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Slovak Electricity Pricing and Retail Tariff Study

Final Report

Volume I

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In cooperation with: The Ministry of Economy, Republic of Slovakia
The Ministry of Finance, Republic of Slovakia
The Slovak National Power Company
The West Slovak Distribution Company
The Central Slovak Distribution Company
The East Slovak Distribution Company

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FOREWORD

This report was prepared by a team headed by Bechtel Corporation as part of a program funded by the U.S. Agency for International Development. The purpose of the program was to provide assistance to the Republic of Slovakia in the utilization of appropriate methodologies to develop its energy sector on an economically sound basis. The Electricity Pricing and Retail Tariff Study was carried out over a period of more than one year, from April 1994 to May 1995. It included review and evaluation of available information on current costs, pricing structures, and investment plans as a basis for developing recommendations for modifying tariff structures in the future. A Steering Committee representing the Ministries of Economy and Finance, the Antimonopoly Office, the Slovak National Power Company, and the three Regional Distribution Utilities participated in regular review meetings throughout the course of the study and provided valuable input and guidance.

Throughout the study considerable emphasis was placed on methodology and training. This emphasis was intended not only to provide Steering Committee members and other participants with a thorough understanding of the final study results, but also an ability to adjust the results as necessary to reflect changing future conditions.

Price projections of any commodity are sensitive to numerous assumptions, including future markets, economic conditions, and estimated investment requirements. In the Slovak power sector, these assumptions are embodied in the resource plans of the operating companies. The resource planning process is ongoing and many elements of the plans are likely to change as the future unfolds – and indeed have changed even during the course of this study. The development of a power sector resource plan was not part of the scope of the study. The resource plans used in this study were provided and agreed to by the Steering Committee as an appropriate basis for the application of tariff analysis methodologies. The use of these resource plans does not represent an endorsement of any particular set of planning assumptions by Bechtel, USAID, or any other agency of the U.S. Government.

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ACRONYMS/ABBREVIATIONS

CENTREL	association of Polish, Czech, Slovak, and Hungarian electric power grids
CHP	combined heat and power
DSM	demand side management
EBRD	European Bank for Reconstruction and Development
EdF	Electricité de France
EGU	Bratislava Power Research Institute
EHV	extra-high voltage
ENS	energy-not-saved
GDP	gross domestic product
HV	High Voltage
IAEA	International Atomic Energy Agency
IDC	interest during construction
LOLP	loss-of-load probability
LRMC	long-run marginal cost
RDU	Regional Distribution Utility
SE	Slovak National Power Co.
SR	Republic of Slovakia
SRMC	short-run marginal cost
SSE	Central Slovak Distribution Company
TOD	time of day
UPCTE	Union for Coordination of Production and Transmission of Electricity (the Western European association linking the electric power grids of member countries)
USAID	U.S. Agency for International Development
VHV	Very High Voltage
VSE	East Slovak Distribution Company
WB	World Bank
ZSE	West Slovak Distribution Company

EXECUTIVE SUMMARY

Overview

This is the Final Report of the Electricity Pricing and Retail Tariff Study. The Bechtel Corporation and its subcontractors, Arthur Andersen & Co. and the Power Research Institute (EGU) performed the Study for the Ministry of Economy of the Republic of Slovakia (SR). The U.S. Agency for International Development (USAID) provided funding for this project. A Steering Committee represented by the Ministries of Economy and Finance, the Antimonopoly Office, the Slovak National Power Co. (SE), and the three Regional Distribution Utilities (RDUs) provided critical guidance in the execution of the Study.

The SR is in the process of restructuring its power sector. USAID had previously assisted this process through support in evaluating restructuring alternatives (March and April of 1993), a regulatory seminar (May 1993), and a review of the overall energy sector (May through November 1993). A major issue associated with restructuring is the pricing of electricity. This affects the financial health of organizations providing power and their ability to acquire capital for reconstruction and replacement of existing equipment. All of the analyses and recommendations of the Study should be seen in the context of the steps to increase private participation and competition in the generation of electricity.

The objectives of the Study were to:

- Assemble the facts associated with the cost of providing electricity
- Evaluate the current retail tariff structure and the pricing of bulk power
- Recommend changes in the current system where appropriate

These objectives were accomplished through analyses of:

- Current cost and pricing structure
- Financial requirements of SE and RDUs over the next five years
- Long-run marginal cost (LRMC) of electricity generation, transmission, and distribution for the SR
- Impact of tariff increases on sensitive groups such as electricity-intensive industries and economically vulnerable residential customers

Current Costs and Prices

An analysis was conducted based on the reported costs of providing electricity in that year, the pricing of power from SE, and retail tariffs. Figure ES-1 compares the reported cost of supplying power with the prices received at various voltage levels. Prices were adequate to cover overall reported costs, but surpluses collected from Category B and C customers were used to compensate for shortfalls from residential customers.

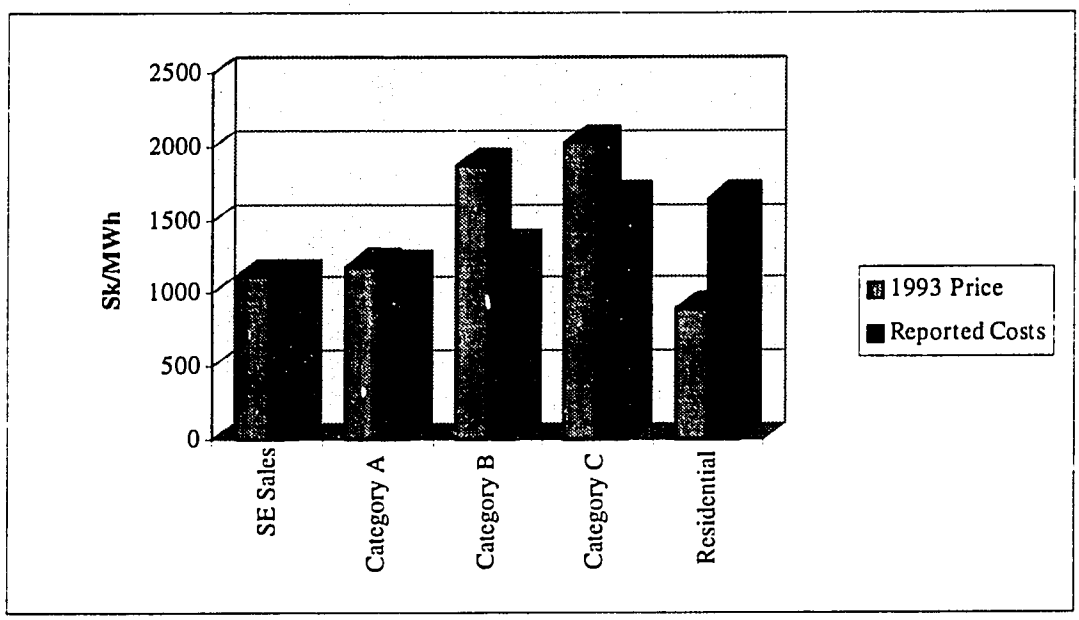

Figure ES-1 Comparison of 1993 Reported Costs and Prices

The overall revenue level, while covering reported costs, is not adequate to support the investments proposed by SE and the RDUs over the next five years. The primary reason for this is an inadequate allowance for depreciation due to the erosion of the value of fixed assets through inflation.

Financial Requirements and Long-Run Marginal Cost (LRMC)

The Study used two types of detailed analyses to determine pricing levels that reflect the longer term needs for power generation, transmission, and distribution.

We conducted studies of the **financial requirements** needed to support the investment requirements of SE and each of the RDUs over the next five years. The projected levelized 5-year revenue requirements value is the minimum estimated price level that can support operating costs and investment requirements over the next five years. The projected revenue requirements included fuel, labor, materials, decommissioning costs of nuclear Bohunice A-1 and V-1 nuclear facilities, an allowance for nonpayment of part of the current accounts receivable, a depreciation allowance reflecting a revaluation of fixed assets, and an allowed rate of return on those assets. Existing generating equipment assets were increased in value by a factor of 5 in order to achieve acceptable financial performance.

In parallel, the **long-run marginal cost (LRMC)** of the system over the next 10 years was estimated by voltage level. The LRMC is a measure of the long-term value of electricity. Under conditions of competition, the LRMC is determined by the marketplace. In situations where prices are regulated, LRMC can be estimated by the price-setting authority. Pricing below LRMC can lead customers to use electricity in uneconomic ways and will not provide adequate revenues to expand the system over the long term. Pricing above LRMC will discourage

economic uses of electricity and, as electricity markets become increasingly competitive, will expose power supply and distribution organization to loss of market share.

Figure ES-2 shows current pricing, the projected levelized 5-year revenue requirements value, and LRMC for the various tariff categories. The following observations can be made:

- The estimated LRMC is adequate to meet revenue requirements at all voltage levels.
- SE sales, representing over 75 percent of the costs of overall power supply, are priced at approximately 85 percent of the level that would satisfy revenue requirements over the next 5 years and 75 percent of LRMC.
- Category A (Very High Voltage) tariffs bear approximately the same relationship to the projected 5-year revenue requirements level and to LRMC as does the SE sales price.
- Category B (High Voltage) tariffs are already above the 5-year revenue requirements level and LRMC.
- Category C (Low Voltage commercial) tariffs are above the 5-year revenue requirements level for service to commercial customers and are almost at the LRMC.
- Residential customer tariffs differ the most significantly from 5-year revenue requirements and LRMC.

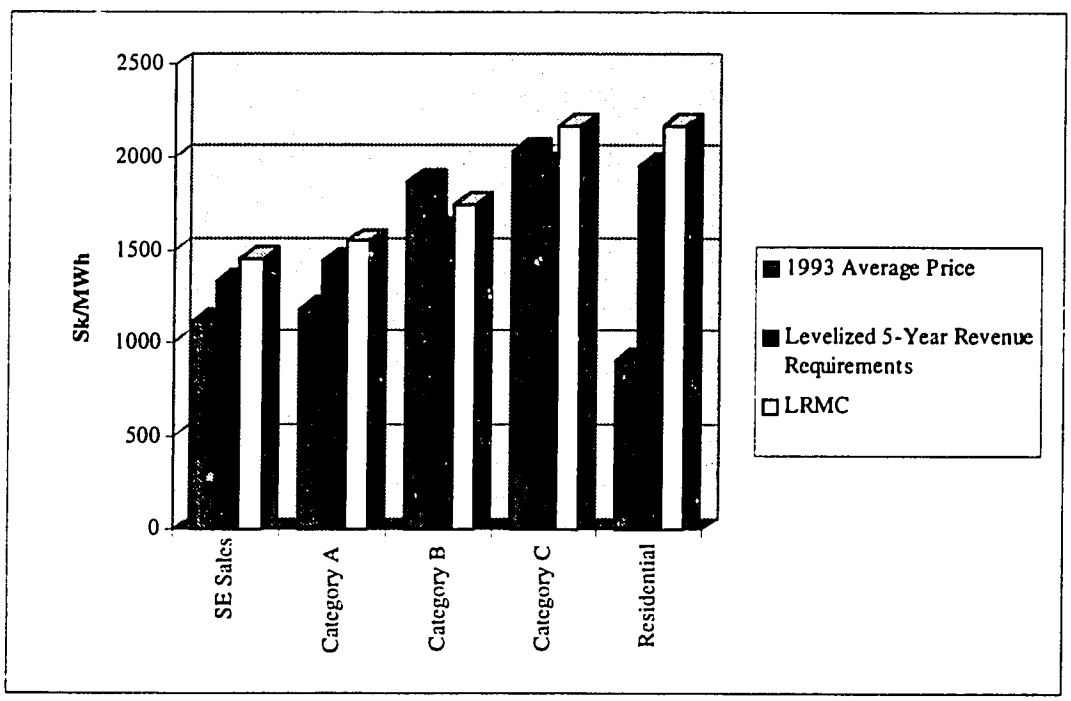

Figure ES-2 Comparison of Average 1993 Price, Levelized 5-Year Revenue Requirements, and LRMC

Impact of Tariff Increases on Electricity-Intensive Industries

Even though the tariff increases needed to meet the 5-year revenue requirements level are relatively modest for Category A, the customers served at the Very High Voltage level are generally the most energy-intensive users. Some of the industries most negatively affected by the economic transition underway in the SR are also represented in this group. The following proposals should be studied in detail with respect to Category A customers in order to accurately reflect the costs associated with service to these customers and the value of their contributions to power supply:

- The introduction of formal tariffs for customers allowing interruptible service. Two levels of interruptibility should be considered – one requiring substantial notice and one with short notice.
- The purchase by SE of excess industrial electric generation at "avoided cost" to reflect its value. As with RDU-owned generation, such transactions would not have to affect physical operation or ownership of facilities and delivery of power would be to the very high voltage (VHV) grid.

The first measure would allow large industrial customers to tailor the level of service they are provided and limit required price increases where appropriate through accepting lower levels of reliability of service if compatible with their operation. The second measure would provide greater income to industrial cogenerators.

There may be a need for additional relief from tariff increases for some customers in this category. The type of relief, and its duration, should be determined on a case-by-case basis and not institutionalized into the retail tariff system.

Protection of Economically Vulnerable Residential Customers

The transition to pricing reflecting long-term cost of service will have the most impact on residential customers because of the current low pricing level for this group. The rapid economic changes that are taking place in the SR make it difficult to accurately target those who are most economically vulnerable. However, in 1992, that last year of detailed census data, electricity payments exceeded 3 percent of the household budget in approximately 60 percent of SR homes and exceeded 5 percent in approximately 10 to 15 percent. This 10 to 15 percent was represented primarily by the lower income retirees who do not live with economically active family members. A dual approach is proposed to ease the impact on residential customers:

- Continued cross-subsidies from Category B and C customers slowly phased out by 1999
- The introduction of an inverted block tariff structure with lower tariffs for the first 100 kWh per household per month

An alternative to this approach is the introduction of direct government payments to the economically disadvantaged to compensate for increased electricity prices. However, the budgetary impact of this alternative is beyond the scope of this Study.

Proposed Tariffs

Application of accepted principles and methodologies of tariff analysis to the resource plan provided by SE leads to the suggestion that the following actions be taken:

- Modify SE sales price and all retail tariffs to meet LRMC by 1999.
- Reduce the number of retail tariff categories.
- Gradually increase SE sales price and Category A tariffs to LRMC so that revenues meet 5-year revenue requirements for operation and investment of the system at these voltage levels.
- Gradually decrease Category B tariffs and immediately increase Category C tariffs to LRMC.
- Use surpluses from Category B and C to cross-subsidize residential customers in the near term with phasing out of cross-subsidies by 1999.
- Provide a special lower tariff for the first 100 kWh of consumption per household per month. This guarantees a minimum level of service and minimizes the impact of tariff increases for households with low electricity consumption.

The profile of the proposed price and tariff increases is shown in Figure ES-3.

A key element of any proposed pricing is the revaluation of assets. It follows that legislation required to support such a revaluation should be implemented as soon as possible.

Based on past experience, we believe that the best way to improve the ongoing tariff-setting process in Slovakia in the long term would be by means of an independent regulatory body. In the meantime, it is recommended that the recognition of tariff analysis as a professional activity be fostered at the Ministries of Finance and Economy, SE, and the three RDUs. The establishment of tariff departments in all operating utilities and increased staffing and training for all organizations should be key elements of this recognition.

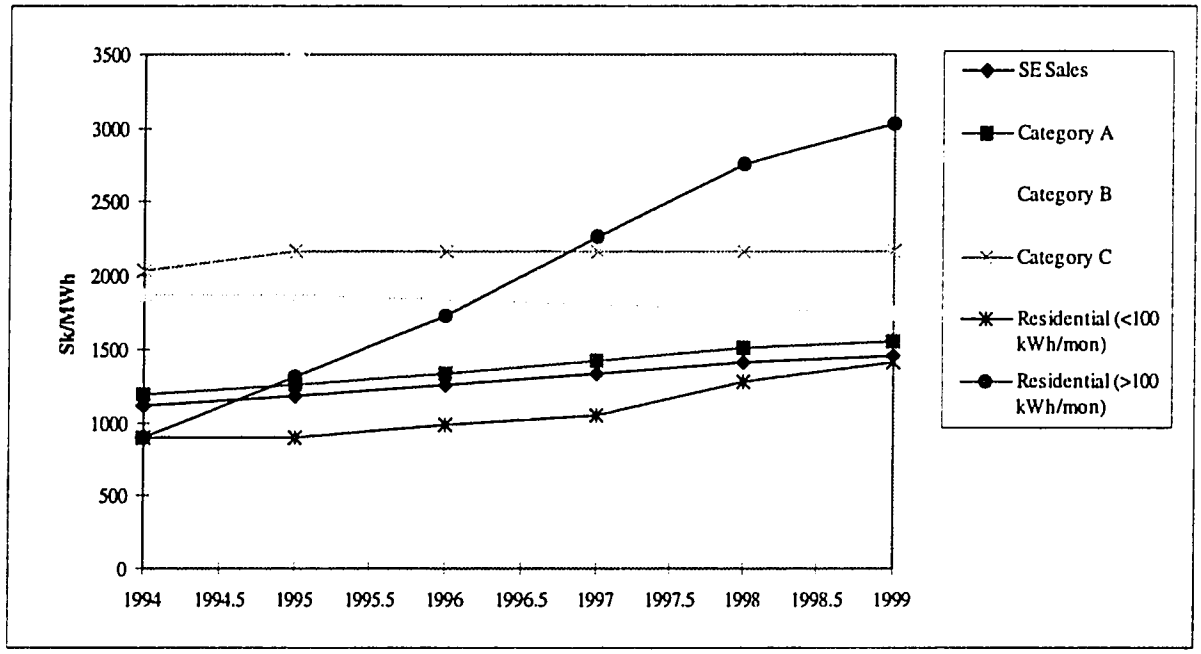

Figure ES-3 Proposed Tariffs for Next Five Years

1 INTRODUCTION

1.1 Study Background and Objectives

This is the Final Report of the Electricity Pricing and Retail Tariff Study. The Study was performed for the Ministry of Economy of the Republic of Slovakia by Bechtel Corporation and its subcontractors, Arthur Andersen & Co. and the Power Research Institute (EGU) of Slovakia. Funding was provided by the U.S. Agency for International Development (USAID). The Study was performed under the guidance of a Steering Committee represented by the Ministries of Economy and Finance, the Antimonopoly Office, the Slovak National Power Co. (SE), and the three Regional Distribution Utilities (RDUs). While the information and guidance of the Steering Committee was invaluable in carrying out the Study, the analyses supporting the Study were conducted independently and the conclusions are those of the Consultant.

The Republic of Slovakia is in the process of restructuring its power sector. USAID had previously assisted this process through support in evaluating restructuring alternatives (March and April of 1993), a regulatory seminar (May 1993), and a review of the overall energy sector (May through November 1993). A major issue associated with restructuring is the pricing of electricity. This affects the financial health of organizations providing power and their ability to acquire capital for reconstruction and replacement of existing equipment. The objectives of the Study were to assemble the facts associated with the cost of providing electricity, evaluate the current retail tariff structure and the pricing of bulk power, and recommend changes in the current system.

Work on the Study was begun in April 1994. Initial data gathering was completed in May. Analysis of supply, demand, and current cost structure; evaluation of the existing pricing and tariff system; and the revenue requirements analysis were completed in June and July. An Interim Presentation was made in July 1994 which addressed existing costs, prices, and overall revenue requirements for electricity production and delivery. The estimation of long-run marginal costs for the various components of the power system was conducted in September and October, and final tariff design was conducted during November.

Steering Committee meetings have been conducted on a monthly basis and each meeting has included a seminar on one of the various aspects of the Study. In addition, individual meetings were conducted with the Ministries, SE, and the RDUs. The data provided by the various organizations represented on the Steering Committee and the information and ideas exchanged during our meetings have been critical to the completion of the Study.

1.2 Overview of the Slovak Power System

The Slovak power system consists of a single state-owned generation and transmission utility (Slovak Power Company, SE), three state-owned regional distribution utilities (RDUs), and generation facilities owned by industries. The RDUs are the West Slovak Distribution Company (ZSE), the Central Slovak Distribution Company (SSE), and the East Slovak Distribution Company (VSE).

SE is responsible for most power generation, power imports and exports, and the 220 kV and 400 kV network. The RDUs are responsible for the network below the 200 kV level. The RDUs are allowed to operate combined heat and power (CHP) facilities and small hydro plants. Currently, ZSE and SSE operate both CHP and hydro plants. Electricity is also generated at industrial plants. This generation is primarily for their own use, but some sales are made to the RDUs.

SE provides capacity and energy to the three RDUs and directly to four industries. The price and terms of delivery are negotiated separately with SE and each of the three RDUs and four industries on an annual basis. The four industries directly served by SE are:

- VSZ a.s.
- Duslo Sala
- Sircka
- Zavlahy Sala

All retail sales are made by the RDUs.

The Ministry of Economy and the Ministry of Finance play key roles in the power sector. The Ministry of Economy is responsible for energy and fuels planning and tariff structure. The Ministry of Finance is responsible for setting the retail price of electricity. The Antimonopoly Office is concerned with monopolistic practices and competitiveness.

The power sector is in a period of transition. Prior to 1990, SE and the RDUs belonged to a single organization. SE became a joint-stock company in November 1994. Its stock is currently completely owned by the National Property Committee. The RDUs have plans to become joint-stock companies. Currently, SE has plans to move to a holding company organization with separate daughter companies for each of the major generating plants and for the transmission network.

1.3 Guide to the Tariff Study Report

The Study Report is organized to answer the following questions:

What are the basic load and resource assumptions used in the Study?	Section 2 for loads and Section 3 for resources
What are the reported costs of electricity compared to the existing prices?	Section 4 for costs and Section 5 for prices
What are the financial requirements for meeting projected investment requirements?	Section 6 for SE and Section 7 for RDUs
What is the strict long-run marginal cost (LRMC) of the various components of electricity supply?	Section 8
How must tariffs based on LRMC be modified to meet other tariff-setting goals?	Section 9

Section 10 addresses tariff issues associated with demand-side management (DSM). The final recommended power pricing and retail tariff design is presented in Section 11 with a proposed implementation plan.

2 REVIEW OF LOAD FORECAST

The purpose of this task was to specify a ten-year (1995-2005) forecast for use in subsequent activities within the overall study. The focus of the analysis was on the next five years; however, the ten-year horizon was used to reflect the impact of long-run investment decisions. This forecast was further defined by voltage level, customer class, and by distribution region.

2.1 Review of Existing Forecasts

A number of power sector load and energy forecasts have been developed during the 1990s for the purposes of least-cost planning. These have included the following:

- Forecasts developed as part of the Tractebel Least-Cost Planning Study (Reference 2-1)
- Forecasts developed by Bratislava Power Research Institute (EGU) as part of the Ministry of Economy energy planning activities. The most recent was for the 1993 Energy Concept Paper (Reference 2-2).
- Forecasts developed by the Slovak National Power Co. (SE) and their contractor, Electricité de France (EdF), as part of SE's ongoing planning efforts (References 2-3 and 2-4).

SE's current investment plan is based on a forecast published in May 1994 and is referred to as the Reference Forecast. It is a minor revision of the EdF January forecast (Reference 2-3). A later EdF study (Reference 2-4) investigates a range of forecasts.

The domestic energy consumption projections for the Reference Forecast, the High and Low of the Tractebel study (Reference 2-1), and the EdF/SE High and Low (Reference 2-4) are illustrated in Figure 2-1.

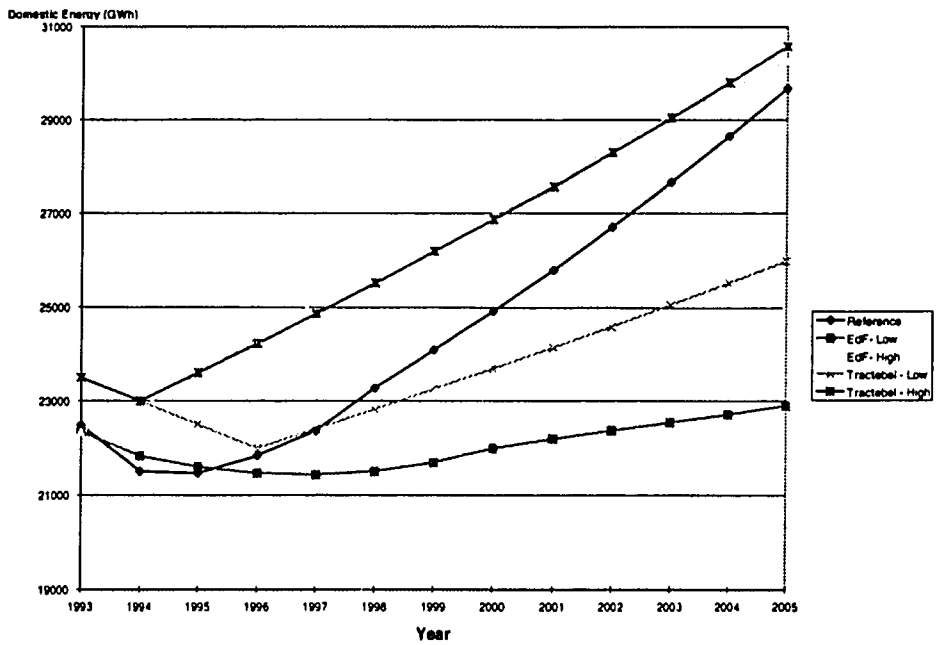

Figure 2-1 Comparison of Electricity Demand Forecasts

All of the forecasts shown reflect the contraction of the Slovak economy after 1989. As can be seen in Figure 2-1, the Tractebel forecasts, which were made in 1992, are substantially higher for 1993 than the others. The EdF/SE and Reference forecasts reflect continued economic decline in 1993 and a slower economic recovery in the future.

All of the forecasts project declines in the intensity of nonresidential electricity use, and all project substantial increases in the intensity of residential electricity use.

The differences between the forecasts can be traced to differences in macroeconomic assumptions. Table 2-1 summarizes these assumptions. In general, the rate of load growth in the Tractebel forecasts is higher than for the EdF/SE forecasts and can be explained by higher projections of GDP growth. The Reference Forecast begins at a lower rate of growth than the EdF/SE Medium forecast but is approximately equal to the EdF/SE High forecast by 2005. The initially lower growth is due to a lower projection of GDP growth in the early years of the forecast. However, the overall GDP growth rate through 2005 for the Reference Forecast is substantially higher than for the EdF/SE Medium case, and there is a much lower projected decline in nonresidential electricity intensity.

Table 2-1
Comparison of Macroeconomic Assumptions in Forecasts

	Average Annual GPD Growth Rate (1993-2005)	Decline in Nonresidential Electricity Use Intensity (1993-2005)	Increase in Number of Households (1993-2005)	Increase in Residential Electricity Intensity (1993-2005)
Reference Forecast	3.3%	9.9%	7.5%	39.9%
Tractebel [1]				
Low	2.2%	16.6%	9.6%	15.3%
Medium	4.0%	27.7%	9.6%	25.6%
High	5.3%	33.2%	9.6%	35.8%
EdF [2]				
Low	1.7%	15.0%	4.9%	22.9%
Medium	2.8%	17.1%	7.5%	39.9%
High	4.1%	21.7%	10.1%	57.7%

1 Reference 2-1

2 Reference 2-4

None of the forecasts have dealt directly with the effects of price elasticity. This is to be expected given the limitations of existing price data and the difficulty of separating price-consumption effects from other structural shifts in the economy during this period of transition. However, current price levels are low compared to most Western European countries. It is likely that electricity prices will rise to levels common in Western European countries and this will tend to temper increases in demand.

2.2 Recommended Forecast for Tariff Planning

Based on discussions with the Steering Committee, the World Bank (WB) and the European Bank for Reconstruction and Development (EBRD), the Reference Forecast, upon which SE has based its investment plan, has been used as a basis for detailed tariff analysis. However, it is recognized that great uncertainty is associated with economic growth over the next ten years, as well as the structural changes that will occur.

The customer category contribution, export assumptions, and projected transmission and distribution system losses are shown in Table 2-2. The power export assumptions are not based on firm contracts.

Table 2-2
Reference Forecast – Electricity Demand (GWh)

	1993	1994	1995	1996	1997	1998	1999	...	2005
Industry	11,708	11,043	10,929	11,053	11,276	11,713	12,170	...	15,269
Agriculture	1,013	948	934	944	954	987	1,020	...	1,251
Construction	145	135	134	136	138	145	153	...	206
Transport	1,006	951	943	951	962	1,003	1,046	...	1,333
Services	1,940	2,023	2,114	2,199	2,287	2,382	2,480	...	3,162
Subtotal	15,812	15,100	15,054	15,283	15,617	16,230	16,869	...	21,221
Residential	3,673	3,771	3,886	4,008	4,149	4,275	4,390	...	5,048
Non-Energy Sector Demand	19,485	18,871	18,940	19,291	19,766	20,505	21,259	...	26,269
Energy Sector Demand	1,147	979	918	916	924	957	990	...	1,248
Net Domestic Energy Demand	20,632	19,850	19,858	20,207	20,690	21,462	22,249	...	27,517
Exports	410	0	225	457	2,500	3,500	3,000	...	1,560
Total Net Energy Demand	21,042	19,850	20,083	20,664	23,190	24,962	25,249	...	29,077
Domestic Peak Load (MW)	3,441	3,307	3,304	3,358	3,434	3,558	3,684	...	4,523

2.3 Disaggregation of the Load Forecast by Voltage Level

The Reference Forecast was disaggregated by voltage level through 1999. This was done based on assumptions concerning the voltage levels servicing various customer categories and estimates of losses at various voltage levels based on reported information for 1993.

The voltage level load forecast by RDU is displayed in Tables 2-3 through 2-5. The following categories are used in referring to voltage levels:

- Extra-High Voltage (EHV) Greater than 200 kV
- Very High Voltage (VHV) 50 - 200 kV
- High Voltage (HV) 1 - 50 kV
- Low Voltage (LV) Less than 1 kV

The Very High, High, and Low Voltage levels are associated with existing tariff categories. The detailed calculations associated with the voltage level forecast are displayed Appendix A.

Table 2-3
Voltage Level Forecast for Western Slovak Distribution Company (ZSE)
(in GWh)

Year	1994	1995	1996	1997	1998	1999
Low Voltage						
Sales	2,697	2,783	2,875	2,976	3,079	3,179
Losses prior to delivery						
> 200 kV	56	58	60	62	64	66
< 200 kV	343	323	327	319	353	351
High Voltage						
Sales	1,897	1,881	1,923	1,987	2,106	2,234
Losses prior to delivery						
> 200 kV	40	39	40	41	44	46
< 200 kV	111	110	111	114	120	127
Very High Voltage						
Sales	1,368	1,332	1,338	1,358	1,414	1,474
Losses prior to delivery						
> 200 kV	29	28	28	28	29	30
< 200 kV	42	40	40	40	42	43
ZSE sales	5,961	5,996	6,136	6,321	6,599	6,887
ZSE losses	496	472	479	474	515	521
Net ZSE generation	263	268	283	645	645	647
Required purchases from SE	6,194	6,200	6,332	6,150	6,469	6,760

Table 2-4
Voltage Level Forecast for Central Slovak Distribution Company (SSE)
(in GWh)

Year	1994	1995	1996	1997	1998	1999
Low Voltage						
' ales	1,883	1,943	2,007	2,078	2,150	2,220
Losses prior to delivery						
> 200 kV	39	41	42	43	45	46
< 200 kV	240	225	229	223	246	245
High Voltage						
Sales	2,588	2,566	2,624	2,711	2,874	3,049
Losses prior to delivery						
> 200 kV	54	54	55	56	59	63
< 200 kV	152	150	152	156	164	173
Very High Voltage						
Sales	1,866	1,818	1,826	1,853	1,930	2,011
Losses prior to delivery						
> 200 kV	39	38	38	38	40	42
< 200 kV	57	55	55	55	57	59
SSE sales	6,337	6,327	6,457	6,642	6,953	7,279
SSE losses	448	430	435	434	467	477
Net SSE generation	296	301	318	725	725	728
Required purchases from SE	6,489	6,455	6,574	6,350	6,695	7,028

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Table 2-5
Voltage Level Forecast for Eastern Slovak Distribution Company (VSE)
(in GWh)

Year	1994	1995	1996	1997	1998	1999
Low Voltage						
Sales	1,681	1,735	1,792	1,855	1,919	1,981
Losses prior to delivery						
> 200 kV	35	36	37	39	40	41
< 200 kV	214	201	204	199	220	219
High Voltage						
Sales	1,589	1,576	1,611	1,664	1,764	1,872
Losses prior to delivery						
> 200 kV	33	33	34	35	37	39
< 200 kV	93	92	93	96	101	106
Very High Voltage						
Sales	1,146	1,116	1,121	1,138	1,185	1,235
Losses prior to delivery						
> 200 kV	24	23	23	24	25	25
< 200 kV	35	34	34	34	35	36
VSE sales	4,415	4,426	4,524	4,657	4,868	5,088
VSE losses	342	327	331	329	356	361
Net VSE generation	0	0	0	0	0	0
Required purchases from SE	4,758	4,753	4,855	4,985	5,224	5,449

2.4 References

2-1. Tractebel Energy Engineering, "Power Sector Least-Cost Development Study for the Czech and Slovak Republics," Volume 1, *Demand Study for the Czech and Slovak Republics,* February 1993.

2-2. Power Research Institute (Bratislava), *The Concept of the Energy Sector in the Slovak Republic by the End of the Year 2005,* May 1993.

2-3. Electricité de France, *Generation Planning Study of the Slovak Electricity System,* January 1994.

2-4. Electricité de France, *Least-Cost Option of the Slovak Power System,* April 1994.

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3 REVIEW OF THE POWER SUPPLY SYSTEM

The objective of this section is to identify the major factors associated with the existing and planned Slovak power supply system affecting electricity pricing and tariff structure.

3.1 The Existing System

3.1.1 Generation

SE operates most of the generating capacity in Slovakia; however SE generation is supplemented by imports, by electricity generation from CHP facilities operated by the RDUs, and by generation by industry. Figure 3-1 summarizes the sources of generation by organization, and Figure 3-2 summarizes the sources of generation by technology for 1993.

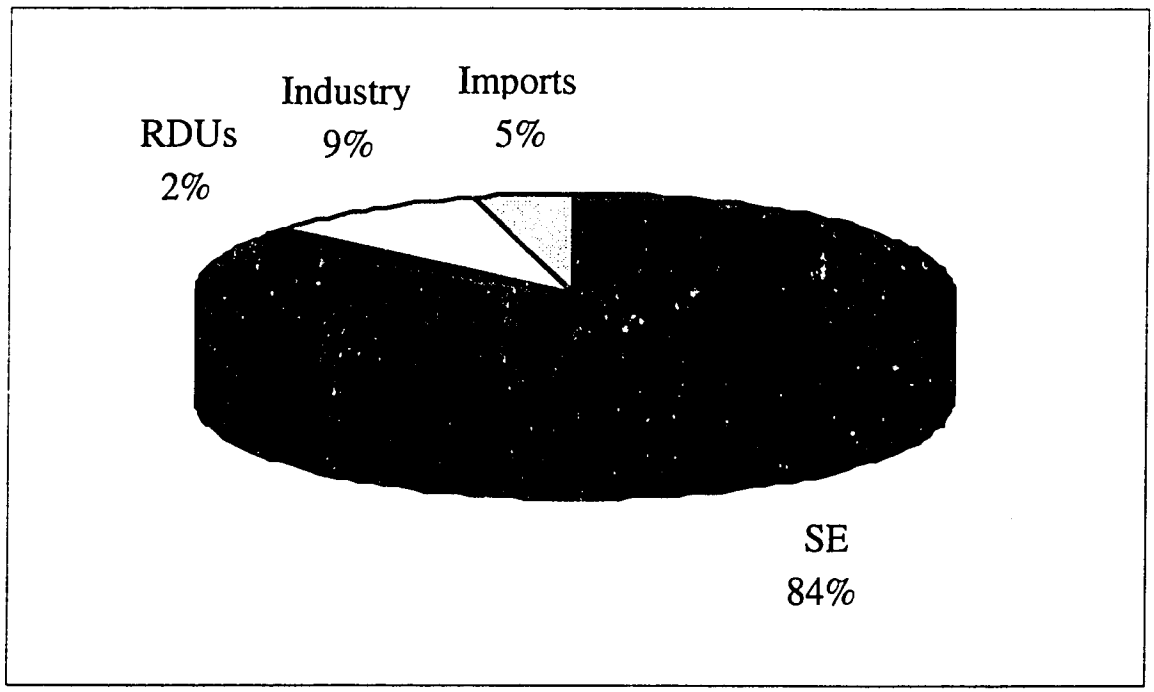
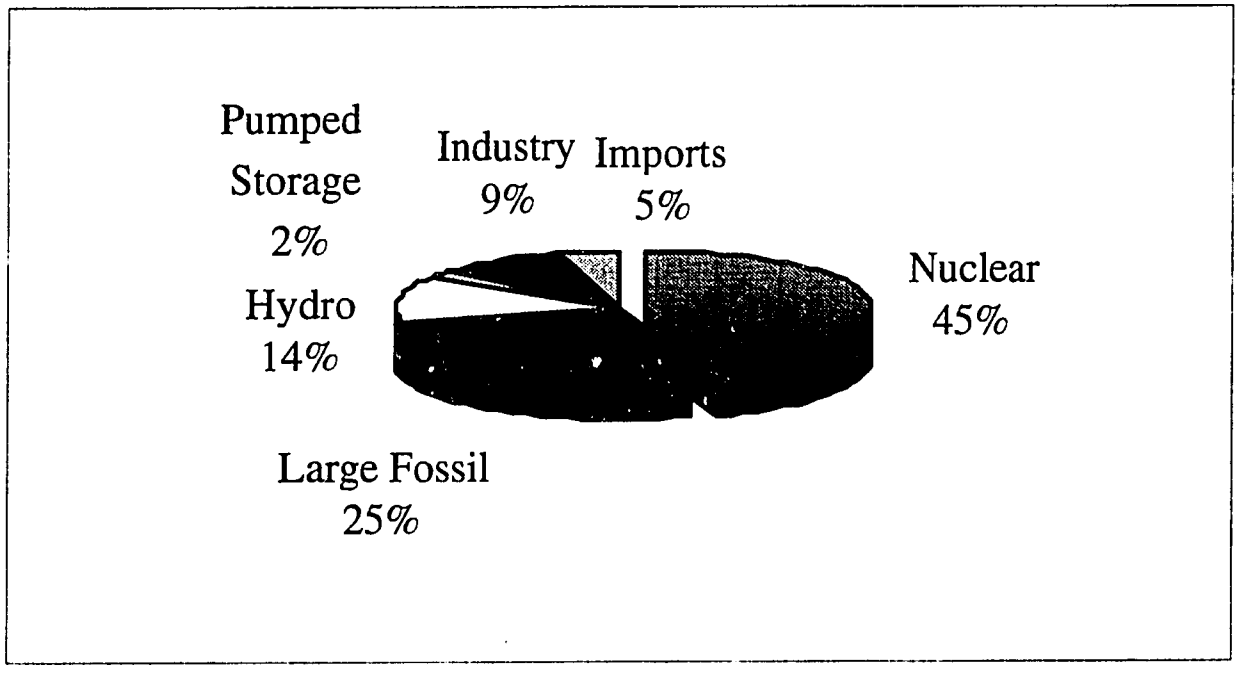


Figure 3-1 1993 Generation by Organization (GWh)



Note: Total 1993 generation and net imports were 24,529 GWh.

Figure 3-2 1993 Generation by Technology (GWh)

As shown, over 45 percent of generation requirements for 1993 were supplied by nuclear power, 25 percent by fossil-fueled facilities, and the remainder with a combination of hydroelectricity, industry-owned generation, and imports. The facilities supplying this generation are described below.

SE-Operated Generation Capacity

SE operates one nuclear power plant, several fossil-fired power plants, a pumped storage plant, and a number of hydroelectric plants. The general characteristics of these power plants are summarized in Table 3-1.

The Bohunice Nuclear Power Station consists of four generating units. All four units are Russian VVER-440 design with a gross capacity of 440 MW each. Units 1 and 2 (referred to as V-1) have been operating since 1981 and are V230 model. Units 3 and 4 (referred to as V-2) have operated since 1985 and are V213 model. A bubble-tower condenser system, considered to be a substitute for reactor containment, was added to the V213 design of V-2. However, the safety of continued operation of the V-1 units, with reactor containment substitute, has been the subject of a number investigations by the International Atomic Energy Agency (IAEA). A number of upgrading measures have been completed with the intent of extending operation through 1995. After that date, significant investments will be required to meet IAEA and Slovak Atomic Energy Commission requirements.

Table 3-1
Characteristics of SE Generating Capacity

Thermal Plants					
Name	Number of Units	Net Capacity (MW)	Fuel	Heat Rate (MJ/kWh)	Forced Outage Rate
Bohunice V-1	2	818	Nuclear	11.7	5%
Bohunice V-2	2	822	Nuclear	11.7	5%
Vojany I	6	600	Coal	11.1-12.7	12%
Vojany II	6	528	Gas	11.0-12.7	10%
Novaky A					
Units 1-2	2	43	Lignite	14.5	10%
Units 3-4	2	54	Lignite	10.1	10%
Novaky B					
Units 1-2	2	200	Lignite	10.5-12.4	4%
Units 3-4	2	158	Lignite	13.9	4%
Kosice	2	121	Gas	7.0	10%

Hydro Plants		
Name	Net Capacity (MW)	Generation for 1993 (GWh)
Gavcikovo	1,646	1,504
Other hydro	450	1,963
Cierny Vah	735	398

In addition, a demonstration nuclear unit referred to as Bohunice A-1 is no longer in operation, but has not been decommissioned.

The Vojany Power Station consists of 12 generating units with gross generating capacity of 110 MW each. The oldest six units, referred to as Vojany I, are fired by imported coal. Four units of Vojany II have dual-firing capability (residual oil and natural gas) and two are fired by natural gas only.

The Novaky Power utilizes domestic coal. Novaky A consists of four units less than 50 MW each. Novaky B consists of four units of comparable size to the Vojany units.

Both the Vojany and Novaky stations have been the subject of rehabilitation studies. Unit 6 of the Vojany I is under reconstruction and SE plans to replace Units 3 through 5 with fluidized bed boilers. SE also plans to replace the four units of Novaky A with fluidized bed boilers. Unit 2 of Novaky B is under reconstruction and SE plans to reconstruct Unit 1. Decommissioning is planned for Units 3 and 4.

SE also operates two CHP units in Kosice.

Generation Capacity Operated by Regional Distribution Utilities

The CHP capacity is used primarily to serve heating loads with electricity production considered as a byproduct. As a result, electricity production tends to follow heating requirements, although the RDUs have the ability to operate this capacity to limit their demand from SE if it is economically to their advantage. The size of RDU-operated small hydro capacity is negligible.

ZSE operates 77 MW of generating capacity from CHP plants from 6 sources ranging from 6 MW to 25 MW in electrical capacity. ZSE also operates 14 small hydro plants with a total capacity of less than 1 MW.

SSE operates three CHP plants with a total capacity of 131 MW and 32 small hydro plants with a total capacity of approximately 2 MW.

VSE does not operate any electric generating capacity.

Table 3-2 summarizes the projected generation from RDUs used in the development of the Reference Generation Plan described later in this section.

Table 3-2
Projected Generation of RDU Capacity

Regional Distribution Utility	1993	1994	1995	1996	1997	1998	1999	2005
Western	257	262	267	282	642	642	645	658
Central	289	297	302	319	728	728	730	746
Eastern	0	0	0	0	0	0	0	0
Total	546	559	569	601	1,370	1,370	1,375	1,404

Industry-Operated Generation Capacity

Industrial generating capacity is used primarily to serve the industrial facilities in which they are located; however, some sales are made to the RDUs. The amount of this capacity and its output have declined with industrial output since 1989.

While this capacity is not controlled by SE or the RDUs, the RDUs can and have requested industries to operate in situations in which they have been in danger of exceeding contractual maximum demand in their purchase contract with SE.

Table 3-3 summarizes the projected generation assumptions from industrial facilities which have been used in the development of the Reference Generation Plan described later in this section.

3.1.2 Extra-High Voltage (EHV) Transmission and Dispatching

The EHV transmission system is defined as equipment operated at voltages greater than 200 kV. This system is operated by SE. Operation and maintenance is conducted by the RDUs under contract from SE. There are approximately 1,500 km of 400 kV transmission lines and 1,000 km of 220 kV lines. There are 18 400 kV/220 kV/110 kV substations.

Table 3-3
Projected Generation of Industry-Owned Capacity

Industry Served By	1993	1994	1995	1996	1997	1998	1999	2005
ZSE	665	652	644	638	632	623	609	493
SSE	419	411	405	402	398	392	383	310
VSE	456	447	441	437	433	427	417	338
SE	640	627	619	613	608	599	585	474
Total	2,180	2,137	2,109	2,090	2,071	2,042	1,995	1,615

The system is dispatched from the Central Dispatch Center in Zilina (operated by SE). The RDUs each operate regional dispatch centers.

Slovakia is interconnected with the Czech Republic, the Ukraine, and Hungary. Interconnections with Poland and Austria are underway. Since October 1992, SE has been a member of CENTREL which includes the power systems of the Czech Republic, Hungary, and Poland and aims at the gradual integration, cooperation, and active interconnection with Western European grid (UCPTE).

3.1.3 Transmission and Distribution

The RDUs operate all transmission and distribution facilities below 220 kV. The transmission levels are categorized as Very High Voltage (VHV), High Voltage (HV), and Low Voltage (LV). The general characteristics of this system are summarized in Table 3-4.

Table 3-4
Transmission and Distribution below 200 kV

	Length of Lines (km)				
			Low Voltage		
Year	Very High Voltage	High Voltage	*Overhead*	*Underground*	*Total*
1989	4,256	26,799	34,520	8,158	42,678
1993 (estimate)	4,637	27,855	35,880	8,479	44,360

3.2 Production of Combined Heat and Power

All of the SE- and RDU-owned electric generating plants in Slovakia have some heat production capability used for district heating, sanitary water, and industrial process steam. In addition, much of the industry-owned electricity generation is based on CHP plants. However, the only SE plants in which a significant percentage of the generation output is associated with CHP operation are Novaky B and Kosice. Most RDU generation is associated with CHP operation.

3.3 Purchases from Independent Power Projects

Currently, all generating capacity is either owned and operated by SE, the RDUs, or by industry. Production by industry-owned capacity is limited to the demand of the facility where the capacity is located. However, it is contemplated that the completion of the Mochovce Nuclear Power Plant and rehabilitation of existing fossil-fired capacity will be done with the assistance of foreign investment. The proposed organizational structure of SE as a holding company would allow individual plants to operate as semi-independent entities. This will require formalization of transfer pricing into contracts.

3.4 Power System Development Plan

A number of studies have been conducted addressing power system least-cost planning in Slovakia. These include the following:

- Tractebel Least-Cost Planning Study (Reference 3-1) funded by the European Community.
- Plans developed by Bratislava Power Research Institute (EGU) as part of the Ministry of Economy energy planning activities. The most recent was for the 1993 Energy Concept Paper (Reference 3-2).
- Plans developed by SE and their contractor, Electricité de France (EdF), as part of SE's ongoing planning efforts.
- A least-cost plan in progress under EBRD funding and directed at the decision to complete Mochovce Units 1 and 2.

SE conducts power system planning on a ongoing basis. Its current official generation plan (Reference 3-3), upon which the tariff analysis is based, was developed in conjunction with EdF using the LOGOS model. This plan was based on the Reference Load Forecast presented in Section 2. The Reference Generation Plan is presented in Tables 3-5 and 3-6. Table 3-5 shows the plan by plant and Table 3-6 is arranged in chronological order. The key features of the Reference Generation Plan are:

- Completion of four units of the Mochovce plant (1997, 1998, 2000, 2001, respectively)
- Retirement of the two units of Bohunice V-1 in 2000 and 2001 respectively
- Reconstruction of the Vojany and Novaky plants
- Addition of 600 MW of gas-fired combined cycle capacity between 2000 and 2005

These features, with adjustments in timing to account for different load forecasts, are common to the Tractebel and Ministry of Economy plans. Discussions with the Ministry indicate that a higher priority may be placed on the development of gas-fired CHP plants (probably not owned by SE) than on the thermal plant reconstruction projects.

Table 3-5
Reference Generation Plan by Plant

Name	Action	Year
Bohunice V-1		
Unit 1	Retire	2000
Unit 2	Retire	2001
Mochovce		
Unit 1	Commission	1997
Unit 2	Commission	1998
Unit 3	Commission	2000
Unit 4	Commission	2001
Vojany I		
Unit 1	Reconstruct	1997
Unit 2	Reconstruct	1998
Unit 3	Reconstruct	1997
Unit 4	Reconstruct	2000
Units 5 and 6	Return to Service	1996
Vojany II		
Units 5 and 6	Retire	1995
Novaky A		
Units 1 and 2	Reconstruct	1995 and 1997
Units 3 and 4	Retire	1997 and 2000
Novaky B		
Unit 1	Reconstruct	1998
Unit 2	Return to Service	1994
Units 3 and 4	Retire	1999
Gas-fired combined-cycle plants		
Plant 1	Commission	2002
Plant 2	Commission	2005

Table 3-6
Reference Generation Plan in Chronological Order of Investments

Year	Name	Action	Net Capacity Increase (Decrease) (MW)	Cumulative Increase (Decrease) (MW)
1995				-209
	Novaky A			
	Unit 1	Reconstruct	-9	
	Vojany II			
	Units 5 & 6	Retire	-200	
1996				-9
	Vojany I			
	Units 5 & 6	Return to Service	200	
1997				341
	Mochovce			
	Unit 1	Commission	411	
	Vojany I			
	Units 1 & 3	Reconstruct	0	
	Novaky A			
	Unit 2	Reconstruct	-7	
	Unit 3	Retire	-54	
1998				808
	Mochovce			
	Unit 2	Commission	411	
	Vojany I			
	Unit 2	Reconstruct	0	
	Novaky B			
	Unit 1	Reconstruct	56	
1999				650
	Novaky B			
	Units 3 & 4	Retire	-158	
2000				810
	Bohunice V-1			
	Unit 1	Retire	-409	
	Mochovce			
	Unit 3	Commission	411	
	Vojany 1			
	Unit 4	Reconstruct	0	
2001				812
	Bohunice V-1			
	Unit 2	Retire	-409	
	Mochovce			
	Unit 4	Commission	411	
2002				
	GCC			1,112
	Plant 1	Commission	300	
2005				
	GCC			1,412
	Plant 2	Commission	300	

3.5 Investment and Operating Cost Assumptions

3.5.1 Macroeconomic Assumptions

The revenue requirements analyses for SE and the RDUs are based on a real return on net fixed assets (valued at replacement value). Real rates of return between 5 percent and 10 percent were considered. Analysis was conducted in 1993 money values (Sk and US $). Real price increases (i.e., increases that occur in terms of 1994 $ or Sk) are considered. However, price increases associated with general inflation (i.e., associated with the declining value of currency) are not.

3.5.2 Exchange Rate

An exchange rate of 32 Sk per US$ was used in converting currencies.

3.5.3 Fuel Prices

Fuel price assumptions are intended to reflect world market levels and are summarized in Table 3-7. Except for lignite for the Novaky plant, all fuels are imported.

3.6 References

3-1. Tractebel Energy Engineering, "Power Sector Least-Cost Development Study for the Czech and Slovak Republics," Volume 1, *Generation System Study for the Czech and Slovak Republics*, February 1993.

3-2. Power Research Institute (Bratislava), *The Concept of the Energy Sector in the Slovak Republic by the End of the Year 2005*, May 1993.

3-3. Electricité de France, *Generation Planning Study of the Slovak Electricity System*, January 1994.

3-4. Electricité de France, *Least-Cost Option of the Slovak Power System*, April 1994.

3-5. ETSU, Comprehensive Energy Sector Study and Integrated Energy Pricing/Taxation Study for the Czech and Slovak Republics, Second Interim Report, May 1994.

Table 3-7
Fuel Price Projection
(Expressed in 1993 Currency)

	1993	1994	1995	1996	1997	1998	1999	2005	Explanation
US $/GJ									
Crude oil	3.96	3.88	3.80	3.97	4.14	4.32	4.50	5.20	IEA/OECD forecast taken to represent market price
Natural gas	3.38	3.46	3.70	3.79	3.89	3.99	4.09	4.90	
Coal	1.98	1.94	1.90	1.92	1.94	1.96	1.98	2.10	
US $/GJ									
Nuclear	0.31	0.33	0.36	0.38	0.41	0.44	0.47	0.53	10 Sk/GJ in 1993 and 1 percent real escalation
Coal	1.52	1.58	1.64	1.71	1.78	1.85	1.92	2.10	Reaches market value in 2000 and 1 percent real escalation thereafter
Lignite	2.19	2.30	2.53	2.64	2.75	2.87	2.99	3.46	Follows imported coal escalation
Residual oil	2.37	2.33	2.28	2.38	2.48	2.59	2.70	3.12	60 percent of projected crude oil price
Natural gas	3.38	3.46	3.70	3.79	3.89	3.99	4.09	4.90	Market price
Sk/GJ									
Nuclear	10	11	11	12	13	14	15	17	10 Sk/GJ in 1993 and 1 percent real escalation
Coal	49	50	52	55	57	59	62	67	Reaches market value in 2000 and 1 percent real escalation thereafter
Lignite	70	74	81	84	88	92	96	111	Follows imported coal escalation
Residual oil	76	74	73	76	79	83	86	100	60 percent of projected crude oil price
Natural gas	108	111	118	121	125	128	131	157	Market price

Note: Based on IEA/OECD forecast of average EC import prices (Reference 3.5).

4 REVIEW OF THE CURRENT POWER SYSTEM COST STRUCTURE

The objective of this section is to present a review of the cost structure of the Slovak power system in terms of supply categories (i.e., generation, transmission, and distribution) and customer categories, fixed and variable costs, and time-of-day and seasonal cost variations. The existing cost structure is analyzed based on 1993 reported costs. An analysis of short-run marginal cost (SRMC) for the generation system is presented in order to address season and time-of-day variations. This analysis also supports the revenue requirements analysis in Sections 6 and 7 and lays the groundwork for the analysis of long-run marginal cost (LRMC) in Section 8. The focus of the SRMC analysis is on the period from 1993 through 1999.

4.1 Costs by Supply Category and Customer Category

Costs of generation, transmission, and distribution were estimated for 1993 based on reported costs. Sections 6 and 7 provide details of the separation of costs that were not directly reported (e.g., separation of generation and transmission cost for 220 kV and above, and heating costs for combined heating and power generation).

The average bulk price for electricity in 1993 was slightly more than 1,100 Sk/MWh (35 $/MWh) and the average retail price was approximately 1,500 Sk/MWh (47 $/MWh). There are no direct subsidies, and a review of the cost information from the various power supply organizations indicates that the prices reflect all operating costs, but limit the ability to replace existing assets. Figure 4-1 shows the contribution of each supply category to overall reported costs. Over 70 percent of overall power supply costs for the Slovak Republic in 1993 were associated with generation.

Figure 4-2 shows the components of reported generation cost. The most significant item concerning these costs is the low contribution of depreciation, given the dominance of nuclear generation. Depreciation only accounts for 10 percent of reported generation costs. High inflation since 1989 has made the book value of existing assets much less than replacement costs. This phenomenon has occurred in the transmission and distribution areas as well. The revenue requirements analyses of SE in Section 6 and the RDUs in Section 7 address the revaluation of assets in terms of the financial health of those organizations.

Customer categories were defined by service voltage as follows:

- Directly served
- Very High Voltage (VHV) – 50 - 200 kV (corresponds to Tariff Category A customers)
- High Voltage (HV) – 1 - 50 kV (corresponds to Tariff Category B customers)
- Low Voltage (LV) – less than 1 kV (corresponds to Tariff Category C customers)

Low Voltage customers include residential and commercial categories. Figure 4-3 shows the contribution of each customer category to overall demand for 1993.

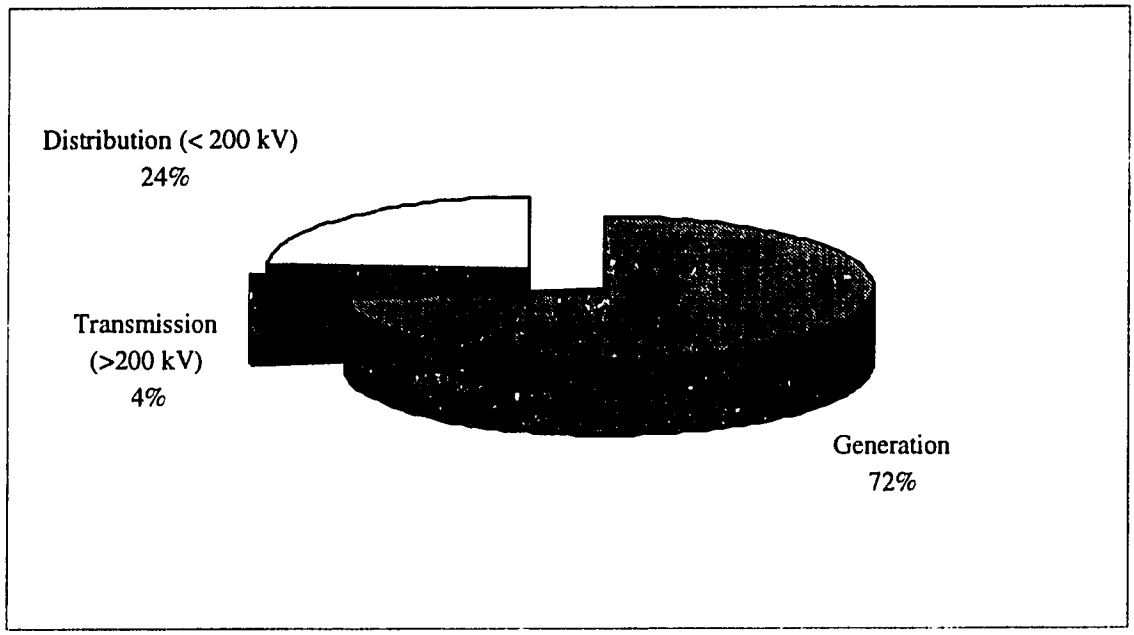


Figure 4-1 Reported Cost Contribution by Supply Category – 1993

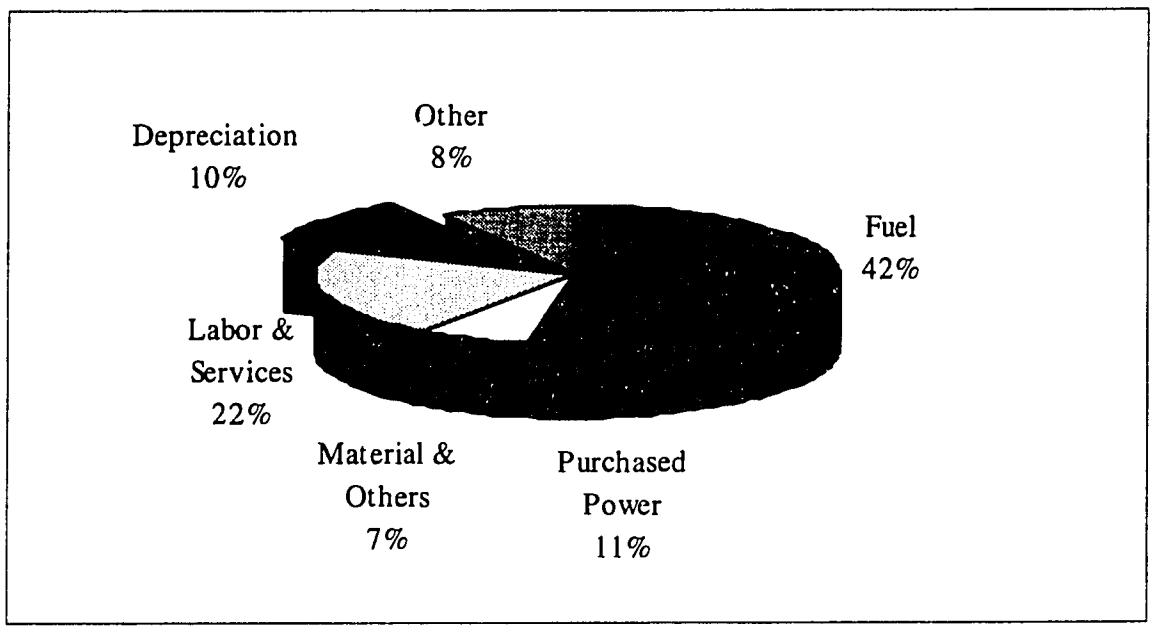


Figure 4-2 Contribution to Generation Costs – 1993

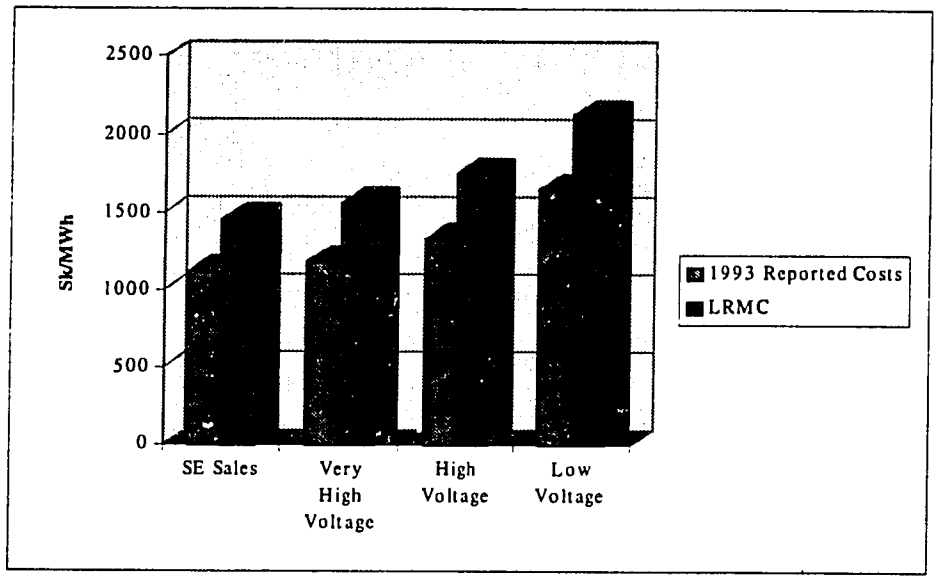


Figure 4-3 Comparison of 1993 Reported Costs with Long-Run Marginal Costs

The reported costs for 1993 were assigned to customer categories to obtain average reported cost by customer category. For example, directly-served customers were assigned the per unit cost of generation and EHV (over 220 kV) transmission adjusted by EHV network losses. Likewise, the VHV category was assigned the per unit cost of generation, EHV and VHV transmission adjusted by EHV, and VHV network losses, etc.

The long-run marginal cost (LRMC) is the incremental investment and operating cost of providing a 1 kWh increase in demand over an indefinite period of time (or the cost savings associated with a reduction of 1 kWh). Figure 4-3 compares the reported costs with the reported LRMC by category as estimated in Section 8. The difference between the two is primarily the result of low estimates for depreciation compared to equipment replacement cost.

4.2 Simulation of the Operation of the Generation System

The operation of the generation system was simulated using the Elfin model. This model was developed by the Environmental Defense Fund and is licensed to Bechtel. It is a commonly used model for power system production simulation for tariff analysis. A copy of this model has been provided to the Ministry of Economy through USAID funding; a description of the model is provided in Appendix B.

The purpose of simulation is to project the operation of plants under a given set of assumptions in order to determine fuel use, calculate the reliability of the generation system, and to identify what units would increase operation if the load were to increase a small amount. The identification of these units and their incremental operating cost is the method of calculating short-run marginal cost (SRMC) and is one of the outputs of the model. The definition of SRMC is the incremental variable cost associated with a small increase in demand. It does not include future investment costs and costs which are fixed in the short term (i.e., costs that do not vary with the amount of generation).

Some of the important factors that affect the operation of the system are:

- Technical characteristics of the generating units including capacity, reliability, and maintenance requirements and the need to provide heat as well as electric power
- Cost characteristics of generating units, including operation and maintenance costs and efficiency as a function of total output
- Fuel prices
- Absolute value of load demand
- Daily and seasonal shape of loads
- Export power agreements

These factors have been discussed in Sections 2 and 3 as they relate to the Slovak power system. The data used for the analysis are provided in Appendix C. The results of the analysis are presented in Appendix D. The entire Slovak generation system was modeled including SE, RDU, and industry generation. Average hydro conditions were assumed.

The Slovak power system was modeled on a monthly basis using the time periods identified below.

First and Fourth Quarters	
Peak:	6 a.m. - 10 a.m.
Mid-peak:	10 a.m. - 10 p.m.
Off-peak:	12 a.m. - 6 a.m. and 10 p.m. - 12 a.m.
Second and Third Quarters	
Peak:	6 a.m. - 10 a.m. and 5 p.m. - 8 p.m.
Mid-peak:	10 a.m. - 1 p.m., 3 p.m. - 5 p.m., and 8 p.m. - 12 a.m.
Off-peak:	12 a.m. - 6 a.m. and 1 p.m. - 3 p.m.

These time periods correspond to the 1993 time periods used for the contractual arrangements by SE and RDUs for the first and second quarters of 1993. The contracts between SE and the RDUs and retail tariffs allow for a quarterly modification of the time period definition to reflect changes in load shapes. The initial load shape used in the system modeling was based on 1993 dispatch data. Figure 4-4 shows the variation of monthly peak loads for 1993. The system is winter peaking and the peak occurred in December in 1993. Figure 4-5 shows the load variation over typical weekly days in each quarter. The daily load factor in each case is more than 90 percent.

4.3 Generation System Reliability Analysis

Two measures of generation system reliability were calculated using the Elfin model: loss-of-load-probability (LOLP) and energy-not-served (ENS). Each is an indication of the likelihood of the generation system to meet system demand given the possibility of the outage of individual generating units.

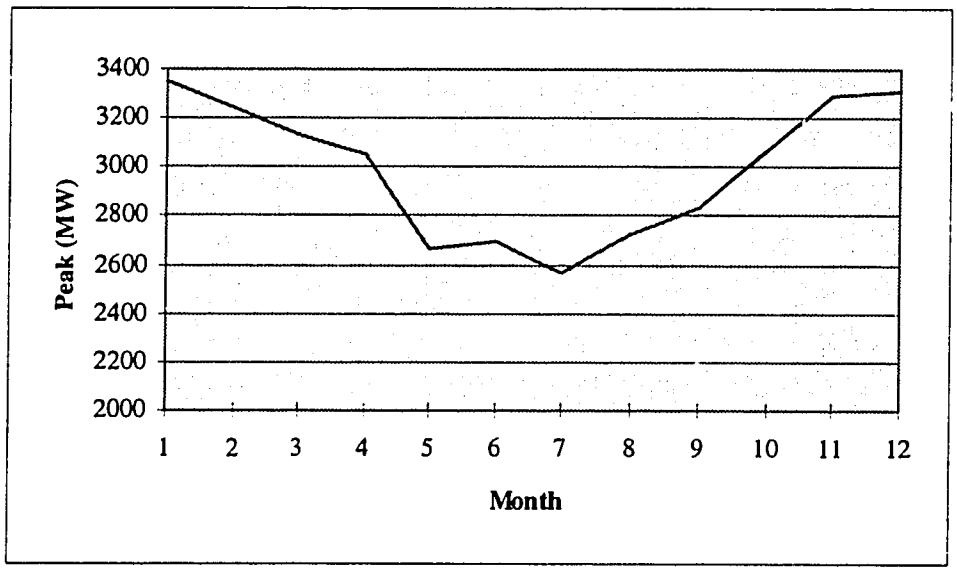


Figure 4-4 Monthly Peaks – 1993

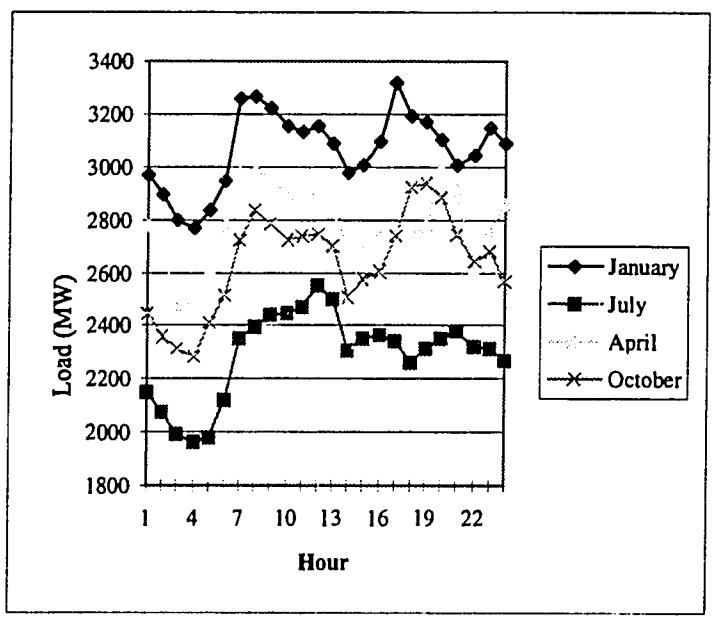


Figure 4-5 Typical Daily Load Shapes for Each Quarter – 1993

This analysis was conducted under average hydro conditions. Therefore, the reliability statistics calculated do not reflect the reliability effects of dry hydro conditions and should not judged in absolute terms. However, the seasonal and time-of-day value of the reliability statistics provide an indication of the degree to which various time periods contribute to the key reliability statistics. The contribution of the various periods to LOLP and ENS was found to be approximately the same.

Figure 4-6 shows the results for 1995. The peak load is projected to be in the fourth quarter as it was in 1993. This quarter contributes about 65 percent to the annual LOLP. The first quarter contributes about 20 percent. The second and third quarters together contribute the remaining 15 percent. These results are sensitive to weather and economic conditions that could shift the peak from the fourth to first quarter, which would affect scheduling of maintenance and reconstruction activities.

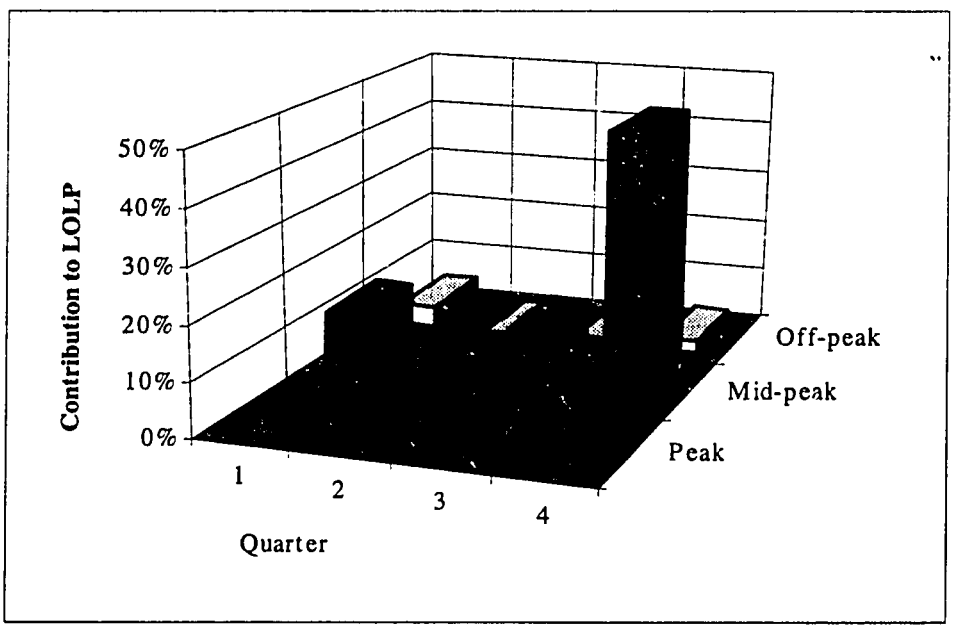


Figure 4-6 Projected Contribution to Loss-Load Probability by Time Period – 1995

The peak period accounts for 16 percent of the annual hours and is responsible for 33 percent of the LOLP. The mid-peak period, accounting for 31 percent of the hours, is responsible for 67 percent of the LOLP. As would be expected, the off-peak period contributes virtually nothing to LOLP. However, it is surprising that the peak and off-peak periods contribute almost equally to LOLP when adjusted for the differing lengths of the periods (i.e., each peak hour contributes approximately the same amount to LOLP as each mid-peak hour). This can be explained by the relatively low peaks, exemplified by high daily load factors, and the relative lack of flexibility of the Slovak generating units.

4.4 Analysis of Average Variable Generation Costs and Short-Run Marginal Costs (SRMC)

Average variable generation cost is the combination of the fuel and non-fuel costs. The SRMC indicates the value of an additional kWh of generation, or conversely the value of reducing demand by a kWh, in the near term. This measure is useful in determining the value of a purchase of energy which cannot be counted on to meet peak demand or is not available on a basis that can result in a modification to the overall investment plan.

Figure 4-7 shows a monthly load curve for the system and the method of covering the load curve with various generating sources. The average generating cost is based on the costs of operating Units A, B, C, D, and E. Units D and E are operating at the edge of the load curve. An increase (or decrease) in system demand will result in more (or less) generation from these sources. The SRMC for the system for the given month is given by the incremental cost of operating Units D, E, and C weighted by the percent of time that each operates on the edge (or margin) of the load curve. The generating costs of Units A, B, and C do not affect the SRMC.

Figure 4-8 shows the resulting average projected variable generating cost and SRMC by year. Average variable generating cost is projected to be relatively low, varying between 220 and 440 Sk/MWh (8 and 14 $/MWh) due to the dominance of nuclear in the generation mix. However, SRMC is determined by the units which would change operation if there was a load increase or decrease. These are generally fossil-fired units on the Slovak system, so that the SRMC is projected to be two to three times as much as average cost (i.e., 850 to 1,500 Sk/MWh between 1995 and 1999, or 25 to 45 $/MWh).

Seasonal and time-of-day SRMC are shown for 1995 in Figure 4-9. Average quarterly SRMC is projected to be the highest in the fourth quarters and lowest in the second quarter with the fourth quarter SRMC about 60 percent higher than the second quarter. Time-of-day differences in SRMC are much less with peak period SRMC averaging about 10 percent greater than off-peak SRMC. As with the low time-of-day differentiation of LOLP discussed above, the small difference in SRMC on a time-of-day basis can be explained by high daily load factors and the relative lack of flexibility of the Slovak generating units.

4.5 Generation System Avoided Costs

Currently, the economic incentive to RDUs to generate electricity is to avoid payments to SE, and the economic incentive to industries to generate electricity is to avoid payments to either the RDUs or to SE (if the industry is directly served). SRMC can be a guide for pricing of this generation. However, SRMC is the incremental generating cost for a very small amount of demand increase (or generation savings for a small decrease). The amount of generation produced by the RDUs and by industry is large enough to justify an analysis of the generation cost with and without the RDU and industrial generation. The cost of the generation avoided by SE as a result of the RDU and industrial generation is termed the "avoided cost" for that category of generation.

The avoided cost is similar to SRMC in principle. However, it is intended to be applied to more than the "small" decrease in demand associated with SRMC.

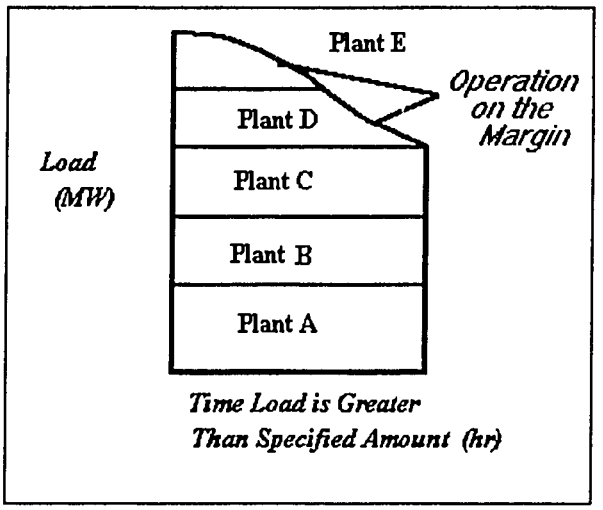


Figure 4-7 Illustration of Short-Run Marginal Cost

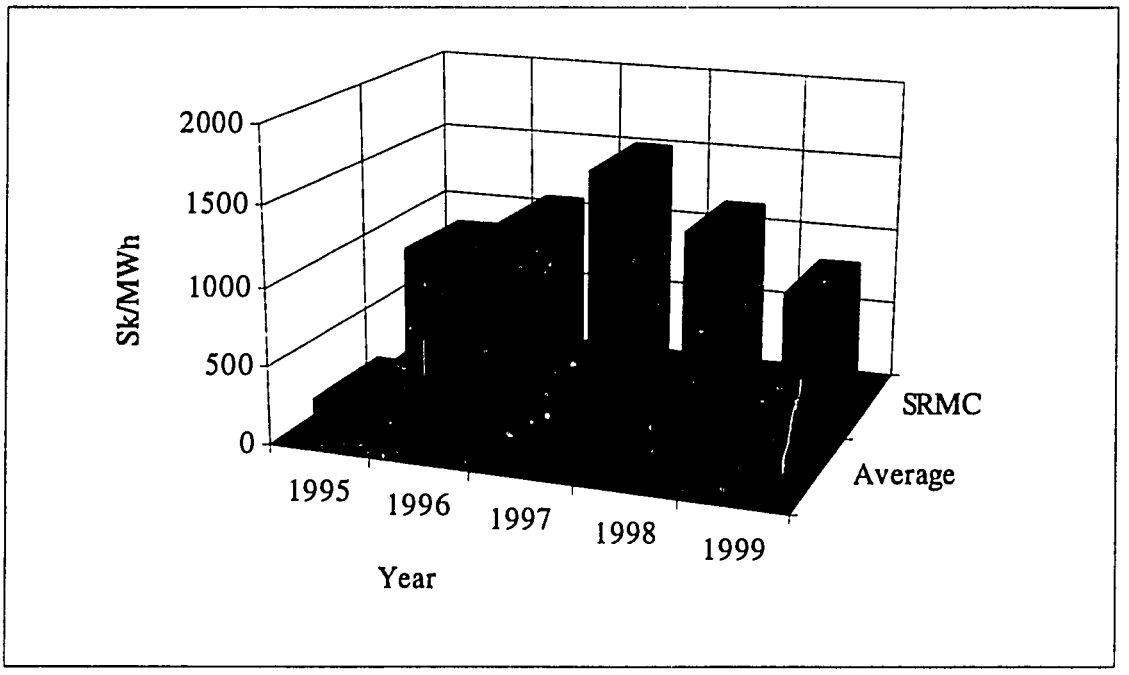


Figure 4-8 Comparison of Projected Average Variable Generating Cost and Short-Run Marginal Cost

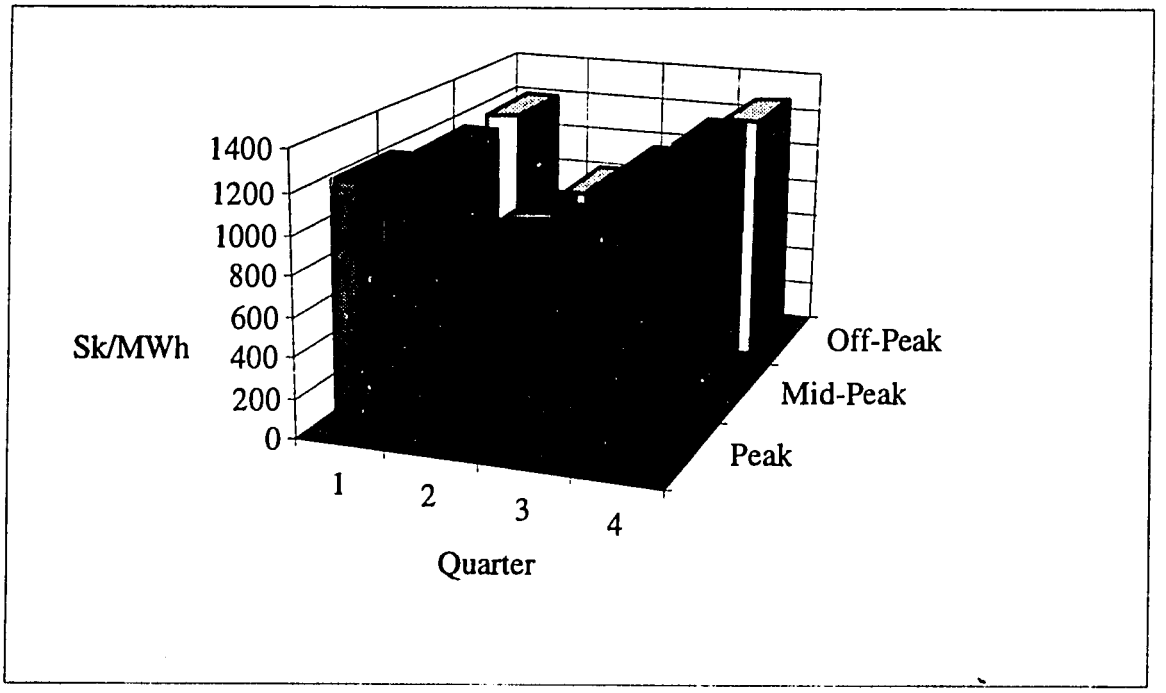


Figure 4-9 Projected Short-Run Marginal Cost by Time Period – 1995

This analysis of total system generation cost with and without RDU and industry generation was conducted. Table 4-1 shows the results of this analysis. As indicated, the levelized avoided short-run cost from 1995 through 1999 for this generation is approximately 1,600 Sk/MWh (50 $/MWh). This value compares with the average of 1,150 Sk/MWh of SE sales to the RDUs and an average retail tariff of 1,300 Sk/MWh for Very High Voltage customers. In both cases the avoided short-run costs exceed the economic incentive provided to the generators.

In addition to avoided short-run costs, the use of this generation should have long-run implications through reducing the need for additional SE capacity. Discussions with RDUs concerning the use of their own capacity and their requests to industry to generate in order to avoid penalties associated with exceeding SE contract capacity indicate that RDU and industry generation already affect long-run costs. However, contractual arrangements would have to exist between SE and the generators guaranteeing performance of the plants, or penalizing nonperformance, before payments in addition to SRMC would be appropriate.

Discussions with SE and consultants engaged in DSM analysis for the Slovak power sector indicated that DSM applications are not expected to have near-term effects on investment requirements assuming the completion of the Mochovce Nuclear Plant. If this is the case, the SRMC values would provide an appropriate measure of minimum DSM value. However, to the degree that investments in DSM can result in the deferment of investments in generation, transmission, and distribution, values closer to the LRMC for the voltage level of the DSM application may be more applicable. A further discussion of the tariff considerations for DSM is presented in Section 10.

Table 4-1
Avoided Cost of Generation Projected to be Supplied by RDUs and Industry

	1995	1996	1997	1998	1999
Total system demand (GWh)	21,462	21,906	22,365	23,274	24,087
Industry generation (GWh)	2,095	2,083	2,057	2,028	1,982
RDU generation (GWh)	569	606	1370	1370	1375
Total generation (GWh)	2,664	2,688	3,427	3,398	3,357
Without industry and RDU generation	280	403	294	221	285
With industry and RDU generation	166	250	114	68	113
Energy value of generation	114	153	180	153	173
($/MWh)	42.7	57.0	52.5	45.0	51.5
(Sk/MWh)	1,366	1,825	1,679	1,439	1,647
Levelized value (1994-1999)	49.7	$/MWh			
	1,589	Sk/MWh			

4.6 Effect of Combined Heat and Power Sales

As discussed in Section 3, all of the plants operated by SE and the RDUs have some combined heat and power (CHP) capability. However, only a small percentage of the electric generation of the Slovak system is associated with CHP generation. The method of pricing heat and power currently requires the allocation of production cost and depreciation to heat and power consumers. Heat tariffs are currently based on these allocated prices. Low-income residential consumers are reimbursed by the government; however, these payments are to be phased out in the near future.

The allocation method used is based on energy use for the two products and is therefore called the "Exergetic Method." This method does not differentiate between the energy quality of heat and power. Many other techniques exist for allocating heat and power costs. They tend to allocate more costs to the power side because of the higher quality of energy associated with electricity or because of its higher economic value. However, there is no perfect cost allocation method.

The avoided cost approach to the pricing of electric generation discussed previously makes cost allocation between heat and power unnecessary. Electricity from CHP plants is priced at its economic value under this method. The economic value of this production is diminished if it cannot be dispatched when needed or if its performance is not guaranteed. However, the system SRMC provides the minimum value of CHP electricity generation even if its capacity is considered of no value.

5 REVIEW OF EXISTING TRANSFER PRICING AND TARIFF STRUCTURE

This chapter presents a review and an evaluation for existing transfer pricing and tariff structures. Transfer pricing and tariff structures will be reviewed in light of reported costs, financial requirements, and long-run marginal cost.

5.1 Overview

The three Regional Distribution Utilities (RDUs) provide approximately 93 percent of the retail electricity for the Slovak Republic (SR). SE provides generation, sells to the three RDUs, and provides the balance of retail sales to four directly served industrial customers. SE and the RDUs provide heat to industries and the district heating system, part of which is provided by combined heat and power (CHP) plants.

5.1.1 Pricing of Electricity Sold to RDUs

Electricity is mostly generated by SE and sold to the RDUs. Electric power sales are governed by contractual agreements between SE and each individual distribution company. Contractual prices and terms are negotiated annually with each distributor. The average 1993 price from SE to the RDUs was approximately 1,100 Sk/MWh (34 $/MWh).

5.1.2 Summary of Existing Retail Tariffs

There are four classes of retail tariffs as follows:

- Large customers connected to the electric network at a voltage over 52 kV. This is referred to as the Very High Voltage (VHV) level. There are three tariffs serving these customers; Tariffs A1, A2, and A10.
- Large customers connected to the network at a voltage from 1 to 52 kV (High Voltage or HV customers). These customers are served by Tariffs B1, B2, B3, B4, B5, B6, B10, B11, B12, and B13.
- Large customers connected to the electric network at a voltage less than 1 kV. These customers are billed based on Tariffs C1, C2, C3, C4, C10, and C11.
- This class of tariffs is to serve residential customers (households). There are many tariffs that suit different customers with varying consumption needs for electricity. Their features include peak, mid-peak, and off-peak energy pricing. Customers are given some economic signals for differentiated production cost periods.

The C category and the residential customers are served below 1 kV, referred to as the Low Voltage (LV) level. Ultimate customers in the SR are served by the RDUs except for four large customers, which are directly served by SE. All tariffs applicable to the existing four classes of customers are summarized in Tables 5-1 and 5-2. Large customers under Tariffs A and B are summarized in Table 5-1. Residential and Tariff C customers are shown in Table 5-2.

Table 5-1
1993 Retail Tariffs for Customers Served at Very High and High Voltage

	Demand Charge					Energy Charge (Sk/MWh)		
Tariff	Technical Maximum Demand (Sk/kW)	Agreed 15-Minute Peak (Sk/kW)	Penalty for Overpassing 15-Minute Peak (Sk/kW)	Measured 15-Minute Peak (Sk/kW)	Transformer Capacity (Sk/kVA)	Peak Period	Mid-Peak Period	Off-Peak Period
Category A								
A1	74	163	550			830	660	610
A2	74			185		830	660	610
A10							1,100	
Category B								
B1	90	185	640			930	740	660
B2	90			211		930	740	660
B3	90	207	700				740	660
B4	90			235			740	660
B5	90			235			740	660
B6					139		740	660
B10							1,460	
B11				320 [1]			740	660
B12				320 [1]			930	730
B13							370	660

[1] Measured in the high tariff band.

Table 5-2
1993 Retail Tariffs for Customers Served at Low Voltage

Tariff	Energy Charge: Peak Period (Sk/MWh)	Energy Charge: Off-Peak Period (Sk/MWh)	Customer Charge: Sk/Month
Residential			
BS-V	1,640		5.0
BS-N		370	25.5
B-V	870		34.0
B-N		370	25.5
N		370	25.5
BV-V	800		[1]
BV-N		250	[1]
BH-V	720		[2]
BH-N		250	[2]
BP-V	1,640		[3]
BP-N		370	[3]
EN			
Businesses			
C1-V	4,400		10.0
C1-N		660	100.0
C2-V	297		70.0
C2-N		660	100.0
C3-V	205		3,400.0
C3-N		660	100.0
C4		660	100.0
C10	126		
C8			[4]
C11-V	297		[5]
C11-N		660	[5]
BS-V	164		5.0
BS-N		370	25.5

[1] 6 Sk for 1-2 rooms, 117 Sk for 3-4 rooms, and 149 Sk for 5 or more rooms.

[2] 76 Sk for 1-2 rooms, 99 Sk for 3-4 rooms, and 122 Sk for 5 or more rooms.

[3] 84 Sk for up to 3x25 A breaker, 126 Sk for up to 3x35 breaker, 189 Sk for up to 3x50 A breaker, and 241 Sk for up to 3x63 breaker.

[4] This tariff is for unmeasured demand. A monthly fixed charge of 11 Sk/ 10 W per point.

[5] 320 Sk for up to 3x10 A breaker, 540 Sk for up to 3x16 breaker, 800 Sk for up to 3x25 A breaker, 1,120 Sk for up to 3x35 breaker, 1,120 Sk for up to 3x35 A breaker, 1,600 Sk for up to 3x50 breaker, 3,200 Sk for up to 3x100 A breaker, and 5,120 Sk for up to 3x160 breaker.

The average 1993 tariffs for the various categories are:

A category (VHV)	1,188 Sk/MWh (37 $/MWh)
B category (HV)	1,870 Sk/MWh (58 $/MWh)
C category	2,034 Sk/MWh (64 $/MWh)
Residential	898 Sk/MWh (28 $/MWh)

5.2 Structure of Retail Sales

Retail electric energy sales and coincident peak demands are summarized in Table 5-3. These amounts are shown by distributor and by customer class. These statistics are discussed in detail in the following sections.

Table 5-3
SR Electricity Sales and Coincident Peak Demand in 1993

	Very High Voltage (GWh)	High Voltage (GWh)	Low Voltage		Contribution	
			Business (GWh)	Residential (GWh)	To Sales [1]	To Peak [2] (MW)
ZSE	1,147	2,212	775	1,299	31%	36%
SSE	2,686	1,897	606	1,220	37%	34%
VSE	1,227	1,588	549	1,028	25%	26%
Directly served	1,196				7%	4%
Contribution to sales [1]	36%	33%	11%	20%	100%	
Contribution to peak [2]	22%	26%	52%			100%

[1] Contribution to sales was based on published data.
[2] Contribution to peak was estimated.

5.2.1 Sales and Revenues by Tariff Category

Total sales by SE and RDUs in the SR were about 17,900 GWh in 1993 of which 6,300 GWh were sold to Tariff A customers (35 percent of total sales); 5,700 GWh were sold to Tariff B customers (32 percent of total sales); 1,900 GWh were sold to Tariff C customers (11 percent of total sales); and 4,000 GWh were sold to residential customers (households) which represented 22 percent of total sales in the SR.

Total revenues generated by the electric sector in the SR are 24,180 million Sk in 1993. Tariff A generated 28 percent, and 44 percent, 16 percent, and 12 percent were generated by Tariffs B, and C, and residential customers, respectively.

5.2.2 Sales and Revenues by RDU

In 1993, ZSE sold customers about 5,900 GWh, and SSE and VSE sold their customers 6,408 and 4,390 GWh respectively. ZSE has the highest percentage of residential energy sales in comparison to SSE and VSE. SSE has the highest percentage of energy sales to the A tariff customers in comparison to ZSE and VSE.

Total 1993 retail revenues collected from all customers in the SR were approximately 24,180 million Sk. ZSE is responsible for 8,513 million Sk which represents 35.2 percent of total revenues. SSE collected 8,569 million Sk in 1993 which represents 35.4 percent. VSE collected 6,224 million Sk from rate payers (25.7 percent of total revenues). SE collected 874 million Sk from the four customers it serves.

5.2.3 Contribution of Tariff Categories to Peak Demand

The coincident peak demand for the electric system in the SR was 3,441 MW in 1993. There is currently no assignment of tariff category peak responsibility and inadequate data to make estimates accurately. We have estimated peak responsibility by tariff class based on load factor assumptions. Based on this analysis, Tariff A customers had a coincident peak of 898 MW which was 26 percent. The coincident peak demand for Tariff B customers was 989 MW which represents 29 percent of the total system. The coincident peak demand for businesses and residential customers were 504 and 1,050 MW, respectively. These amounts represent 15 percent and 31 percent of the total system, respectively.

5.3 Contractual Arrangements for Power Supply to RDUs

SE has a contractual agreement with each RDU for electric energy sale. These contracts are negotiated separately, and the pricing contained in the contracts is not subject to regulation by the Ministry of Finance. However, the retail prices set by the Ministry clearly have a bearing on the negotiating position of the various parties.

5.3.1 Contract Terms

This agreement has five articles and one attachment. The five articles cover subject and duration, delivery of energy and its evaluation, billing and invoicing, rights and duties of contract parties, and final regulations. The important features of the contract include the following:

1. The contract period is one year, but the electric energy evaluation period is three months; electric capacity is contracted on a monthly basis. Tariff periods are determined on quarterly basis.

2. There are energy and capacity tolerance bands requiring the RDUs to commit to specified consumption within the tolerance bands. The energy tolerance band is -5 percent to +0 percent, and the capacity upper limit is +4 percent for all year. If the consumed electric energy or capacity falls outside the tolerance band, the distributor will be charged at a different rate which is usually higher than that for contracted amounts.

3. Billing is monthly and is based on contracted monthly maximum of electric capacity and consumed electric energy. The energy charge is based on energy amounts consumed during peak, mid-peak, and off-peak periods and rates associated with these periods. There is an additional energy component that is related to the energy delivered during additional capacity assistance.
4. Value added tax (VAT) will added to the bill separately.

The key features of the contract are the overall pricing levels of time-of-day pricing, the demand-related charges (in the form of the contract maximum demand and capacity tolerance range), and energy tolerance requirements. These are discussed below.

5.3.2 Overall Pricing Level

The exact pricing contained in the various contracts is confidential and varies slightly between RDUs. The average 1993 price was approximately 1,100 Sk/MWh (34 $/MWh). This compares with an estimated long-run marginal cost (LRMC), discussed in detail in Section 8, of between 1,400 and 1,500 Sk/MWh (44 to 47 $/MWh). There will continue to be pressure to increase this price to support future investment requirements. If this upward pressure is not matched by changes in retail tariffs, the financial position of the RDUs, already difficult, will deteriorate.

5.3.3 Energy Pricing

The contract allows for peak, mid-peak, and off-peak pricing of energy. Peak period energy pricing is 800 to 1,000 Sk/MWh (depending on the RDU), and off-peak pricing is approximately 600 Sk/MWh. These levels were somewhat below SRMCs in 1993, but significantly above average energy costs.

The peak-load energy rate was about 30 percent to 60 percent greater than the off-peak rate. This variation is higher than the difference in the underlying energy costs. The analysis of the current cost structure of the power sector, presented in Section 4, indicates a peak/off-peak energy cost variation of less than 15 percent.

There is currently no provision for seasonal variation in energy pricing. The cost structure analysis in Section 4 indicates that the seasonal variation in energy costs is significantly higher than the time-of-day variation.

5.3.4 Demand-Related Charges

The demand-related charges and the penalties associated with exceeding contractual agreed-upon maximum demand levels (technical maximum) appear to be effectively encouraging RDUs to flatten their load profiles. As discussed in Section 4, daily load factors are over 90 percent. Winter heating is the primary contributor to peak load, and unexpectedly cold weather is the primary cause for RDUs exceeding technical maximum loads. Discussions with RDU personnel indicate that a number of techniques are used to control this situation. These techniques include utilization of their own generation (available only to ZSE and SSE), requesting more generation from industries in their service area, and the use of ripple control.

5.3.5 Energy Tolerance Requirements

The use of penalties if RDUs use energy over or under a tolerance band around a specific amount of energy in each quarter reflects the high fixed costs and the lack of flexibility in fuel procurement and plant operation on the SE system. The penalty for using less than the projected amount of energy has the obvious shortcoming of discouraging conservation beyond what may be projected for a given quarter. Furthermore, under the existing organizational structure, the RDUs have limited mechanisms for marketing power if they overestimate demand, whereas SE has export opportunities. Increased flexibility of generating units, future participation in CENTREL, and eventually UCPTE, and increased competition should make this contractual provision obsolete.

5.4 Sales to Wholesale Customers

SE serves special large customers under Tariffs A and B. The four industries directly served by SE are:

- VSZ a.s.
- Duslo Sala
- Siroka
- Zavlahy Sala

There are three customers on Tariff A and one on Tariff B. SE negotiates power sales agreements with the customers who are directly served and places them under the agreed-upon tariff schedule. Total energy sales to these four customers in 1993 was 1,196 GWh. This amount represents 6.7 percent of total sales in the SR. SE collected approximately 874 million Sk from these customers directly (about 3.6 percent of total electricity revenues in the SR).

5.5 Sales to Retail Customers

The following is a discussion of the various tariff categories. The information contained in this section is summarized in Table 5-1 for Very High and High Voltage categories (A and B) and in Table 5-2 for Low Voltage.

Very High Voltage Tariffs

The following section discusses Tariffs A1, A2, and A10.

Tariff A1 accounted for 80 percent of the Tariff A sales in 1993 (23 percent of total sales). It applies to the Very High Voltage customers with a demand charge for the agreed-upon maximum. Key features of this tariff are as follows:

- Negotiated meter charge.
- Demand charge which is based on two basic components: a 74 Sk/kW rate for the technical maximum demand of the month, and a second part equal to 163 Sk/kW for the agreed-upon 15-minute monthly peak. The demand charge is adjusted for exceeding the agreed-upon 15-minute peak demand using 550 Sk/kW.
- Energy rates are 0.83, 0.66, and 0.61 Sk/kWh during peak, mid-peak, and off-peak periods respectively.

Tariff A2 applies to Very High Voltage customers with a demand charge for the measured maximum. This tariff is similar to A1 from the energy point of view, but the demand charge components are based on two rates for the monthly technical maximum demand and the monthly measured 15-minute peak. These rates are 74 and 185 Sk/kW, respectively.

Tariff A10 applies to railways connected to a voltage exceeding 52 kV. This tariff has a single rate for energy consumption. The energy charge is 1.10 Sk/kWh.

High Voltage Tariffs

This section of the report discusses B tariffs; these are applicable to large customers connected to a high voltage (defined as the range of 1 to 52 kV).

Tariffs B1 and B2 apply to customers with an agreed-upon monthly technical maximum peak equal to or more than 1,000 kW. These tariffs are described below.

Tariff B1 is very similar in structure to Tariff A1 except that the rates are different. This tariff has three parts, and they are as follows:

- Meter charge.
- Demand charge with two rates of 90 and 185 Sk/kW for the monthly technical maximum peak and agreed-upon monthly 15-minute peak respectively. The demand charge is adjusted for exceeding the agreed-upon 15-minute peak demand using 640 Sk per kW.
- Energy charge is based on three rates equal to 0.93, 0.74, and 0.66 Sk/kWh for peak, mid-peak, and off-peak period respectively.

Tariff B2 is very similar to A2 in structure. This tariff applies to customers with a demand charge based on monthly measured 15-minute maximum demand. Demand and energy charges are as follows:

- Demand charge is based on two rates for the monthly technical maximum demand and the monthly measured 15-minute peak. These rates are 90 and 211 Sk/kW respectively.
- Energy charges are exactly the same as in Tariff A2.

Tariffs B3 and B4 apply to customers with an agreed-upon monthly technical maximum peak from 150 kW to 1,000 kW. Both tariffs have two energy rates for mid-peak and off-peak periods.

Tariff B3 is similar to Tariffs A1 and B1 from the demand charge structure point of view. This tariff applies to customers with a demand charge for agreed-upon maximum. The components of the tariff are as follows:

- The demand charge has two rate parts, and these are 90 Sk/kW for the monthly technical maximum and 207 Sk/kW for the agreed-upon 15-minute monthly peak. The penalty for exceeding that maximum is 700 Sk/kW.
- The energy charge only has two parts, and these are 0.74 and 0.66 Sk/kWh for mid-peak and off-peak period respectively.

Tariff B4 is similar to Tariffs A2 and B2 from the demand rate structure point of view. This tariff is for customers with measured maximum demand. Aside from the meter charge, demand and energy charges are as follows:

- The demand charge is based on two rates, and these are 90 Sk/kW and 235 Sk/kW for the monthly technical maximum and the measured 15-minute monthly peak respectively.
- The energy charge is based on two rates as mentioned above.

Tariffs B5 and B6 apply to customers with demand equal to or less than 150 kW. Both tariffs have two rates for the energy charge. These rates are applicable to mid-peak and off-peak periods.

Tariff B5 is applicable to customers with measured maximum demand. Aside from the meter charge, the demand and energy charges are as follows:

- The demand charge is based on two rates. These are 90 Sk/kW and 235 Sk/kW for the monthly technical maximum and the measured monthly 15-minute peak respectively.
- The energy charge is based on two energy rates, and these are 0.74 and 0.66 Sk/kWh for mid-peak and off-peak periods respectively.

Tariff B6 is a demand charge based on connected transformer size with a rate equal to 139 Sk/kVA. The energy charge is based on 0.74 and 0.66 Sk/kWh for mid-peak and off-peak periods. It is our understanding that this tariff has been discontinued.

Tariffs B10, B11, B12, and B13 are for special customers, and they are the High Voltage customers.

Tariff B10 is applicable to railways, and it has only an energy rate. The energy charge is 1.46 Sk/kWh. Energy consumption is considered to be during mid-peak period.

Tariff B11 applies to customers with off-peak heating to total installed power requirement ratio of not less than 80 percent. Aside from the meter charge, there are two basic charges and they are as follows:

- The demand charge is based on 320 Sk/kW for the measured demand during high tariff band.
- The energy charge is based on 0.74 and 0.66 Sk/kWh for mid-peak and off-peak periods.

Tariff B12 is applicable only to customers with a measured 15-minute monthly peak who meet certain criteria as stated below:

- The customer must have his electrical heating controlled by bulk remote control system.
- The ratio of installed power for the electric heating to the total installed power should be less than 80 percent.

The components of the B12 tariff are as follows:

- Demand charge is based on 320 Sk/kW for the measured 15-minute monthly maximum during the high tariff band.
- Energy charge is based on 0.93 and 0.73 Sk/kWh for energy consumed during mid-peak and off-peak periods.

Tariff B13 has a meter charge and an energy charge which are shown below. The energy charge is based on two rates, 3.70 and 0.66 Sk/kWh for energy used during mid-peak and off-peak periods respectively.

Low Voltage Tariffs

This class represents residential and commercial (business) customers. Their tariffs are summarized in Table 5-2. These customers have two basic charges; these are energy and customer charges. These tariffs are discussed below.

- **BS-V tariff** is recommended by the Ministry of Economy for residential customers with consumption less than 451 kWh per year. It is applied to energy consumed during the high-tariff period.
- **BS-N tariff** is the same as Tariff N. This tariff is combined with Tariff BS-V for customers with two kWh meters.
- **B-V tariff** is for residential customers with one meter to measure energy consumption during the high-tariff period.
- **B-N tariff** is the same as Tariff N. This tariff is combined with Tariff B-V for customers with two kWh meters.
- N tariff is applied to customers with consumption during the system's low loads.
- **BV-V and BV-N** tariffs are applicable to residential customers with electric storage heating and hot water storage tanks. The monthly fixed charge is based on the apartment size. The energy charge is based on two different rates for different periods of electric system loading. The equipment is controlled by bulk remote control.
- **BH-V and BH-N** tariffs are applied to customers with a combination of electric storage heating and a hot water storage tank. The monthly fixed charge is based on the apartment size. The energy charge is based on two different rates for different periods of electric system loading. This equipment is controlled by bulk remote control.
- **BP-V and BP-N** tariffs apply to residential customers with electric heating. The monthly fixed charge is based on the size of apartment's main circuit breaker. The energy charge is based on energy consumed during different times of the day.

Low Voltage customers other than residential are defined here as businesses. These customers are under C tariffs which are summarized below.

- **C1-V** tariff applies to small businesses with annual energy consumption less than 500 kWh. This tariff includes a monthly fixed charge and an energy charge for usage during high-tariff period.
- **C1-N** tariff uses Tariff C4 for billing and is used for energy consumed during the low-tariff period.
- **C2-V** tariff generally applies to customers with low consumption. This tariff has a fixed charge and a high energy charge.
- **C2-N** tariff is the same as Tariff C4 and has a fixed monthly charge and an energy rate for usage during the low-tariff period.
- **C3** tariff is used for small customers. It has a relatively high customer charge and a high energy charge.
- **C4** tariff is explained in Table 5-2. It has an off-peak energy charge and a customer charge.
- **C8** tariff is used for unmeasured consumption.
- **C10** tariff is used for public space illumination. It has an energy charge based on a rate for the high-tariff period.
- **C11** tariff is used for customers with electric heating, and it has two energy rates for high- and low-tariff periods. In addition to the energy charge, there is a monthly fixed charge that varies and depends on the main circuit breaker size.

5.6 Tariff Levels Versus Cost

As has been discussed in the previous analysis of the present cost structure of the power system (Section 4), the current tariff levels are adequate to support reported costs (i.e., there are no direct subsidies to the power sector). However, for a number of reasons, existing prices do not reflect the long-run marginal cost (LRMC) for some tariff categories.

Each voltage level must share in the costs and energy losses of the higher voltage level systems, so that the cost of delivering energy to lower voltage levels is higher. This pattern is seen in the pricing of the A, B, and C tariff categories. Residential tariffs are lower than any of the other categories even though delivery is at low voltage.

The LRMC reflects the long-term cost of electricity including the investment cost for adding capacity to the system. The calculation of LRMC for each voltage level is the topic of Section 8 and is discussed in detail there. Figure 5-1 compares the 1993 prices with projected LRMC for various tariff categories. The B and C tariffs are approximately at LRMC at their current level. The B tariffs are about 10 percent greater than projected LRMC, and the C tariffs are about 1 percent below. However, both the A tariffs and residential tariffs are far below LRMC. The A tariffs are about 75 percent of LRMC, and the residential tariffs average 50 percent of LRMC.

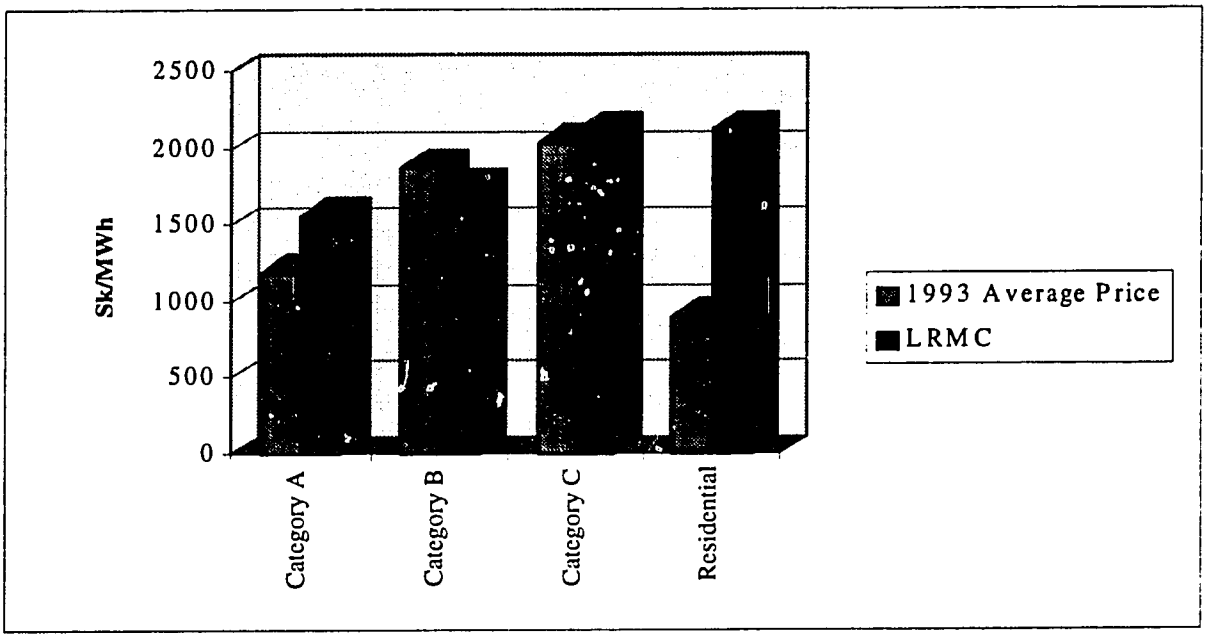


Figure 5-1 1993 Average Prices Versus LRMC

5.7 Effect of Combined Heat and Power Sales (CHP)

SE, ZSE, and SSE produce electricity in CHP plants. There is no direct pricing mechanism associated with this production except for the contracts between SE and the RDUs and the retail tariffs. In effect, SE is compensated according to the price it sells to the RDUs minus the cost of transmission at the 220 kV level.

The effective compensation for the RDUs is reduced purchases from SE. Since all the RDUs are winter peaking, the operation of the CHP plants tends to reduce the technical maximum of ZSE and SSE in the contract with SE.

The method for allocating costs between heat and power in CHP plants, discussed in Section 4, has the effect of significantly understating the economic cost of CHP power. This is reported to be approximately 750 Sk/MWh (23 $/MWh) in 1993. However, this cost allocation is primarily done for reporting; the economic signal for the value of CHP generation is provided by the SE/RDU contracts.

At current pricing levels of SE electricity (approximately 1,100 Sk/MWh), it will be very difficult to justify new CHP projects. An analysis of CHP generation, presented in Section 4, indicates that its value is significantly higher than the pricing of the SE power. This is because the marginal cost of production on the SE system, using fossil-fuels, is significantly higher than the average cost, which is dominated by nuclear generation. The use of contract pricing based on LRMC would raise the SE price to a level which would provide correct economic signals as to the value of generation by RDUs or others.

A temporary alternative to the current system (until the SE price levels can by raised to reflect LRMC), would be to allow the RDUs to sell to the SE system at a price that would reflect the cost that SE avoids in not having to produce the RDU generation. This would in effect provide certain categories of generators with marginal cost price signals before they are fully incorporated into wholesale and retail tariffs. This avoided cost would provide a better economic signal of the value of RDU generation than the current system. The analysis of avoided cost presented in Section 4 indicates that the value of RDU and industrial generation is approximately 1,500 Sk/MWh (47 $/MWh) under the economic assumptions of this Study. Should such a system be instituted, a formal and transparent mechanism for calculating avoided cost (such as the one presented in Section 4) is crucial to ensure the interests of customers and project owners.

5.8 Purchases from Industry-Owned Capacity

The discussion of the value of RDU electric generation is true for industrial generation as well. However, the economic signals for industrial generation are provided by retail tariff rates rather the SE/RDU contract. The economic incentive for an industry to generate electricity is to avoid purchases from the RDUs, or from SE if it is directly served.

For industries in the A tariff category, the average 1993 pricing of approximately 1,200 Sk/MWh is less than the value of generation. Retail pricing at LRMC would raise this to over 1,500 Sk/MWh and provide true economic price signals to industrial generators. Short of this, a system of selling to the grid at avoided cost could be used to provide proper price signals to generators before they are fully incorporated into the tariffs as a whole.

The B tariff category currently provides price signals that are very close to LRMC. Therefore, industries in this category already receive proper price signals for the value of electricity and the value of self-generation.

5.9 Other Issues

Some additional observations made in the review of current tariffs concern metering technology and billing, the need for additional load research, and the revenue collection process. These are discussed below.

5.9.1 Utilization of Energy Planning Efforts in Tariff Setting

SR has an ongoing planning process for the energy sector as a whole, and for the power sector in particular, which is sponsored by the Ministry of Economy. As the tariff-setting process becomes formalized, it would be advantageous to coordinate it with this planning effort in order to have a common and consistent set of resource and demand assumptions that are available to all interested parties. This is being done in this study; however, the energy planning and tariff setting processes will be ongoing. A key area requiring improvement is the extension of power sector planning to the distribution level to facilitate the development of investment plans at the RDU level that are consistent with overall demand forecasts.

5.9.2 Metering Technology and Billing

All large customers are metered with at least one meter, and a great many have various energy meters and demand meters. These meters are read monthly. However, the meters of small customers, including residential customers, are read only once every six months. Large customers

are billed monthly using actual consumption data, but small customers are billed monthly using estimated billing. An adjustment is made once every six months. Five-minute demand meters are recommended for the industrial users. Also, magnetic tape recorders for the very large customers could be of great value to benefit the distributors and ultimately all customers.

5.9.3 Load Research

There is no formal load research program in the SR. The embryo of such a program exists in the form of preliminary demand-side management studies being conducted by SE. A formal load research program is essential in the rate making, demand side management (DSM), distribution equipment loading, and distribution planning studies.

5.9.4 Revenue Collection

The rate of revenue as compared to other utilities in Western Europe and in the United States is low and needs to be improved. An action is required and a rigid procedure must be followed. It is our understanding that the accumulated amount of the accounts receivable over the last few years has been approximately 4 billion Sk.

5.10 Conclusions

The major conclusions that can be drawn from the review of existing pricing mechanisms and retail tariffs are:

- The existing tariff structure and the SE/RDU contracts incorporate many of the elements that allow tariffs to reflect LRMC including time-of-day pricing and demand charges.
- Future modifications to pricing should be cost based, and the number of retail tariff categories at each voltage level should be reduced.
- The 1993 SE price to the RDUs is approximately 75 percent of LRMC.
- The tariffs for Category B (high voltage industrial) and C (low voltage commercial) which reflect more than 40 percent of 1993 sales are currently close to projected LRMC.
- Tariff A, constituting 35 percent of sales, is at approximately 75 percent of LRMC.
- Residential tariffs, the fastest growing category and accounting for slightly less than 25 percent of 1993 sales, are less than 50 percent of LRMC. This category has the highest cost of service and the lowest tariffs.
- The fact that the SE contract price and the residentialy A tariff are below LRMC results in undervaluing of electric generation by the RDUs and industries served at the Very High Voltage level.
- While increases will be required in SE prices and the residentialy A and residential tariffs, gradual changes in tariffs will be required for various reasons. During the transition period, a system of pricing electric generation from RDUs and residentialy A industries at levels reflecting their value would ensure investment in economic district heating and cogeneration projects.

- A formalized tariff-setting process free from commercial and political interests should be instituted that provides review of tariffs on an annual basis.
- A formal load research program will be required to support a cost-based tariff-setting process.

6 REVENUE REQUIREMENTS ANALYSIS FOR THE SLOVAK ELECTRICITY COMPANY (SE)

The objective of this section is to determine the revenue requirements necessary to operate and provide investment capital to SE. SE owns and operates most of the generation capacity and the transmission network at 200 kV and above. Tariffs based on the analysis of this and the following section (dealing with the RDUs) will satisfy the projected financial requirements of the power sector. As will be discussed in the discussion of a pricing strategy based on long-run marginal cost (LRMC) in Section 8, meeting financial requirements is one of several goals in the tariff-setting process.

6.1 Approach

The scope of this study is the power sector. Much of the SE reported financial data is consolidated and includes revenues and expenses for electricity generation and transmission at 200 kV and above and for some heat production at generating plants for district heating and industrial use. System dispatching functions were included under transmission.

The first step was to separate SE reported 1993 data into electric generation, electricity transmission, and heat generation. This separation is shown in Table 6-1. The resulting financial data for 1993 provided a point of reference for future projections. The time period considered was 1994 through 2000.

For electricity generation, the following steps were taken:

- Project fuel and variable non-fuel operating expense using the Elfin production simulation model
- Project nuclear plant decommissioning and waste disposal costs based on reported information
- Project fixed non-fuel plant costs based on 1993 fixed costs by plant and the projected plants in service
- Incorporate the generation investment plan based on the SE Reference Generation Plan
- Determine the necessary level of asset revaluation and real rate of return on revalued assets to meet financial performance criteria
- Calculate revenue requirements based on projected expenses plus operating income based on a fixed before-tax rate of return on fixed assets
- Analyze sensitivity of results relative to key assumptions

For transmission at 200 kV and above, the following analogous steps were taken:

- Project fixed and variable costs based on an extrapolation of 1993 costs
- Incorporate transmission investment plan
- Determine the necessary level of asset revaluation and real rate of return on revalued assets necessary to meet financial performance criteria

Table 6-1
Separation of SE Electricity Generation, Heat Production, and Transmission

Currency	Millions Sk					Thousands US$	
		Accounting Adjustments and Electricity Transit Sales	Heat Sales	Electricity Transmission > 220 kV	Electricity Generation	Electricity Transmission > 220 kV	Electricity Generation
	(A)	(B)	(C)	(D)	(E=A-B-C-D)		
Revenues							
Domestic electricity sales	21,266	0	0	675	20,591	21,084	643,475
Exports	975	0	0	0	975	0	30,473
Transit electricity sales	4,026	4,026	0	0	0	0	0
Heat sales	1,445	1	1,444	0	0	0	0
Other	488	488	0	0	0	0	0
Total Revenue	28,200	4,515	1,444	675	21,566	21,084	673,948
Expenses							
Fuel	5,841	0	1,011	86	4,744	2,684	148,257
Purchased power	1,280	0	0	23	1,257	711	39,289
Material and others	963	0	144	24	795	739	24,842
Labor and services	2,769	0	72	236	2,460	7,388	76,883
Depreciation	1,279	0	0	110	1,169	3,430	36,539
Transit electricity purchases	4,035	4,035	0	0	0	0	0
Other	1,854	1,854	-937	0	937	0	29,270
Total expenses	18,021	5,889	291	478	11,363	14,951	355,081
Total interest	871	0	0	0	871	0	27,219

This approach is based on the observation that depreciation is the primary cost category that appears undervalued in currently reported power supply costs. Discussions with the Ministry of Finance indicate that there is currently no provision under Slovak law for asset revaluation. If modifications cannot be made to accommodate asset revaluation, this will be a fundamental obstacle to continued use of cost-based tariffs. An alternative is tariffs based on long-run marginal costs, or some modification thereof.

The necessary asset revaluation that was calculated to meet financial performance criteria was compared with the replacement value of the assets estimated on an engineering basis. The approach for individual revenue requirement elements is discussed below.

6.1.1 Fuel

Fuel costs were projected using the Elfin production simulation model based on the Reference Load Forecast and Generation Plan and fuel price forecast discussed in Section 3. The results of the production simulation analysis are presented in Appendix D.

6.1.2 Purchased Power

The Reference Generation Plan, developed by SE, is based on developing national independence in power supply so that no long-term imports are considered. In the modeling of the system for purposes of this study, 300 MW of emergency imports were allowed. However, the projected demand/resource balance is such that virtually no emergency imports were projected under the assumption of average hydro conditions through 2000.

6.1.3 Material and Other

SE provided 1993 operating cost data categorized as "labor" and "other" by plant and overhead. There is no differentiation between variable and fixed costs in the reported data. In the plant-specific data, projections were adjusted to reflect retirements and the startup of new generating capacity according to the Reference Generation Plan. Variable operations and maintenance costs were calculated by plant as a function of plant operation in the production simulation analysis, using the Elfin model. Some of the SE reported costs overlap with the projected costs in the production simulation analysis and judgment was used to avoid double counting.

The "material" and "other" categories in the income statement for electricity generation were projected as 15 percent of the reported "other" category and 50 percent of the projected variable operations and maintenance cost. "Material" and "other" costs for transmission were projected based on 0.1 percent of fixed transmission assets on an annual basis.

6.1.4 Labor and Services

The same data and analysis as used for the material and other category were used for labor and services. For electricity generation, these were projected as 30 percent of the reported plant-specific other costs, 100 percent of the reported overhead costs, and 50 percent of the projected variable operations and maintenance cost based on the production simulation analysis. Labor and services for transmission were projected based on 1 percent of revalued fixed assets on an annual basis.

6.1.5 Depreciation

Depreciation in 1993 is based on reported values. Depreciation for 1994 through 2000 was based on revaluation of fixed assets. The necessary revaluation to achieve a set of financial performance criteria was a major goal of the analysis.

6.1.6 Decommissioning

Projected decommissioning costs for Bohunice V-1 and A-1 are included in the revenue requirements. This estimate is based on a combination of data provided by SE and information provided by the World Bank. For purposes of this analysis, these costs have been treated as an expense. Capitalization of the these expenses may be possible, which will tend to delay their full impact on revenue requirements.

6.1.7 Allowance for Nonpayment

Because of the downturn and restructuring of the economy that has occurred since 1989, a number of industrial customers have ceased, or have been slow in paying electricity bills. These customers are significant employers, and the problem is large enough that it cannot be dealt with by the normal process of interrupting service.

The initial effect of this lack of payment is on the RDUs. This is particularly acute in the case of SSE, which has the highest percentage of industrial customers, particularly those related to the defense industry. There is no mechanism for bankruptcy in the SR so that the RDUs are not able to write off this lack of payment. Furthermore, accounting practices do not differentiate between short- and long-term receivables.

This problem is passed on to SE from the RDUs in terms of slow payments. SE accounts receivable was on the order of 4 billion Sk at the end of 1993, amounting to an average of 66 days between billing and payment.

The effect of nonpayment of SE sales will be to increase the price for the remaining customers unless this amount is subsidized by the government. For purposes of the revenue requirements analysis, an allowance for nonpayment has been made in the income statement for SE reflecting a future write-off of some accounts receivable. This allowance has been set at 5 percent of total revenue requirements.

This allowance for nonpayment was made at the SE sales level. The resulting increase in SE price was passed through to all retail customers in calculating revenue requirements at each voltage level. No attempt was made to identify the voltage level of the nonpaying customers or the effect of nonpayment on the incremental price for transmission and distribution below 200 kV.

6.1.8 Operating Income

Operating income is equal to revenues minus expenses (not including interest). It is a measure of the profitability of the organization and in cost-based tariff setting for regulated monopolies, it is usually determined by the allowable real rate of return on fixed assets. This rate of return could be in the range of 5 percent to 10 percent per year.

6.1.9 Interest on Loans

A real interest rate of 4 percent per year with a 20-year term was assumed for long-term debt. The real interest rate used for short-term debt was 5 percent per annum. The low interest rate compared to commercial terms is based on an adjustment to remove the effect of general inflation since the analysis is conducted in 1993 currency.

6.1.10 Corporate Taxes

Corporate taxes were calculated as 40 percent of operating income minus interest charges. However, this calculation had no bearing on the calculation of overall revenue requirements as after-tax profitability was not a criterion in the analysis. Revenue requirements were calculated as expenses plus an allowable operating income based on a fixed before-tax rate of return on assets.

6.1.11 Investment Requirements

Investment requirements for electricity generation were based on the SE Reference Generation Plan. Estimates for reconstruction work required for Bohunice V-1 and V-2 and for waste fuel storage were included.

6.1.12 Fixed Assets

The necessary increase in the book value of existing assets to achieve financial objectives was determined for the year 1994. Such a revaluation of assets has not occurred during 1994, but the analysis indicates the effect on revenue requirements if it had. Only a single revaluation of existing assets was considered.

6.1.13 Current Assets

The primary components of current assets are cash, accounts receivable, and inventory. A cash target of 12 percent of labor and materials expenses was used. Accounts receivable in 1993 reflected an average period of 66 days between billing and payment. This was assumed to decline to 45 days by 2000. It was assumed that some existing and future accounts receivable would be written off. (See Section 6.1.7, Allowance for Nonpayment.) Inventory levels were over 70 percent of fuel and material expenses in 1993. This was assumed to decline to approximately 50 percent by 2000.

6.1.14 Long-Term Debt

After 1994, it was assumed that 50 percent of investment requirements would be financed through long-term debt. Of this 20 percent was assumed to be domestic and 80 percent foreign.

6.1.15 Current Liabilities

The primary contributors to current liabilities are short-term loans and accounts payable. Short-term loans were estimated at 50 percent of annual operating income. Accounts payable were projected at 15 percent of expenses.

6.1.16 Key Financial Performance Criteria

The financial performance criteria used as a basis for determining the appropriate real rate of return on revalued assets and the amount of revaluation included the following:

- Operating ratio

- Current ratio
- Cash generation ratio
- Debt coverage ratio
- Debt/equity ratio
- Turnaround in accounts receivable (days)
- Number of times interest earned ratio

Appendix E provides a discussion of the calculation of these financial statistics. The rate of return on fixed assets, one of the results of this analysis, is itself a key financial criterion. In determining the required amount of asset revaluation, the constraining criterion in this analysis were found to be the cash generation ratio.

The rate of return on fixed assets is a measure of the profitability of the organization. The rate of return on fixed assets in a given year is equal to the operating income (i.e., revenues minus expenses, or gross profits) divided by the value of net fixed assets. For cost-based tariff regulation of monopolies, it is common to select an allowable rate of return on fixed assets. For a given value of fixed assets, this value determines the allowable operating income.

The analysis was conducted in 1993 currency. This means that real cost increases in the various components of the power sector was considered, but general inflation was not. Real rate of return refers to the measure of return in this kind of analysis. If the real rate of return is 5 percent and general inflation is 20 percent, the return in inflated currency would be approximately 26 percent [(1.05 x 1.20-1) x 100 percent].

The cash generation ratio is a measure of the ability of an organization to meet its investment requirements through its own cash generation. For a given year, it is defined as internal cash generation divided by investment requirements. Internal cash generation is made up of two primary factors, depreciation and operating income (i.e., revenues minus expenses). As discussed previously, operating income is usually determined by the allowed rate of return on fixed assets for cost-based regulation of monopolies.

The cash generation ratio is directly affected by the revaluation of assets in two ways. First, the revaluation increases the amount of depreciation. Second, the increase in fixed assets increases the operating income for a given rate of return on fixed assets. A cash generation ratio of 1.0 is generally expected.

6.2 Base Case Results

Projected income statements, balance sheets, and sources and uses statements for electricity generation and transmission (>200 kV) by SE are displayed in Tables 6-2 through 6-4 for the Base Case. The year 1993 reflects reported information modified to remove heat production costs and revenues and some accounting adjustments as discussed previously. The remaining years reflect projections. The year 1994 reflects what would have occurred if an asset revaluation had occurred during that year.

Table 6-2
Projected Base Case SE Income Statement

	Year						
	1993	1994	1995	1996	1997	1998	1999
GWh							
SE generation	19,304	18,812	18,784	19,148	18,924	19,862	20,717
Network losses	356	371	375	387	439	475	480
Domestic sales	18,948	18,441	18,409	18,761	18,485	19,387	20,237
Exports	720	0	225	457	2,500	3,500	3,000
Sk/MWh							
Domestic	1,122	1,152	1,261	1,414	1,361	1,306	1,312
Export	1,354	-	1,384	1,425	1,459	1,499	1,539
millions Sk							
Revenue							
Domestic sales	21,266	21,246	23,222	26,525	25,154	25,320	26,560
Exports	975	0	311	651	3,649	5,246	4,618
Total Revenue	22,241	21,246	23,533	27,176	28,803	30,567	31,178
Expenses							
Fuel	4,830	4,372	5,461	8,072	7,095	7,228	8,015
Purchased power	1,280	1	1	381	2	1	2
Material and others	819	705	716	730	835	828	838
Labor and services	2,697	3,439	3,462	3,489	4,277	4,276	4,292
Depreciation	1,279	6,351	6,663	6,069	7,355	7,124	7,252
Decommissioning	0	0	985	2,211	1,878	2,098	1,933
Allowance for nonpayment	0	1,062	1,177	1,359	1,440	1,528	1,559
Total Expenses	10,904	15,930	18,463	22,310	22,883	23,084	23,890
Operating Income	11,337	5,316	5,070	4,866	5,921	7,483	7,288
Interest	876	1,212	1,436	1,634	1,968	2,228	2,444
Corporate Taxes	3,544	1,642	1,454	1,293	1,581	2,102	1,937
Net Income	5,985	2,463	2,181	1,939	2,372	3,153	2,906

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Table 6-3
Base Case SE Sources and Application of Funds Statement
(millions Sk)

	Year						
	1993	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Sources	15,979	12,963	17,638	16,396	21,521	20,988	21,190
Internal Generation							
Operating income	11,337	5,316	5,070	4,866	5,921	7,483	7,288
Depreciation	1,279	6,351	6,663	6,069	7,355	7,124	7,252
Total Internal Generation	12,616	11,667	11,733	10,935	13,276	14,606	14,540
Borrowing	3,363	1,296	5,906	5,461	8,245	6,382	6,650
Applications	15,979	12,963	17,638	16,396	21,521	20,988	21,190
Investment	6,511	2,592	11,811	10,922	16,490	12,763	13,300
Debt service							
Principle	222	2,830	2,911	3,007	3,834	4,864	5,034
Interest	876	1,212	1,436	1,634	1,968	2,228	2,444
Total	1,097	4,042	4,347	4,642	5,802	7,091	7,479
Taxes	3,544	1,642	1,454	1,293	1,581	2,102	1,937
Change in working capital	7,121	-4,640	942	1,929	-1,010	-647	435
Change in cash	-2,294	9,328	-915	-2,389	-1,342	-322	-1,961

Table 6-4
Projected Base Case SE Balance Sheet
(in millions Sk)

	Year						
	1993	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Assets	60,159	136,178	141,460	146,262	153,523	159,040	163,598
Fixed Assets							
Fixed assets	38,714	114,551	117,105	119,782	144,709	177,866	181,876
Accumulated depreciation	-19,595	-25,946	-32,609	-38,678	-46,033	-53,157	-60,409
Net fixed assets	19,119	88,605	84,497	81,104	98,676	124,709	121,467
Work in progress	32,613	32,047	41,358	49,678	41,317	21,009	30,339
Total	51,732	120,652	125,855	130,783	139,993	145,718	151,806
Current Assets							
Cash and banks	-2,294	7,034	6,119	3,729	2,387	2,066	105
Accounts receivable	4,002	3,377	3,577	3,941	3,976	4,006	3,868
Inventory	5,296	3,692	4,487	6,387	5,744	5,827	6,396
Others	1,423	1,423	1,423	1,423	1,423	1,423	1,423
Total	8,427	15,526	15,605	15,480	13,530	13,322	11,792
Equity and Liabilities	60,159	136,178	141,460	146,262	153,523	159,040	163,598
Equity	51,580	126,422	128,382	130,067	132,127	134,963	137,529
Long-term debt	6,952	5,680	8,956	11,720	16,464	18,345	20,313
Current Liabilities							
Short-term loans	98	2,658	2,535	2,433	2,960	3,741	3,644
Accounts payable	1,388	1,278	1,446	1,901	1,831	1,850	1,972
Other	141	141	141	141	141	141	141
Total	1,627	4,077	4,122	4,475	4,933	5,732	5,757

Generation and transmission systems were analyzed separately and separate financial projections for these supply sectors are provided in Appendix F. Table 6-5 shows the projected financial statistics for these statements. Of these financial statistics, the cash generation ratio was found to deviate the most from normal financial goals without a revaluation of assets. In order to achieve a cash generation ratio of approximately 1.0 for generation and transmission, it was necessary to increase the book value of assets by a factor of 5.0 for generation and 4.5 for transmission with a real rate of return on revalued fixed assets of 6 percent.

Table 6-5
Projected Base Case Financial Statistics
(millions Sk)

	Year						
	1993	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Operating ratio	0.61	0.87	0.89	0.92	0.91	0.88	0.89
Current ratio	5.18	3.81	3.79	3.46	2.74	2.32	2.05
Cash generation ratio	1.16	1.08	0.46	0.43	0.35	0.38	0.36
Debt coverage ratio	11.50	2.89	2.70	2.36	2.29	2.06	1.94
Debt/equity	0.13	0.04	0.07	0.09	0.12	0.14	0.15
Debt (%)	12%	4%	7%	8%	11%	12%	13%
Equity (%)	88%	96%	93%	92%	89%	88%	87%
Accounts receivable (days)	66	58	55	53	50	48	45
Number of times interest earned	12.94	4.39	3.53	2.98	3.01	3.36	2.98
Return on fixed assets	59.3%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%

Figure 6-1 shows the total revenue requirements over the study period compared with the 1993 average price for SE. The levelized revenue requirements from 1995 through 2000 are projected to be approximately 1,370 Sk/MWh of domestic sales (43 $/MWh). The components of the projected revenue requirements are illustrated in Figure 6-2. Depreciation and operating income, the components which affect the key cash generation ratio, make up approximately 50 percent of total revenue requirements.

Transmission (>200 kV) and dispatching contributes approximately 6.5 percent to the total revenue requirements if transmission losses are allocated as a transmission expense.

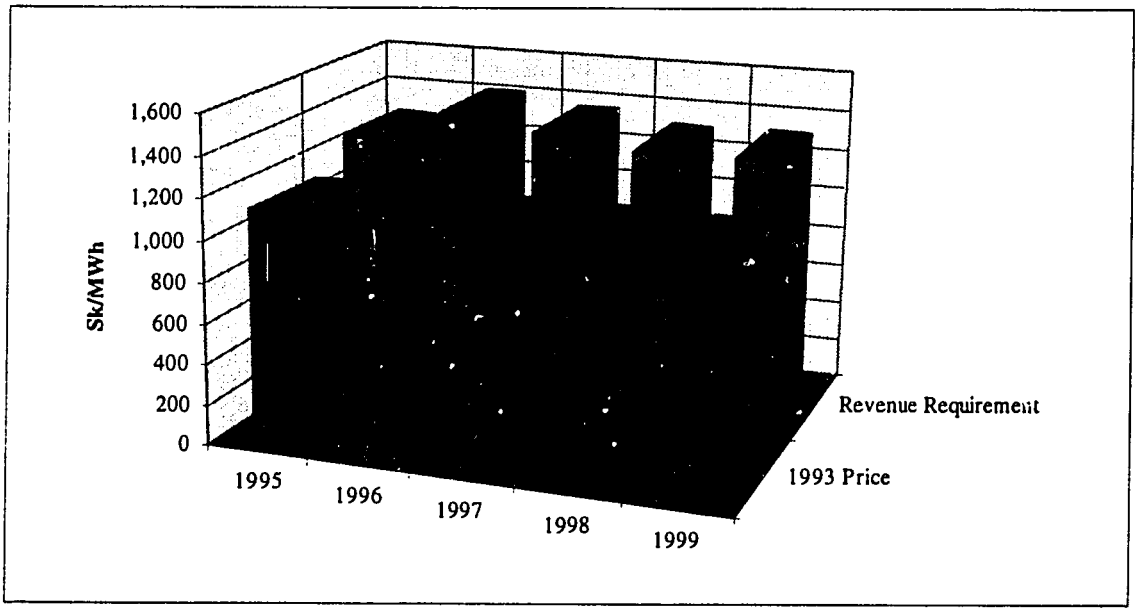

Figure 6-1 Projected Base Case Revenue Requirements for SE

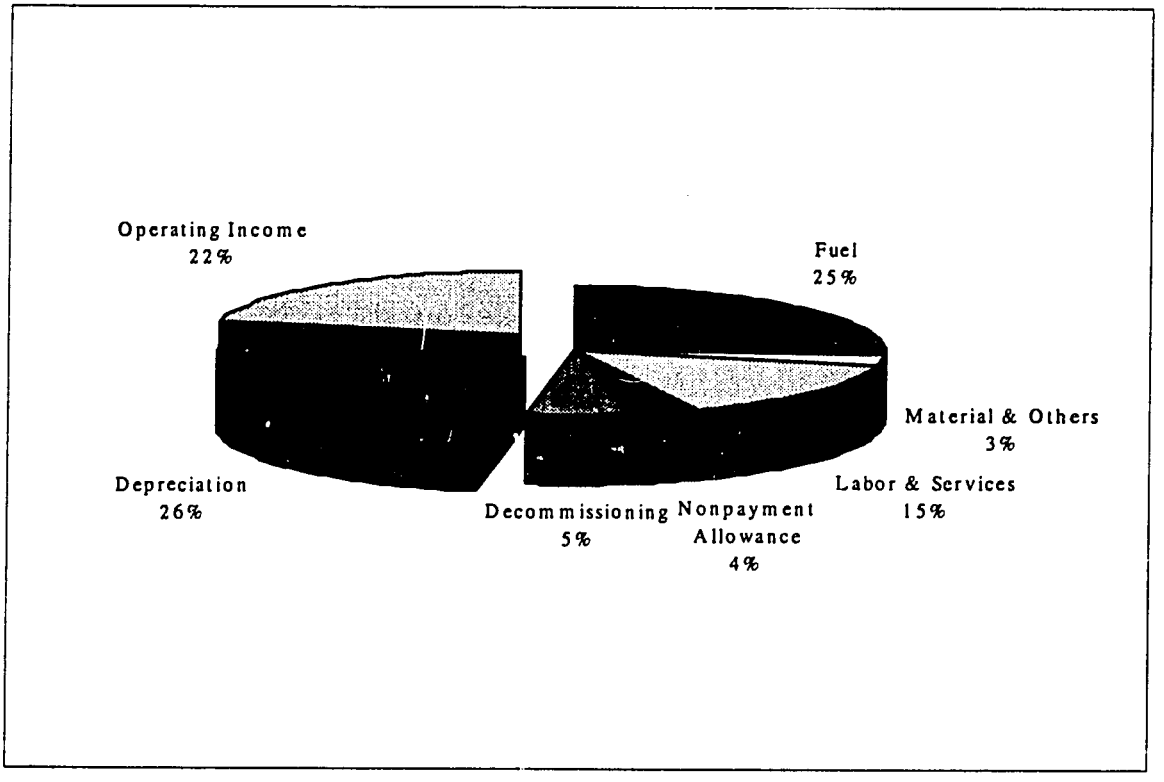

Figure 6-2 Components of Revenue Requirements for SE – 1995-2000

6.3 Comparison of Necessary Asset Revaluation With Engineering Replacement Value

The required asset revaluation estimated in the revenue requirements analysis was based on satisfying financial performance indicators. The revaluation is at "replacement value" in the sense that it allows the system to be replaced according to the investment plan. Based on the Base Case revenue requirements analysis, the book value of existing electricity generation assets was increased in value by a factor of 5.0 at a real before-tax rate of return on fixed assets of 6 percent in order to satisfy the financial performance criteria. A factor of 4.5 was required for the existing transmission system assets (>200 kV).

An alternative engineering approach to revaluation is to estimate replacement value for individual assets and to determine the necessary adjustment to book value to generate adequate generation to replace that asset. This approach was carried out for comparison and illustration purposes only. The results are shown in Table 6-6. The following replacement value assumptions were used in this analysis:

- Replacement value of Bohunice V-1 based on the projected cost of completing Mochovce Units 1 and 2 (An economic life of 20 years was used for Bohunice V-1 to reflect plans to retire the plant because of safety concerns.)
- Replacement value of Bohunice V-2 based on the projected cost of completing Mochovce Units 3 and 4
- Replacement of the solid fuel-fired Vojany I and Novaky estimated at 700 US$/kW plus interest during construction (IDC)
- Replacement of the gas-fired Vojany II at 500 US$/kW plus IDC
- Replacement of hydro and pumped storage capacity at 500 US$/kW plus IDC
- Replacement of the combined heat and power capacity at Kosice at 800 US$/kW plus IDC

A real discount rate of 6 percent was used in calculating interest during construction, corresponding to the rate of return of 6 percent in the revenue requirements analysis. The overall revaluation under the engineering approach required an increase in the book value of existing generating capacity assets by a factor of 4.7 compared to the 5.0 in the revenue requirements analysis. This verifies the result that existing assets are significantly undervalued and that the revaluation determined in the revenue requirements analysis is reasonable. Some of the reasons for differences between the two approaches are discussed below.

The engineering approach has shortcomings and is intended for comparison and illustration purposes only. It has shortcomings as applied in the analysis shown in Table 6-6. First, the methodology is based on the required revaluation based on a economic lifetime of depreciation. It does not reflect the fact that some existing assets are near the end of their economic life. Therefore, higher revaluations would be required to develop an adequate depreciation fund by the time the assets are to be replaced or reconstructed. This factor contributes to the revaluation factor estimate under the engineering approach being lower than under the revenue requirements approach.

Table 6-6
Revaluation Based on Engineering Estimate of Replacement Value

	Life (Years)	Net Capacity (MW)	Current Depreciation (thousands $)	Replacement Cost ($/kW)	Required Depreciation (thousands $)	Revaluation Factor
	(A)	(B)	(C)	(D)	(E=B*D)	(F=E/C)
Bohunice V-1	20	818	10,919	1,012	41,406	3.79
Bohunice V-2	30	822	10,972	1,399	38,320	3.49
Vojany I	30	600	1,221	764	15,279	12.51
Vojany II	30	600	1,221	546	10,913	8.94
Novaky	30	500	2,053	764	12,732	6.20
Gabcikovo	50	360	720	578	4,165	5.78
Cierny Vah	50	735	1,470	578	8,503	5.78
Other Hydro	50	1,271	1,700	578	14,703	8.65
Kosice	30	121	1,448	925	3,733	2.58
Total			31,725		149,753	4.72

Second, the engineering approach is based on the assumption that the generating capacity will be replaced in kind at the end of economic life. The purpose of asset revaluation is not to provide funds for such replacement, but to replace the system in a least-cost way which may lead to changes in the capacity mix. The revenue requirements analysis provides the best estimate of what it will take for the system to replace itself.

Aside from verifying the approximate magnitude of the overall asset revaluation arrived at through the revenue requirements approach, the engineering approach provides a basis for allocating the overall asset revaluation to individual assets.

6.4 Sensitivity Analysis

The following sensitivity analysis was conducted:

- Operating cost variation, including fuel, material, and labor
- Variation in decommissioning cost
- Variation in the allowance for nonpayment
- Variation in cost for Mochovce Units 1 and 2
- Variation in rate of return on fixed assets and revaluation of existing assets
- Variation in price and amount of power exports

The results of this analysis are discussed below.

6.4.1 Operating Costs

The impact of variation in the operating costs is dependent upon their contribution to total costs, as discussed earlier. Figure 6-3 illustrates the impact of a 10 percent change in fuel, material, labor, decommissioning, and allowance for nonpayment on the present worth of total revenue requirements from 1995 through 2000.

6.4.2 Investment Cost for Mochovce Units 1 and 2

The projected cost of completing Mochovce Units 1 and 2 as provided by SE is approximately 18 billion Sk. It is the largest investment to be made by SE prior to 2000. A 10 percent increase in the cost of completing the project will result in a 0.5 percent increase in the present 1995 to 2000 revenue requirements.

6.4.3 Rate of Return on Fixed Assets and Asset Revaluation

The cash generation ratio was a key financial parameter in determining the proper amount of asset revaluation required. In the Base Case analysis, existing assets were revalued at five times their book value given a real rate of return on assets of 6 percent. The amount of cash generation is dependent upon the amount of depreciation and the operating income in a given year. The revaluation factor affects the amount of depreciation, and the rate of return affects the allowable operating income. Therefore, if the rate of return varies, the revaluation of existing assets also changes if the same financial goals are met and the overall before-tax revenue requirements are unchanged. Figure 6-4 shows the relationship between real rate of return and required asset revaluation keeping the same overall revenue requirements.

If the rate of return is increased without changing the revaluation factor, the amount of cash generation increases so that the total revenue requirements increase. Figure 6-5 shows the impact of real rate of return on revenue requirements.

6.4.4 Power Exports

The completion of Mochovce Units 1 and 2 will put SE in a temporary over-capacity situation under the assumptions of the Reference Generation Plan. Power exports have been proposed as a means of utilizing this capacity, offsetting the cost impact of completing the plant, and providing foreign currency to assist in financing project completion. However, the current electricity supply/demand balance in Europe is such that the prospects for significant sales at a high price are uncertain. Discussions with EBRD personnel indicate that financing of the project will have to justified with sales.

The generation system simulation model used in the Base Case was also run considering no power exports with the same timing for new capacity and project rehabilitation. Based on this "with and without" analysis, the impact of having no exports was determined and the marginal generating cost associated with the exports was calculated.

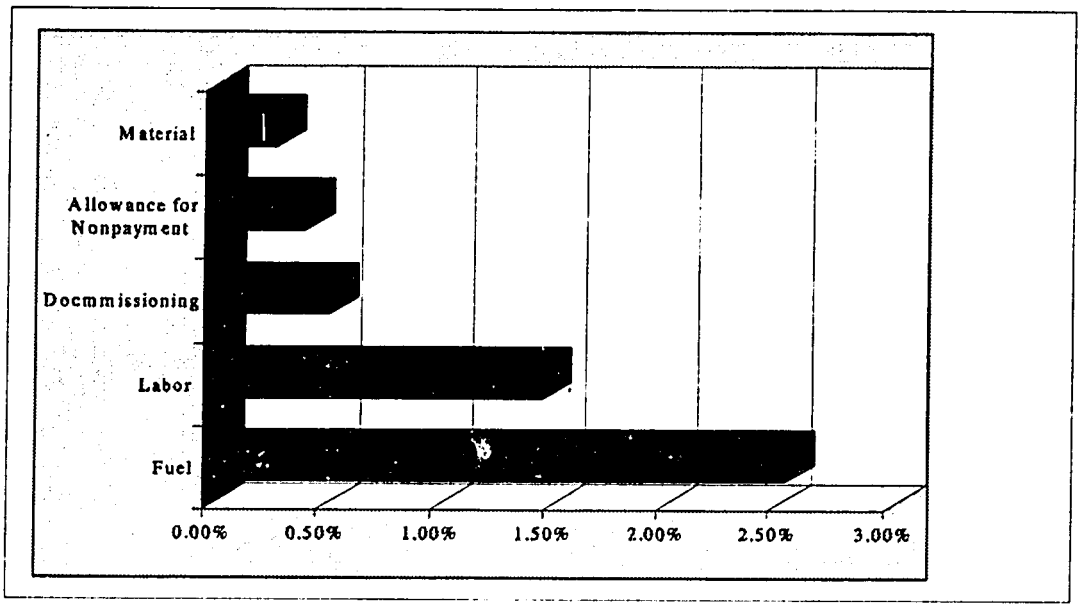

Figure 6-3 Sensitivity of Revenue Requirements to a 10 Percent Increase in Selected Operating Costs

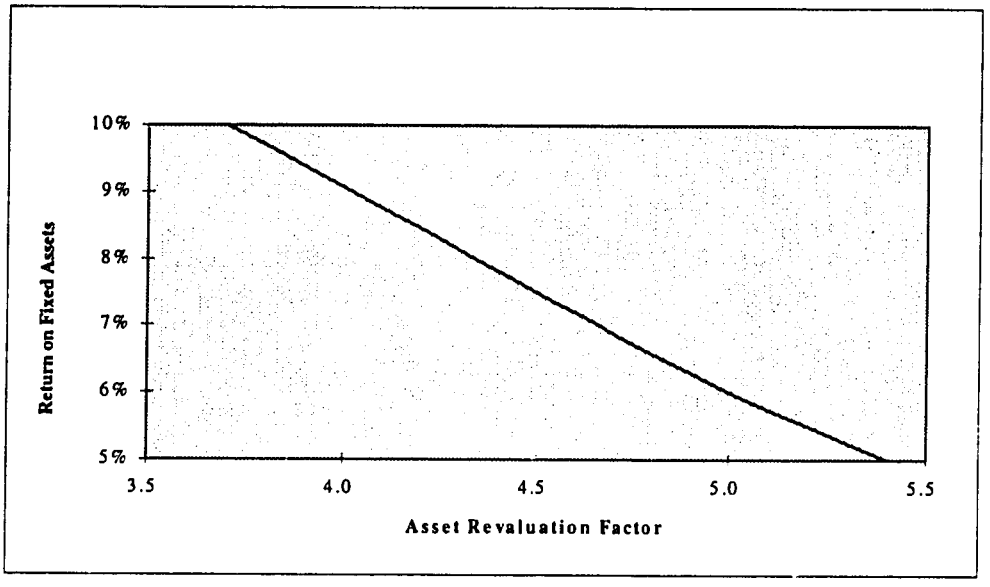

Figure 6-4 Rate of Return on Fixed Assets Versus Required Asset Revaluation Factor

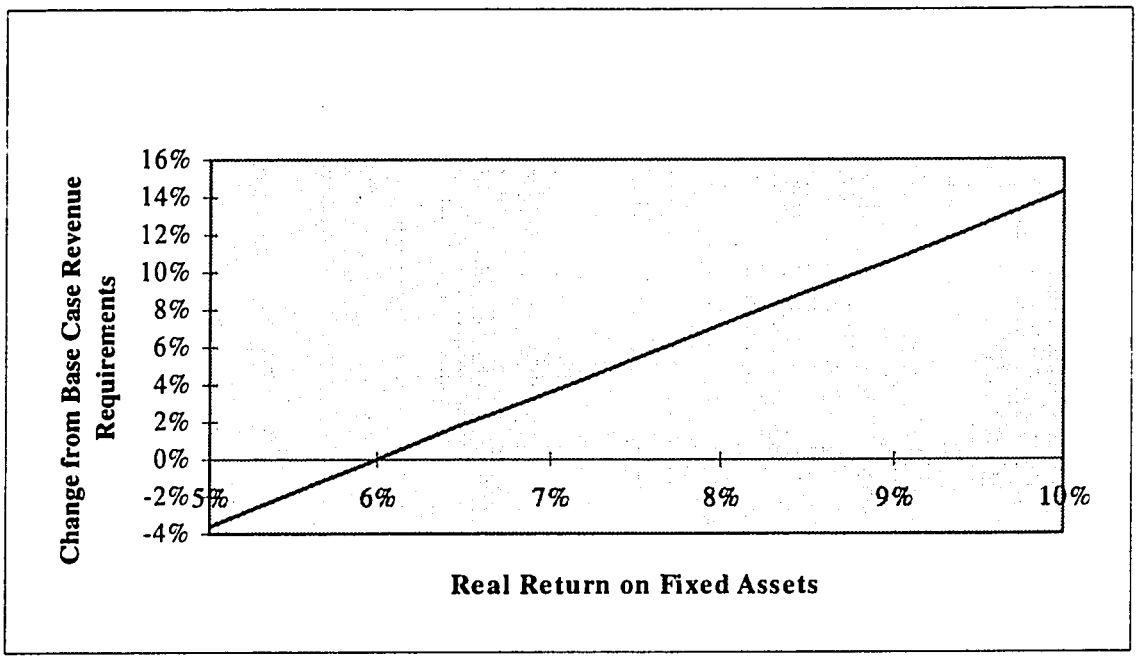

Figure 6-5 Sensitivity of Revenue Requirements to Rate of Return on Fixed Assets

The projected levelized price of exports in the Base Case was 1,475 Sk/MWh (46 $/MWh) which is higher than the marginal generating cost. The margin on the sales has the effect of reducing revenue requirements associated with domestic sales. Without sales the present worth of revenue requirements from 1995 through 2000 would increase by 5 percent.

The impact of exports is not just dependent upon the amount of export sales, but also on the price. An increase of 10 percent in export price would result in a decrease in revenue requirements associated with domestic sales of 0.5 percent compared to the Base Case.

7 REVENUE REQUIREMENTS ANALYSIS FOR THE REGIONAL DISTRIBUTION UNITS

This section presents an analysis of the future revenue requirements of the three Regional Distribution Utilities (RDUs) providing retail electricity in SR. These are the West Slovak Distribution Company (ZSE), the Central Slovak Distribution Company (SSE), and the East Slovak Distribution Company (VSE). The focus of this section is on the revenue requirements which are incremental to those associated with the SE sales price at the 220 kV level. (The revenue requirements for SE were described in Section 6.) The objectives in this analysis are to:

- Conduct an analysis to determine the required revenue from each voltage level without financial constraints
- Determine the revenue level that would ensure SE's and the RDU's financial health and viability

The results presented in this section are consolidated for all three of the RDUs by voltage level. Results for individual RDUs are presented in Appendices G, H, and I for ZSE, SSE, and VSE, respectively. The voltage categories, corresponding to retail customer categories, are defined as follows:

- Very High Voltage (VHV) 50 - 200 kV
- High Voltage (HV) 1 - 50 kV
- Low Voltage (LV) Less than 1 kV

7.1 Objectives and Approach

This analysis is carried out for each distributor as well as for all combined as one distribution company. The actual information and data used are for 1993. Projections are made for 1994 to 2000. Revenue requirements for 1994 to 2000 are calculated in constant 1993 currency.

Electricity enters the transmission system at high voltage and flows to lower voltage systems. The cost of supply to customers at a given voltage level includes the costs of building and operating the given voltage network and the allocated costs of higher voltage networks and of generation. The revenue requirement for each voltage level calculated in this section is the incremental impact of the costs incurred in serving retail customers at that level. Total per unit revenue requirements at a given voltage level can be calculated by adding the increment requirements at that level the per unit requirements at high voltage levels adjusted by losses.

Section 6 investigated the required revenue for the generation and transmission above 200 kV (for SE). The per unit revenue requirements of this system must be adjusted for losses and added to the Very High, High, and Low Voltage revenue requirement results. Likewise, Very High per unit revenue requirements must be added to the High and Low Voltage results, and the High Voltage per unit revenue requirements must be added to the Low Voltage results.

The approach adopted in this analysis uses a fixed rate of return on the fixed assets to determine the operating income. Operating expenses are added to operating income which determines the required revenue for each customer class for each RDU. Since fixed assets have been in place for many years

and their current value does not reflect their real value, the analysis considers asset revaluation. Assets are revalued and new depreciation figures are computed.

The revenue requirements analysis was conducted for each of the RDUs operating separately. income statements, balance sheets, and sources and uses of funds statements were projected for each RDU and separated by voltage category.

7.2 Financial Performance Criteria

Several financial performance criteria were examined to ensure the financial health of all companies involved in this analysis, including SE and the RDUs. In this analysis the following criteria are examined:

- Operating ratio – defined as the ratio of operating expenses to total revenues.
- Current ratio – defined as the ratio of current assets to current liabilities.
- Debt to equity – defined as the ratio of long term debt to equity.
- Accounts receivable outstanding in days.
- Rate of return or return on fixed assets. This rate in a given year is the operating income divided by net fixed assets expressed as a percentage. Net fixed assets is defined as total fixed assets less accumulated depreciation.
- Cash generation ratio is the quotient of internal cash generation over annual investment. This ratio is an indication of the utility's financial capacity.

The setting of the Base Case real rate of return and the revaluation of existing assets was done in such a way as to satisfy these financial performance criteria. Base Case analysis was conducted using a real rate of return on fixed assets of 6 percent.

7.3 Base Case Results

Pro forma financial statements were developed for each RDU and for each voltage level service. Projected income statements for Very High, High and Low voltage levels (all RDUs consolidated) are shown in Tables 7-1 through 7-3, respectively for years through 1999. The 1993 statement reflects actual data allocated to voltage level. Only the incremental expenses and allocated revenues associated with each voltage service are shown. (Purchased power from SE and expenses for generating electricity are not shown. The costs and revenues associated with generation are covered in Section 6.) The 1994 statement reflects costs and revenues as they would have appeared had an asset revaluation taken place in that year.

Pro forma sources and uses of funds statements are shown by voltage level in Tables 7-4 through 7-6. Pro forma Balance Sheets are summarized for all voltage levels in Table 7-7 and projected financial ratios are shown by voltage level in Tables 7-8 through 7-10. All produced financial ratios are in a reasonable range except that the accounts receivable outstanding in days is substantially higher than corresponding target figure. This indicates that an improvement is necessary.

The analysis was conducted for each RDU separately. As discussed previously, individual year-by-year RDU analysis is presented in Appendices G, H, and I for ZSE, SSE, and VSE, respectively.

Table 7-1
Projected Base Case RDU Income Statement for Very High Voltage Service
(millions Sk)

	Year						
	1993	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Revenue							
Domestic sales	821	1,088	989	987	985	983	981
Other	92	3	3	3	3	3	3
Total revenue	913	1,091	991	989	987	985	983
Expenses							
Material and other	297	306	306	306	306	306	306
Labor and services	254	261	261	261	261	261	261
Depreciation	62	124	58	59	59	59	60
Total expenses	613	691	626	626	627	627	628
Operating income	300	400	366	363	361	358	356
Interest	0	0	4	8	12	16	19
Corporate taxes	120	160	145	142	139	137	135
Net income	180	240	221	220	220	220	219

Table 7-2
Projected Base Case RDU Income Statement for High Voltage Service
(millions Sk)

	Year						
	1993	1994	1995	1996	1997	1998	1999
Revenue							
Domestic sales	1,413	2,049	1,861	1,856	1,852	1,847	1,840
Other	60	0	0	0	0	0	3
Total revenue	1,473	2,049	1,861	1,856	1,852	1,847	1,843
Expenses							
Material and others	424	437	437	437	437	437	306
Labor and services	406	418	418	418	418	418	261
Depreciation	142	283	138	139	140	141	60
Total expenses	972	1,139	993	994	995	996	628
Operating income	501	910	868	862	857	851	846
Interest		0	10	19	28	36	45
Corporate taxes		364	343	337	332	326	320
Net income		546	524	523	523	522	522

Table 7-3
Projected Base Case RDU Income Statement for Low Voltage Service
(millions Sk)

	Year						
	1993	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Revenue							
Domestic sales	1,230	1,880	1,685	1,680	1,675	1,670	1,663
Other	61	0	0	0	0	0	3
Total revenue	1,291	1,880	1,685	1,680	1,675	1,670	1,666
Expenses							
Material and other	412	424	424	424	424	424	424
Labor and services	338	348	348	348	348	348	348
Depreciation	135	270	120	121	122	123	124
Total expenses	885	1,042	893	894	895	895	896
Operating income	406	837	792	786	781	775	769
Interest	0	0	9	17	25	33	41
Corporate taxes	162	335	313	308	302	297	291
Net income	243	502	478	476	475	474	473

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Table 7-4
Base Case RDU Sources and Application of Funds for Very High Voltage Service
(millions Sk)

	Year						
	1993	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
SOURCES	362	575	505	505	505	504	504
Internal Generation							
Operating income	300	400	366	363	361	358	356
Depreciation	62	124	58	59	59	59	60
Total	362	523	424	422	420	418	416
Borrowing	0	52	82	83	85	87	88
APPLICATIONS	362	575	505	505	505	504	504
Investment	0	52	82	83	85	87	88
Debt service							
Principle	1	1	4	8	12	17	22
Interest	0	0	4	8	12	16	19
Total debt service	1	1	8	16	24	32	41
Taxes	120	160	145	142	139	137	135
Change in working capital	145	0	-445	-123	-124	-125	-127
Change in cash	96	363	716	386	380	374	367

Table 7-5
Base Case RDU Sources and Application of Funds for High Voltage Service
(millions Sk)

	Year						
	1993	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
SOURCES	643	1,314	1,196	1,195	1,195	1,194	1,194
Internal generation							
Operating income	501	910	868	862	857	851	846
Depreciation	142	283	138	139	140	141	142
Total	643	1,194	1,006	1,001	997	992	988
Borrowing	0	120	191	194	198	202	206
APPLICATIONS	643	1,314	1,196	1,195	1,195	1,194	1,194
Investment	0	120	191	194	198	202	206
Debt service							
Principle	1	1	9	18	28	39	51
Interest	0	0	10	19	28	36	45
Total debt service	1	1	18	37	56	76	96
Taxes	201	364	343	337	332	326	320
Change in working capital	300	0	-975	-234	-240	-246	-251
Change in cash	141	828	1619	861	849	836	823

Table 7-6
Base Case RDU Sources and Application of Funds for Low Voltage Service
(millions Sk)

	Year						
	1993	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
SOURCES	541	1,219	1,086	1,085	1,083	1,082	1,081
Internal generation							
Operating income	406	837	792	786	781	775	769
Depreciation	135	270	120	121	122	123	124
Total	541	1,107	912	907	903	898	893
Borrowing	0	112	174	177	181	184	188
APPLICATIONS	541	1,219	1,086	1,085	1,083	1,082	1,081
Investment	0	112	174	177	181	184	188
Debt service							
Principle	1	1	8	17	26	36	46
Interest	0	0	9	17	25	33	41
Total debt service	1	1	17	34	51	69	87
Taxes	162	335	313	308	302	297	291
Change in working capital	238	0	-930	-233	-238	-243	-247
Change in cash	139	771	1512	799	787	775	762

Table 7-7
Projected Base Case RDU Balance Sheet
(millions Sk)

	1993			1994			1999		
	Very High Voltage	High Voltage	Low Voltage	Very High Voltage	High Voltage	Low Voltage	Very High Voltage	High Voltage	Low Voltage
Assets	3,626	7,358	6,833	8,099	17,939	16,510	9,558	21,393	19,652
Fixed Assets									
Fixed assets in operation	4,114	9,618	8,951	12,341	28,854	26,852	8,878	21,259	19,633
Less accumulated depreciation	2,059	4,742	4,498	6,176	14,226	13,494	6,842	15,596	14,228
Net fixed assets	2,055	4,876	4,453	6,165	14,629	13,358	5,929	14,101	12,823
Work in progress	298	686	649	298	686	649	0	0	0
Total fixed assets	2,353	5,562	5,102	6,463	15,314	14,007	5,929	14,101	12,823
Current Assets									
Cash and banks	96	141	139	459	969	910	2,682	5,957	5,544
Accounts receivable	1,015	1,422	1,363	1,015	1,422	1,363	785	1,100	1,055
Inventory	157	228	224	157	228	224	157	228	224
Other	5	6	6	5	6	6	5	6	6
Total	1,273	1,796	1,732	1,636	2,625	2,503	3,629	7,291	6,829
Equity and Liabilities	3,626	7,358	6,833	8,099	17,939	16,510	9,558	21,393	19,652
Equity									
Capital	2,223	5,133	4,810	6,456	15,167	13,984	6,456	15,167	13,984
Retained earnings	226	512	505	466	1,058	1,008	1,566	3,672	3,384
Total	2,450	5,645	5,315	6,923	16,226	14,992	8,022	18,840	17,368
Long-term debt	3	7	6	3	7	6	363	846	771
Current Liabilities									
Short-term loans	216	313	275	216	313	275	216	313	275
Accounts payable	946	1,378	1,222	946	1,378	1,222	946	1,378	1,222
Other	11	16	15	11	16	15	11	16	15
Total	1,173	1,707	1,512	1,173	1,707	1,512	1,173	1,707	1,512

Table 7-8
Projected Base Case Financial Statistics for Very High Voltage Service

	1993	1994	1999	Target Ratios
Operating ratio	0.77	0.74	0.76	< 1
Current ratio	1.08	1.39	3.09	1 to 4
Cash generation ratio	NA	6.89	2.01	> .4
Debt coverage ratio	NA	NA	10.15	> 1
Debt/equity	0.1%	0.0%	4.5%	
Debt	0.1%	0.0%	4.3%	60.0%
Equity	99.9%	100.0%	95.7%	40.0%
Accounts receivable outstanding in days	406	339	291	30 to 45
Number of times interest earned	NA	NA	18.51	> 1
Return on fixed assets	14.6%	6.5%	6.0%	5 to 10%

Table 7-9
Projected Base Case Financial Statistics for High Voltage Service

	1993	1994	1999	Target Ratios
Operating ratio	0.76	0.68	0.67	< 1
Current ratio	1.05	1.54	4.27	1 to 4
Cash generation ratio	NA	6.81	2.04	> .4
Debt coverage ratio	NA	NA	10.34	> 1
Debt/equity	0.1%	0.0%	4.5%	
Debt	0.1%	0.0%	4.3%	60.0%
Equity	99.9%	100.0%	95.7%	40.0%
Accounts receivable outstanding in days	341	245	273	30 to 45
Number of times interest earned	NA	NA	18.87	> 1
Return on fixed assets	10.3%	6.2%	6.0%	5 to 10%

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Table 7-10
Projected Base Case Financial Statistics for Low Voltage Service

	1993	1994	1999	Target Ratios
Operating ratio	0.78	0.67	0.67	< 1
Current ratio	1.15	1.65	4.52	1 to 4
Cash generation ratio	NA	6.79	2.02	> .4
Debt coverage ratio	NA	NA	10.26	> 1
Debt/equity	0.1%	0.0%	4.4%	
Debt	0.1%	0.0%	4.3%	60.0%
Equity	99.9%	100.0%	95.7%	40.0%
Accounts receivable outstanding in days	385	265	231	30 to 45
Number of times interest earned	NA	NA	18.82	> 1
Return on fixed assets	9.1%	6.3%	6.0%	5 to 10%

8 PRICING STRATEGY BASED ON LONG-RUN MARGINAL COST

The objective of this section is to present a pricing strategy based on strict Long-Run Marginal Cost (LRMC) not considering financial, social, or political factors that could affect the tariff structure. The per unit LRMC is defined as the levelized incremental investment and operating cost of serving an additional kWh of energy demand (or kW of peak) of demand for an indefinite period of time.

This section is closely related to many of the other sections of the report. The load and resource assumptions used in the calculation of the generation system LRMC are the subjects of Sections 2 and 3. The simulation of power system dispatch, an integral part of LRMC calculation, is discussed in Section 4.

In Section 9 adjustments will be made to this strict LRMC pricing strategy to reflect the critical financial, social, and political factors. Sections 6 and 7 specifically address the financial requirements of the Slovak National Power Company (SE) and the three Regional Distribution Utilities (RDUs) in detail. The strict LRMC pricing strategy developed in this section is a benchmark for estimating the cost of incorporating these factors into the final tariff design.

8.1 Overall Approach

The general approach used in developing the LRMC pricing strategy was to estimate generation LRMC and long-run transmission and distribution costs by voltage category. In each case, LRMC was separated by energy-related, capacity-related, and customer-related costs where appropriate. The reason for this separation is that energy-related costs provide a guideline to which component of tariffs should be variable based on energy demand; capacity-related costs provide a guideline to which component of the tariff should be related to peak demand; customer-related costs should be related to the tariff component related to the number of customers. These estimates were then used as the building blocks for estimating LRMC to various customer categories.

The Base Case estimate utilizes an opportunity cost of capital of 10 percent. The results for each of the supply categories are presented below.

8.2 Generation System LRMC

A number of methods exist for calculating generation system LRMC and for separating this value into energy-related and capacity-related costs. Each has advantages and disadvantages based on theoretical considerations, data requirements, and difficulty of application. Two methods of calculating generation system LRMC were used for this study to illustrate the use of alternative methods and to demonstrate the sensitivity of results to methodological approach. The methods selected are referred to as the Incremental Plant Method and the Revenue Requirements Method. In both cases projected investment and operating costs through 2005 were considered.

These methods and their results as applied to the Slovak power system are discussed below. Generation system costs were separated into energy-related and capacity-related costs. Customer-related costs are not applicable to the generation system.

8.2.1 Incremental Plant Method

The Incremental Plant Method was applied in the following way:

- Energy-related (i.e., variable) costs were estimated based on Short-Run Marginal Cost (SRMC).
- Capacity-related costs (i.e., fixed) costs were estimated based on the investment costs of the incremental plant.
- Levelized capacity-related costs were calculated per unit of peak demand increase and per unit of energy demand increase.
- Energy-related and capacity-related costs per unit of energy demand increase were combined for a total generation system LRMC.

The SRMC of the Reference Generation Plan (Reference 8-1) was estimated using the Elfin model as described in Section 4.

The incremental plant is defined as the first unit in the development plan which can either be deferred in case of a decrease in demand or accelerated in case of an increase in demand. The results of this method are dependent upon the identification of this plant. The Reference Power Development Plan shows the following new units:

- Mochovce – Unit 1 - 1997, Unit 2 - 1998, Unit 3 - 2000, Unit 4 - 2001
- Combined heat and power plants – 1997 (ZSE) and 1997 (SSE)
- Generic gas-fired combined cycle units – Unit 1- 2002 and 2005

The schedules of the Mochovce units are dependent upon many considerations besides load demand. A study of various planning scenarios for the Mochovce units (Reference 8-2) indicates that their schedules are unchanged over a wide range of load forecasts. Furthermore, the investment cost of Units 3 and 4 have not been estimated with the same degree of accuracy at this point as the other options.

The timing of the combined heat and power plants is dependent upon heat demand as well as electricity demand so that small changes in electricity demand will most likely not influence the timing of these units.

Therefore, the first plant that can either be accelerated in case of an increase in projected load or deferred in case of a decrease is a gas-fired, combined cycle unit planned for 2002. This is the incremental plant. The technical and operating characteristics assumed for this plant are shown in Table 8-1. A capacity factor of 60 percent was assumed for the incremental plant. This is consistent with the results of the Elfin production simulation model. Table 8-2 displays the calculation of the generation LRMC using the Incremental Plant Method.

Table 8-1
Technical and Operating Characteristics of the Incremental Plant

Net Capacity	Overnight Capital Cost (per kW of net capacity)		IDC Factor*	Installed Capital Cost (per kW of net capacity)		Planning Reserve Margin	Installed Capital Cost (per kW of peak load)	
(MW)	(Sk/kW)	($/kW)		(Sk/kW)	($/kW)		(Sk/kW)	($/kW)
(A)	(B)		(C)	(D=B x C)		(E)	(F=D x (1+E)	
300	22,000	688	1.19	26,184	818	20%	31,427	982

* The IDC factor was based on a 10 percent real opportunity cost of capital with 3-year construction and a cash flow of 20 percent in Year 1, 40 percent in Year 2, and 40 percent in Year 3.

Table 8-2
Generation LRMC – Incremental Plant Method

	Cost per kW of Peak Load Increase ($)										
	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Investment	0	0	0	0	165	330	330	0	0	0	0
Present worth in 1st year of operation								982			
Capital recovery	0	0	0	0	0	0	0	104	104	104	104
Fixed O&M	0	0	0	0	0	0	0	28	28	28	28
Total fixed cost	0	0	0	0	0	0	0	132	132	132	132
Energy (MWh) (assuming 60 percent load factor)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3	5.3	5.3	5.3
	Cost per MWh of Energy Increase										
Energy cost (SRMC)	34.0	46.9	35.9	25.5	31.5	38.1	25.8	31.7	40.3	43.8	74.2
Capacity cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.2	25.2	25.2	25.2
Total	34.0	46.9	35.9	25.5	31.5	38.1	25.8	56.9	65.5	68.9	99.4

	Levelized Cost (per MWh of Generation)	
	$	Sk
Variable	37.5 $/MWh	1,119 Sk/MWh
Fixed	6.3 $/MWh	202 Sk/MWh
	3[illegible].1 $/kW-yr	1,060 Sk/kW-yr
Total	3[illegible].8 $/MWh	1,400 Sk/MWh

8.2.2 Revenue Requirements Method

The Revenue Requirements Method uses the following procedure:

- Develop optimized generation plan for a given electricity demand forecast.
- Develop optimized generation plan for a electricity demand forecast with a small increase in demand.
- Calculate the revenue requirements for each optimized plan (investment and operating costs).
- Separate revenue requirements into energy-related and capacity-related costs.
- Calculate the levelized cost per unit of demand increase for energy-related, capacity-related, and total costs.

The development of alternative optimized generation plans is beyond the scope of this study. However, the optimization of generation expansion under alternative planning scenarios has been done by SE and the Electricité de France (Reference 8-2). This was done for high, medium, and low electricity demand forecasts for the following scenarios:

- Scenario 1 – Completion of Mochovce Units 1 and 2, and cancellation of Units 3 and 4
- Scenario 2 – Completion of Mochovce Units 1 through 4
- Scenario 3 – Cancellation of Mochovce Units 1 through 4

In Scenarios 1 and 2, Mochovce Units 1 and 2 are to be completed in 1997 and 1998, regardless of load demand. The Reference Power Development Plan presented in Section 4 corresponds most closely to Scenario 2 because SE currently plans to complete all four units of Mochovce. However, the estimated completion costs of Units 3 and 4 are considered much more questionable than for Units 1 and 2 or for alternative gas-fired, combined cycle units.

Therefore, Scenario 1 was selected because the completion of Mochovce Units 1 and 2 corresponds to the Reference Generation Plan during the time period of tariff study (i.e., through 1999), but the costs of adding gas-fired, combined cycle units provides a firmer basis for estimating generation LRMC than the costs of completing Units 3 and 4 of Mochovce.

Table 8-3 shows the effect of load on the generation plan (Reference 8-2). As shown, planning studies have indicated that load variations will not affect the timing of Mochovce Unit 1 and 2 or the investments required for reconstruction of Vojany and Novaky. The High Forecast required accelerated installation of gas-fired combined, cycle units and the addition of a coal plant.

The revenue requirements for the optimized plans for the Low and High Forecasts were compared for Scenario 2 and the levelized cost per unit of demand increase was calculated. This is shown in Table 8-4.

Table 8-3
Generation Plan as a Function of Forecasted Load

Name	Action	Low Forecast Year	High Forecast Year	Difference
Bohunice V-1				
Unit 1	Retire	2000	2000	None
Unit 2	Retire	2001	2001	None
Mochovce				
Unit 1	Commission	1997	1997	None
Unit 2	Commission	1998	1998	None
Vojany I				
Units 1 through 4	Reconstruct	1997-2000	1997-2000	None
Units 5 and 6	Return to service	1996	1996	None
Novaky A				
Units 1 and 2	Reconstruct	1995 and 1997	1995 and 1997	None
Units 3 and 4	Retire	1997 and 2000	1997 and 2000	None
Novaky B				
Unit 1	Reconstruct	1998	1998	None
Unit 2	Return to service	1994	1994	None
Units 3 and 4	Retire	1999	1999	None
Gas-fired combined cycle plants				
Plant 1	Commission	2002	1997	Accelerate 5 years
Plant 2	Commission	2002	1999	Accelerate 3 years
Plant 3	-	-	2000	Add
Coal-fired plant	-	-	2004	Add

Table 8-4
Generation LRMC – Revenue Requirements Method
(thousands US$)

	High Case Minus Low Case										
	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Energy (GWh)	1,793	2,633	3,401	4,049	4,412	4,608	4,897	5,711	6,075	6,460	6,861
Peak (MW)	299	439	566	671	731	764	811	938	997	1,060	1,124
Incremental load factor	68.5%	68.5%	68.6%	68.9%	68.9%	68.8%	68.9%	69.5%	69.6%	69.6%	69.7%
Fuel	73,676	86,013	100,798	99,599	117,236	130,265	143,351	199,370	223,543	171,517	179,146
Purchased power	224	41,533	(6)	9	(28)	(52,203)	(14,134)	10	10	(1)	(1)
Material and others	286	1,234	548	671	738	759	895	872	937	3,162	3,250
Labor and services	286	1,234	548	671	738	759	895	872	937	3,162	3,250
Capital recovery (annualized)	0	0	26,107	50,075	73,861	97,828	97,828	74,042	50,075	130,996	(47,754)
Total incremental revenue requirements	74,472	130,013	127,994	151,026	192,545	177,408	228,836	275,167	275,502	308,836	137,892
Variable	74,472	130,013	101,887	100,952	118,684	79,580	131,008	201,125	225,427	177,840	185,645
Fixed	0	0	26,107	50,075	73,861	97,828	97,828	74,042	50,075	130,996	(47,754)

	Levelized Value	
Energy	30.6 $/MWh	979 $/MWh
Capacity	10.9 $/MWh	348 $/MWh
	65.7 $/kW-yr	2,103 $/kW-yr
Total	41.5 $/MWh	1,327 $/MWh

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8.2.3 Conclusion

There is a very close correspondence between the two methods for total LRMC. There is a difference between the allocation of costs between those which are energy-related and those which are capacity-related.

A criticism of the Revenue Requirements Method is that it tends to average baseload, intermediate, and peaking costs and thus does not represent the cost of providing a small increment of demand increase. The difference between the Low and High Forecasts in Reference 8-2 is certainly more than a "small" increment. The result is that higher-capital-cost, lower-energy-cost baseload plants influence the allocation of energy- and capacity-related costs. Thus, some of the capacity-related cost as calculated under the Revenue Requirements Method is not always related to meeting increased in peak demand, but can represent investment to reduce energy-related costs. This is clearly exemplified in the addition of the coal-fired plant under the High Forecast.

For this reason, it is our judgment that the Incremental Plant Method provides a better allocation between energy- and capacity-related costs in this application. For purposes of overall estimated LRMC for generation, an average of the two methods was used.

8.3 Extra-High Voltage (EHV) Transmission System LRMC

For purposes of this study the EHV transmission system refers to equipment at 220 kV and above. This transmission equipment is owned and operated by SE. The method used is analogous to the Revenue Requirements Method used for the generation system. The costs were separated in energy- and capacity-related costs in the following way:

- Component 1 of energy-related costs was based on the energy-related component of the generation system LRMC and the loss rate for the EHV system.
- Component 1 of the capacity-related costs was based on the capacity-related component of the generation-system energy-related costs and the loss rate of the EHV system.
- Component 2 of the capacity-related costs was based on the revenue requirements associated with incremental investment required for transmission equipment at 220 kV and above.
- Component 2 of the energy-related costs was based the incremental revenue requirements associated with operation of the transmission network at 220 kV and above.

Transmission plans for equipment above 220 kV for two load forecasts were available as part of the Tractebel least-cost planning study (Reference 8-3). High and low cost estimates were provided for each plan. For each of the high and low cost estimates, the differential revenue requirements were levelized per unit of peak demand increase and per unit of energy increase assuming a system load factor of 68 percent. Costs associated with energy losses were based on a loss rate of 2 percent. Transmission system operating costs were estimated at 2 percent of fixed costs.

The calculation of EHV system LRMC is shown in Table 8-5.

Table 8-5
Transmission LRMC (>200 kV)
(thousands $)

	High Minus Low Growth Cases										
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Energy (GWh)	2,369	2,673	2,977	3,281	3,585	3,889	4,193	4,497	4,801	5,105	5,408
Peak (MW)	460	519	578	637	696	755	814	873	932	991	1,050
Investment											
Lines	8,052	8,052	8,052	8,052	8,052	8,052	8,052	8,052	8,052	8,052	8,052
Substations	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207
Total	11,259	11,259	11,259	11,259	11,259	11,259	11,259	11,259	11,259	11,259	11,259
O&M	225	450	676	901	1,126	1,351	1,576	1,801	2,027	2,252	2,477
Capital recovery	1,151	2,303	3,454	4,605	5,756	6,908	8,059	9,210	10,362	11,513	12,664
Total	1,376	2,753	4,129	5,506	6,882	8,259	9,635	11,012	12,388	13,765	15,141
Variable	225	450	676	901	1,126	1,351	1,576	1,801	2,027	2,252	2,477
Fixed	1,151	2,303	3,454	4,605	5,756	6,908	8,059	9,210	10,362	11,513	12,664

	Levelized Cost (per MWh of sales from EHV grid)	
Variable	0.3 $/MWh	10 Sk/MWh
Fixed	1.6 $/MWh	52 Sk/MWh
	8.3 $/kW-yr	267 Sk/kW-yr
Total	1.9 $/MWh	62 Sk/MWh

Table 8-6
Long-Run Average Incremental Cost – Very High Voltage (average of all RDUs)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
						GWh						
VHV sales	4,379	4,266	4,285	4,349	4,528	4,719	4,914	5,117	5,326	5,535	5,750	5,963
Energy leaving VHV												
Grid for lower voltages	13,113	13,206	13,564	13,982	14,685	15,328	15,981	16,688	17,430	18,205	19,010	19,845
Total VHV service	17,492	17,472	17,849	18,331	19,213	20,047	20,895	21,805	22,756	23,741	24,760	25,808
Incremental VHV demand		-20	377	482	882	834	848	910	951	984	1,019	1,048
						millions Sk						
Total investment in VHV grid		82	83	85	87	88	90	92	94	96	98	100
For maintenance		49	50	51	52	53	54	55	56	57	59	60
For incremental demand		33	33	34	35	35	36	37	38	38	39	40
LRAIC for VHV service	53 Sk/MWh											

Table 8-7
Long-Run Average Incremental Cost – High Voltage (average of all RDUs)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
						GWh						
HV sales	6,073	6,022	6,158	6,362	6,744	7,155	7,586	8,045	8,526	9,025	9,547	10,085
Energy leaving HV Grid for lower voltages	6,690	6,833	7,047	7,252	7,558	7,776	7,984	8,216	8,461	8,721	8,986	9,266
Total HV service	12,763	12,855	13,205	13,614	14,303	14,931	15,570	16,261	16,987	17,746	18,534	19,352
Incremental HV demand		92	351	409	688	629	638	691	726	759	788	818
						millions Sk						
Total investment in HV grid		191	194	198	202	206	210	215	219	223	228	232
For maintenance		114	117	119	121	124	126	129	131	134	137	139
For incremental demand		76	78	79	81	82	84	86	88	89	91	93
LRAIC for HV service	153 Sk/MWh											

8.4 Transmission and Distribution System LRMC

Long-Run Marginal Transmission and Distribution Costs were calculated for all three RDUs. These LRMCs are calculated for all customer classes based on their voltage level, for VHV, HV and LV customers. The transmission and distribution LRMC is defined as levelized cost to meet one additional kW in demand. Traditionally, the Long Run Average Incremental Cost (LRAIC) is used as a good approximation of LRMC.

The RDUs did not have capital investment plans based on the Reference Load Forecast which is used in the study. Therefore, assumptions are made for transmission and distribution investment plans to compute the LRAIC for customer classes for each RDU.

An LRAIC model was developed for each RDU. Each model uses energy sales by voltage class for the period of 1994 to 2010. Annual costs to meet the annual additional demand are computed. The average (levelized) cost is calculated over the considered period of time. The average results of the LRAIC calculation as a function of energy served at a given voltage level are presented in Tables 8-6 through 8-8 for Very High, High, and Low Voltage categories respectively. Results for individual RDUs as a function of non-coincident peak growth are presented in Appendix J.

8.5 Summary

Strict LRMC for the Slovak power system is summarized in Table 8-9 by voltage level and by capacity- and energy-related components. The average price of sales from SE under this strategy would be approximately 1,450 Sk/MWh (43 $/MWh) of which 14 percent would be capacity related. This is an increase of approximately 30 percent over the 1993 level.

Strict LRMC retail tariffs was estimated as follows:

- Category A tariffs (Very High Voltage) — Approximately 1,450 Sk/MWh (45 $/MWh), an increase of approximately 30 percent from 1993 levels
- Category B tariffs (High Voltage) — Approximately 1,750 Sk/MWh (55 $/MWh), a decrease of 6 percent
- Category C tariffs and residential — Approximately 2,150 Sk/MWh (66 $/MWh), a 4 percent increase for business customers and a 235 percent increase for residential customers

Figure 8-1 shows the contributions of the generation, transmission greater than 200 kV, and transmission and distribution below 200 kV to LRMC. Figure 8-2 shows the contribution of fuel, labor and materials, and the capital-related items (i.e., depreciation and operating income) at the wholesale level based on Incremental Plant Method. The contribution of capital-related items is low because of the long period of time that will pass before it is projected that demand will affect investment requirements (until 2002).

Table 8-8
Long-Run Average Incremental Cost – Low Voltage (average of all RDUs)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
	GWh											
LV Sales	6,261	6,461	6,673	6,908	7,147	7,380	7,603	7,841	8,082	8,331	8,590	8,854
Incremental LV Demand		200	213	235	240	233	223	239	240	250	259	264
	millions Sk											
Total Investment in LV Grid		174	177	181	184	188	192	196	199	203	208	212
For maintenance		104	106	108	111	113	115	117	120	122	125	127
For incremental demand		69	71	72	74	75	77	78	80	81	83	85
LRAIC for LV Service	327 Sk/MWh											

Table 8-9
Summary of Strict LRMC by Voltage Category

Point of Sale	Loss Factor	Strict LRMC (Sk/MWh)						Point of Sale
		Generation	EHV	VHV	HV	LV	Total	
Generation		1,363					1,363	Generation
EHV	1.02	1,394	62				1,456	EHV
VHV	1.05	1,434	64	53			1,551	VHV
HV	1.08	1,473	65	54	153		1,746	HV
LV	1.14	1,550	69	57	161	327	2,164	LV

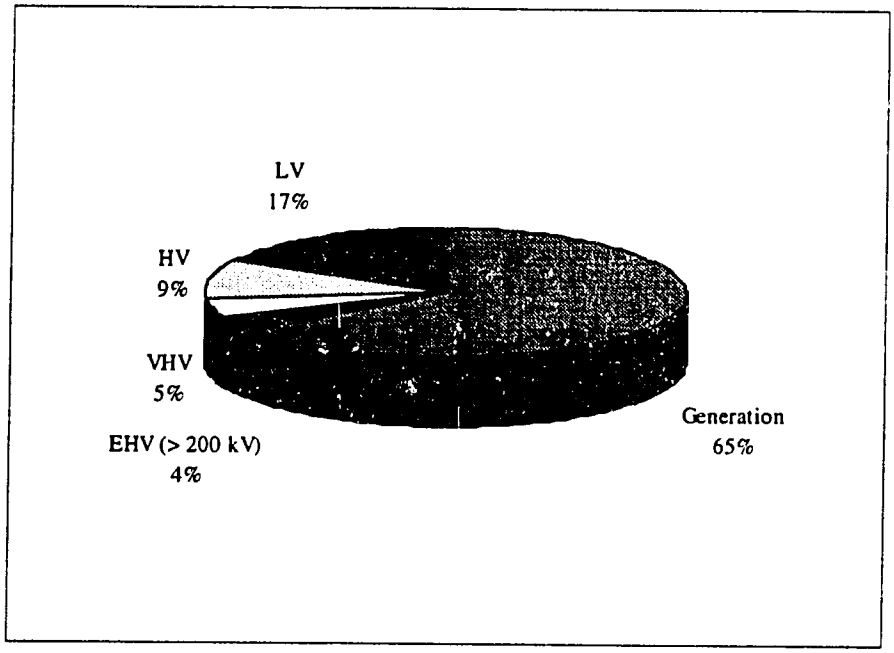

Figure 8-1 Contribution of Supply Sectors to LRMC

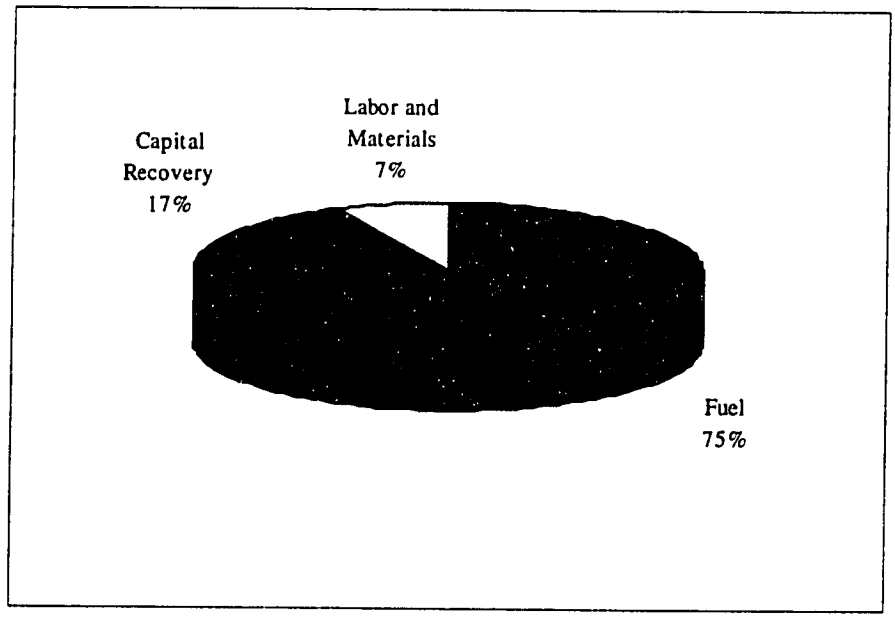

Figure 8-2 Contribution to LRMC by Cost Category

8.6 Sensitivity Analysis

The major contributing factors to LRMC are fuel cost and capital-related factors. The value of the fuel component is dependent upon fuel cost assumptions. The capital-related items are dependent upon projected capital cost of equipment and the opportunity cost of capital.

Projected fuel cost affects the marginal cost of generation which in turn affects LRMC. Capital cost assumptions affect generation, transmission, and distribution. Figure 8-3 shows the effect of a 10 percent increase in each of the fuel and capital cost categories on LRMC at the wholesale level.

The Base Case LRMC analysis utilized a 10 percent opportunity cost of capital. The capital-related component of LRMC is sensitive to the opportunity cost of capital considered. Figure 8-4 shows the impact of alternative opportunity costs of capital of 8 and 12 percent on LRMC at the wholesale level (i.e., SE sales). The reason for the relatively low impact of changes in the opportunity cost of capital is because of the low contribution of capital-related items to LRMC at the wholesale level.

8.7 References

8-1. Electricité de France, *Generation Planning Study of the Slovak Electricity System*, January 1994.

8-2. Electricité de France, *Least-Cost Option of the Slovak Power System*, April 1994.

8-3. Tractebel Energy Engineering, Power Sector Least Cost Development Study for the Czech and Slovak Republics, Volume 7, *Transmission System Study for the Czech and Slovak Republics*, February 1993.

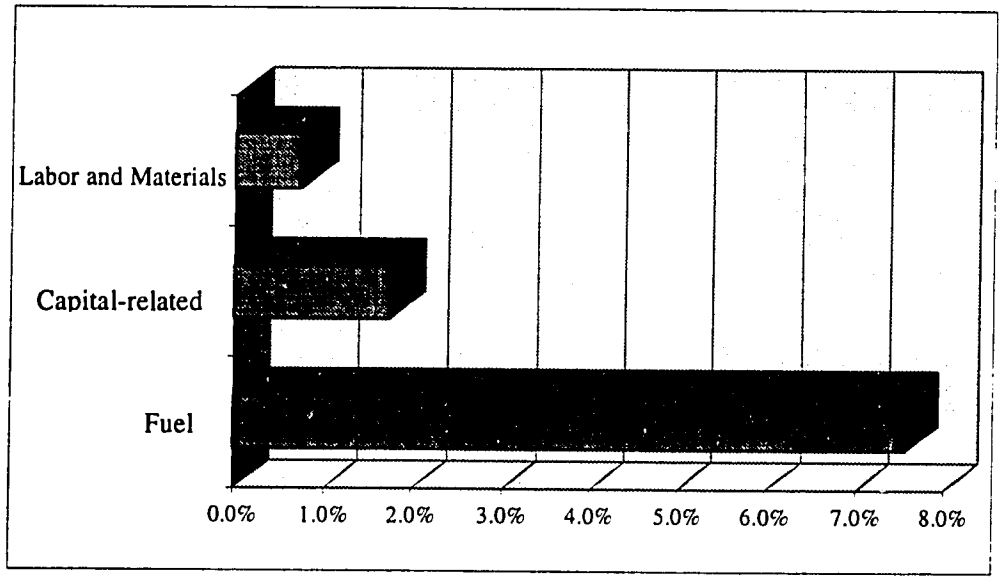

Figure 8-3 Sensitivity of LRMC to a 10 Percent Increase in Selected Costs

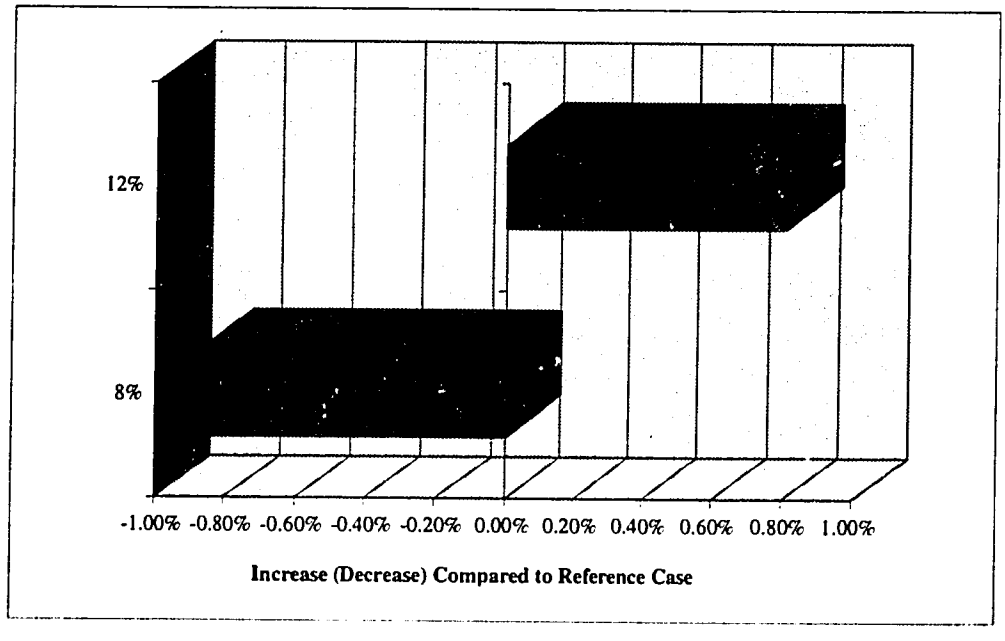

Figure 8-4 Sensitivity of LRMC to Opportunity Cost of Capital

9 ADJUSTMENT TO LRMC PRICING STRATEGY

A tariff structure based on the strict LRMC developed in Section 8 would provide the proper economic price signals to ensure an efficient use of resources. The objective of this section is to adjust the strict LRMC to meet other tariff-setting objectives as well. These include meeting the financial requirements of the various organizations supplying and distributing power, minimizing the impact on existing energy-intensive industries, and protecting economically vulnerable segments of the population. The results of this section are incorporated into the final tariff design presented in Section 11.

9.1 Financial Requirements

9.1.1 Overall Requirements

An analysis of the projected financial requirements of SE and the RDUs until the year 2000 is presented in Sections 6 and 7, respectively. Figure 9-1 shows a comparison of the average 1993 price, the projected 5-year levelized revenue requirements estimated in Sections 6 and 7, and the LRMC estimated in Section 8 for each voltage class. The estimated 5-year revenue requirements are somewhat lower than LRMC at each level, but the pattern among the various voltage levels is essentially the same for revenue requirements and for LRMC.

Existing prices are substantially lower than either LRMC or projected 5-year levelized revenue requirements at the SE sales (220 kV), Very High Voltage (Category A), and residential retail levels. The alignment of prices and tariffs with cost of service is an essential need for the electric sector to be economically and financially independent.

9.1.2 SE Financial Requirements

There is no direct price regulation at the SE sales level (>200 kV). However, the effect of retail price regulation is to limit the revenues of SE. An analysis was conducted to determine the amount of price increases that will be required to ensure that SE meets its revenue requirements with the goal of moving toward pricing based on LRMC.

As shown in Figure 9-1, SE levelized revenue requirements through 1999 are estimated to be less than LRMC. This suggests that a strategy to gradually increase SE prices to reach LRMC in order to meet revenue requirements may be feasible. The rate of price increase required is dependent upon the amount of delay that occurs before price increases at the retail level allow the SE contract price to be raised. Three cases were considered: 1) deliberate action in the near term to raise prices, 2) a one-year delay, and 3) a two-year delay.

Figure 9-2 shows the profiles of the required average SE price for the three cases over the next five years meet the present worth of revenue requirements projected in Section 6 (at a discount rate of 6 percent). In the first case, the 5-year revenue requirements can be met with a relatively modest 5.4 percent real price increase per year starting in 1995 and reaching LRMC in 1999. The required real price increase is in addition to the rate of inflation. If the rate of general inflation were 20 percent, the required annual rate of increase would be over 26 percent [(1.054 * 1.2-1) * 100 percent].

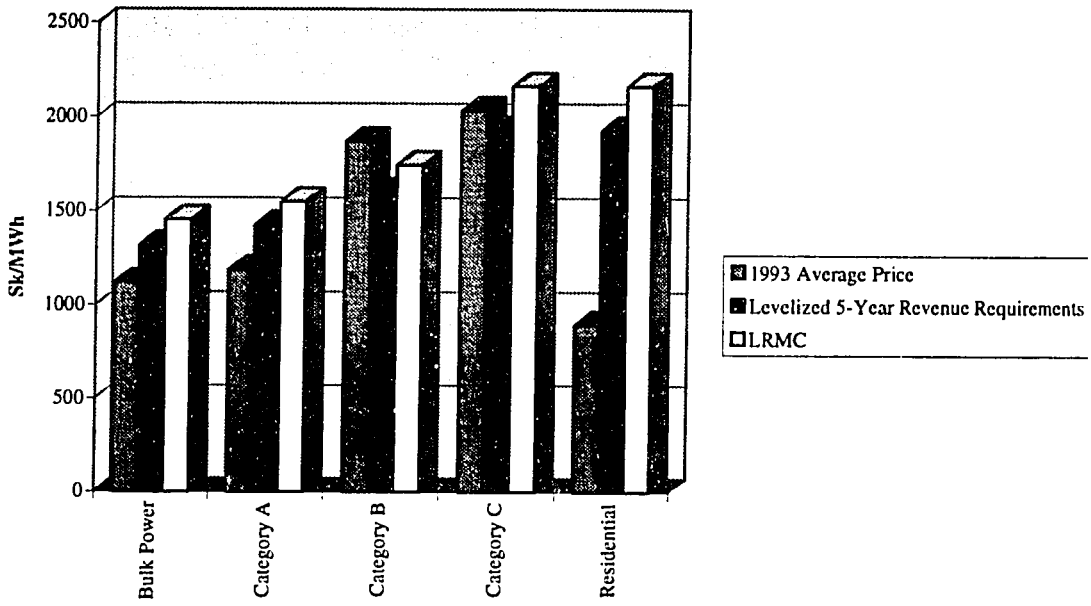

Figure 9-1 Comparison of Average 1993 Price, Levelized 5-Year Revenue Requirements, and LRMC

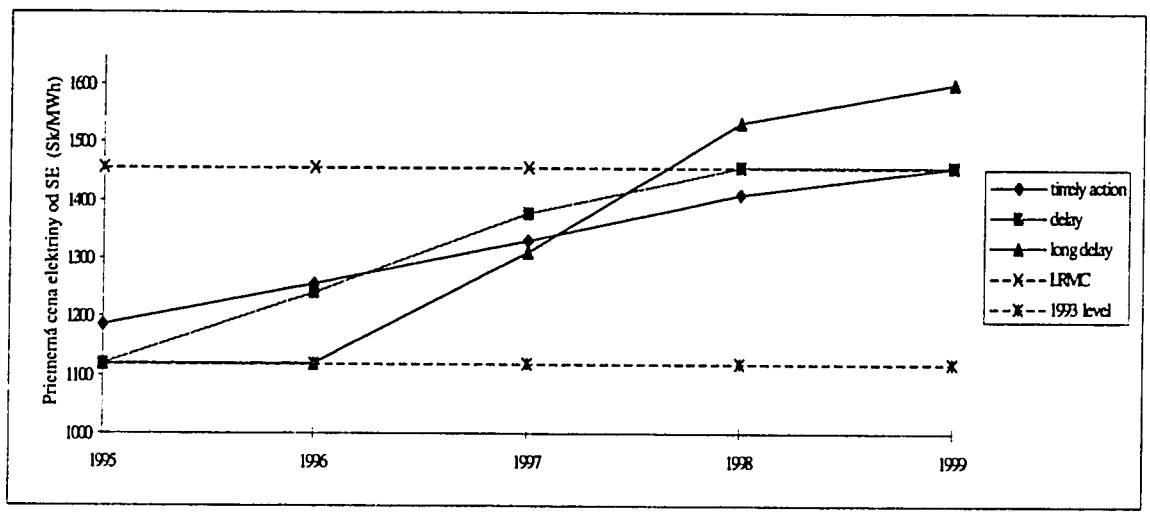

Figure 9-2 Alternative Strategies for Meeting SE Financial Requirements

A delay of one year would result in the need for SE prices to increase at a much higher rate in the future. The analysis conducted indicates that 5-year revenue requirements can be met with a real price increase of greater than 10 percent beginning in 1996 and reaching LRMC in 1998. Aside from the difficulty of imposing high rates of increase in the future, the signal given to lenders and potential investors through such a delay would be negative.

Figure 9-2 shows that a delay of 2 years creates an extremely difficult situation. In order for 5-year revenue requirements to be met on a present worth basis, a real increase of over 15 percent would be required in 1997, and it would necessary for the price to rise above the LRMC to make up for the significant revenue deficits in the near term. The rate of increase would probably not be tolerable from a social point of view; prices above the LRMC could have serious consequences for SE, and the signal to potential lenders and investors would seriously jeopardize the proposed investment plan.

Should separate transmission grid services be offered either through a separate entity or through SE, its near-term prices would be higher than the LRMC. This reflects the need to invest to achieve membership in CENTREL and UCPTE and not strictly for reasons of growth. In the long-term prices could be decreased to reflect LRMC. Conversely, generation services could be offered at less than LRMC in the near term with enough gradual increase to meet revenue requirements over the next 5 years.

9.1.3 RDU Financial Requirements

As shown in Figure 9-1, the projected 5-year levelized revenue requirements are less than LRMC for all classes of customers. The current tariffs for Category A (Very High Voltage) and residential customers are well below the levelized revenue requirements level and LRMC. An analysis was conducted to determine the minimum necessary increases in these tariffs in order for the present worth of projected revenues from 1995 through 1999 to be equal to the projected revenue requirements.

Table 9-1 summarizes the pricing strategy to meet revenue requirements with no cross-subsidies between customer classes. All categories are priced at approximately LRMC by 1999. In order to accomplish this, a real price increase of more than 60 percent is required in 1995 and more than 40 percent the following year. Discussions with the SR government officials indicate that such a rate of increase is not acceptable.

Table 9-1
Pricing Strategy to Meet Financial Requirements
(in Sk/MWh)

Sk/MWh	1995	1996	1997	1998	1999
SE Sales	1,185	1,256	1,331	1,410	1,456
Category A	1,260	1,337	1,418	1,504	1,552
Category B	1,578	1,578	1,578	1,578	1,578
Category C	1,864	1,864	1,864	1,864	1,864
Residential	1,907	2,241	2,241	2,241	2,241

Category B and C tariffs are currently both above the projected 5-year levelized revenue requirements level. (Category B is slightly above the estimated LRMC and Category C is slightly below.) From a strict revenue responsibility point of view, tariff decreases for these categories could occur.

9.2 Impact on Energy-Intensive Industries

Based on the previous discussion, there is a need to gradually increase Category A tariffs for large industries. Eight industrial facilities accounted for more than 20 percent of domestic electricity sales in 1993. Table 9-2 lists these industries and their major products, along with their electricity purchases in 1989 and 1993. The figures shown only indicate purchases from SE and the RDUs. The Kosice ironworks and the Slovnaft refinery are also a major cogenerators.

Table 9-2
Sales to Large Industrial Customers

Name	Product	Service Organization	Purchases (GWh) 1989	Purchases (GWh) 1993	% of SR Sales %	% of SR Sales Cumulative
ZSNP Ziar	Aluminum	SSE	1,258	756	4.5%	4.5%
VSZ Kosice	Iron works	SE	620	575	3.4%	7.9%
NCHZ Novaky	Chemicals	SSE	913	459	2.7%	10.6%
OFZ Srioka	Iron	SE	645	459	2.7%	13.3%
OFZ Istebne	Iron	SSE	562	364	2.2%	15.5%
SPP Velke Kapusany	Gas transport	VSE	240	346	2.1%	17.6%
SPP DTS Jablonov	Gas transport	VSE		341	2.0%	19.6%
Slovnaft	Oil refining	ZSE	573	290	1.7%	21.3%

The iron, chemical, and oil refining industries are energy intensive, but are not overly electricity intensive. Because of their energy intensity, these industries provide significant opportunities for cogeneration which would provide them with protection from high electricity prices.

The gas transportation facilitates served by VSE are pumping stations for the Brotherhood Pipeline traversing SR from the Ukraine to the Czech Republic border. The cost of gas transportation is less than 10 percent of the selling price of gas, with the cost of electricity a very small portion of transportation cost. This makes the economics of the gas industry relatively insensitive to the price of electricity.

Aluminum is by far the most electricity-intensive product of the major SR industries, requiring between 13 and 18 kWh per kg of product. The average commodity price for aluminum has varied between 1.25 and 2.40 $/kg (40-75 Sk/kg) in the last few years. At the current level of 1,000 Sk/MWh (33 $/MWh), electricity can account for as much as 45 percent of aluminum price during periods of low commodity prices. The smelter is currently operating at half capacity in response to low prices in the current market. Electricity price increases to the level of LRMC will affect the competitiveness, if not the economic viability of this industry.

There is precedent for special treatment of aluminum smelting in other parts of the world. The Bonneville Power Agency in the U.S. provides incentive rates to aluminum smelters. In Australia, electricity prices to the Portsmouth smelter have been tied to aluminum commodity prices with the goal that over the cycle of commodity price variation, the revenues to the electricity supplier will not be impaired.

While there may be a need for special pricing for some facilities, such as the aluminum smelter, these should be done on a case-by-case basis, rather than distorting the entire tariff structure. However, two measures, which are in line with the goals of LRMC pricing, may be applied. These are inverted block tariffs and interruptible tariffs.

Inverted block tariffs have increasing energy rates with increased levels of consumption. This type of tariff has the effect of allowing some customers lower tariffs if they limit consumption through investments to improve efficiency.

Interruptible tariffs give customers the option of differing levels of service at different prices. The structuring and pricing of interruptible tariffs is highly dependent upon the conditions for interruption. A customer allowing interruptions on a few hours or few days notice could incur pricing below LRMC (but greater or equal to SRMC) because their needs require less capital investment. The pricing for a customer who could have his load controlled on a minute-to-minute basis without prior notice could be below SRMC because of the potential benefits to the utility's operation. The needs of specific industries affect the structuring of interruptibility agreements. (Note: This type of tariff is generally does not meet the technical requirements of smelter operation.)

9.3 Protection of Low-Income Groups

Current prices for residential customers are approximately 45 percent of LRMC and are substantially below costs as they are currently reported. The price increases required for even a gradual increase to LRMC in the next five years could become a burden to many households, particularly those on fixed incomes. Figure 9-3 shows payments for electricity in 1992 in relation to overall income by income group (Reference 9-1). Electricity is just one component of the energy budget in SR households. Most heating and hot water is supplied through district heating systems. The graph also shows energy expenditures as a whole. Electricity expenditures accounted for 3 percent or more of household income in all households in which the per capita income was less the 28,800 Sk per year ($900 per year). This makes up more than 60 percent of the households in the SR.

Figure 9-4 shows the same data by social group. Clearly, price increases will have the largest impact on households headed by retired people not living with working family members. In these households electricity accounts for almost 5 percent of household income on the average. This demographic category accounts for more than 25 percent of the households in SR. The household electricity consumption of this group is about 1,800 kWh per year compared to an average household consumption of about 2,250 kWh per year.

Not every retired person living without family is economically disadvantaged. On the average, this group pays 5 percent of their income for electricity as discussed above. Those with the lowest income pay a higher percentage of their income for electricity. Those with higher incomes pay a lower percentage. Figure 9-5 shows electricity and total energy expenditures for the households

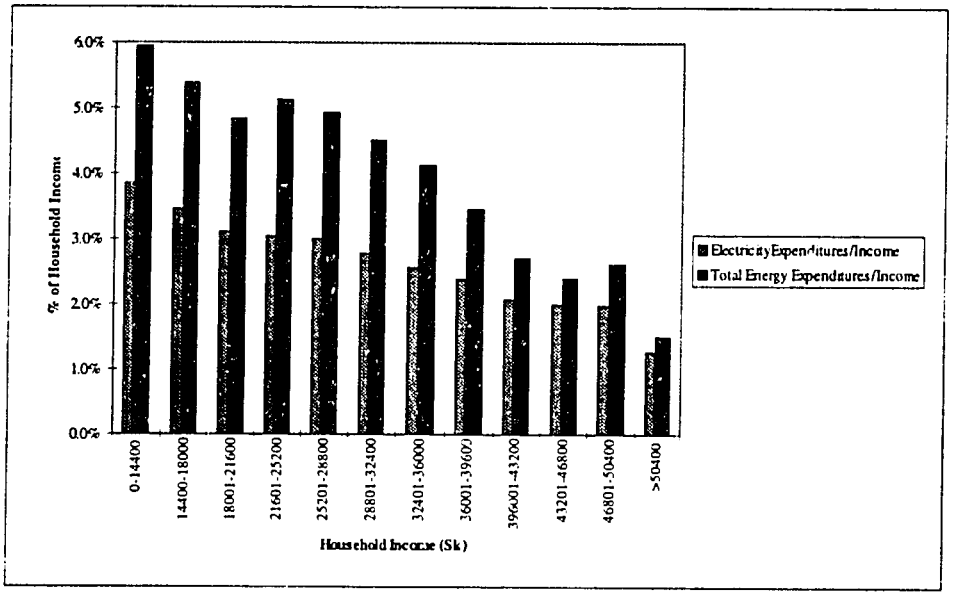

Figure 9-3 Total Energy and Electricity Expenditures in SR by Income Level

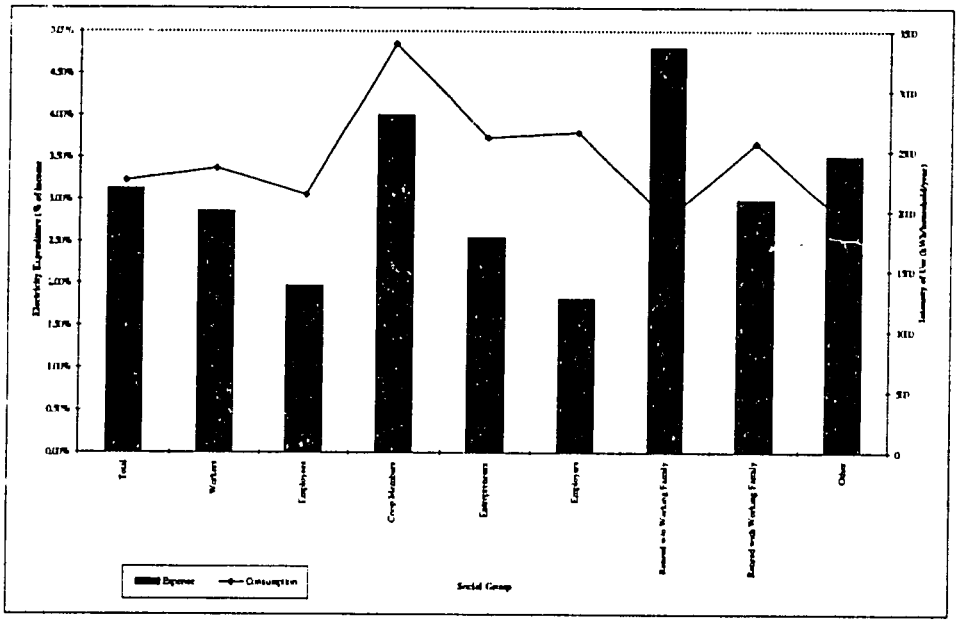

Figure 9-4 Electricity Expenditures and Intensity of Use by Social Group

99

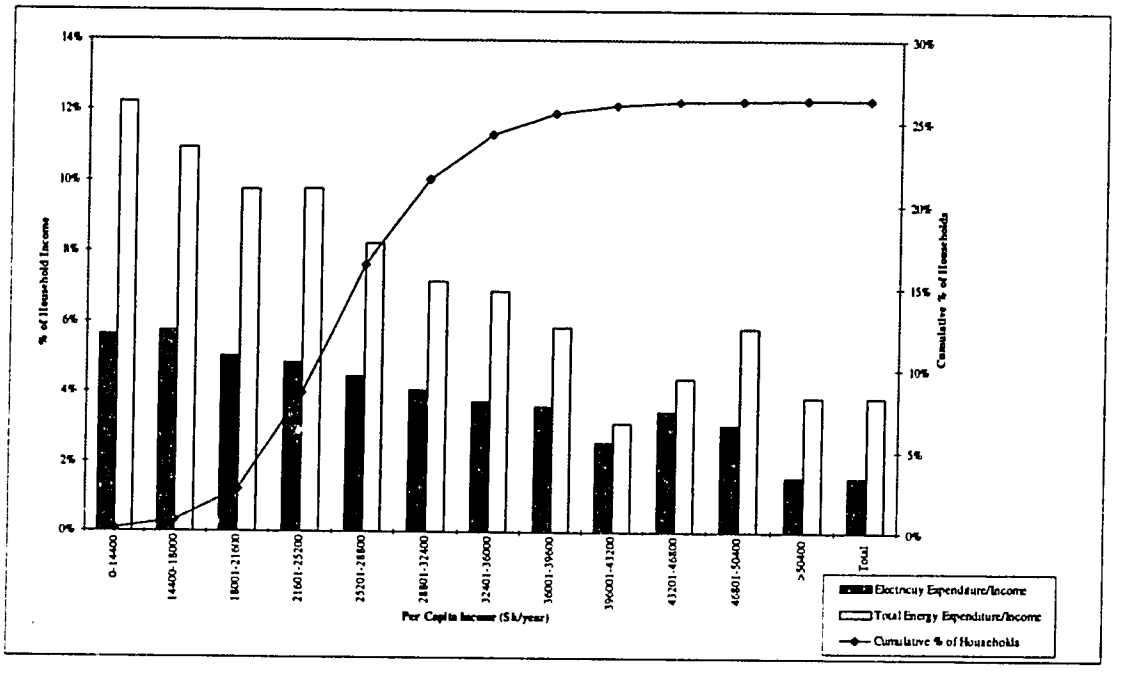

Figure 9-5 Total Energy and Electricity Expenditures for Households without Economically Active Members

without economically active members by income level. Based on this, it can be estimated that the number of households in which electricity accounts for more than 5 percent of household income was approximately 10 to 15 percent of total population in 1992.

The data indicate that payments for electricity are a significant portion of the household budget for a majority of SR households and that 10 to 15 percent of households are particularly vulnerable to price increases. These results suggest a dual approach for residential customers. The first approach is to limit the rate of increase on all residential customers, because of the significant contribution of electricity to the expenses of a high percentage of households. This will require cross-subsidies from other customer classes. The second approach is an inverted block tariff for residential customers. The first block should be priced at a low levels to ensure that economically vulnerable customers can afford critical levels of usage.

If priced at levelized 5-year revenue requirements, each of these Category B and C customers would be entitled to a real price decrease. However, this would result in pricing below LRMC. The following strategy is proposed for these categories:

- Category B – a gradual price decline to LRMC by 1999
- Category C – an immediate increase to LRMC

The surplus generated by these customer classes over their own financial requirements can be used to reduce the impact on the residential sector when meeting overall revenue requirements. Table 9-3 shows the impact of this cross-subsidy on required residential price increases. The levelized revenue requirements shown are the result of the analysis of financial requirements in Section 9.1. The increases for residential users that are shown are the minimum that still meet 5-year revenue requirements on a present worth basis (at 6 percent discount rate). The impact of the cross-subsidy is to reduce required residential tariffs for 1995 from almost 1,500 Sk/MWh to under 1,100 Sk/MWh.

Table 9-3
Strategy for Limiting Near-Term Residential Tariff Increase

	1995	1996	1997	1998	1999
			Sk/MWh		
Revenue requirements					
Category B	1,578	1,578	1,578	1,578	1,578
Category C	1,864	1,864	1,864	1,864	1,864
Residential	1,907	2,241	2,241	2,241	2,241
Proposed average level					
Category B	1,870	1,839	1,808	1,777	1,746
Category C	2,164	2,164	2,164	2,164	2,164
Residential	1,093	1,331	1,620	1,972	2,164
Sales (GWh)					
Category B	6,022	6,158	6,362	6,744	7,155
Category C	2,575	2,665	2,759	2,872	2,990
Residential	3,886	4,008	4,149	4,275	4,390
			millions Sk		
Net change compared to revenue requirements					
Category B	1,762	1,610	1,465	1,343	1,202
Category C	772	799	827	861	896
Residential	-3,162	-3,650	-2,578	-1,152	-339
Total	-628	-1,241	-286	1,052	1,759
Net present value (at 10 percent)	0				

Even with these cross-subsidies, substantial increases are required for residential customers. Table 9-4 shows a proposal for an inverted block structure for residential customers incorporating a low rate for essential use (lifeline tariff). The lifeline level has been set at 1,200 kWh per household, and it is assumed in the estimate that all households would reach this level. The average consumption in SR has been estimated at 2,250 kWh per household (based on Reference 9-1). Table 9-5 shows the average tariff for different levels of usage under this proposed approach. It should be noted that a more accurate determination of the energy block size in the inverted tariff design requires the use of bill frequency information from the RDUs. This information, not readily available under currently tabulated statistics, shows the number of customers using various levels of energy.

Table 9-4
Lifeline Tariff for Residential Customers

	1995	1996	1997	1998	1999
			Sk/MWh		
Average residential after cross-subsidy	1,093	1,331	1,620	1,972	2,164
			kWh		
Size of lifeline block	1,200	1,200	1,200	1,200	1,200
Average consumption/household	2,250	2,250	2,250	2,250	2,250
			Sk/MWh		
Proposed lifeline tariff	902	981	1,053	1282	1,407
2nd block tariff	1,312	1,730	2,268	2,761	3,030

Table 9-5
Average Residential Tariffs as a Function of Consumption

	Average Tariff (Sk/MWh)								
Usage	1200	1400	1600	1800	2000	2200	2400	2600	2800
				(kWh/household/year)					
1995	902	960	1,004	1,038	1,066	1,088	1,107	1,122	1,136
1996	981	1,088	1,168	1,231	1,281	1,322	1,356	1,384	1,409
1997	1,053	1,226	1,357	1,458	1,539	1,605	1,660	1,707	1,747
1998	1,282	1,493	1,651	1,775	1,873	1,954	2,021	2,078	2,127
1999	1,407	1,639	1,812	1,948	2,056	2,144	2,218	2,281	2,334
				Average Annual Increase					
	9.4%	12.8%	15.1%	16.8%	18.0%	19.0%	19.8%	20.5%	21.1%

Further reduction in tariffs for low consumption residential customers can be accomplished with further cross-subsidies by raising the price for high consumption residential customers. However, care must be taken because of the broad economic vulnerability of this customer class. Further reduction in overall projected residential tariffs can only be accomplished by additional cross-subsidies from Categories B and C, cross-subsidies from Category A, or direct government subsidies.

9.4 References

9-1 Slovak Statistics, Microcensus 1992, March 1994.

10 DEFINITION OF TARIFFS FOR DEMAND-SIDE MANAGEMENT

The objective of this section is to address tariff issues associated with demand-side management (DSM). DSM encompasses a wide range of activities that either increase energy efficiency or shift load demand to improve electricity demand load shape.

10.1 Demand-Side Management Overview

DSM is defined as the planning and implementation of utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility load, both in magnitude and shape. The overall economic goals of DSM are better utilization of resources. The operational goals for the power supply organizations can include:

- Improved financial performance
- Improved customer relations
- Increased utilization of generation, transmission, and distribution equipment
- Reduced need for new capacity
- Reduced dependence on imported fuels

The approaches used in DSM can be divided into those that are oriented more toward technology and those which emphasize the market. These approaches are interdependent. Technology- oriented approaches include the use of energy and load control equipment, the use of thermal storage equipment, and increasing appliance efficiency. Market approaches include education programs to make customers aware of the technical options available to them, the use of pricing structures that reflect the true costs of supplying electricity, and direct incentives for the use of DSM.

This section addresses the pricing and direct incentive approaches.

10.2 Tariff Structures Applicable to Demand-Side Programs

Section 8 of this report addresses pricing strategies for the SR based on long-run marginal cost (LRMC). LRMC is defined as the incremental investment and operating cost of serving an additional kWh of energy demand (or kW of peak) over a long period of time. The LRMC has fixed and variable components. The variable component is called the short-run marginal cost (SRMC) and reflects variable operating costs associated with the power system which vary by time of day and by season.

Tariff structures based on LRMC support DSM. Such pricing transfers information to suppliers and customers regarding the cost or value of electric energy and capacity and provides incentives to use efficient production and consumption methods. Some of the LRMC-based tariff approaches relevant to DSM are:

- Demand charges – based on maximum kilowatt usage
- Time-of-day tariffs – variable tariffs with higher per unit costs during peak periods and lower costs during off-peak periods

- Off-peak tariffs – similar to time-of-day tariffs, but directed at specific end uses such as storage heating
- Inverted tariffs – tariffs in which consumers pay more for higher levels of consumption
- Seasonal tariffs – tariffs which vary by season
- Variable levels of service – allow customers different levels of service for different prices (e.g., interruptible tariffs).
- Promotional tariffs – designed to attract or maintain targeted customers for strategic reasons
- Conservation tariffs – reduced tariffs based on customer's dwelling or facility; must meet specified energy-efficiency standards

The present tariff structure incorporates demand charges and time-of-day tariffs for a large segment of the customer base. Off-peak tariffs are directed toward off-peak storage heating with the B11 tariff. The high annual and daily load factors on the system (i.e., 68 percent annual load factor for 1993, over 90 percent daily load factor) suggest that this has been effective and that there may be limited potential for further load shifting. A load research program would help in quantifying the impact of various options.

10.3 Direct Incentive Options

The pricing of electricity based on LRMC provides clear signals to customers on the value of DSM options. The SRMC component provides signals associated with the value of energy, and the remainder of LRMC provides signals associated with the value of capacity. For various reasons, it may not be possible to price at LRMC, either in overall amount or in the allocation to energy- and capacity-related components or for some customer categories. As a result, some DSM options, while economically viable, will not be justified based on the price signals provided by the tariffs. This is currently the situation with the Category A and residential tariffs. In such cases, the offer of direct incentives provides an alternative way of promoting economically viable DSM options. Some example of direct incentives are:

- Cash grants – payments (usually one-time sums) made to customers who adopt one or more cost control options
- Rebates – provided for the purchase of specific equipment such as electronic ballasts, insulation, etc.
- Buyback programs – payment by utility to customer's installation contractor for energy efficiency options (usually based on the difference between average and LRMC)
- Billing credits – applied to a customer's bill in return for energy and load control option (generally offered in proportion to the size of the connected load being controlled)

- Low-interest loans – offered to customers for the purchase and installation of specific energy efficiency equipment

It should be noted that this type of program is much inferior to pricing as a DSM incentive. Generally speaking, these programs represent additional subsidies to groups that already benefit from cross-subsidies.

10.4 Existing Implementation of Demand-Side Management (DSM)

The Slovak National Energy Policy incorporates DSM as one of the goals in energy system development. Some of the present DSM programs are well established. For example, time-of-day tariffs have been in place since the late 1960s. Others, such as advisory services provided by the RDUs, are more recent. A summary of existing measures which can be classified as DSM are:

- Time-of-day (TOD) tariffs – applied to 64 percent of total 1993 sales (94 percent of Very High and High Voltage sales and 6 percent of Low Voltage sales)
- Demand charges – applied to approximately the same sales as TOD tariffs
- Off-peak tariff (B11) for heating and irrigation
- Utilization of ripple control to manage peak load
- Informal interruptibility agreements between RDUs and some industrial customers (invoked to avoid exceeding contract maximum with SE)
- Advisory services to customers on electricity use provided by SE and RDUs
- An Energy Agency in the Slovak Energy Inspectorate who reports to the Ministry of Economy, has an advisory role in the rational use of energy, and provides demonstrations and education
- Use of high pressure sodium lamps for municipal street and roadway lighting (Reference 10-2)

The impact of these measures has not been estimated; however, the system has achieved very high annual and daily load factors. As discussed previously, a load research program could help target specific applications and provide a basis for quantitative assessment.

Even so, investments by customers are discouraged by the current system to the extent that tariffs are lower than LRMC (as in the case of Category A [Very High Voltage] and residential customers). Furthermore, there are currently no mechanisms for rewarding utilities (SE or RDUs) for investments in DSM or direct incentives to customers for utilizing DSM options.

10.5 Future Implementation

A number of studies have been conducted concerning DSM potential in Slovakia (References 10-1 and 10-2). In addition, SE has begun to incorporate DSM into its planning process. Reference 2 estimates the long-term potential for DSM savings to be approximately 740 GWh per year and 600 MW of peak load reduction. More recent SE analysis has placed the long-term potential at 1,100 GWh and 320 MW by 2010. However, the SE analysis indicates that the savings are negligible before 1999.

The European Bank for Reconstruction and Development (EBRD) is currently considering funding a program to provide loans to Slovak industries to fund DSM measures.

Inverted tariffs may have potential in promoting conservation. The use of lifeline tariffs (a special application of inverted tariffs) with low rates for necessary domestic use and progressively higher rates for increased use may have an application in protecting low income groups.

There may be potential for seasonal tariffs. The analysis of the existing cost structure presented in Section 4 indicates much greater seasonal variation in costs than time-of-day variation. However, any seasonal tariff would have to reflect the scheduling of maintenance, particularly the refueling of nuclear plants. Off-season marginal generating costs can sometimes be higher than during the peak season if more than one nuclear unit is not operating.

Interruptible tariffs, while currently carried out on an informal basis between RDUs and industries, could be formalized. This may be a particularly attractive option for some industries under Category A tariffs that have lower than average reliability requirements.

10.6 References

10-1. Tractebel Energy Engineering, "Power Sector Least-Cost Development Study for the Czech and Slovak Republics," *Demand-Side Management Study for the Czech and Slovak Republics*, February 1993.

10-2 Power Smart, Inc., *Demand-Side Management in Slovakia*, Phase I Report, September 7, 1993.

11 TARIFF DESIGN AND PROPOSED IMPLEMENTATION PLAN

The tariff design and implementation plan discussed in this section reflects the revenue requirements analysis of SE and the RDUs conducted in Sections 6 and 7, respectively, the LRMC by voltage level estimated in Section 9, and the balancing of LRMC and financial requirements, impact of price increases on electricity-intensive industries, and the protection of low-income groups.

11.1 Sales from SE

Table 11-1 shows the proposed target level for 1999 electricity prices from SE for capacity and energy compared with current prices and LRMC. Table 11-2 shows a profile of price increases over the next 5 years that will meet this target. The key features of this plan are:

- LRMC is reached by 1999.
- The present worth of the projected revenues produced (at a 6 percent real discount rate) equal the present worth of the estimated revenue required to maintain SE financial health and support its investment program over this period.
- Demand-related charges are kept at their current levels. By 1999, approximately 27 percent of the projected electricity price is associated with demand charges, whereas approximately 23 percent of the LRMC is demand related.
- The required amount of increase in 1995 is 6.5 percent in addition to general inflation.

This proposal could be accomplished through the current approach of negotiation between SE and the RDUs only if overall price increases are made in retail sales. However, institutional changes incorporating the use of an independent regulatory body should be considered.

Currently, electricity produced by the RDUs is used to reduce purchases from SE. Thus, the implied value is at average SE cost. Also shown in Table 11-2 is a proposal for avoided cost payments by SE to the RDUs for this generation which more accurately reflect the true value of the generation. This proposal would require an independent body to determine the avoided cost level on a periodic basis and regulate the conditions for receiving this price. It should be noted that this proposal does not imply a change in the physical operation of facilities or in their ownership. RDU generation is to the RDU-owned grid and could continue in the same way.

11.2 Retail Sales Tariff Design

An overall comment concerning the modification of retail tariffs concerns the need for load research. The Base Case load forecast, developed by SE, and the analysis in this study were conducted without data concerning the relationship of electricity demand and price. The considerable changes that have occurred in the structure of the economy make recent data of questionable value. However, the implicit assumption of the analysis is that there is no relationship between demand and price, and this is clearly untrue. A load research program is needed to establish this relationship, collect data for the structuring of multi-block tariffs, and develop end use data specific to the SR. Such research will support the future tariff-setting process and provide greater understanding of the impact of tariff modifications.

Table 11-1
SE Sales Price – Current Average, 1999 Goals, and LRMC

	Current Average	1999 Goal	Strict LRMC
Basic Charges			
Demand-related charge (thousand Sk/kW/month)	220	220	148
Average energy-related charge (Sk/MWh)			
Peak	800	1,151	1,289
Mid-Peak	660	1,072	1,201
Off-Peak	610	1,024	1,146
Average Price (Sk/MWh)	1,118	1,456	1,456

Table 11-2
Implementation of Required SE Sales Price Increases

	Current Average	1995	1996	1997	1998	1999	Strict LRMC
Load Characteristics							
Annual load factor	68.4%	68.6%	68.7%	68.8%	68.9%	68.9%	68.9%
Annual peak/average	1.12	1.12	1.12	1.12	1.12	1.12	1.12
Monthly Peak Basic Charges							
Demand-related charge (Sk/kW/month)	220	220	220	220	220	220	148
Average energy-related charge (Sk/MWh)	725	793	864	939	1,019	1,066	1,193
Average price (Sk/MWh)							
Energy	725	793	864	939	1,019	1,066	1,193
Capacity	393	392	392	391	391	390	263
Total	1,118	1,185	1,256	1,331	1,410	1,456	1,456
Annual increase (%)		6.0%	6.0%	6.0%	6.0%	3.3%	0.0%
Purchase price for RDU Generation (Sk/MWh)		1,086	1,194	1,314	1,445	1,589	

There is a clear need for modifications of the existing tariff levels and of overall structure; this cannot wait for the results of a load research program. The modifications are discussed below. However, it is important that the modifications recommended be incorporated in a process that accommodates change as better information becomes available and as unforeseen events occur.

11.2.1 Category A (Very High Voltage)

Table 11-3 shows the 1999 target tariff for Category A (Very High Voltage) compared to current prices and to LRMC. Table 11-4 shows a plan for graduated increases to meet this target. The key features of this plan are similar to those of the proposed price increases for SE sales. They are:

- LRMC is reached by 1999.
- The present worth of the projected revenues produced (at a 6 percent real discount rate) equal the present worth of the estimated revenue required to meet the financial requirement of SE and the RDU over this period.
- Demand-related charges are kept at their current levels. By 1999, almost 30 percent of the projected electricity price is associated with demand charges whereas approximately 20 percent of the LRMC at this voltage level is demand related.
- The required amount of increase in 1995 is 6.6 percent in addition to general inflation.

The following proposals should be studied in detail with respect to Category A customers:

- The introduction of formal tariffs for customers allowing interruptible service. Two levels of interruptibility should be considered – one requiring substantial notice and one with short notice.
- The purchase by SE of excess industrial electric generation at avoided cost to reflect its value. As with RDU-owned generation, such transactions would not have to affect physical operation or ownership of facilities and delivery of power would be to the VHV grid.

The first measure would allow large industrial customers to tailor the level of service they are provided and limit required price increases where appropriate (by accepting lower levels of reliability of service if compatible with their operation). The second measure would provide greater income to industrial cogenerators.

There may be a need for additional relief from tariff increases for some customers in this category. In some cases, this is because of the difficulty of some industries in finding markets during this period of economic transition. In others, electricity cost is a high percentage of manufactured product cost (as in aluminum smelting). In either situation the type of relief and its duration should be determined on a case-by-case basis and not institutionalized into the retail tariff system.

Table 11-3
Category A – Current Average, 1999 Goals, and LRMC

	Current Average	1999 Goal	LRMC
Basic Charges			
Demand-related charge (thousand Sk/kW/month)	278	278	202
Average energy-related charge (Sk/MWh)			
Peak	845	1,196	1,326
Mid-Peak	758	1,114	1,235
Off-Peak	664	1,063	1,179
Average price (Sk/MWh)	1,188	1,552	1,551

Table 11-4
Implementation of Proposed Category A Tariff Increases

Category A	Current Average	1995	1996	1997	1998	1999	LRMC
Load Characteristics							
Annual load factor	85.5%	85.5%	85.5%	85.5%	85.5%	85.5%	85.5%
Annual peak/average monthly peak	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Basic Charges							
Demand-related charges (thousand Sk/kW/month)	278	278	278	278	278	278	202
Average energy-related charge (Sk/MWh)	742	815	891	972	1059	1107	1,227
Average price (Sk/MWh)							
Energy	742	815	891	972	1,059	1,107	1,227
Capacity	445	445	445	445	445	445	323
Total	1,188	1,260	1,337	1,418	1,504	1,552	1,551
Annual increase (%)		**6.1%**	**6.1%**	**6.1%**	**6.1%**	**3.2%**	

The proposed tariffs for Category A customers fully meet the projected revenue requirements for this customer category. As will be discussed in the following sections, there is a need for cross-subsidies from the Category B and Category C customers to residential customers in the near term to moderate required price increases there. Even with this, 20 to 30 percent real annual increases in residential tariffs will be required. Any cross-subsidy to Category A customers will accentuate the required residential tariff increases.

11.2.2 Category B (High Voltage)

Table 11-5 shows the 1999 target tariff for Category B (High Voltage), compared to current prices and to LRMC at this voltage level. Table 11-6 shows a plan for a gradual decrease in Category B tariffs to LRMC by 1999. The key features of this plan are:

- LRMC is reached by 1999.
- The present worth of the projected revenues produced (at a 6 percent real discount rate) are greater than the present worth of the estimated revenue required by SE and the RDUs for service at this voltage level. The surplus generated is used to moderate required tariff increases for residential customers.
- Demand-related charges are reduced. By 1999, slightly more than 30 percent of the projected electricity price is associated with demand charges, compared with almost 60 percent in the current tariff. Slightly more than 25 percent of the LRMC at this voltage level is demand related.
- Average prices decline at real value of approximately 1.5 percent per year until 1999.

11.2.3 Low Voltage Customers

The current tariff for Category C is slightly below estimated LRMC. The current residential tariff is about 40 percent of LRMC. The goals of having tariffs reflect LRMC and cover the costs of the appropriate customer class will have the largest impact on residential tariffs because of their currently low level. Table 11-7 shows a plan to accomplish this through a combination of cross-subsidies for Category B and Category C customers and the introduction of an inverted block tariff structure. This calls for an immediate increase in Category C tariffs to LRMC. The key features of this plan are:

- An immediate increase of Category C tariffs to LRMC (slightly over 4 percent increase).
- A gradual increase in residential tariffs so that average residential tariffs are at the approximate LRMC level by 1999.
- The present worth of the projected revenues produced (at a 6 percent real discount rate) are greater than the present worth of the estimated revenue required by SE and the RDUs for service at this voltage level. The surplus generated is used to moderate required tariff increases for residential customers.
- The introduction of an inverted block tariff structure for residential customers so that customers with lower usage have lower tariffs.

Table 11-5
Category B – Current Average, 1999 Goals, and LRMC

	Current Average	1999 Goal	LRMC
Basic Charges			
Demand-related charge (thousand Sk/kW/month)	675	350	303
Average energy-related charge (Sk/MWh)			
Peak	931	1,280	1,362
Mid-Peak	824	1,192	1,268
Off-Peak	660	1,138	1,211
Average price (Sk/MWh)	1,870	1,746	1,746

Table 11-6
Implementation of Proposed Category B Tariff Decreases

Category B	Current Average	1995	1996	1997	1998	1999	LRMC
Load Characteristics							
Annual load factor	85.5%	85.5%	85.5%	85.5%	85.5%	85.5%	85.5%
Annual peak/average monthly peak	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Basic Charges							
Demand-related charges (thousand Sk/kW/month)	675	675	593	512	431	350	303
Average energy-related charge (Sk/MWh)	789	789	888	987	1,086	1,185	1,260
Average price (Sk/MWh)							
Energy	789	789	888	987	1,086	1,185	1,260
Capacity	1,081	1,081	951	821	691	561	485
Total	1,870	1,870	1,839	1,808	1,777	1,746	1,746
Annual increase (%)		**0.0%**	**-1.7%**	**-1.7%**	**-1.7%**	**-1.8%**	

Table 11-7
Implementation of Low Voltage Tariff Increases

	Current Average	1995	1996	1997	1998	1999	LRMC
Average Price (Sk/MWh)							
Category C	2,034	2,164	2,164	2,164	2,164	2,164	2,164
Increase		6.4%	0.0%	0.0%	0.0%	0.0%	
Residential							
First 100 kWh/month	898	902	981	1,053	1,282	1,407	
>100 kWh/month	898	1,312	1,730	2,268	2,761	3,030	
Example residential tariff increases as a function of usage							
For 1,200 kWh/yr	898	902	981	1,053	1,282	1,407	2,164
Increase		0.4%	8.8%	7.3%	21.7%	9.7%	
For 1,600 kWh/yr	898	1,004	1,168	1,357	1,651	1,812	2,164
Increase		11.8%	16.4%	16.1%	21.7%	9.7%	
For 2,200 kWh/yr	898	1,088	1,322	1,605	1,954	2,144	2,164
Increase		21.2%	21.5%	21.5%	21.7%	9.7%	

Approximately 15 percent of the present worth of the revenue required for supplying residential customers is supplied through cross-subsidies from Category B and C customers. The effect of the inverted tariff structure for residential customers is for consumers of more electricity to subsidize consumers of less electricity. Further reduction in residential tariffs can only be accomplished in one of the following ways:

- Further cross-subsidization from Category B and C customers. This can only be accomplished if their tariffs are placed above LRMC.
- Cross-subsidization from Category A customers. This is the most electricity-intensive customer category. Price increases required of this category to meet its cost of service are manageable, but significant. Further increases will be difficult to rationalize with economic competitiveness.
- Direct government subsidies to residential customers. If this course is taken, the program should be directed at economically vulnerable groups.

11.2.4 Regional Tariffs

Retail tariffs are currently uniform throughout the SR. This is administratively simple and may produce socially desirable results with respect to balanced economic growth. However, the use of uniform tariffs can undermine the financial viability of individual RDUs if their fundamental cost or revenue structure varies significantly from the average.

With respect to costs, the cost of purchased power, which accounts for more than 75 percent of total costs, is essentially the same for all RDUs. However, our analysis of transmission and distribution costs below the 200 kV level indicates differences among RDUs at the various voltage levels. Whether these variations represent fundamental cost-of-service differences among RDUs, differences in efficiency, or the analytical error that can occur at this level of study would require more detailed analysis.

With respect to revenue structure two issues arise that affect the finances of individual RDUs. The first is variation in customer mix. Under current retail prices, Category B and C customers carry more than their share of their associated costs; Category A and residential customers carry far less. Therefore, SSE, with the lowest proportion of Category B and C customers (approximately 39 percent in 1993 compared to 55 percent for ZSE and 49 percent for VSE), has the least profitable customer mix. Our recommendation to raise Category A prices will help alleviate this situation. However, continue cross-subsidies from Category B and C to residential customers will create inequities in the profitability of individual RDUs if uniform retail tariffs are to be continued.

A second issue affecting revenues is the degree to which individual RDUs generate their own electricity. This is a relatively small issue since no RDU generates as much as 5 percent of their needs. However, our recommendation in the next section that RDUs be compensated at avoided cost rather than simply reducing purchases from SE (in effect compensating them at average cost) will create near-term inequities in that VSE has no generating capacity.

These cost and revenue structure differences between the RDUs suggest a need for regional tariffs. If these differences are not considered in the interest of overall policy, the resulting inequities must be addressed. The method can take the form of a special fund in which RDUs with favorable cost and revenue characteristics contribute and others collect, or it can be through modifications to the tax code.

11.3 Compensation for RDU and Industry Generation

As described in Section 11.1, a procedure of SE purchasing electricity at avoided cost from the RDUs and industry should be investigated in detail. The projected avoided cost will at least be at the SRMC. The analysis conducted in this study suggests a somewhat higher value of 1,500 Sk/MWh. Technical requirements for providing electricity at this rate should be the focus of the investigation.

11.4 Compensation for Demand-Side Management (DSM)

The tariff increases proposed above should provide significant support to economically viable DSM alternatives. In the near term Category A and residential prices will be below LRMC so that direct incentive programs, such as low interest loans for DSM options, should be directed in these areas.

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Final Report

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Appendix A Voltage Level Load and Energy Forecast

SEP May Forecast (GWh)	1995	1996	1997	1998	1999	2000	2005	
Industry	10929	11053	11276	11713	12170	12644	15269	*(A)*
Agriculture	934	944	954	987	1020	1056	1251	*(B)*
Civil Engineering	134	136	138	145	153	161	206	*(C)*
Transport	943	951	962	1003	1046	1090	1333	*(D)*
Services	2114	2199	2287	2382	2480	2582	3162	*(E)*
Subtotal	15054	15283	15617	16230	16869	17533	21221	*(F)*
Households	3886	4008	4149	4275	4390	4490	5048	*(G)*
Non-Energy Sector Consumption	18940	19291	19766	20505	21259	22023	26269	*(H=F+G)*
Mining and Heating	918	916	924	957	990	1026	1248	*(I)*
Pumping	530	530	530	530	530	530	540	*(J)*
Losses	1604	1632	1675	1812	1838	1864	2162	*(K)*
Gross Domestic Consumption	21992	22369	22895	23804	24617	25443	30219	*(L)*
Export	225	457	2500	3500	3000	2500	1560	*(M)*
Total SR consumption with Export	22217	22826	25395	27304	27617	27943	31779	*(N=L+M)*
Net Distributor Generation	569	601	1370	1370	1375	1375	1404	*(O)*
Net Industry Generation	2109	2090	2071	2042	1995	1947	1615	*(P)*
SEP Responsibility	19539	20135	21954	23892	24247	24621	28760	*(Q=N-O-P)*

Voltage Summary- Assumptions	1995	1996	1997	1998	1999	2000	2005	
Ratio VHV/(HV+VHV) Sales of RDUs (1)	41.5%	41.0%	40.6%	40.2%	39.7%	39.3%	37.2%	*(AAA)*
Distributor Generation (GWh,2)	569	601	1370	1370	1375	1375	1404	*(BBB=0)*
ZSE	268	283	645	645	647	647	661	*(BBB1)*
SSE	301	318	725	725	728	728	743	*(BBB2)*
VSE	0	0	0	0	0	0	0	*(BBB3)*
RDU Purchases from Industry (GWh,3))	82	82	82	82	82	82	82	*(CCC)*
Industry Generation for Own Use (GWh)	2109	2090	2071	2042	1995	1947	1615	*(DDD=P)*
Losses								
Low Voltage (<1 kV)	5.76%	5.60%	4.98%	5.75%	5.37%	5.01%	4.66%	*(EEE=BB/AA-FFF-GGG-HHH)*
High Voltage (1 - 52 kV,4)	2.82%	2.80%	2.77%	2.75%	2.73%	2.71%	2.61%	*(FFF)*
Very High Voltage (> 52 kV,5)	3.02%	3.00%	2.97%	2.95%	2.93%	2.91%	2.81%	*(GGG)*
Transmission > 200 kV (6)	2.09%	2.08%	2.08%	2.07%	2.06%	2.06%	2.03%	*(HHH)*
Total	7.99%	7.90%	7.22%	7.26%	7.28%	7.30%	7.44%	*(III=K/(H+I+M))*
Share of RDU Sales (based on 1993)								
Low Voltage								
ZSE	43.1%	43.1%	43.1%	43.1%	43.1%	43.1%	43.1%	*(JJJ)*
SSE	30.1%	30.1%	30.1%	30.1%	30.1%	30.1%	30.1%	*(KKK)*
VSE	26.8%	26.8%	26.8%	26.8%	26.8%	26.8%	26.8%	*(LLL)*
High Voltage (HV+VHV)								
ZSE	31.2%	31.2%	31.2%	31.2%	31.2%	31.2%	31.2%	*(MMM)*
SSE	42.6%	42.6%	42.6%	42.6%	42.6%	42.6%	42.6%	*(NNN)*
VSE	26.2%	26.2%	26.2%	26.2%	26.2%	26.2%	26.2%	*(OOO)*

1. The ratios for 1992 and 1993 are based on actual data. 2010 is projected. There is linear interpolation between 1993 and 2010.

2. The total is based on SEP forecast with 1992 and 1993 actuals. The breakdown by RDU is based on the 1993 proportion of production.

3. This is actual generation for 1992 and 1993. The projection is based on the assumption that 1993 generation levels continue through 2010.

4. The HV loss estimate for 1992 is based on VSE report to the Ministry of Economy as assumed to be the same for other RDUs.

5. The VHV loss estimate for 1992 is based on VSE report to the Ministry of Economy as assumed to be the same for other RDUs.

6. The transmission system loss rate in 1992 and 1993 is based on 1993 Annual Report. It refers to the 220 kV and 400 kV systems only.

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Voltage Level Sales Summary								
Losses are assigned to voltage class having responsibility								
(i.e., low voltage supply results in losses on the transmission, very high, high and low voltage systems.)								
	1995	1996	1997	1998	1999	2000	2005	
Low Voltage								
Sales	6461	6673	6908	7147	7380	7603	8854	*(AA=.35*B+C+E+G)*
Losses	884	899	885	967	967	965	1071	*{BB=K-sum(DD,FF,HH,JJ)}*
High Voltage								
Sales	6022	6158	6362	6744	7155	7586	10085	*{CC=H+I-}*
Losses	477	485	498	524	553	583	750	*{DD=sum(BBB.DDD)*CC}*
Very High Voltage								
Sales	4266	4285	4349	4528	4719	4914	5963	*(EE=H+I-)*
Losses	218	218	220	228	236	244	288	*{FF=sum(CCC.DDD)*EE)*
Directly Served								
Sales	1000	1000	1000	1000	1000	1000	1000	*(GG)*
Losses	21	21	21	21	21	21	20	*(HH=DDD*GG)*
Exports								
Sales	225	457	2500	3500	3000	2500	1560	*(II=M)*
Losses	5	10	52	72	62	51	32	*(JJ=DDD*II)*
Total								
Sales	17974	18574	21119	22920	23254	23602	27462	*{JJ= sum(AA,CC*
Losses	1604	1632	1675	1812	1838	1864	2162	*(KK=K)*
Gross Demand from SEP and RDUs	19578	20206	22794	24732	25092	25466	29624	*(KK=JJ+KK)*

Disaggregation by Regional Distributor	1995	1996	1997	1998	1999	2000	2005	
Total Sales Made by RDUs	16749	17117	17619	18420	19254	20102	24902	*{AAAA=H+I-GG-P*
Direct Sales by SEP	1000	1000	1000	1000	1000	1000	1000	*(BBBB=GG)*
ZSE								
Low Voltage								
Sales	1735	1792	1855	1919	1981	2041	2377	*(CCCC1=AA*JJJ)*
Losses Prior to Delivery								
Transmission	36	37	39	40	41	42	48	*(DDDD1=CCCC1*HHH)*
Distribution	201	204	199	220	219	217	239	*{EEEE1=CCCC1*(EEE+*
High Voltage								*FFF+GGG)}*
Sales	1576	1611	1664	1764	1872	1985	2639	*(FFFF1=CC*MMM)*
Losses Prior to Delivery								
Transmission	33	34	35	37	39	41	54	*(GGGG1=FFFF1*HHH)*
Distribution	92	93	96	101	106	112	143	*{HHHH1=CCCC1**
Very High Voltage								*(FFF+GGG)}*
Sales	1116	1121	1138	1185	1235	1285	1560	*(IIII1=EE*MMM)*
Losses Prior to Delivery								
Transmission	23	23	24	25	25	26	32	*(JJJJ1=IIII1*HHH)*
Distribution	34	34	34	35	36	37	44	*(KKKK1=IIII1*GGG)*
ZSE Sales	4426	4524	4657	4868	5088	5311	6576	*(LLLL1=CCCC1+FFFF1+IIII1)*
ZSE Losses	327	331	329	356	361	366	426	*(MMMM1=DDDD1+GGGG1+KKKK1)*
Net ZSE Generation	0	0	0	0	0	0	0	*(NNNN1=BBB1)*
Required Purchases from SEP	4753	4855	4985	5224	5449	5677	7002	*(OOOO1=KKKK1+LLLL1-MMMM1)*

SSE								
Low Voltage								
Sales	1943	2007	2078	2150	2220	2287	2663	*same pattern as for ZSE*
Losses Prior to Delivery								*CCCC2*
Transmission	41	42	43	45	46	47	54	*DDDD2*
Distribution	225	229	223	246	245	243	268	*EEEE2*
High Voltage								
Sales	2566	2624	2711	2874	3049	3232	4297	*FFFF2*
Losses Prior to Delivery								
Transmission	54	55	56	59	63	67	87	*GGGG2*
Distribution	150	152	156	164	173	182	233	*HHHH2*
Very High Voltage								
Sales	1818	1826	1853	1930	2011	2094	2541	*IIII2*
Losses Prior to Delivery								
Transmission	38	38	38	40	42	43	52	*JJJJ2*
Distribution	55	55	55	57	59	61	71	*KKKK2*
SSE Sales	6327	6457	6642	6953	7279	7612	9501	*LLLL2*
SSE Losses	430	435	434	467	477	486	572	*MMMM2*
Net SSE Generation	301	318	725	725	728	728	743	*NNNN2*
Required Purchases from SEP	6455	6574	6350	6695	7028	7371	9330	*OOOO2*

VSE								
Low Voltage								
Sales	1735	1792	1855	1919	1981	2041	2377	*same pattern as for ZSE*
Losses Prior to Delivery								*CCCC3*
Transmission	36	37	39	40	41	42	48	*DDDD3*
Distribution	201	204	199	220	219	217	239	*EEEE3*
High Voltage								
Sales	1576	1611	1664	1764	1872	1985	2639	*FFFF3*
Losses Prior to Delivery								
Transmission	33	34	35	37	39	41	54	*GGGG3*
Distribution	92	93	96	101	106	112	143	*HHHH3*
Very High Voltage								
Sales	1116	1121	1138	1185	1235	1285	1560	*IIII3*
Losses Prior to Delivery								
Transmission	23	23	24	25	25	26	32	*JJJJ3*
Distribution	34	34	34	35	36	37	44	*KKKK3*
VSE Sales	4426	4524	4657	4868	5088	5311	6576	*LLLL3*
VSE Losses	327	331	329	356	361	366	426	*MMMM3*
Net VSE Generation	0	0	0	0	0	0	0	*NNNN3*
Required Purchases from SEP	4753	4855	4985	5224	5449	5677	7002	*OOOO3*

Voltage Class Summary for Losses								
Losses are assigned to voltage class where they occur.								
Low Voltage	311	313	288	344	332	319	346	*{AAAAA=EEE*CCCC1,2,3}*
High Voltage	313	320	328	341	354	368	443	*{BBBBB=FFF*(CCCC1,2,3+FFFF1,2,3)}*
Very High Voltage	458	464	475	493	512	531	636	*{CCCCC=GGG*(CCCC1,2,3+*
								FFFF1,2,3+IIII1,2,3)}
Transmission > 200 kV	343	353	404	439	443	447	512	*{DDDDD=HHH*(HH+JJ+DDDD1,2,3+*
								GGGG1,2,3+JJJJ1,2,3,)}
Total	1425	1450	1495	1617	1641	1666	1936	*(EEEEE=AAAAA+BBBBB+CCCCC+*
								DDDDD+EEEEE)

Peak Load Responsibility

Assumptions

Load Factor based on peak responsibility

		ZSE	SSE	VSE
Directly Served Industries (1)	94.7%			
Very High Voltage (2)	85.5%	81.5%	77.7%	116.5%
High Voltage (2)	71.3%	57.4%	92.4%	65.7%

1. Based on dispatch center data and maximum load at system peak.

2. Based on peak month (November) measured demand for A and B rates where available. Additional assumptions are used as shown in VO93.WK1 where demand is no

	1995	1996	1997	1998	1999	2000	2005
Domestic Peak (MW)	3304	3358	3434	3558	3684	3812	4523
Total Sales (GWh)	19858	20207	20690	21462	22249	23049	27517
Load Factor	68.6%	68.7%	68.8%	68.9%	68.9%	69.0%	69.4%

Peak Responsibility without diversity adjustment (MW)

	1995	1996	1997	1998	1999	2000	2005
Directly Served Industries	123	123	123	123	123	123	123
ZSE							
Low Voltage	687	697	710	724	735	745	796
High Voltage	325	332	343	364	386	409	542
Very High Voltage	187	188	191	198	207	215	261
Total ZSE	1199	1217	1244	1286	1327	1369	1599
SSE							
Low Voltage	479	487	496	505	513	520	556
High Voltage	276	282	291	309	327	347	460
Very High Voltage	370	378	390	414	439	465	617
Total SSE	1125	1147	1177	1227	1279	1332	1632

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VSE							
Low Voltage	428	435	443	451	458	465	496
High Voltage	272	278	288	305	323	342	454
Very High Voltage	157	157	160	166	173	180	218
Total VSE	857	870	890	922	954	987	1169
Voltage Level Summary (MW)							
Low Voltage	1594	1619	1648	1680	1706	1731	1848
High Voltage	873	893	922	977	1036	1098	1456
Very High Voltage	714	723	741	778	818	860	1096
Transmission > 200 kV	123	123	123	123	123	123	123

Appendix B Description of the Elfin Production Simulation Model

Elfin

Electric Utility Production Cost & Financial Model

We believe
state-of-the-art and
easy to use
electric utility modeling
should be available
at reasonable costs
to all who
analyze and create utility plans.

Elfin for
electric utility analysis:
a state-of-the-art
easy to use
production cost
optimization and
financial model,
created and supported by EDF.

We license Elfin to a growing
national and international customer base
by providing
reasonable prices,
excellent support and
continually improving software products.

The Elfin team at

EDF
ENVIRONMENTAL
DEFENSE FUND

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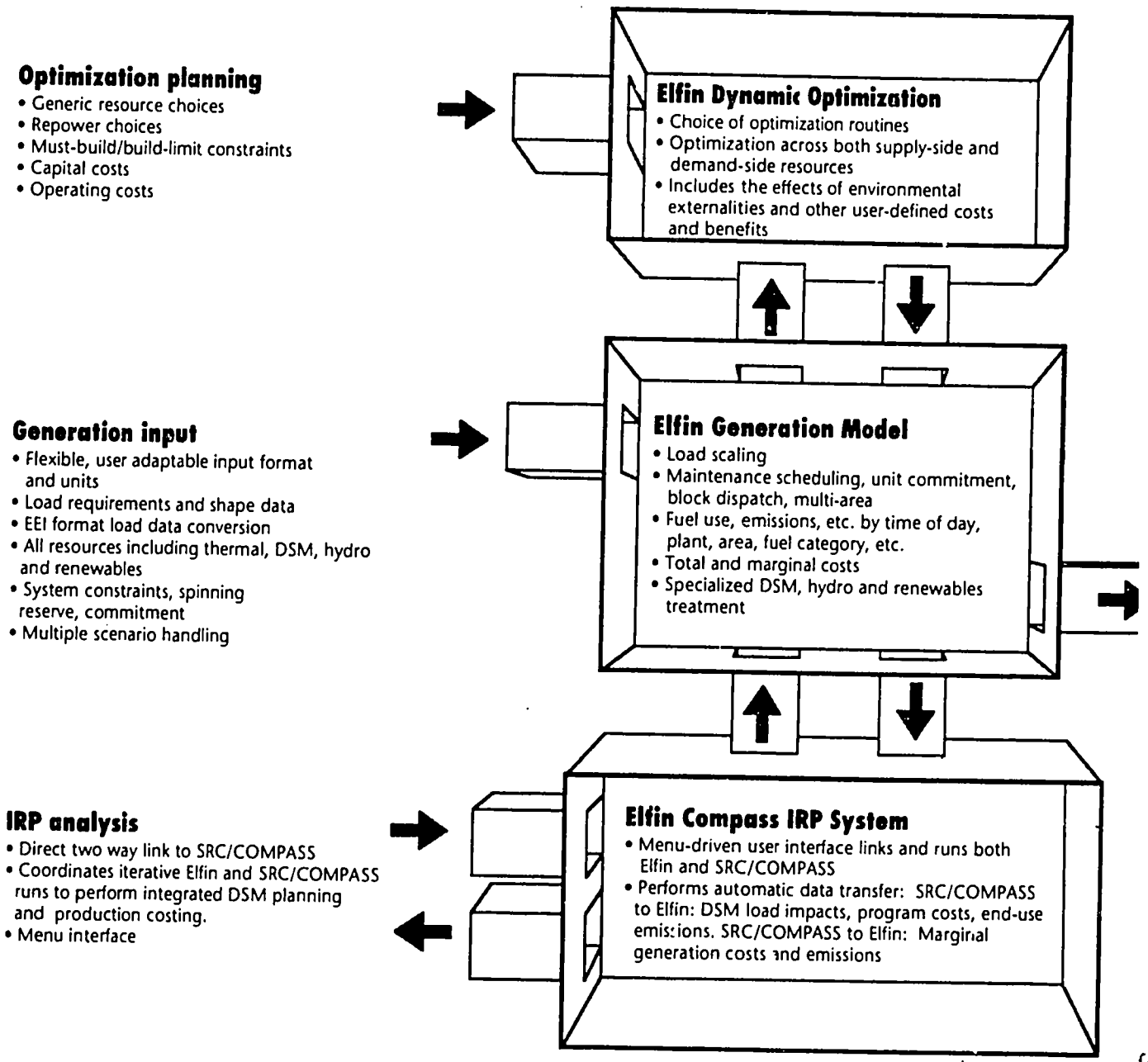
Introduction to Elfin

Elfin simulates the operation of electric utility systems. Elfin can perform production cost analyses, integrated resource planning analyses, and financial analyses.

1 The Elfin Generation model simulates the production of electricity to meet loads. The generation model also performs automated capacity expansion (resource optimization) across both supply-side and demand-side resources. The Generation model accounts for operating results such as fuel use, reliability, and emissions. Automated capacity expansion can include externality values and other benefits.

2 The Elfin/COMPASS Integrated Resource Planning System links Elfin and SRC/COMPASS, the demand-side planning model from Synergic Resources Corporation (SRC). SRC/COMPASS keeps track of demand-side details such as appliance stocks by type and vintage, and performs cost-effectiveness and market penetration analyses. Elfin provides data (such as marginal costs) to SRC/COMPASS for screening analyses of potential demand-side programs. SRC/COMPASS provides candidate DSM programs to Elfin for use in resource optimization analyses.

3 The Elfin Financial model can then use the results of these analyses to simulate and report the financial status of the utility system. The financial model produces income statements, balance sheets, and tax calculations, as well a variety of financial statistics.

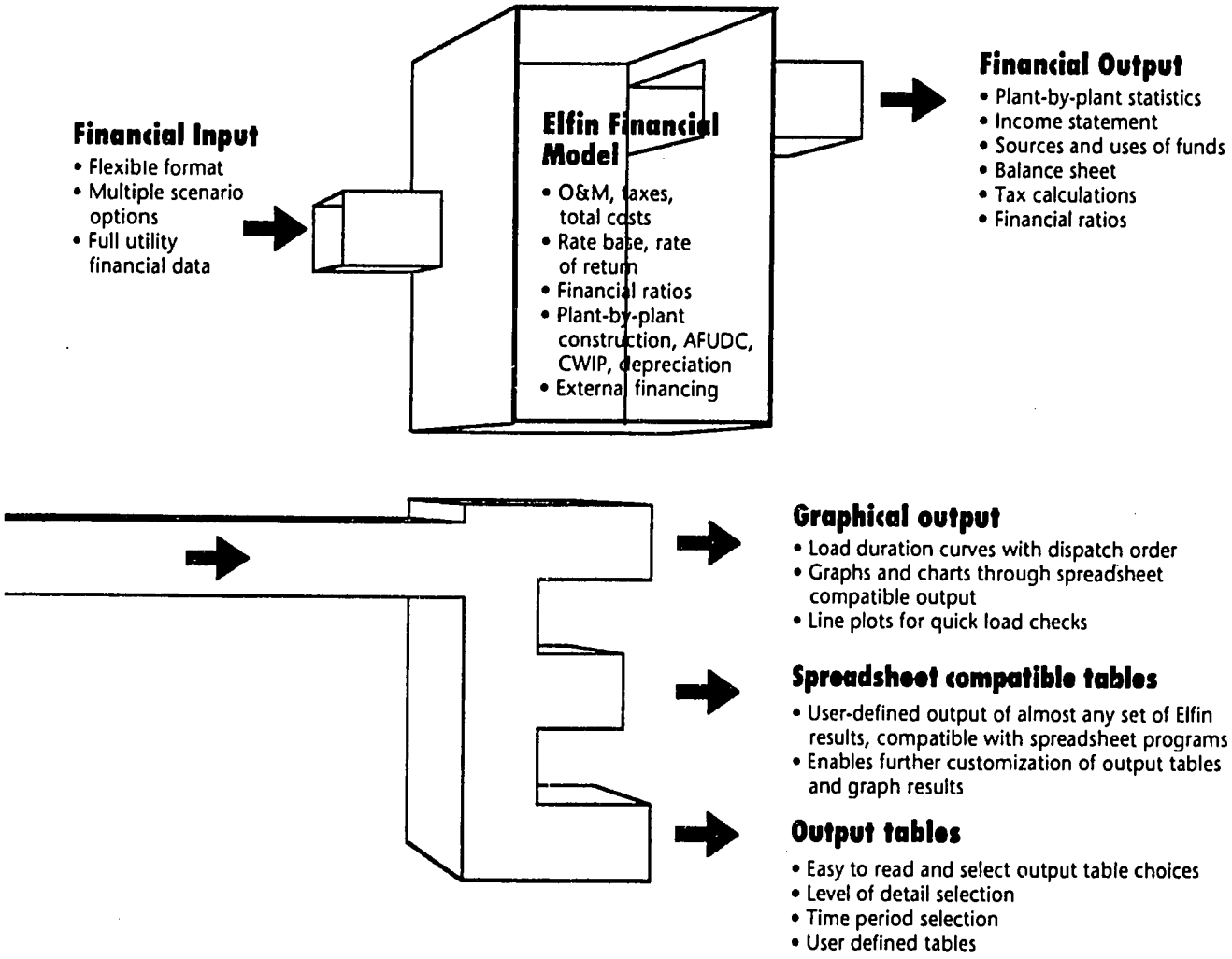


Elfin's data input format is structured to provide efficient data handling. The input format is flexible so that the data conform to your needs. You choose the level of detail you wish to provide — from simple annual figures which are constant across years to hourly detail.

Clear, concise tabular output makes it easy for you to understand and analyze results. An interface to spreadsheets allows you to designate any simulation details for importation into spreadsheets. Elfin also produces graphics which illustrate its simulation methods.

Elfin is used by utility planners, state regulators, government laboratory scientists and environmental analysts in the U.S. and elsewhere to explore solutions to electric planning and regulation challenges. These analysts use Elfin to explore diverse questions such as: maintenance planning; independent power pricing; contract evaluation; renewable resource valuation; and comprehensive integrated resource planning.

For 15 years the Environmental Defense Fund has been operating, refining and improving Elfin to integrate the most advanced analysis techniques into an easy-to-operate system, including the best documentation and user guides. Elfin's documentation includes complete explanations of all algorithms. The documentation is designed to help you produce results quickly and with confidence.



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Elfin Features Overview

Elfin provides all of the following:

Comprehensive features for electric system planning analysis with integration into a broad modeling environment with flexibility for the user.

Comprehensive Features

- Automated Integrated Resource Planning provides automated capacity expansion (resource optimization) across both supply-side and demand-side resources. Optimization can include the effects of environmental externalities and other user-defined costs and benefits.
- 52 week-per-year simulation and 8760 hours per year modeling capability. EEI-format load data can be read to allow detailed simulations. Elfin's level of detail — from weekly simulations, to monthly, to seasonal — can be easily changed without requiring any change to the input data.
- Low-emissions dispatch based on user specified costs for each emissions category or externality within air basins. Users choose reporting options for whether emissions costs will affect total costs in the output.
- Simulation of DSM and of time varying resources, as well as hydroelectric generation and pumped-storage units.
- Simulation of energy contract or energy-limited units, including contracts or constraints that apply simultaneously to multiple units. Both output energy (GWh) or input fuel (Btu) limits can be applied.

Integration:

- Integrated link with SRC/COMPASS DSM planning software for easy and complete handling of demand-side management (DSM) details. SRC/COMPASS is the DSM planning and screening package developed by Synergic Resources Corporation (SRC). The Elfin/COMPASS Integrated Resource Planning System documentation outlines the capabilities of the linked software models.
- Financial modeling of annual results, including plant-by-plant accounting for CWIP, AFUDC, additions to rate base, and depreciation.
- Alternative financial targets including municipal utility debt service ratios, as well as investor-owned utility return on equity, interest coverage, and others.
- Multi-area generation analysis including transmission constraints between two areas and cost allocation among three or more areas.

Flexibility:

- Input format that is simple and easy, with scenario handling for efficient data set creation and multiple model runs. The input format is flexible, allowing users to enter complicated data in the easiest way possible. Extensive error checking helps find data inconsistencies.
- Output reports in a wide variety and files that allow many convenient options for viewing and presenting Elfin results. Reporting options include standard and user- configured reports, tables, and graphics, including spreadsheet-readable data tables.
- The **Elfin Algorithms Guide** outlines how Elfin works and gives detailed descriptions of the calculation methods used by Elfin. The **Elfin Algorithms Guide** is a tool unique to Elfin that overcomes the "black box" syndrome of many other complex IRP models.
- The **Elfin User's Manual** provides a well-written, comprehensive guide to using Elfin, including sample inputs and tutorials.
- Available for mainframe, workstation, IBM-PC 386 and 486 platforms, plus source code available for other platforms, including Macintosh.

Generation Model methodology:

Elfin's Generation Model algorithm extends the chronological capabilities of the probabilistic, load duration curve method to subperiods within typical weeks. The Generation Model can simulate up to eight subperiods in up to 54 weeks per year (allowing partial weeks at the beginning and end of the year). Elfin has been designed and enhanced to allow the user to conveniently use advanced capabilities.

Generation model capabilities include:

DSM resources separately identified. Scalable time-of-day shapes (hourly DSM program effects) allow for easy entry of DSM program data.

Commitment algorithm simulates the decision to operate or shut down slow-start units.

Spinning reserve algorithm provides accuracy in the simulation of combustion turbine operation. The algorithm simulates the start-up of quick-start units for spinning reserve requirements.

Emissions can be calculated and reported for up to ten user-defined types of emissions. Emission rates can be defined as average rates or as varying with operating level, either per MBtu or per kWh.

Reliability calculations include loss-of-load probability (LOLP) and expected unserved energy. LOLP can be reported for every hour.

Heat rates can be defined in detail — at up to nine operating levels — and can be input as either average rates, incremental rates, or as parameters of the plant input-output curve (i.e., in polynomial form).

Hourly data input. Nearly any of the input data — including unit capacities, heat rates, and fuel costs — can be entered with time-of-day variation if the user desires.

Maintenance scheduling and reporting algorithm levelizes reserve margins among time periods. Users can also specify maintenance schedules with a start-date/end-date format.

Multiple plant energy limits can be specified for both "floors" (must-take) or "ceilings"(limited-energy). Limits can be specified in terms of either output (GWh) or input fuel (Btu).

Fuel costs to ratepayers different than dispatch fuel costs can be accounted for and totals reported.

Hydroelectric algorithms account for both run-of-river and limited-energy pondage optimization.

Pumped-storage algorithms optimize pumped-storage operation, including inflows.

Transmission line modeling simulates and reports the import of electricity over capacity-constrained lines.

Multi-area modeling allows full simulation of linked areas, including two-area transmission contraints and multi-area cost allocation.

Capital costs can be specified for each resource with up to four different user-defined categories. For example, plant capital can be entered separately from emission offset costs. Capital costs can be entered in constant dollars with escalation automatically calculated by the program.

Shortage costs or reliability values are user-defined for resource optimization.

Emissions valuation by air basin. Each user-defined emission can be valued (e.g., $/ton) for both operations (low-emissions dispatch) and planning (least social cost).

O&M costs and/or benefits can be specified — per kW, kWh, or in millions of dollars. Thus DSM, transmission and distribution benefits can be accounted for.

Dependable and nameplate capacities may be distinguished from operating capacity for the sake of shortage cost and capital cost calculations.

Summarizations of results may be user-defined, in up to three different ways. For example, results may be summarized by fuel type, by ownership, and by air basin.

Monthly and seasonal summaries may be created.

User-defined tables. Any subset of Elfin's outputs may be selected for transfer to a spreadsheet.

Marginal costs and expected time on margin can be reported by plant, time of day, pricing period and season.

Fast run times due to use of efficient algorithms and program structure.

Capabilities of Elfin
(cont.)

Elfin/COMPASS Integrated Resource Planning System methodology:

SRC/COMPASS from Synergic Resources Corporation is the leading model for predicting the penetration and effects of DSM programs. The Elfin/COMPASS System allows DSM resources to be evaluated in a fully integrated manner alongside supply-side resources. In addition, the System allows for quick, automatic updates of resource plan data, and the integration of updated resource plan statistics — such as marginal costs and marginal emissions — into DSM screening analysis.

ELFIN /COMPASS IRP SYSTEM CAPABILITIES:

Menu driven interface running both Elfin and SRC/Compass

Automatically transferring data:

- ELFIN → SRC/COMPASS:
  - Marginal generation costs
  - Emission rates
- SRC/COMPASS → ELFIN:
  - DSM load impacts
  - DSM Program costs
  - End-use emission rate

Financial Model methodology:

The Financial Model performs an annual simulation, including plant-by-plant accounting for CWIP, AFUDC. It produces year-by-year income statements, balance sheets, tax calculation results, financial ratios, and complete summary statistics:

Financial Model capabilities include:

Both investor-owned and municipal utility accounting.

Utility financial analysis: debt service coverage, external financing requirements, AFUDC, CWIP, and depreciation.

Capital costs accounting.

Additions to rate base.

Financial ratios.

CWIP in rate base.

Earnings attrition.

Tables for: income statement, sources and uses of funds, balance sheet, tax calculation, and general summary financial ratios.

Rate of return on rate base and equity.

Other capabilities: depreciation, external financing requirements, debt service coverage, AFUDC, CWIP.

Elfin Input and Data Management Capabilities:

Elfin's data input is handled in a format that gives you maximum control over creation, editing and updating of information. The data handling methods also provide simple ways to maintain varying data scenarios for comparison studies. Data input is accomplished with an input data file that you create and edit. Templates in the form of sample data sets are provided. A flexible and intuitive format is used to enter plant information, system parameters and load data. Each entry can be fully annotated with comments about the sources and status of data:

Data input management features include:

Tutorials, sample data and comprehensive input guide.

Human-readable and flexible input format.

Error checking and automatic consistency checking throughout.

Easy and documentable modifications to data.

Multiple-scenario data management.

End-use load shape scaling.

Fuel and O&M class references.

Results and output reporting features include:

Generation results by pricing period, weekly, monthly, seasonal, and/or annual averages.

Generation details by generation resource, demand-side program and pumped storage unit.

Results reported in tables selected by: type,week, month, season, year, pricing period, subperiod, and level of detail.

Standard and user-defined summary classes of up to three different tabulations of selected resource groupings.

Graphics for creating load curve plots and dispatch by block.

Spreadsheet output format available for tables that can be imported into spreadsheets for greater lexibility in creating reports and graphics.

Standard and user-defined formats.

Partial Elfin User List

Albrecht & Associates
Chesterfield, Missouri

Applied Cooperative Technology Systems
Atlanta, Georgia

Asian Institute of Technology
Bangkok, Thailand

Bechtel Corporation
San Francisco, CA

California Energy Commission
Sacramento, CA

Center for Energy Efficiency
Prague, Czech Republic UCB

Energy and Resources Group
Berkeley, CA

Energy Efficiency Center, CENEF
Moscow, Russia

Hawaii Division of Consumer Advocacy
Honolulu, HI

Imperial Irrigation District
Imperial, CA

INESTENE
Paris, France

Lawrence Risman,
Consultant, Lafayette, CA

L.A. Dept. of Water and Power
Los Angeles, CA

Morse, Richard, Weisenmiller
Oakland, CA

National Power Company
Oakland, CA

National Renewable Energy Lab
Golden, CO

Northwest Power Planning Council
Portland, OR

Pacific Gas and Electric
San Francisco, CA

Polish Foundation for Energy Efficiency, FEWE
Warsaw, Poland

RCG/Hagler, Baily, Inc.
Oakland, CA

Recon Research Corp.
Los Angeles, CA

Resource Management Int'l, Inc.
Sacramento, CA

San Diego Gas & Electric
San Diego, CA

Sierra Research
Sacramento, CA

Southern California Edison
Rosemead, CA

Southern Environmental Law Center
Charlottesville, VA

Synergic Resources Corporation
Bala Cynwyd, PA

Stone & Webster
Denver, CO

Tata Energy and Resources Institute
New Delhi, India

Tellus Institute
Boston, MA

Toward Utility Rate Normalization
San Francisco, CA

Tri-State
Montrose, CO

Union of Concerned Scientists
Cambridge, MA

USAID-EPIC
Arlington, VA

WALHI
Jakarta, Indonesia

Customer Support and Licensing

Elfin users receive comprehensive support and technical assistance. Because our technical support staff is actively involved in using and programming Elfin, they have the experience to answer your questions.

EDF works to keep the license fees for Elfin as low as possible so that the model is available to as wide a range of users as possible. We are accustomed to working with the needs of diverse organizations, including:

- Public utility commissions
- Small utilities, municipal and private
- Large utilities
- Consulting firms
- Non-profit organizations

Evaluations and Custom Configurations:

Evaluation Versions of Elfin are available, as well as the Elfin manuals and specifications. Elfin can be customized to meet specialized analysis needs. Consult with the EDF development team for details and rates.

We welcome all inquiries and questions. Contact the Elfin staff at the Environmental Defense Fund's Oakland, California offices. (510) 658-8008.

Elfin Feedback

The following is some feedback from experienced Elfin users discussing how they have applied Elfin in their work:

"Southern California Edison has been using the Elfin Model in its System Planning and System Operation Divisions for the past three years. This Model has been used effectively in our long range generation planning and forecasting our annual fuel and purchase power budget.

"EDF's staff has been very helpful and responsive in modifying Elfin whenever changes were necessary to meet Edison's special needs and requirements. We've always been very satisfied with EDF's efforts to help us to meet our requirements."

Fred Mobasheri,
Power Resources Engineering Manager
Southern California Edison

"The Hawaii Division of Consumer Advocacy acquired and uses the Elfin model to expand the scope of the types of analysis used in long-range electric utility planning and to provide broader public access to the analytical tools used in utility planning and regulation."

Carl Freedman
Hawaii Division of Consumer Advocacy

"Elfin has human readable, free-form input files, a very flexible output report capability, and a rapid turn around time that is measured in minutes, not hours. I am also impressed with the support we get for our questions and problems. It's nice to be able to speak directly to the programmers and see suggestions implemented in the next release."

Eric Hiaasen,
Planning Engineer
Pacific Gas & Electric Company

"Elfin is the adopted 'benchmark' model of the California Public Utilities Commission. It is a 'user friendly' model that has undergone a high level of scrutiny in Commission proceedings relating to electric resource planning and system operations. It has been successfully adopted to account for trends in industry and regulation, e.g. integration of Demand Side Management."

Scott Cauchois,
Project Manager, Resource Plng. & System Modeling,
California Public Utilities Commission

"MRW's analysts have successfully used Elfin since Elfin became publicly available. The staff at MRW have modeled the three large California utilities, Nevada utilities, the Lower Colorado River Authority, and several East Coast utilities.

"It is our model of choice when we are performing comprehensive, long range projections of utility operations and costs. Elfin is straight forward to operate and we have been able to count on excellent technical support."

Robert Weisenmiller,
Morse, Richard, Weisenmiller & Associates

Elfin

Elfin Electric Utility Financial & Production Cost Model

Environmental Defense Fund
Rockridge Market Hall,
5655 College Avenue, Oakland, CA 94618
510 658-8008 / fax:510 658-0630

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Appendix C Dataset for the Production Simulation Analysis

```
#     ********************** TARIF1.dat **************************
#     **                                                  **
#     **     Slovak Transfer Pricing and Retail Tariff Study  **
#     **                                                  **
#     **     Basic Input File for Generation Analysis        **
#     **                                                  **
#     **                                                  **
#     **     Unit Data are from EdF Model Output File        **
#     **     marked SEP Unit Data and Planned Outages        **
#     **     (changes are marked with 5/2)              **
#     **                                                  **
#     **     - commitment dates, net capacity, fixed O&M,    **
#     **       variable O&M, forced outages, planned        **
#     **       maintenance                            **
#     **                                                  **
#     **     - minimum capacity and heat curves are from     **
#     **       file SEP Efficiency Curves provided to Bechtel **
#     **       in May 1994                            **
#     **                                                  **
#     **                                                  **
#     **     Variant 1 - SEP Plan for SEP forecast of May 94  **
#     **     Variant 2 - SEP Plan for SEP forecast of May 94  **
#     **                 no hydro, or industry generation  **
#     **     Variant 3 - EdF Plan- High Forecast            **
#     **     Variant 4 - EdF Plan- Medium Forecast          **
#     **     Variant 5 - EdF Plan- Low Forecast             **
#     **     Variant 5 - SEP Plan- with Mohovce 3 and 4      **
#     **                                                  **
#     **                                                  **
#     ************************************************************
#


#
#   *Create Input Data file:
#
#       **Define the generation parameters:
#
#
#         ***Define the base year.
baseyr 1 z kladn~ rok
     2  1993
#         ***Define the ending year.
lastyr 1 posledn~ rok
     2  2010

# fyear  1 contribution of each month to total year
#     7  0.0849  0.0769  0.0849  0.0822  0.0849  0.0822
#        0.0849  0.0849  0.0822  0.0849  0.0822  0.0849
```

```
elegen 1   plant names used in ELFIN
     7  'ebo1'  'ebo2'
        'emo1'  'emo2'
        'ev12'  'ev34'  'ev56'
        'ev24'  'ev26'
        'ena1'  'ena3'  'ena4'  'enar'
        'enb1'  'enbh'  'enb2'  'enb3'
        'vahc'  'hydr'  'gabc'
        'teko'  'ppcs'
        'dzse'  'dsse'
        'senn'  'kosc'  'ziln'  'mart'
        'ziar'  'prsv'  'vojn'  'gast'
        'brat'  'komr'
        'izse'  'isse'  'ivse'  'isep'
        'dsmr'  'intr'
        'imp1'  'imp2'  'expt'
        'coal'
#
```

```
#  relationship of plant names and more complete descriptions
#
ebo1xx 0 Bohunice V-1
ebo2xx 0 Bohunice V-2
emo1xx 0 Mochovce 1
emo2xx 0 Mochovce 2
ev12xx 0 Vojany 1 1,2
ev34xx 0 Vojany 1 3,4
ev56xx 0 Vojany 1 5,6
ev24xx 0 Vojany 2 1-4
ev26xx 0 Vojany 2 5-6
ena1xx 0 Novaky A- 1-2
ena3xx 0 Novaky A- 3
ena4xx 0 Novaky A- 4
enarxx 0 Novaky A- New
enb1xx 0 Novaky B- 1a
enbhxx 0 Novaky B- 1b
enb2xx 0 Novaky B- 2
enb3xx 0 Novaky B- 3-4
tekoxx 0 Kosice CHP
vahcxx 0 Vah Cascade
gabcxx 0 Gabcikovo
hydrxx 0 Other hydro
izsexx 0 Ind-ZSE
issexx 0 Ind-SSE
ivsexx 0 Ind-VSE
isepxx 0 Ind-SEP
dzsexx 0 RDU-ZSE
dssexx 0 RDU-SSE
bratxx 0 Bratislava GCC
komrxx 0 Komarno CHP
ppcsxx 0 Generic GCC
sennxx 0 Senne GCC
koscxx 0 Kosice GCC
zilnxx 0 Zilina GCC
martxx 0 Martin GCC
ziarxx 0 Ziar GCC
prsvxx 0 Presov GCC
vojnxx 0 Vojany GCC
gastxx 0 Simple Cycle
dsmrxx 0 DSM
intrxx 0 Interruptible
imp1xx 0 Imports
imp2xx 0 Emergency
exptxx 0 Exports
coalxx 0 Generic Coal
ps 1xx 0 Pumped Storage

#
```

```
#          **Define the Generation Summary Categories (used for the
#               generation reports)
#

gensum 1 Nuclear
     7  'ebo1'  'ebo2'  'emo1'  'emo2'
gensum 2 Lignite
     7  'ena1' 'ena3' 'ena4' 'enar' 'enb1' 'enbh' 'enb2' 'enb3'
gensum 3 Coal
     7  'ev12' 'ev34'  'ev56'  'teko'  'coal'
gensum 4 Gas- power
     7  'vojn' 'gast' 'ziar'  'ev24'  'ev26'  'ppcs'
gensum 5 Hydro
     7  'vahc' 'gabc'  'hydr'
gensum 6 Industry
     7  'izse' 'isse'  'ivse'  'isep'
gensum 7 Distribution
     7  'dzse'  'dsse'  'brat'  'komr'
        'senn'  'kosc'  'ziln'  'mart'  'prsv'
gensum 8 DSM.
     7  'dsmr'
gensum 9 Interruptible
     7  'intr'
gensum10 Import/Export
     7  'imp1'  'imp2'  'expt'
```

Reference case
energy 1 net energy requirements (SEP forecast as of May 1994)
includes T&D losses, does not include self-consumption

20 0.0959 0.0857 0.0916 0.0824 0.0770 0.0744
0.0708 0.0755 0.0761 0.0853 0.0908 0.0945

y1993	22490
y1994	21508
y1995	21462
y1996	21839
y1997	22365
y1998	23274
y1999	24087
y2000	24913
y2001	25788
y2002	26708
y2003	27665
y2004	28655
y2005	29679
y2006	30186
y2007	30731
y2008	31281
y2009	31824
y2010	32364

peak 1 peak demand based on SEP May 1994 forecast

25 1.000 0.967 0.934 0.911 0.886 0.774
0.764 0.812 0.847 0.916 0.980 0.987

y1993	3441
y1994	3307
y1995	3304
y1996	3358
y1997	3434
y1998	3558
y1999	3684
y2000	3812
y2001	3945
y2002	4083
y2003	4224
y2004	4372
y2005	4523
y2006	4606
y2007	4694
y2008	4781
y2009	4867
y2010	4953

```
# High scenario (Edf, May, 94)
energy 2 net energy requirements (SEP forecast as of May 1994)
#       includes T&D losses, does not include self-consumption

    20  0.0959 0.0857 0.0916 0.0824 0.0770 0.0744
        0.0708 0.0755 0.0761 0.0853 0.0908 0.0945

# High scenario, energy
            y1993    22490
            y1994    22861
            y1995    23547
            y1996    24326
            y1997    25126
            y1998    25898
            y1999    26473
            y2000    26986
            y2001    27498
            y2002    28517
            y2003    29076
            y2004    29660
            y2005    30269
            y2006    30905
            y2007    31569
            y2008    32261
            y2009    32982
            y2010    32351

peak  2 peak demand based on SEP May 1994 forecast
#       based on 61% load factor
#       should be updated to reflect exact forecast

    25  1.000 0.967 0.934 0.911 0.886 0.774
        0.764 0.812 0.847 0.916 0.980 0.987

# High scenario, Peak
            y1993    3441
            y1994    3515
            y1995    3625
            y1996    3740
            y1997    3858
            y1998    3959
            y1999    4049
            y2000    4129
            y2001    4206
            y2002    4359
            y2003    4440
            y2004    4526
            y2005    4613
            y2006    4716
            y2007    4822
            y2008    4931
            y2009    5044
            y2010    4951
```

Low scenario (Edf, May, 94)
energy 4 net energy requirements (SEP forecast as of May 1994)
includes T&D losses, does not include self-consumption

20 0.0959 0.0857 0.0916 0.0824 0.0770 0.0744
0.0708 0.0755 0.0761 0.0853 0.0908 0.0945

Low scenario, energy

y1993	22490
y1994	21835
y1995	21603
y1996	21471
y1997	21440
y1998	21511
y1999	21693
y2000	21996
y2001	22196
y2002	22377
y2003	22546
y2004	22716
y2005	22896
y2006	23087
y2007	23289
y2008	23501
y2009	23724
y2010	23959

peak 4 peak demand based on SEP May 1994 forecast
based on 51% load factor
should be updated to reflect exact forecast

25 1.000 0.967 0.934 0.911 0.886 0.774
0.764 0.812 0.847 0.916 0.980 0.987

Low scenario, Peak

y1993	3441
y1994	3357
y1995	3326
y1996	3301
y1997	3292
y1998	3288
y1999	3318
y2000	3365
y2001	3395
y2002	3421
y2003	3443
y2004	3466
y2005	3489
y2006	3523
y2007	3557
y2008	3592
y2009	3628
y2010	3667

```
#          *** Define the subperiods.
#
#            1 = weekday peak period
#            2 = weekday mid-peak period
#            3 = weekday off-peak period
#            4 = weekend mid-peak period
#            5 = weekend off-peak period
#
# Definition according to contractual arrangements between SEP and
#  and distributors for secon quarter 1993.
#  These time periods can be adjusted contractually.
#
```

```
subprd 1
     19  y1993  mon 12am 3   6am 1  10am 2  10pm 3
            sat 12am 5   6am 4  10pm 5


# maxmnt 1 maximum maintenance factor
     17  y1993  5
#
#          *** Define seasons for seasonal summary report
#          *** Quarters are used to follow contracting convention
#

seasum 1   Q1
     7    1  2  3
seasum 2   Q2
     7    4  5  6
seasum 3   Q3
     7    7  8  9
seasum 4   Q4
     7   10  11  12

#
```

```
#        ** Define the commitment requirements.
#

commit 1

#
# Commitment levels adjusted to assure that Vojany I is committed
# assuming full capacity availability from Gabcikovo and pumped storage.
# It is recognized that Gabcikovo capacity is not fully available, so
# that commitment levels are overstated. If Gabcikovo modeling is
# modified, these committment levels should be adjusted.
#
    24 y1993 1.1  1.1  1.1  1.1  1.1  1.1
             1.1  1.1  1.1  1.1  1.1  1.1

spnfr  1 10% above peak load for all subperiods
    2   .10   # This covers largest unit.

mrordr 1 overall must-run order
    7       'ena1' 'enbh'
            'teko'
            'brat' 'kosc' 'ziln' 'mart' 'prsv' 'senn'
            'ebo1' 'ebo2' 'emo1' 'emo2'
            'ev12' 'ev34' 'ev56'
mrlast 1 commit all units of Vojany during peak month
    27
            y199301  'ev34'
            y199302  'ev34'
            y199303  'ev56'
            y199304  'ev34'
            y199305  'ev34'
            y199306  'ev12'
            y199307  'ev34'
            y199308  'ev34'
            y199309  'ev34'
            y199310  'ev12'
            y199311  'ev12'
            y199312  'ev12'

mrordr 2 overall must-run order- unconstrained
    7       'ebo1' 'ev12'
#
```

```
#          *** Set fuel costs (Another option would be to use each
#             plant name instead of the fuel classes.)
#
#   Scenario 1- forecast based on IEA/OECD forecast provided by ETSU (May
#          1994)
# Fuel costs expressed in US $ per GJ. Heat rates in kJ/kWh.
          # (Designation per mbtu is program convention.)
          # End of 1993 exchange rate of 32 Sk/US$ was used where
          # conversion was necessary.

#   Scenario 1- IEA/OECD forecast

ngasfc 1 natural gas projected cost
     /mbtu 17       # IEA/OECD forecast from ETSU
#          Gas
             y1993     3.38
             y1994     3.46
             y1995     3.70
             y1996     3.79
             y1997     3.89
             y1998     3.99
             y1999     4.09
             y2000     4.20
             y2001     4.33
             y2002     4.47
             y2003     4.61
             y2004     4.75
             y2005     4.90
             y2006     4.90
             y2007     4.90
             y2008     4.90
             y2009     4.90
             y2010     4.90
lignfc 1 lignite projected cost
     /mbtu 17       # detailed assumptions in ASSUME_1.wk1
#          Lignite
             y1993     2.19
             y1994     2.30
             y1995     2.53
             y1996     2.64
             y1997     2.75
             y1998     2.87
             y1999     2.99
             y2000     3.12
             y2001     3.19
             y2002     3.25
             y2003     3.32
             y2004     3.39
             y2005     3.46
             y2006     3.46
             y2007     3.46
             y2008     3.46
             y2009     3.46
             y2010     3.46
```

```
coalfc 1 coal projected cost
    /mbtu 17        # detailed assumptions in ASSUME_1.wk1
#       Coal
            y1993    1.52
            y1994    1.58
            y1995    1.64
            y1996    1.71
            y1997    1.78
            y1998    1.85
            y1999    1.92
            y2000    2.00
            y2001    2.02
            y2002    2.04
            y2003    2.06
            y2004    2.08
            y2005    2.10
            y2006    2.12
            y2007    2.14
            y2008    2.16
            y2009    2.18
            y2010    2.20
nuclfc 1 nuclear fuel projected cost
    /mbtu 17      # based on EdF Mohovce Study
#       Nuclear
            y1993    0.40
            y1994    0.45
            y1995    0.50
            y1996    0.55
            y1997    0.61
            y1998    0.66
            y1999    0.71
            y2000    0.76
            y2001    0.76
            y2002    0.76
            y2003    0.77
            y2004    0.77
            y2005    0.77
            y2006    0.77
            y2007    0.78
            y2008    0.78
            y2009    0.78
            y2010    0.78
```

```
resdfc 1 residual fuel oil projected cost
     /mbtu 17          # IEA/OECD from ETSU (60% of crude)
#          Residual
             y1993     2.12
             y1994     2.08
             y1995     2.28
             y1996     2.38
             y1997     2.48
             y1998     2.59
             y1999     2.70
             y2000     2.82
             y2001     2.88
             y2002     2.94
             y2003     3.00
             y2004     3.06
             y2005     3.12
             y2006     3.12
             y2007     3.12
             y2008     3.12
             y2009     3.12
             y2010     3.12
#
# Import/Export costs  (expressed in US$/kwh)
# Intended only as the energy component of purchase contracts.
# Demand portion should be calculated separately.

imptfc 1 import power cost
     /kwh  1  .041
                y1994  .21  # same as lignite cost escalation
impefc 1 emergency import power cost
     /kwh  1  .045
                y1994  .21  # same as lignite cost escalation
exptfc 1 export power cost
     /kwh  1  .041
                y1994  .027 # based on SEP draft report to W.B.
                y2001  .01
avodfc 1 avoided cost for industry and distribution-owned plants
     /kwh  17  y1993   0  # used in estimating avoided cost
avodfc 2 avoided cost for industry and distribution-owned plants
     /kwh  17  y1993   0
            y1994   .0475  # estimated avoided cost using
                           # with and without analysis
                           # on AVOID_1.WK1
avodfc 3 avoided cost for industry and distribution-owned plants
     /kwh  17  y1993   0
            y1994   .0497  # estimated avoided cost using
                           # with and without analysis
                           # on AVOID_3.WK1
                           # based on detailed subperiods
                           # changed by quarter
cstens 1 cost of energy-not-served
     2   .05
cstdmp 1 cost of dump energy
     2   .00
```

```
#
# Variable O&M costs (US $/kWh)
#  based on SEP analysis of variable costs (SEP-17a)

omn1om 1 variable o&m for Vojany I
     1  0.0012        y1994 .00
omn6om 1 variable o&m for Vojany II and new GCC
     1  0.00028       y1994 .00
omn2om 1 variable o&m for Novaky A
     1  0.00028       y1994 .00
omn3om 1 variable o&m nuclear for Bohunice 1
     1  0.00022       y1994 .00
omn4om 1 variable o&m nuclear for Bohunice 2
     1  0.00019       y1994 .00
omn5om 1 variable o&m nuclear for Mochovce
     1  0.00013       y1994 .00
omn7om 1 variable o&m nuclear for Novaky B pre vsetky bloky
     1  0.00013       y1994 .00
omn8om 1 variable o&m for TEKO
     1  0.00013       y1994 .00


#
```


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```
#   ************ NUCLEAR PLANTS *************
#          *** Bohunice V-1 ***
ebolcw 1 weekend-constrained capacity (net MW)
# 5/2
     27 y199301   344   409
#     22  399  399  399  399  399  399
#        399  399  399  399  399  399
ebolmu 1 number of units - reference case from SEP
# based on SEP May 1994 Plan
     27  y199301  2
        y200001  2
        y200010  1
        y200101  1
        y200107  0
        y200201  0
ebolmu 2 number of units - EdF high, medium and low scenarios (5/94)
# based on EdF May 1994 Report
     27  y199301  2
        y199901  2
        y199907  1
        y200001  1
        y200007  0
        y200101  0
ebolha 1 average heat rate (kJ/kWh) from SEP
# 5/2
     27 y199301   11800   11650
ebolfc 1 uranium, cost estimates above in 'nuclfc'
     fc=nucl
ebolfr 1 forced outage rate from SEP
# 5/2
     17 y1993  0  0.95
ebolmr 1 pre-scheduled maintenance from SEP
c INPUT MAINTENANCE SCHEDULE BASED ON SEP DATES.
# 5/2
     24 y1993 .500  .500  1.00 .500  .500  .250
          .000  .000  .000 .000  .300  .300
       y1994 .000  .000  .500 .250  .000  .000
          .000  .000  .250 .500  .000  .000
       y1995 .000  .268  .500 .500  .097  .000
          .000  .000  .267 .500  .500  .097
       y1996 .306  .500  .500 .500  .000  .000
          .193  .500  .500 .500  .951  .000
       y1997 .000  .357  .500 .500  .387  .000
          .000  .048  .500 .500  .500  .177
       y1998 .000  .000  .322 .500  .067  .000
          .000  .000  .383 .500  .000  .000
       y1999 .000  .000  .177 .500  .210  .000
          .000  .000  .300 .500  .083  .000
       y2000 .000  .000  .355 .500  .032  .000
          .130  .130  .000 .000  .000  .000
       y2001 .322  .000  .000 .000  .000  .000
          .000  .000  .000 .000  .000  .000
ebolom 1 O&M
    om=omn3
```


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```
#          *** Bohunice V-2 ***
ebo2cw 1 weekend-constrained capacity (net MW)
     27 y199301  345.0   411.0
ebo2mu 1 number of units
# based on SEP May 1994 Plan
     27  y199301  2
ebo2ha 1 average heat rate (kJ/kWh)
# 5/2 from SEP
     27 y199301  11800   11650
ebo2fc 1 uranium, cost estimates above in 'nuclfc'
     fc=nucl
ebo2fr 1 forced outage rate
     17 y1993  0  0.95
ebo2mr 1 pre-scheduled maintenance
# INPUT MAINTENANCE SCHEDULE BASED ON SEP DATES.
#  5/2
     24 y1993 .000  .000  .000 .000  .000  .067
          .500  .451  .450 .000  .000  .000
       y1994 .000  .000  .000 .033  .500  .333
          .403  .435  .000 .000  .000  .000
       y1995 .000  .000  .000 .000  .419  .500
          .500  .500  .322 .000  .000  .000
       y1996 .000  .000  .000 .067  .500  .500
          .667  .500  .000 .000  .000  .000
       y1997 .000  .000  .000 .000  .097  .500
          .645  .452  .000 .000  .000  .000
       y1998 .000  .000  .000 .000  .097  .500
          .645  .452  .000 .000  .000  .000
       y1999 .000  .000  .000 .000  .435  .533
          .500  .500  .250 .000  .000  .000
       y2000 .000  .000  .000 .083  .500  .500
          .733  .435  .000 .000  .000  .000
       y2001 .000  .000  .000 .000  .484  .383
          .000  .403  .450 .000  .000  .000
       y2002 .000  .000  .000 .050  .500  .300
          .274  .500  .067 .000  .000  .000
       y2003 .000  .000  .000 .183  .500  .500
          .500  .500  .033 .000  .000  .000
       y2004 .000  .000  .000 .267  .500  .500
          .564  .387  .000 .000  .000  .000
       y2005 .000  .000  .000 .183  .500  .183
          .500  .339  .000 .000  .000  .000
       y2006 .000  .000  .000 .166  .500  .200
          .500  .339  .000 .000  .000  .000
       y2007 .000  .000  .000 .267  .500  .433
          .500  .500  .033 .000  .000  .000
       y2008 .000  .000  .000 .383  .500  .500
          .500  .339  .000 .000  .000  .000
       y2009 .000  .000  .000 .267  .500  .116
          .500  .339  .000 .000  .000  .000
       y2010 .000  .000  .000 .166  .500  .200
          .500  .339  .000 .000  .000  .000
ebo2om 1 O&M
     om=omn4
```

```
#          *** Mohovce 1 ***
emo1cw 1 weekend-constrained capacity (net MW)
#  5/2
     27 y199301  345.0    411.0
emo1mu 1 number of units
# based on SEP May 1994 Plan
     27 y199301 0
        y199701 1
        y199801 2
emo1mu 2 number of units
# based on EdF high medium and low scenarios (5/94)
#  5/2
     27 y199301 0
        y199701 1
        y199801 2
emo1mu 3 number of units
# without Mohovce 1 and 2
     27 y199301 0
emo1ha 1 average heat rate (kJ/kWh)
#  5/2
     27 y199301  11800    11650
emo1fc 1 uranium, cost estimates above in 'nuclfc'
     fc=nucl
emo1fr 1 forced outage rate
     17 y1993  0  0.95
emo1mr 1 pre-scheduled maintenance
     24 y1993 .000  .000  .000 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y1994 .000  .000  .000 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y1995 .000  .000  .000 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y1996 .000  .000  .000 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y1997 .000  .143  .290 .000  .033  .290
          .000  .177  .048 .000  .000  .322
       y1998 .143  .290  .000 .667  .500  .450
          .000  .048  .283 .000  .000  .250
       y1999 .226  .500  .500 .083  .403  .500
          .468  .000  .000 .000  .000  .000
       y2000 .000  .143  .500 .500  .225  .260
          .250  .250  .000 .000  .000  .000
       y2001 .000  .143  .500 .210  .000  .133
          .500  .210  .000 .000  .000  .000
       y2002 .000  .000  .468 .371  .000  .233
          .500  .113  .000 .000  .000  .000
       y2003 .000  .143  .500 .450  .500  .500
          .250  .000  .000 .000  .000  .000
       y2004 .000  .143  .500 .550  .750  .290
          .000  .000  .000 .000  .000  .000
       y2005 .000  .071  .500 .322  .500  .290
          .000  .000  .000 .000  .000  .000
emo1om 1 O&M
    om=omn5
```

```
#          *** Mohovce 2
emo2cw 1 weekend-constrained capacity (net MW)
#  5/2
     27 y199301  345.0   411.0
emo2mu 1 number of units
# based on SEP May 1994 Plan
     27 y199301 0
        y200001 0
        y200010 1
        y200101 1
        y200107 2
        y200201 2
emo2mu 2 number of units
# based on no construction of Units 3 and 4
     27 y199301 0
emo2ha 1 average heat rate (kJ/kWh)
#  5/2
     27 y199301  11800   11650
emo2fc 1 uranium, cost estimates above in 'nuclfc'
     fc=nucl
emo2fr 1 forced outage rate
# 5/2
     17 y1993  0  0.95
emo2mr 1 pre-scheduled maintenance
# 5/2
     24 y1993 .000  .000  .000 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y1994 .000  .000  .000 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y1995 .000  .000  .000 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y1996 .000  .000  .000 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y1997 .000  .000  .000 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y1998 .000  .000  .000 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y1999 .000  .000  .000 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y2000 .000  .000  .000 .000  .000  .000
          .000  .000  .000 .322  .166  .323
       y2001 .484  .000  .000 .000  .000  .000
          .000  .000  .161 .500  .500  .581
       y2002 .000  .000  .000 .000  .000  .000
          .226  .500  .783 .564  .100  .000
       y2003 .000  .000  .000 .000  .000  .000
          .177  .500  .633 .693  .210  .000
       y2004 .000  .000  .000 .000  .000  .000
          .226  .500  .417 .500  .000  .000
       y2005 .000  .000  .000 .000  .000  .000
          .177  .500  .455 .500  .067  .000

emo2om 1 O&M
     om=omn5
```


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```
# LIGNITE PLANTS *************
#
#
#         *** Novaky Unit A- 22.4 MW (gross) turbines
#           Units 1 and 2
#
enalcw 1 net capacity - slow start unit
    sh=enal  1  21.25   # capacity is  24 MW, but max month. average is
                        # 17 MW. Annual energy is given 109 GWh for all
                        # years, when used.

              0.000  0.000 0.000   # growth rates from 1993
      0.000 0.000  0.000  0.000 0.000   # is not given
      0.000 0.000  0.000  0.000 0.000
      0.000 0.000  0.000  0.000 0.000

enalsh 1 zadavam tyzdenny priebeh pre jednotlive roky
    29  y199301 mon 12am    21.25
      y199302 mon 12am    17.5
      y199303 mon 12am    16.25
      y199304 mon 12am    13.75
      y199305 mon 12am    13.75
      y199306 mon 12am    12.5
      y199307 mon 12am    12.5
      y199308 mon 12am    12.5
      y199309 mon 12am    13.75
      y199310 mon 12am    16.25
      y199311 mon 12am    17.5
      y199312 mon 12am    20
enalha 1 average heat rates for each capacity state
    27  y199301  14500
      y199501  8500
enalmu 1 number of units
    27  y199301  2
      y199501  1
      y199701  0
enalmr 1 annual requirement, model will schedule among months
    24 y1992 .000  .000  .080 .150  .000  .000
         .000  .000  .000 .000  .000  .000
      y1994 .000  .000  .080 .150  .000  .000
         .000  .000  .000 .000  .000  .000
      y1995 .000  .000  .080 .150  .000  .000
         .000  .000  .000 .000  .000  .000
      y1996 .000  .000  .080 .150  .000  .000
         .000  .000  .000 .000  .000  .000
      y1997 .000  .000  .080 .150  .000  .000
         .000  .000  .000 .000  .000  .000
      y1998 .000  .000  .000 .000  .000  .230
         .000  .000  .000 .000  .000  .000
      y1999 .000  .000  .000 .000  .000  .230
         .000  .000  .000 .000  .000  .000
      y2000 .000  .000  .000 .000  .000  .230
         .000  .000  .000 .000  .000  .000
      y2001 .000  .000  .000 .000  .000  .230
```

```
        .000  .000  .000 .000  .000  .000
    y2002 .000  .000  .000 .000  .000  .230
        .000  .000  .000 .000  .000  .000
    y2003 .000  .000  .000 .000  .000  .230
        .000  .000  .000 .000  .000  .000
    y2004 .000  .000  .000 .000  .000  .230
        .000  .000  .000 .000  .000  .000
    y2005 .000  .000  .000 .000  .000  .230
        .000  .000  .000 .000  .000  .000
enalfr 1 forced outage rate
    27 y199301 0.04
       y199501 0.10
       y199801 0.04
enalfc 1 coal, cost estimates above in 'coalfc'
    fc=lign
enalom 1 O&M
    om=omn2
#
#
```

```
#          *** Novaky Unit A - first 1 x 32 MW (gross) turbine
#             Unit 3
#
# SEP N-21,   N-22,   N-31,   N-32,    N-03
#    + 10 MW          + 10 MW
#    in winter        in summer
ena3cm 1 net capacity - slow start unit
     25 .77 .77 .77 1.0 1.0 1.0
       1.0 1.0 1.0 .77 .77 .77
       y1993  27

ena3ha 1 average heat rates for each capacity state
# 5/2 from SEP efficiency curves
     25 .61 .61 .61 1.0 1.0 1.0
       1.0 1.0 1.0 .61 .61 .61
       y1993  10050
       y1998  7500
ena3mu 1 number of units
# SEP May Plan
     27  y199301  1
       y200001  1
       y200004  0
       y200101  0
ena3mr 1 annual requirement, model will schedule among months
     24 y1993 .000  .000  .000  .000  .000  .000
          .000  .000  .000  .000  .000  .000
       y1994 .000  .000  .000  .000  .000  .000
          .000  .000  .500  .500  .500  .000
       y1995 .000  .000  .000  .000  .000  .000
          .000  .000  .500  .500  .500  .000
       y1996 .000  .000  .000  .000  .000  .000
          .250  .250  .250  .000  .000  .000
       y1997 .000  .000  .000  .000  .000  .000
          .000  .000  .000  .000  .000  .000
       y1998 .000  .000  .000  .700  .419  .000
          .000  .000  .000  .000  .000  .000
       y1999 .000  .000  .000  .467  .000  .000
          .000  .000  .000  .000  .000  .000
ena3fr 1 forced outage rate
     27  y199301  0.04
       y199801  0.14
ena3fc 1 coal, cost estimates above in 'coalfc'
     fc=lign
ena3om 1 O&M
     om=omn2
#
#
```

```
#          *** Novaky Unit A - second 1 x 32 MW (gross) turbine
#             Unit 4
#
# SEP    N-04
ena4cm 1 net capacity - slow start unit
     25 .77 .77 .77 1.0 1.0 1.0
       1.0 1.0 1.0 .77 .77 .77
       y1993   27
ena4ha 1 average heat rates for each capacity state
# 5/2 from SEP efficiency curves
     25 .61 .61 .61 1.0 1.0 1.0
       1.0 1.0 1.0 .61 .61 .61
       y1993   10050
ena4mu 1 number of units
# SEP May Plan
     27 y199301 1
       y199701 1
       y199705 0
       y199801 0
ena4mu 2 number of units
# EdF May Plan
     27 y199301 1
       y199601 1
       y199605 0
       y199701 0
ena4mr 1 annual requirement, model will schedule among months
     24 y1993 1.00  1.00  1.00 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y1994 .000  .290  1.00 1.00  1.00  .710
          .000  .000  .000 .000  .000  .000
       y1995 .000  .000  .000 .000  .000  .467
          .000  .000  .000 .000  .000  .000
       y1996 .000  .000  .000 .000  .000  .467
          .000  .000  .000 .000  .000  .000
       y1997 .000  .000  .000 .000  .000  .000
          .000  .000  .000 .000  .000  .000
ena4fr 1 forced outage rate
     27 y199301 0.14
ena4fc 1 coal, cost estimates above in 'coalfc'
     fc=lign
ena4om 1 O&M
     om=omn2
#
#
```

```
#          *** Novaky A- reconstructed FBC units
#
enarcw 1 net capacity - slow start unit
     sh=ena1  1  12        # two FBC units 10 and 14 MW net
                    # modeled as 2x12 MW with same output profile as
                    # Novaky A Units 1 and 2
               0.000  0.000 0.000   # growth rates from 1993
        0.000 0.000  0.000  0.000 0.000   # is not given
        0.000 0.000  0.000  0.000 0.000
        0.000 0.000  0.000  0.000 0.000
enarha 1 average heat rates for each capacity state
     27  y199301  8500
enarmu 1 number of units
     27  y199301  0
        y199501  1
        y199701  2
enarmu 2 number of units
     27  y199301  0
enarmr 1 annual requirement, model will schedule among months
     24 y1992 .000  .000  .080 .150  .000  .000
           .000  .000  .000 .000  .000  .000
       y1994 .000  .000  .080 .150  .000  .000
           .000  .000  .000 .000  .000  .000
       y1995 .000  .000  .080 .150  .000  .000
           .000  .000  .000 .000  .000  .000
       y1996 .000  .000  .080 .150  .000  .000
           .000  .000  .000 .000  .000  .000
       y1997 .000  .000  .080 .150  .000  .000
           .000  .000  .000 .000  .000  .000
       y1998 .000  .000  .000 .000  .000  .230
           .000  .000  .000 .000  .000  .000
       y1999 .000  .000  .000 .000  .000  .230
           .000  .000  .000 .000  .000  .000
       y2000 .000  .000  .000 .000  .000  .230
           .000  .000  .000 .000  .000  .000
       y2001 .000  .000  .000 .000  .000  .230
           .000  .000  .000 .000  .000  .000
       y2002 .000  .000  .000 .000  .000  .230
           .000  .000  .000 .000  .000  .000
       y2003 .000  .000  .000 .000  .000  .230
           .000  .000  .000 .000  .000  .000
       y2004 .000  .000  .000 .000  .000  .230
           .000  .000  .000 .000  .000  .000
       y2005 .000  .000  .000 .000  .000  .230
           .000  .000  .000 .000  .000  .000
enarfr 1 forced outage rate
     27  y199301  0.04
        y199501  0.10
        y199801  0.04
enarfc 1 coal, cost estimates above in 'coalfc'
     fc=lign
enarom 1 O&M
     om=omn2
#
```

```
#          *** Novaky Unit B- Unit 1- second reconstructed unit
#
# enb1 is the dispatchable portion of unit
# enbh is non-dispatchable portion of unit used for heating
#
enb1cp 1 net capacity (two capacity states) - (modeled as fast start
#          since heating portion of plant will be operating)
# 5/2
    27 y199301     70    100
       y199801     47    68
enb1ha 1 average heat rates for each capacity state
# 5/2 SEP eff. curves
    27 y199301    12850 12400
       y199801    12850 12400
enb1mu 1 number of units
# SEP May 1994 Plan
    27 y199301 1

enb1mr 1 annual requirement, model will schedule among months
# 5/2
    24 y1993 .000  .000  .000 .000  .000  .000
          .000  .333  1.00 1.00  .000  .000
       y1994 .000  .000  .000 .000  .000  .000
          .000  .355  .548 .000  .000  .000
       y1995 .000  .000  .000 1.00  1.00  1.00
          .900  .000  .000 .000  .000  .000
       y1996 .000  .000  .000 .000  .000  .000
          .000  .355  .548 .000  .000  .000
       y1997 .000  .000  .000 .000  .000  .000
          .355  .523  .000 .000  .000  .000
       y1998 1.00  1.00  .935 .000  .000  .000
          .000  .000  .000 1.00  1.00  1.00
       y1999 1.00  1.00  .935 .000  .000  .000
          .000  .000  .000 1.00  1.00  1.00
       y2000 1.00  1.00  .935 .000  .000  .000
          .000  .000  .000 1.00  1.00  1.00
       y2001 1.00  1.00  .935 .000  .000  .000
          .000  .000  .000 1.00  1.00  1.00
       y2002 1.00  1.00  .935 .000  .000  .000
          .000  .000  .000 1.00  1.00  1.00
       y2003 1.00  1.00  .935 .000  .000  .000
          .000  .000  .000 1.00  1.00  1.00
       y2004 1.00  1.00  .935 .000  .000  .000
          .000  .000  .000 1.00  1.00  1.00
       y2005 1.00  1.00  .935 .000  .000  .000
          .000  .000  .000 1.00  1.00  1.00
enb1fr 1 forced outage rate
    17  y1993  0   0.90
enb1fc 1 coal, cost estimates above in 'coalfc'
    fc=lign
enb1om 1 O&M
    om=omn7
#
```

```
#          *** Novaky Unit B- Unit 1- second reconstructed unit
#
# enbl is the dispatchable portion of unit
# enbh is non-dispatchable portion of unit used for heating
#
enbhcm 1 net capacity (two capacity states) - slow start unit
# 5/2
     27 y199301     34    56
enbhha 1 average heat rates for each capacity state
# 5/2
     27 y199301    6200  6200
enbhmu 1 number of units
     27 y199301 0
       y199801 1
enbhmr 1 annual requirement, model will schedule among months
# 5/2
     24 y1993 .000  .000  .000 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y1998 .000  .000  .903 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y1999 .000  .000  .000 .000  .000  .000
          1.00  1.00  1.00 .193  .000  .000
       y2000 .000  .000  .903 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y2001 .000  .000  .903 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y2002 .000  .000  .903 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y2003 .000  .000  .903 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y2004 .000  .000  .903 .000  .000  .000
          .000  .000  .000 .000  .000  .000
       y2005 .000  .000  .903 .000  .000  .000
          .000  .000  .000 .000  .000  .000
enbhfr 1 forced outage rate
     17 y1993  0   0.90
enbhfc 1 coal, cost estimates above in 'coalfc'
     fc=lign
enbhom 1 O&M
     om=omn7
#
```

```
#          *** Novaky Unit B- Unit 2- first reconstructed unit
#
enb2cm 1 net capacity (two capacity states) - slow start unit
# 5/2
     27 y199301     75    100
        y199601     75     95
enb2ha 1 average heat rates for each capacity state
# 5/2  from SEP eff. curves
     27 y199301    11000 10500
        y199601    11000 10200
enb2mu 1 number of units
     27 y199301 0
        y199401 0
        y199403 1
        y199501 1

enb2mr 1 annual requirement, model will schedule among months
# 5/2
     24 y1993 .000  .000  .000 .933  .500  .417
          .000  .000  .000 .000  .000  .000
        y1994 .000  .000  .000 .817  .500  .500
          .167  .000  .000 .000  .000  .000
        y1995 .000  .000  .000 .000  .000  .000
          .000  .080  .500 .339  .000  .000
        y1996 .000  .000  .000 .000  .000  .000
          .403  .500  .000 .000  .000  .000
        y1997 .000  .000  .000 .000  .000  .000
          .080  .371  .000 .194  .500  .161
        y1998 .000  .000  .000 .000  .355  .097
          .452  .000  .000 .000  .000  .000
enb2fr 1 forced outage rate
     17 y1993  0   0.90
enb2fc 1 coal, cost estimates above in 'coalfc'
     fc=lign
enb2om 1 O&M
     om=omn7
#
```

```
#          *** Novaky Unit B- 79 MW turbine- Units 3 and 4
#
enb3cm 1 net capacity (two capacity states) - slow start unit
     27 y199301     65    79
enb3ha 1 average heat rates for each capacity state
     27 y199301    13900 13900
enb3mu 1 number of units
     27 y199301 2
       y199901 0
enb3mr 1 annual requirement, model will schedule among months
# 5/2
     24 y1993 .000  .000  .000 .933  .500  .417
          .000  .000  .000 .000  .000  .000
       y1994 .000  .000  .000 .817  .500  .500
          .167  .000  .000 .000  .000  .000
       y1995 .000  .000  .000 .000  .000  .000
          .000  .080  .500 .339  .000  .000
       y1996 .000  .000  .000 .000  .000  .000
          .403  .500  .000 .000  .000  .000
       y1997 .000  .000  .000 .000  .000  .000
          .080  .371  .000 .194  .500  .161
       y1998 .000  .000  .000 .000  .355  .097
          .452  .000  .000 .000  .000  .000
enb3fr 1 forced outage rate
     17 y1993   0   0.90
enb3fc 1 coal, cost estimates above in 'coalfc'
     fc=lign
enb3om 1 O&M
     om=omn7

#
#
```

```
#    ************* COAL PLANTS *************
#
#          *** Vojany I, bl. 1,2
#
ev12cm 1 net capacity (three capacity states) - slow start unit
c ev12cp 1 net capacity (three capacity states) - slow start unit
####  27 y199301 50   75   100
# 5/2 SEP eff. curves
###   27 y199301 90   100   110  used in Phase 1
    27 y199301 80   90   100
ev12ha 1 average heat rates for each capacity state
####  27 y199301 13000 12000 11000
# 5/2 SEP eff. curves  (average for units 1 & 2)
    27 y199301 10850 10900 11100
ev12mu 1 number of units
    27 y199301 2
      y199701 2
      y199704 1 # Unit 1 off
      y199710 2 # Unit 1 on
      y199801 2
      y199804 1 # Unit 2 off
      y199810 2 # Unit 2 off
      y199901 2
ev12mr 1 annual requirement, model will schedule among months
    27 y199301 0.058
ev12fr 1 forced outage rate
    17 y1993  0 0 0.88
ev12fc ! coal, cost estimates above in 'coalfc'
    fc=coal
ev12om 1 O&M
    om=omnl

#
```

```
#          *** Vojany I   ,bl. 3,4
#

ev34cm 1 net capacity (three capacity states) - slow start unit
c ev34cp 1 net capacity (three capacity states) - slow start unit
# with rehabilitation   SEP
     27  y199301  90    95    100
        y200001  50    75    100
ev34ha 1 average heat rates for each capacity state
# new plant characteristics after 2000 with rehabilitation
#  5/2 SEP eff. curves
     27  y199301  11250  11300  11550
#  after rehabilitation ?
        y200001  10500  10000  9700
ev34mu 1 number of units with rehabilitation
# SEP May Plan
     27  y199301  2
        y199701  2
        y199710  1
        y199801  1
        y199807  0
        y199901  0
        y200001  0
        y200003  1
#       y201001  2  correction after Phase 1
        y200101  2
ev34mu 2 number of units with rehabilitation
# EdF May Plan
     27  y199301  2
        y199701  2
        y199710  1
        y199801  1
        y199807  0
        y199901  0
        y200001  0
        y200003  1
        y200101  2
ev34mr 1 annual requirement, model will schedule among months
     2   0.05
ev34fr 1 forced outage rate
     17  y1993    0    0   0.88
ev34fc 1 coal, cost estimates above in 'coalfc'
     fc=coal
ev34om 1 O&M
     om=omnl

#
```

```
#          *** Vojany I, bl. 5,6
ev56cm 2 net capacity (three capacity states) - slow start unit
c ev56cp 2 net capacity (three capacity states) - slow start unit
     27  y199301  90    95    100
ev56ha 2 average heat rates for each capacity state
     27  y199301  12850  12750  12650
ev56cm 1 net capacity (three capacity states) - slow start unit
# with rehabilitation
     27  y199301  90    95    100
        y199601  50    75    100
ev56ha 1 average heat rates for each capacity state
# with rehabilitation
#  5/2 SEP eff. curves until 96
     27  y199301  11250  11300  11550
# after rehabilitation
        y199601  10500  10000  9700  # ?
ev56mu 1 number of units  with rehabilitation
# SEP May Plan
#     27  y199301  1      #  Phase 1 correction
#        y199309  2      #  Phase 1 correction
     27  y199301  1
        y199309  0
        y199401  0
        y199601  0
        y199607  1
        y199610  2
        y199701  2
ev56mu 2 number of units  with rehabilitation
# EdF Plan
     27  y199301  1      #  y199308  1
        y199309  0
        y199401  0
        y199601  0
        y199607  1
        y199610  2
        y199701  2
ev56mr 2 annual requirement, model will schedule among months
     2    0.10
ev56fr 2 forced outage rate
     17  y1993    0   0  0.88
ev56mr 1 annual requirement, model will schedule among months
# with rehabilitation
     27  y199301  .058
        y200001  .163
        y200201  .058
        y200501  .163
ev56fr 1 forced outage rate
# with rehabilitation
     27  y199301  0   0  0.88
        y199404  0   0  0.88
        y199601  0   0  0.88
        y199607  0   0  0.93
        y199610  0   0  0.93
        y199701  0   0  0.93
```

```
ev56fc 1 coal, cost estimates above in 'coalfc'
     fc=coal
ev56om 1 O&M
     om=omn1

#
#  ************* OIL and GAS PLANTS *************
#
#          *** Vojany II bl. 21,22,23,24,
#

ev24cp 1 net capacity (two capacity states) - slow start unit
     27  y199301  65    88
ev24cp 2 net capacity (three capacity states) - slow start unit
     27  y199301  50    75    100
ev24ha 1 average heat rates for each capacity state
     27  y199301    12000  11000
ev24ha 2 average heat rates for each capacity state
     27  y199301  13000  12000  11000
ev24mu 1 number of units
# SEP May Plan
     27  y199301  4
ev24mr 1 annual requirement, model will schedule among months
     2   0.00
ev24fr 1 forced outage rate
     17  y1993  0   0.90
ev24fr 2 forced outage rate
     17  y1993  0   0   0.90
ev24fc 1
     fc=ngas
ev24om 1 O&M
     om=omn6
```

```
#       ************ GAS *************
#         *** Vojany II bl. 25,26
#

ev26cp 1 net capacity (two capacity states)
     27  y199301  65    88
ev26ha 1 average heat rates for each capacity state
     27  y199301  12000  11000
ev26mu 1 number of units
#  SEP May Plan
     27  y199301  0
        y199501  2
        y200201  0
ev26mu 2 number of units
#  EdF May Plan
     27  y199301  0
        y199501  2
ev26mr 1 annual requirement, model will schedule among months
#      2    0.15
     22  0 0 0 0 0 0 1 1 0 0 0 0
ev26fr 1 forced outage rate
     17  y1993   0   0.90
ev26fc 1
     fc=ngas
ev26om 1 O&M
     om=omn6
#
```

```
# Generic gas combined cycle

ppcscp 1 net capacity (three capacity states) - slow start unit
      27  y199301  100  200  300
ppcsha 1 average heat rates for each capacity state
      27  y199301  11000 11000 7200
ppcsmu 1 number of units with SEP May plan
      27  y199301  0
        y200201  0
        y200207  1
        y200301  1
        y200501  1
        y200507  2
        y200601  2
        y201001  3
ppcsmu 2 number of units
# EdF May Plan- high scenario
      27  y199301  0
        y199701  1
        y199706  2
        y199901  3
        y199906  4
        y200001  4
ppcsmu 3 number of units
# EdF May Plan- medium scenario
      27  y199301  0
        y200001  1
        y200006  2
        y200101  2
        y200501  3
        y200506  4
        y200601  4
ppcsmu 4 number of units
# EdF May Plan- low scenario
      27  y199301  0
        y200201  1
        y200206  2
        y200301  2
ppcsmu 5 number of units
# based on replacement of Mohovce 3 and 4 in Reference Plan
      27  y199301  0
        y200001  0
        y200010  1
        y200101  1
        y200107  2
        y200201  2
        y200207  3
        y200301  3
        y200501  3
        y200507  4
        y200601  4
        y201001  5
ppcsmu 6 number of units
# no additions
```

```
    27 y199301 0
ppcsmr 1 annual requirement, model will schedule among months
    2   0.10
ppcsfr 1 forced outage rate
    17 y1993 0  0 0.98
ppcsfc 1
    fc=ngas
ppcsom 1 O&M
    om=omn6
```

```
#       ************ COAL/GAS ********
#
# This is the SEP-owned Kosice combined heat and power project. It
# is made up of one 55 MW unit and one 66 MW unit.
#
# Separation of district heating plants (dist) in teko, dzse and dsse
# done by F.D. on 6/5/94
#
tekocm 1 varies on a monthly basis
#       J  F  M  A  M  J  J  A  S  O  N  D
     25 1.00 1.00 .63 .47 .25 .25 .25 .25 .25 .47 .47 .63
        y1993 121
tekoha 1
     2  7000
tekomr 1
#     2 .05  # used to avoid bug
     22 0 0 0 0 0 0 1 1 0 0 0 0
tekofr 1 forced outage rate
     2  0.10
tekofc 1
     fc=ngas
tekoom 1 O&M
     om=omn8
#
#     ********* NEW FOSSIL PLANTS ******
# COMBINED CYCLE AND COAL PLANT FOR ADDITION IN THE EDF CASES
coalcp 1 net capacity (two capacity states)
     27 y199301 300   450   600
coalha 1 average heat rates for each capacity state
     27 y199301 11000 10000  9500
coalmu 1 number of units
# SEP May Plan
     27 y199301 0
coalmu 2 number of units
# EdF May Plan- high scenario
     27 y199301 0
       y200401 1
       y200901 2
coalmr 1 annual requirement, model will schedule among months
     2   0.10
coalfr 1 forced outage rate
     17 y1993 0  0  0.94
coalfc 1
     fc=coal
coalom 1 O&M
     om=omn1
```

```
#     ********* INDUSTRY-OWNED PLANTS ******
#
#
# Industry generation is divided into industries served by RDUs and by
# SEP.
# Shape of generation is based on overall industry generation data from
# Zilina and collected by EGU. Growth was estimated by EGU. (Note: This
# does not correspond to the May 1994 SEP forecast.)
#
izsenl 1     # F.D. change from weekend constrained to non-firm 6/5/94
                 # typical industry output developed by EGU
     sh=indy

     # capacity= 232 MW from 1993 Annual Report on Electic Energy
     # Consumption, adjusted to meet SEP projected output (INDUSTRY.WK1)

#     ZSE- territory
      17       y1993     106.6
               y1994     105.2
               y1995     103.8
               y1996     102.8
               y1997     101.9
               y1998     100.5
               y1999      98.2
               y2000      95.8
               y2001      92.6
               y2002      89.3
               y2003      86.0
               y2004      82.7
               y2005      79.5
               y2006      77.6
               y2007      75.7
               y2008      73.9
               y2009      72.0
               y2010      70.1

izsenl 2     no generation from industry for avoided cost analysis
     sh=indy
      17       y1993     0.0

izsefc 1
     fc=avod

#
issenl 1     # F.D. change from weekend constrained to non-firm 6/5/94
                 # typical industry output developed by EGU
     sh=indy

     # capacity= 146 MW from 1993 Annual Report on Electic Energy
     # Consumption, adjusted to meet SEP projected output (INDUSTRY.WK1)
```

```
#     SSE- territory
      17      y1993     67.0
              y1994     66.2
              y1995     65.3
              y1996     64.7
              y1997     64.1
              y1998     63.2
              y1999     61.8
              y2000     60.3
              y2001     58.2
              y2002     56.2
              y2003     54.1
              y2004     52.0
              y2005     50.0
              y2006     48.8
              y2007     47.6
              y2008     46.5
              y2009     45.3
              y2010     44.1

issenl 2    no generation from industry for avoided cost analysis
    sh=indy
     17      y1993     0.0

issefc 1
    fc=avod

#
ivsenl 1    # F.D. change from weekend constrained to non-firm 6/5/94
                # typical industry output developed by EGU
    sh=indy

    # capacity= 159 MW from 1993 Annual Report on Electic Energy
    # Consumption, adjusted to meet SEP projected output (INDUSTRY.WK1)
```

```
#     VSE- territory
      17      y1993     73.1
              y1994     72.1
              y1995     71.1
              y1996     70.5
              y1997     69.9
              y1998     68.9
              y1999     67.3
              y2000     65.7
              y2001     63.4
              y2002     61.2
              y2003     59.0
              y2004     56.7
              y2005     54.5
              y2006     53.2
              y2007     51.9
              y2008     50.6
              y2009     49.3
              y2010     48.1

ivsenl 2     no generation from industry for avoided cost analysis
     sh=indy
      17      y1993     0.0

ivsefc 1
     fc=avod

#
```

```
isepnl 1     # F.D. change from weekend constrained to non-firm 6/5/94
                 # typical industry output developed by EGU
     sh=indy

     # capacity= 223 MW from 1993 Annual Report on Electic Energy
     # Consumption, adjusted to meet SEP projected output (INDUSTRY.WK1)
#    This made up of
#
#              Industry        Capacity
#
#              VSZ Kosice        177
#              Duslo Sala        46
#
#    SEP served customers
     17     y1993     102.4
            y1994     101.0
            y1995     99.7
            y1996     98.8
            y1997     97.9
            y1998     96.5
            y1999     94.3
            y2000     92.0
            y2001     88.9
            y2002     85.7
            y2003     82.6
            y2004     79.5
            y2005     76.3
            y2006     74.5
            y2007     72.7
            y2008     70.9
            y2009     69.1
            y2010     67.4

isepnl 2     no generation from industry for avoided cost analysis
     sh=indy
     17     y1993     0.0

isepfc 1
     fc=avod
```

indysh 1 typical industry generation output

29 y199301 mon 310 308 306 312 315 330 330 330 330 328 330 327
327 329 329 331 332 333 333 331 331 327 325 323
tue 324 321 323 321 323 331 332 330 328 330 329 329
332 332 333 332 333 334 331 332 332 329 325 326
wed 325 324 325 325 326 334 335 334 334 331 328 331
330 332 332 333 333 332 334 334 336 331 329 328
thu 328 327 328 327 326 338 335 335 337 336 337 335
335 333 332 334 334 333 334 334 335 327 326 325
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```
#  ************ DISTRIBUTION-OWNED PLANTS *************
#

#  Tp Komarno
# This is a potential project. It is not considered for the Case Study
# demonstration based on the uncertainty of project future and the
# small electric capacity. (Agreed on in discussion between Bechtel and
# EGU on October 27, 1993).

komrcm 1 net capacity (two capacity states) - slow start unit
     27  y199301  5     6
komrha 1 average heat rates for each capacity state
     27  y199301  13000  12000
komrmu 1 number of units
     27  y199301  0
komrmr 1 annual requirement, model will schedule among months
     2    0.15
komrfr 1 forced outage rate
     27 y1993  0   0.90
komrfc 1
     fc=resd
komrom 1 O&M
     om=omn1

# Other Distibution-Owned Plants

# This group of units is modeled assuming that units cannot operate if
# they are not delivering heat. Heat delivery is assumed to be 50% of the
# time for May and September and 100% of the time for Jan-Mar. and Oct.-
# Dec. SEP-owned TEKO project is modeled in the same way.
# Monthly capacity is based on heating requirements. Remaining capacity
# is assumed not to be dispatchable (Meeting Bechtel/EGU October 27, 1993).
# It is modeled as non-firm capacity, so does not count toward commitment
# and spinning reserve.
# Does not include 120 MW owned by SEP having similar district heating
# characteristics (TEKO at Kosice).
#
#
```

```
# ZSE owned capacity. This includes
#
#          Name            Capacity (MW)
#
#          Bratislava I        14
#          Bratislava II       20
#          Bratislava III       6
#          Bratislava West        25
#          Trnava              12
#                            --
#          Total               77
#
# The Trnava plant had a major outage at the beginning of 1994 and is
# assumed to not be replaced.
#
dzselm 1 varies on a monthly basis

       sh=dist

#       ZSE-owned generation
     17       y1993     139.4
              y1994     142.7
              y1995     145.3
              y1996     153.4
              y1997     349.7
              y1998     349.7
              y1999     351.0
              y2000     351.0
              y2001     351.0
              y2002     351.0
              y2003     351.0
              y2004     351.0
              y2005     358.4
              y2006     358.4
              y2007     358.4
              y2008     358.4
              y2009     358.4
              y2010     358.4

dzselm 2 no generation for avoided cost analysis

       sh=dist

     17       y1993     0.0

dzsefc 1
     fc=avod
#
```

```
# SSE owned capacity. This includes
#
#          Name          Capacity (MW)
#
#          Martin          47
#          Zvolen          35
#          Zilina          49
#                         --
#          Total          131
#
dsselm 1 varies on a monthly basis

        sh=dist

#       SSE-owned generation
     17       y1993     158.0
              y1994     161.8
              y1995     164.7
              y1996     173.9
              y1997     396.5
              y1998     396.5
              y1999     397.9
              y2000     397.9
              y2001     397.9
              y2002     397.9
              y2003     397.9
              y2004     397.9
              y2005     406.3
              y2006     406.3
              y2007     406.3
              y2008     406.3
              y2009     406.3
              y2010     406.3

dsselm 2 no generation for avoided cost analysis

        sh=dist

     17       y1993     0.0

dssefc 1
     fc=avod
#
```

```
distsh 1 typical distribution-owned generation output
    29    y199301 mon   80    70    60    50    40    50
                  60    70    80    70    60    50
                  40    30    30    40    50    60
                  70    80    90   100   100   100
          y199302 mon   80    70    60    50    40    50
                  60    70    80    70    60    50
                  40    30    30    40    50    60
                  70    80    90   100   100   100
          y199303 mon    0     0     0     0     0     0
                   0     0     0     0     0     0
                   0     0     0     0     0     0
                   0     0     0     0     0     0
          y199304 mon    0     0     0     0     0     0
                   0     0     0     0     0     0
                   0     0     0     0     0     0
                   0     0     0     0     0     0
          y199305 mon    0     0     0     0     0     0
                   0     0     0     0     0     0
                   0     0     0     0     0     0
                   0     0     0     0     0     0
          y199306 mon    0     0     0     0     0     0
                   0     0     0     0     0     0
                   0     0     0     0     0     0
                   0     0     0     0     0     0
          y199307 mon    0     0     0     0     0     0
                   0     0     0     0     0     0
                   0     0     0     0     0     0
                   0     0     0     0     0     0
          y199308 mon    0     0     0     0     0     0
                   0     0     0     0     0     0
                   0     0     0     0     0     0
                   0     0     0     0     0     0
          y199309 mon    0     0     0     0     0     0
                   0     0     0     0     0     0
                   0     0     0     0     0     0
                   0     0     0     0     0     0
          y199310 mon    0     0     0     0     0     0
                   0     0     0     0     0     0
                   0     0     0     0     0     0
                   0     0     0     0     0     0
          y199311 mon   80    70    60    50    40    50
                  60    70    80    70    60    50
                  40    30    30    40    50    60
                  70    80    90   100   100   100
          y199312 mon   80    70    60    50    40    50
                  60    70    80    70    60    50
                  40    30    30    40    50    60
                  70    80    90   100   100   100
#
```

```
# HYDRO PLANTS *************
#
# UPDATED 4.11.1993 BIRO
#          *** Vah Cascade
#          *** without pumped storage Cerny Vah
#
vahchc 1 capacity varies by month
     25     .728 .702 .939 1.000 .886 .781
            .649 .588 .500 .500 .737 .754
c total capacity (MW)
       y1993  560    # M.B. 11/11/93
#      y1993  1550    # F.D. 6/5/94 based on 1993 Annual Report Phase 1
vahchm 1 minimum flow varies by month
     25     .728 .702 .939 1.000 .886 .781
            .649 .588 .500 .500 .737 .754
c total minimum flow (MW)
       y1993  50        # Lowered based on Ursiny/Fronc 8/2/94
#      y1993  133        # Phase 1
vahche 1 AVERAGE YEAR - energy varies by month
     20 0.083 0.080 0.107 0.114 0.101 0.089
        0.074 0.067 0.057 0.057 0.084 0.086
c total energy (GWh)
       y1993  1834       # average
#      y1993  1500        # 1993 level F.D. 6/5/94       used in
                     # used for comparison with 93    Phase 1
vahche 2 DRY YEAR - energy varies by month
     20 0.083 0.080 0.107 0.114 0.101 0.089
        0.074 0.067 0.057 0.057 0.084 0.086
c total energy (GWh)
       y1993  1205       # Based on fax from Argia 9/20/94

vahcfc 1 no variable cost for hydro energy
    /kwh 2 0.0

#
#          *** Gabcikovo 61.8 % for Slovakia
#
gabchc 1 capacity varies by month
     25   0.54  0.58  0.71  0.88   1.00  1.00
          0.93  0.79  0.58  0.47   0.43  0.55
c total capacity (MW)
# This represent effective capacity reflect run-of-river operation
# and lack of reservoir.
       y1993  375     # based on discussion with Ursiny/Fronc 8/2/94
# changed from 300 to 375 to accomodate for energy M.B. 9/19/94
#      y1993  450     used in Phase 1 analysis
gabchc 2 DRY YEAR - varies by month
     25   0.54  0.58  0.71  0.88   1.00  1.00
          0.93  0.79  0.58  0.47   0.43  0.55
c total capacity (MW)
# Ratio used for DRY year
       y1993  270
gabchm 1 capacity varies by month
     25   0.54  0.58  0.71  0.88   1.00  1.00
```

```
          0.93  0.79  0.58  0.47   0.43  0.55
c minimum capacity (MW)
       y1993  180      # based on discussion with Ursiny/Fronc 8/2/94
#      y1993  340      # Phase 1
gabchm 2 capacity varies by month
      25   0.54  0.58  0.71  0.88   1.00  1.00
          0.93  0.79  0.58  0.47   0.43  0.55
c minimum capacity (MW)
       y1993  130      # Ratio used for DRY year
gabche 1 AVERAGE YEAR - energy varies by month
c average flow and total consumption from Mr.Vladimir Ondrusek
      20 0.064 0.069 0.084 0.104 0.118 0.118
        0.110 0.093 0.068 0.056 0.051 0.065
c total energy (GWh)
     y1993  1900  # based on discussion with Ursiny/Fronc 8/2/94
     y1994  2100  # based on discussion with Ursiny/Fronc 8/2/94
     y1996  1300  # based on discussion with Ursiny/Fronc 8/2/94

                  # Ondrusek data
#    y1993  1900
#    y1994  2173  # udaj V.Ondrusek ak prietok vody do stareho
                  # koryta bude 400 m3/s

gabche 2 DRY YEAR - energy varies by month
c average flow and total consumption from Mr.Vladimir Ondrusek
      20 0.064 0.069 0.084 0.104 0.118 0.118
        0.110 0.093 0.068 0.056 0.051 0.065
c total energy (GWh)
     y1993  1365  # based on fax from Argia 9/20/94
     y1994  1505  # used same ratio 1725/2405=x/1900..2100..1300
     y1996  932   #
gabcfc 1 no variable cost for hydro energy
     /kwh  2  0.0

#
```

```
#    *********** Other Hydro ***********
#

hydrhc 1 capacity varies by month
     25     .728 .702 .939 1.000 .886 .781
            .649 .588 .500 .500 .737 .754
c total capacity (MW)
#        y1993  40    # used for 1993 planning analysis
         y1993  96    # F.D. 6/5/93 based on 1993 Annual Report
hydrhm 1 minimum flow varies by month
     25     1.00 1.00 1.00 1.00 1.00 1.00
            1.00 1.00 1.00 1.00 1.00 1.00
c total minimum flow (MW)
         y1993  2
hydrhe 1 energy varies by month
     20 0.083 0.080 0.107 0.114 0.101 0.089
          0.074 0.067 0.057 0.057 0.084 0.086
c total energy (GWh)
#        y1993  71         # average
         y1993  56         # 1993 level F.D. 6/5/94
hydrfc 1 no variable cost for hydro energy
     /kwh 2  0.0
#
#          *** All Pumped Storage Plants
#
pscap  1 unit 1 generating capacity (MW)
#     2  735
     2  600  # This should be changed to 600 MW to reflect
             # operational constraints (discussion with Ursiny,
             # Fronz, 8/2/94)
pseff  1 efficiency (.72 gWh generation for every gWh pumped)
     2  .72
psres  1 reservoir size (gWh)
     2  350
#
#
```


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```
#          *** Import Power

#          First Variant - No Imports
imp1cn 1
     25 . .8817 .8925 .9032 .9032  .9140 .9570
          .9140 .9140 1.0000 1.0000  .9784 1.0000
c total capacity (MW)
       y1993    0
#
#          *** Emergency Import Power
#

imp2cp 1  # change from non-firm to firm by F.D. 6/5/94 based on
#         on discussions with SEP indicating emergency imports
#         are used to meet largest contingency outage.
     25    .8817 .8925 .9032 .9032  .9140 .9570
          .9140 .9140 1.0000 1.0000  .9784 1.0000
c total capacity (MW)
       y1993    300
imp2fr 1 no forced outage rate
     2  0
imp2mr 1 no maintenance
     2  0
imp2fc 1 cost for imported energy - cost estimates above in 'impefc'
     fc=impe
#
#          *** Export Power
#
#   First Variant - SEP Projection of Exports
exptlm 1
# Exports model by load modification based on the following sales
# assumptions.

     sh=expt

# total sales (GWh)
#     17  y1993  -410
#         y1994    -0
#         y1995  -225
#         y1996  -457
#         y1997 -2500
#         y1998 -3500
#         y1999 -3000
#         y2000 -2500
#         y2001 -2100
#         y2002 -1900
#         y2003 -1800
#         y2004 -1600
#         y2005 -1560
#         y2006 -1300
#         y2007 -1100
#         y2008 -1100
#         y2009 -1100
#         y2010 -1100
```


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Appendix D Base Case Production Simulation Results

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NOTE: The Elfin computer model is confidential and proprietary. USE IS RESTRICTED.

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EDF must be identified clearly as the designer and owner of the Elfin model in any work product derived from use of the Elfin model that may be seen by third parties.

```
Version 1.98
Licensed to Bechtel Corporation.
Serial number: 0603
Generation model only.
Maximum number of generation plants: 225.
Optimized for 8087, which is required.
# COMMAND FILE FOR THE VARIANT 1 - REFERENCE CASE
beggen94 -- reset beginning of generation simulation to 1994
lastyr 5 -- Reset last year of simulation to 2005
tbldef 1 ebo1-en 'Bohunice V-1'
tbldef 1 ebo2-en 'Bohunice V-2'
tbldef 1 emo1-en 'Mohovce 1'
tbldef 1 emo2-en 'Mohovce 2'
tbldef 1 ev12-en 'Vojany 1 1-2'
tbldef 1 ev34-en 'Vojany 1 3-4'
tbldef 1 ev56-en 'Vojany 1 5-6'
tbldef 1 ev24-en 'Vojany 2 1-4'
tbldef 1 ev26-en 'Vojany 2 5-6'
tbldef 1 ena1-en 'Novaky A 1-2'
tbldef 1 ena3-en 'Novaky A 3'
tbldef 1 ena4-en 'Novaky A 4'
tbldef 1 enar-en 'Novaky A New'
tbldef 1 enb1-en 'Novaky B 1a'
tbldef 1 enbh-en 'Novaky B 1b'
tbldef 1 enb2-en 'Novaky B 2'
tbldef 1 enb3-en 'Novaky B 3'
tbldef 1 teko-en 'TEKO-Kosice'
tbldef 1 vahc-en 'Vah Cascade'
tbldef 1 gabc-en 'Gabcikovo'
tbldef 1 hydr-en 'Other hydro'
tbldef 1 ppcs-en 'Generic GCC'
tbldef 1 izse-en 'Ind-ZSE'
tbldef 1 isse-en 'Ind-SSE'
tbldef 1 ivse-en 'Ind-VSE'
tbldef 1 isep-en 'Ind-SEP'
tbldef 1 dzse-en 'RDU-ZSE'
tbldef 1 dsse-en 'RDU-SSE'
```

```
tbldef 1 brat-en 'Tp Bratislava'
tbldef 1 komr-en 'Tp Komarno'
tbldef 1 senn-en 'Senne GCC'
tbldef 1 kosc-en 'Kosice GCC'
tbldef 1 ziln-en 'Zilina GCC'
tbldef 1 mart-en 'Martin GCC'
tbldef 1 ziar-en 'Ziar GCC'
tbldef 1 prsv-en 'Presov GCC'
tbldef 1 vojn-en 'Vojany GCC'
tbldef 1 gast-en 'Simple Cycle'
tbldef 1 dsmr-en 'DSM'
tbldef 1 intr-en 'Interruptible'
tbldef 1 imp1-en 'Imports'
tbldef 1 imp2-en 'Emergency'
tbldef 1 expt-en 'Exports'
tbldef 1 ebo1-varc 'Bohunice V-1'
tbldef 1 ebo2-varc 'Bohunice V-2'
tbldef 1 emo1-varc 'Mohovce 1'
tbldef 1 emo2-varc 'Mohovce 2'
tbldef 1 ev12-varc 'Vojany 1 1-2'
tbldef 1 ev34-varc 'Vojany 1 3-4'
tbldef 1 ev56-varc 'Vojany 1 5-6'
tbldef 1 ev24-varc 'Vojany 2 2-4'
tbldef 1 ev26-varc 'Vojany 2 5-6'
tbldef 1 ena1-varc 'Novaky A 1-2'
tbldef 1 ena3-varc 'Novaky A 3'
tbldef 1 ena4-varc 'Novaky A 4'
tbldef 1 enar-varc 'Novaky A New'
tbldef 1 enb1-varc 'Novaky B 1a'
tbldef 1 enbh-varc 'Novaky B 1b'
tbldef 1 enb2-varc 'Novaky B 2'
tbldef 1 enb3-varc 'Novaky B 3'
tbldef 1 teko-varc 'TEKO-Kosice'
tbldef 1 vahc-varc 'Vah Cascade'
tbldef 1 gabc-varc 'Gabcikovo'
tbldef 1 hydr-varc 'Other hydro'
tbldef 1 ppcs-varc 'Generic GCC'
tbldef 1 izse-varc 'Ind-ZSE'
tbldef 1 isse-varc 'Ind-SSE'
tbldef 1 ivse-varc 'Ind-VSE'
tbldef 1 isep-varc 'Ind-SEP'
tbldef 1 dzse-varc 'RDU-ZSE'
tbldef 1 dsse-varc 'RDU-SSE'
tbldef 1 brat-varc 'Tp Bratislava'
tbldef 1 komr-varc 'Tp Komarno'
tbldef 1 senn-varc 'Senne GCC'
tbldef 1 kosc-varc 'Kosice GCC'
tbldef 1 ziln-varc 'Zilina GCC'
tbldef 1 mart-varc 'Martin GCC'
tbldef 1 ziar-varc 'Ziar GCC'
tbldef 1 prsv-varc 'Presov GCC'
tbldef 1 vojn-varc 'Vojany GCC'
tbldef 1 gast-varc 'Simple Cycle'
```

```
tbldef 1 dsmr-varc 'DSM'
tbldef 1 intr-varc 'Inter. Load'
tbldef 1 imp1-varc 'Imports'
tbldef 1 imp2-varc 'Emergency'
tbldef 1 expt-varc 'Exports'
tbldef 1 sys-load 'Total load'
tbldef 1 sys-sstc 'Total System'
tbldef 1 sys-sfcs 'Total Fuel'
tbldef 1 sys-somc 'Variable O&M'
tbldef 1 sys-cens 'ENS cost'
tbldef 1 sys-ens 'ENS'
tbldef 1 sys-lolp 'LOLP'
tbldef 1 sys-endu 'Dump energy'
tbldef 1 sys-mc 'Marginal Cost'
tbldef 1 izse-cp 'Ind-owned-ZSE'
tbldef 1 isse-cp 'Ind-owned-SSE'
tbldef 1 ivse-cp 'Ind-owned-VSE'
tbldef 1 isep-cp 'Ind-owned-SEP'
tbldef 1 dzse-cp 'RDU-owned-ZSE'
tbldef 1 dsse-cp 'RDU-owned-SSE'
npwks    -- No weekly tables will be printed.
prgen ann
# prgen  1 2 3 4 5 6 7 8 9 10 11 12 ann # Print annual generation tables
pranmc   -- End of year Marginal Cost, LOLP and  ENS tables will be printed.
c prspgn                    # Print subperiod generation tables in
npspgn   -- Tables of unit-by-unit generation by subperiod will NOT be printed.
c premis 1                # Print annual emissions tables
npspem   -- Subperiod emissions tables will NOT be printed.
npemgs   -- Summary tables of emissions (GENSUM) will NOT be printed.
npspgs   -- Summary tables of generation by subperiod (GENSUM) will NOT be printed.
maxerr   -- Maximum number of errors allowed set to  500.
usemla   -- Mono-linear load scaling algorithm will be used.
# prpic
# Perform the simulation
mrordr 1                                                    - overall must-run order
# mrordr 2    # unconstrained
# exptlm 2    #no exports
avodfc 3                                                    - avoided cost for industry and distribution-owned plants
rungen   -- begin run number  1--    Scenario 1- SEP May 1994 Plan- with industrial and RDU generation, wit
```

Load Summary and Maintenance Allocation -- 1994

		Raw load data				Load data scaled to match weekly input requirements				Load data after demand side modifications			Gross firm capacity and maintenance allocation						Remaining load after exogenous load modifications			
Typ. Wk	Hrs.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Gross cap. (MW)	Res. mar. (Pct)	Maint cap. (MW)	Net cap. (MW)	Res. mar. (Pct)	Maint fac.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)
1	744	2157	3352	2287	86.5	2063	3307	2051	83.8	2063	3307	2051	4552	37.6	12	4540	37.3	0.000	1697	2815	1561	81.0
2	672	1927	3242	2296	88.5	1843	3198	2048	85.8	1843	3198	2048	4606	44.0	18	4589	43.5	0.000	1516	2657	1557	84.9
3	744	2058	3129	2251	88.4	1970	3089	2023	85.7	1970	3089	2023	4654	50.7	444	4210	36.3	0.000	1763	2774	1736	85.4
4	720	1853	3053	2044	84.3	1772	3013	1851	81.7	1772	3013	1851	4745	57.5	485	4260	41.4	0.000	1596	2737	1596	81.0
5	744	1731	2669	1912	87.1	1656	2930	1376	76.0	1656	2930	1376	4692	60.1	579	4114	40.4	0.000	1500	2704	1150	74.6
6	720	1672	2694	1836	86.2	1600	2560	1781	86.8	1600	2560	1781	4634	81.0	483	4150	62.1	5.000	1456	2558	1571	79.1
7	744	1592	2562	1733	83.5	1523	2527	1586	81.0	1523	2527	1586	4508	78.4	466	4042	60.0	5.000	1389	2526	1394	73.9
8	744	1698	2720	1721	83.9	1624	2685	1539	81.3	1624	2685	1539	4415	64.4	454	3961	47.5	1.935	1482	2683	1339	74.2
9	720	1710	2838	1895	83.7	1637	2801	1725	81.2	1637	2801	1725	4307	53.8	284	4023	43.6	0.000	1493	2580	1516	80.4
10	744	1918	3071	1949	83.9	1835	3029	1749	81.4	1835	3029	1749	4285	41.5	431	3854	27.2	0.000	1652	2748	1491	80.8
11	720	2041	3286	2203	86.3	1953	3241	1974	83.7	1953	3241	1974	4574	41.1	22	4552	40.5	0.000	1611	2777	1497	80.6
12	744	2124	3307	2232	86.3	2033	3264	2000	83.7	2033	3264	2000	4661	42.8	12	4649	42.4	0.000	1671	2787	1504	80.6
AN	8760	22479	3352	1721	76.6	21508	3307	1376	74.2	21508	3307	1376							18826	2815	1150	76.3

S u m m a r y (gensum) -- A n n u a l g e n e r a t i o n 1994

	Peak capacity MW	Week Units	Com-mit. %	-Outage- FOR %	MOR %	-------Energy------- GWh Load	Pump	Dump	Total	Cap. fac. %	Fuel tr. btu	Btu /kWh	Fuel $/ Mbtu	--Variable--- mills/kWh Fuel	O&M	Tot.	-Marginal- time %	mills /kWh	-------M$------- Other O&M	Fuel + var O&M
Nuclear	1640	4	100	5.0	13.5	11546	188	0	11733	81.7	137	11655	0.45	5.2	0.2	5.4	1.07	5.1	0.00	63.94
Lignite	342	7	21.3z	9.1	12.8	504	2	0	506	17.1	6.8	13478	2.30	31.0	0.2	31.2	4.01	28.6	0.00	15.79
Coal	521	5	73.9	11.5	8.1	2244	68	0	2312	57.5	24.0	10386	1.81	18.8	1.0	19.8	1.15	21.4	0.00	45.89
Gas- power	352	4		10.0	0.0	414	0	0	414	13.4	4.6	11046	3.46	38.2	0.3	38.5	11.48	38.3	0.00	15.94
Hydro	680	3		0.0	0.0	3957	27	6	3990	61.2	0.0	0	0.00	0.0	0.0	0.0	37.71	27.0	0.00	0.00
Industry	339	0		0.0	0.0	2123	0	0	2123	111	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	105.52
Distribution	152	0		0.0	0.0	559	0	0	559	117	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	27.79
DSM.	0	0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Interruptible	0	0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Import/Export	265	1		0.0	0.0	1	0	0	1	0.0	0.0	0	0.00	54.4	0.0	54.4	0.07	54.4	0.00	0.03
Pumped storage	600					160			160	3.0							11.58	29.9		
(pumping nec.)	(600)						(223)										32.94	22.2		
Total firm 4552 + CS =	4552		37.6%	reserv		21508	285	6	21799		172.2					12.6	100.0	26.8	0.00	274.90
Committed 4152 =	4152		25.6%		ENS		0.0318		LOLP 0.000040		(0.015 days)		Energy Not Served				0.00	50.0		0.00
after MOR 4141 =	4141		25.2%				==========		Commit target		3638 MW 10.0%		Avg. Marginal Cost					26.8		=====
after FOR 3977yy =	3977		20.3%		Load	21508 GWh			Spin. target		331 MW 10.0%			-- based on RC				26.8		274.90
post-DS Peak (4pm Tue)	3307			Fuel $269.96			- Dump 0.00		+ O&M 4.94		+ ENS 0.00 = Total var.					$274.90	+ Other		0.00 =	$274.90

* Values from last typical week.
z Commitment reflects must-run and minimum-constrained units -- others excluded from capacity-weighted average.
yy Available capacity meets commitment target.

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S E A S O N A L S U M M A R Y -- A v e r a g e M a r g i n a l C o s t s by season and subperiod (mills/kWh)

Subperiod	Annual	Season Q1	Q2	Q3	Q4
1	28.1	30.6	18.6	29.6	33.7
2	28.3	30.7	18.2	29.8	34.3
3	26.2	29.7	16.8	26.6	31.6
4	25.0	27.0	16.1	26.0	30.9
5	25.0	28.6	16.0	24.9	30.4
Average	26.8	29.5	17.3	27.8	32.6

L o s s o f l o a d p r o b a b i l i t y (%)

1	0.0051	0.0025	0.0002	0.0063	0.0115
2	0.0087	0.0054	0.0003	0.0057	0.0232
3	0.0013	0.0030	0.0001	0.0003	0.0017
4	0.0000	0.0000	0.0000	0.0000	0.0001
5	0.0001	0.0003	0.0000	0.0000	0.0002
Average	0.0040	0.0030	0.0001	0.0029	0.0101

E n e r g y n o t s e r v e d (GWh)

1	0.0041	0.0006	0.0000	0.0013	0.0023
2	0.0255	0.0044	0.0001	0.0042	0.0168
3	0.0020	0.0013	0.0000	0.0001	0.0006
4	0.0000	0.0000	0.0000	0.0000	0.0000
5	0.0001	0.0000	0.0000	0.0000	0.0000
Total	0.0318	0.0063	0.0002	0.0056	0.0197

Load Summary and Maintenance Allocation -- 1995

		Raw load data				Load data scaled to match weekly input requirements				Load data after demand side modifications			Gross firm capacity and maintenance allocation						Remaining load after exogenous load modifications			
Typ. Wk	Hrs.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Gross cap. (MW)	Res. mar. (Pct)	Maint cap. (MW)	Net cap. (MW)	Res. mar. (Pct)	Maint fac.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)
1	744	2157	3352	2287	86.5	2058	3304	2041	83.7	2058	3304	2041	4796	45.1	12	4784	44.8	0.000	1712	2840	1578	81.0
2	672	1927	3242	2296	88.5	1839	3195	2038	85.7	1839	3195	2038	4853	51.9	231	4622	44.7	0.000	1529	2680	1573	84.9
3	744	2058	3129	2251	88.4	1966	3086	2013	85.6	1966	3086	2013	4797	55.4	423	4374	41.7	0.000	1780	2801	1756	85.4
4	720	1853	3053	2044	84.3	1768	3010	1843	81.6	1768	3010	1843	4890	62.5	524	4366	45.0	0.000	1614	2764	1617	81.1
5	744	1731	2669	1912	87.1	1653	2927	1369	75.9	1653	2927	1369	4837	65.2	555	4282	46.3	1.936	1517	2730	1171	74.7
6	720	1672	2694	1836	86.2	1597	2557	1773	86.7	1597	2557	1773	4779	86.9	585	4193	64.0	5.000	1473	2581	1591	79.3
7	744	1592	2562	1733	83.5	1520	2524	1579	80.9	1520	2524	1579	4653	84.3	769	3884	53.9	5.000	1407	2549	1416	74.2
8	744	1698	2720	1721	83.9	1620	2683	1532	81.2	1620	2683	1532	4560	70.0	649	3911	45.8	0.000	1500	2707	1360	74.5
9	720	1710	2838	1895	83.7	1633	2798	1718	81.1	1633	2798	1718	4452	59.1	637	3814	36.3	0.000	1510	2606	1537	80.5
10	744	1918	3071	1949	83.9	1831	3026	1740	81.3	1831	3026	1740	4428	46.3	518	3910	29.2	0.000	1669	2775	1512	80.9
11	720	2041	3286	2203	86.3	1949	3238	1964	83.6	1949	3238	1964	4719	45.8	431	4288	32.4	0.000	1626	2801	1514	80.6
12	744	2124	3307	2232	86.3	2028	3261	1990	83.6	2028	3261	1990	4805	47.4	91	4714	44.6	0.000	1686	2811	1521	80.6
AN	8760	22479	3352	1721	76.6	21462	3304	1369	74.2	21462	3304	1369							19023	2840	1171	76.5

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S u m m a r y (gensum) -- A n n u a l g e n e r a t i o n 1995

	Peak capacity MW	Week	Un it s	Com- mit. %	-Outage- FOR %	MOR %	-------Energy------- GWh Load	Pump	Dump	Total	Cap. fac. %	Fuel tr. btu	Btu /kWh	Fuel $/ Mbtu	--Variable--- mills/kWh Fuel	O&M	Tot.	-Marginal- time %	mills /kWh	-------M$------- Other O&M	Fuel + var O&M
Nuclear	1640		4	100	5.0	20.7	10689	123	0	10811	75.3	126	11651	0.50	5.8	0.2	6.0	0.58	5.6	0.00	65.19
Lignite	433		8	6.7z	9.9	13.0	551	12	0	563	14.9	6.5	11571	2.53	29.3	0.2	29.4	2.67	31.5	0.00	16.57
Coal	521		5	90.3	11.5	8.1	2841	45	0	2886	71.7	30.6	10608	1.84	19.5	1.0	20.6	0.95	22.4	0.00	59.38
Gas- power	528		6		10.0	5.7	834	18	0	852	18.4	9.4	11046	3.70	40.9	0.3	41.1	18.24	41.0	0.00	35.05
Hydro	680		3		0.0	0.0	3973	17	0	3990	61.2	0.0	0	0.00	0.0	0.0	0.0	39.27	36.4	0.00	0.00
Industry	335		0		0.0	0.0	2095	0	0	2095	111	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	104.11
Distribution	155		0		0.0	0.0	569	0	0	569	117	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	28.29
DSM.	0		0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Interruptible	0		0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Import/Export	239		1		0.0	0.0	-225	0	0	-225	-10.0	0.0	0	0.00	43.2	0.0	43.2	0.03	65.9	0.00	-9.71
Pumped storage	600						135			135	2.6							8.56	37.3		
(pumping nec.)	(600)							(188)										29.68	26.9		
Total firm	4796 + CS =		4796	45.1%	reserv		21462	214	0	21676	172.5						13.8	100.0	34.0	0.00	298.88
Committed	4284 =		4284	29.7%		ENS	0.0123		LOLP 0.000017 (0.006 days) Energy Not Served									0.00	50.0		0.00
after MOR	4273 =		4273	29.3%		==========			Commit target 3634 MW 10.0% Avg. Marginal Cost										34.0		=====
after FOR	4091yy =		4091	23.8%	Load		21462 GWh		Spin. target 330 MW 10.0% -- based on RC										34.0		298.88
post-DS Peak (4pm Tue)	3304				Fuel $293.33		- Dump 0.00		+ O&M 5.55 + ENS 0.00 = Total var. $298.88 + Other											0.00 =	$298.88

* Values from last typical week.
z Commitment reflects must-run and minimum-constrained units -- others excluded from capacity-weighted average.
yy Available capacity meets commitment target.

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S E A S O N A L S U M M A R Y -- A v e r a g e M a r g i n a l C o s t s by season and subperiod (mills/kWh)

Subperiod	Annual	Season Q1	Q2	Q3	Q4
1	35.6	38.8	27.4	33.5	42.9
2	35.6	38.7	27.4	33.1	43.1
3	33.4	37.7	25.5	30.5	39.9
4	31.9	34.3	24.0	30.3	38.9
5	32.3	36.1	24.6	29.4	39.0
Average	34.0	37.4	26.1	31.6	41.1

L o s s o f l o a d p r o b a b i l i t y (%)

1	0.0015	0.0009	0.0001	0.0004	0.0045
2	0.0040	0.0027	0.0001	0.0020	0.0109
3	0.0004	0.0010	0.0000	0.0000	0.0006
4	0.0000	0.0000	0.0000	0.0000	0.0000
5	0.0000	0.0001	0.0000	0.0000	0.0000
Average	0.0017	0.0013	0.0000	0.0008	0.0046

E n e r g y n o t s e r v e d (GWh)

1	0.0011	0.0002	0.0000	0.0001	0.0009
2	0.0105	0.0019	0.0000	0.0012	0.0074
3	0.0006	0.0004	0.0000	0.0000	0.0002
4	0.0000	0.0000	0.0000	0.0000	0.0000
5	0.0000	0.0000	0.0000	0.0000	0.0000
Total	0.0123	0.0025	0.0001	0.0013	0.0084

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Load Summary and Maintenance Allocation -- 1996

		Raw load data				Load data scaled to match weekly input requirements				Load data after demand side modifications			Gross firm capacity and maintenance allocation						Remaining load after exogenous load modifications			
Typ. Wk	Hrs.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Gross cap. (MW)	Res. mar. (Pct)	Maint cap. (MW)	Net cap. (MW)	Res. mar. (Pct)	Maint fac.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)
1	744	2157	3352	2287	86.5	2094	3358	2082	83.8	2094	3358	2082	4773	42.1	262	4511	34.3	0.000	1762	2915	1638	81.2
2	696	1996	3242	2296	88.5	1938	3247	2080	85.8	1938	3247	2080	4834	48.9	421	4413	35.9	0.000	1630	2749	1634	85.2
3	744	2058	3129	2251	88.4	2000	3136	2054	85.7	2000	3136	2054	4765	51.9	423	4343	38.5	0.000	1837	2881	1826	85.7
4	720	1853	3053	2044	84.3	1800	3059	1880	81.7	1800	3059	1880	4858	58.8	479	4379	43.2	0.000	1665	2842	1683	81.4
5	744	1731	2669	1912	87.1	1682	2975	1397	76.0	1682	2975	1397	4805	61.5	442	4363	46.6	1.968	1567	2806	1228	75.1
6	720	1672	2694	1836	86.2	1625	2599	1808	86.8	1625	2599	1808	4747	82.6	485	4262	64.0	5.000	1522	2649	1655	79.8
7	744	1592	2562	1733	83.5	1546	2566	1610	81.0	1546	2566	1610	4721	84.0	1039	3683	43.6	0.000	1455	2617	1475	74.7
8	744	1698	2720	1721	83.9	1649	2727	1563	81.3	1649	2727	1563	4629	69.8	1212	3416	25.3	0.000	1549	2777	1419	75.0
9	720	1710	2838	1895	83.7	1662	2844	1752	81.2	1662	2844	1752	4520	58.9	488	4032	41.8	0.000	1559	2680	1600	80.8
10	744	1918	3071	1949	83.9	1863	3076	1776	81.4	1863	3076	1776	4597	49.4	432	4165	35.4	0.000	1723	2853	1576	81.2
11	720	2041	3286	2203	86.3	1983	3291	2004	83.7	1983	3291	2004	4897	48.8	801	4095	24.4	0.000	1673	2874	1573	80.8
12	744	2124	3307	2232	86.3	2064	3314	2030	83.7	2064	3314	2030	4982	50.3	73	4909	48.1	5.000	1735	2885	1580	80.8
AN	8784	22548	3352	1721	76.6	21906	3358	1397	74.3	21906	3358	1397							19676	2915	1228	76.8

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S u m m a r y (gensum) -- A n n u a l g e n e r a t i o n 1996

	Peak capacity MW	Week Units	Com-mit. %	-Outage- FOR %	MOR %	-------Energy------- GWh Load	Pump	Dump	Total	Cap. fac. %	Fuel tr. btu	Btu /kWh	Fuel $/ Mbtu	--Variable--- mills/kWh Fuel	O&M	Tot.	-Marginal- time %	mills /kWh	-------M$------- Other O&M	Fuel + var O&M
Nuclear	1640	4	100	5.0	27.8	9847	33	0	9880	68.6	115	11650	0.55	6.4	0.2	6.6	0.00	0.0	0.00	65.31
Lignite	428	8	7.2z	9.9	6.9	810	6	0	816	21.9	9.6	11748	2.64	31.0	0.2	31.2	3.00	32.9	0.00	25.44
Coal	521	7	93.3	11.5	8.1	3363	20	0	3383	72.0	36.0	10637	1.88	20.0	1.1	21.1	0.30	26.7	0.00	71.39
Gas- power	528	6		10.0	5.6	2208	85	0	2292	49.4	25.3	11032	3.79	41.8	0.3	42.1	26.38	42.0	0.00	96.47
Hydro	680	3		0.0	0.0	3188	10	0	3199	49.0	0.0	0	0.00	0.0	0.0	0.0	43.12	47.4	0.00	0.00
Industry	332	0		0.0	0.0	2083	0	0	2083	111	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	103.50
Distribution	164	0		0.0	0.0	606	0	0	606	116	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	30.11
DSM.	0	0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Interruptible	0	0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Import/Export	212	1		0.0	0.0	-309	0	0	-309	-15.3	0.0	0	0.00	27.4	0.0	27.4	4.82	79.7	0.00	-8.46
Pumped storage	600					111			111	2.1							11.48	52.8		
(pumping nec.)	(600)						(153)										10.89	40.8		
Total firm 4773 + CS =	4773		42.1%	reserv		21906	153	0	22059	186.0						17.4	100.0	46.9	0.00	383.78
Committed 4266 =	4266		27.0%		ENS	0.0358		LOLP 0.000054	(0.020 days)	Energy Not Served							0.01	50.0		0.00
after MOR 4004 =	4004		19.2%		==========			Commit target	3694 MW 10.0%	Avg. Marginal Cost								46.9		=====
after FOR 3835yy =	3835		14.2%		Load	21906 GWh		Spin. target	336 MW 10.0%	-- based on RC								46.9		383.78
post-DS Peak (4pm Tue)	3358		Fuel $377.41		- Dump 0.00		+ O&M 6.37	+ ENS 0.00 = Total var.	$383.78 + Other										0.00 =	$383.78

* Values from last typical week.
z Commitment reflects must-run and minimum-constrained units -- others excluded from capacity-weighted average.
yy Available capacity meets commitment target.

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S E A S O N A L S U M M A R Y -- A v e r a g e M a r g i n a l C o s t s by season and subperiod (mills/kWh)

Subperiod	Annual	Season Q1	Q2	Q3	Q4
1	49.2	42.1	42.0	54.7	57.6
2	48.9	42.1	42.0	54.7	56.8
3	46.1	42.0	39.6	51.3	51.3
4	44.5	40.2	38.1	51.0	48.5
5	43.7	41.3	37.7	47.5	48.2
Average	46.9	41.6	40.3	52.5	53.2

L o s s o f l o a d p r o b a b i l i t y (%)

1	0.0048	0.0030	0.0001	0.0024	0.0136
2	0.0128	0.0075	0.0002	0.0111	0.0324
3	0.0010	0.0020	0.0000	0.0001	0.0018
4	0.0000	0.0000	0.0000	0.0000	0.0001
5	0.0001	0.0001	0.0000	0.0000	0.0001
Average	0.0054	0.0035	0.0001	0.0042	0.0136

E n e r g y n o t s e r v e d (GWh)

1	0.0033	0.0006	0.0000	0.0004	0.0023
2	0.0311	0.0051	0.0001	0.0060	0.0200
3	0.0013	0.0007	0.0000	0.0000	0.0006
4	0.0000	0.0000	0.0000	0.0000	0.0000
5	0.0000	0.0000	0.0000	0.0000	0.0000
Total	0.0358	0.0064	0.0001	0.0064	0.0229

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Load Summary and Maintenance Allocation -- 1997

		Raw load data				Load data scaled to match weekly input requirements				Load data after demand side modifications			Gross firm capacity and maintenance allocation						Remaining load after exogenous load modifications			
Typ. Wk	Hrs.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Gross cap. (MW)	Res. mar. (Pct)	Maint cap. (MW)	Net cap. (MW)	Res. mar. (Pct)	Maint fac.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)
1	744	2157	3352	2287	86.5	2145	3434	2139	83.9	2145	3434	2139	5351	55.8	61	5290	54.0	4.333	1789	3017	1679	79.7
2	672	1927	3242	2296	88.5	1917	3321	2137	85.9	1917	3321	2137	5497	65.5	382	5115	54.0	0.895	1598	2766	1675	86.0
3	744	2058	3129	2251	88.4	2049	3207	2110	85.9	2049	3207	2110	5136	60.1	553	4583	42.9	0.000	2060	3188	2117	86.9
4	720	1853	3053	2044	84.3	1843	3128	1930	81.8	1843	3128	1930	5130	64.0	429	4701	50.3	0.000	1878	3147	1968	82.9
5	744	1731	2669	1912	87.1	1722	3043	1436	76.1	1722	3043	1436	5050	66.0	427	4623	51.9	0.000	1783	3109	1502	77.1
6	720	1672	2694	1836	86.2	1664	2658	1856	86.9	1664	2658	1856	4992	87.8	591	4401	65.6	5.000	1730	2941	1938	81.7
7	744	1592	2562	1733	83.5	1583	2624	1652	81.1	1583	2624	1652	4867	85.5	825	4041	54.0	1.795	1666	2908	1752	77.0
8	744	1698	2720	1721	83.9	1689	2788	1605	81.4	1689	2788	1605	4774	71.2	853	3921	40.6	0.000	1769	3072	1697	77.2
9	720	1710	2838	1895	83.7	1702	2909	1798	81.3	1702	2909	1798	4665	60.4	446	4219	45.0	0.000	1768	2980	1881	82.4
10	744	1918	3071	1949	83.9	1908	3146	1824	81.5	1908	3146	1824	4647	47.7	481	4166	32.4	0.000	1943	3158	1860	82.7
11	720	2041	3286	2203	86.3	2031	3365	2059	83.8	2031	3365	2059	5155	53.2	559	4597	36.6	0.000	1698	2975	1612	79.3
12	744	2124	3307	2232	86.3	2113	3389	2086	83.8	2113	3389	2086	5240	54.6	341	4899	44.5	0.000	1761	2987	1620	79.3
AN	8760	22479	3352	1721	76.6	22365	3434	1436	74.3	22365	3434	1436							21438	3188	1502	76.8

S u m m a r y (gensum) -- A n n u a l g e n e r a t i o n 1997

	Peak capacity MW	Week	Un it s	Com- mit. %	-Outage- FOR %	MOR %	-------Energy------- GWh Load	Pump	Dump	Total	Cap. fac. %	Fuel tr. btu	Btu /kWh	Fuel $/ Mbtu	--Variable--- mills/kWh Fuel	O&M	Tot.	-Marginal- time %	mills /kWh	-------M$------- Other O&M	Fuel + var O&M
Nuclear	2051		5	100	5.0	19.4	13571	115	0	13686	76.2	160	11655	0.61	7.1	0.2	7.3	3.16	6.8	0.00	99.86
Lignite	398		7	0.0z	9.7	9.0	465	8	0	473	13.7	5.9	12412	2.75	34.1	0.1	34.3	4.07	34.2	0.00	16.20
Coal	721		6	78.2	10.3	7.5	3086	69	0	3155	61.7	33.0	10454	1.97	20.6	1.1	21.7	0.94	26.0	0.00	68.35
Gas- power	528		6		10.0	5.7	959	48	0	1007	21.8	11.1	11041	3.89	43.0	0.3	43.2	17.93	43.1	0.00	43.53
Hydro	680		3		0.0	0.0	3167	23	0	3190	49.0	0.0	0	0.00	0.0	0.0	0.0	42.50	36.1	0.00	0.00
Industry	329		0		0.0	0.0	2057	0	0	2057	111	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	102.24
Distribution	373		0		0.0	0.0	1370	0	0	1370	117	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	68.09
DSM.	0		0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Interruptible	0		0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Import/Export	-21		1		0.0	0.0	-2499	0	0	-2499	7338	0.0	0	0.00	45.6	0.0	45.6	0.06	96.5	0.00	-113.96
Pumped storage	600						190			190	3.6							12.57	39.9		
(pumping nec.)	(600)							(263)										18.76	31.7		
Total firm 5330 + CS =	5330			55.2%	reserv		22365	263	0	22628	209.5						12.6	100.0	35.9	0.00	284.32
Committed 4632 =	4632			34.9%		ENS	0.0504		LOLP 0.000056	(0.020 days)	Energy Not Served							0.01	50.0		0.00
after MOR 4621 =	4621			34.6%		==========			Commit target	3777 MW 10.0%	Avg. Marginal Cost								35.9		=====
after FOR 4421yy =	4421			28.7%	Load		22365 GWh		Spin. target	343 MW 10.0%	-- based on RC								35.9		284.32
post-DS Peak (4pm Tue)	3434			Fuel $278.09	- Dump 0.00		+ O&M 6.23		+ ENS 0.00 = Total var.	$284.32 + Other										0.00 =	$284.32

* Values from last typical week.
z Commitment reflects must-run and minimum-constrained units -- others excluded from capacity-weighted average.
yy Available capacity meets commitment target.

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S E A S O N A L S U M M A R Y -- A v e r a g e M a r g i n a l C o s t s by season and subperiod (mills/kWh)

Subperiod	Annual	Season Q1	Q2	Q3	Q4
1	38.4	24.7	43.1	42.1	43.6
2	38.0	24.4	43.1	41.6	42.6
3	35.0	24.0	39.9	37.0	38.8
4	33.2	21.2	37.8	36.8	37.0
5	33.1	22.2	37.9	35.7	36.3
Average	35.9	23.5	40.8	39.1	40.1

L o s s o f l o a d p r o b a b i l i t y (%)

1	0.0083	0.0002	0.0005	0.0067	0.0254
2	0.0121	0.0006	0.0003	0.0067	0.0406
3	0.0011	0.0004	0.0001	0.0004	0.0035
4	0.0001	0.0000	0.0000	0.0001	0.0004
5	0.0002	0.0000	0.0000	0.0000	0.0005
Average	0.0056	0.0003	0.0002	0.0033	0.0185

E n e r g y n o t s e r v e d (GWh)

1	0.0085	0.0000	0.0001	0.0017	0.0067
2	0.0395	0.0004	0.0001	0.0051	0.0338
3	0.0022	0.0002	0.0000	0.0002	0.0018
4	0.0002	0.0000	0.0000	0.0000	0.0001
5	0.0001	0.0000	0.0000	0.0000	0.0001
Total	0.0504	0.0006	0.0003	0.0069	0.0426

Load Summary and Maintenance Allocation -- 1998

		Raw load data				Load data scaled to match weekly input requirements				Load data after demand side modifications			Gross firm capacity and maintenance allocation						Remaining load after exogenous load modifications			
Typ. Wk	Hrs.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Gross cap. (MW)	Res. mar. (Pct)	Maint cap. (MW)	Net cap. (MW)	Res. mar. (Pct)	Maint fac.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)
1	744	2157	3352	2287	86.5	2232	3558	2247	84.3	2232	3558	2247	5551	56.0	209	5342	50.1	0.000	1964	3260	1906	81.0
2	672	1927	3242	2296	88.5	1995	3441	2247	86.3	1995	3441	2247	5697	65.6	342	5355	55.6	5.000	1755	3004	1904	86.9
3	744	2058	3129	2251	88.4	2132	3323	2216	86.2	2132	3323	2216	5336	60.6	401	4935	48.5	0.000	2231	3422	2342	87.6
4	720	1853	3053	2044	84.3	1918	3241	2024	82.2	1918	3241	2024	5324	64.2	994	4330	33.6	0.000	2038	3378	2180	83.8
5	744	1731	2669	1912	87.1	1792	3152	1511	76.4	1792	3152	1511	5271	67.2	664	4607	46.1	0.000	1940	3336	1695	78.2
6	720	1672	2694	1836	86.2	1732	2754	1948	87.3	1732	2754	1948	5213	89.3	838	4375	58.9	5.000	1882	3151	2147	82.9
7	744	1592	2562	1733	83.5	1648	2718	1731	81.5	1648	2718	1731	4988	83.5	870	4117	51.5	0.892	1818	3117	1948	78.4
8	744	1698	2720	1721	83.9	1757	2889	1687	81.7	1757	2889	1687	4895	69.4	635	4260	47.5	0.000	1919	3287	1895	78.5
9	720	1710	2838	1895	83.7	1771	3014	1885	81.6	1771	3014	1885	4786	58.8	563	4222	40.1	0.000	1921	3202	2085	83.3
10	744	1918	3071	1949	83.9	1985	3259	1916	81.9	1985	3259	1916	4868	49.4	500	4368	34.0	0.000	2108	3390	2070	83.6
11	720	2041	3286	2203	86.3	2113	3487	2164	84.2	2113	3487	2164	5376	54.2	95	5281	51.5	1.578	1866	3215	1835	80.6
12	744	2124	3307	2232	86.3	2199	3512	2192	84.2	2199	3512	2192	5461	55.5	297	5164	47.1	0.000	1935	3228	1845	80.6
AN	8760	22479	3352	1721	76.6	23274	3558	1511	74.7	23274	3558	1511							23376	3422	1695	78.0

S u m m a r y (gensum) -- A n n u a l g e n e r a t i o n 1998

	Peak capacity MW	Week	Un it s	Com- mit. %	-Outage- FOR %	MOR %	-------Energy------- GWh Load	Pump	Dump	Total	Cap. fac. %	Fuel tr. btu	Btu /kWh	Fuel $/ Mbtu	--Variable--- mills/kWh Fuel	O&M	Tot.	-Marginal- time %	mills /kWh	-------M$------- Other O&M	Fuel + var O&M
Nuclear	2462		6	100	5.0	16.9	16409	122	0	16531	76.6	193	11673	0.66	7.7	0.2	7.9	10.95	7.4	0.00	130.35
Lignite	422		8	15.7z	9.9	14.1	443	10	0	452	12.3	3.6	7999	2.87	23.0	0.1	23.1	1.37	34.3	0.00	10.44
Coal	521		5	83.2	9.6	8.4	2185	62	0	2247	62.7	21.9	9753	2.14	20.9	1.0	21.9	1.38	19.1	0.00	49.19
Gas- power	528		6		10.0	5.7	854	0	0	854	18.5	9.4	11036	3.99	44.0	0.3	44.3	14.45	44.2	0.00	37.84
Hydro	680		3		0.0	0.0	3140	50	0	3190	49.0	0.0	0	0.00	0.0	0.0	0.0	45.37	26.0	0.00	0.00
Industry	324		0		0.0	0.0	2028	0	0	2028	111	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	100.80
Distribution	373		0		0.0	0.0	1370	0	0	1370	117	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	68.09
DSM.	0		0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Interruptible	0		0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Import/Export	-135		1		0.0	0.0	-3500	0	0	-3500	338	0.0	0	0.00	46.8	0.0	46.8	0.03	117	0.00	-163.90
Pumped storage	600						176			176	3.3							14.34	23.4		
(pumping nec.)	(600)							(244)										12.08	20.0		

Total firm	5451 + CS =	5451	53.2%	reserv	23105	243	0	23348	227.9					10.0	100.0	25.5	0.00	232.81
Committed	4953 =	4953	39.2%	ENS	0.0256	LOLP 0.000027 (0.010 days) Energy Not Served									0.00	50.0		0.00
after MOR	4756 =	4756	33.7%	==========		Commit target 3914 MW 10.0% Avg. Marginal Cost										25.5		=====
after FOR	4546yy =	4546	27.8%	Load	23105 GWh	Spin. target 356 MW 10.0% -- based on RC										25.5		232.81
post-DS Peak (4pm Tue)		3558	Fuel $227.28	- Dump 0.00	+ O&M 5.53	+ ENS 0.00 = Total var. $232.81 + Other											0.00 =	$232.81

* Values from last typical week.
z Commitment reflects must-run and minimum-constrained units -- others excluded from capacity-weighted average.
yy Available capacity meets commitment target.

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SEASONAL SUMMARY -- Average Marginal Costs by season and subperiod (mills/kWh)

Subperiod	Annual	Season Q1	Q2	Q3	Q4
1	26.9	20.1	35.2	32.4	19.8
2	26.9	20.1	35.2	32.4	19.8
3	24.9	19.9	33.6	28.2	17.8
4	23.9	17.6	33.0	27.7	17.3
5	23.6	18.7	32.4	26.7	16.4
Average	25.5	19.4	34.1	30.0	18.5

Loss of load probability (%)

1	0.0039	0.0022	0.0004	0.0040	0.0090
2	0.0055	0.0033	0.0003	0.0055	0.0127
3	0.0011	0.0029	0.0001	0.0002	0.0012
4	0.0001	0.0000	0.0000	0.0000	0.0001
5	0.0002	0.0005	0.0000	0.0000	0.0002
Average	0.0027	0.0022	0.0002	0.0025	0.0059

Energy not served (GWh)

1	0.0041	0.0006	0.0001	0.0010	0.0025
2	0.0188	0.0027	0.0002	0.0043	0.0117
3	0.0024	0.0016	0.0000	0.0001	0.0006
4	0.0001	0.0000	0.0000	0.0000	0.0001
5	0.0002	0.0001	0.0000	0.0000	0.0000
Total	0.0256	0.0050	0.0002	0.0054	0.0150

Load Summary and Maintenance Allocation -- 1999

		Raw load data				Load data scaled to match weekly input requirements				Load data after demand side modifications			Gross firm capacity and maintenance allocation						Remaining load after exogenous load modifications			
Typ. Wk	Hrs.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Gross cap. (MW)	Res. mar. (Pct)	Maint cap. (MW)	Net cap. (MW)	Res. mar. (Pct)	Maint fac.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)
1	744	2157	3352	2287	86.5	2310	3684	2323	84.3	2310	3684	2323	5351	45.3	277	5074	37.7	0.000	2003	3335	1930	80.7
2	672	1927	3242	2296	88.5	2064	3562	2323	86.2	2064	3562	2323	5498	54.3	502	4996	40.2	0.000	1789	3074	1928	86.6
3	744	2058	3129	2251	88.4	2206	3441	2291	86.2	2206	3441	2291	5135	49.2	643	4493	30.6	0.000	2268	3489	2366	87.3
4	720	1853	3053	2044	84.3	1985	3356	2093	82.1	1985	3356	2093	5223	55.6	513	4710	40.3	0.000	2067	3442	2198	83.4
5	744	1731	2669	1912	87.1	1855	3264	1562	76.4	1855	3264	1562	5170	58.4	918	4252	30.3	0.000	1963	3395	1693	77.7
6	720	1672	2694	1836	86.2	1792	2851	2014	87.3	1792	2851	2014	5112	79.3	885	4228	48.3	0.000	1904	3192	2160	82.9
7	744	1592	2562	1733	83.5	1705	2815	1790	81.4	1705	2815	1790	4987	77.2	1124	3863	37.2	0.000	1836	3156	1954	78.2
8	744	1698	2720	1721	83.9	1819	2991	1744	81.7	1819	2991	1744	4894	63.6	696	4198	40.3	0.000	1941	3332	1900	78.3
9	720	1710	2838	1895	83.7	1833	3120	1949	81.6	1833	3120	1949	4785	53.3	530	4255	36.4	0.000	1945	3256	2097	83.0
10	744	1918	3071	1949	83.9	2055	3375	1981	81.8	2055	3375	1981	4767	41.3	511	4256	26.1	0.000	2139	3454	2083	83.2
11	720	2041	3286	2203	86.3	2187	3610	2237	84.1	2187	3610	2237	5277	46.2	159	5118	41.7	0.000	1902	3287	1856	80.3
12	744	2124	3307	2232	86.3	2276	3636	2266	84.1	2276	3636	2266	5361	47.5	91	5270	44.9	0.000	1973	3301	1867	80.3
AN	8760	22479	3352	1721	76.6	24087	3684	1562	74.6	24087	3684	1562							23730	3489	1693	77.6

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S u m m a r y (gensum) -- A n n u a l g e n e r a t i o n 1999

	Peak capacity MW	Week Units	Com- mit. %	-Outage- FOR %	MOR %	-------Energy------- GWh Load	Pump	Dump	Total	Cap. fac. %	Fuel tr. btu	Btu /kWh	Fuel $/ Mbtu	--Variable--- mills/kWh Fuel	O&M	Tot.	-Marginal- time %	mills /kWh	-------M$------- Other O&M	Fuel + var O&M
Nuclear	2462	6	100	5.0	18.5	16227	130	0	16356	75.8	191	11666	0.71	8.3	0.2	8.5	8.07	7.9	0.00	138.44
Lignite	264	6	23.7z	9.8	21.6	455	7	0	461	20.2	4.1	8829	2.99	26.4	0.1	26.5	2.18	36.3	0.00	12.24
Coal	521	5	89.8	9.6	8.4	2782	98	0	2880	71.6	28.6	9940	2.15	21.3	1.0	22.4	1.31	22.1	0.00	64.46
Gas- power	528	6		10.0	5.7	916	0	0	916	19.8	10.1	11038	4.09	45.1	0.3	45.4	19.23	45.3	0.00	41.63
Hydro	680	3		0.0	0.0	3159	31	0	3190	49.0	0.0	0	0.00	0.0	0.0	0.0	42.35	32.5	0.00	0.00
Industry	317	0		0.0	0.0	1982	0	0	1982	111	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	98.51
Distribution	374	0		0.0	0.0	1375	0	0	1375	117	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	68.34
DSM.	0	0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Interruptible	0	0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Import/Export	-78	1		0.0	0.0	-3000	0	0	-3000	562	0.0	0	0.00	48.1	0.0	48.1	0.04	141	0.00	-144.25
Pumped storage	600					191			191	3.6							12.52	30.2		
(pumping nec.)	(600)						(266)										14.29	24.7		
Total firm 5351 + CS =	5351		45.3%	reserv		24087	266	0	24353	233.6						11.5	100.0	31.5	0.00	279.35
Committed 5012 =	5012		36.0%		ENS	0.0337		LOLP 0.000035	(0.013 days)					Energy Not Served			0.00	50.0		0.00
after MOR 4746 =	4746		28.8%			==========		Commit target		4052 MW 10.0%				Avg. Marginal Cost				31.5		=====
after FOR 4539yy =	4539		23.2%	Load		24087 GWh		Spin. target		368 MW 10.0%				-- based on RC				31.5		279.35
post-DS Peak (4pm Tue)	3684			Fuel $273.07		- Dump 0.00		+ O&M 6.27		+ ENS 0.00 = Total var. $279.35 + Other									0.00 =	$279.35

* Values from last typical week.
z Commitment reflects must-run and minimum-constrained units -- others excluded from capacity-weighted average.
yy Available capacity meets commitment target.

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S E A S O N A L S U M M A R Y -- A v e r a g e M a r g i n a l C o s t s by season and subperiod (mills/kWh)

Subperiod	Annual	Season Q1	Q2	Q3	Q4
1	33.3	24.4	45.3	42.6	20.9
2	33.2	24.2	45.2	42.6	20.9
3	30.8	23.7	43.1	37.5	18.9
4	29.4	21.8	40.4	36.9	18.5
5	29.0	22.5	40.8	35.3	17.6
Average	31.5	23.5	43.4	39.6	19.7

L o s s o f l o a d p r o b a b i l i t y (%)

1	0.0049	0.0012	0.0003	0.0023	0.0155
2	0.0075	0.0024	0.0003	0.0053	0.0217
3	0.0009	0.0015	0.0000	0.0002	0.0020
4	0.0001	0.0000	0.0000	0.0000	0.0002
5	0.0001	0.0002	0.0000	0.0000	0.0003
Average	0.0035	0.0014	0.0002	0.0022	0.0101

E n e r g y n o t s e r v e d (GWh)

1	0.0055	0.0002	0.0001	0.0005	0.0046
2	0.0262	0.0016	0.0002	0.0041	0.0204
3	0.0018	0.0006	0.0000	0.0001	0.0011
4	0.0001	0.0000	0.0000	0.0000	0.0001
5	0.0001	0.0000	0.0000	0.0000	0.0001
Total	0.0337	0.0024	0.0003	0.0047	0.0263

Load Summary and Maintenance Allocation -- 2000

Typ. Wk	Hrs.	Raw load data Energy (GWh)	Raw load data Peak load (MW)	Raw load data Min. load (MW)	Raw load data Load fac. (Pct)	Load data scaled to match weekly input requirements Energy (GWh)	Load data scaled Peak load (MW)	Load data scaled Min. load (MW)	Load data scaled Load fac. (Pct)	Load data after demand side modifications Energy (GWh)	Load data after demand side Peak load (MW)	Load data after demand side Min. load (MW)	Gross firm capacity and maintenance allocation Gross cap. (MW)	Gross firm Res. mar. (Pct)	Gross firm Maint cap. (MW)	Gross firm Net cap. (MW)	Gross firm Res. mar. (Pct)	Gross firm Maint fac.	Remaining load after exogenous load modifications Energy (GWh)	Remaining Peak load (MW)	Remaining Min. load (MW)	Remaining Load fac. (Pct)
1	744	2157	3352	2287	86.5	2389	3812	2400	84.2	2389	3812	2400	5408	41.9	112	5296	38.9	0.000	2045	3414	1957	80.5
2	696	1996	3242	2296	88.5	2211	3686	2400	86.2	2211	3686	2400	5555	50.7	239	5316	44.2	2.276	1892	3148	1955	86.3
3	744	2058	3129	2251	88.4	2282	3560	2367	86.1	2282	3560	2367	5292	48.6	860	4432	24.5	0.000	2305	3559	2392	87.1
4	720	1853	3053	2044	84.3	2053	3473	2163	82.1	2053	3473	2163	5353	54.1	932	4421	27.3	0.000	2098	3507	2216	83.1
5	744	1731	2669	1912	87.1	1918	3377	1614	76.3	1918	3377	1614	5300	56.9	700	4600	36.2	0.000	1988	3457	1693	77.3
6	720	1672	2694	1836	86.2	1854	2950	2081	87.3	1854	2950	2081	5242	77.7	702	4540	53.9	5.000	1928	3234	2175	82.8
7	744	1592	2562	1733	83.5	1764	2912	1850	81.4	1764	2912	1850	5117	75.7	1208	3909	34.2	0.000	1855	3197	1961	78.0
8	744	1698	2720	1721	83.9	1881	3095	1802	81.7	1881	3095	1802	5024	62.3	920	4104	32.6	0.000	1964	3379	1905	78.1
9	720	1710	2838	1895	83.7	1896	3229	2015	81.6	1896	3229	2015	4915	52.2	65	4850	50.2	5.000	1970	3313	2110	82.6
10	744	1916	3071	1949	83.9	2125	3492	2047	81.8	2125	3492	2047	4905	40.5	245	4661	33.5	0.000	2171	3521	2098	82.9
11	720	2041	3286	2203	86.3	2262	3736	2312	84.1	2262	3736	2312	5415	44.9	180	5235	40.1	0.000	1940	3363	1880	80.1
12	744	2124	3307	2232	86.3	2354	3762	2342	84.1	2354	3762	2342	5500	46.2	245	5255	39.7	0.000	2013	3377	1893	80.1
AN	8784	22548	3352	1721	76.6	24989	3812	1614	74.6	24989	3812	1614							24169	3559	1693	77.3

S u m m a r y (gensum) -- A n n u a l g e n e r a t i o n 2000

	Peak capacity MW	Week	Un it s	Com- mit. %	-Outage- FOR %	MOR %	-------Energy------- GWh Load	Pump	Dump	Total	Cap. fac. %	Fuel tr. btu	Btu /kWh	Fuel $/ Mbtu	--Variable--- mills/kWh Fuel	O&M	Tot.	-Marginal- time %	mills /kWh	-------M$------- Other O&M	Fuel + var O&M
Nuclear	2462		6	100	5.0	15.4	16616	147	0	16763	77.5	196	11668	0.76	8.9	0.2	9.0	9.89	8.4	0.00	151.62
Lignite	243		5	31.4z	9.4	18.8	470	14	0	484	23.3	3.9	8088	3.12	25.2	0.1	25.4	1.84	36.6	0.00	12.27
Coal	521		6	81.2	9.6	12.4	2735	89	0	2824	59.2	28.0	9908	2.24	22.2	1.0	23.2	0.57	26.7	0.00	65.52
Gas- power	528		6		10.0	5.6	921	27	0	948	20.4	10.5	11032	4.20	46.3	0.3	46.6	11.57	46.5	0.00	44.19
Hydro	680		3		0.0	0.0	3153	46	0	3199	49.0	0.0	0	0.00	0.0	0.0	0.0	39.95	41.3	0.00	0.00
Industry	309		0		0.0	0.0	1940	0	0	1940	111	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	96.44
Distribution	374		0		0.0	0.0	1386	0	0	1386	116	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	68.91
DSM.	0		0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Interruptible	0		0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Import/Export	-21		1		0.0	0.0	-2465	0	0	-2465	7131	0.0	0	0.00	47.3	0.0	47.3	2.47	171	0.00	-116.72
Pumped storage	600						232			232	4.4							16.46	32.4		
(pumping nec.)	(600)							(323)										17.23	29.0		

Total firm 5388 + CS = 5388 41.3% reserv 24989 323 0 25312 237.9 12.7 100.0 38.1 0.00 322.22
Committed 5069 = 5069 33.0% ENS 0.0539 LOLP 0.000053 (0.019 days) Energy Not Served 0.01 50.0 0.00
after MOR 4989 = 4989 30.9% ========== Commit target 4193 MW 10.0% Avg. Marginal Cost 38.1 =====
after FOR 4773yy = 4773 25.2% Load 24989 GWh Spin. target 381 MW 10.0% -- based on RC 38.1 322.22
post-DS Peak (4pm Tue) 3812 Fuel $316.00 - Dump 0.00 + O&M 6.22 + ENS 0.00 = Total var. $322.22 + Other 0.00 = $322.22

* Values from last typical week.
z Commitment reflects must-run and minimum-constrained units -- others excluded from capacity-weighted average.
yy Available capacity meets commitment target.

S E A S O N A L S U M M A R Y -- A v e r a g e M a r g i n a l C o s t s by season and subperiod (mills/kWh)

Subperiod	Annual	Season Q1	Q2	Q3	Q4
1	40.6	64.1	41.4	35.0	22.0
2	40.4	63.6	41.4	34.6	22.4
3	37.2	60.1	38.1	31.1	19.9
4	34.8	52.2	36.7	31.1	19.4
5	35.2	56.0	36.6	29.4	18.9
Average	38.1	59.9	39.3	32.7	20.8

L o s s o f l o a d p r o b a b i l i t y (%)

1	0.0079	0.0075	0.0006	0.0017	0.0218
2	0.0099	0.0103	0.0005	0.0023	0.0265
3	0.0031	0.0101	0.0000	0.0001	0.0022
4	0.0001	0.0001	0.0000	0.0000	0.0004
5	0.0005	0.0015	0.0000	0.0000	0.0004
Average	0.0053	0.0071	0.0002	0.0010	0.0127

E n e r g y n o t s e r v e d (GWh)

1	0.0087	0.0018	0.0001	0.0004	0.0064
2	0.0378	0.0082	0.0003	0.0015	0.0278
3	0.0068	0.0055	0.0000	0.0000	0.0013
4	0.0002	0.0000	0.0000	0.0000	0.0002
5	0.0004	0.0003	0.0000	0.0000	0.0001
Total	0.0539	0.0157	0.0004	0.0020	0.0358

Load Summary and Maintenance Allocation -- 2001

		Raw load data				Load data scaled to match weekly input requirements				Load data after demand side modifications			Gross firm capacity and maintenance allocation						Remaining load after exogenous load modifications			
Typ. Wk	Hrs.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Gross cap. (MW)	Res. mar. (Pct)	Maint cap. (MW)	Net cap. (MW)	Res. mar. (Pct)	Maint fac.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)
1	744	2157	3352	2287	86.5	2473	3945	2486	84.3	2473	3945	2486	5635	42.8	443	5192	31.6	0.000	2102	3512	2006	80.4
2	672	1927	3242	2296	88.5	2210	3815	2486	86.2	2210	3815	2486	5782	51.6	230	5552	45.5	0.000	1877	3242	2004	86.2
3	744	2058	3129	2251	88.4	2362	3685	2452	86.2	2362	3685	2452	5419	47.1	569	4850	31.6	0.000	2358	3647	2439	86.9
4	720	1853	3053	2044	84.3	2125	3594	2240	82.1	2125	3594	2240	5501	53.1	237	5264	46.5	2.000	2143	3592	2255	82.9
5	744	1731	2669	1912	87.1	1986	3495	1672	76.4	1986	3495	1672	5447	55.9	476	4972	42.2	0.000	2026	3536	1712	77.0
6	720	1672	2694	1836	86.2	1919	3053	2155	87.3	1919	3053	2155	5390	76.5	531	4859	59.1	5.000	1965	3291	2210	82.9
7	744	1592	2562	1733	83.5	1826	3014	1916	81.4	1826	3014	1916	5266	74.7	754	4512	49.7	5.000	1887	3253	1987	78.0
8	744	1698	2720	1721	83.9	1947	3203	1866	81.7	1947	3203	1866	5174	61.5	754	4419	38.0	0.000	2001	3441	1930	78.1
9	720	1710	2836	1895	83.7	1962	3341	2086	81.6	1962	3341	2086	5065	51.6	546	4518	35.2	0.000	2008	3387	2142	82.4
10	744	1918	3071	1949	83.9	2200	3614	2120	81.8	2200	3614	2120	5053	39.8	523	4530	25.3	0.000	2217	3606	2133	82.6
11	720	2041	3286	2203	86.3	2342	3866	2394	84.1	2342	3866	2394	5563	43.9	523	5039	30.3	0.000	1993	3457	1926	80.1
12	744	2124	3307	2232	86.3	2437	3894	2425	84.1	2437	3894	2425	5647	45.0	590	5058	29.9	0.000	2069	3473	1940	80.1
AN	8760	22479	3352	1721	76.6	25788	3945	1672	74.6	25788	3945	1672							24645	3647	1712	77.1

S u m m a r y (gensum) -- A n n u a l g e n e r a t i o n 2001

	Peak capacity MW	Week Units	Com- mit. %	-Outage- FOR %	MOR %	-------Energy------- GWh Load	Pump	Dump	Total	Cap. fac. %	Fuel tr. btu	Btu /kWh	Fuel $/ Mbtu	--Variable--- mills/kWh Fuel	O&M	Tot.	-Marginal- time %	mills /kWh	-------M$------- Other O&M	Fuel + var O&M
Nuclear	2055	6	100	5.0	15.2	15432	189	0	15621	78.8	182	11656	0.76	8.9	0.2	9.0	4.33	8.4	0.00	140.75
Lignite	243	5	31.4z	9.4	18.7	374	9	0	383	18.5	2.8	7301	3.19	23.3	0.1	23.4	1.40	33.2	0.00	8.97
Coal	721	7	91.1	10.3	10.4	3495	144	0	3639	63.0	36.1	9920	2.21	21.9	1.1	23.0	3.49	20.9	0.00	83.74
Gas- power	528	6		10.0	5.7	362	0	0	362	7.8	4.0	11047	4.33	47.8	0.3	48.1	11.22	47.9	0.00	17.42
Hydro	680	3		0.0	0.0	3147	43	0	3190	49.0	0.0	0	0.00	0.0	0.0	0.0	40.72	25.2	0.00	0.00
Industry	299	0		0.0	0.0	1868	0	0	1868	111	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	92.84
Distribution	374	0		0.0	0.0	1375	0	0	1375	117	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	68.34
DSM.	0	0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Interruptible	0	0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Import/Export	25	1		0.0	0.0	-2100	0	0	-2100	-574	0.0	0	0.00	49.9	0.0	49.9	0.02	207	0.00	-104.69
Pumped storage	600					295			295	5.6							16.96	24.0		
{pumping nec.}	{ 600}						{409}										20.33	21.2		

Total firm	5226 + CS =	5226	32.5%	reserv	24248	385	0	24633	225.0					12.5	98.47	26.0	0.00	307.38
Committed	5516 =	5516	39.8%	ENS	0.0291	LOLP 0.000030	(0.011 days)	Energy Not Served						0.00	50.0			0.00
after MOR	5073 =	5073	28.6%	==========		Commit target	4340 MW 10.0%	Avg. Marginal Cost							25.8			=====
after FOR	4838yy =	4838	22.6%	Load	24248 GWh	Spin. target	395 MW 10.0%	-- based on RC							25.8			307.38
post-DS Peak (4pm Tue)		3945	Fuel $300.94	~ Dump 0.00		+ O&M 6.44	+ ENS 0.00 = Total var.	$307.38 + Other									0.00 =	$307.38

* Values from last typical week.
z Commitment reflects must-run and minimum-constrained units -- others excluded from capacity-weighted average.
yy Available capacity meets commitment target.

S E A S O N A L S U M M A R Y -- A v e r a g e M a r g i n a l C o s t s by season and subperiod (mills/kWh)

Subperiod	Annual	Season Q1	Q2	Q3	Q4
1	27.8	26.1	26.0	27.1	31.9
2	27.6	25.9	25.4	26.9	32.1
3	25.0	25.1	23.4	23.1	28.3
4	23.3	22.6	21.0	22.2	27.5
5	23.4	23.5	22.0	21.2	26.7
Average	25.8	24.9	23.8	24.6	29.8

L o s s o f l o a d p r o b a b i l i t y (%)

1	0.0044	0.0024	0.0010	0.0015	0.0129
2	0.0063	0.0035	0.0004	0.0019	0.0191
3	0.0009	0.0022	0.0002	0.0000	0.0012
4	0.0000	0.0000	0.0000	0.0000	0.0001
5	0.0001	0.0003	0.0000	0.0000	0.0001
Average	0.0030	0.0021	0.0003	0.0009	0.0087

E n e r g y n o t s e r v e d (GWh)

1	0.0050	0.0006	0.0003	0.0003	0.0038
2	0.0220	0.0028	0.0003	0.0013	0.0176
3	0.0020	0.0012	0.0001	0.0000	0.0006
4	0.0001	0.0000	0.0000	0.0000	0.0001
5	0.0001	0.0001	0.0000	0.0000	0.0000
Total	0.0291	0.0047	0.0006	0.0017	0.0221

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Load Summary and Maintenance Allocation -- 2002

Typ. Wk	Hrs.	Raw load data: Energy (GWh)	Raw load data: Peak load (MW)	Raw load data: Min. load (MW)	Raw load data: Load fac. (Pct)	Load data scaled to match weekly input requirements: Energy (GWh)	Load data scaled: Peak load (MW)	Load data scaled: Min. load (MW)	Load data scaled: Load fac. (Pct)	Load data after demand side modifications: Energy (GWh)	Load data after demand side: Peak load (MW)	Load data after demand side: Min. load (MW)	Gross firm capacity and maintenance allocation: Gross cap. (MW)	Gross: Res. mar. (Pct)	Gross: Maint cap. (MW)	Net cap. (MW)	Net: Res. mar. (Pct)	Net: Maint fac.	Remaining load after exogenous load modifications: Energy (GWh)	Remaining: Peak load (MW)	Remaining: Min. load (MW)	Remaining: Load fac. (Pct)
1	744	2157	3352	2287	86.5	2561	4083	2578	84.3	2561	4083	2578	5484	34.3	91	5393	32.1	0.000	2180	3637	2086	80.5
2	672	1927	3242	2296	88.5	2289	3948	2578	86.3	2289	3948	2578	5631	42.6	94	5537	40.2	0.108	1946	3362	2084	86.1
3	744	2058	3129	2251	88.4	2446	3814	2543	86.2	2446	3814	2543	5268	38.1	522	4746	24.4	0.000	2432	3763	2517	86.9
4	720	1853	3053	2044	84.3	2201	3720	2323	82.2	2201	3720	2323	5349	43.8	369	4980	33.9	0.000	2208	3703	2323	82.8
5	744	1731	2669	1912	87.1	2057	3618	1734	76.4	2057	3618	1734	5296	46.4	468	4828	33.5	0.000	2085	3642	1759	76.9
6	720	1672	2694	1836	86.2	1987	3160	2235	87.3	1987	3160	2235	5239	65.8	599	4640	46.8	5.000	2021	3375	2274	83.2
7	744	1592	2562	1733	83.5	1891	3119	1986	81.5	1891	3119	1986	5413	73.5	1039	4375	40.2	4.784	1939	3335	2041	78.1
8	744	1698	2720	1721	83.9	2016	3315	1936	81.7	2016	3315	1936	5321	60.5	968	4352	31.3	0.000	2058	3531	1983	78.3
9	720	1710	2838	1895	83.7	2032	3458	2163	81.6	2032	3458	2163	5211	50.7	722	4489	29.8	0.000	2066	3487	2203	82.3
10	744	1918	3071	1949	83.9	2278	3740	2199	81.9	2278	3740	2199	5200	39.0	555	4645	24.2	0.000	2284	3718	2197	82.6
11	720	2041	3286	2203	86.3	2425	4001	2483	84.2	2425	4001	2483	5709	42.7	173	5536	38.4	0.000	2066	3579	2002	80.2
12	744	2124	3307	2232	86.3	2524	4030	2515	84.2	2524	4030	2515	5794	43.8	143	5651	40.2	2.053	2146	3596	2017	80.2
AN	8760	22479	3352	1721	76.6	26708	4083	1734	74.7	26708	4083	1734							25431	3763	1759	77.1

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S u m m a r y (gensum) -- A n n u a l g e n e r a t i o n 2002

	Peak capacity MW	Week	Unit s	Com-mit. %	-Outage- FOR %	MOR %	-------Energy------- GWh Load	Pump	Dump	Total	Cap. fac. %	Fuel tr. btu	Btu /kWh	Fuel $/ Mbtu	--Variable--- mills/kWh Fuel	O&M	Tot.	-Marginal- time %	mills /kWh	-------M$------- Other O&M	Fuel + var O&M
Nuclear	2466		6	100	5.0	15.5	17055	220	0	17275	80.0	201	11653	0.76	8.9	0.2	9.0	5.00	8.4	0.00	155.58
Lignite	243		5	31.4z	9.4	18.7	460	11	0	471	22.7	3.7	7853	3.25	25.5	0.1	25.7	1.99	36.3	0.00	12.07
Coal	721		7	76.5	10.3	7.5	3313	60	0	3373	58.4	33.4	9903	2.26	22.4	1.1	23.4	2.05	21.2	0.00	79.00
Gas- power	352		5		10.0	0.0	1102	153	0	1255	28.5	11.2	8943	4.47	40.0	0.3	40.3	14.99	43.9	0.00	50.51
Hydro	680		3		0.0	0.0	3158	32	0	3190	49.0	0.0	0	0.00	0.0	0.0	0.0	35.60	30.3	0.00	0.00
Industry	288		0		0.0	0.0	1802	0	0	1802	111	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	89.56
Distribution	374		0		0.0	0.0	1375	0	0	1375	117	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	68.34
DSM.	0		0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Interruptible	0		0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Import/Export	48		1		0.0	0.0	-1899	0	0	-1899	-336	0.0	0	0.00	50.3	0.0	50.3	0.06	250	0.00	-95.47
Pumped storage	600						343			343	6.5							20.49	36.3		
{pumping nec.}	{ 600}							{476}										19.82	26.2		
Total firm 5484 + CS =			5484	34.3%	reserv		26708	476	0	27184	249.6						13.2	100.0	31.7	0.00	359.58
Committed 4965 =			4965	21.6%		ENS	0.0724		LOLP 0.000076 (0.028 days) Energy Not Served									0.01	50.0		0.00
after MOR 4886 =			4886	19.7%			==========		Commit target 4491 MW 10.0% Avg. Marginal Cost										31.7		=====
after FOR 4687yy =			4687	14.8%		Load	26708 GWh		Spin. target 408 MW 10.0% -- based on RC										31.7		359.59
post-DS Peak (4pm Tue)			4083		Fuel $352.99		- Dump 0.00		+ O&M 6.60 + ENS 0.00 = Total var. $359.59 + Other											0.00 =	$359.59

* Values from last typical week.
z Commitment reflects must-run and minimum-constrained units -- others excluded from capacity-weighted average.
yy Available capacity meets commitment target.

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SEASONAL SUMMARY -- Average Marginal Costs by season and subperiod (mills/kWh)

Subperiod	Annual	Season Q1	Q2	Q3	Q4
1	34.5	30.9	29.6	46.6	30.8
2	34.0	30.0	29.4	46.3	30.4
3	30.3	28.1	27.5	39.5	26.2
4	28.8	26.0	25.7	38.5	24.8
5	28.5	26.4	26.2	37.0	24.4
Average	31.7	28.5	28.0	42.3	27.8

Loss of load probability (%)

1	0.0131	0.0194	0.0133	0.0068	0.0130
2	0.0144	0.0277	0.0047	0.0064	0.0191
3	0.0035	0.0112	0.0017	0.0002	0.0011
4	0.0001	0.0002	0.0000	0.0000	0.0001
5	0.0006	0.0019	0.0003	0.0000	0.0001
Average	0.0076	0.0151	0.0037	0.0031	0.0086

Energy not served (GWh)

1	0.0139	0.0053	0.0031	0.0017	0.0037
2	0.0504	0.0245	0.0033	0.0051	0.0176
3	0.0075	0.0062	0.0007	0.0001	0.0005
4	0.0001	0.0001	0.0000	0.0000	0.0001
5	0.0005	0.0004	0.0000	0.0000	0.0000
Total	0.0724	0.0364	0.0072	0.0069	0.0220

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Load Summary and Maintenance Allocation -- 2003

		Raw load data				Load data scaled to match weekly input requirements				Load data after demand side modifications			Gross firm capacity and maintenance allocation						Remaining load after exogenous load modifications			
Typ. Wk	Hrs.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Gross cap. (MW)	Res. mar. (Pct)	Maint cap. (MW)	Net cap. (MW)	Res. mar. (Pct)	Maint fac.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)
1	744	2157	3352	2287	86.5	2653	4224	2678	84.4	2653	4224	2678	5796	37.2	91	5704	35.0	0.000	2270	3777	2183	80.8
2	672	1927	3242	2296	88.5	2371	4085	2679	86.4	2371	4085	2679	5942	45.5	348	5594	37.0	3.489	2027	3497	2182	86.2
3	744	2058	3129	2251	88.4	2534	3945	2641	86.3	2534	3945	2641	5579	41.4	548	5031	27.5	0.000	2517	3893	2612	86.9
4	720	1853	3053	2044	84.3	2280	3848	2411	82.3	2280	3848	2411	5661	47.1	544	5117	33.0	0.000	2284	3829	2408	82.9
5	744	1731	2669	1912	87.1	2130	3742	1802	76.5	2130	3742	1802	5608	49.8	879	4729	26.4	0.000	2155	3763	1823	77.0
6	720	1672	2694	1836	86.2	2058	3269	2320	87.4	2058	3269	2320	5550	69.8	1058	4493	37.4	5.000	2089	3473	2354	83.5
7	744	1592	2562	1733	83.5	1959	3227	2062	81.6	1959	3227	2062	5425	68.1	1005	4420	37.0	3.664	2002	3432	2110	78.4
8	744	1698	2720	1721	83.9	2089	3430	2010	81.9	2089	3430	2010	5332	55.5	875	4457	29.9	0.000	2126	3634	2053	78.6
9	720	1710	2838	1895	83.7	2105	3578	2245	81.7	2105	3578	2245	5223	46.0	571	4652	30.0	0.000	2135	3602	2280	82.3
10	744	1918	3071	1949	83.9	2360	3869	2284	82.0	2360	3869	2284	5211	34.7	661	4550	17.6	0.000	2363	3845	2279	82.6
11	720	2041	3286	2203	86.3	2512	4140	2579	84.3	2512	4140	2579	5721	38.2	264	5457	31.8	0.000	2151	3716	2096	80.4
12	744	2124	3307	2232	86.3	2614	4169	2613	84.3	2614	4169	2613	5806	39.3	96	5710	37.0	0.120	2234	3734	2113	80.4
AN	8760	22479	3352	1721	76.6	27665	4224	1802	74.8	27665	4224	1802							26354	3893	1823	77.3

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S u m m a r y (gensum) -- A n n u a l g e n e r a t i o n 2003

	Peak Week capacity MW	Un it s	Com- mit. %	-Outage- FOR %	MOR %	-------Energy------- GWh Load	Pump	Dump	Total	Cap. fac. %	Fuel tr. btu	Btu /kWh	Fuel $/ Mbtu	--Variable--- mills/kWh Fuel	O&M	Tot.	-Marginal- time %	mills /kWh	-------M$------- Other O&M	Fuel + var O&M
Nuclear	2466	6	100	5.0	18.9	16533	110	0	16643	77.0	194	11650	0.77	9.0	0.2	9.1	0.03	8.5	0.00	151.79
Lignite	243	5	36.0z	9.4	18.7	591	21	0	612	29.5	4.9	8031	3.32	26.7	0.1	26.8	2.59	38.1	0.00	16.40
Coal	721	7	78.7	10.3	7.5	3671	69	0	3740	64.7	37.1	9923	2.27	22.5	1.1	23.6	0.84	26.4	0.00	88.11
Gas- power	652	5		6.3	4.6	2076	208	0	2284	40.0	19.0	8320	4.61	38.4	0.3	38.6	19.74	40.6	0.00	88.26
Hydro	680	3		0.0	0.0	3184	6	0	3190	49.0	0.0	0	0.00	0.0	0.0	0.0	37.75	41.0	0.00	0.00
Industry	278	0		0.0	0.0	1736	0	0	1736	111	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	86.28
Distribution	374	0		0.0	0.0	1375	0	0	1375	117	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	68.34
DSM.	0	0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Interruptible	0	0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Import/Export	59	1		0.0	0.0	-1799	0	0	-1799	-270	0.0	0	0.00	50.8	0.0	50.8	0.10	303	0.00	-91.32
Pumped storage	600					298			298	5.7							18.61	46.5		
{pumping nec.}	{ 600}						{413}										20.33	32.7		

Total firm 5796 + CS =	5796	37.2%	reserv	27665	413	0	28078	254.9				14.5	100.0	40.3	0.00	407.85
Committed 5277 =	5277	24.9%	ENS	0.0822	LOLP 0.000088	(0.032 days)	Energy Not Served						0.01	50.0		0.00
after MOR 5197 =	5197	23.0%	==========		Commit target	4646 MW 10.0%	Avg. Marginal Cost							40.3		=====
after FOR 4992yy =	4992	18.2%	Load	27665 GWh	Spin. target	422 MW 10.0%	-- based on RC							40.3		407.86
post-DS Peak (4pm Tue)	4224	Fuel $400.60	- Dump 0.00	+ O&M 7.25	+ ENS 0.00 = Total var.	$407.86 + Other									0.00 =	$407.86

* Values from last typical week.
z Commitment reflects must-run and minimum-constrained units -- others excluded from capacity-weighted average.
yy Available capacity meets commitment target.

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S E A S O N A L S U M M A R Y -- A v e r a g e M a r g i n a l C o s t s by season and subperiod (mills/kWh)

Subperiod	Annual	Season Q1	Q2	Q3	Q4
1	43.7	42.8	44.1	46.1	41.8
2	43.1	41.9	43.0	45.4	42.1
3	38.8	40.2	40.0	38.9	36.1
4	36.8	35.4	38.5	38.1	35.4
5	36.6	37.1	38.0	36.7	34.5
Average	40.3	39.9	41.1	41.7	38.6

L o s s o f l o a d p r o b a b i l i t y (%)

1	0.0134	0.0154	0.0022	0.0059	0.0299
2	0.0174	0.0150	0.0019	0.0052	0.0474
3	0.0035	0.0116	0.0001	0.0001	0.0024
4	0.0002	0.0002	0.0000	0.0000	0.0007
5	0.0007	0.0022	0.0000	0.0000	0.0006
Average	0.0088	0.0102	0.0009	0.0026	0.0213

E n e r g y n o t s e r v e d (GWh)

1	0.0147	0.0038	0.0004	0.0015	0.0090
2	0.0588	0.0117	0.0012	0.0040	0.0419
3	0.0078	0.0064	0.0000	0.0001	0.0013
4	0.0003	0.0001	0.0000	0.0000	0.0003
5	0.0005	0.0004	0.0000	0.0000	0.0001
Total	0.0822	0.0224	0.0017	0.0056	0.0525

Load Summary and Maintenance Allocation -- 2004

		Raw load data				Load data scaled to match weekly input requirements				Load data after demand side modifications			Gross firm capacity and maintenance allocation						Remaining load after exogenous load modifications			
Typ. Wk	Hrs.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Gross cap. (MW)	Res. mar. (Pct)	Maint cap. (MW)	Net cap. (MW)	Res. mar. (Pct)	Maint fac.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)
1	744	2157	3352	2287	86.5	2748	4372	2778	84.5	2748	4372	2778	5818	33.1	91	5727	31.0	0.000	2355	3913	2270	80.9
2	696	1996	3242	2296	88.5	2543	4228	2779	86.4	2543	4228	2779	5965	41.1	293	5672	34.2	2.103	2178	3628	2270	86.2
3	744	2058	3129	2251	88.4	2625	4083	2740	86.4	2625	4083	2740	5602	37.2	548	5054	23.8	0.000	2598	4018	2697	86.9
4	720	1853	3053	2044	84.3	2361	3983	2501	82.3	2361	3983	2501	5684	42.7	695	4989	25.3	0.000	2354	3949	2483	82.8
5	744	1731	2669	1912	87.1	2206	3874	1870	76.6	2206	3874	1870	5631	45.4	1084	4546	17.4	0.000	2219	3878	1875	76.9
6	720	1672	2694	1836	86.2	2132	3384	2407	87.5	2132	3384	2407	5573	64.7	885	4688	38.5	5.000	2150	3565	2424	83.8
7	744	1592	2562	1733	83.5	2029	3340	2138	81.6	2029	3340	2138	5447	63.1	946	4502	34.8	5.000	2060	3522	2170	78.6
8	744	1698	2720	1721	83.9	2163	3550	2086	81.9	2163	3550	2086	5355	50.8	783	4572	28.8	0.000	2188	3731	2111	78.8
9	720	1710	2838	1895	83.7	2181	3703	2328	81.8	2181	3703	2328	5246	41.7	366	4880	31.8	0.000	2199	3712	2347	82.3
10	744	1918	3071	1949	83.9	2444	4005	2369	82.0	2444	4005	2369	5234	30.7	502	4732	18.2	0.000	2436	3966	2349	82.6
11	720	2041	3286	2203	86.3	2602	4285	2676	84.3	2602	4285	2676	5744	34.1	91	5652	31.9	0.000	2231	3847	2178	80.5
12	744	2124	3307	2232	86.3	2708	4315	2710	84.3	2708	4315	2710	5829	35.1	91	5737	33.0	0.000	2318	3868	2198	80.5
AN	8784	22548	3352	1721	76.6	28743	4372	1870	74.8	28743	4372	1870							27285	4018	1875	77.3

S u m m a r y (gensum) -- A n n u a l g e n e r a t i o n 2004

	Peak Week capacity MW	Unit s	Com-mit. %	-Outage- FOR %	MOR %	-------Energy------- GWh Load	Pump	Dump	Total	Cap. fac. %	Fuel tr. btu	Btu /kWh	Fuel $/ Mbtu	--Variable--- mills/kWh Fuel	O&M	Tot.	-Marginal- time %	mills /kWh	-------M$------- Other O&M	Fuel + var O&M
Nuclear	2466	6	100	5.0	17.0	16972	109	0	17081	78.9	199	11650	0.77	9.0	0.1	9.1	0.60	8.6	0.00	155.78
Lignite	243	5	32.1z	9.4	18.8	591	27	0	618	29.7	5.2	8383	3.39	28.4	0.1	28.5	2.04	41.2	0.00	17.64
Coal	721	7	84.9	10.3	7.4	3927	82	0	4008	69.2	39.7	9906	2.28	22.6	1.1	23.7	2.01	22.7	0.00	94.97
Gas- power	652	5		6.3	4.6	2318	169	0	2487	43.4	21.5	8657	4.75	41.1	0.3	41.4	22.20	45.0	0.00	102.97
Hydro	680	3		0.0	0.0	3193	6	0	3199	49.0	0.0	0	0.00	0.0	0.0	0.0	35.14	43.9	0.00	0.00
Industry	267	0		0.0	0.0	1675	0	0	1675	111	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	83.25
Distribution	374	0		0.0	0.0	1386	0	0	1386	116	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	68.91
DSM.	0	0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Interruptible	0	0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Import/Export	82	1		0.0	0.0	-1602	0	0	-1602	-185	0.0	0	0.00	51.0	0.0	51.0	0.17	366	0.00	-81.73
Pumped storage	600					282			282	5.3							17.37	51.1		
{pumping nec.}	{ 600}						{391}										20.46	36.5		
Total firm 5818 + CS =	5818		33.1%	reserv		28743	391	0	29134	265.4						15.2	100.0	43.8	0.00	441.79
Committed 5499 =	5499		25.8%		ENS	0.212		LOLP 0.000209	(0.076 days)	Energy Not Served							0.02	50.0		0.01
after MOR 5420 =	5420		24.0%		==========			Commit target	4809 MW 10.0%	Avg. Marginal Cost								43.8		=====
after FOR 5191yy =	5191		18.7%		Load	28743 GWh		Spin. target	437 MW 10.0%	-- based on RC								43.8		441.80
post-DS Peak (4pm Tue)	4372			Fuel $434.10		- Dump 0.00		+ O&M 7.68	+ ENS 0.01 = Total var.	$441.80 + Other									0.00 =	$441.80

* Values from last typical week.
z Commitment reflects must-run and minimum-constrained units -- others excluded from capacity-weighted average.
yy Available capacity meets commitment target.

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SEASONAL SUMMARY -- Average Marginal Costs by season and subperiod (mills/kWh)

Subperiod	Annual	Season Q1	Q2	Q3	Q4
1	48.2	36.8	59.9	50.6	45.6
2	46.9	36.4	56.3	50.1	44.9
3	42.0	34.7	51.5	42.7	39.0
4	39.5	30.2	48.3	41.8	37.8
5	39.4	31.7	48.8	40.0	37.2
Average	43.8	34.4	53.3	45.9	41.5

Loss of load probability (%)

1	0.0418	0.0123	0.0400	0.0594	0.0551
2	0.0413	0.0124	0.0287	0.0443	0.0794
3	0.0037	0.0084	0.0006	0.0020	0.0040
4	0.0008	0.0001	0.0000	0.0004	0.0026
5	0.0010	0.0014	0.0000	0.0003	0.0022
Average	0.0209	0.0090	0.0152	0.0235	0.0366

Energy not served (GWh)

1	0.0496	0.0032	0.0099	0.0191	0.0174
2	0.1519	0.0105	0.0235	0.0409	0.0770
3	0.0085	0.0048	0.0002	0.0010	0.0023
4	0.0014	0.0000	0.0000	0.0002	0.0011
5	0.0008	0.0003	0.0000	0.0001	0.0005
Total	0.2122	0.0189	0.0336	0.0613	0.0984

Load Summary and Maintenance Allocation -- 2005

		Raw load data				Load data scaled to match weekly input requirements				Load data after demand side modifications			Gross firm capacity and maintenance allocation						Remaining load after exogenous load modifications			
Typ. Wk	Hrs.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)	Energy (GWh)	Peak load (MW)	Min. load (MW)	Gross cap. (MW)	Res. mar. (Pct)	Maint cap. (MW)	Net cap. (MW)	Res. mar. (Pct)	Maint fac.	Energy (GWh)	Peak load (MW)	Min. load (MW)	Load fac. (Pct)
1	744	2157	3352	2287	86.5	2846	4523	2884	84.6	2846	4523	2884	5831	28.9	112	5719	26.4	0.000	2449	4062	2372	81.0
2	672	1927	3242	2296	88.5	2543	4374	2886	86.5	2543	4374	2886	5981	36.7	171	5810	32.8	0.000	2187	3769	2372	86.3
3	744	2058	3129	2251	88.4	2719	4224	2845	86.5	2719	4224	2845	5607	32.7	569	5037	19.2	0.000	2694	4165	2806	87.0
4	720	1853	3053	2044	84.3	2446	4120	2595	82.4	2446	4120	2595	5688	38.0	459	5229	26.9	0.000	2441	4091	2581	82.9
5	744	1731	2669	1912	87.1	2285	4007	1942	76.6	2285	4007	1942	5635	40.6	900	4735	18.2	0.000	2300	4014	1949	77.0
6	720	1672	2694	1836	86.2	2208	3501	2498	87.6	2208	3501	2498	5578	59.3	721	4857	38.7	5.000	2228	3677	2517	84.1
7	744	1592	2562	1733	83.5	2101	3456	2218	81.7	2101	3456	2218	5752	66.5	950	4802	39.0	5.000	2133	3633	2251	78.9
8	744	1698	2720	1721	83.9	2241	3673	2166	82.0	2241	3673	2166	5659	54.1	765	4894	33.3	0.020	2266	3849	2193	79.1
9	720	1710	2838	1895	83.7	2259	3831	2416	81.9	2259	3831	2416	5550	44.9	445	5105	33.3	0.486	2278	3842	2436	82.3
10	744	1918	3071	1949	83.9	2532	4143	2460	82.1	2532	4143	2460	5538	33.7	523	5015	21.1	0.000	2526	4109	2444	82.6
11	720	2041	3286	2203	86.3	2695	4433	2779	84.4	2695	4433	2779	6056	36.6	167	5889	32.9	0.000	2320	3993	2276	80.7
12	744	2124	3307	2232	86.3	2805	4464	2814	84.4	2805	4464	2814	6141	37.6	192	5949	33.3	1.446	2410	4014	2297	80.7
AN	8760	22479	3352	1721	76.6	29679	4523	1942	74.9	29679	4523	1942							28231	4165	1949	77.4

S u m m a r y (gensum) -- A n n u a l g e n e r a t i o n 2005

	Peak capacity MW	Week Unit s	Com-mit. %	-Outage- FOR %	MOR %	-------Energy------- GWh Load	Pump	Dump	Total	Cap. fac. %	Fuel tr. btu	Btu /kWh	Fuel $/ Mbtu	--Variable--- mills/kWh Fuel	O&M	Tot.	-Marginal- time %	mills /kWh	-------M$------- Other O&M	Fuel + var O&M
Nuclear	2466	6	100	5.0	14.2	17543	56	0	17599	81.5	205	11650	0.77	9.0	0.1	9.1	0.00	0.0	0.00	160.51
Lignite	243	5	31.4z	9.4	18.7	530	15	0	544	26.2	4.2	7759	3.46	26.8	0.1	27.0	1.81	43.0	0.00	14.68
Coal	721	7	80.0	10.3	10.4	3606	69	0	3675	63.6	36.5	9931	2.33	23.1	1.1	24.2	0.88	26.6	0.00	88.98
Gas- power	652	6		6.3	4.6	3004	237	0	3241	46.1	26.7	8244	4.90	40.4	0.3	40.7	28.12	42.9	0.00	131.82
Hydro	680	3		0.0	0.0	3188	2	0	3190	49.0	0.0	0	0.00	0.0	0.0	0.0	33.38	91.3	0.00	0.00
Industry	256	0		0.0	0.0	1604	0	0	1604	111	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	79.73
Distribution	382	0		0.0	0.0	1404	0	0	1404	117	0.0	0	0.00	49.7	0.0	49.7	0.00	0.0	0.00	69.78
DSM.	0	0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Interruptible	0	0		0.0	0.0	0	0	0	0	0.0	0.0	0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	0.00
Import/Export	86	1		0.0	0.0	-1472	0	0	-1472	-163	0.0	0	0.00	28.6	0.0	28.6	2.34	443	0.00	-42.11
Pumped storage	600					273			273	5.2							15.16	74.4		
(pumping nec.)	{ 600}						{379}										18.30	48.9		
Total firm 5831 + CS =	5831		28.9%	reserv		29679	379	0	30058	272.5						16.7	100.0	74.2	0.00	503.38
Committed 5312 =	5312		17.4%		ENS	0.204		LOLP 0.000199	(0.073 days) Energy Not Served								0.02	50.0		0.01
after MOR 5232 =	5232		15.7%		==========			Commit target	4975 MW 10.0%					Avg. Marginal Cost				74.2		=====
after FOR 5027yy =	5027		11.2%	Load		29679 GWh		Spin. target	452 MW 10.0%					-- based on RC				74.2		503.40
post-DS Peak (4pm Tue)	4523			Fuel $495.81		- Dump 0.00		+ O&M 7.57	+ ENS 0.01 = Total var. $503.40 + Other										0.00 =	$503.40

* Values from last typical week.
z Commitment reflects must-run and minimum-constrained units -- others excluded from capacity-weighted average.
yy Available capacity meets commitment target.

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S E A S O N A L S U M M A R Y -- A v e r a g e M a r g i n a l C o s t s by season and subperiod (mills/kWh)

Subperiod	Annual	Season Q1	Q2	Q3	Q4
1	80.4	182.7	55.9	41.7	43.1
2	79.1	180.6	55.1	40.0	42.8
3	72.1	167.0	50.4	35.3	37.3
4	66.4	149.5	47.0	35.1	35.8
5	68.9	160.8	47.3	34.3	34.8
Average	74.2	169.8	51.8	37.6	39.4

L o s s o f l o a d p r o b a b i l i t y (%)

1	0.0368	0.0619	0.0452	0.0064	0.0345
2	0.0355	0.0627	0.0269	0.0054	0.0474
3	0.0093	0.0338	0.0016	0.0001	0.0023
4	0.0007	0.0021	0.0000	0.0000	0.0006
5	0.0050	0.0194	0.0002	0.0000	0.0005
Average	0.0199	0.0400	0.0154	0.0027	0.0217

E n e r g y n o t s e r v e d (GWh)

1	0.0428	0.0189	0.0117	0.0017	0.0106
2	0.1319	0.0604	0.0223	0.0043	0.0449
3	0.0233	0.0213	0.0007	0.0001	0.0012
4	0.0012	0.0009	0.0000	0.0000	0.0002
5	0.0050	0.0048	0.0000	0.0000	0.0001
Total	0.2041	0.1062	0.0347	0.0061	0.0571

Appendix E Review of Engineering Economics and Financial Terms

Appendix E - REVIEW OF ENGINEERING ECONOMICS AND FINANCIAL TERMS

This section provides a review of financial and economic terms and methods used in this report. The following areas are covered

- Guide to accounting and financial statements
- Inflation and escalation
- Current (or nominal) and constant currency analysis
- Discount rate
- Present value or present worth
- Cost and price levelization
- Depreciation and valuation

E.1. Guide to Accounting / Financial Statements

E.1.1 Balance Sheet

All accounting revolves around the fundamental accounting equation which is

Assets = Liabilities + Equities

Assets are those things of value that are possessed by an individual or a firm (utility). Liabilities are obligations owed by an individual or firm whereas equities are the ownership worth.

The Balance Sheet or Statement of Financial Condition utilizes the above relationship directly. It shows the financial status of an individual or business at a particular point in time.

The balance sheet does not tell what caused the changes in the relationships between assets, liabilities, and equities from one point in time to another. This important information is summarized in the second main type of accounting report and that is the income statement.

E.1.2 Income Statement

This report is based on the relationship:

Revenues - Expenses = Profit (or Loss)

Other key items in the Income Statement are:

Operating Income = Gross Revenue - (Fuel Cost+Purchased Power Cost+Material and Other Cost+ Wages and Services+ Depreciation)
Net Income = Operating Income - Interest Payments - Taxes

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E.1.3 Sources and Applications of Funds Statement

This report generally deals with sources of funds and how these funds are used for an enterprise. The main equation for this report is:

Sources = Applications

Sources and applications are defined as follows:

- Sources = Internal Generation + Borrowing
- Internal Generation = Operating Income + Depreciation + Other Sources
- Borrowing = Foreign Loans + Domestic Loans
- Applications = Investment + Debt Service + Taxes + Change in Working Capital + Change in Cash
- Debt Service = Principal + Interest

E.1.4 Financial Performance Indicators

There are a number of indicators of financial performance based on various components of the Balance Sheet, Income Statement and Sources and Uses of Funds Statement. Some of these are discussed below.

The **Operating Ratio** is defined as the ratio of operating Expenses to total Revenues less Interest and Tax payments. It should be less than 1.

The **Current Ratio** is defined as the ratio of Current Assets to Current Liabilities. It should generally have a value between 1 and 4.

The **Cash Generation Ratio** is defined as the ratio of after-tax cash generation (Operating Income + Depreciation - Taxes - Principal Payments) to total annual Investment and Debt Service requirements. Generally, this ratio should be greater than 0.6.

The **Debt Coverage Ratio** is the ratio of Internal Cash Generation to Debt Coverage (Interest and Principle payments). It should be greater than 1.

Accounts Receivable outstanding in days is a measure of the speed that bills are paid. It is measured as the ratio of annual Accounts Receivable to total annual Revenue.

The **Number of Times Interest Earned Ratio** is the ratio of Operating Income to annual Interest expense. It should be greater than 1.

E.2. Inflation and Escalation

The annual **general inflation rate** is the rate of rise in price caused by a general increase in the prices for goods and services due to the change in the value of currency. The rate of inflation is sensitive to economic and monetary policy and can vary significantly by country.

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The **real escalation rate** is the annual rate of increase in the price of a good due to causes such as resource depletion, increased demand, or changing technical requirements, such as reduction of environmental impact in the production of a given good or service. Real escalation is independent of and exclusive of general inflation.

The price increases that are actually experienced for a given good or service are a combination of general inflation and real escalation. The rate of increase in the price increases as they are experienced is referred to as the **apparent escalation rate**. It is given by the following formula:

apparent escalation rate = (1-general inflation rate) * (1+real escalation rate) - 1

E.3. Current (or Nominal) Currency and Constant Currency Analysis

Economic and financial analysis can be conducted using prices and costs expressed in the terms that they are actually experienced in the years in which they occur. These costs and prices reflect both general inflation and real escalation. Analysis using data expressed in these terms is referred to as **current (or nominal) currency analysis**.

The effects of general inflation does not affect the selection between alternatives in economic studies. These studies are concerned with underlying cost changes, reflected by real escalation, rather than the apparent changes which include the effects of general inflation. **Constant currency analysis** uses costs and prices of goods and services expressed in the value of currency at a given point in time (e.g., Sk in the first quarter of 1994) and the real escalation of those goods and services. In this type of analysis, it is important that all goods and services are expressed in the value of currency at the same point in time. The costs and prices in this type of analysis are often referred to as **real costs and prices.** These costs and prices differ from those actually experienced in that they do not reflect the effects of general inflation.

The same principles of time value of money, and the formulas described previously, apply to both current and constant currency analysis. However, a different discount rate is used in each type of analysis. This is described in more detail in the following section.

Generally, the results from current currency and constant currency analysis are equivalent in terms of selection between alternatives. However, the results of constant currency analysis must be adjusted by the effects of general inflation in order to reflect the prices of goods and services that would actually be experienced by consumers. In addition, studies which focus on taxation issues can be distorted in constant currency analysis because taxes are levied on profits as they are experienced, including the effects of inflation, not in real, or constant currency terms.

Current currency analysis is often used in studies of prices as they are experienced by the final consumer in cases where general inflation is relatively low and stable. This is because the prices are expressed in terms that are actually expected to be experienced by the consumer. In situations of high and unpredictable inflation, constant currency analysis is often applied to pricing studies. However, it is important that the results are qualified as reflecting real price changes and neglecting the effects of general inflation.

E.4. Discount Rate

In economics, the discount rate refers to value reflecting the time value of money and the compound interest formulas apply with the discount rate used as **i** in those formulas. In most economic studies, the discount rate is based on the weighted cost of capital, but can reflect social costs as well.

In economic studies, there is a differentiation between the discount rates used in constant currency and current (or nominal) currency analysis, as described previously. Since general inflation reduces the value of a currency, the cost of capital in constant currency is less than the discount rate as it is actually experienced. The constant currency discount rate is referred to as the real discount rate and is related to the discount rate as it is actually experienced (current currency discount rate) in the following way:

real discount rate = (1 + current currency discount rate)/(1 + general inflation rate) - 1

E.5. Present Value or Present Worth

Since money can earn at a certain interest rate, it is recognized that a dollar in hand at present is worth more than a dollar to be received at some future date. Therefore, the time value of money is an important element in most decision situations involving money flow over time.

Assuming that interest payments are made at the end of each period, if P is invested at interest rate i per year, the interest for the first year is iP and the total amount of principle and interest at the end of the first year is $P + iP = P(1 + i)$.

In the second year, $P(1+i)$ is invested, and therefore, the amount at the end of the third year is $P(1 + i) + P(1 + i)i = P(1 + i)^2$. Similarly, at the end of the third year the amount is $P(1 + i)^3$ and at the end of n periods, it is $P(1 + i)^n$.

Using our notation:

$$F = P(1 + i)^n$$

From the above expression, we can express P in terms of F, I and n as follows:

$$P = F[1/(1 + i)^n]$$

Here P may be thought of as the principle that will give a required amount F in n years; in other words, P is the present worth of a payment of F in n years from now.

E.6. Per Unit Cost and Price Levelization

The purpose of levelization is to provide a means of expressing the value of a varying cost or revenue stream per unit of production or sale with a single number. Single values are often used to describe key characteristics of groups of numbers (e.g., average, mean, etc.). The levelized

value (per unit) is a single number that when multiplied by the number of units or production or sale per year produces a cost (or revenue) stream with the same present worth as the actual costs (or revenues). For example:

The present worth of 6-year revenue requirements in 1994 =
$RR_{95}/(1+i) + RR_{96}/(1+i)^2 + RR_{97}/(1+i)^3 + RR_{98}/(1+i)^4 + RR_{99}/(1+i)^5 + RR_{2000}/(1+i)^6$

where Rm = revenue requirement in year m

By definition, the is present worth of the 6-year revenue requirements =
$LRR*S_{95}/(1+i) + LRR*S_{96}/(1+i)^2 + LRR*S_{97}/(1+i)^3 +$
$LRR*S_{98}/(1+i)^4 + LRR*S_{99}/(1+i)^5 + LRR*S_{2000}/(1+i)^6$

where:
LRR = Levelized revenue requirements per unit of sales
Sm = Sales in year m

Therefore, the per unit levelized revenue requirements (LRR)=

$$\frac{\sum_{n=1,5} RR_{94+n} / (1+i)^n}{\sum_{n=1,5} S_{94+n} / (1+i)^n}$$

E.7. Depreciation and Valuation

The actual amount of depreciation can never be determined until the asset is retired from service. Depreciation represents a decrease in value because the ability of the asset to produce these future cash flows decreases, due to one or more of several causes, with passage of time.

E.7.1.1 Definition of Value

One of the best definitions of value, in a commercial sense, is that it is the **present worth of all the future profits that are to be received through ownership of a particular property**. This is difficult to apply.

A second definition of value is the **market value**. A third type of value is known as **fair value**. This usually is determined by a disinterested party in order to establish a price that is fair to both seller and buyer.

Book Value is the worth of a property as shown on the accounting records of a company. It is ordinarily taken to mean the original cost of the property less the amounts that have been charged as depreciation expense.

Salvage, or resale, value is the price that can be obtained from the sale of the property second-hand. Salvage value implies that the property has further utility (use).

E.7.1.2 Purposes of Depreciation

Because property decreases in value, it is desirable to consider the effect that this depreciation has on engineering projects. Primarily, it is necessary to consider depreciation for two reasons:

- To provide for the recovery of capital that has been invested in physical property.
- To enable the cost of depreciation to be charged to the cost of producing products or services that result from the use of the property. Depreciation cost is real, as are labor and material costs, and it is deductible in computing profits on which income taxes are paid.

E.7.1.3 Economic Life

In an economic study we are concerned with the length of time during which a physical asset can be used, in competition, so as to be profitable. When it no longer can be used profitably, it has no further commercial value, and we do not wish to posses it longer. Consequently, we are concerned with what often is called economic life. The entire amount of depreciation should be written off during this economic life.

E.7.1.4 Straight Line Depreciation

There are many methods for depreciating an asset. The most common and the only method used in the study is the straight line method. There are other methods that involve more rapid depreciation and are generally used for tax purposes under the tax codes of some countries.

The straight line method of computing depreciation assumes that the loss in value is directly proportional to the age of the structure. The straight line relationship gives the name to the method. Using the following notations:

L = useful life of the structure in years,

C = the original cost,

d = the annual cost of depreciation,

Cn= the book value at the end of n years,

CL= the value at the end of the life of the structure, the scrap value (including gain or loss due to removal), and

Dn= depreciation up to age n years

then

$$d = (C - CL) / L$$

$$Dn = n (C - CL) / L$$

$$Cn = C - n (C - CL) / L$$

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Example

A new asset is purchased for 120,000 Sk and is estimated to have a life of 10 years and a scrap value of 20,000 Sk at the end of that time. What is the annual depreciation cost, the total depreciation cost up to the end of the sixth year, and the book value at the end of the sixth year?

Applying the Straight Line Method

d = (120,000 - 20,000) / 10 = 10,000 Sk

D6= 6 (120,000 - 20,000) / 10 = 60,000 Sk

A. C6= 120,000 - 6 (120,000 - 20,000) / 10 = 60,000 Sk

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Slovak Electricity Pricing and Retail Tariff Study

Final Report

Volume III
Appendix F

Prepared under Contract EUR-0030-C00-2055-00
U.S. AGENCY FOR INTERNATIONAL DEVELOPMENT
Bureau for Europe – Energy and Infrastructure Division
Eastern Europe Energy Efficiency Project – Electric Power

performed by

Bechtel Corporation

with subcontractors

Arthur Andersen & Co.
Power Research Institute, Bratislava

In cooperation with: The Ministry of Economy, Republic of Slovakia
The Ministry of Finance, Republic of Slovakia
The Slovak National Power Company
The West Slovak Distribution Company
The Central Slovak Distribution Company
The East Slovak Distribution Company

July 1995

Appendix F Pro Forma Financial Statements for the Slovak National Power Co. (SE)

Generation System

SE Generation								
Income Statement								
(thousands U.S. $)								
Year	1993	1994	1995	1996	1997	1998	1999	2000
SEP Domestic Generation (GWh)	19,304	18,812	18,784	19,148	18,924	19,862	20,717	21,591
EHV Transmission Losses (GWh	356	371	375	387	439	475	480	486
Domestic Sales (GWh)	18,948	18,441	18,409	18,761	18,485	19,387	20,237	21,105
Exports (GWh)	720	0	225	457	2,500	3,500	3,000	2,500
Peak (MW)	3,441	3,307	3,304	3,358	3,434	3,558	3,684	3,812
Domestic Sales Price (mills/kWh)	34.2	33.8	37.0	41.6	39.7	38.0	38.2	44.9
Export Sales Price (mills/kWh)	42.3	#N/A	43.2	44.5	45.6	46.8	48.1	49.5
Revenue								
Domestic Sales	647,809	622,758	681,636	779,837	734,137	735,810	773,220	947,826
Exports	30,473	0	9,728	20,352	114,023	163,946	144,322	123,853
Total Revenue	678,282	622,758	691,364	800,189	848,161	899,756	917,542	1,071,680
Expenses								
Fuel	148,257	133,923	167,232	247,149	216,575	220,488	244,678	261,354
Purchased Power	39,289	34	18	11,657	64	45	67	6,976
Material & Others	25,236	21,654	21,955	22,369	25,603	25,350	25,622	28,899
Labor & Services	80,819	103,722	104,023	104,436	128,585	128,333	128,605	152,797
Depreciation	36,544	182,027	191,016	171,431	210,595	202,165	205,613	312,592
Decommissioning	0	0	30,781	69,094	58,688	65,572	60,396	65,112
Nonpayment Allowance	0	31,138	34,568	40,009	42,408	44,988	45,877	53,584
Total Expenses	330,144	472,498	549,593	666,145	682,517	686,941	710,858	881,314
Operating Income	348,138	150,260	141,771	134,044	165,643	212,815	206,684	190,366
Interest								
Foreign Loans	0	0	5,448	10,108	17,370	22,407	27,889	34,316
Domestic Loans	27,219	37,215	38,173	38,944	41,342	43,564	44,556	45,521
Total Interest	27,219	37,215	43,621	49,052	58,711	65,971	72,445	79,836
Corporate Taxes	108,283	45,218	39,260	33,997	42,773	58,738	53,695	44,212
Net Income	183,366	67,827	58,890	50,996	64,159	88,106	80,543	66,318

SE Generation
Sources and Applications of Funds Statement
(thousands U.S. $)

Year	1993	1994	1995	1996	1997	1998	1999	2000
SOURCES	489,776	366,215	503,037	456,804	614,207	591,855	609,797	737,646
Internal Generation								
Operating Income	348,138	150,260	141,771	134,044	165,643	212,815	206,684	190,366
Depreciation	36,544	182,027	191,016	171,431	210,595	202,165	205,613	312,592
Other	0	0	0	0	0	0	0	0
Total Internal Generation	384,682	332,287	332,787	305,476	376,239	414,980	412,297	502,958
Borrowing								
Foreign Loans	0	0	136,200	121,063	190,375	141,500	158,000	187,750
Domestic Loans	105,094	33,928	34,050	30,266	47,594	35,375	39,500	46,938
Total Borrowing	105,094	33,928	170,250	151,328	237,969	176,875	197,500	234,688
APPLICATIONS	489,776	366,215	503,037	456,804	614,207	591,855	609,797	737,646
Investment								
General Investment	193,695	67,856	340,500	302,656	475,938	353,750	395,000	469,375
Interest During Construct	5,024	0	0	0	0	0	0	0
Total Investment	198,719	67,856	340,500	302,656	475,938	353,750	395,000	469,375
Debt Services								
Principal								
Foreign Loans	0	0	4,574	8,822	15,568	20,943	27,086	34,475
Domestic Loans	3,856	80,267	77,358	74,757	92,451	117,597	116,293	110,215
Interest								
Foreign Loans	0	0	5,448	10,108	17,370	22,407	27,889	34,316
Domestic Loans	27,219	37,215	38,173	38,944	41,342	43,564	44,556	45,521
Total Debt Service	31,075	117,482	125,553	132,631	166,731	204,510	215,824	224,526
Taxes	108,283	45,218	39,260	33,997	42,773	58,738	53,695	44,212
Change in Working Capit	221,688	(145,053)	29,709	59,441	(32,449)	(20,587)	13,087	26,670
Change in Cash	(69,989)	280,712	(31,985)	(71,922)	(38,785)	(4,556)	(67,810)	(27,138)

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SE Generation								
Balance Sheet								
(thousands U.S. $)								
Year	1993	1994	1995	1996	1997	1998	1999	2000
ASSETS	1,815,336	3,973,265	4,121,313	4,250,052	4,457,742	4,608,278	4,743,590	4,899,405
Fixed Assets								
Fixed Assets in Operation	1,084,250	3,234,468	3,283,999	3,326,655	4,063,895	5,052,251	5,155,689	5,196,314
Less Accumulated Depreciation	(548,106)	(730,133)	(921,149)	(1,092,580)	(1,303,176)	(1,505,341)	(1,710,954)	(2,023,546)
Net Fixed Assets	536,144	2,504,334	2,362,850	2,234,075	2,760,719	3,546,910	3,444,735	3,172,767
Work in Progress	1,019,150	1,001,481	1,292,450	1,552,450	1,291,148	656,541	948,104	1,376,854
Total Fixed Assets	1,555,294	3,505,816	3,655,300	3,786,525	4,051,867	4,203,452	4,392,838	4,549,621
Current Assets								
Cash	(69,989)	210,723	178,738	106,816	68,031	63,475	(4,335)	(31,472)
Accounts Receivable	122,281	98,998	105,079	116,034	117,070	117,912	113,839	125,483
Inventory	163,281	113,260	137,728	196,209	176,305	178,970	196,779	211,304
Others	44,469	44,469	44,469	44,469	44,469	44,469	44,469	44,469
Total Current Assets	260,042	467,450	466,014	463,527	405,876	404,826	350,752	349,784
EQUITY & LIABILITIES	1,815,336	3,905,439	4,062,423	4,199,056	4,393,583	4,520,172	4,663,047	4,833,087
Equity								
Capital	1,368,033	3,616,091	3,683,918	3,742,808	3,793,804	3,857,963	3,946,069	4,026,612
Retained Earnings	183,366	67,827	58,890	50,996	64,159	88,106	80,543	66,318
Total Equity	1,551,399	3,683,918	3,742,808	3,793,804	3,857,963	3,946,069	4,026,612	4,092,930
Long-term Debt								
Foreign Loans	0	0	131,626	243,866	418,673	539,230	670,144	823,419
Domestic Loans	217,250	170,911	127,603	83,112	38,254	(43,967)	(120,760)	(184,037)
Total Long-Term Debt	217,250	170,911	259,229	326,978	456,928	495,263	549,384	639,382
Current Liabilities								
Short-Term Loans	0	75,130	70,885	67,022	82,822	106,407	103,342	95,183
Accounts Payable	42,281	38,900	43,984	57,842	55,624	56,132	59,846	67,504
Other	4,406	4,406	4,406	4,406	4,406	4,406	4,406	4,406
Total Current Liabilities	46,688	118,436	119,276	129,270	142,852	166,946	167,594	167,093

Transmission System (>200 kV)

SEP EHV Transmission System								
Income Statement								
(thousands U.S. $)								
Year	1993	1994	1995	1996	1997	1998	1999	2000
SEP Generation (GWh)	19,304	18,812	18,784	19,148	18,924	19,862	20,717	21,591
Transmission Losses (GWh)	356	371	375	387	439	475	480	486
Domestic Sales (GWh)	18,948	18,441	18,409	18,761	18,485	19,387	20,237	21,105
Exports (GWh)	720	0	225	457	2,500	3,500	3,000	2,500
Peak (MW)	3,441	3,307	3,304	3,358	3,434	3,558	3,684	3,812
Domestic Sales Price ($/MWh)	0.9	2.2	2.3	2.6	2.7	2.8	2.7	2.7
Revenue								
Domestic Sales	16,750	41,195	44,049	49,075	51,940	55,450	56,778	58,361
Exports	0	0	0	0	0	0	0	0
Total Revenue	16,750	41,195	44,049	49,075	51,940	55,450	56,778	58,361
Expenses								
Fuel	2,684	2,694	3,410	5,095	5,138	5,397	5,805	6,017
Purchased Power	711	1	0	240	2	1	2	161
Material & Others	345	376	417	458	506	528	551	574
Labor & Services	3,452	3,755	4,165	4,583	5,061	5,279	5,511	5,743
Depreciation	3,425	16,437	17,194	18,219	19,262	20,457	21,004	21,798
Decommissioning	0	0	0	0	0	0	0	0
Nonpayment Allowance	0	2,060	2,202	2,454	2,597	2,773	2,839	2,918
Total Expenses	10,617	25,322	27,389	31,049	32,565	34,435	35,712	37,212
Operating Income	6,133	15,874	16,660	18,026	19,374	21,015	21,066	21,150
Interest								
Foreign Loans	0	0	458	1,061	1,654	2,316	2,560	2,810
Domestic Loans	153	660	785	961	1,133	1,330	1,382	1,436
Total Interest	153	660	1,243	2,022	2,787	3,646	3,942	4,245
Corporate Taxes	2,453	6,085	6,167	6,402	6,635	6,948	6,850	6,762
Net Income	3,680	9,128	9,251	9,603	9,952	10,421	10,275	10,143

SEP EHV Transmission System
Sources and Uses of Funds Statement
(thousands U.S. $)

Year	1993	1994	1995	1996	1997	1998	1999	2000
SOURCES	9,558	38,888	48,152	55,573	58,324	64,019	52,383	53,886
Internal Generation								
Operating Income	6,133	15,874	16,660	18,026	19,374	21,015	21,066	21,150
Depreciation	3,425	16,437	17,194	18,219	19,262	20,457	21,004	21,798
Other	0	0	0	0	0	0	0	0
Total Internal Generation	9,558	32,310	33,855	36,245	38,637	41,472	42,070	42,948
Borrowing								
Foreign Loans	0	0	11,438	15,463	15,750	18,038	8,250	8,750
Domestic Loans	0	6,578	2,859	3,866	3,938	4,509	2,063	2,188
Total Borrowing	0	6,578	14,297	19,328	19,688	22,547	10,313	10,938
APPLICATIONS	9,558	38,888	48,152	55,573	58,324	64,019	52,383	53,886
Investment								
General Investment	4,738	13,156	28,594	38,656	39,375	45,094	20,625	21,875
Interest During Constructic	0	(0)	0	0	0	0	0	0
Total Investment	4,738	13,156	28,594	38,656	39,375	45,094	20,625	21,875
Debt Services								
Principal								
Foreign Loans	0	0	384	919	1,484	2,149	2,513	2,907
Domestic Loans	3,066	8,158	8,656	9,482	10,307	11,303	11,430	11,581
Interest								
Foreign Loans	0	0	458	1,061	1,654	2,316	2,560	2,810
Domestic Loans	153	660	785	961	1,133	1,330	1,382	1,436
Total Debt Service	3,220	8,818	10,283	12,422	14,578	17,099	17,885	18,733
Taxes	2,453	6,085	6,167	6,402	6,635	6,948	6,850	6,762
Change in Working Capital	840	55	(277)	842	875	375	496	1,725
Change in Cash	(1,693)	10,774	3,385	(2,749)	(3,140)	(5,496)	6,527	4,791

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SEP EHV Transmission System								
Balance Sheet								
(thousands U.S. $)								
Year	1993	1994	1995	1996	1997	1998	1999	2000
ASSETS	64,620	282,300	299,314	320,640	339,857	361,723	368,859	374,679
Fixed Assets								
Fixed Assets in Operation	125,569	345,237	375,547	416,522	458,260	506,059	527,922	551,109
Less Accumulated Depreciation	(64,242)	(80,678)	(97,873)	(116,092)	(135,354)	(155,811)	(176,815)	(198,613)
Net Fixed Assets	61,327	264,559	277,674	300,431	322,906	350,248	351,107	352,496
Work in Progress	0	0	0	0	0	0	0	0
Total Fixed Assets	61,327	264,559	277,674	300,431	322,906	350,248	351,107	352,496
Current Assets								
Cash & Banks	(1,693)	9,081	12,467	9,718	6,578	1,082	7,609	12,400
Accounts Receivable	2,780	6,549	6,695	7,116	7,169	7,267	7,044	6,834
Inventory	2,205	2,111	2,479	3,375	3,204	3,126	3,099	2,949
Others	0	0	0	0	0	0	0	0
Total Current Assets	3,292	17,742	21,640	20,209	16,951	11,475	17,753	22,183
EQUITY & LIABILITIES	64,620	282,300	299,314	320,640	339,857	361,723	368,859	374,679
Equity								
Capital	56,795	253,9[illegible]	247,073	239,137	229,378	219,485	208,854	196,867
Retained Earnings	3,680	12,[illegible]	22,058	31,661	41,613	52,035	62,309	72,452
Total Equity	60,474	266,762	269,131	270,798	270,991	271,519	271,163	269,319
Long-term Debt								
Foreign Loans	0	0	11,438	26,516	41,347	57,900	64,001	70,238
Domestic Loans	0	6,578	9,217	12,756	16,225	20,115	21,382	22,672
Total Long-Term Debt	0	6,578	20,654	39,272	57,573	78,015	85,383	92,911
Current Liabilities								
Short-Term Loans	3,066	7,937	8,330	9,013	9,687	10,507	10,533	10,575
Accounts Payable	1,079	1,024	1,199	1,556	1,606	1,681	1,780	1,874
Other	0	0	0	0	0	0	0	0
Total Current Liabilities	4,145	8,961	9,529	10,569	11,293	12,188	12,314	12,449

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Slovak Electricity Pricing and Retail Tariff Study

Final Report

Volume IV
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In cooperation with: The Ministry of Economy, Republic of Slovakia
The Ministry of Finance, Republic of Slovakia
The Slovak National Power Company
The West Slovak Distribution Company
The Central Slovak Distribution Company
The East Slovak Distribution Company

July 1995

Appendix G Pro Forma Financial Statements for the West Slovak Distribution Co. (ZSE)

ZSE Distribution System

Income Statement

(millions Sk)

Year	1993	1993	1993	1993	1994	1994	1994	1994	1999	1999	1999	1999
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
Energy Delivered To Grid (GWh)	6548	4943	2876	N/A	6457	4909	2882	N/A	7408	5732	3350	N/A
T&D Losses (Assoc. W/Grid) (GWh)	183	131	247	561	181	130	185	496	202	148	171	521
Energy Leaving Less Losses (GWh)	6365	4813	2629	N/A	6276	4778	2697	N/A	7206	5584	3179	N/A
Energy Sales By Voltage Class (GWh)	1421	1937	2629	5987	1368	1897	2697	5961	1474	2234	3179	6887
Grid Cost (SK/MWh)	59.92	136.79	208.87	N/A	76.28	184.60	275.63	N/A	63.17	155.11	227.52	N/A
T&D Avg. Price (SK/MWh)	59.92	198.33	425.85	N/A	76.28	262.96	556.63	N/A	63.17	219.96	459.29	N/A
Revenue												
Domestic Sales-Voltage Class	2079	3037	3779	8895	476	882	743	2101	452	863	721	2042
Other	48	0	0	48	3	0	0	3	3	3	3	3
Total Revenue	2127	3037	3779	8943	479	882	743	2104	455	866	723	2045
Expenses												
Fuel	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	1746	2379	3229	7354	0	0	0	0	0	0	0	0
Material & Others	137	183	169	490	141	189	175	504	141	189	175	504
Labor & Services	126	195	135	456	130	200	139	469	130	200	139	469
Depreciation	29	68	59	156	58	137	119	313	60	141	123	324
Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0
Total Expenses	2038	2825	3594	8456	329	526	433	1287	331	530	437	1297
Operating Income	90	212	185	487	150	357	311	817	125	336	287	747
Interest												
World Bank & EBRD	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	9	21	18	47
Total Interest	0	0	0	0	0	0	0	0	9	21	18	47
Corporate Taxes	36	85	74	195	60	143	124	327	46	126	107	280
Net Income	54	127	111	292	90	214	186	490	78	210	179	467

ZSE Distribution System

Income Statement

(millions Sk)

Year	1993	1993	1993	1993	1994	1994	1994	1994	1995	1995	1995	199
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	To
Energy Delivered To Grid (GWh)	6548	4943	2876	N/A	6457	4909	2882	N/A	6468	4955	2943	N
T&D Losses (Assoc. W/Grid) (GWh)	183	131	247	561	181	130	185	496	181	131	160	47
Energy Leaving Less Losses (GWh)	6365	4813	2629	N/A	6276	4778	2697	N/A	6287	4824	2783	N
Energy Sales By Voltage Class (GWh)	1421	1937	2629	5987	1368	1897	2697	5961	1332	1881	2783	599
Grid Cost (SK/MWh)	59.92	136.79	208.87	N/A	76.28	184.60	275.63	N/A	72.90	181.15	262.29	N
T&D Avg. Price (SK/MWh)	59.92	198.33	425.85	N/A	76.28	262.96	556.63	N/A	72.90	256.03	533.06	N
Revenue												
Domestic Sales-Voltage Class	2079	3037	3779	8895	476	882	743	2101	456	874	730	205
Other	48	0	0	48	3	0	0	3	3	0	0	
Total Revenue	2127	3037	3779	8943	479	882	743	2104	458	874	730	206
Expenses												
Fuel	0	0	0	0	0	0	0	0	0	0	0	
Purchased Power	1746	2379	3229	7354	0	0	0	0	0	0	0	
Material & Others	137	183	169	490	141	189	175	504	141	189	175	50
Labor & Services	126	195	135	456	130	200	139	469	130	200	139	46
Depreciation	29	68	59	156	58	137	119	313	58	137	119	31
Decommissioning	0	0	0	0	0	0	0	0	0	0	0	
Total Expenses	2038	2825	3594	8456	329	526	433	1287	329	526	433	128
Operating Income	90	212	185	487	150	357	311	817	130	348	297	77
Interest												
World Bank & EBRD	0	0	0	0	0	0	0	0	0	0	0	
Domestic Loans	0	0	0	0	0	0	0	0	2	4	4	1
Total Interest	0	0	0	0	0	0	0	0	2	4	4	1
Corporate Taxes	36	85	74	195	60	143	124	327	51	137	117	30
Net Income	54	127	111	292	90	214	186	490	78	210	180	46

ZSE Distribution System

Income Statement

(millions Sk)

Year	1996	1996	1996	1996	1997	1997	1997	1997	1998	1998	1998
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV
Energy Delivered To Grid (GWh)	6615	5093	3036	N/A	6795	5248	3124	N/A	7114	5505	3256
T&D Losses (Assoc. W/Grid) (GWh)	184	134	161	479	188	138	148	474	195	143	177
Energy Leaving Less Losses (GWh)	6431	4959	2875	N/A	6607	5111	2976	N/A	6919	5362	3079
Energy Sales By Voltage Class (GWh)	1338	1923	2875	6136	1358	1987	2976	6321	1414	2106	3079
Grid Cost (SK/MWh)	71.14	175.82	253.33	N/A	69.13	170.21	244.16	N/A	65.90	161.88	235.44
T&D Avg. Price (SK/MWh)	71.14	248.88	516.15	N/A	69.13	241.20	497.37	N/A	65.90	229.53	478.17
Revenue											
Domestic Sales-Voltage Class	455	872	728	2055	454	870	727	2050	453	868	725
Other	3	0	0	3	3	0	0	3	3	0	0
Total Revenue	458	872	728	2058	457	870	727	2053	456	868	725
Expenses											
Fuel	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0
Material & Others	141	189	175	504	141	189	175	504	141	189	175
Labor & Services	130	200	139	469	130	200	139	469	130	200	139
Depreciation	58	138	120	317	59	139	121	319	59	140	122
Decommissioning	0	0	0	0	0	0	0	0	0	0	0
Total Expenses	329	527	434	1290	330	528	435	1293	330	529	436
Operating Income	128	345	294	767	127	342	292	760	126	339	289
Interest											
World Bank & EBRD	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	4	9	7	20	5	13	11	29	7	17	15
Total Interest	4	9	7	20	5	13	11	29	7	17	15
Corporate Taxes	50	134	115	299	49	132	112	292	48	129	110
Net Income	78	210	179	468	78	210	179	468	78	210	179

ZSE Distribution System

Income Statement

(millions Sk)

Year	1998	1999	1999	1999	1999
Voltage Class	Total	VHV	HV	LV	Total
Energy Delivered To Grid (GWh)	N/A	7408	5732	3350	N/A
T&D Losses (Assoc. W/Grid) (GWh)	515	202	148	171	521
Energy Leaving Less Losses (GWh)	N/A	7206	5584	3179	N/A
Energy Sales By Voltage Class (GWh)	6599	1474	2234	3179	6887
Grid Cost (SK/MWh)	N/A	63.17	155.11	227.52	N/A
T&D Avg. Price (SK/MWh)	N/A	63.17	219.96	459.29	N/A
Revenue					
Domestic Sales-Voltage Class	2046	452	863	721	2042
Other	3	3	3	3	3
Total Revenue	2049	455	866	723	2045
Expenses					
Fuel	0	0	0	0	0
Purchased Power	0	0	0	0	0
Material & Others	504	141	189	175	504
Labor & Services	469	130	200	139	469
Depreciation	321	60	141	123	324
Decommissioning	0	0	0	0	0
Total Expenses	1295	331	530	437	1297
Operating Income	754	125	336	287	747
Interest					
World Bank & EBRD	0	0	0	0	0
Domestic Loans	38	9	21	18	47
Total Interest	38	9	21	18	47
Corporate Taxes	286	46	126	107	280
Net Income	468	73	210	179	467

ZSE Distribution System
Balance Sheets
(millions Sk)

Year	1993	1993	1993	1993	1994	1994	1994	1994	1999	1999	1999	1999
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
ASSETS	1202	2688	2335	6224	2812	6957	5985	15754	3364	8388	7213	18966
Fixed Assets												
Fixed Assets in Operation	1631	4094	3533	9258	4894	12283	10598	27775	5067	12695	10956	28719
Less Accumulated Depreciation	900	2135	1860	4894	2699	6404	5579	14681	2990	7095	6181	16265
Net Fixed Assets	732	1960	1673	4364	2195	5879	5019	13093	2077	5600	4776	12454
Work in Progress	97	231	202	530	97	231	202	530	0	0	0	0
Total Fixed Assets	829	2191	1874	4895	2293	6111	5220	13623	2077	5600	4776	12454
Current Assets												
Cash & Banks	53	71	66	190	200	420	370	991	1026	2440	2115	5581
Accounts Receivable	257	343	318	918	257	343	318	918	199	266	246	710
Inventory	62	82	76	220	62	82	76	220	62	82	76	220
Others	0	0	0	1	0	0	0	1	0	0	0	1
Total Current Assets	372	497	460	1330	520	847	764	2130	1287	2788	2437	6512
EQUITY & LIABILITIES	1202	2688	2335	6224	2812	6957	5985	15754	3364	8388	7213	18966
Equity												
Capital	1009	2393	2085	5487	2529	6448	5549	14526	2529	6448	5549	14526
Retained Earnings	22	51	45	118	112	265	231	608	504	1316	1128	2948
Total Equity	1030	2445	2130	5605	2641	6713	5780	15134	3033	7764	6677	17473
Long-term Debt												
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	3	7	6	15	3	7	6	15	163	387	338	888
Total Long-Term Debt	3	7	6	15	3	7	6	15	163	387	338	888
Current Liabilities												
Short-Term Loans	25	35	29	88	25	35	29	88	25	35	29	88
Accounts Payable	140	197	166	503	140	197	166	503	140	197	166	503
Other	4	5	4	13	4	5	4	13	4	5	4	13
Total Current Liabilities	168	237	199	604	168	237	199	604	168	237	199	604

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ZSE Distribution System
Balance Sheets
(millions Sk)

Year	1993	1993	1993	1993	1994	1994	1994	1994	1995	1995	1995	1995
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
ASSETS	1202	2688	2335	6224	2812	6957	5985	15754	2923	7244	6231	16398
Fixed Assets												
Fixed Assets in Operation	1631	4094	3533	9258	4894	12283	10598	27775	4916	12336	10643	27895
Less Accumulated Depreciation	900	2135	1860	4894	2699	6404	5579	14681	2756	6540	5698	14994
Net Fixed Assets	732	1960	1673	4364	2195	5879	5019	13093	2160	5795	4945	12900
Work in Progress	97	231	202	530	97	231	202	530	0	0	0	0
Total Fixed Assets	829	2191	1874	4895	2293	6111	5220	13623	2160	5795	4945	12900
Current Assets												
Cash & Banks	53	71	66	190	200	420	370	991	457	1040	907	2404
Accounts Receivable	257	343	318	918	257	343	318	918	244	326	302	872
Inventory	62	82	76	220	62	82	76	220	62	82	76	220
Others	0	0	0	1	0	0	0	1	0	0	0	1
Total Current Assets	372	497	460	1330	520	847	764	2130	763	1449	1285	3497
EQUITY & LIABILITIES	1202	2688	2335	6224	2812	6957	5985	15754	2923	7244	6231	16398
Equity												
Capital	1009	2393	2085	5487	2529	6448	5549	14526	2529	6448	5549	14526
Retained Earnings	22	51	45	118	112	265	231	608	190	476	411	1077
Total Equity	1030	2445	2130	5605	2641	6713	5780	15134	2719	6924	5959	15602
Long-term Debt												
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	3	7	6	15	3	7	6	15	35	83	72	191
Total Long-Term Debt	3	7	6	15	3	7	6	15	35	83	72	191
Current Liabilities												
Short-Term Loans	25	35	29	88	25	35	29	88	25	35	29	88
Accounts Payable	140	197	166	503	140	197	166	503	140	197	166	503
Other	4	5	4	13	4	5	4	13	4	5	4	13
Total Current Liabilities	168	237	199	604	168	237	199	604	168	237	199	604

ZSE Distribution System
Balance Sheets
(millions Sk)

Year	1996	1996	1996	1996	1997	1997	1997	1997	1998	1998	199
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	L
ASSETS	3035	7535	6481	17051	3146	7823	6728	17697	3256	8107	697
Fixed Assets											
Fixed Assets in Operation	4953	12423	10719	28095	4990	12512	10797	28299	5028	12603	1087
Less Accumulated Depreciation	2814	6678	5817	15309	2872	6816	5937	15625	2931	6955	605
Net Fixed Assets	2139	5745	4902	12786	2118	5696	4859	12673	2098	5648	481
Work in Progress	0	0	0	0	0	0	0	0	0	0	
Total Fixed Assets	2139	5745	4902	12786	2118	5696	4859	12673	2098	5648	481
Current Assets											
Cash & Banks	603	1397	1215	3215	746	1749	1519	4015	887	2097	181
Accounts Receivable	232	310	287	828	220	294	272	787	209	280	25
Inventory	62	82	76	220	62	82	76	220	62	82	76
Others	0	0	0	1	0	0	0	1	0	0	
Total Current Assets	897	1790	1578	4265	1028	2127	1868	5023	1159	2460	215
EQUITY & LIABILITIES	3035	7535	6481	17051	3146	7823	6728	17697	3256	8107	697
Equity											
Capital	2529	6448	5549	14526	2529	6448	5549	14526	2529	6448	554
Retained Earnings	269	686	590	1545	347	896	770	2013	425	1106	94
Total Equity	2798	7134	6139	16071	2876	7344	6318	16539	2954	7554	649
Long-term Debt											
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	69	164	143	376	102	242	210	554	133	316	275
Total Long-Term Debt	69	164	143	376	102	242	210	554	133	316	275
Current Liabilities											
Short-Term Loans	25	35	29	88	25	35	29	88	25	35	29
Accounts Payable	140	197	166	503	140	197	166	503	140	197	166
Other	4	5	4	13	4	5	4	13	4	5	4
Total Current Liabilities	168	237	199	604	168	237	199	604	168	237	199

ZSE Distribution System
Balance Sheets
(millions Sk)

Year	1998	1999	1999	1999	1999
Voltage Class	Total	VHV	HV	LV	Total
ASSETS	18335	3364	8388	7213	18966
Fixed Assets					
Fixed Assets in Operation	28507	5067	12695	10956	28719
Less Accumulated Depreciation	15944	2990	7095	6181	16265
Net Fixed Assets	12562	2077	5600	4776	12454
Work in Progress	0	0	0	0	0
Total Fixed Assets	12562	2077	5600	4776	12454
Current Assets					
Cash & Banks	4804	1026	2440	2115	5581
Accounts Receivable	748	199	266	246	710
Inventory	220	62	82	76	220
Others	1	0	0	0	1
Total Current Assets	5773	1287	2788	2437	6512
EQUITY & LIABILITIES	18335	3364	8388	7213	18966
Equity					
Capital	14526	2529	6448	5549	14526
Retained Earnings	2480	504	1316	1128	2948
Total Equity	17006	3033	7764	6677	17473
Long-term Debt					
Foreign Loans	0	0	0	0	0
Domestic Loans	725	163	387	338	888
Total Long-Term Debt	725	163	387	338	888
Current Liabilities					
Short-Term Loans	88	25	35	29	88
Accounts Payable	503	140	197	166	503
Other	13	4	5	4	13
Total Current Liabilities	604	168	237	199	604

ZSE Distribution System
Sources and Uses of Funds Statement
(millions Sk)

Year	1993	1993	1993	1993	1994	1994	1994	1994	1999	1999	1999	1999
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
SOURCES	118	281	244	643	230	545	475	1250	224	572	492	1287
Internal Generation												
Operating Income	90	212	185	487	150	357	311	817	125	336	287	747
Depreciation	29	68	59	156	58	137	119	313	60	141	123	324
Other	0	0	0	0	0	0	0	0	0	0	0	0
Total Internal Generation	118	281	244	643	208	493	430	1130	184	477	410	1071
Borrowing												
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	22	52	46	120	40	94	82	216
Total Borrowing	0	0	0	0	22	52	46	120	40	94	82	216
APPLICATIONS	118	281	244	643	230	545	475	1250	224	572	492	1287
Investment												
General Investment	0	0	0	0	22	52	46	120	40	94	82	216
Interest During Construction	0	0	0	0	0	0	0	0	0	0	0	0
Total Investment	0	0	0	0	22	52	46	120	40	94	82	216
Debt Services												
Principal												
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	1	1	1	3	1	1	1	3	10	23	20	53
Interest												
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	9	21	18	47
Total Debt Service	1	1	1	3	1	1	1	3	18	44	38	100
Taxes	36	85	74	195	60	143	124	327	46	126	107	280
Change in Working Capital	29	123	103	255	0	0	0	0	-19	-35	-32	-86
Change in Cash	53	71	66	190	147	349	304	801	139	343	295	777

ZSE Distribution System
Sources and Uses of Funds Statement
(millions Sk)

Year	1993	1993	1993	1993	1994	1994	1994	1994	1995	1995	1995
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV
SOURCES	118	281	244	643	230	545	475	1250	224	572	492
Internal Generation											
Operating Income	90	212	185	487	150	357	311	817	130	348	297
Depreciation	29	68	59	156	58	137	119	313	58	137	119
Other	0	0	0	0	0	0	0	0	0	0	0
Total Internal Generation	118	281	244	643	208	493	430	1130	187	485	416
Borrowing											
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	22	52	46	120	37	87	76
Total Borrowing	0	0	0	0	22	52	46	120	37	87	76
APPLICATIONS	118	281	244	643	230	545	475	1250	224	572	492
Investment											
General Investment	0	0	0	0	22	52	46	120	37	87	76
Interest During Construction	0	0	0	0	0	0	0	0	0	0	0
Total Investment	0	0	0	0	22	52	46	120	37	87	76
Debt Services											
Principal											
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	1	1	1	3	1	1	1	3	2	4	4
Interest											
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	2	4	4
Total Debt Service	1	1	1	3	1	1	1	3	4	8	7
Taxes	36	85	74	195	60	143	124	327	51	137	117
Change in Working Capital	29	123	103	255	0	0	0	0	-124	-280	-245
Change in Cash	52	71	66	190	147	349	304	801	257	620	537

ZSE Distribution System
Sources and Uses of Funds Statement
(millions Sk)

Year	1995	1996	1996	1996	1996	1997	1997	1997	1997
Voltage Class	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
SOURCES	1288	224	572	492	1288	224	572	492	1287
Internal Generation									
Operating Income	774	128	345	294	767	127	342	292	760
Depreciation	314	58	138	120	317	59	139	121	319
Other	0	0	0	0	0	0	0	0	0
Total Internal Generation	1088	187	483	414	1084	186	481	413	1079
Borrowing									
Foreign Loans	0	0	0	0	0	0	0	0	0
Domestic Loans	200	37	89	78	204	38	91	79	208
Total Borrowing	200	37	89	78	204	38	91	79	208
APPLICATIONS	1288	224	572	492	1288	224	572	492	1287
Investment									
General Investment	200	37	89	78	204	38	91	79	208
Interest During Construction	0	0	0	0	0	0	0	0	0
Total Investment	200	37	89	78	204	38	91	79	208
Debt Services									
Principal									
Foreign Loans	0	0	0	0	0	0	0	0	0
Domestic Loans	9	4	8	7	19	5	13	11	30
Interest									
Foreign Loans	0	0	0	0	0	0	0	0	0
Domestic Loans	10	4	9	7	20	5	13	11	29
Total Debt Service	19	7	17	15	39	11	26	22	59
Taxes	306	50	134	115	299	49	132	112	292
Change in Working Capital	-649	-16	-26	-23	-65	-17	-29	-26	-72
Change in Cash	1413	146	357	308	811	143	352	304	800

ZSE Distribution System
Sources and Uses of Funds Statement
(millions Sk)

Year	1998	1998	1998	1998	1999	1999	1999	1999
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total
SOURCES	224	572	492	1287	224	572	492	1287
Internal Generation								
Operating Income	126	339	289	754	125	336	287	747
Depreciation	59	140	122	321	60	141	123	324
Other	0	0	0	0	0	0	0	0
Total Internal Generation	185	479	411	1075	184	477	410	1071
Borrowing								
Foreign Loans	0	0	0	0	0	0	0	0
Domestic Loans	39	93	81	212	40	94	82	216
Total Borrowing	39	93	81	212	40	94	82	216
APPLICATIONS	224	572	492	1287	224	572	492	1287
Investment								
General Investment	39	93	81	212	40	94	82	216
Interest During Construction	0	0	0	0	0	0	0	0
Total Investment	39	93	81	212	40	94	82	216
Debt Services								
Principal								
Foreign Loans	0	0	0	0	0	0	0	0
Domestic Loans	8	18	16	41	10	23	20	53
Interest								
Foreign Loans	0	0	0	0	0	0	0	0
Domestic Loans	7	17	15	38	9	21	18	47
Total Debt Service	15	35	30	79	18	44	38	100
Taxes	48	129	110	286	46	126	107	280
Change in Working Capital	-18	-32	-29	-79	-19	-35	-32	-86
Change in Cash	141	348	300	789	139	343	295	777

ZSE Distribution System
Financial Ratios

Year	1993	1993	1993	1993	1994	1994	1994	1994	1995	1995	1995	1995	1999	1999	1999	1999
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
Operating Ratio	0.96	0.93	0.95	0.95	0.69	0.60	0.58	0.61	0.72	0.60	0.59	0.62	0.73	0.61	0.60	0.63
Current Ratio	2.21	2.10	2.31	2.20	3.08	3.57	3.84	3.52	4.53	6.12	6.46	5.79	7.64	11.77	12.25	10.78
Cash Generation Ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3.52	3.99	3.90	3.87	3.13	3.56	3.48	3.45
Debt Coverage Ratio	167.06	167.06	167.06	167.06	280.45	280.45	280.45	280.45	36.59	41.37	40.53	40.17	6.76	7.68	7.52	7.45
Debt/Equity	0.003	0.003	0.003	0.003	0.001	0.001	0.001	0.001	0.013	0.012	0.012	0.012	0.054	0.050	0.051	0.051
Debt	0.27%	0.27%	0.27%	0.27%	0.11%	0.10%	0.10%	0.10%	1.27%	1.19%	1.20%	1.21%	5.11%	4.75%	4.81%	4.84%
Equity	99.73%	99.73%	99.73%	99.73%	99.89%	99.90%	99.90%	99.90%	98.73%	98.81%	98.80%	98.79%	94.89%	95.25%	95.19%	95.16%
Accounts Receivable Outstanding in Days	44	41	31	37	196	142	156	159	194	136	151	154	159	112	124	127
Number of Times Interest earned	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	70.50	79.71	78.09	77.40	14.41	16.37	16.02	15.87
Return on Fixed Assets	10.79%	9.69%	9.87%	9.95%	6.55%	5.83%	5.95%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%

ZSE Distribution System
Financial Ratios

Year	1993	1993	1993	1993	1994	1994	1994	1994	1595	1995	1995	1995	1996	1996	1996	1996
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
Operating Ratio	0.96	0.93	0.95	0.95	0.69	0.60	0.58	0.61	0.72	0.60	0.59	0.62	0.72	0.60	0.60	0.63
Current Ratio	2.21	2.10	2.31	2.20	3.08	3.57	3.84	3.52	4.53	6.12	6.46	5.79	5.32	7.55	7.93	7.06
Cash Generation Ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3.52	3.99	3.90	3.87	3.42	3.87	3.79	3.76
Debt Coverage Ratio	167.06	167.06	167.06	167.06	280.45	280.45	280.45	280.45	36.59	41.37	40.53	40.17	17.94	20.30	19.89	19.71
Debt/Equity	0.003	0.003	0.003	0.003	0.001	0.001	0.001	0.001	0.013	0.012	0.012	0.012	0.025	0.023	0.023	0.023
Debt	0.27%	0.27%	0.27%	0.27%	0.11%	0.10%	0.10%	0.10%	1.27%	1.19%	1.20%	1.21%	2.41%	2.24%	2.27%	2.28%
Equity	99.73%	99.73%	99.73%	99.73%	99.89%	99.90%	99.90%	99.90%	98.73%	98.81%	98.80%	98.79%	97.59%	97.76%	97.73%	97.72%
Accounts Receivable Outstanding in Days	44	41	31	37	196	142	156	159	194	136	151	154	185	130	144	147
Number of Times Interest earned	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	70.50	79.71	78.09	77.40	35.37	40.04	39.22	38.87
Return on Fixed Assets	10.79%	9.69%	9.87%	9.95%	6.55%	5.83%	5.95%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%

ZSE Distribution System
Financial Ratios

Year	1997	1997	1997	1997	1998	1998	1998	1998	1999	1999	1999	1999
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
Operating Ratio	0.72	0.61	0.60	0.63	0.72	0.61	0.60	0.63	0.73	0.61	0.60	0.63
Current Ratio	6.10	8.98	9.39	8.31	6.88	10.38	10.83	9.55	7.64	11.77	12.25	10.78
Cash Generation Ratio	3.32	3.77	3.69	3.65	3.23	3.66	3.58	3.55	3.13	3.56	3.48	3.45
Debt Coverage Ratio	11.72	13.29	13.01	12.89	8.62	9.78	9.58	9.49	6.76	7.68	7.52	7.45
Debt/Equity	0.035	0.033	0.033	0.033	0.045	0.042	0.042	0.043	0.054	0.050	0.051	0.051
Debt	3.42%	3.18%	3.22%	3.24%	4.32%	4.02%	4.07%	4.09%	5.11%	4.75%	4.81%	4.84%
Equity	96.58%	96.82%	96.78%	96.76%	95.68%	95.98%	95.93%	95.91%	94.89%	95.25%	95.19%	95.16%
Accounts Receivable Outstanding in Days	176	124	137	140	168	118	130	133	159	112	124	127
Number of Times Interest earned	23.69	26.85	26.29	26.06	17.87	20.28	19.86	19.68	14.41	16.37	16.02	15.87
Return on Fixed Assets	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%

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Appendix H Pro Forma Financial Statements for the Central Slovak Distribution Co. (SSE)

SSE Distribution System
Income Statement
(millions Sk)

Year	1993	1993	1993	1993	1994	1994	1994	1994	1999	1999	1999	1999
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
Energy Delivered To Grid (GWh)	6915	4779	2008	N/A	6785	4727	2012	N/A	7756	5531	2339	N/A
T&D Losses (Assoc. W/Grid) (GWh)	196	128	173	497	192	127	129	448	213	144	119	477
Energy Leaving Loss Losses (GWh)	6719	4651	1835	N/A	6593	4600	1883	N/A	7542	5388	2220	N/A
Energy Sales By Voltage Class GWh)	1940	2643	1835	6418	1866	2588	1883	6337	2011	3049	2220	7279
Grid Cost (SK/MWh)	53.11	104.53	183.93	N/A	61.80	169.51	347.72	N/A	47.03	121.50	245.87	N/A
T & D Sales Avg. Price (SK/MWh)	53.11	159.10	357.99	N/A	61.80	233.01	596.71	N/A	47.03	169.78	424.76	N/A
Revenue												
Domestic Sales-Voltage Class	2592	3532	2452	8576	407	780	655	1842	355	655	546	1555
Other	0	0	0	0	0	0	0	0	0	0	0	0
Total Revenue	2592	3532	2452	8576	407	780	655	1842	355	655	546	1555
Expenses												
Fuel	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	2235	3046	2115	7396	0	0	0	0	0	0	0	0
Material & Others	116	155	143	414	119	160	148	427	119	160	148	427
Labor & Services	59	91	63	214	61	94	65	220	61	94	65	220
Depreciation	21	50	43	114	42	99	87	228	0	0	0	1
Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0
Total Expenses	2431	3342	2365	8138	222	353	300	875	181	254	213	648
Operating Income	161	190	87	438	185	427	355	967	174	401	332	907
Interest												
World Bank & EBRD	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	9	21	18	47
Total Interest	0	0	0	0	0	0	0	0	9	21	18	47
Corporate Taxes	64	76	35	175	74	171	142	387	66	152	126	344
Net Income	96	114	52	263	111	256	213	580	108	249	207	563

SSE Distribution System
Income Statement
(millions Sk)

Year	1993	1993	1993	1993	1994	1994	1994	1994	1995	1995	1995
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV
Energy Delivered To Grid (GWh)	6915	4779	2008	N/A	6785	4727	2012	N/A	6757	4748	2055
T&D Losses (Assoc. W/Grid) (GWh)	196	128	173	497	192	127	129	448	191	127	112
Energy Leaving Less Losses (GWh)	6719	4651	1835	N/A	6593	4600	1883	N/A	6566	4621	1943
Energy Sales By Voltage Class GWh)	1940	2643	1835	6418	1866	2588	1883	6337	1818	2566	1943
Grid Cost (SK/MWh)	53.11	104.53	183.93	N/A	61.80	169.51	347.72	N/A	54.19	142.22	282.02
T & D Sales Avg. Price (SK/MWh)	53.11	159.10	357.99	N/A	61.80	233.01	596.71	N/A	54.19	197.90	491.31
Revenue											
Domestic Sales-Voltage Class	2592	3532	2452	8576	407	780	655	1842	356	657	548
Other	0	0	0	0	0	0	0	0	0	0	0
Total Revenue	2592	3532	2452	8576	407	780	655	1842	356	657	548
Expenses											
Fuel	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	2235	3046	2115	7396	0	0	0	0	0	0	0
Material & Others	116	155	143	414	119	160	148	427	119	160	148
Labor & Services	59	91	63	214	61	94	65	220	61	94	65
Depreciation	21	50	43	114	42	99	87	228	0	0	0
Decommissioning	0	0	0	0	0	0	0	0	0	0	0
Total Expenses	2431	3342	2365	8138	222	353	300	875	181	254	213
Operating Income	161	190	87	438	185	427	355	967	175	403	335
Interest											
World Bank & EBRD	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	2	4	4
Total Interest	0	0	0	0	0	0	0	0	2	4	4
Corporate Taxes	64	76	35	175	74	171	142	387	69	160	132
Net Income	96	114	52	263	111	256	213	580	106	244	202

SSE Distribution System
Income Statement
(millions Sk)

Year	1995	1996	1996	1996	1996	1997	1997	1997	1997	1998	1998
Voltage Class	Total	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV
Energy Delivered To Grid (GWh)	N/A	6892	4873	2120	N/A	7075	5025	2181	N/A	7420	5285
T&D Losses (Assoc. W/Grid) (GWh)	430	193	129	112	435	198	133	104	434	205	138
Energy Leaving Less Losses (GWh)	N/A	6699	4743	2007	N/A	6878	4892	2078	N/A	7215	5147
Energy Sales By Voltage Class GWh)	6327	1826	2624	2007	6457	1853	2711	2078	6642	1930	2874
Grid Cost (SK/MWh)	N/A	53.07	138.39	272.72	N/A	51.64	134.05	263.17	N/A	49.20	127.29
T & D Sales Avg. Price (SK/MWh)	N/A	53.07	192.90	476.42	N/A	51.64	187.09	459.58	N/A	49.20	177.80
Revenue											
Domestic Sales-Voltage Class	1561	355	656	547	1559	355	656	547	1558	355	655
Other	0	0	0	0	0	0	0	0	0	0	0
Total Revenue	1561	355	656	547	1559	355	656	547	1558	355	655
Expenses											
Fuel	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0
Material & Others	427	119	160	148	427	119	160	148	427	119	160
Labor & Services	220	61	94	65	220	61	94	65	220	61	94
Depreciation	1	0	0	0	1	0	0	0	1	0	0
Decommissioning	0	0	0	0	0	0	0	0	0	0	0
Total Expenses	648	181	254	213	648	181	254	213	648	181	254
Operating Income	913	175	402	334	911	175	402	333	910	174	401
Interest											
World Bank & EBRD	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	10	4	9	7	20	5	13	11	29	7	17
Total Interest	10	4	9	7	20	5	13	11	29	7	17
Corporate Taxes	361	69	158	131	357	68	156	129	352	67	154
Net Income	552	106	245	203	555	107	246	204	558	107	247

SSE Distribution System
Income Statement
(millions Sk)

Year	1998	1998	1999	1999	1999	1999
Voltage Class	LV	Total	VHV	HV	LV	Total
Energy Delivered To Grid (GWh)	2273	N/A	7756	5531	2339	N/A
T&D Losses (Assoc. W/Grid) (GWh)	124	467	213	144	119	477
Energy Leaving Less Losses (GWh)	2150	N/A	7542	5388	2220	N/A
Energy Sales By Voltage Class GWh)	2150	6953	2011	3049	2220	7279
Grid Cost (SK/MWh)	254.09	N/A	47.03	121.50	245.87	N/A
T & D Sales Avg. Price (SK/MWh)	442.12	N/A	47.03	169.78	424.76	N/A
Revenue						
Domestic Sales-Voltage Class	546	1556	355	655	546	1555
Other	0	0	0	0	0	0
Total Revenue	546	1556	355	655	546	1555
Expenses						
Fuel	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0
Material & Others	148	427	119	160	148	427
Labor & Services	65	220	61	94	65	220
Depreciation	0	1	0	0	0	1
Decommissioning	0	0	0	0	0	0
Total Expenses	213	648	181	254	213	648
Operating Income	333	908	174	401	332	907
Interest						
World Bank & EBRD	0	0	0	0	0	0
Domestic Loans	15	38	9	21	18	47
Total Interest	15	38	9	21	18	47
Corporate Taxes	127	348	66	152	126	344
Net Income	206	560	108	249	207	563

SSE Distribution System
Balance Sheets
(millions Sk)

Year	1993	1993	1993	1993	1994	1994	1994	1994	1999	1999	1999	1999
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
ASSETS	1868	3593	3091	8552	3982	8459	7137	19577	4680	10077	8497	23253
Fixed Assets												
Fixed Assets in Operation	1745	4069	3453	9267	5234	12208	10360	27802	2505	5945	5179	13628
Less Accumulated Depreciation	764	1814	1580	4159	2293	5442	4741	12476	2903	6675	5540	15118
Net Fixed Assets	980	2255	1873	5109	2941	6766	5619	15326	2903	6675	5540	15118
Work in Progress	146	347	302	795	146	347	302	795	0	0	0	0
Total Fixed Assets	1127	2602	2175	5904	3087	7113	5921	16121	2903	6675	5540	15118
Current Assets												
Cash & Banks	23	31	29	84	176	387	329	892	1206	2638	2251	6095
Accounts Receivable	649	867	802	2317	649	867	802	2317	502	670	620	1793
Inventory	65	87	81	234	65	87	81	234	65	87	81	234
Others	4	5	5	13	4	5	5	13	4	5	5	13
Total Current Assets	741	990	916	2648	894	1346	1216	3456	1777	3401	2957	8135
EQUITY & LIABILITIES	1868	3593	3091	8552	3982	8459	7137	19577	4680	10077	8497	23253
Equity												
Capital	857	2033	1771	4662	2859	6643	5604	15107	2859	6643	5504	15107
Retained Earnings	142	337	294	773	253	593	507	1354	788	1824	1529	4141
Total Equity	999	2371	2065	5435	3113	7237	6111	16460	3647	8467	7133	19248
Long-term Debt												
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	163	387	338	888
Total Long-Term Debt	0	0	0	0	0	0	0	0	163	387	338	888
Current Liabilities												
Short-Term Loans	170	238	200	608	170	238	200	608	170	238	200	608
Accounts Payable	694	976	820	2490	694	976	820	2490	694	976	820	2490
Other	5	7	6	19	5	7	6	19	5	7	6	19
Total Current Liabilities	869	1222	1026	3117	869	1222	1026	3117	869	1222	1026	3117

SSE Distribution System
Balance Sheets
(millions Sk)

Year	1993	1993	1993	1993	1994	1994	1994	1994	1995	1995	1995
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV
ASSETS	1868	3593	3091	8552	3982	8459	7137	19577	4123	8786	7412
Fixed Assets											
Fixed Assets in Operation	1745	4069	3453	9267	5234	12208	10360	27802	2335	5541	4827
Less Accumulated Depreciation	764	1814	1580	4159	2293	5442	4741	12476	2921	6715	5578
Net Fixed Assets	980	2255	1873	5109	2941	6766	5619	15326	2921	6719	5578
Work in Progress	146	347	302	795	146	347	302	795	0	0	0
Total Fixed Assets	1127	2602	2175	5904	3087	7113	5921	16121	2921	6719	5578
Current Assets											
Cash & Banks	23	31	29	84	176	387	329	892	516	1151	987
Accounts Receivable	649	867	802	2317	649	867	802	2317	616	823	762
Inventory	65	87	81	234	65	87	81	234	65	87	81
Others	4	5	3	13	4	5	5	13	4	5	5
Total Current Assets	741	990	916	2648	894	1346	1216	3456	1201	2066	1834
EQUITY & LIABILITIES	1868	3593	3091	8552	3982	8459	7137	19577	4123	8786	7412
Equity											
Capital	857	2033	1771	4662	2859	6643	5604	15107	2859	6643	5604
Retained Earnings	142	337	294	773	253	593	507	1354	359	837	709
Total Equity	999	2371	2065	5435	3113	7237	6111	16460	3219	7480	6313
Long-term Debt											
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	35	83	72
Total Long-Term Debt	0	0	0	0	0	0	0	0	35	83	72
Current Liabilities											
Short-Term Loans	170	238	200	608	170	238	200	608	170	238	200
Accounts Payable	694	976	820	2490	694	976	820	2490	694	976	820
Other	5	7	6	19	5	7	6	19	5	7	6
Total Current Liabilities	869	1222	1026	3117	869	1222	1026	3117	869	1222	1026

SSE Distribution System
Balance Sheets
(millions Sk)

Year	1995	1996	1996	1996	1996	1997	1997	1997	1997	1998	1998
Voltage Class	Total	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV
ASSETS	20320	4263	9111	7685	21059	4403	9435	7958	21795	4542	9757
Fixed Assets											
Fixed Assets in Operation	12704	2377	5641	4914	12932	2419	5741	5002	13163	2462	5843
Less Accumulated Depreciation	15218	2916	6707	5567	15189	2911	6695	5557	15163	2907	6685
Net Fixed Assets	15218	2916	6707	5567	15189	2911	6695	5557	15163	2907	6685
Work in Progress	0	0	0	0	0	0	0	0	0	0	0
Total Fixed Assets	15218	2916	6707	5567	15189	2911	6695	5557	15163	2907	6685
Current Assets											
Cash & Banks	2653	692	1530	1309	3532	866	1904	1628	4398	1037	2274
Accounts Receivable	2201	586	782	724	2091	556	743	687	1987	528	706
Inventory	234	65	87	81	234	65	87	81	234	65	87
Others	13	4	5	5	13	4	5	5	13	4	5
Total Current Assets	5102	1347	2404	2118	5870	1492	2740	2401	6632	1635	3072
EQUITY & LIABILITIES	20320	4263	9111	7685	21059	4403	9435	7958	21795	4542	9757
Equity											
Capital	15107	2859	6643	5604	15107	2859	6643	5604	15107	2859	6643
Retained Earnings	1906	466	1082	913	2460	573	1328	1117	3018	680	1575
Total Equity	17012	3325	7725	6517	17567	3432	7971	6721	18124	3539	8219
Long-term Debt											
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	191	69	164	143	376	102	242	210	554	133	316
Total Long-Term Debt	191	69	164	143	376	102	242	210	554	133	316
Current Liabilities											
Short-Term Loans	608	170	238	200	608	170	238	200	608	170	238
Accounts Payable	2490	694	976	820	2490	694	976	820	2490	694	976
Other	19	5	7	6	19	5	7	6	19	5	7
Total Current Liabilities	3117	869	1222	1026	3117	869	1222	1026	3117	869	1222

SSE Distribution System
Balance Sheets
(millions Sk)

Year	1998	1998	1999	1999	1999	1999
Voltage Class	LV	Total	VHV	HV	LV	Total
ASSETS	8228	22527	4680	10077	8497	23253
Fixed Assets						
Fixed Assets in Operation	5090	13395	2505	5945	5179	13628
Less Accumulated Depreciation	5548	15139	2903	6675	5540	15118
Net Fixed Assets	5548	15139	2903	6675	5540	15118
Work in Progress	0	0	0	0	0	0
Total Fixed Assets	5548	15139	2903	6675	5540	15118
Current Assets						
Cash & Banks	1942	5253	1206	2638	2251	6095
Accounts Receivable	653	1887	502	670	620	1793
Inventory	81	234	65	87	81	234
Others	5	13	4	5	5	13
Total Current Assets	2680	7387	1777	3401	2957	8135
EQUITY & LIABILITIES	8228	22527	4680	10077	8497	23253
Equity						
Capital	5604	15107	2859	6643	5604	15107
Retained Earnings	1323	3578	788	1824	1529	4141
Total Equity	6927	18685	3647	8467	7133	19248
Long-term Debt						
Foreign Loans	0	0	0	0	0	0
Domestic Loans	275	725	163	387	338	888
Total Long-Term Debt	275	725	163	387	338	888
Current Liabilities						
Short-Term Loans	200	608	170	238	200	608
Accounts Payable	820	2490	694	976	820	2490
Other	6	19	5	7	6	19
Total Current Liabilities	1026	3117	869	1222	1026	3117

SSE Distribution System
Sources and Uses of Funds Statement
(millions Sk)

Year	1993	1993	1993	1993	1994	1994	1994	1994	1999	1999	1999	1999
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Tota
SOURCES	182	240	131	552	249	578	487	1315	214	495	415	1125
Internal Generation												
Operating Income	161	190	87	438	185	427	355	967	174	401	332	907
Depreciation	21	50	43	114	42	99	87	228	0	0	0	1
Other	0	0	0	0	0	0	0	0	0	0	0	0
Total Internal Generation	182	240	131	552	227	526	442	1195	174	401	333	908
Borrowing												
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	22	52	46	120	40	94	82	216
Total Borrowing	0	0	0	0	22	52	46	120	40	94	82	216
APPLICATIONS	182	240	131	552	249	578	487	1315	214	495	415	1125
Investment												
General Investment	0	0	0	0	22	52	46	120	40	94	82	216
Interest During Construction	0	0	0	0	0	0	0	0	0	0	0	0
Total Investment	0	0	0	0	22	52	46	120	40	94	82	216
Debt Services												
Principal												
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	10	23	20	53
Interest												
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	9	21	18	47
Total Debt Service	0	0	0	0	0	0	0	0	18	44	38	100
Taxes	64	76	35	175	74	171	142	387	66	152	126	344
Change in Working Capital	94	132	67	293	0	0	0	0	-79	-159	-141	-378
Change in Cash	23	31	29	84	153	355	300	808	168	364	309	842

SSE Distribution System
Sources and Uses of Funds Statement
(millions Sk)

Year	1993	1993	1993	1993	1994	1994	1994	1994	1995	1995	1995
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV
SOURCES	182	240	131	552	249	578	487	1315	212	491	411
Internal Generation											
Operating Income	161	190	87	438	185	427	355	967	175	403	335
Depreciation	21	50	43	114	42	99	87	228	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0
Total Internal Generation	182	240	131	552	227	526	442	1195	175	404	335
Borrowing											
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	22	52	46	120	37	87	76
Total Borrowing	0	0	0	0	22	52	46	120	37	87	76
APPLICATIONS	182	240	131	552	249	578	487	1315	212	491	411
Investment											
General Investment	0	0	0	0	22	52	46	120	37	87	76
Interest During Construction	0	0	0	0	0	0	0	0	0	0	0
Total Investment	0	0	0	0	22	52	46	120	37	87	76
Debt Services											
Principal											
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	2	4	4
Interest											
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	2	4	4
Total Debt Service	0	0	0	0	0	0	0	0	4	8	7
Taxes	64	76	35	175	74	171	142	387	69	160	132
Change in Working Capital	94	132	67	293	0	0	0	0	-237	-528	-463
Change in Cash	23	31	29	84	153	355	300	808	339	764	658

SSE Distribution System
Sources and Uses of Funds Statement
(millions Sk)

Year	1995	1996	1996	1996	1996	1997	1997	1997	1997	1998
Voltage Class	Total	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV
SOURCES	1114	213	492	412	1116	213	493	413	1119	214
Internal Generation										
Operating Income	913	175	402	334	911	175	402	333	910	174
Depreciation	1	0	0	0	1	0	0	0	1	0
Other	0	0	0	0	0	0	0	0	0	0
Total Internal Generation	914	175	403	334	912	175	402	334	911	175
Borrowing										
Foreign Loans	0	0	0	0	0	0	0	0	0	0
Domestic Loans	200	37	89	78	204	38	91	79	208	39
Total Borrowing	200	37	89	78	204	38	91	79	208	39
APPLICATIONS	1114	213	492	412	1116	213	493	413	1119	214
Investment										
General Investment	200	37	89	78	204	38	91	79	208	39
Interest During Construction	0	0	0	0	0	0	0	0	0	0
Total Investment	200	37	89	78	204	38	91	79	208	39
Debt Services										
Principal										
Foreign Loans	0	0	0	0	0	0	0	0	0	0
Domestic Loans	9	4	8	7	19	5	13	11	30	8
Interest										
Foreign Loans	0	0	0	0	0	0	0	0	0	0
Domestic Loans	10	4	9	7	20	5	13	11	29	7
Total Debt Service	19	7	17	15	39	11	26	22	59	15
Taxes	361	69	158	131	357	68	156	129	352	67
Change in Working Capital	-1228	-77	-151	-134	-361	-78	-154	-136	-367	-78
Change in Cash	1762	176	379	323	878	174	374	318	867	171

SSE Distribution System
Sources and Uses of Funds Statement
(millions Sk)

Year	1998	1998	1998	1999	1999	1999	1999
Voltage Class	HV	LV	Total	VHV	HV	LV	Total
SOURCES	494	414	1122	214	495	415	1125
Internal Generation							
Operating Income	401	333	908	174	401	332	907
Depreciation	0	0	1	0	0	0	1
Other	0	0	0	0	0	0	0
Total Internal Generation	402	333	909	174	401	333	908
Borrowing							
Foreign Loans	0	0	0	0	0	0	0
Domestic Loans	93	81	212	40	94	82	216
Total Borrowing	93	81	212	40	94	82	216
APPLICATIONS	494	414	1122	214	495	415	1125
Investment							
General Investment	93	81	212	40	94	82	216
Interest During Construction	0	0	0	0	0	0	0
Total Investment	93	81	212	40	94	82	216
Debt Services							
Principal							
Foreign Loans	0	0	0	0	0	0	0
Domestic Loans	18	16	41	10	23	20	53
Interest							
Foreign Loans	0	0	0	0	0	0	0
Domestic Loans	17	15	38	9	21	18	47
Total Debt Service	35	30	79	18	44	38	100
Taxes	154	127	348	66	152	126	344
Change in Working Capital	-156	-138	-373	-79	-159	-141	-378
Change in Cash	370	314	855	168	364	309	842

SSE Distribution System
Financial Ratios

Year	1993	1993	1993	1993	1994	1994	1994	1994	1995	1995	1995	1995	1999	1999	1999	1999
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
Operating Ratio	0.94	0.95	0.96	0.95	0.55	0.45	0.46	0.47	0.51	0.39	0.39	0.42	0.51	0.39	0.39	0.42
Current Ratio	0.85	0.81	0.89	0.85	1.03	1.10	1.18	1.11	1.38	1.69	1.79	1.64	2.04	2.78	2.88	2.61
Cash Generation Ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	4.77	4.62	4.40	4.57	4.38	4.24	4.04	4.19
Debt Coverage Ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	95.35	92.42	88.07	91.31	20.13	19.51	18.58	19.27
Debt/Equity	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.011	0.011	0.011	0.011	0.045	0.046	0.047	0.046
Debt	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.08%	1.10%	1.13%	1.11%	4.28%	4.38%	4.52%	4.41%
Equity	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	98.92%	98.90%	98.87%	98.89%	95.72%	95.62%	95.48%	95.59%
Accounts Receivable Outstanding in Days	91	90	119	99	581	406	447	459	632	457	507	515	517	374	415	421
Number of Times Interest earned	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	95.35	92.42	88.07	91.31	20.13	19.51	18.58	19.27
Return on Fixed Assets	14.27%	7.31%	4.02%	7.43%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%

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SSE Distribution System
Financial Ratios

Year	1993	1993	1993	1993	1994	1994	1994	1994	1995	1995	1995	1995	1996	1996	1996
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV
Operating Ratio	0.94	0.95	0.96	0.95	0.55	0.45	0.46	0.47	0.51	0.39	0.39	0.42	0.51	0.39	0.39
Current Ratio	0.85	0.81	0.89	0.85	1.03	1.10	1.18	1.11	1.38	1.69	1.79	1.64	1.55	1.97	2.06
Cash Generation Ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	4.77	4.62	4.40	4.57	4.67	4.52	4.31
Debt Coverage Ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	95.35	92.42	88.07	91.31	48.22	46.74	44.54
Debt/Equity	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.011	0.011	0.011	0.011	0.021	0.021	0.022
Debt	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.08%	1.10%	1.13%	1.11%	2.03%	2.08%	2.14%
Equity	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	98.92%	98.90%	98.87%	98.89%	97.97%	97.92%	97.86%
Accounts Receivable Outstanding in Days	91	90	119	99	581	406	447	459	632	457	507	515	601	435	482
Number of Times Interest earned	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	95.35	92.42	88.07	91.31	48.22	46.74	44.54
Return on Fixed Assets	14.27%	7.31%	4.02%	7.43%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%

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SSE Distribution System
Financial Ratios

Year	1996	1997	1997	1997	1997	1998	1998	1998	1998	1999	1999	1999	1999
Voltage Class	Total	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
Operating Ratio	0.42	0.51	0.39	0.39	0.42	0.51	0.39	0.39	0.42	0.51	0.39	0.39	0.42
Current Ratio	1.88	1.72	2.24	2.34	2.13	1.88	2.51	2.61	2.37	2.04	2.78	2.88	2.61
Cash Generation Ratio	4.47	4.57	4.43	4.22	4.37	4.47	4.33	4.13	4.28	4.38	4.24	4.04	4.19
Debt Coverage Ratio	46.18	32.56	31.56	30.07	31.18	24.77	24.01	22.87	23.71	20.13	19.51	18.58	19.27
Debt/Equity	0.021	0.030	0.030	0.031	0.031	0.038	0.038	0.040	0.039	0.045	0.046	0.047	0.046
Debt	2.09%	2.88%	2.94%	3.04%	2.97%	3.63%	3.71%	3.83%	3.74%	4.28%	4.38%	4.52%	4.41%
Equity	97.91%	97.12%	97.06%	96.96%	97.03%	96.37%	96.29%	96.17%	96.26%	95.72%	95.62%	95.48%	95.59%
Accounts Receivable Outstanding in Days	489	572	414	459	465	543	393	436	443	517	374	415	421
Number of Times Interest earned	46.18	32.56	31.56	30.07	31.18	24.77	24.01	22.87	23.71	20.13	19.51	18.58	19.27
Return on Fixed Assets	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%

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Appendix I Pro Forma Financial Statements for the East Slovak Distribution Co. (VSE)

VSE Distribution System
Income Statement
(millions Sk)

Year	1993	1993	1993	1993	1994	1994	1994	1994	1999	1999	1999	1999
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
Energy Delivered To Grid (GWh)	4835	3508	1792	N/A	4758	3478	1796	N/A	5449	4065	2088	N/A
T&D Losses (Assoc. W/Grid) (GWh)	136	93	154	136	134	93	115	342	149	105	106	361
Energy Leaving Less Losses (GWh)	4699	3415	1638	N/A	4623	3385	1681	N/A	5300	3960	1981	N/A
Energy Sales By Voltage Class (GWh)	1191	1623	1638	1191	1146	1589	1681	4415	1235	1872	1981	5088
Grid Cost (SK/MWh)	37.26	96.30	246.73	N/A	44.30	114.31	286.40	N/A	32.73	81.43	200.23	N/A
Avg. T&D Sales Price (SK/MWh)	37.26	134.58	393.96	N/A	44.30	159.82	457.19	N/A	32.73	115.04	321.44	N/A
Revenue												
Domestic Sales-Voltage Class	1709	2419	2514	6643	205	387	481	1073	173	322	397	893
Other	44	60	61	166	0	0	0	0	0	0	0	0
Total Revenue	1754	2480	2575	6809	205	387	481	1073	173	322	397	893
Expenses												
Fuel	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	1579	2151	2171	5901	0	0	0	0	0	0	0	0
Material & Others	44	86	99	229	46	89	102	236	46	89	102	236
Labor & Services	69	120	140	329	71	124	144	339	71	124	144	339
Depreciation	12	24	32	68	24	48	64	136	0	0	0	1
Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0
Total Expenses	1704	2381	2442	6527	140	260	310	711	117	213	246	576
Operating Income	50	99	133	282	64	127	171	362	57	110	150	317
Interest												
World Bank & EBRD	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	2	4	5	11
Total Interest	0	0	0	0	0	0	0	0	2	4	5	11
Corporate Taxes	20	39	53	113	26	51	69	145	22	42	58	122
Net Income	30	59	80	169	39	76	103	217	33	63	87	184

VSE Distribution System
Income Statement
(millions Sk)

Year	1993	1993	1993	1993	1994	1994	1994	1994	1995	1995
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV
Energy Delivered To Grid (GWh)	4835	3508	1792	N/A	4758	3478	1796	N/A	4753	3503
T&D Losses (Assoc. W/Grid) (GWh)	136	93	154	136	134	93	115	342	134	93
Energy Leaving Less Losses (GWh)	4699	3415	1638	N/A	4623	3385	1681	N/A	4619	3410
Energy Sales By Voltage Class (GWh)	1191	1623	1638	1191	1146	1589	1681	4415	1116	1576
Grid Cost (SK/MWh)	37.26	96.30	246.73	N/A	44.30	114.31	286.40	N/A	38.39	96.77
Avg. T&D Sales Price (SK/MWh)	37.26	134.58	393.96	N/A	44.30	159.82	457.19	N/A	38.39	136.21
Revenue										
Domestic Sales-Voltage Class	1709	2419	2514	6643	205	387	481	1073	177	330
Other	44	60	61	166	0	0	0	0	0	0
Total Revenue	1754	2480	2575	6809	205	387	481	1073	177	330
Expenses										
Fuel	0	0	0	0	0	0	0	0	0	0
Purchased Power	1579	2151	2171	5901	0	0	0	0	0	0
Material & Others	44	86	99	229	46	89	102	236	46	89
Labor & Services	69	120	140	329	71	124	144	339	71	124
Depreciation	12	24	32	68	24	48	64	136	0	0
Decommissioning	0	0	0	0	0	0	0	0	0	0
Total Expenses	1704	2381	2442	6527	140	260	310	711	117	213
Operating Income	50	99	133	282	64	127	171	362	61	117
Interest										
World Bank & EBRD	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	0	1
Total Interest	0	0	0	0	0	0	0	0	0	1
Corporate Taxes	20	39	53	113	26	51	69	145	24	47
Net Income	30	59	80	169	39	76	103	217	36	70

VSE Distribution System
Income Statement
(millions Sk)

Year	1995	1995	1996	1996	1996	1996	1997	1997	1997	1997
Voltage Class	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
Energy Delivered To Grid (GWh)	1834	N/A	4855	3598	1892	N/A	4985	3709	1947	N/A
T&D Losses (Assoc. W/Grid) (GWh)	100	327	136	95	100	331	139	98	92	329
Energy Leaving Less Losses (GWh)	1735	N/A	4719	3503	1792	N/A	4847	3612	1855	N/A
Energy Sales By Voltage Class (GWh)	1735	4426	1121	1611	1792	4524	1138	1664	1855	4657
Grid Cost (SK/MWh)	234.60	N/A	37.37	93.66	225.70	N/A	36.18	90.32	216.66	N/A
Avg. T&D Sales Price (SK/MWh)	378.65	N/A	37.37	132.04	365.13	N/A	36.18	127.49	350.50	N/A
Revenue										
Domestic Sales-Voltage Class	407	914	176	328	404	909	175	326	402	903
Other	0	0	0	0	0	0	0	0	0	0
Total Revenue	407	914	176	328	404	909	175	326	402	903
Expenses										
Fuel	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0
Material & Others	102	236	46	89	102	236	46	89	102	236
Labor & Services	144	339	71	124	144	339	71	124	144	339
Depreciation	0	1	0	0	0	1	0	0	0	1
Decommissioning	0	0	0	0	0	0	0	0	0	0
Total Expenses	246	576	117	213	246	576	117	213	246	576
Operating Income	161	339	60	115	158	333	59	113	156	328
Interest										
World Bank & EBRD	0	0	0	0	0	0	0	0	0	0
Domestic Loans	1	2	1	2	2	5	1	2	3	7
Total Interest	1	2	1	2	2	5	1	2	3	7
Corporate Taxes	64	134	24	45	62	131	23	44	61	128
Net Income	96	202	35	68	94	197	35	67	91	193

VSE Distribution System
Income Statement
(millions Sk)

Year	1998	1998	1998	1998	1999	1999	1999	1999
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total
Energy Delivered To Grid (GWh)	5224	3895	2029	N/A	5449	4065	2088	N/A
T&D Losses (Assoc. W/Grid) (GWh)	144	101	110	356	149	105	106	361
Energy Leaving Less Losses (GWh)	5080	3794	1919	N/A	5300	3960	1981	N/A
Energy Sales By Voltage Class (GWh)	1185	1764	1919	4868	1235	1872	1981	5088
Grid Cost (SK/MWh)	34.34	85.49	208.07	N/A	32.73	81.43	200.23	N/A
Avg. T&D Sales Price (SK/MWh)	34.34	120.74	335.75	N/A	32.73	115.04	321.44	N/A
Revenue								
Domestic Sales-Voltage Class	174	324	399	898	173	322	397	893
Other	0	0	0	0	0	0	0	0
Total Revenue	174	324	399	898	173	322	397	893
Expenses								
Fuel	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0
Material & Others	46	89	102	236	46	89	102	236
Labor & Services	71	124	144	339	71	124	144	339
Depreciation	0	0	0	1	0	0	0	1
Decommissioning	0	0	0	0	0	0	0	0
Total Expenses	117	213	246	576	117	213	246	576
Operating Income	58	111	153	322	57	110	1[illegible]	317
Interest								
World Bank & EBRD	0	0	0	0	0	0	0	0
Domestic Loans	2	3	4	9	2	4	5	11
Total Interest	2	3	4	9	2	4	5	11
Corporate Taxes	23	43	60	125	22	42	58	122
Net Income	34	65	89	188	33	63	87	184

VSE Distribution System
Balance Sheets
(millions Sk)

Year	1993	1993	1993	1993	1994	1994	1994	1994	1999	1999	1999	1999
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
ASSETS	556	1077	1407	3041	1305	2523	3388	7217	1514	2928	3942	8384
Fixed Assets												
Fixed Assets in Operation	738	1454	1965	4157	2213	4363	5895	12471	1305	2620	3498	7423
Less Accumulated Depreciation	395	793	1058	2246	1184	2380	3174	6738	949	1826	2507	5282
Net Fixed Assets	343	661	907	1911	1029	1983	2721	5733	949	1826	2507	5282
Work in Progress	54	107	145	307	54	107	145	307	0	0	0	0
Total Fixed Assets	398	769	1052	2218	1084	2091	2866	6040	949	1826	2507	5282
Current Assets												
Cash & Banks	20	38	44	102	82	162	211	455	451	879	1178	2508
Accounts Receivable	109	212	244	564	109	212	244	564	84	164	188	437
Inventory	30	58	67	154	30	58	67	154	30	58	67	154
Others	1	1	1	3	1	1	1	3	1	1	1	3
Total Current Assets	159	309	355	823	222	433	522	1177	565	1102	1434	3102
EQUITY & LIABILITIES	556	1077	1407	3041	1305	2523	3388	7217	1514	2928	3942	8384
Equity												
Capital	358	706	954	2017	1068	2076	2832	5976	1068	2076	2832	5976
Retained Earnings	63	123	167	353	101	200	270	570	274	532	727	1533
Total Equity	421	829	1120	2370	1169	2275	3101	6546	1342	2608	3558	7509
Long-term Debt												
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	36	71	96	204
Total Long-Term Debt	0	0	0	0	0	0	0	0	36	71	96	204
Current Liabilities												
Short-Term Loans	22	40	46	107	22	40	46	107	22	40	46	107
Accounts Payable	112	205	237	554	112	205	237	554	112	205	237	554
Other	2	4	4	10	2	4	4	10	2	4	4	10
Total Current Liabilities	136	248	287	671	136	248	287	671	136	248	287	671

VSE Distribution System
Balance Sheets
(millions Sk)

Year	1993	1993	1993	1993	1994	1994	1994	1994	1995	1995	1995	1995
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
ASSETS	556	1077	1407	3041	1305	2523	3388	7217	1349	2609	3505	7462
Fixed Assets												
Fixed Assets in Operation	738	1454	1965	4157	2213	4363	5895	12471	1208	2427	3238	6874
Less Accumulated Depreciation	395	793	1058	2246	1184	2380	3174	6738	1013	1952	2678	5642
Net Fixed Assets	343	661	907	1911	1029	1983	2721	5733	1013	1952	2678	5642
Work in Progress	54	107	145	307	54	107	145	307	0	0	0	0
Total Fixed Assets	398	769	1052	2218	1084	2091	2866	6040	1013	1952	2678	5642
Current Assets												
Cash & Banks	20	38	44	102	82	162	211	455	202	397	528	1127
Accounts Receivable	109	212	244	564	109	212	244	564	103	201	231	536
Inventory	30	58	67	154	30	58	67	154	30	58	67	154
Others	1	1	1	3	1	1	1	3	1	1	1	3
Total Current Assets	159	309	355	823	222	433	522	1177	336	657	827	1820
EQUITY & LIABILITIES	556	1077	1407	3041	1305	2523	3388	7217	1349	2609	3505	7462
Equity												
Capital	358	706	954	2017	1068	2076	2832	5976	1068	2076	2832	5976
Retained Earnings	63	123	167	353	101	200	270	570	137	269	365	772
Total Equity	421	829	1120	2370	1169	2275	3101	6546	1206	2345	3197	6747
Long-term Debt												
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	8	15	21	44
Total Long-Term Debt	0	0	0	0	0	0	0	0	8	15	21	44
Current Liabilities												
Short-Term Loans	22	40	46	107	22	40	46	107	22	40	46	107
Accounts Payable	112	205	237	554	112	205	237	554	112	205	237	554
Other	2	4	4	10	2	4	4	10	2	4	4	10
Total Current Liabilities	136	248	287	671	136	248	287	671	136	248	287	671

VSE Distribution System
Balance Sheets
(millions Sk)

Year	1996	1996	1996	1996	1997	1997	1997	1997	1998	1998	1998
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV
ASSETS	1392	2692	3618	7702	1434	2772	3729	7935	1475	2851	3837
Fixed Assets											
Fixed Assets in Operation	1232	2475	3303	7010	1256	2523	3368	7147	1281	2571	3433
Less Accumulated Depreciation	997	1920	2635	5552	981	1888	2592	5461	965	1857	2550
Net Fixed Assets	997	1920	2635	5552	981	1888	2592	5461	965	1857	2550
Work in Progress	0	0	0	0	0	0	0	0	0	0	0
Total Fixed Assets	997	1920	2635	5552	981	1888	2592	5461	965	1857	2550
Current Assets											
Cash & Banks	267	522	696	1484	329	644	860	1833	391	763	1021
Accounts Receivable	98	191	220	509	93	182	209	484	89	172	198
Inventory	30	58	67	154	30	58	67	154	30	58	67
Others	1	1	1	3	1	1	1	3	1	1	1
Total Current Assets	395	772	983	2150	453	884	1137	2474	510	994	1287
EQUITY & LIABILITIES	1392	2692	3618	7702	1434	2772	3729	7935	1475	2851	3837
Equity											
Capital	1068	2076	2832	5976	1068	2076	2832	5976	1068	2076	2832
Retained Earnings	173	337	459	969	207	404	550	1162	241	469	640
Total Equity	1241	2413	3291	6945	1276	2480	3382	7137	1309	2545	3471
Long-term Debt											
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	15	30	41	86	23	44	60	127	29	58	79
Total Long-Term Debt	15	30	41	86	23	44	60	127	29	58	79
Current Liabilities											
Short-Term Loans	22	40	46	107	22	40	46	107	22	40	46
Accounts Payable	112	205	237	554	112	205	237	554	112	205	237
Other	2	4	4	10	2	4	4	10	2	4	4
Total Current Liabilities	136	248	287	671	136	248	287	671	136	248	287

VSE Distribution System
Balance Sheets
(millions Sk)

Year	1998	1999	1999	1999	1999
Voltage Class	Total	VHV	HV	LV	Total
ASSETS	8163	1514	2928	3942	8384
Fixed Assets					
Fixed Assets in Operation	7285	1305	2620	3498	7423
Less Accumulated Depreciation	5371	949	1826	2507	5282
Net Fixed Assets	5371	949	1826	2507	5282
Work in Progress	0	0	0	0	0
Total Fixed Assets	5371	949	1826	2507	5282
Current Assets					
Cash & Banks	2175	451	879	1178	2508
Accounts Receivable	460	84	164	188	437
Inventory	154	30	58	67	154
Others	3	1	1	1	3
Total Current Assets	2791	565	1102	1434	3102
EQUITY & LIABILITIES	8163	1514	2928	3942	8384
Equity					
Capital	5976	1068	2076	2832	5976
Retained Earnings	1350	274	532	727	1533
Total Equity	7325	1342	2608	3558	7509
Long-term Debt					
Foreign Loans	0	0	0	0	0
Domestic Loans	166	36	71	96	204
Total Long-Term Debt	166	36	71	96	204
Current Liabilities					
Short-Term Loans	107	22	40	46	107
Accounts Payable	554	112	205	237	554
Other	10	2	4	4	10
Total Current Liabilities	671	136	248	287	671

VSE Distribution System
Sources and Uses of Funds Statement
(millions Sk)

Year	1993	1993	1993	1993	1994	1994	1994	1994	1999	1999	1999	1999
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
SOURCES	62	122	165	350	96	190	257	543	66	127	174	368
Internal Generation												
Operating Income	50	99	133	282	64	127	171	362	57	110	150	317
Depreciation	12	24	32	68	24	48	64	136	0	0	0	1
Other	0	0	0	0	0	0	0	0	0	0	0	0
Total Internal Generation	62	122	165	350	88	174	236	498	57	110	151	318
Borrowing												
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	8	16	21	45	9	17	23	50
Total Borrowing	0	0	0	0	8	16	21	45	9	17	23	50
APPLICATIONS	62	122	165	350	96	190	257	543	66	127	174	368
Investment												
General Investment	0	0	0	0	8	16	21	45	9	17	23	50
Interest During Construction	0	0	0	0	0	0	0	0	0	0	0	0
Total Investment	0	0	0	0	8	16	21	45	9	17	23	50
Debt Services												
Principal												
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	2	4	6	12
Interest												
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	2	4	5	11
Total Debt Service	0	0	0	0	0	0	0	0	4	8	11	23
Taxes	20	39	53	113	26	51	69	145	22	42	58	122
Change in Working Capital	22	45	68	135	0	0	0	0	-29	-57	-75	-161
Change in Cash	20	38	44	102	63	124	167	353	60	116	157	333

VSE Distribution System
Sources and Uses of Funds Statement
(millions Sk)

Year	1993	1993	1993	1993	1994	1994	1994	1994	1995	1995	1995	1995
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
SOURCES	62	122	165	350	96	190	257	543	69	133	183	385
Internal Generation												
Operating Income	50	99	133	282	64	127	171	362	61	117	161	339
Depreciation	12	24	32	68	24	48	64	136	0	0	0	1
Other	0	0	0	0	0	0	0	0	0	0	0	0
Total Internal Generation	62	122	165	350	88	174	236	498	61	117	161	340
Borrowing												
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	8	16	21	45	8	16	22	46
Total Borrowing	0	0	0	0	8	16	21	45	8	16	22	46
APPLICATIONS	62	122	165	350	96	190	257	543	69	133	183	385
Investment												
General Investment	0	0	0	0	8	16	21	45	8	16	22	46
Interest During Construction	0	0	0	0	0	0	0	0	0	0	0	0
Total Investment	0	0	0	0	8	16	21	45	8	16	22	46
Debt Services												
Principal												
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	0	1	1	2
Interest												
Foreign Loans	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Loans	0	0	0	0	0	0	0	0	0	1	1	2
Total Debt Service	0	0	0	0	0	0	0	0	1	2	2	4
Taxes	20	39	53	113	26	51	69	145	24	47	64	134
Change in Working Capital	22	45	68	135	0	0	0	0	-84	-166	-222	-471
Change in Cash	20	38	44	102	63	124	167	353	120	235	317	672

VSE Distribution System
Sources and Uses of Funds Statement
(millions Sk)

Year	1996	1996	1996	1996	1997	1997	1997	1997	1998	1998
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV
SOURCES	68	132	181	381	67	130	179	376	67	129
Internal Generation										
Operating Income	60	115	158	333	59	113	156	328	58	111
Depreciation	0	0	0	1	0	0	0	1	0	0
Other	0	0	0	0	0	0	0	0	0	0
Total Internal Generation	60	116	159	334	59	114	156	329	58	112
Borrowing										
Foreign Loans	0	0	0	0	0	0	0	0	0	0
Domestic Loans	8	16	22	47	8	17	23	48	9	17
Total Borrowing	8	16	22	47	8	17	23	48	9	17
APPLICATIONS	68	132	181	381	67	130	179	376	67	129
Investment										
General Investment	8	16	22	47	8	17	23	48	9	17
Interest During Construction	0	0	0	0	0	0	0	0	0	0
Total Investment	8	16	22	47	8	17	23	48	9	17
Debt Services										
Principal										
Foreign Loans	0	0	0	0	0	0	0	0	0	0
Domestic Loans	1	2	2	4	1	2	3	7	2	3
Interest										
Foreign Loans	0	0	0	0	0	0	0	0	0	0
Domestic Loans	1	2	2	5	1	2	3	7	2	3
Total Debt Service	2	3	4	9	2	5	6	14	3	6
Taxes	24	45	62	131	23	44	61	128	23	43
Change in Working Capital	-29	-58	-76	-163	-29	-57	-76	-162	-29	-57
Change in Cash	64	125	168	357	63	122	164	349	61	119

VSE Distribution System
Sources and Uses of Funds Statement
(millions Sk)

Year	1998	1998	1999	1999	1999	1999
Voltage Class	LV	Total	VHV	HV	LV	Total
SOURCES	176	372	66	127	174	368
Internal Generation						
Operating Income	153	322	57	110	150	317
Depreciation	0	1	0	0	0	1
Other	0	0	0	0	0	0
Total Internal Generation	153	323	57	110	151	318
Borrowing						
Foreign Loans	0	0	0	0	0	0
Domestic Loans	23	49	9	17	23	50
Total Borrowing	23	49	9	17	23	50
APPLICATIONS	176	372	66	127	174	368
Investment						
General Investment	23	49	9	17	23	50
Interest During Construction	0	0	0	0	0	0
Total Investment	23	49	9	17	23	50
Debt Services						
Principal						
Foreign Loans	0	0	0	0	0	0
Domestic Loans	4	9	2	4	6	12
Interest						
Foreign Loans	0	0	0	0	0	0
Domestic Loans	4	9	2	4	5	11
Total Debt Service	9	18	4	8	11	23
Taxes	60	125	22	42	58	122
Change in Working Capital	-75	-162	-29	-57	-75	-161
Change in Cash	161	341	60	116	157	333

VSE Distribution System
Financial Ratios

Year	1993	1993	1993	1993	1994	1994	1994	1994	1995	1995	1995	1995	1999	1999	1999	1999
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
Operating Ratio	0.97	0.96	0.95	0.96	0.69	0.67	0.64	0.66	0.66	0.65	0.61	0.63	0.67	0.66	0.62	0.64
Current Ratio	1.17	1.24	1.24	1.23	1.63	1.74	1.82	1.75	2.47	2.65	2.88	2.71	4.16	4.44	5.00	4.62
Cash Generation Ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	7.47	7.30	7.41	7.38	6.46	6.31	6.41	6.38
Debt Coverage Ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	77.52	75.75	76.93	76.62	13.96	13.62	13.84	13.78
Debt/Equity	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.006	0.007	0.006	0.006	0.027	0.027	0.027	0.027
Debt	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.64%	0.65%	0.64%	0.64%	2.62%	2.66%	2.63%	2.64%
Equity	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.36%	99.35%	99.36%	99.36%	97.38%	97.34%	97.37%	97.36%
Accounts Receivable Outstanding in Days	23	31	35	30	194	200	185	192	213	222	208	214	177	185	173	178
Number of Times Interest earned	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	149.37	145.95	148.23	147.63	29.73	29.00	29.49	29.36
Return on Fixed Assets	12.59%	12.84%	12.67%	12.72%	5.93%	6.06%	5.98%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%

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VSE Distribution System
Financial Ratios

Year	1993	1993	1993	1993	1994	1994	1994	1994	1995	1995	1995	1995	1996	1996	1996
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV
Operating Ratio	0.97	0.96	0.95	0.96	0.69	0.67	0.64	0.66	0.66	0.65	0.61	0.63	0.66	0.65	0.61
Current Ratio	1.17	1.24	1.24	1.23	1.63	1.74	1.82	1.75	2.47	2.65	2.88	2.71	2.91	3.11	3.43
Cash Generation Ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	7.47	7.30	7.41	7.38	7.21	7.04	7.15
Debt Coverage Ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	77.52	75.75	76.93	76.62	37.77	36.89	37.47
Debt/Equity	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.006	0.007	0.006	0.006	0.012	0.012	0.012
Debt	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.64%	0.65%	0.64%	0.64%	1.22%	1.23%	1.22%
Equity	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.36%	99.35%	99.36%	99.36%	98.78%	98.77%	98.78%
Accounts Receivable Outstanding in Days	23	31	35	30	194	200	185	192	213	222	208	214	203	213	198
Number of Times Interest earned	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	149.37	145.95	148.23	147.63	74.48	72.75	73.90
Return on Fixed Assets	12.59%	12.84%	12.67%	12.72%	5.93%	6.06%	5.98%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%

VSE Distribution System
Financial Ratios

Year	1996	1997	1997	1997	1997	1998	1998	1998	1998	1999	1999	1999	1999
Voltage Class	Total	VHV	HV	LV	Total	VHV	HV	LV	Total	VHV	HV	LV	Total
Operating Ratio	0.63	0.66	0.65	0.61	0.64	0.67	0.66	0.62	0.64	0.67	0.66	0.62	0.64
Current Ratio	3.20	3.33	3.56	3.96	3.69	3.75	4.01	4.48	4.16	4.16	4.44	5.00	4.62
Cash Generation Ratio	7.12	6.95	6.79	6.90	6.87	6.70	6.54	6.65	6.62	6.46	6.31	6.41	6.38
Debt Coverage Ratio	37.32	24.53	23.95	24.33	24.23	17.92	17.49	17.77	17.70	13.96	13.62	13.84	13.78
Debt/Equity	0.012	0.018	0.018	0.018	0.018	0.023	0.023	0.023	0.023	0.027	0.027	0.027	0.027
Debt	1.22%	1.74%	1.76%	1.74%	1.75%	2.20%	2.23%	2.21%	2.22%	2.62%	2.66%	2.63%	2.64%
Equity	98.78%	98.26%	98.24%	98.26%	98.25%	97.80%	97.77%	97.79%	97.78%	97.38%	97.34%	97.37%	97.36%
Accounts Receivable Outstanding in Days	204	194	203	190	195	186	194	181	187	177	185	173	178
Number of Times Interest earned	73.60	49.57	48.39	49.17	48.97	37.15	36.25	36.85	36.69	29.73	29.00	29.49	29.36
Return on Fixed Assets	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%

Appendix J Long-Run Average Incremental Cost Calculations by Regional Distribution Utility and Voltage Level

ZSE Distribution System
Marginal T/D Demand Cost

Year	1993	1993	1993	1993	1994	1994	1994	1994
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total
Total Investment (10^6 Sk)	0.00	0.00	0.00	0.00	22.06	52.34	45.60	120.00
Inv. to Maintain System (10^6 Sk)					13.23	31.41	27.36	72.00
Discounted Inv.- Add. Demand (10^6 Sk)					8.82	20.94	18.24	48.00
Forecast Peak in Mw	199.64	305.09	742.31	1247.04	192.04	298.64	712.99	1203.66
Annual inremental Peak Load Mw					-7.61	-6.45	-29.32	-43.37
Annual Incremental Grid Load					-43.37263106	-35.76604203	-29.32066472	
Discount Factor using 6.00%					1.00	1.00	1.00	1.00
Discounted to 1994 (Mw)					-43.37263106	-35.76604203	-29.32066472	0
Annual Incremental Demand cost (Sk/Kw)					-203	-585	-622	N/A
Annual Embedded cost (Sk/Mwh)	60	198	426 N/A		76	263	557 N/A	
					1.00	3.45	7.30	

ZSE Distribution System
Marginal T/D Demand Cost

Year		1995	1995	1995	1995	2010	2010	2010	2010
Voltage Class		VHV	HV	LV	Total	VHV	HV	LV	Total
Total Investment (10^6 Sk)		36.76	87.24	76.00	200.00	49.48	117.41	102.28	269.17
Inv. to Maintain System (10^6 Sk)		22.06	52.34	45.60	120.00	29.69	70.45	61.37	161.50
Discounted Inv.- Add. Demand (10^6 Sk)		13.87	32.92	28.68	75.47	7.79	18.49	16.11	42.38
Forecast Peak in Mw		187.03	296.00	720.27	1203.30	262.94	545.93	946.89	1755.76
Annual inremental Peak Load Mw		-5.01	-2.64	7.28	-0.37	-0.35	9.40	21.52	30.58
Annual Incremental Grid Load		-0.366647234	4.641036429	7.280942667		30.57710415	30.9269411	21.52436686	
Discount Factor using	6.00%	0.94	0.94	0.94	0.94	0.39	0.39	0.39	0.39
Discounted to 1994 (Mw)		-0.345893617	4.378336254	6.868813837	0	12.03656342	12.17427543	8.472987022	0
Annual Incremental Demand cost (Sk/Kw)		-40107	7519	4175	N/A	647	1519	1901	N/A
Annual Embedded cost (Sk/Mwh)		73	256	533	N/A				

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ZSE Distribution System
Marginal T/D Demand Cost

	Year	Total	Total	Total	
	Voltage Class	VHV	HV	LV	
Total Investment (10^6 Sk)					
Inv. to Maintain System (10^6 Sk)					
Discounted Inv.- Add. Demand (10^6 Sk)		177.7880831	421.8941447	367.5337899	
Forecast Peak in Mw					
Annual inremental Peak Load Mw					
Annual Incremental Grid Load					
Discount Factor using	6.00%				
Discounted to 1994 (Mw)		292.9860098	255.8271975	110.9457504	
Annual Incremental Demand cost (Sk/Kw)		607	1649	3313	ZSE grid LRAIC in Sk/Kw/yr
		607	2256	5569	ZSE T/D LRAIC in Sk/Kw/yr
		0.098958617	0.378718679	0.977991869	ZSE T/D LRAIC in Sk/Kwh
Annual Embedded cost (Sk/Mwh)		98.95861722	378.7186791	977.9918687	ZSE T/D LRAIC in Sk/Mwh
		1	3.827040936	9.882836847	Ratios to VHV's LRAIC
		76.27963801	262.9649552	556.6272643	Embedded Rates for 1994

SSE Distribution System
Marginal T/D Demand Cost

Year	1993	1993	1993	1993	1994	1994	1994	1994
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total
Total Investment (10^6 Sk)	0.00	0.00	0.00	0.00	22.06	52.34	45.60	120.00
Inv. to Maintain System (10^6 Sk)					13.23	31.41	27.36	72.00
Discounted Inv.- Add. Demand (10^6 Sk)					8.82	20.94	18.24	48.00
Forecast Peak in Mw	381.34	258.91	518.12	1158.38	373.18	253.37	497.84	1124.39
Annual inremental Peak Load Mw					-8.17	-5.55	-20.28	-33.99
Annual Incremental Grid Load					-33.98885977	-25.82134691	-20.27599007	
Discount Factor using 6.00%					1.00	1.00	1.00	1.00
Discounted to 1994 (Mw)					-33.98885977	-25.82134691	-20.27599007	0
Annual Incremental Demand cost (Sk/Kw)					-260	-811	-900	N/A
Annual Embedded cost (Sk/Mwh)	53	159	358	N/A	62	233	597	N/A
					1.00	3.77	9.66	

SSE Distribution System

Marginal T/D Demand Cost

Year		1995	1995	1995	1995	2010	2010	2010	2010
Voltage Class		VHV	HV	LV	Total	VHV	HV	LV	Total
Total Investment (10^6 Sk)		36.76	87.24	76.00	200.00	49.48	117.41	102.28	269.17
Inv. to Maintain System (10^6 Sk)		22.06	52.34	45.60	120.00	29.69	70.45	61.37	161.50
Discounted Inv.- Add. Demand (10^6 Sk)		13.87	32.92	28.68	75.47	7.79	18.49	16.11	42.38
Forecast Peak in Mw		369.88	251.13	502.93	1123.93	682.17	463.16	661.17	1[illegible].51
Annual inremental Peak Load Mw		-3.30	-2.24	5.08	-0.45	11.75	7.98	15.03	34.76
Annual Incremental Grid Load		-0.454549888	2.84421163	5.083915447		34.75577532	23.00655119	15.02938097	
Discount Factor using	6.00%	0.94	0.94	0.94	0.94	0.39	0.39	0.39	0.39
Discounted to 1994 (Mw)		-0.428820649	2.683218519	4.796146648	0	13.68148179	9.056443376	5.916259964	0
Annual Incremental Demand cost (Sk/Kw)		-32351	12269	5980	N/A	569	2041	2722	N/A
Annual Embedded cost (Sk/Mwh)		54	198	491	N/A				

SSE Distribution System
Marginal T/D Demand Cost

	Year	Total	Total	Total	
	Voltage Class	VHV	HV	LV	
Total Investment (10^6 Sk)					
Inv. to Maintain System (10^6 Sk)					
Discounted Inv.- Add. Demand (10^6 Sk)		177.7880831	421.8941447	367.5337899	
Forecast Peak in Mw					
Annual inremental Peak Load Mw					
Annual Incremental Grid Load					
Discount Factor using	6.00%				
Discounted to 1994 (Mw)		381.4324667	200.5057241	77.66498095	
Annual Incremental Demand cost (Sk/Kw)		466	2104	4732	SSE grid LRAIC in Sk/Kw/yr
		466	2570	7303	SSE T/D LRAIC in Sk/Kw/yr
		0.07601212	0.43148275	1.282499803	SSE T/D LRAIC in Sk/Kwh
Annual Embedded cost (Sk/Mwh)		76.01211991	431.4827502	1282.499803	SSE T/D LRAIC in Sk/Mwh
		1	5.676499362	16.87230674	Ratios to VHV's LRAIC
		61.80190626	233.0142082	596.7142826	Embedded Rates for 1994

VSE Distribution System
Marginal T/D Demand Cost

Year	1993	1993	1993	1993	1994	1994	1994	1994
Voltage Class	VHV	HV	LV	Total	VHV	HV	LV	Total
Total Investment (10^6 Sk)	0.00	0.00	0.00	0.00	7.98	15.73	21.25	44.96
Inv. to Maintain System (10^6 Sk)	0.00	0.00	0.00	0.00	4.79	9.44	12.75	26.98
Discounted Inv.- Add. Demand (10^6 Sk)	0.00	0.00	0.00	0.00	3.19	6.29	8.50	17.98
Forecast Peak in Mw	167.30	255.66	462.49	885.46	160.88	250.19	444.40	855.46
Annual inremental Peak Load Mw					-6.42	-5.48	-18.10	-30.00
Annual Incremental Grid Load					-29.99716662	-23.57494502	-18.09922165	
Discount Factor using 6.00%					1.00	1.00	1.00	1.00
Discounted to 1994 (Mw)					-29.99716662	-23.57494502	-18.09922165	0
Annual Incremental Demand cost (Sk/Kw)					-106	-267	-470	N/A
Annual Embedded cost (Sk/Mwh)	37	135	394	N/A	44	160	457	N/A
					1.00	3.61	10.32	

VSE Distribution System
Marginal T/D Demand Cost

Year		1995	1995	1995	1995	2010	2010	2010	2010
Voltage Class		VHV	HV	LV	Total	VHV	HV	LV	Total
Total Investment (10^6 Sk)		8.14	16.05	21.68	45.86	10.95	21.60	29.16	61.72
Inv. to Maintain System (10^6 Sk)		4.88	9.63	13.01	27.52	6.57	12.96	17.51	37.03
Discounted Inv.- Add. Demand (10^6 Sk)		3.07	6.06	8.18	17.31	1.72	3.40	4.59	9.72
Forecast Peak in Mw		156.68	247.98	448.93	853.59	220.28	457.35	590.19	1267.82
Annual inremental Peak Load Mw		-4.20	-2.21	4.54	-1.87	-0.29	7.88	13.42	21.00
Annual Incremental Grid Load		-1.868641518	2.326542117	4.5381218		20.9997971	21.29287277	13.41587249	
Discount Factor using	6.00%	0.94	0.94	0.94	0.94	0.39	0.39	0.39	0.39
Discounted to 1994 (Mw)		-1.762869356	2.194851054	4.281246981	0	8.266492086	8.381860234	5.281108349	0
Annual Incremental Demand cost (Sk/Kw)		-1742	2759	1911	N/A	209	406	870	N/A
Annual Embedded cost (Sk/Mwh)		38	136	379	N/A				

VSE Distribution System
Marginal T/D Demand Cost

	Year	Total	Total	Total	
	Voltage Class	VHV	HV	LV	
Total Investment (10^6 Sk)					
Inv. to Maintain System (10^6 Sk)					
Discounted Inv.- Add. Demand (10^6 Sk)		40.59071968	80.04070848	108.133006	
Forecast Peak in Mw					
Annual inremental Peak Load Mw					
Annual Incremental Grid Load					
Discount Factor using	6.00%				
Discounted to 1994 (Mw)		221.7052914	190.625328	69.32710561	
Annual Incremental Demand cost (Sk/Kw)		183	420	1560	VSE grid LRAIC in Sk/Kw/yr
		183	603	2163	VSE T/D LRAIC in Sk/Kw/yr
		0.029857164	0.101223658	0.379824351	VSE T/D LRAIC in Sk/Kwh
Annual Embedded cost (Sk/Mwh)		29.85716354	101.2236584	379.8243508	VSE T/D LRAIC in Sk/Mwh
		1	3.390263722	12.72138093	Ratios to VHV's LRAIC
		44.29549913	159.8196167	457.1855765	Embedded Rates for 1994