45	2.47	2.47	2.45	2.45	2.08	2.01
14	2.15	2.22	2.22	2.17	2.15	2.06	2.00
15	2.16	2.28	2.26	2.18	2.17	2.06	2.00
16	2.18	2.37	2.31	2.20	2.20	2.06	2.00
17	2.18	2.38	2.32	2.19	2.20	2.05	2.00
18	2.17	2.30	2.28	2.17	2.20	2.05	2.00
19	2.32	2.45	2.43	2.33	2.33	2.07	2.01
20	2.47	2.49	2.49	2.47	2.46	2.16	2.04
21	2.49	2.50	2.51	2.50	2.48	2.22	2.06
22	2.44	2.45	2.46	2.45	2.44	2.20	2.06
23	2.15	2.21	2.26	2.16	2.17	2.08	2.03
24	2.08	2.08	2.09	2.08	2.07	2.04	2.02

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SUMMER SEASON - MAY TO OCTOBER
MORNING PEAK PRICING PERIOD

NO. OF WEEKLY HOURS=	30.00
AVERAGE WEEKLY MARGINAL COST (CENTS/KWH)=	2.45

SUMMER SEASON - MAY TO OCTOBER
EVENING PEAK PRICING PERIOD

NO. OF WEEKLY HOURS=	15.00
AVERAGE WEEKLY MARGINAL COST (CENTS/KWH)=	2.46

SUMMER SEASON - MAY TO OCTOBER
OFF PEAK PRICING PERIOD

NO. OF WEEKLY HOURS=	123.00
AVERAGE WEEKLY MARGINAL COST (CENTS/KWH)=	2.12

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
C.Yermoli/Hagler,Bailly Inc. - Arlington, VA., USA
Release: 930201 Polish Power Grid Company - PPGC - Warsaw
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UNIT	AVAILABLE CAPACITY MW	FAILURE RATE %	VARIABLE COST Cents/Kwh
1	190.10	10.60	1.56
2	190.10	10.60	1.56
3	190.10	10.60	1.56
4	190.10	10.60	1.56
5	190.10	10.60	1.56
6	190.10	10.60	1.56
7	190.10	10.60	1.56
8	190.10	10.60	1.56
9	342.20	16.30	1.57
10	342.20	16.30	1.57
11	342.20	16.30	1.57
12	342.20	16.30	1.57
13	342.20	16.30	1.57
14	342.20	16.30	1.57
15	342.20	16.30	1.57
16	342.20	16.30	1.57
17	342.20	16.30	1.57
18	342.20	16.30	1.57
19	342.20	16.30	1.57
20	342.20	16.30	1.57
21	190.10	10.50	1.71
22	190.10	10.50	1.71
23	190.10	10.50	1.71
24	190.10	10.50	1.71
25	190.10	10.50	1.71
26	190.10	10.50	1.71
27	190.10	10.50	1.71
28	190.10	10.50	1.71
29	114.10	12.10	1.72
30	114.10	12.10	1.72
31	100.80	11.20	1.78
32	100.80	11.20	1.78
33	31.40	10.00	1.78
34	31.40	10.00	1.78
35	31.40	10.00	1.78
36	86.70	15.80	1.80
37	86.70	15.80	1.80
38	86.70	15.80	1.80
39	86.70	15.80	1.80
40	86.70	15.80	1.80
41	38.00	13.00	1.92
42	38.00	13.00	1.92
43	38.00	13.00	1.92
44	38.00	13.00	1.92
45	38.00	13.00	1.92
46	38.00	13.00	1.92
47	53.20	12.30	1.93
48	190.10	9.50	1.99
49	190.10	9.50	1.99
50	190.10	9.50	1.99
51	190.10	9.50	1.99
52	190.10	9.50	1.99
53	190.10	9.50	1.99
54	190.10	9.50	1.99
55	190.10	9.50	1.99
56	467.10	30.00	2.00
57	467.10	30.00	2.00
58	342.20	10.80	2.00
59	342.20	10.80	2.00
60	342.20	10.80	2.00
61	342.20	10.80	2.00
62	342.20	10.80	2.00
63	342.20	10.80	2.00
64	190.10	7.10	2.00
65	190.10	7.10	2.00

66	190.10	7.10	2.00
67	190.10	7.10	2.00
68	190.10	7.10	2.00
69	190.10	7.10	2.00
70	190.10	7.10	2.00
71	190.10	7.10	2.00
72	190.10	10.80	2.07
73	190.10	10.80	2.07
74	190.10	10.80	2.07
75	190.10	10.80	2.07
76	190.10	10.80	2.07
77	190.10	10.80	2.07
78	190.10	10.80	2.07
79	190.10	10.80	2.07
80	171.10	13.40	2.11
81	171.10	13.40	2.11
82	171.10	13.40	2.11
83	171.10	13.40	2.11
84	95.10	16.20	2.11
85	95.10	16.20	2.11
86	190.10	11.60	2.11
87	190.10	11.60	2.11
88	190.10	11.60	2.11
89	190.10	11.70	2.11
90	190.10	11.70	2.11
91	190.10	11.70	2.11
92	190.10	11.70	2.11
93	190.10	11.70	2.11
94	190.10	11.70	2.11
95	190.10	11.70	2.11
96	190.10	11.70	2.11
97	180.60	10.70	2.12
98	180.60	10.70	2.12
99	180.60	10.70	2.12
100	180.60	10.70	2.12
101	180.60	10.70	2.12
102	180.60	10.70	2.12
103	97.90	11.90	2.24
104	97.90	11.90	2.24
105	97.90	11.90	2.24
106	97.90	11.90	2.24
107	97.90	11.90	2.24
108	97.90	11.90	2.24
109	97.90	11.90	2.24
110	99.80	11.60	2.26
111	99.80	11.60	2.26
112	99.80	11.60	2.26
113	99.80	11.60	2.26
114	99.80	11.60	2.26
115	99.80	11.60	2.26
116	42.80	10.40	2.42
117	42.80	10.40	2.42
118	42.80	10.40	2.42
119	39.00	10.70	2.52
120	47.50	11.80	2.53
121	47.50	11.80	2.53
122	47.50	11.80	2.53
123	47.50	11.80	2.53
124	40.90	10.40	2.68
125	40.90	10.40	2.68
126	40.90	10.40	2.68
127	40.90	10.40	2.68
128	40.90	10.40	2.68
129	40.90	10.40	2.68
130	40.90	10.40	2.68
131	47.50	11.80	2.76
132	47.50	11.80	2.76
133	47.50	11.80	2.76
134	18.10	15.70	2.82
135	18.10	15.70	2.82
136	18.10	15.70	2.82
137	18.10	15.70	2.82

138	18.10	15.70	2.82
139	18.10	15.70	2.82
140	117.40	12.00	4.64
141	117.40	12.00	4.64

LOAD MW	LOSS OF LOAD PROBABILITY	EXPECTED MARGINAL COST Cents/Kwh
0.	.000000E+00	.0000
1000.	.000000E+00	1.5611
2000.	.000000E+00	1.5720
3000.	.000000E+00	1.5721
4000.	.000000E+00	1.5789
5000.	.000000E+00	1.6451
6000.	.000000E+00	1.7243
7000.	.122754E-41	1.8453
8000.	.110676E-35	1.9779
9000.	.272631E-30	1.9922
10000.	.205746E-25	1.9950
11000.	.519644E-21	1.9962
12000.	.470831E-17	2.0058
13000.	.161428E-13	2.0410
14000.	.217555E-10	2.0794
15000.	.117887E-07	2.1034
16000.	.258609E-05	2.1127
17000.	.227513E-03	2.1330
18000.	.782415E-02	2.2291
19000.	.101275E+00	2.5026
20000.	.480160E+00	2.9921
21000.	.905330E+00	3.5894
22000.	.998465E+00	4.2347
22880.	.100000E+01	4.6370

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
C.Yermoli/Hagler,Bailly Inc. - Arlington, VA., USA
Release: 930201 Polish Power Grid Company - PPGC - Warsaw
****

PERIOD 2 HYDROCONDITION 1

HOURLY LOADS IN MW

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	14735.4	16129.1	15678.5	15793.1	15758.3	15381.7	14254.7
2	14617.1	15940.7	15540.8	15610.9	15627.9	15314.1	13995.8
3	14591.3	15902.5	15453.8	15549.5	15552.2	15280.9	13998.3
4	14718.5	15894.9	15494.7	15575.5	15548.1	15194.1	14048.8
5	15128.2	16159.9	15712.1	15811.6	15792.2	15212.7	14156.3
6	15872.0	16552.8	16066.0	16207.4	16100.3	15053.2	13952.1
7	19541.5	20313.9	19425.7	19543.5	19322.3	15416.7	14052.2
8	20925.0	21616.6	20707.5	20766.3	20570.8	15658.6	14006.0
9	21112.0	21743.4	20800.7	20862.2	20610.0	15928.1	13886.3
10	20899.3	21448.5	20699.0	20559.7	20257.9	16159.5	14020.8
11	21257.6	21581.2	20599.0	20763.4	20331.2	16281.8	14083.9
12	21422.4	21626.3	20706.9	20785.5	20265.2	16262.1	14122.0
13	20886.7	20886.2	20101.6	20172.8	19571.4	15932.3	13985.8
14	19478.7	19472.1	18747.3	18907.0	16751.1	15619.2	13838.9
15	19811.7	19875.8	19084.9	19174.5	18656.5	15801.5	13906.4
16	20948.3	21142.8	20053.2	20216.0	19815.3	16227.2	14289.3
17	22519.9	22627.3	21645.1	21664.7	21162.9	18652.2	15025.7
18	23495.6	23526.8	22581.3	22553.8	22119.2	19577.6	15641.2
19	23519.2	23699.6	22860.8	22919.3	22265.5	19411.5	15873.4
20	23425.7	23453.2	22657.6	22690.6	22043.3	19591.2	16161.5
21	21672.9	21669.9	21025.5	21046.4	20470.3	16639.5	15591.4
22	19224.1	19455.0	18932.5	18751.0	18540.5	16164.6	15070.4
23	16705.7	16760.6	16429.7	16344.9	16165.1	15442.6	14710.1
24	16336.4	16422.9	15959.1	15982.5	15544.8	14696.9	14412.4

PERIOD 2 HYDROCONDITION 1

TOTAL HYDRO MW

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6
2	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6
3	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6
4	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6
5	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6
6	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6
7	2571.6	3351.6	2551.6	2591.6	2551.6	2551.6	2551.6
8	3971.6	4651.6	3751.6	3811.6	3611.6	2551.6	2551.6
9	4151.6	4771.6	3831.6	3891.6	3651.6	2551.6	2551.6
10	3931.6	4491.6	3731.6	3591.6	3291.6	2551.6	2551.6
11	4291.6	4611.6	3631.6	3791.9	3371.6	2551.6	2551.6
12	4451.6	4671.6	3751.6	3831.6	3311.6	2551.6	2551.6
13	3931.6	3931.6	3131.6	3211.6	2611.6	2551.6	2551.6
14	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6
15	2851.6	2911.6	2551.6	2551.6	2551.6	2551.6	2551.6
16	3991.6	4171.6	3091.6	3251.6	2851.6	2551.6	2551.6
17	5551.6	5671.6	4691.6	4711.6	4191.6	2551.6	2551.6
18	6531.6	6571.6	5611.6	5591.6	5151.6	2611.6	2551.6
19	6551.6	6671.6	5891.6	5951.6	5311.6	2551.6	2551.6
20	6471.6	6491.6	5691.6	5731.6	5071.6	2631.6	2551.6
21	4711.6	4711.6	4071.6	4091.6	3511.6	2551.6	2551.6
22	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6
23	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6
24	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6	2551.6

TOTAL HYDRO ENERGY AVAILABLE (AV.MW) 3246.8700000
TOTAL HYDRO ENERGY DISPATCHED (AV.MW) 3246.8750000

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
C.Yermoli/Hagler,Bailly Inc. - Arlington, VA., USA
Release: 930201 Polish Power Grid Company - PPGC - Warsaw
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PERIOD 2 HYDROCONDITION 1

THERMAL LOADS IN MW

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	12183.8	13577.5	13126.9	13241.5	13206.7	12830.1	11703.1
2	12065.5	13389.1	12989.2	13059.3	13076.3	12762.5	11444.2
3	12039.7	13350.9	12902.2	12997.9	13000.6	12729.3	11446.7
4	12166.9	13343.3	12943.1	13023.9	12996.5	12642.5	11497.2
5	12576.6	13608.3	13160.5	13260.0	13240.6	12661.1	11604.7
6	13320.4	14001.2	13514.4	13655.8	13548.7	12501.6	11400.5
7	16969.9	16962.3	16874.1	16951.9	16770.7	12865.1	11500.6
8	16953.4	16964.9	16955.9	16954.7	16959.2	13107.0	11454.4
9	16960.4	16971.8	16969.1	16970.6	16958.4	13376.5	11334.7
10	16967.7	16956.8	16967.4	16968.1	16966.3	13607.9	11469.2
11	16966.0	16969.5	16967.4	16971.5	16959.6	13730.2	11532.3
12	16970.8	16954.7	16955.3	16953.9	16953.6	13710.5	11570.4
13	16955.1	16954.6	16970.0	16961.2	16959.8	13380.7	11434.2
14	16927.1	16920.5	16195.7	16355.4	14199.5	13067.6	11287.3
15	16960.1	16964.2	16533.3	16622.9	16104.9	13249.9	11354.8
16	16956.7	16971.2	16961.6	16964.4	16963.7	13675.6	11737.7
17	16968.3	16955.7	16953.4	16953.0	16971.3	16100.6	12474.1
18	16963.9	16955.2	16969.7	16962.2	16967.5	16966.0	13089.6
19	16967.5	17027.9	16969.2	16967.7	16953.8	16859.9	13321.8
20	16954.0	16961.5	16965.9	16958.9	16971.7	16959.6	13609.9
21	16961.3	16958.3	16953.9	16954.8	16958.7	14087.9	13039.8
22	16672.5	16903.4	16280.9	16199.4	15988.9	13613.0	12518.8
23	14154.1	14209.0	13878.1	13793.3	13613.5	12891.0	12158.5
24	13784.8	13871.3	13407.5	13430.9	12993.2	12145.3	11860.8

PERIOD 2 HYDROCONDITION 1

HOURLY LOLP

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	.0000000	.0000002	.0000000	.0000000	.0000000	.0000000	.0000000
2	.0000000	.0000001	.0000000	.0000000	.0000000	.0000000	.0000000
3	.0000000	.0000001	.0000000	.0000000	.0000000	.0000000	.0000000
4	.0000000	.0000001	.0000000	.0000000	.0000000	.0000000	.0000000
5	.0000000	.0000003	.0000000	.0000001	.0000000	.0000000	.0000000
6	.0000001	.0000017	.0000002	.0000004	.0000002	.0000000	.0000000
7	.0135080	.0321958	.0112320	.0135351	.0094149	.0000000	.0000000
8	.0444574	.0496157	.0409007	.0419625	.0381646	.0000000	.0000000
9	.0466999	.0498759	.0425617	.0435491	.0389857	.0000001	.0000000
10	.0441021	.0490420	.0407506	.0379346	.0307981	.0000003	.0000000
11	.0479560	.0495246	.0387656	.0419248	.0326212	.0000005	.0000000
12	.0489350	.0496319	.0408891	.0422931	.0309724	.0000005	.0000000
13	.0439067	.0438989	.0268057	.0286283	.0141106	.0000001	.0000000
14	.0122468	.0121178	.0029207	.0041769	.0000041	.0000000	.0000000
15	.0195073	.0210727	.0060399	.0071877	.0023562	.0000000	.0000000
16	.0447794	.0470074	.0255549	.0297345	.0195966	.0000004	.0000000
17	.0501894	.0501806	.0496754	.0497180	.0471922	.0023321	.0000000
18	.0501870	.0501805	.0501910	.0501850	.0501548	.0142432	.0000000
19	.0501898	.0502419	.0501910	.0501899	.0501680	.0109697	.0000001
20	.0501797	.0501851	.0501884	.0501831	.0501346	.0145224	.0000003
21	.0497410	.0497325	.0457530	.0459956	.0359378	.0000025	.0000000
22	.0078877	.0117861	.0035460	.0029459	.0017695	.0000003	.0000000
23	.0000034	.0000042	.0000010	.0000007	.0000003	.0000000	.0000000
24	.0000006	.0000010	.0000001	.0000001	.0000000	.0000000	.0000000

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GPT-M Generation Planning Tools-Marginal Cost Analysis Module
C.Yermoli/Hagler,Bailly Inc. - Arlington, VA., USA
Release: 930201 Polish Power Grid Company - PPGC - Warsaw
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PERIOD 2 HYDROCONDITION 1

HOURLY LOLP AS PERCENT OF THE WEEKLY LOLP OF = .285134E+01

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	.00000	.00001	.00000	.00000	.00000	.00000	.00000
2	.00000	.00000	.00000	.00000	.00000	.00000	.00000
3	.00000	.00000	.00000	.00000	.00000	.00000	.00000
4	.00000	.00000	.00000	.00000	.00000	.00000	.00000
5	.00000	.00001	.00000	.00000	.00000	.00000	.00000
6	.00000	.00006	.00001	.00001	.00001	.00000	.00000
7	.47374	1.12915	.39392	.47469	.33019	.00000	.00000
8	1.55917	1.74009	1.43444	1.47168	1.33848	.00000	.00000
9	1.63782	1.74921	1.49269	1.52732	1.36728	.00000	.00000
10	1.54671	1.71996	1.42917	1.33041	1.08013	.00001	.00000
11	1.68188	1.73689	1.35956	1.47036	1.14407	.00002	.00000
12	1.71621	1.74065	1.43403	1.48327	1.08624	.00002	.00000
13	1.53986	1.53959	.94011	1.00403	.49488	.00000	.00000
14	.42951	.42499	.10243	.14649	.00014	.00000	.00000
15	.68414	.73904	.21183	.25208	.08263	.00000	.00000
16	1.57047	1.64861	.89624	1.04282	.68728	.00001	.00000
17	1.76020	1.75989	1.74218	1.74367	1.65509	.08179	.00000
18	1.76012	1.75989	1.76026	1.76005	1.75899	.49953	.00000
19	1.76022	1.76204	1.76026	1.76022	1.75945	.38472	.00000
20	1.75986	1.76006	1.76017	1.75998	1.75828	.50932	.00001
21	1.74448	1.74418	1.60461	1.61312	1.26038	.00009	.00000
22	.27663	.41335	.12436	.10332	.06206	.00001	.00000
23	.00012	.00015	.00003	.00002	.00001	.00000	.00000
24	.00002	.00003	.00000	.00000	.00000	.00000	.00000

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
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****

PERIOD 2 HYDROCONDITION 1

HOURLY MARGINAL GENERATION COST IN $/MWH

HOUR	1 MON	2 TUE	3 WED	4 THU	5 FRI	6 SAT	7 SUN
1	2.01	2.07	2.05	2.05	2.05	2.04	2.01
2	2.01	2.06	2.04	2.05	2.05	2.03	2.00
3	2.01	2.06	2.04	2.04	2.04	2.03	2.00
4	2.01	2.06	2.04	2.05	2.04	2.03	2.00
5	2.03	2.07	2.05	2.06	2.05	2.03	2.00
6	2.06	2.03	2.07	2.07	2.07	2.02	2.00
7	2.16	2.18	2.16	2.16	2.15	2.04	2.00
8	2.20	2.22	2.20	2.20	2.19	2.05	2.00
9	2.21	2.23	2.20	2.20	2.19	2.06	2.00
10	2.20	2.2[illegible]	2.20	2.19	2.18	2.07	2.00
11	2.21	2.22	2.19	2.20	2.18	2.07	2.00
12	2.22	2.22	2.20	2.20	2.18	2.07	2.00
13	2.20	2.20	2.18	2.18	2.16	2.06	2.00
14	2.16	2.16	2.13	2.13	2.09	2.05	2.00
15	2.17	2.17	2.14	2.14	2.13	2.06	2.00
16	2.20	2.21	2.18	2.18	2.17	2.07	2.01
17	2.25	2.26	2.22	2.23	2.21	2.13	2.02
18	2.26	2.26	2.26	2.25	2.24	2.16	2.05
19	2.26	2.26	2.26	2.26	2.25	2.16	2.06
20	2.26	2.26	2.26	2.26	2.24	2.16	2.07
21	2.23	2.23	2.20	2.21	2.19	2.08	2.05
22	2.15	2.16	2.13	2.13	2.12	2.07	2.02
23	2.09	2.09	2.08	2.08	2.07	2.04	2.01
24	2.07	2.08	2.06	2.06	2.04	2.01	2.01

GPT-M Generation Planning Tools-Marginal Cost Analysis Module
C.Yermoli/Hagler,Bailly Inc. - Arlington, VA., USA
Release: 930201 Polish Power Grid Company - PPGC - Warsaw
****

WINTER SEASON - NOVEMBER TO APRIL
MORNING PEAK PRICING PERIOD
NO. OF WEEKLY HOURS= 30.00
AVERAGE WEEKLY MARGINAL COST (CENTS/KWH)= 2.20

WINTER SEASON - NOVEMBER TO APRIL
EVENING PEAK PRICING PERIOD
NO. OF WEEKLY HOURS= 25.00
AVERAGE WEEKLY MARGINAL COST (CENTS/KWH)= 2.24

WINTER SEASON - NOVEMBER TO APRIL
OFF PEAK PRICING PERIOD
NO. OF WEEKLY HOURS= 113.00
AVERAGE WEEKLY MARGINAL COST (CENTS/KWH)= 2.07

Appendix 6.1
Evaluation Case Expansion for Avoided Cost Estimate

POLAND - ELECTRICTY PRICING STUDY - 1992
POLISH POWER GRID COMPANY - POLSKIE SIECI ELEKTROENERGETYCZNE

FILE: P4001.GSU (SEE FILE P4001.GDE FOR FULL DETAILS)

EVALUATION CASE EXPANSION FOR AVOIDED COST ESTIMATE

EXCLUDES ALL RESOURCES UNDER EVALUATION, CHP, SMALL HYDRO AND AUTOPRODUCERS

LIMITED RESOURCES DENOTE "ENERGY LIMITED" AND INCLUDE ALL CHP, ALL HYDROELECTRIC AND ALL AUTOPRODUCERS.

ECONOMIC RESOURCES DENOTE RESOURCES DISPATCHED IN ORDER OF ECONOMIC VARIABLE COSTS AND INCLUDE ALL OTHER PLANTS.

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1992	22024.0	125018.8	27.74	.14	.00	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	1330.	326.7	.0	14.4	.0	.0	14.4	.0	13.6	.0	.0	13.6
ECONOMIC	26803.	124690.6	233.1	481.8	.0	2465.8	3180.8	220.3	455.3	.0	2330.0	3005.6
TOTAL	28133.	125017.3	233.1	496.2	.0	2465.8	3195.2	220.3	468.9	.0	2330.0	3019.1

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1993	22922.2	127117.3	27.42	.07	.00	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	1330.	1844.4	.0	14.4	.0	.0	14.4	.0	25.7	.0	.0	25.7
ECONOMIC	26986.	125270.7	276.1	481.1	.0	2539.6	3296.8	453.2	861.2	.0	4472.5	5787.0
TOTAL	28316.	127115.1	276.1	495.5	.0	2539.6	3311.1	453.2	886.9	.0	4472.5	5812.7

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1994	22533.3	129686.5	27.85	.40	.00	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	1330.	358.9	.0	14.4	.0	.0	14.4	.0	36.5	.0	.0	36.5
ECONOMIC	27478.	129327.4	300.6	486.7	.0	2665.2	3452.5	679.7	1227.8	.0	6480.2	8387.7
TOTAL	28808.	129686.3	300.6	501.0	.0	2665.2	3466.9	679.7	1264.3	.0	6480.2	8424.2

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1995	23006.5	133417.6	27.76	.31	.00	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	1330.	208.4	.0	14.4	.0	.0	14.4	.0	46.2	.0	.0	46.2
ECONOMIC	28062.	133208.7	300.6	495.4	.0	2747.6	3543.6	881.9	1561.0	.0	8328.1	10771.0
TOTAL	29392.	133417.1	300.6	509.8	.0	2747.6	3558.0	881.9	1607.2	.0	8328.1	10817.2

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1996	23121.6	136110.1	27.91	.33	.00	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	1330.	204.8	.0	14.4	.0	.0	14.4	.0	54.8	.0	.0	54.8
ECONOMIC	28245.	135905.0	276.1	497.1	.0	2777.6	3550.8	1047.7	1859.5	.0	9996.1	12903.3
TOTAL	29575.	136109.8	276.1	511.5	.0	2777.6	3565.1	1047.7	1914.3	.0	9996.1	12958.1

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1997	23699.6	139720.5	27.97	.42	.00	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	1330.	173.9	.0	14.4	.0	.0	14.4	.0	62.5	.0	.0	62.5
ECONOMIC	28999.	139546.6	288.4	505.3	.0	2864.5	3658.2	1202.3	2130.4	.0	11531.9	14864.7
TOTAL	30329.	139720.4	288.4	519.7	.0	2864.5	3672.6	1202.3	2192.9	.0	11531.9	14927.2

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1998	24221.0	143430.9	26.80	.13	.00	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	2080.	1124.0	134.7	22.5	.0	.0	157.1	64.5	73.3	.0	.0	137.7
ECONOMIC	28632.	142305.5	288.4	496.1	.0	2987.7	3772.2	1340.4	2367.9	.0	12962.2	16670.5
TOTAL	30712.	143429.5	423.0	518.5	.0	2987.7	3929.3	1404.8	2441.2	.0	12962.2	16808.2

YEAR PEAK (MW) LOAD (GWH) ICR(%) TECR(%) EUE (%) LOLP (%)
1999 24802.3 147090.5 26.67 .22 .00 .00

RESOURCE	MW	GWH	COST IN MILLIONS CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	ACCUMULATED DISCOUNTED COST CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	2080.	1088.3	134.7	22.5	.0	.0	157.1	122.0	82.9	.0	.0	204.9
ECONOMIC	29336.	146001.2	325.2	503.9	.0	3136.7	3965.8	1479.3	2583.3	.0	14303.0	18365.6
TOTAL	31416.	147089.4	459.8	526.4	.0	3136.7	4122.9	1601.4	2666.2	.0	14303.0	18570.5

YEAR PEAK (MW) LOAD (GWH) ICR(%) TECR(%) EUE (%) LOLP (%)
2000 25323.1 151066.7 26.35 .10 .00 .00

RESOURCE	MW	GWH	COST IN MILLIONS CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	ACCUMULATED DISCOUNTED COST CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	2080.	1050.4	134.7	22.5	.0	.0	157.1	173.4	91.4	.0	.0	264.8
ECONOMIC	29916.	150014.3	349.7	510.1	.0	3293.1	4153.0	1612.8	2778.0	.0	15559.7	19950.5
TOTAL	31996.	151064.7	484.4	532.6	.0	3293.1	4310.1	1786.2	2869.4	.0	15559.7	20215.4

YEAR PEAK (MW) LOAD (GWH) ICR(%) TECR(%) EUE (%) LOLP (%)
2001 25399.1 149072.5 26.55 .36 .00 .00

RESOURCE	MW	GWH	COST IN MILLIONS CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	ACCUMULATED DISCOUNTED COST CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	2080.	1023.9	134.7	22.5	.0	.0	157.1	219.3	99.1	.0	.0	318.4
ECONOMIC	30062.	148048.3	368.1	509.2	.0	3276.2	4153.5	1738.2	2951.5	.0	16676.1	21365.8
TOTAL	32142.	149072.2	502.8	531.7	.0	3276.2	4310.6	1957.5	3050.6	.0	16676.1	21684.2

YEAR PEAK (MW) LOAD (GWH) ICR(%) TECR(%) EUE (%) LOLP (%)
2002 25983.3 153184.0 26.42 .35 .00 .00

RESOURCE	MW	GWH	COST IN MILLIONS CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	ACCUMULATED DISCOUNTED COST CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	2080.	986.1	134.7	22.5	.0	.0	157.1	260.3	105.9	.0	.0	366.2
ECONOMIC	30767.	152197.6	411.1	524.2	.0	3493.2	4428.4	1863.3	3111.0	.0	17738.8	22713.1
TOTAL	32847.	153183.6	545.7	546.6	.0	3493.2	4535.5	2123.6	3216.9	.0	17738.8	23079.3

YEAR PEAK (MW) LOAD (GWH) ICR(%) TECR(%) EUE (%) LOLP (%)
2003 26580.9 157638.6 26.30 .02 .00 .00

RESOURCE	MW	GWH	COST IN MILLIONS CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	ACCUMULATED DISCOUNTED COST CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	2080.	960.3	134.7	22.5	.0	.0	157.1	296.8	112.0	.0	.0	408.9
ECONOMIC	31492.	156675.0	560.5	541.0	.0	3603.5	4705.1	2015.6	3257.9	.0	18717.7	23991.2
TOTAL	33572.	157635.4	695.2	563.5	.0	3603.5	4862.2	2312.4	3370.0	.0	18717.7	24400.0

YEAR PEAK (MW) LOAD (GWH) ICR(%) TECR(%) EUE (%) LOLP (%)
2004 27192.3 161978.9 26.80 .11 .00 .00

RESOURCE	MW	GWH	COST IN MILLIONS CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	ACCUMULATED DISCOUNTED COST CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	2080.	914.5	134.7	22.5	.0	.0	157.1	329.5	117.5	.0	.0	447.0
ECONOMIC	32399.	161062.3	849.6	553.1	.0	3594.7	4997.4	2221.6	3392.1	.0	19589.5	25203.2
TOTAL	34479.	161976.8	984.3	575.6	.0	3594.7	5154.5	2551.1	3509.6	.0	19589.5	25650.2

YEAR PEAK (MW) LOAD (GWH) ICR(%) TECR(%) EUE (%) LOLP (%)
2005 27817.7 166435.5 27.06 .09 .00 .00

RESOURCE	MW	GWH	COST IN MILLIONS CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	ACCUMULATED DISCOUNTED COST CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	2080.	879.3	134.7	22.5	.0	.0	157.1	358.7	122.3	.0	.0	481.0
ECONOMIC	33266.	165554.3	1089.3	561.2	.0	3605.0	5255.4	2457.5	3513.6	.0	20370.2	26341.3
TOTAL	35346.	166433.6	1223.9	583.6	.0	3605.0	5412.6	2816.2	3635.9	.0	20370.2	26822.3

YEAR PEAK (MW) LOAD (GWH) ICR(%) TECR(%) EUE (%) LOLP (%)
2006 28457.5 171011.3 27.16 03 .00 .00

RESOURCE	MW	GWH	COST IN MILLIONS CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	ACCUMULATED DISCOUNTED COST CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	2080.	823.8	134.7	22.5	.0	.0	157.1	384.7	126.7	.0	.0	511.4
ECONOMIC	34106.	170185.0	1266.5	573.8	.0	3680.5	5520.8	2702.4	3624.5	.0	21081.8	27408.7
TOTAL	36186.	171008.8	1401.2	596.2	.0	3680.5	5677.9	3087.1	3751.2	.0	21081.8	27920.1

YEAR PEAK (MW) LOAD (GWH) ICR(%) TECR(%) EUE (%) LOLP (%)
2007 29112.0 175709.7 27.17 .04 .00 .00

RESOURCE	MW	GWH	COST IN MILLIONS CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	ACCUMULATED DISCOUNTED COST CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	2080.	777.8	134.7	22.5	.0	.0	157.1	407.9	130.6	.0	.0	538.5
ECONOMIC	34942.	174929.3	1278.8	592.3	.0	3821.4	5692.5	2923.1	3726.8	.0	21741.5	28391.4
TOTAL	37022.	175707.1	1413.4	614.7	.0	3821.4	5849.6	3331.1	3857.3	.0	21741.5	28929.9

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
2008	29781.6	180533.6	27.32	.08	.00	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	2080.	710.7	134.7	22.5	.0	.0	157.1	428.7	134.0	.0	.0	562.7
ECONOMIC	35838.	179820.8	1381.3	609.9	.0	3910.7	5901.8	3136.0	3820.8	.0	22344.3	29301.1
TOTAL	37918.	180531.5	1515.9	632.3	.0	3910.7	6058.9	3564.7	3954.8	.0	22344.3	29863.8

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
2009	30466.6	185219.7	27.61	.09	.00	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	2080.	681.2	134.7	22.5	.0	.0	157.1	447.2	137.1	.0	.0	584.3
ECONOMIC	36798.	184536.5	1620.9	624.3	.0	3933.4	6178.6	3359.1	3906.7	.0	22885.6	30151.4
TOTAL	38878.	185217.7	1755.6	646.7	.0	3933.4	6335.8	3806.3	4043.8	.0	22885.6	30735.7

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
2010	31167.3	190025.8	27.82	.16	.00	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	2080.	629.6	134.7	22.5	.0	.0	157.1	463.8	139.9	.0	.0	603.6
ECONOMIC	37758.	189394.9	1804.3	638.7	.0	4018.7	6461.7	3580.8	3985.2	.0	23379.4	30945.4
TOTAL	39838.	190024.5	1938.9	661.1	.0	4016.7	6618.8	4044.6	4125.1	.0	23379.4	31549.0

Appendix 6.2
Base Case Expansion for Avoided Cost Estimate

POLAND - ELECTRICTY PRICING STUDY - 1992
POLISH POWER GRID COMPANY - POLSKIE SIECI ELEKTROENERGETYCZNE

FILE: P4000.GSU (SEE FILE P4000.GDE FOR FULL DETAILS)

BASE CASE EXPANSION FOR AVOIDED COST ESTIMATE

LIMITED RESOURCES DENOTE "ENERGY LIMITED" AND INCLUDE ALL CHP, ALL HYDROELECTRIC AND ALL AUTOPRODUCERS.

ECONOMIC RESOURCES DENOTE RESOURCES DISPATCHED IN ORDER OF ECONOMIC VARIABLE COSTS AND INCLUDE ALL OTHER PLANTS.

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1992	22024.0	125018.8	32.96	1.05	.00	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	7041.	14630.2	.0	60.0	7.2	.0	67.2	.0	56.7	6.8	.0	63.5
ECONOMIC	22243.	110388.6	.0	413.4	.0	2037.6	2451.1	.0	390.7	.0	1925.4	2316.1
TOTAL	29284.	125018.8	.0	473.4	7.2	2037.6	2518.3	.0	447.3	6.8	1925.4	2379.5

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1993	22222.2	127117.3	31.75	.14	.10	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	7091.	16477.8	.0	60.0	7.2	.0	67.2	.0	107.3	12.9	.0	120.2
ECONOMIC	22186.	110514.3	30.7	409.1	.0	2078.1	2517.9	25.9	735.8	.0	3678.6	4440.3
TOTAL	29277.	126992.0	30.7	469.1	7.2	2078.1	2585.1	25.9	843.1	12.9	3678.6	4560.5

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1994	22533.3	129686.5	31.49	.08	.14	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	7191.	15658.3	.0	60.0	7.2	.0	67.2	.0	152.5	18.3	.0	170.8
ECONOMIC	22438.	113847.8	42.9	411.1	.0	2161.1	2615.1	58.2	1045.5	.0	5306.5	6410.2
TOTAL	29629.	129506.2	42.9	471.1	7.2	2161.1	2682.3	58.2	1197.9	18.3	5306.5	6581.0

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1995	23006.5	133417.6	31.45	.32	.03	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	7341.	16494.7	.0	60.0	7.2	.0	67.2	.0	192.8	23.2	.0	216.0
ECONOMIC	22902.	116881.6	36.8	418.0	.0	2211.1	2665.9	83.0	1326.6	.0	6793.6	8203.2
TOTAL	30243.	133376.3	36.8	478.0	7.2	2211.1	2733.1	83.0	1519.4	23.2	6793.6	8419.2

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1996	23121.6	136110.1	31.89	.93	.00	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	7531.	17786.9	.0	60.0	7.2	.0	67.2	.0	228.8	27.5	.0	256.3
ECONOMIC	22965.	118323.3	6.1	417.9	.0	2199.2	2623.3	86.7	1577.6	.0	8114.3	9778.5
TOTAL	30496.	136110.2	6.1	477.9	7.2	2199.2	2690.5	86.7	1806.4	27.5	8114.3	10034.8

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1997	23699.6	139720.5	31.77	1.62	.00	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	7871.	20024.4	.0	60.0	7.2	.0	67.2	.0	261.0	31.4	.0	292.3
ECONOMIC	23359.	119696.0	.0	420.7	.0	2216.5	2637.2	86.7	1803.1	.0	9302.7	11192.5
TOTAL	31230.	139720.4	.0	480.7	7.2	2216.5	2704.4	86.7	2064.1	31.4	9302.7	11484.9

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1998	24221.0	143430.9	32.34	1.50	.00	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	9061.	23892.4	134.7	68.1	7.2	.0	209.9	64.5	293.6	34.8	.0	392.8
ECONOMIC	22992.	119538.5	.0	411.5	.0	2211.2	2622.7	86.7	2000.1	.0	10361.3	12448.1
TOTAL	32053.	143430.9	134.7	479.5	7.2	2211.2	2832.6	151.1	2293.7	34.8	10361.3	12840.9

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
1999	24802.3	147090.5	30.54	.23	.06	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	9161.	24516.8	134.7	68.1	7.2	.0	209.9	122.0	322.6	37.9	.0	482.6
ECONOMIC	23216.	122478.5	12.3	412.1	.0	2289.7	2714.0	91.9	2176.3	.0	11339.9	13608.1
TOTAL	32377.	146995.3	146.9	480.2	7.2	2289.7	2924.0	213.9	2498.9	37.9	11339.9	14090.7

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
2000	25323.1	151066.7	29.83	.08	.11	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	9681.	27952.1	134.7	68.1	7.2	.0	209.9	173.4	348.6	40.6	.0	562.7
ECONOMIC	23196.	122941.2	6.1	409.3	.0	2293.0	2708.5	94.3	2332.5	.0	12215.0	14641.8
TOTAL	32877.	150893.3	140.8	477.4	7.2	2293.0	2918.4	267.7	2681.1	40.6	12215.0	15204.5

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
2001	25399.1	149072.5	29.78	.77	.00	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	9981.	29954.9	134.7	68.1	7.2	.0	209.9	219.3	371.8	43.1	.0	634.2
ECONOMIC	22982.	119117.6	6.1	403.0	.0	2210.7	2619.8	96.4	2469.8	.0	12968.3	15534.5
TOTAL	32963.	149072.5	140.8	471.1	7.2	2210.7	2829.8	315.6	2841.6	43.1	12968.3	16168.7

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
2002	25983.3	153184.0	28.88	.32	.03	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	10281.	31906.4	134.7	68.1	7.2	.0	209.9	260.3	392.5	45.3	.0	698.1
ECONOMIC	23207.	121234.2	24.5	410.8	.0	2300.6	2735.9	103.8	2594.8	.0	13668.2	16366.8
TOTAL	33488.	153140.5	159.2	478.8	7.2	2300.6	2945.8	364.1	2987.3	45.3	13668.2	17064.9

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
2003	26580.9	157638.6	28.04	.04	.14	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	10581.	33884.4	134.7	68.1	7.2	.0	209.9	296.8	411.0	47.3	.0	755.1
ECONOMIC	23452.	123529.7	36.8	420.4	.0	2384.4	2841.6	113.8	2709.0	.0	14315.9	17138.7
TOTAL	34033.	157414.1	171.5	488.5	7.2	2384.4	3051.5	410.7	3120.0	47.3	14315.9	17893.8

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
2004	27192.3	161978.9	27.83	.40	.03	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	10881.	35785.4	134.7	68.1	7.2	.0	209.9	329.5	427.5	49.0	.0	806.0
ECONOMIC	23879.	126141.8	67.5	425.3	.0	2502.2	2995.0	130.2	2812.1	.0	14922.8	17865.1
TOTAL	34760.	161927.2	202.1	493.4	7.2	2502.2	3204.9	459.7	3239.7	49.0	14922.8	18671.1

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
2005	27817.7	166435.5	26.99	.12	.12	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	11181.	37808.7	134.7	68.1	7.2	.0	209.9	358.7	442.3	50.6	.0	851.5
ECONOMIC	24146.	128415.6	85.9	424.4	.0	2584.9	3095.2	148.8	2904.0	.0	15482.5	18535.4
TOTAL	35327.	166224.2	220.6	492.5	7.2	2584.9	3305.1	507.4	3346.3	50.6	15482.5	19386.9

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
2006	28457.5	171011.3	26.88	.54	.00	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	11481.	39720.3	134.7	68.1	7.2	.0	209.9	384.7	455.4	52.0	.0	892.1
ECONOMIC	24626.	131291.1	110.4	431.6	.0	2710.7	3252.7	170.1	2987.5	.0	16006.7	19164.3
TOTAL	36107.	171011.4	245.1	499.7	7.2	2710.7	3462.7	554.8	3442.9	52.0	16006.7	20056.4

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
2007	29112.0	175709.7	26.28	.06	.16	.00

			COST IN MILLIONS					ACCUMULATED DISCOUNTED COST				
RESOURCE	MW	GWH	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	11781.	41688.6	134.7	68.1	7.2	.0	209.9	407.9	467.2	53.2	.0	928.3
ECONOMIC	24982.	133743.0	154.5	442.9	.0	2688.3	3285.7	196.8	3063.9	.0	16470.7	19731.5
TOTAL	36763.	175431.6	289.1	511.0	7.2	2688.3	3495.6	604.7	3531.1	53.2	16470.7	20659.8

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
2008	29781.6	180533.6	25.85	.09	.13	.00

RESOURCE	MW	GWH	COST IN MILLIONS CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	ACCUMULATED DISCOUNTED COST CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	12081.	43608.6	134.7	68.1	7.2	.0	209.9	428.7	477.7	54.3	.0	960.7
ECONOMIC	25398.	136685.0	98.2	453.3	.0	2821.2	3372.6	211.9	3133.8	.0	16905.6	20251.3
TOTAL	37479.	180293.6	232.8	521.4	7.2	2821.2	3582.6	640.6	3611.5	54.3	16905.6	21212.0

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
2009	30466.6	185219.7	25.58	.05	.13	.00

RESOURCE	MW	GWH	COST IN MILLIONS CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	ACCUMULATED DISCOUNTED COST CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	12381.	45539.2	134.7	68.1	7.2	.0	209.9	447.2	487.1	55.3	.0	989.6
ECONOMIC	25878.	139431.9	200.7	460.5	.0	2868.0	3529.2	239.6	3197.2	.0	17300.3	20737.0
TOTAL	38259.	184971.0	335.3	528.6	7.2	2868.0	3739.1	686.8	3684.2	55.3	17300.3	21726.6

YEAR	PEAK (MW)	LOAD (GWH)	ICR(%)	TECR(%)	EUE (%)	LOLP (%)
2010	31167.3	190025.8	25.42	.07	.12	.00

RESOURCE	MW	GWH	COST IN MILLIONS CAPITAL	F.O&M	V.O&M	FUEL	TOTAL	ACCUMULATED DISCOUNTED COST CAPITAL	F.O&M	V.O&M	FUEL	TOTAL
LIMITED	12851.	48822.0	182.1	69.9	7.2	.0	259.2	469.6	495.6	56.2	.0	1021.4
ECONOMIC	26238.	140978.3	353.3	465.9	.0	2809.0	3628.2	283.0	3254.4	.0	17645.4	21182.8
TOTAL	39089.	189800.3	535.4	535.8	7.2	2809.0	3887.4	752.6	3750.1	56.2	17645.4	22204.3

Appendix 7.1
Network Investment Plan

PPGC NETWORK INVESTMENT PLAN (as of December 1992)

No.	Investment	Year of commission	Foreign Cost (%)	Voltage Level	Spent in 1992	To spend in years 1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
					Investment program (bln PZL prices 1992)										
1	2	3	4	5	8	9	10	11	12	13	14	15	16	17	18
7	Const. 400kV sgl-circ. Gdańsk – Olsztyn line	1993	20%	VHV	98.0	40.0									
11	Const. 400kV sgl-circ. Nur – Narew line	1993	20%	VHV	98.0	17.0									
10	Const. 400kV sgl-circ. Mi³osna – Nur line	1993	20%	VHV	135.0	101.0									
42	Const. 220kV sgl-circ. Wrzosowa – Joachimów line	1994	20%	VHV			39.0								
55	Const. 400kV sgl-circ. Mikułowa – Kiesdorf (Germany) line	1995	20%	VHV			20.0	26.0							
28	Ext. and mod. of the 400/220kV Grudziądz s/s	1995	35%	VHV			50.0	61.0							
51	Const. 400kV sgl-circ. Mikułowa – Babilon line	1995	20%	VHV				57.0							
43	Const. 220kV sgl-circ. Krajnik – Pomorzany line	1996	20%	VHV				10.0	25.0						
16	Const. 400kV dbl-circ. Ostrów – Plewiska line	1996	20%	VHV			120.0	250.0	166.0						
19	Const. 400kV dbl-circ. Dobrzeń – Wielopole line	1996	20%	VHV			150.0	300.0	150.0						
13	Const. 400kV dbl-circ. Broszęcin – Ostrów line	1996	20%	VHV				200.0	327.0						
20	Const. 400kV sgl-circ. Dobrzeń – wiebodzice line	1997	20%	VHV				90.0	200.0	156.0					
50	Const. 400kV dbl-circ. Krajnik – Neuenmagen (Germany) line	1997	20%	VHV											
52	Const. 400kV sgl-circ. Krosno – Lemieszany (Slovakia) line	1998	20%	VHV					42.0	50.0	50.0				
22	Const. 400kV sgl-circ. wiebodzice – Czarna line	1999	20%	VHV							80.0	136.0			
33	Const. 220kV sgl-circ. Olsztyn – Mątki – Olsztyn I line	2000	20%	VHV									27.0		
24	Ext. 750/400/110kV Widełka s/s	2000	35%	VHV									8.0		
25	Const. 400kV sgl-circ. Widełka – Mokre line	2000	20%	VHV							70.0	180.0	144.0		
45	Const. 220kV single circuit Glinki – Rec³aw line	2000	20%	VHV								35.0	44.0		
29	Const. 400kV sgl-circ. E³k – Narew line	2001	20%	VHV								50.0	140.0	140.0	
53	Const. 400kV sgl-circ. E³k – Alytus (Lituania) line	2001	20%	VHV								60.0	120.0	120.0	
54	Back to back HV DC in 750/400/110kV Widełka s/s	2002	35%	VHV			700.0	700.0	700.0			700.0	700.0	700.0	
31	Const. 400kV sgl-circ. Olsztyn – E³k line	2002	20%	VHV									60.0	200.0	196.0
8	Ext. 400/110kV Gdańsk B³onia s/s	1992	35%	HV	13.0										
6	Const. 400/110kV Olsztyn Mątki s/s	1992	35%	HV											
9	Ext. 400/220/110kV Mi³osna s/s	1993	35%	HV	23.0	52.0									
12	Const. 400/110kV Narew s/s	1993	35%	HV	102.0	64.0									
27	Ext. 220/110kV E³k s/s	1993	35%	HV	5.0	2.0									
35	Ext. 220/110kV Zgierz Antoniew s/s	1993	35%	HV	20.0	14.0									
40	Reactor installation in 400/110kV P³ock s/s	1994	35%	HV		7.0	18.0								
41	Ext. 220kV Wrzosowa s/s	1994	35%	HV			14.0								
36	Const. 400/110kV Mocisko s/s	1994	35%	HV											
38	Ext. 220/110kV s/s in Kozienice Power Plant	1995	35%	HV				5.0							
14	Const. 400/110kV Ostrów s/s	1995	35%	HV		50.0	85.0	62.0							
37	Const. 220/110kV Siedlce s/s	1995	35%	HV		18.0	60.0	40.0							
15	Ext. 400/110kV Pasikurowice s/s	1995	35%	HV		20.0	40.0	30.0							
39	Const. 220/110kV Kawęczyn s/s with 220kV line incoming	1996	35%	HV			10.0	20.0	16.0						
18	Ext. 400/110kV Dobrzeń s/s	1996	35%	HV											
47	Const. 220/110kV Pomorzany s/s	1996	35%	HV				15.0	24.0						
46	Ext. 220/110kV Krajnik s/s	1996	35%	HV					5.0						
17	Ext. 400/220/110kV Plewiska s/s	1996	35%	HV				40.0	54.0						
21	Const. 400/220/110kV wiebodzice s/s	1997	35%	HV				50.0	120.0	43.0					
49	Const. 220/110kV Wrzenia s/s	1997	35%	HV					24.0	39.0					
23	Ext. 400/110kV Czarna s/s	1999	35%	HV							5.0	5.0			
32	Ext. 400/110kV Olsztyn – Mątki s/s (220kV s/s)	2000	35%	HV								46.0	80.0		
34	Ext. 220/110kV Olsztyn I s/s	2000	35%	HV									5.0		
44	Const. 220/110kV Rec³aw s/s	2000	35%	HV								15.0	24.0		
46	Ext. 220/110kV Glinki s/s	2000	35%	HV									5.0		
26	Const. 400/110kV Mokre s/s and mod. of the 220kV s/s	2000	35%	HV							20.0	50.0	50.0		
30	Const. 400/110kV E³k s/s	2001	35%	HV									64.0	100.0	
3	Const. fiber optic wire telecomm. systems on existing HV lines	2002	70%	HV		200.0	250.0	250.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
PSE INVESTMENT PROGRAM				TOTAL	494.0	565.0	1556.0	2206.0	1993.0	428.0	365.0	1419.0	1811.0	1400.0	336.0
				VHV	331.0	158.0	1079.0	1694.0	1610.0	206.0	200.0	1161.0	1243.0	1160.0	196.0
				HV	163.0	427.0	477.0	512.0	383.0	222.0	165.0	258.0	368.0	240.0	140.0

DISTRIBUTION NETWORK INVESTMENTS
(WITHOUT INFLATION & IDC)

	Start Constr	Date of Comm'n	Length/ S/S MVA	TOTAL PROJECT COST 1/ (10^9 1991 Zloty) TOTAL	LOCAL 2/	FOREIGN 3/	TOTAL PROJECT COST (10^9 1992 Zloty) 4/ TOTAL	LOCAL	FOREIGN	1992 TOTAL	1992 LOCAL	1992 FOREIGN	1993 TOTAL	1993 LOCAL	1993 FOREIGN
HV: 60 to 220 KV															
110 kV Lines	1991	1992	283	198.1	168.4	29.7	268.4	232.4	36.0	152.2	116.2	36.0	0.0	0.0	0.0
110 kV Lines	1992	1993	280	196.0	166.6	29.4	265.5	229.9	35.6	115.0	115.0	0.0	150.6	115.0	35.6
110 kV Lines	1993	1994	290	203.0	172.6	30.5	275.0	238.1	36.9	0.0	0.0	0.0	119.1	119.1	0.0
110 kV Lines	1994	1995	290	203.0	172.6	30.5	275.0	238.1	36.9	0.0	0.0	0.0	0.0	0.0	0.0
110 kV Lines	1995	1996	430	301.0	255.9	45.2	407.6	353.1	54.7	0.0	0.0	0.0	0.0	0.0	0.0
110 kV Lines	1996	1997	430	301.0	255.9	45.2	407.6	353.1	54.7	0.0	0.0	0.0	0.0	0.0	0.0
110 kV Lines	1997	1998	440	308.0	261.8	46.2	417.3	361.3	56.0	0.0	0.0	0.0	0.0	0.0	0.0
110 kV Lines	1998	1999	450	315.0	267.8	47.3	426.8	369.5	57.3	0.0	0.0	0.0	0.0	0.0	0.0
110 kV Lines	1999	2000	450	315.0	267.8	47.3	426.8	369.5	57.3	0.0	0.0	0.0	0.0	0.0	0.0
110 kV Lines	2000	2001	450	315.0	267.8	47.3	426.8	369.5	57.3	0.0	0.0	0.0	0.0	0.0	0.0
MV: 1 to 60 KV															
s/s 110 kV / MV	1992	1992	18	376.0	321.3	56.7	512.1	443.4	68.7	512.1	443.4	68.7	0.0	0.0	0.0
s/s 110 kV / MV	1993	1993	19	399.0	339.2	59.9	540.6	468.0	72.5	0.0	0.0	0.0	540.6	468.0	72.5
s/s 110 kV / MV	1994	1994	19	399.0	339.2	59.9	540.6	468.0	72.5	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 kV / MV	1995	1995	20	420.0	357.0	63.0	569.0	492.7	76.3	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 kV / MV	1996	1996	16	336.0	285.6	50.4	455.2	394.1	61.1	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 kV / MV	1997	1997	17	357.0	303.5	53.6	483.7	418.8	64.9	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 kV / MV	1998	1998	17	357.0	303.5	53.6	483.7	418.8	64.9	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 kV / MV	1999	1999	17	357.0	303.5	53.6	483.7	418.8	64.9	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 kV / MV	2000	2000	18	378.0	321.3	56.7	512.1	443.4	68.7	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 kV / MV	2001	2001	18	378.0	321.3	56.7	512.1	443.4	68.7	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	1992	1992	1047	183.2	155.7	27.5	248.2	214.9	33.3	248.2	214.9	33.3	0.0	0.0	0.0
MV Overhead Lines	1993	1993	1060	189.0	160.7	28.4	256.1	221.7	34.4	0.0	0.0	0.0	256.1	221.7	34.4
MV Overhead Lines	1994	1994	1030	180.3	153.2	27.0	244.2	211.4	32.8	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	1995	1995	1070	187.3	159.2	28.1	253.7	219.6	34.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	1996	1996	1700	297.5	252.9	44.6	403.0	349.0	54.1	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	1997	1997	1700	297.5	252.9	44.6	403.0	349.0	54.1	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	1998	1998	1700	297.5	252.9	44.6	403.0	349.0	54.1	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	1999	1999	1670	292.3	248.4	43.8	395.9	342.8	53.1	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	2000	2000	1730	302.8	257.3	45.4	410.2	355.1	55.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	2001	2001	1730	302.8	257.3	45.4	410.2	355.1	55.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	1992	1992	877	438.5	372.7	65.8	594.1	514.4	79.7	594.1	514.4	79.7	0.0	0.0	0.0
MV Cables	1993	1993	870	435.0	369.8	65.3	589.3	510.3	79.1	0.0	0.0	0.0	589.3	510.3	79.1
MV Cables	1994	1994	870	435.0	369.8	65.3	589.3	510.3	79.1	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	1995	1995	930	465.0	395.3	69.8	630.0	545.4	84.5	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	1996	1996	1300	650.0	552.5	97.5	880.8	762.5	118.2	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	1997	1997	1400	700.0	595.0	105.0	948.3	821.1	127.2	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	1998	1998	1400	700.0	595.0	105.0	948.3	821.1	127.2	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	1999	1999	1460	730.0	620.5	109.5	989.0	856.3	132.7	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	2000	2000	1440	720.0	612.0	108.0	975.4	844.6	130.9	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	2001	2001	1440	720.0	612.0	108.0	975.4	844.6	130.9	0.0	0.0	0.0	0.0	0.0	0.0

DISTRIBUTION NETWORK INVESTMENTS
(WITHOUT INFLATION & IDC)

	Start Constr	Date of Comm's'n	Length/ S/S MVA	TOTAL PROJECT COST 1/ (10^9 1991 Zloty) TOTAL	LOCAL 2/	FOREIGN 3/	TOTAL PROJECT COST (10^9 1992 Zloty) 4/ TOTAL	LOCAL	FOREIGN	1992 TOTAL	LOCAL	FOREIGN	1993 TOTAL	LOCAL	FOREIGN
LV: Less than 1 KV															
s/s MV / LV	1992	1992	3047	298.6	253.8	44.8	404.5	350.3	54.3	404.5	350.3	54.3	0.0	0.0	0.0
s/s MV / LV	1993	1993	3090	302.8	257.4	45.4	410.3	355.2	55.0	0.0	0.0	0.0	410.3	355.2	55.0
s/s MV / LV	1994	1994	3140	307.7	261.6	46.2	416.9	361.0	55.9	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	1995	1995	3190	312.6	265.7	46.9	423.5	366.7	56.8	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	1996	1996	3290	322.4	274.1	48.4	436.8	378.2	58.6	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	1997	1997	3350	328.3	279.1	49.2	444.8	385.1	59.7	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	1998	1998	3400	333.2	283.2	50.0	451.4	390.8	60.6	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	1999	1999	3450	338.1	287.4	50.7	458.0	396.6	61.5	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	2000	2000	3510	344.0	292.4	51.6	466.0	403.5	62.5	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	2001	2001	3510	344.0	292.4	51.6	466.0	[illegible]	62.5	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	1992	1992	2289	366.2	311.3	54.9	496.2	429.6	66.6	496.2	429.6	66.6	0.0	0.0	0.0
LV Overhead Lines	1993	1993	2280	364.6	310.1	[illegible]	494.2	427.9	66.3	0.0	0.0	0.0	494.2	427.9	66.3
LV Overhead Lines	1994	1994	2220	355.2	301.9	53.3	481.2	416.6	64.6	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	1995	1995	2320	371.2	315.5	55.7	502.9	435.4	67.5	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	1996	1996	2050	328.0	278.8	49.2	444.4	384.7	59.6	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	1997	1997	2060	329.6	280.2	49.4	446.5	386.6	59.9	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	1998	1998	2080	332.8	282.9	49.9	450.9	390.4	60.5	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	1999	1999	2100	336.0	285.6	50.4	455.2	394.1	61.1	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	2000	2000	2110	337.6	287.0	50.6	457.4	396.0	61.4	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	2001	2001	2110	337.6	287.0	50.6	457.4	396.0	61.4	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	1992	1992	2097	440.4	374.3	66.1	596.6	516.6	80.0	596.6	516.6	80.0	0.0	0.0	0.0
LV Cables	1993	1993	2180	453.6	385.6	68.0	614.5	532.1	82.5	0.0	0.0	0.0	614.5	532.1	82.5
LV Cables	1994	1994	2220	466.2	396.3	69.9	631.6	546.9	84.7	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	1995	1995	2280	478.6	407.0	71.8	646.7	561.6	87.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	1996	1996	2320	487.2	414.1	73.1	660.0	571.5	88.6	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	1997	1997	2370	497.7	423.0	74.7	674.3	583.6	90.5	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	1998	1998	2400	504.0	428.4	75.6	682.6	591.2	91.6	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	1999	1999	2430	510.3	433.8	76.5	691.3	598.6	92.8	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	2000	2000	2480	520.8	442.7	78.1	705.6	610.9	94.7	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	2001	2001	2480	520.8	442.7	78.1	705.6	610.9	94.7	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL DISTRIBUTION NETWORK COSTS															
VHV							35912.5	31094.0	4818.5	3118.9	2700.2	418.6	3174.6	2749.2	425.4
HV							0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV							3597.1	3114.4	482.6	267.1	231.1	36.0	269.6	234.0	35.6
LV							16640.0	14407.3	2232.6	1354.4	1172.7	181.7	1385.9	1200.0	186.0
ck							15675.5	13572.3	2103.2	1497.3	1296.4	200.9	1519.0	1315.2	203.8
							35912.5	31094.0	4818.5	3118.9	2700.2	418.6	3174.6	2749.2	425.4
TOTAL PSE NETWORK COSTS															
VHV										494.0	123.3	370.6	565.0	251.1	334.0
HV										331.0	66.2	264.8	158.0	31.6	126.4
										163.0	57.1	106.0	427.0	219.5	207.6
TOTAL SYSTEM NETWORK COSTS															
VHV							35912.5	31094.0	4818.5	3612.9	2823.5	789.4	3759.6	3000.2	759.3
HV							0.0	0.0	0.0	331.0	66.2	264.8	158.0	31.6	126.4
MV							3597.1	3114.4	482.6	430.1	289.2	142.0	696.6	453.5	243.2
LV							16640.0	14407.3	2232.6	1354.4	1172.7	181.7	1385.9	1200.0	186.0
ck							15675.5	13572.3	2103.2	1497.3	1296.4	200.9	1519.0	1315.2	203.8
							35912.5	31094.0	4818.5	3612.9	2823.5	789.4	3759.6	3000.2	759.3

NOTES:

1/ Total Project Costs for Distribution Co. Investments estimated by Power Engineering Institute in 1991 Prices
2/ LOCAL = Total cost of local materials and labor in billion Zloty.
Local costs incurred evenly throughout period, including Start and Commissioning Years
3/ FOREIGN = Foreign exchange part of total cost in billion Zloty.
Foreign share of Distribution Co. Investments estimated to represent 15.0% of total project cost in 1991 Zloty.
4/ 1991 Price estimates translated to 1992 Prices with the following assumptions:

Foreign Inflation Rate	4.0%
Domestic Inflation Rate	36.0%
1991 Exchange Rate (Zl/$)	11500
1992 Exchange Rate (Zl/$)	13400

DISTRIBUTION NETWORK INVESTMENT
(WITHOUT INFLATION & IDC)

	1994			1995			1996			1997			1998		
	TOTAL	LOCAL	FOREIGN	TOTAL	LOCAL	FOREIGN	TOTAL	LOCAL	FOREIGN	TOTAL	LOCAL	FOREIGN	TOTAL	LOCAL	FOREIGN
HV. 60 to 220 KV															
110 KV Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110 KV Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110 KV Lines	156.0	119.1	36.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110 KV Lines	119.1	119.1	0.0	156.0	119.1	36.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110 KV Lines	0.0	0.0	0.0	176.5	176.5	0.0	231.3	176.5	54.7	0.0	0.0	0.0	0.0	0.0	0.0
110 KV Lines	0.0	0.0	0.0	0.0	0.0	0.0	176.5	176.5	0.0	231.3	176.5	54.7	0.0	0.0	0.0
110 KV Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	180.6	180.6	0.0	236.6	180.6	56.0
110 KV Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	184.7	184.7	0.0
110 KV Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110 KV Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV. 1 to 60 KV															
s/s 110 KV / MV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 KV / MV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 KV / MV	540.8	468.0	72.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 KV / MV	0.0	0.0	0.0	569.0	492.7	76.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 KV / MV	0.0	0.0	0.0	0.0	0.0	0.0	455.2	394.1	61.1	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 KV / MV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	483.7	418.8	64.9	0.0	0.0	0.0
s/s 110 KV / MV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	483.7	418.8	64.9
s/s 110 KV / MV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 KV / MV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	244.2	211.4	32.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	0.0	0.0	0.0	253.7	219.8	34.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	403.0	349.0	54.1	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	403.0	349.0	54.1	0.0	0.0	0.0
MV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	403.0	349.0	54.1
MV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	589.3	510.3	79.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	0.0	0.0	0.0	630.0	545.4	84.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	0.0	0.0	0.0	0.0	0.0	0.0	880.6	762.5	118.2	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	948.3	821.1	127.2	0.0	0.0	0.0
MV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	948.3	821.1	127.2
MV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

(WITHOUT INFLATION & IDC)

	1994			1995			1996			1997			1998		
	TOTAL	LOCAL	FOREIGN	TOTAL	LOCAL	FOREIGN	TOTAL	LOCAL	FOREIGN	TOTAL	LOCAL	FOREIGN	TOTAL	LOCAL	FOREIGN
LV: Less than 1 KV															
s/s MV / LV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	416.9	361.0	55.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	0.0	0.0	0.0	423.5	366.7	56.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	0.0	0.0	0.0	0.0	0.0	0.0	436.8	378.2	58.6	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	444.8	385.1	59.7	0.0	0.0	0.0
s/s MV / LV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	451.4	390.8	60.6
s/s MV / LV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	461.2	416.6	64.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	0.0	0.0	0.0	502.9	435.4	67.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	444.4	384.7	59.6	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	446.5	386.6	59.9	0.0	0.0	0.0
LV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	450.9	390.4	60.5
LV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	631.6	546.9	84.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	0.0	0.0	0.0	648.7	561.6	87.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	0.0	0.0	0.0	0.0	0.0	0.0	660.0	571.5	88.6	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	674.3	583.8	90.5	0.0	0.0	0.0
LV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	682.8	591.2	91.6
LV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL DISTRIBUTION NETWORK COSTS	3178.8	2752.3	426.5	3360.2	2917.1	443.1	3687.9	3193.0	494.8	3612.5	3301.5	511.0	3841.5	3326.6	514.9
VHV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HV	275.0	238.1	36.9	332.5	295.6	36.9	407.8	353.1	54.7	411.9	357.2	54.7	421.4	365.4	56.0
MV	1374.1	1189.7	184.4	1452.7	1257.7	194.9	1738.9	1505.5	233.3	1835.0	1588.8	246.2	1835.0	1588.8	246.2
LV	1529.7	1324.5	205.2	1575.1	1363.8	211.3	1541.2	1334.4	206.8	1565.6	1355.5	210.1	1585.1	1372.4	212.7
ck	3178.8	2752.3	426.5	3360.2	2917.1	443.1	3687.9	3193.0	494.8	3612.5	3301.5	511.0	3841.5	3326.6	514.9
TOTAL PSE NETWORK COSTS	1556.0	582.6	973.3	2203.0	719.7	1486.4	1993.0	610.1	1383.0	428.0	167.9	260.1	365.0	146.8	218.3
VHV	1079.0	328.3	750.7	1694.0	453.0	1241.1	1610.0	427.0	1183.0	206.0	41.2	164.8	200.0	40.0	160.0
HV	477.0	254.5	222.6	512.0	266.7	245.3	383.0	183.1	200.0	222.0	126.7	95.3	165.0	106.8	58.3
TOTAL SYSTEM NETWORK COSTS	4734.8	3335.0	1399.8	5566.2	3633.7	1929.5	5680.9	3803.1	1877.8	4240.5	3469.4	771.1	4206.5	3473.4	733.1
VHV	1079.0	328.3	750.7	1694.0	453.0	1241.1	1610.0	427.0	1183.0	206.0	41.2	164.8	200.0	40.0	160.0
HV	752.0	492.8	259.5	844.5	562.3	282.2	790.8	536.1	254.7	633.9	483.9	150.0	586.4	472.1	114.2
MV	1374.1	1189.7	184.4	1452.7	1257.7	194.9	1738.9	1505.5	233.3	1835.0	1588.8	246.2	1835.0	1588.8	246.2
LV	1529.7	1324.5	205.2	1575.1	1363.8	211.3	1541.2	1334.4	206.8	1565.6	1355.5	210.1	1585.1	1372.4	212.7
ck	4734.8	3335.0	1399.8	5566.2	3633.7	1929.5	5680.9	3803.1	1877.8	4240.5	3469.4	771.1	4206.5	3473.4	733.1

DISTRIBUTION NETWORK INVESTMENT
(WITHOUT INFLATION & IDC)

	1999			2000			2001		
	TOTAL	LOCAL	FOREIGN	TOTAL	LOCAL	FOREIGN	TOTAL	LOCAL	FOREIGN
HV: 60 to 220 KV									
110 kV Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110 kV Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110 kV Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110 kV Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110 kV Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110 kV Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110 kV Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110 kV Lines	242.0	184.7	57.3	0.0	0.0	0.0	0.0	0.0	0.0
110 kV Lines	184.7	184.7	0.0	242.0	184.7	57.3	0.0	0.0	0.0
110 kV Lines	0.0	0.0	0.0	184.7	184.7	0.0	242.0	184.7	57.3
MV 1 to 60 KV									
s/s 110 kV / MV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 kV / MV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 kV / MV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 kV / MV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 kV / MV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 kV / MV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 kV / MV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 kV / MV	463.7	418.8	64.9	0.0	0.0	0.0	0.0	0.0	0.0
s/s 110 kV / MV	0.0	0.0	0.0	512.1	443.4	68.7	0.0	0.0	0.0
s/s 110 kV / MV	0.0	0.0	0.0	0.0	0.0	0.0	512.1	443.4	68.7
MV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	395.9	342.8	53.1	0.0	0.0	0.0	0.0	0.0	0.0
MV Overhead Lines	0.0	0.0	0.0	410.2	355.1	55.0	0.0	0.0	0.0
MV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	410.2	355.1	55.0
MV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	989.0	856.3	132.7	0.0	0.0	0.0	0.0	0.0	0.0
MV Cables	0.0	0.0	0.0	975.4	844.6	130.9	0.0	0.0	0.0
MV Cables	0.0	0.0	0.0	0.0	0.0	0.0	975.4	844.6	130.9

DISTRIBUTION NETWORK INVESTMENT
(WITHOUT INFLATION & IDC)

	1999			2000			2001		
	TOTAL	LOCAL	FOREIGN	TOTAL	LOCAL	FOREIGN	TOTAL	LOCAL	FOREIGN
LV: Less than 1 KV									
s/s MV / LV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	458.0	396.6	61.5	0.0	0.0	0.0	0.0	0.0	0.0
s/s MV / LV	0.0	0.0	0.0	466.0	403.5	62.5	0.0	0.0	0.0
s/s MV / LV	0.0	0.0	0.0	0.0	0.0	0.0	466.0	403.5	62.5
LV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	455.2	394.1	61.1	0.0	0.0	0.0	0.0	0.0	0.0
LV Overhead Lines	0.0	0.0	0.0	457.4	396.0	61.4	0.0	0.0	0.0
LV Overhead Lines	0.0	0.0	0.0	0.0	0.0	0.0	457.4	396.0	61.4
LV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	691.3	598.6	92.6	0.0	0.0	0.0	0.0	0.0	0.0
LV Cables	0.0	0.0	0.0	705.6	610.9	94.7	0.0	0.0	0.0
LV Cables	0.0	0.0	0.0	0.0	0.0	0.0	705.6	610.9	94.7
TOTAL DISTRIBUTION NETWORK COSTS	3899.9	3376.7	523.3	3953.4	3423.0	530.4	3766.7	3236.2	530.4
VHV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HV	426.8	369.5	57.3	426.8	369.5	57.3	242.0	184.7	57.3
MV	1868.6	1617.9	250.7	1897.7	1643.1	254.6	1897.7	1643.1	254.6
LV	1604.6	1389.3	215.3	1629.0	1410.4	218.6	1629.0	1410.4	218.6
ck	3899.9	3376.7	523.3	3953.4	3423.0	530.4	3766.7	3236.2	530.4
TOTAL PSE NETWORK COSTS	1419.0	476.5	942.5	1411.0	532.6	1076.4	1400.0	470.0	930.0
VHV	1161.0	337.2	823.8	1243.0	354.8	888.2	1160.0	337.0	823.0
HV	258.0	139.3	118.7	368.0	177.8	190.2	240.0	133.0	107.0
TOTAL SYSTEM NETWORK COSTS	5318.9	3853.2	1465.8	5564.4	3955.6	1608.8	5166.7	3706.2	1460.4
VHV	1161.0	337.2	823.8	1243.0	354.8	888.2	1160.0	337.0	823.0
HV	684.8	508.8	176.0	794.8	547.3	247.5	482.0	317.7	164.3
MV	1868.6	1617.9	250.7	1897.7	1643.1	254.6	1897.7	1643.1	254.6
LV	1604.6	1389.3	215.3	1629.0	1410.4	218.6	1629.0	1410.4	218.6
ck	5318.9	3853.2	1465.8	5564.4	3955.6	1608.8	5166.7	3706.2	1460.4

Appendix 7.2
Basic Planning Assumptions

PSE/POLISH POWER GRID
BASIC PLANNING ASSUMPTIONS

15-Jun 12:40 PM

Macroeconomic Assumptions:

Year of Study	1992
Last Planning Year	2001
Planning Reserve Margin	20.0%
Discount Rate 1/	12.0%
Conversion Factors:	
Foreign 2/	1.00
Standard (SCF) 3/	1.00
Local Labor 4/	1.00
Exchange Rate (tysZl/US$) 5/	13.400

Assumptions for Marginal Capacity Cost Calculations:	GENERATION		TRANSMISSION & DISTRIBUTION 6/			
	PEAKER METHOD	"NEXT PLANT"	VHV	HV	MV	LV
Marginal Plant	C-TURB	LIGNITE				
Life (years)	20	30	40	40	25	25
O&M and A&G (% of capital cost)	4.50%	1.87%	2.0%	2.0%	2.5%	2.5%
T&D Construction Lag (years)	-	-	2	2	1	1
Year Generation Required	1997	2001				
Capital Cost:						
Foreign (tysZl/KW)	4332.7	3556.8				
Local Materials	1083.2	20155.4				
Local Labor 4/	0.0	0.0				

Assumptions for Marginal Energy Cost Calculations:	SUMMER SEASON 8/				WINTER SEASON 8/			
	PEAK-1	PEAK-2	MID-PK	OFF-PK	PEAK-1	PEAK-2	MID-PK	OFF-PK
Marginal Plant	C-TURB		COAL	COAL	C-TURB		COAL 9/	COAL
Heat Rate (BTU/kWh)	12000		13289	9984	12000		18700	9734
Fuel Used	Gas		Coal	Coal	Gas		Coal	Coal
Fuel Cost (US$/unit) 7/	3.86		2.12	2.12	3.86		2.12	2.12
Heat Content (MMBtu/unit)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Variable O&M ($/MMBtu)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Utilization of Plant on Peak (%)	100%	0%			100%	0%		

1/ Estimates of the opportunity cost of capital range from 10 to 15 percent.
2/ Taxes/duties excluded from cost streams; no adjustment.
3/ Based on discussion with IBRD and USAID economists.
4/ Unskilled labor was not separated in the cost streams.
5/ Unless otherwise noted, all currency expressed in thousand Zloty - tysZl
6/ Network defined as: VHV (220 kv & above), HV (60-220 kV), MV (1-60 kV), LV (below 1 kV).
7/ Assumed economic fuel costs:

	$/MMBtu	tysZl/GJ
Coal	2.12	26.94
Lignite	1.61	20.47
Mazout	2.19	27.61
Gas	3.86	49.05

8/ The Summer season includes 6 months, May through October.
Winter Peak hours 4 p.m. to 9 p.m.; Mid-peak hours 7 a.m. to 1 p.m.
Summer Peak hours 7 p.m. to 10 p.m.; Mid-peak hours 7 a.m. to 1 p.m.
9/ Dummy heat rate assigned to reflect actual system operating costs.

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PSE/POLISH POWER GRID
GRID SALES AND LOSS FORECAST

YEAR ENDING	PEAK (MW)	GROSS GEN (GWh)	LOAD FACTOR	CONSUMPTION BY VOLTAGE LEVEL (GWh) 1,2 TOTAL	GEN	VHV	HV	MV	LV	AVERAGE LOSSES BY VOLTAGE LEVEL (GWh) 3/ STN USE	VHV	HV	MV	LV	TOTAL
1992	22024	125100	64.8	102625	4352	3200	28229	24943	41901	8986	1840	4179	2241	5229	22475
1993	22224	127100	65.3	105175	4400	3200	28158	25471	43945	9129	1745	3965	2126	4960	21925
1994	22528	129700	65.7	108191	4450	3300	28146	26102	46193	9315	1663	3778	2028	4727	21509
1995	22978	133200	66.2	112300	4500	3300	28410	27051	49040	9565	1546	3512	1883	4394	20900
1996	22989	135300	67.2	113658	4530	1900	29049	27665	50506	9736	1624	3689	1978	4615	21642
1997	23570	138900	67.3	116633	4578	1900	29742	28329	52084	10016	1671	3796	2035	4749	22267
1998	24077	142600	67.6	119689	4618	1900	30451	29010	53711	10304	1720	3906	2094	4887	22911
1999	24660	146300	67.7	122742	4659	1900	31153	29684	55347	10593	1758	4017	2154	5025	23557
2000	25173	148600	67.4	125000	4700	1900	31637	30151	56613	10781	1749	3972	2129	4969	23600
2001	25279	150400	67.0	126187	4719	0	32373	30906	58188	10900	1816	4125	2212	5160	24213

1/ Consumption at generation includes pumping in hydro plants plus heat generation auxilliary use minus self-producer supply to grid; consumption at VHV includes net exports.
2/ Flows are subsequently converted in the model as consumption demand by applying the system load factor.
3/ Average network losses by voltage level have been estimated based on the following allocation of total losses at a percent of net generation:

TOTAL	VHV	HV	MV	LV
11.1%	1.5%	3.4%	1.8%	4.3%

PSE/POLISH POWER GRID
AVERAGE AND PEAK LOSS FACTORS (FRACTION OF INCOMING)

YEAR ENDING	STATION USE AVERAGE	STATION USE PEAK	VHV AVERAGE	VHV PEAK	HV AVERAGE	HV PEAK	MV AVERAGE	MV PEAK	LV AVERAGE	LV PEAK
1992	0.072	0.072	0.016	0.022	0.039	0.052	0.030	0.040	0.111	0.147
1993	0.072	0.072	0.015	0.020	0.037	0.048	0.028	0.037	0.101	0.134
1994	0.072	0.072	0.014	0.019	0.034	0.045	0.026	0.034	0.093	0.122
1995	0.072	0.072	0.013	0.017	0.031	0.040	0.023	0.030	0.082	0.108
1996	0.072	0.072	0.013	0.017	0.031	0.041	0.023	0.030	0.084	0.109
1997	0.072	0.072	0.013	0.017	0.031	0.041	0.023	0.030	0.084	0.108
1998	0.072	0.072	0.013	0.017	0.031	0.041	0.023	0.030	0.083	0.108
1999	0.072	0.072	0.013	0.017	0.032	0.041	0.023	0.030	0.083	0.108
2000	0.073	0.073	0.013	0.017	0.031	0.040	0.023	0.029	0.081	0.105
2001	0.072	0.072	0.013	0.017	0.031	0.040	0.023	0.030	0.081	0.105
Average	0.072	0.072	0.014	0.018	0.033	0.043	0.025	0.032	0.088	0.115

PSE/POLISH POWER GRID
DEMAND AND LOSS FORECAST AT TIME OF SYSTEM PEAK (MW)

YEAR ENDING	PEAK	STATION USE	GEN CONSUM	VHV LOSS	VHV PEAK	VHV CONSUM	HV LOSS	HV PEAK	HV CONSUM	MV LOSS	MV PEAK	MV CONSUM	LV LOSS	LV PEAK
1992	22024	1582.0	766.2	429.7	19246.1	563.4	970.5	17712.3	4969.8	509.7	12232.8	4391.2	1153.9	6687.7
1993	22224	1596.2	769.4	403.2	19454.9	559.5	911.1	17984.3	4923.6	479.4	12581.3	4453.7	1089.0	7038.7
1994	22528	1617.9	772.9	380.1	19757.2	573.2	859.4	18324.6	4888.8	453.0	12982.8	4533.8	1031.9	7417.1
1995	22978	1650.0	776.3	349.5	20201.9	569.3	790.5	18842.2	4900.8	417.6	13523.8	4666.4	954.3	7903.1
1996	22989	1654.2	771.2	358.2	20205.1	322.8	810.4	19071.9	4935.7	428.2	13708.0	4700.5	979.1	8028.5
1997	23570	1699.6	776.6	367.9	20726.2	322.4	832.2	19571.6	5047.0	439.8	14084.8	4807.3	1005.6	8271.9
1998	24077	1739.7	779.7	375.5	21182.4	320.8	849.5	20012.1	5141.5	449.0	14421.6	4898.1	1027.1	8496.4
1999	24660	1785.5	785.2	385.1	21703.9	320.3	871.2	20512.5	5251.0	460.5	14801.0	5003.4	1053.6	8743.9
2000	25173	1826.4	796.2	383.8	22166.5	321.9	868.4	20976.3	5359.2	459.1	15157.9	5107.5	1050.8	8999.5
2001	25279	1832.1	793.2	393.6	22259.7	0.0	890.6	21369.1	5441.2	470.9	15457.0	5194.5	1078.1	9184.4

PSE/POLISH POWER GRID
GENERATION CAPACITY COST – PEAKER AND "NEXT PLANT" METHODS (tysZl/KW)

ASSUMPTIONS	PEAKER METHOD	"NEXT PLANT"
Marginal Plant	C–TURB	LIGNITE
Life (years)	20	30
O&M and A&G (% of capital cost)	4.50%	1.87%
Year Generation Required	1997	2001
Capital Cost:		
Foreign (tysZl/KW)	4332.7	3550.8
Local Materials	1083.2	20155.4
Local Labor 4/	0.0	0.0
CAPACITY COST (discounted to study year)		
Market Price	3073.09	8550.86
Border Price	3073.09	8550.86

PSE/POLISH POWER GRID
RANKING OF GENERATING PLANTS BY VARIABLE COST – 1997

GENERATING PLANT GROUPS	TYPE	MEGA-WATTS (MW) 1/	ANNUAL USE Hrs/Yr	VARIABLE COST $/KWh	VARIABLE COST tysZl/KWh	HEAT RATE Btu/KWh	FUEL COST $/MMBtu	VAR. O&M (% FUEL COST)	VARIABLE O&M 3/ $/KWh
BASE HYDRO	HYDRO	80	8760	–	–	–	–	–	–
COMB. HEAT AND POWER 2/	CHP	5901	2597	–	–	–	–	–	–
LIGNITE–FIRED	LIGNITE	8791	7579	0.0163	0.2187	10118	1.61	0.0%	0.00000
COAL–FIRED STEAM 1	COAL–1	11652	5948	0.0203	0.2725	9582	2.12	0.0%	0.00000
COAL–FIRED STEAM 2	COAL–2	2292	284	0.0226	0.3029	10652	2.12	0.0%	0.00000
COMBUSTION TURBINES	C–TURB	240	6	0.0464	0.6214	12000	3.86	0.0%	0.00000
PUMPED STORAGE	P–STOR	1890	1420	–	–	–	–	–	–

1/ Installed capacity.
2/ Megawatt capacity includes 1290 MW autogeneration.
3/ Based on PSE practice, all O&M is treated as a fixed cost.

ASSOCIATED FUEL SAVINGS – "NEXT PLANT" METHOD

---UNIT TYPE--- NEW	DISPL	COST (tysZl/KWh) NEW	DISPL	HRS/YR	SAVINGS (tysZl/KW)
LIGNITE	COAL–1	0.2187	0.2725	5948	320.01
COAL–1	COAL–2	0.2725	0.3029	284	8.64
COAL–2	C–TURB	0.3029	0.6214	6	1.91
TOTAL FUEL SAVINGS (tysZl/KW/Yr)					330.56

PSE/POLISH POWER GRID
NETWORK CAPACITY COSTS (tysZl MILLION)

YEAR ENDING	VHV COSTS TOTAL	VHV COSTS FOREIGN	VHV COSTS LOC Mat	VHV COSTS LOC Labor	HV COSTS TOTAL	HV COSTS FOREIGN	HV COSTS LOC Mat	HV COSTS LOC Labor	MV COSTS TOTAL	MV COSTS FOREIGN	MV COSTS LOC Mat	MV COSTS LOC Labor	LV COSTS TOTAL	LV COSTS FOREIGN	LV COSTS LOC Mat	LV COSTS LOC Labor
1992	331.00	264.80	66.20	0.00	430.15	111.96	288.19	0.00	1354.40	181.72	1172.68	0.00	1497.32	200.90	1296.42	0.00
1993	158.00	126.40	31.60	0.00	696.64	243.18	453.46	0.00	1385.93	185.95	1199.98	0.00	1519.00	203.81	1315.19	0.00
1994	1079.00	750.70	328.30	0.00	752.02	259.45	492.57	0.00	1374.08	184.36	1189.72	0.00	1529.70	205.24	1324.46	0.00
1995	1694.00	1241.05	452.95	0.00	844.50	282.20	562.30	0.00	1452.66	194.91	1257.75	0.00	1575.09	211.33	1363.75	0.00
1996	1610.00	1183.00	427.00	0.00	790.79	254.66	536.12	0.00	1738.85	233.31	1505.55	0.00	1541.22	206.79	1334.43	0.00
1997	206.00	184.80	41.20	0.00	633.89	150.01	483.88	0.00	1835.04	246.21	1588.83	0.00	1565.58	210.06	1355.52	0.00
1998	200.00	160.00	40.00	0.00	586.38	114.24	472.14	0.00	1835.04	246.21	1588.83	0.00	1585.09	212.68	1372.41	0.00
1999	1161.00	823.80	337.20	0.00	684.75	175.96	508.80	0.00	1868.57	250.71	1617.86	0.00	1604.59	215.29	1389.30	0.00
2000	1243.00	888.20	354.80	0.00	794.75	247.46	547.30	0.00	1897.70	254.62	1643.08	0.00	1628.95	218.56	1410.39	0.00
2001	1160.00	823.00	337.00	0.00	482.01	164.26	317.75	0.00	1897.70	254.62	1643.08	0.00	1628.95	218.56	1410.39	0.00

PSE/POLISH POWER GRID
AVERAGE INCREMENTAL NETWORK CAPACITY COSTS BY VOLTAGE LEVEL (tysZl MILLION)

VHV NETWORK

YEAR ENDING	PEAK MW TOTAL	PEAK MW DISCOUNTED	INVESTMENT COST MARKET	INVESTMENT COST BORDER	INVESTMENT COST DISCOUNTED
1992	0.00	0.00	331.00	331.00	331.00
1993	208.79	186.42	158.00	158.00	141.07
1994	302.26	240.96	1079.00	1079.00	860.17
1995	444.75	316.57	1694.00	1694.00	1205.76
1996	3.18	2.02	1610.00	1610.00	1023.18
1997	521.05	295.66	206.00	206.00	116.89
1998	456.24	231.15	200.00	200.00	101.33
1999	521.50	235.90	1161.00	1161.00	525.18
2000	462.58	186.83	1243.00	1243.00	502.03
2001	93.22	33.62	1160.00	1160.00	418.31
Lagged Total		1542.70 (1994-2001)			4304.58 (1992-99)
AVERAGE INCREMENTAL VHV CAPACITY COST/KW =					2790.29

HV NETWORK

YEAR ENDING	PEAK MW TOTAL	PEAK MW DISCOUNTED	INVESTMENT COST MARKET	INVESTMENT COST BORDER	INVESTMENT COST DISCOUNTED
1992	0.00	0.00	430.15	430.15	430.15
1993	272.02	242.88	696.64	696.64	622.00
1994	340.32	271.30	752.02	752.02	599.51
1995	517.58	368.40	844.50	844.50	601.10
1996	229.73	146.00	790.79	790.79	502.56
1997	499.64	283.51	633.89	633.89	359.69
1998	440.53	223.19	586.38	586.38	297.08
1999	500.38	226.35	684.75	684.75	309.75
2000	463.79	187.32	794.75	794.75	320.99
2001	392.89	141.68	482.01	482.01	173.82
Lagged Total		1847.73 (1994-2001)			3721.82 (1992-99)
AVERAGE INCREMENTAL HV CAPACITY COST/KW =					2014.26

MV NETWORK

YEAR ENDING	PEAK MW TOTAL	PEAK MW DISCOUNTED	INVESTMENT COST MARKET	INVESTMENT COST BORDER	INVESTMENT COST DISCOUNTED
1992	0.00	0.00	1354.40	1354.40	1354.40
1993	348.51	311.17	1385.93	1385.93	1237.44
1994	401.45	320.03	1374.08	1374.08	1095.41
1995	541.05	385.11	1452.66	1452.66	1033.97
1996	184.19	117.05	1738.85	1738.85	1105.07
1997	376.79	213.80	1835.04	1835.04	1041.25
1998	336.83	170.65	1835.04	1835.04	929.69
1999	379.35	171.60	1868.57	1868.57	845.25
2000	356.93	144.16	1897.70	1897.70	766.45
2001	299.13	107.87	1897.70	1897.70	684.33
Lagged Total		1941.44 (1993-2001)			9408.93 (1992-00)
AVERAGE INCREMENTAL MV CAPACITY COST/KW =					4846.38

LV NETWORK

YEAR ENDING	PEAK MW TOTAL	PEAK MW DISCOUNTED	INVESTMENT COST MARKET	INVESTMENT COST BORDER	INVESTMENT COST DISCOUNTED
1992	0.00	0.00	1497.32	1497.32	1497.32
1993	351.02	313.41	1519.00	1519.00	1356.25
1994	378.38	301.64	1529.70	1529.70	1219.47
1995	486.05	345.96	1575.09	1575.09	1121.12
1996	125.35	79.66	1541.22	1541.22	979.47
1997	243.39	138.10	1565.58	1565.58	888.35
1998	224.48	113.73	1585.09	1585.09	803.05
1999	247.59	112.00	1604.59	1604.59	725.84
2000	255.59	103.23	1628.95	1628.95	657.91
2001	184.88	66.67	1628.95	1628.95	587.42
Lagged Total		1574.41 (1993-2001)			9248.77 (1992-00)
AVERAGE INCREMENTAL LV CAPACITY COST/KW =					5874.43

PSE/POLISH POWER GRID
SUMMARY OF CAPACITY COSTS

GENERATION:	PEAKER METHOD	"NEXT PLANT"
CAPITAL COST (tysZl/KW) (adjusted to local prices and for reserve margin and station losses at peak)	3974.27	11058.38
CAPITAL COST PER YEAR (tysZl/KW/Yr)	532.07	1372.83
ASSOCIATED FUEL SAVINGS (tysZl/KW/Yr) (adjusted to local prices and for station losses)	--	356.25
CAPITAL COST NET OF FUEL SAVINGS (tysZl/KW/Yr)	532.07	1016.58
O&M COST PER YEAR (tysZl/KW/Yr)	179.04	206.36
TOTAL CAPITAL COST PER YEAR (tysZl/KW/Yr)	711.11	1222.94
CAPACITY COST PER MONTH	59.26	101.91

TRANSMISSION & DISTRIBUTION:	VHV	HV	MV	LV
CAPITAL COST (tysZl/KW) (adjusted to local prices)	2790.29	2014.26	4846.36	5874.43
CAPITAL COST PER YEAR (tysZl/KW/Yr)	338.47	244.34	617.91	748.99
O&M COST PER YEAR (tysZl/KW/Yr)	55.81	40.29	121.16	146.66
TOTAL CAPITAL COST PER YEAR (tysZl/KW/Yr)	394.28	284.62	739.07	895.65
CAPACITY COST PER MONTH	32.86	23.72	61.59	74.65

PSE/POLISH POWER GRID
STRICT LONG RUN MARGINAL COST BASED TARIFF BY VOLTAGE LEVEL

MARGINAL CAPACITY COST (tysZl/COINCIDENT KW/MONTH):

	GENERATION		TRANSMISSION & DISTRIBUTION					TOTAL MARGINAL CAPACITY COST	
	PEAKER METHOD	"NEXT PLANT"	VHV	HV	MV	LV	TOTAL	PEAKER METHOD	"NEXT PLANT"
VHV	60.36	103.80	32.86				32.86	93.21	136.66
HV	63.06	108.44	34.33	23.72			58.04	121.10	166.49
MV	65.14	112.03	35.46	24.50	61.59		121.55	186.70	233.59
LV	73.63	126.63	40.08	27.70	69.62	74.65	212.05	285.69	338.68

MARGINAL ENERGY COST (tysZl/KWh): 1/

	SUMMER SEASON 2/			WINTER SEASON 2/			ANNUAL AVERAGE 2/		
	PEAK	MID-PK	OFF-PK	PEAK	MID-PK	OFF-PK	PEAK	MID-PK	OFF-PK
GEN (adjusted to local prices and for station losses)	0.670	0.407	0.306	0.670	0.573	0.298	0.670	0.490	0.302
VHV	0.682	0.415	0.310	0.682	0.584	0.303	0.682	0.499	0.306
HV	0.713	0.433	0.321	0.713	0.610	0.313	0.713	0.522	0.317
MV	0.736	0.448	0.329	0.736	0.630	0.321	0.736	0.539	0.325
LV	0.832	0.506	0.361	0.832	0.712	0.352	0.832	0.609	0.356

1/ Energy Costs derived directly from basic assumptions regarding marginal plant, heat rate, fuel cost, fuel heat content, and variable O&M.

PSE/POLISH POWER GRID
STRICT LONG RUN MARGINAL COST BASED TARIFF BY TARIFF CLASS - BULK

TARIFF CLASS	SERVICE VOLTAGE	COINCI-DENCE	LOAD FACTOR	ENERGY SHARES PEAK	MID-PEAK	TOTAL MARGINAL COST/MONTH CAPACITY tysZl/KW	ENERGY tysZl/KWh	TOTAL tysZl/KWh	DEMAND CHARGE SHARE	H1/1992 SALES GWh	CURRENT YIELD tysZl/KWh
DISTRIBUTION COS.	HV	1.00	0.65	0.20	0.28	121.10	0.4533	0.7085	36%	50434	0.3398
BULK SYSTEM AVERAGE				0.20	0.28	121.10	0.4533	0.7085		50434	0.3398
Equivalent tysZl/KWh						0.2552	0.4533	0.7085			
% of System Average						36%	64%	100%			

PSE/POLISH POWER GRID
STRICT LONG RUN MARGINAL COST BASED TARIFF BY TARIFF CLASS - RETAIL

TARIFF CLASS	SERVICE VOLTAGE	COINCI-DENCE	LOAD FACTOR	ENERGY SHARES PEAK	MID-PEAK	TOTAL MARGINAL COST/MONTH CAPACITY tysZl/KW	ENERGY tysZl/KWh	TOTAL tysZl/KWh	DEMAND CHARGE SHARE	H1/1992 SALES GWh	CURRENT YIELD tysZl/KWh
INDUSTRIAL	HV	0.76	0.60	0.16	0.27	92.04	0.4354	0.6455	33%	14090	0.3874
	MV	0.54	0.42	0.18	0.31	100.82	0.4652	0.7940	41%	8884	0.4995
	LV	0.48	0.31	0.18	0.31	137.13	0.5203	1.1262	54%	1334	0.7828
TRACTION	HV	0.86	0.48	0.19	0.30	104.15	0.4534	0.7506	40%	67	0.4606
	MV	0.86	0.48	0.19	0.30	160.56	0.4671	0.9254	50%	2178	0.4715
COMMERCIAL	MV	0.63	0.49	0.20	0.32	117.62	0.4755	0.8044	41%	641	0.4934
	LV	0.45	0.25	0.20	0.32	128.56	0.5323	1.2367	57%	4464	0.7745
AGRICULTURAL	MV	0.54	0.38	0.20	0.32	100.82	0.4755	0.8390	43%	320	0.5287
RETAIL	LV	0.44	0.21	0.27	0.25	125.70	0.5479	1.3679	60%	13616	0.6310
ST. LIGHTING	LV	1.00	0.50	0.21	0.04	285.69	0.4659	1.2486	63%	742	0.7884
DISTRIBUTION COMPANY AVERAGE				0.20	0.28						
Equivalent tysZl/KWh						115.18	0.4888	0.9836		46336	0.5421
% of System Average						0.4948	0.4888	0.9836			
						50%	50%	100%			

PSE/POLISH POWER GRID
REVENUE RESPONSIBILITY BY CUSTOMER/TARIFF CLASS - BULK

BILLING YEAR	1994
TOTAL GRID SALES (GWh)	109072
REVENUE REQUIREMENT	
TOTAL (tysZl MILLION)	61408
AVERAGE (tysZl/KWh) 1/	0.5630

CUSTOMER/ TARIFF CLASS	H1/1992 SALES GWh	CURRENT YIELD2/ tysZl/KWh	STRICT LRMC3/ tysZl/KWh	REVENUE NEUTRAL STRICT LRMC tysZl/KWh	% CHNG	REVENUE RESPONSIBILITY tysZl/KWh	% CHNG
DISTRIBUTION COS.	50434	0.3398	0.7085	0.5630	66%	0 5630	66%
TOTAL BULK	50434	0.3398	0.7085	0.5630	66%	0.5630	66%

1/ Approximate revenue target for 1994.
2/ Estimated average current yield after tariff increase of Q1/1993, in mid - 1992 prices.
3/ Escalated to 1994 prices, a 0.00% increase.

PSE/POLISH POWER GRID
REVENUE RESPONSIBILITY BY CUSTOMER/TARIFF CLASS - RETAIL

BILLING YEAR	1994
TOTAL GRID SALES (GWh)	100441
REVENUE REQUIREMENT	
TOTAL (tysZl MILLION)	78846
AVERAGE (tysZl/KWh) 1/	0.7850

CUSTOMER/ TARIFF CLASS		H1/1992 SALES GWh	CURRENT YIELD2/ tysZl/KWh	STRICT LRMC3/ tysZl/KWh	REVENUE NEUTRAL STRICT LRMC tysZl/KWh	% CHNG	REVENUE RESPONSIBILITY tysZl/KWh	% CHNG
"A"	HV	14157	0.3877	0.6460	0.5156	33%	0.5156	33%
"B"	MV	12023	0.4949	0.8195	0.6541	32%	0.6541	32%
"C" (>40 kW)	LV	1334	0.7828	1.1262	0.8989	15%	0.8989	15%
"C" (<40 kW)	LV	4464	0.7745	1.2367	0.9871	27%	0.9871	27%
RETAIL	LV	13616	0.6310	1.3679	1.0918	73%	1.0918	73%
ST. LIGHTING	LV	742	0.7884	1.2486	0.9965	26%	0.9965	26%
TOTAL DC RETAIL		46336	0.5421	0.9836	0.7850	45%	0.7850	45%

1/ Approximate revenue target for 1994.
2/ Estimated average current yield after tariff increase of Q1/1993, in mid - 1992 prices.
3/ Escalated to 1994 prices, a 0.00% increase.

PSE/POLISH POWER GRID
LRMC SENSITIVITY ANALYSIS (tysZl/Kwh)

DISCOUNT RATE	Bulk LRMC	Retail LRMC
12%	0.7085	0.9836
8%	0.6538	0.8733
10%	0.6807	0.9272
12%	0.7085	0.9836
14%	0.7370	1.0420

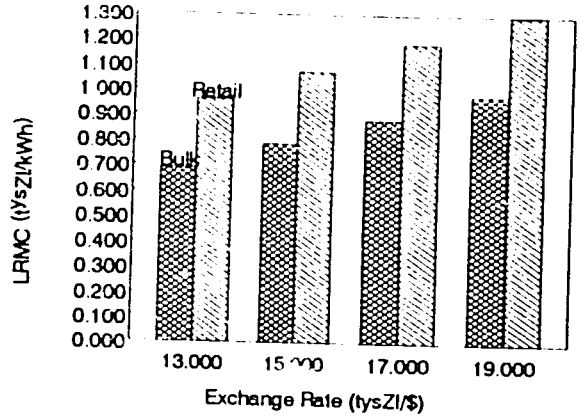
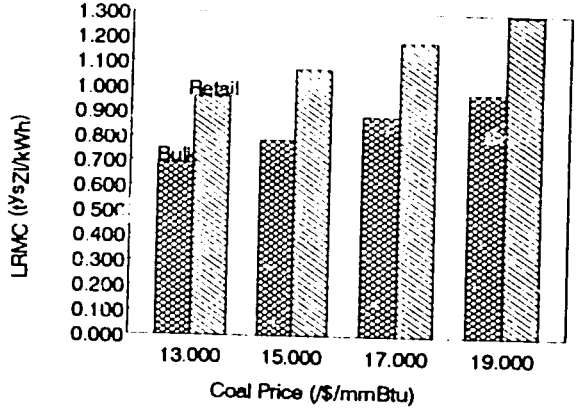
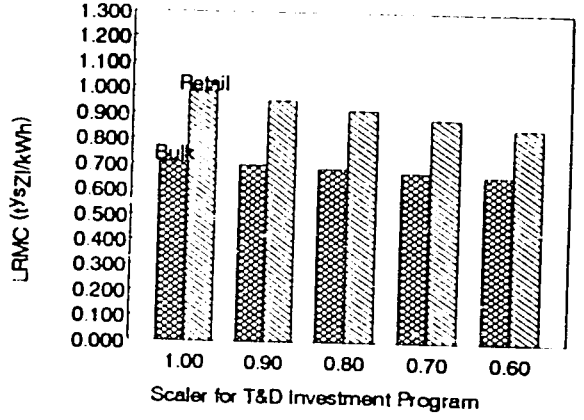
EXCHANGE RATE	Bulk LRMC	Retail LRMC
13.400	0.7085	0.9836
13.000	0.6890	0.9612
15.000	0.7867	1.0728
17.000	0.8844	1.1843
19.000	0.9821	1.2959

COAL PRICE	Bulk LRMC	Retail LRMC
2.12	0.7085	0.9836
1.50	0.6174	0.8869
1.75	0.6540	0.9257
2.00	0.6906	0.9646
2.25	0.7272	1.0034
2.50	0.7639	1.0423

T&D INVSTMNT	Bulk LRMC	Retail LRMC	T&D % of Capac Csts
1.00	0.7085	0.9836	74%
0.90	0.6963	0.9494	72%
0.80	0.6840	0.9152	70%
0.70	0.6718	0.8810	67%
0.60	0.6596	0.8468	63%

Note: Program must be "RUN" to update sensitivity analysis.

SCF	Bulk LRMC	Retail LRMC
1.00	0.7085	0.9836
0.85	0.8193	1.1101
0.90	0.7783	1.0632
0.95	0.7416	1.0213
1.00	0.7085	0.9836

YEAR GEN NEEDED	Bulk LRMC	Retail LRMC
1997	0.7035	0.9836
1996	0.7244	1.0019
1997	0.7085	0.9836
1998	0.6943	0.9672
1999	0.6816	0.9526

RESERVE MARGIN	Bulk LRMC	Retail LRMC
20.0%	0.7085	0.9836
15.0%	0.7030	0.9772
17.5%	0.7057	0.9804
20.0%	0.7085	0.9836
22.5%	0.7113	0.9867
25.0%	0.7140	0.9899