PN-ACC-442
97493

Bulgaria Tariff Implementation Project

Interim Report: Electricity and District Heating Tariffs

February 1996

Prepared under Contract to

U.S. Agency for International Development

Regulatory Reform and Energy Sector Restructuing in Central and Eastern Europe and the Baltics
Contract No EHR-0030-C-00-5016-00

BECHTEL
International
Consulting Group

22934-002-001

Contents

Executive Summary

Electricity Tariffs

1 Introduction
2 Review of the Electric Demand Forecast
3 Review of Bulgarian Power System
4 Electric System Operating Cost Structure
5 Review of Existing Tariffs
6 Long Run Marginal Cost Forecast
7 Financial Requirements and Cost of Electric Service
8 Tariff Design

District Heating Tariffs

1 Introduction
2 District Heating Supply and Demand
3 Review of Existing District Heating Tariff Structure, Pricing and Regulation
4 Long-Run Marginal Cost Estimate
5 Implementation Issues

Bulgaria Tariff Implementation Project

Interim Report: Electricity Tariffs

February 1996

Prepared under Contract to

U.S. Agency for International Development

Regulatory Reform and Energy Sector Restructuring in Central and Eastern Europe and the Baltics

Contract No EHR-0030-C-00-5016-00

TECHNICAL
International
Consulting Group

3

Contents

Electricity Tariffs

1 Introduction

1 1 Project Background 1-1

1 2 Project Objectives 1-1

1 3 Contents of This Report 1-1

1 4 Objectives for Tariffs 1-2

1 5 Sources of Information 1-3

1 6 Guide to the Interim Report 1-3

2 Review of the Electric Demand Forecast

2 1 Electric Demand Forecast 2-1

2 1 1 Annual Energy and Peak Demand Forecasts 2-1

2 1 2 Seasonal and Daily Variations in Demand 2-3

2 2 Demand Forecast Disaggregation by Tariff Category 2-3

2 2 1 Methodology 2-5

2 2 2 Tariff Category Sales Forecast 2-5

2 2 3 Losses by Tariff Category 2-6

2 2 4 Total Energy Demand 2-9

2 2 5 Pattern of Demand 2-9

3 Review of Bulgarian Power System

3 1 The Generation System 3-1

3 1 1 Characteristics of Existing Bulgarian Power Plants 3-1

3 1 2 Fuel Prices 3-1

3 1 3 Imported Power Costs 3-2

3 1 4 O&M Costs 3-2

3 2 Generation Development and Investment Plans 3-3

3 2 1 Capacity Development 3-3

3 2 2 Capital Requirements 3-4

4

Contents

3 3 Future Generating Mix and Associated Production Costs 3-5

3 3 1 Capacity and Energy Balances 3-5

3 3 2 Current and Future Mix of Fuels Used to Generate Electricity 3-5

4 Electric System Operating Cost Structure

4 1 Marginal Costing Using Production Simulation 4-1

4 2 Marginal Capacity Cost Structure 4-2

4 3 Marginal Energy Cost Structure 4-3

5 Review of Existing Tariffs

5 1 Current Tariff Setting and Regulation 5-1

5 2 Current Tariffs 5-1

5 3 Financial Requirements 5-2

5 4 Economic Signals to Customers And Suppliers 5-3

5 4 1 Comparison by Tariff Category 5-3

5 4 2 Comparison by Time-of-Day 5-4

5 4 3 Seasonal Tariffs 5-6

5 4 4 Pricing for Power Purchased from Industrial and CHP Plants 5-8

6 Long Run Marginal Cost Forecast

6 1 Introduction to LRMC 6-1

6 2 Generation System LRMC 6-2

6 2 1 Incremental Plant Method 6-2

6 2 2 Revenue Requirements Method 6-4

6 2 3 LRMC Summary for the Two Methods 6-6

6 2 4 Conclusions 6-8

6 3 LRMC of T&D 6-8

6 4 LRMC Loss Adjustment by Voltage Level 6-11

6 5 LRMC by Voltage Level 6-11

6 6 LRMC Time-of-Day Variation 6-12

5

Contents

7 Financial Requirements and Cost of Electric Service

7 1 Utility Financial Requirements 7-1

7 1 1 Financial Objectives 7-1

7 1 2 Financial Assumptions for NEK 7-1

7 1 3 Financial Results 7-3

7 1 4 Financial Uncertainties 7-4

7 2 Cost-of-Service by Customer Category 7-6

7 2 1 Introduction 7-6

7 2 2 Cost-of-Service Methodology 7-7

7 2 3 Cost-of-Service Results 7-7

8 Tariff Design

8 1 LRMC-Based Revenue Allocation 8-1

8 1 1 Overview of Revenue Allocation 8-1

8 1 2 Comparison of Current Tariffs with LRMC and Financial Requirements 8-1

8 1 3 Revenue Allocation to Customer Class 8-2

8 1 4 Revenue Allocation to Customer Classes Illustration 8-2

8 1 5 Capacity and Energy Components of Tariffs 8-3

8 1 6 LRMC-based Seasonal Allocation 8-4

8 2 Summary of Tariff Results 8-4

8 3 Block Pricing Structure 8-5

8 4 Protection of the Poor from High Electric Prices 8-5

8 5 Other Issues 8-6

Illustrations

Figure		Page
2-1	Forecasts of the Annual Electric Energy Consumption in Bulgaria	2-2
2-2	Forecasts of the Annual Electric Peak Load in Bulgaria	2-2
2-3	Bulgarian Maximum Monthly Demand for 1995	2-3
2-4	Typical Peak Day Load Shapes for January and July Peak Day	2-4
2-5	Illustration of Electricity Flow- 1995	2-8
2-6	Forecast Percentage of Annual Electric Energy Consumption	2-9
2-7	Demand by Tariff Category for a Typical Winter Day	2-10
2-8	Demand by Tariff Category for a Typical Summer Day	2-10
4-3	Projected Contribution to Expected Unserved Energy by Time Period	4-3
4-4	Illustration of Marginal Energy Cost (SRMC)	4-4
4-5	Comparison of Projected Average Variable Generating Cost and Short-Run Marginal Cost for Plan A	4-5
4-6	Projected Short-Run Marginal Cost by Time Period for 1996	4-6
5-1	Comparison of Current Tariffs with LRMC	5-3
5-2a	High Voltage Tariffs and LRMC by Time of Day	5-5
5-2b	Low Voltage- Non-household Tariffs and LRMC by Time of Day	5-6
5-2c	Household Tariffs and LRMC by Time of Day	5-6
5-3	Ratio of Winter to Summer Prices and Costs- High Voltage	5-7
5-4	Comparison of Pricing for Power Purchased from Industrial and CHP Plants with SRMC and LRMC by Time of Day	5-9
8-1	Comparison of Tariffs, Financial Requirements, and LRMC	8-2

1

Tables

Table		Page
2-1	Development of Sectoral Forecast	2-6
2-2	Assumed Voltage Level of Service of Economic Sectors	2-6
2-3	Loss Responsibility by Voltage Level of Service-1995	2-8
2-4	Load Shape Assumptions for Non-household Tariff Categories	2-9
3-4	Comparative Fuel Price Projections	3-2
3-8	Power Plant Rehabilitation Projects	3-4
3-9	New Hydro Projects	3-5
3-1	Operating Characteristics of Existing Thermal Power Plants	3-7
3-2	Operating Characteristics of Bulgarian Hydroelectric Power Plants	3-8
3-3	Operating Characteristics of Pumped-Storage Power Plants	3-8
3-5	O&M Costs for Major Thermal Power Plants in Bulgaria	3-9
3-6	Capacity additions for Plan A, B and C for the period 1995-2005	3-10
3-7a	Operating Characteristics of New Capacity Additions	3-12
3-7b	Cost Characteristics of New Capacity Additions	3-12
3-10	Capacity Balance in MW for NEK (Plan A)	3-13
3-11	Energy Balance in GWh for NEK (Plan A)	3-14
5-1	Non-household Tariffs- September 1995 (leva/kWh)	5-2
5-2	Electricity Buyback Rates for Industry and District Heating Cos	5-2
6-1	Technical and Economic Characteristics of Gas Turbines	6-2
6-2	Generation LRMC – Incremental Plant Method Plan A	6-4
6-3	Generation LRMC – Revenue Requirements Method for Plan A	6-6
6-4	Generation LRMC Summary	6-6
6-5	International Comparison of LRMC for T&D ($US 1995 per kW-year)	6-10
6-6	Assumptions for LRMC for Bulgarian T&D ($US 1995)	6-10
6-7	Derivation of HV LRMC from Fichner Study ($US 1995)	6-10
6-8	LRMC by Voltage Level	6-11
6-9	Time-of-Day Variation in SRMC and EUE for 1995 for Plan A	6-12
7-2	Key Financial Ratios	7-4
7-3	Examples of Cost of Nuclear Decommissioning	7-5
7-4	Comparison of Cost-of-Service and LRMC for NEK	7-8
7-5	Forecasted Capital Expenditures	7-9
8-1	Alternative Revenue Allocation to Customer Classes	8-3

8

Section 1
Introduction

1 1 PROJECT BACKGROUND

This first part of the Interim Report for the Bulgaria Energy Tariff Implementation Project evaluates the electricity tariff setting process The second part of this report addresses tariffs for district heating The project was originally requested by Deputy Prime Minister Tsochev, and is funded by the U S Agency for International Development (USAID) Project guidance and technical support is provided by a Bulgarian Working Group made up of members of the following Bulgarian organizations

- Committee of Energy (CoE)
- National Electric Company (NEK)
- Ministry of Finance
- Commission on Pricing
- Parliamentary Commission for Energy and Natural Resources, and
- Energoproekt

1 2 PROJECT OBJECTIVES

The objectives of the energy tariff implementation project are

- To investigate the existing cost and pricing of electricity
- To estimate the level and structure of tariffs based on long-run marginal cost (LRMC)
- To estimate financial requirements of the National Electricity Company
- To make recommendations on tariffs taking into consideration LRMC, financial requirements of the entities responsible for production and delivery of energy, impact on energy-intensive industries, and protection of economically disadvantaged groups
- To support institutional development through a training program in the above areas

1 3 CONTENTS OF THIS REPORT

This Interim Report on the Bulgaria Energy Tariff Implementation Project describes the electric tariff analysis conducted by the Bechtel team in consultation with the Bulgarian Working Group The specific tasks described in this report include

9

- ***Task 1 Evaluate Energy Demand*** – We present an analysis of current electricity consumption and future demand projections, select an existing overall forecast, and disaggregate the forecast by voltage level of service
- ***Task 2 Evaluate Supply Systems*** – We analyze the existing and projected electricity supply system and associated investment plan
- ***Task 3 Analysis of Economic Cost Structure*** – The electric power system is modeled to allocate capacity and energy costs by time of day and by season
- ***Task 4 Evaluation of Existing Tariffs*** – Existing tariffs are evaluated based on how well they reflect the current economic cost structure as analyzed in Task 3 and how well they reflect LRMC as developed in Task 5
- ***Task 5 Formulation of a Pricing Strategy Based upon Marginal Cost Structure*** – Strict LRMC is estimated for generation and transmission and for delivery by voltage level
- ***Task 6 Financial Analysis*** – A financial analysis is used to determine the minimum revenue required for the financial viability of NEK
- ***Task 7 Adjustment of Strict LRMC-Based Tariffs for Financial and Other Considerations*** – Revenues based on strict LRMC pricing are compared with financial requirements and alternatives are suggested for adjusting revenues to meet financial requirements Transitional pricing is developed to reduce the impact of price changes on all customer groups, especially residential consumers

1 4 OBJECTIVES FOR TARIFFS

The objectives of the final tariff design are identified below

- Provide clear economic signals to customers on the long-run marginal costs of electricity Marginal cost pricing promotes efficient consumer behavior for consumption of electric services
- Differentiate tariffs to the degree practical Efficient pricing recognizes separate pricing for capacity and energy, time-of-day, season, service voltage and customer class distinctions
- Provide adequate funds to operate the power system and provide a reasonable return on investment
- Address social equity and economic development issues such as protection of economically disadvantaged groups and consideration of economic competitiveness This may require that cross-subsidies are phased out over a period of time and that financial objectives are met on a multi-year rather than annual basis

10

1 5 SOURCES OF INFORMATION

We are indebted to the planning personnel at NEK for technical and financial data, and for the IRP Manager Modeling that is used in this report CoE has provided guidance and information on all aspects of Bulgarian tariffs and electric sector development We have gained insights from several Bulgarian studies of the energy sector, including

- the work of NEK, Energoproekt and independent Bulgarian experts to develop electric resource strategies for the development of the electric sector
- CoE technical papers and media articles on energy pricing
- Energoproekt's study of the future development of the natural gas sector

We have benefited from the work of other consultants and advisors working in Bulgaria, including World Bank, NERA, Arthur Andersen, Central Maine Power, RCG/Hagler Bailly and PowerGen The following key documents have been useful for the tariff project

- *Organization and Policy Formulation for the Bulgarian Energy Sector* (NERA, April 1994)
- *Protection of the Poor in Bulgaria from the Effects of Sharply Higher Energy Prices* (World Bank, February 1995)
- *Electricity Prices in Bulgaria* (World Bank, December 1994)
- *Bulgaria Energy Strategy Study* (World Bank, December 1991)
- *Power Complex Rehabilitation Project in Bulgaria* (Bechtel, October 1993)
- *Bulgaria Electricity Study Management of Electricity Demand* (RCG/Hagler, Bailly, Inc , April 1993)

1 6 GUIDE TO THE INTERIM REPORT

The Interim Report is organized so as to answer the following questions

What are the basic load and resource assumptions underlying our tariff scenarios?	Section 2 for loads and Section 3 for resources
What is the cost structure for NEK? What are the long-run marginal costs for NEK compared to existing tariffs?	Section 4 for cost structure and Section 5 for comparison of LRMC with prices

What is the strict long-run marginal cost (LRMC) of the various components of electricity supply?	Section 6
What are NEK's financial requirements to assure the ongoing viability of its electric operations?	Section 7
How must tariffs based on LRMC be modified to meet financial requirements and other tariff-setting goals?	Section 8

12

Executive Summary

OVERVIEW

This is the Interim Report of the Bulgarian Energy Tariff Implementation Project This report has been prepared by Bechtel under contract to USAID The Bulgarian Energy Tariff Working Group, made up of representatives from the Committee of Energy (CoE), the Commission of Prices (CoP), the Ministry of Finance (MoF), and the National Electric Company (NEK), has provided key data and analysis used in this report However, many of the results of the Interim Report have been developed with only limited oversight of the complete Working Group Therefore the results should be considered preliminary and the Interim Report should be considered a working document

The goal of the Project is to provide assistance in implementing a tariff-setting process that reflects the true costs of energy supply, transmission and distribution The scope of the Project is limited to electric tariffs and district heating tariffs We present scenario estimates of the level and structure of tariffs based on marginal costing These results provide a useful benchmark for comparison with current tariffs

The Bulgaria Tariff Implementation Project summarized in this report includes the following elements

- Analyzing the current pricing structure for electricity and district heating
- Estimating the financial requirements of NEK and Sofia District Heating
- Forecasting the long-run marginal cost of electricity and district heating generation, transmission, and distribution
- Developing alternative approaches to meeting social goals through tariff adjustments
- Developing tariffs taking into account long-run marginal cost, financial requirements, and social considerations

PLANNING ASSUMPTIONS

Electricity Demand An electricity demand scenario used by NEK in its least-cost planning activities with the World Bank is used as the basis for the electric sector analysis This demand forecast has been disaggregated by the tariff categories used in the current Bulgarian tariff structure These are High Voltage (110 kV), Medium Voltage (< 110 kV and > 1 kV) and Low Voltage (< 1 kV) Low Voltage customers are further differentiated as Household and Non-Household Figure ES-1 shows forecast demand by tariff category Note that we recommend future demand forecasting should be done separately for each tariff category for both electricity and district heating

13

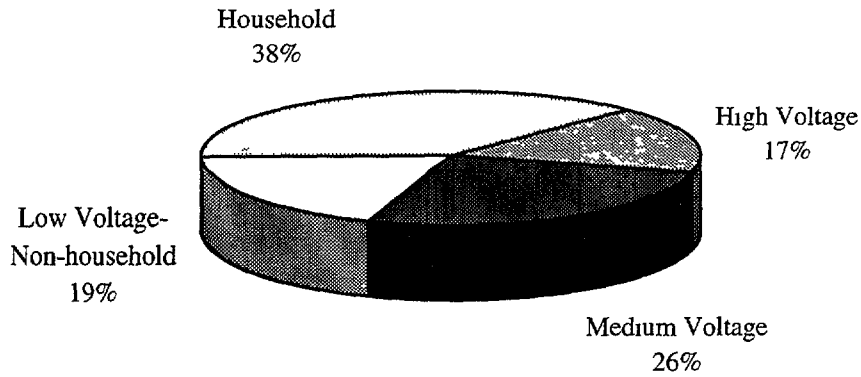


Figure ES-1 Contribution to Electricity Demand by Tariff Category

Electric Supply Debate over nuclear and gas supply choices and financing constraints makes it impossible to select a supply plan that is acceptable to all Major areas of contention include plans for shutdown of the Kozluduy 1-4 units, rehabilitation and expansion of coal plants, completion of the Belene Nuclear Plant and the degree of dependence on imported natural gas that is acceptable

It is beyond the scope of this Project to examine the many resource planning choices available, and to evaluate the tariff implications of each one For this Interim Report, we consider three alternative sets of assumptions represented by Plans A, B and C Each of the three alternative scenarios has been developed to meet the long term reliability requirements of the power system by gradually adding generating resources (Note that prior to year 2000, the time horizon for the financial plans evaluated in this report, we assume no expenditures for Belene) Plans A, B and C are differentiated as follows

- Plan A is based on a shutdown of Kozluduy 1 and 2 in 1998 and 1999, respectively, and Kozluduy 3 and 4 in 2003 and 2004
- Plan B assumes a delay in the shutdown of Kozluduy 1 and 2 to 2001 and 2002, respectively The shutdown of Kozluduy 3 and 4 is beyond the tariff planning horizon in Plan B
- Plan C is based on shutdown of Kozluduy 1 and 2 at the end of 1997 and Kozluduy 3 and 4 in 1998 Plan C adheres to the strict wording of conditions for loans with the World Bank and the European Bank for Reconstruction and Development

District Heating Supply and Demand New district heating demand in Sofia is projected to be offset by decreasing transmission losses and by increased efficiency of usage by

14

customers, based on a feasibility study of investment options for the Sofia and Pernik systems A key uncertainty for district heating supply is the feasibility of combined heat and power plants, specifically the Sofia and Sofia East Combined Cycle Power Plants These plants are included in the electric supply plan in the year 2000, however our analysis of the Sofia District Heating Company does not include these plants This is an area that will require coordinated assumptions in future work

ESTIMATED LONG-RUN MARGINAL COST (LRMC)

LRMC is the cost of providing incremental electric services LRMC can be used in tariff design to provide an economically efficient cost signal for consumers' choices for electric services Pricing below LRMC can lead customers to use electricity in uneconomic ways and will not provide adequate revenues to expand the system over its long-term growth

LRMC has been calculated for the various tariff categories for both electricity and district heating The weighted average electricity LRMC is $US 47 per MWh High Voltage customers are the least expensive to serve because of lower transmission and distribution losses and lower investment requirements The LRMC for serving these customers is $US 35 per MWh Low Voltage customers are the highest cost to serve and their LRMC is estimated at slightly over $US 50 per MWh These results are consistent for each planning scenario that we consider

EXISTING TARIFFS

Table ES-1 summarizes key characteristics of existing electricity and district heating tariffs, including the tariff categories in use in Bulgaria, seasonal and time-of-day differentiation, current tariffs levels, and the ratio of current tariffs to LRMC The current level of price control for the various categories is also shown in the table "Fixed" prices receive the highest level of control by the Commission of Pricing Besides electricity and district heating, natural gas is the only other commodity in the fixed category Non-budget commodities have been placed in the category of "supervised" prices, freeing them of rigid price control, but still subject to regulatory oversight by the Commission of Pricing

15

Table ES-1
Structure of Bulgarian Electricity and District Heating Tariffs

Tariff Category	Time-of-Day	Season	Classification	% of 1994 Sales	September 95 Tariff	% of LRMC
Electricity (NEK)					$/MWh	
High Voltage (>110 kV)	Peak	Summer	fixed	17%	27 2	77%
	Daytime	Winter				
	Nighttime					
Medium Voltage (1 to 110 kV)	Peak	Summer	fixed	26%	28 5	67%
	Daytime	Winter				
	Nighttime					
Low Voltage (<1 kV)- Non-household	Peak	none	fixed	38%	31 5	60%
	Daytime					
	Nighttime					
Low Voltage- Household	Daytime	Summer	fixed	19%	19 6	38%
	Nighttime	Winter				
District Heating (Sofia District Heating Co)					$/Gcal	
Industrial Steam	none	none	suprvsd	6%		100%
Public Sector- Non-budg	none	none	suprvsd	16%		100%
Public Sector Budget	none	none	fixed	10%	12 1	43%
Household	none	none	fixed	68%	12 1	43%

Electricity tariffs The existing electricity tariff structure is appealing because it is simple, yet at the same time it captures essential differentiation of season, time-of-day, service voltage level and customer class But the tariffs themselves are too low We make the following observations based on our comparison of existing electricity tariffs with LRMC

- In general, as shown in Table ES-1, electricity tariffs are priced below LRMC In the table, the ratio of current tariff to LRMC is less than one for all tariff categories We find that the ratio of current tariff to LRMC decreases with the voltage level of service Non-household tariffs increase in absolute terms as voltage level decreases, but not enough to reflect the

16

increase in true economic cost Household customers cost the most to serve and have the lowest tariffs

- Peak period electricity tariffs are close to estimated LRMC for non-household tariff categories Daytime and nighttime tariffs are significantly less
- LRMC for the summer is higher than for the winter due to nuclear refueling requirements and summer operating constraints The relationship between the existing winter and summer tariffs is the opposite
- The price paid by NEK for electric generation from industry and district heating companies is lower than the estimated value of that generation to the power system It is lower than even the incremental operating cost of the electric system in all periods except the Peak period We note that the revenues received by Sofia District Heating for electricity generation do not appear to offset the fuel cost associated with its production

District heating tariffs Compared with the electricity tariff structure, the district heating tariff structure allows much less potential for reflecting the cost of providing the service Public Sector- Budget and Non-budget are differentiated to facilitate the allocation of subsidies rather than cost of service Lack of seasonal or time-of-day differentiation prevents the signaling of true cost to the consumer However, the lack of time differentiation of district heating tariffs does reflect the metering and control limitations of the industry in Bulgaria Individuals cannot not control their usage and metering has only begun at the substation level

Table ES-1 shows that Industrial and Public Sector- Industrial and Public Sector- Non-budget district heating tariffs, which have been freed of rigid price control, have reached full LRMC Other sales, accounting for 78% of Sofia District Heating Company's sales, are priced at slightly more than 40% of LRMC Household district heating and electricity are both priced at comparable percentages of their full economic cost, although our estimates indicate that pricing at LRMC would require somewhat larger Household electricity tariff increases than for district heating

FINANCIAL REQUIREMENTS

A major goal of cost-based tariffs is to cover financial requirements When we use the terms financial requirements and cost of service in this report we are referring to the actual costs of owning and operating the utility This report estimates financial requirements for the next five years to support operating costs and capital investments for NEK and for Sofia District Heating In each case we have increased the required depreciation allowance in order to meet financial planning criteria

17

We note that, in the case of Bulgaria, financial cost of service is distinct from official reported accounting cost Official accounting statements indicate that NEK is profitable and that Sofia District Heating, like most district heating companies, is unprofitable, requiring direct government subsidies It is not in the scope of this project to verify all reported costs However, there are clear, and generally accepted, ways in which the official statements understate the actual cost of service

- In the case of both NEK and Sofia District Heating, depreciation is understated in real terms due to the effects of hyper-inflation
- For NEK, energy production costs do not reflect the subsidies to domestic lignite producers that are made by the government
- In addition, there is no accounting for costs associated with nuclear plant decommissioning and waste fuel storage

In the case of NEK, we recommend further investigation of the following financial requirements

- costs associated with nuclear decommissioning
- costs associated with waste fuel storage costs
- financial requirements for expansion scenarios other than Plan A, which is used as the base case to illustrate NEK financial requirements

Electricity financial requirements Figure ES-1 shows a comparison of current electricity tariffs, financial requirements allocated to tariff categories based on estimated cost-of-service, and LRMC Current tariffs are set too low to fully recover NEK's financial requirements Each tariff category receives indirect subsidies, and households receive the largest share These subsidies are at the expense of future consumers who will have lower quality and/or higher priced electric services

For the Plan A scenario, average financial requirements per unit of sales are approximately the same as LRMC We estimate that the unaccounted nuclear costs, not included in either Plan A or in Figure ES-1, could add $US 5 per MWh of sales Under this scenario, the average cost of electric service *exceeds* LRMC Tariffs based on LRMC will not be adequate to meet financial requirements, even assuming full payment by all customers Continuing to defer tariff increases will magnify the differential between average cost of service and LRMC with resulting reduction in the use of electricity to less than economically optimum levels, creating the opposite of the current situation

18

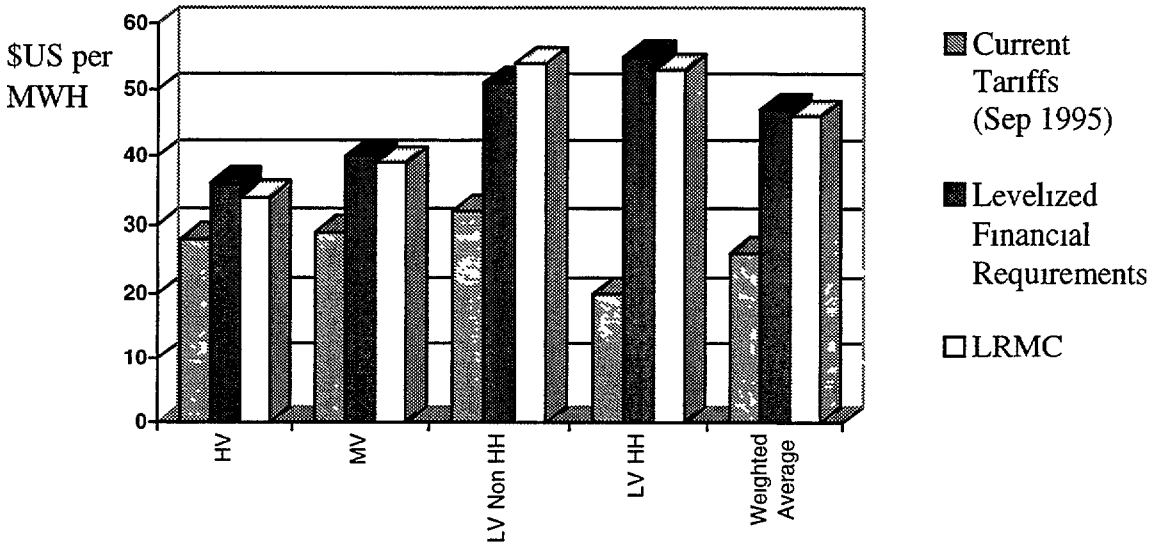


Figure ES-1 Comparison of Current Electricity Tariffs, Financial Requirements, and LRMC

District heating financial requirements The per unit financial requirements for district heating are approximately the same as LRMC Therefore, tariffs based on LRMC would meet financial requirements, assuming that all customers pay

Conclusions For electricity and district heating tariffs we find that financial requirements are equal or greater than LRMC This has the following implications for tariff policy

- There is little room for gradual transitioning to LRMC-based tariffs If financial requirements were less than LRMC there would be time to transition to LRMC-based tariffs, but Bulgaria is facing the opposite scenario Any delays necessitate deferring required investments, resulting in deterioration of utility plant and service reliability
- Tolerance of non-payment will eventually result in tariffs higher than LRMC
- Any cross-subsidies used to lower Household tariffs will raise other tariff categories above LRMC

19

TARIFF REFORM PROGRAM

We recommend the following reform measures

- There is a need to raise tariffs based on economic principals to ensure the financial viability of NEK and the district heating companies, to eliminate subsidies provided at the cost of future consumers, and to minimize price distortions among competing energy sources
- Recognizing that there will be a continuing need for some price regulation, the CoP should adopt a transparent methodology for the setting of electricity and district heating tariffs NEK and CoE should adopt transparent processes for developing and implementing tariffs
- We recommend an LRMC-based technical approach for developing tariffs But we are not recommending strict use of LRMC for tariffs Historic financial cost-of-service is an important consideration
- The electricity and district heating industries should encourage competition and reduce the need for price regulation wherever possible A step in this direction would be to increase the buyback tariff for generation from industrial and combined heat and power producers to reflect its incremental value to the power system
- We recommend developing transfer pricing among NEK and third-party generation, transmission and distribution entities The transfer pricing mechanism provides a transparent framework for pricing on the basis of full economic cost, and also for performance-based incentives to operating entities
- Programs to protect the poor should concentrate benefits on those with the greatest need, and at the same time preserve marginal cost-based pricing signals for consumption It is not possible to adapt Bulgarian electricity and district heating tariff structures to meet both requirements Therefore we advise subsidizing the poor through some means other than subsidized tariffs

20

Section 2
Review of the Electric Demand Forecast

The objective of this section is to review NEK's existing overall electricity demand forecast We also present the results of our demand forecast disaggregation by customer category

2 1 ELECTRIC DEMAND FORECAST

For the tariff study we use NEK's expected case forecast of Bulgarian electricity demand This forecast is used at NEK for least-cost planning NEK and the World Bank reviewed this load forecast prior to adopting it for planning purposes We did not attempt to develop an independent demand forecast for Bulgaria due to the preponderance of prior Bulgarian load forecasting by others and the ongoing work at NEK to refine Bulgarian load forecasting

We reviewed previous forecasting work, primarily the RCG/Hagler, Bailly, Inc April 1993 study *Bulgaria Electricity Study Management of Electricity Demand* This report compared prior demand forecasts from the early 1990's that were made by NEK, the World Bank, Energoproekt and EBRD, and developed an independent forecast, including high, medium and low scenarios, using an econometric equation for household demand and end use modeling for industrial demand Although the RCG/Hagler study dates from 1993, RCG/Hagler's demand forecasts are still considered important reference points The current NEK base case demand forecast has not changed significantly from the forecast that was current at NEK in 1993 when RCG/Hagler made its study

2 1 1 Annual Energy and Peak Demand Forecasts

The NEK high, medium and low forecast scenarios for annual energy demand, along with the RCG/Hagler scenarios, are shown in Figure 2-1 The NEK and RCG/Hagler forecasts for peak demand are shown in Figure 2-2 The medium case NEK electric demand forecast used for the analyses described in this report grows at an average rate of about 2%

The comparisons among the various NEK and RCG/Hagler scenarios show that the NEK forecasts are significantly higher than the RCG/Hagler forecasts For example, NEK's peak load forecast in year 2000 is about 1000 MW greater than RCG/Hagler's The RCG/Hagler study indicates that the NEK forecasts are also higher than previous independent World Bank forecasts In light of these demand forecast comparisons, current efforts underway at NEK to improve data and forecasting methodologies will serve a useful role in the tariff development process The implication for the tariff study of the comparisons among the various demand scenarios is that under the NEK demand forecast there is a need for more intensive power production Thus associated revenue requirements for utility operations and investments, and resulting tariffs, will need to be higher than would be predicted using the RCG/Hagler demand forecast

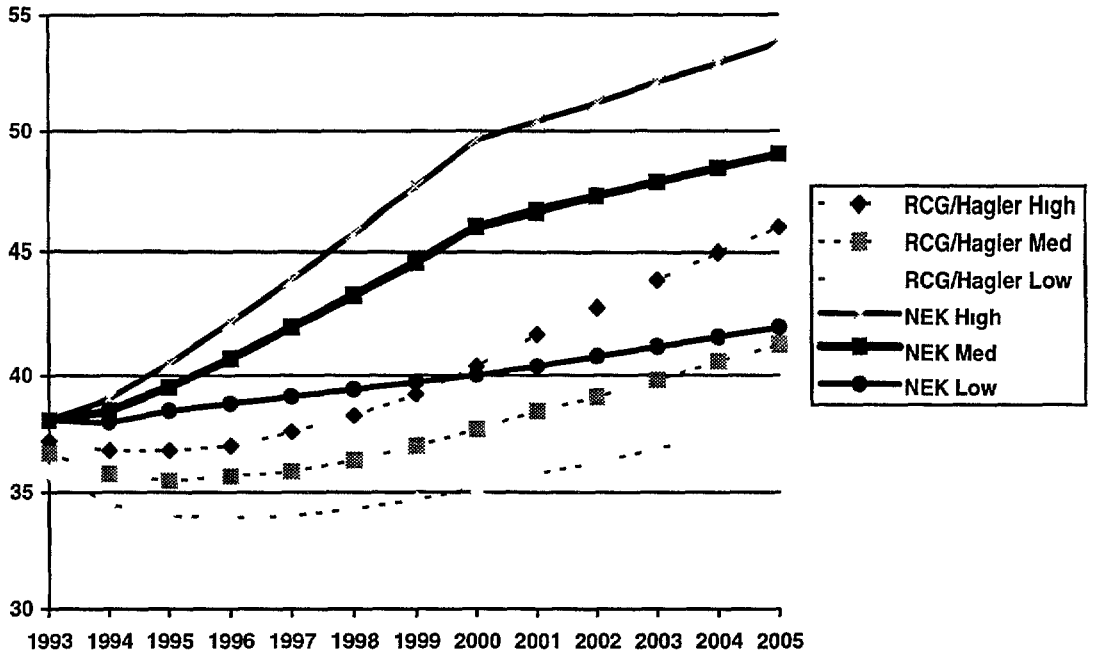


Figure 2-1 Forecasts of the Annual Electric Energy Consumption in Bulgaria

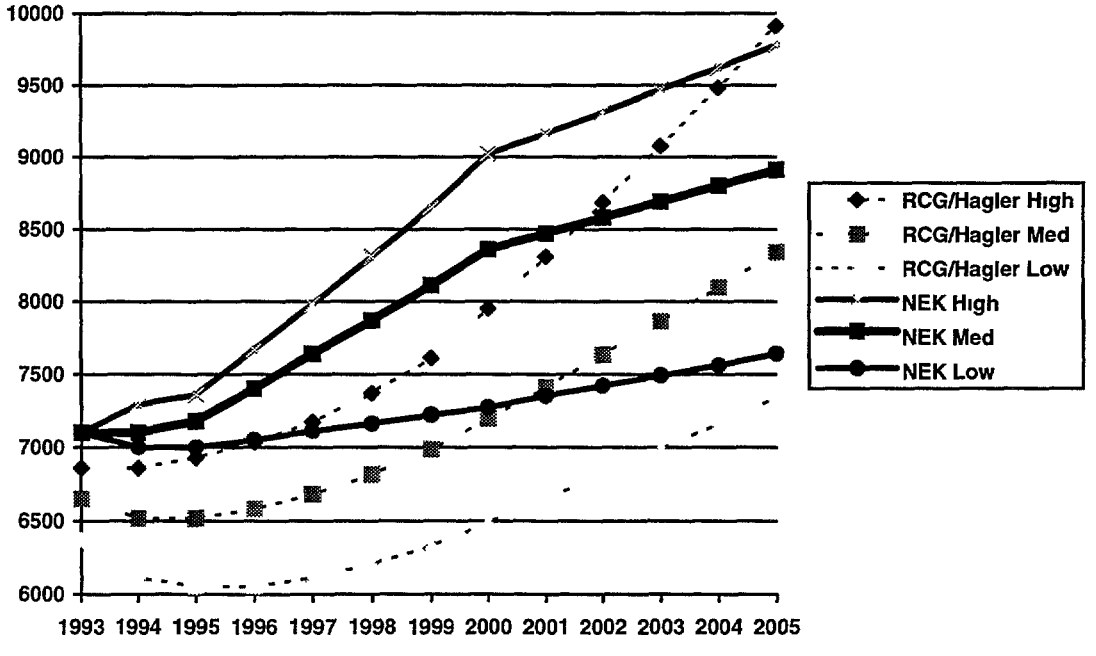


Figure 2-2 Forecasts of the Annual Electric Peak Load in Bulgaria

22

2 1 2 Seasonal and Daily Variations in Demand

The Bulgarian Electrical demand is significantly higher in the winter than in the summer The key factor in the seasonal difference is the electricity used for space heating in the winter According to the NEK demand forecast, the maximum monthly demand occurs in January and the minimum monthly demand occurs in June, July and August The relationship between monthly and annual peak loads for 1994 is shown in Figure 2-3 Figure 2-4 shows the daily load variation for typical January and July weekdays

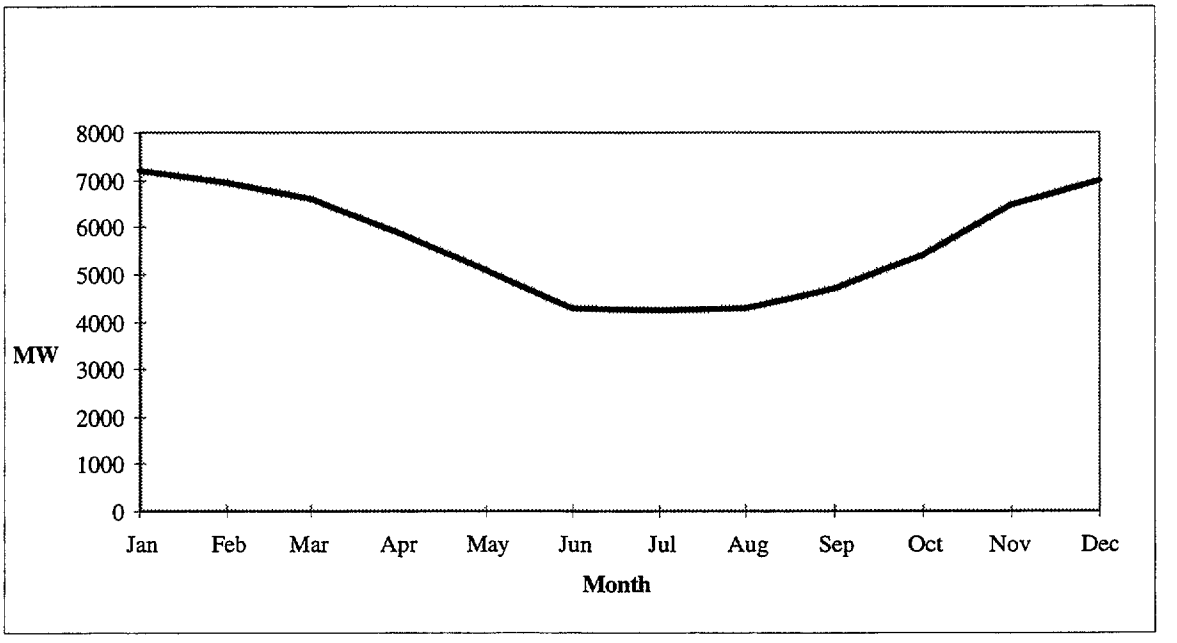


Figure 2-3 Bulgarian Maximum Monthly Demand for 1995

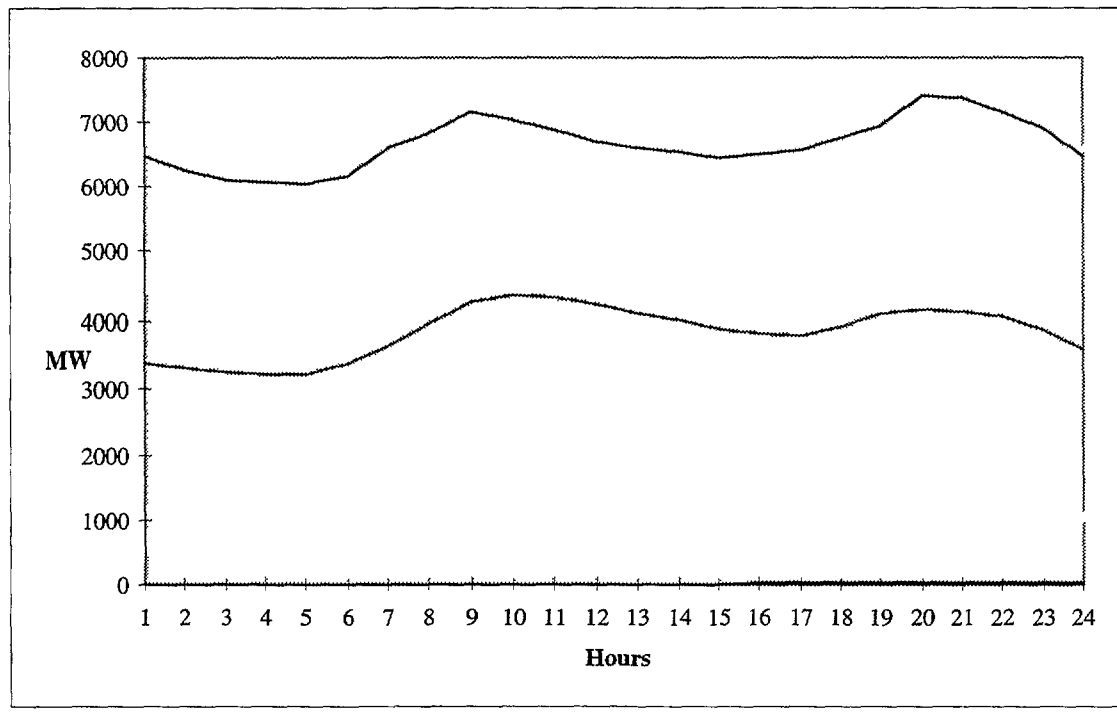


Figure 2-4 Typical Peak Day Load Shapes for January and July Peak Day for 1995

Seasonality in the demand for electricity can drive seasonal differences in the cost of power and thus in cost-based tariffs Seasonality in demand is a key factor influencing the cost of utility operations such as power plant maintenance and dispatch, and can also influence the need for system expansion investments

2 2 DEMAND FORECAST DISAGGREGATION BY TARIFF CATEGORY

The voltage level at which a customer receives service is one determinant of the cost of service to that customer, and the marginal cost of serving that customer For example, the costs associated with the low voltage system are a portion of the cost of serving customers connected at low voltages In the tariff setting process it is important to distinguish customers based on voltage level in order to capture in each customer's tariff the cost of service for that customer It is important to identify both energy and peak demand for each customer category in order to allocate costs to tariff categories separately based on causality, i e energy-related, peak demand-related and customer demand-related

2 2 1 Methodology

For the forecasts of demand by tariff categories used in this study, we disaggregated the NEK expected case demand forecast into the tariff categories used in the current Bulgarian tariff structure These are High Voltage (110 kV and above), Medium Voltage (< 110 kV and > 1 kV) and Low Voltage (< 1 kV) Low Voltage customers are differentiated as Household and Non-Household We estimated the contribution of each category to energy generation requirements and peak load The load shapes for 12 typical weeks were also developed for use in system modeling

The ideal demand forecast disaggregation would use separate end-use forecasts for each customer or tariff category The resulting disaggregated forecasts would be evaluated against historic billing information as a methodological check We are not able to implement this ideal forecasting process because end use forecasts, and historic billing information does not include adequate time-of-day information NEK has been developing end use forecasting, however only partial information is available at the present Forecasts are made by economic sectors However, the relationship between tariff categories and economic sectors is not well defined

Without the benefit of end-use forecasts and historic demand information, we made our load forecast disaggregation based on three simple considerations, 1) disaggregate overall forecast by economic sector, 2) postulate relationship between tariff category and economic sector, and 3) ensure that the judgments regarding overall, seasonal and time-of-day consumption within each tariff category are reasonable and in the aggregate match historic trends This approach ensures that the total of the individual demand forecasts for each customer class matches the expected overall Bulgarian electricity demand

2 2 2 Tariff Category Sales Forecast

The development of the sector forecast was based on the overall forecast and 1992 sectoral sales statistics Forecasts of GDP contribution and electricity intensity for non-household sectors were used to forecast sales by Industry, Transport, Agriculture, and Services The Household sales forecast was taken to be the difference between the overall forecast and the sum of the non-household forecasts This calculation is summarized in Table 2-1

The forecast by economic sector was translated into a forecast by tariff category based on assumptions of the voltage level of service These assumptions are displayed in Table 2-2

Table 2-1
Development of Sectoral Forecast

	1992	1995	1996	1997	1998	1999	2000		
Overall Forecast									
Energy	38 2	39 5	40 7	42 0	43 3	44 6	46 0	A	
Plant losses	4 0	4 0	4 0	4 0	4 1	4 1	4 2	B_t	
Network losses	4 9	5 0	5 2	5 3	5 4	5 6	5 7	C_t	
Total Sales	29 3	30 5	31 5	32 6	33 8	34 9	36 1	D_t	A_t B_t C_t
Relative GDP Contribution									
Industry	100	90 2	91 0	94 0	97 7	101 7	106 8	E_t	
Transport	100	115 0	118 5	125 0	132 8	141 1	151 4	F	
Agriculture	100	81 1	82 3	85 5	89 4	93 5	98 8	G	
Services	100	101 2	103 7	108 7	114 7	121 2	129 2	H_t	
Electricity Intensity									
Industry	0 17	0 18	0 18	0 18	0 18	0 18	0 18	I_t	
Transport	0 04	0 04	0 04	0 04	0 03	0 03	0 03	J	
Agriculture	0 03	0 03	0 03	0 03	0 03	0 03	0 03	K_t	
Services	0 02	0 02	0 02	0 02	0 02	0 02	0 02	L_t	
Sectoral Breakdown									
Industry	13 5	12 8	13 3	13 8	14 2	14 6	15 1	M_t	$M_{92}*E_t/E_{92}*I_t/I_{92}$
Transport	1 5	1 7	1 7	1 8	1 8	1 9	1 9	N	$N_{92}*F_t/F_{92}*J_t/J_{92}$
Agriculture	1 3	1 1	1 1	1 2	1 2	1 3	1 3	O	$O_{92}*G_t/G_{92}*K_t/K_{92}$
Services	3 4	3 4	3 5	3 5	3 6	3 7	3 9	P	$P_{92}*H_t/H_{92}*L_t/L_{92}$
Households	9 6	11 5	11 9	12 4	12 9	13 4	13 8	Q	D M N O, P

Table 2-2
Assumed Voltage Level of Service of Economic Sectors

	High Voltage	Medium Voltage	Low Voltage
Industry	40%	50%	10%
Transport	0%	80%	20%
Agriculture	0%	20%	80%
Services	0%	0%	100%
Households	0%	0%	100%

2 2 3 Losses by Tariff Category

Facilities associated with each voltage level serve customers connected at that voltage level as well as customers at lower voltages (e g , the medium voltage system serves MV customers as well as LV customers) Therefore, network facilities required at a particular voltage level and associated costs for these facilities are dependent upon sales and losses at the service voltage plus sales and losses at lower voltage levels These relationships are depicted in the schematic in Figure 2-5

As shown in the figure, loss assumptions are

- Overall network losses 12 7 percent of gross system electric energy requirements not including station use in 1995 declining to 12 5 percent in 2000
- High voltage system losses 2 percent of energy passing through the system between 35 kV and 200 kV
- Medium voltage system losses 5 percent of energy passing through the system between 1 kV and 35 kV

The remainder of network losses were assumed to take place in the low voltage system The resulting loss responsibility and generation requirements by tariff category for 1995 are shown in Table 2-3

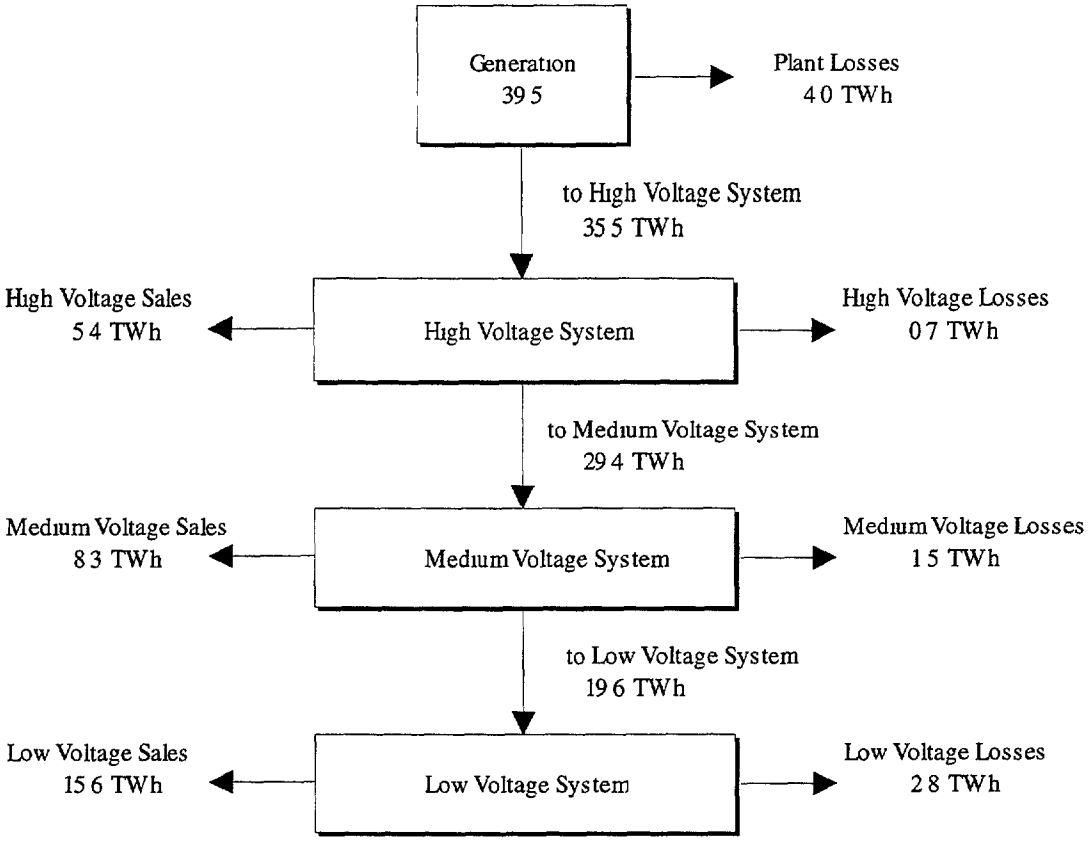


Figure 2-5 Illustration of Electricity Flow- 1995

Table 2-3
Loss Responsibility by Voltage Level of Service-1995

	Responsibility for Plant Losses (TWh)	Responsibility for Network Losses (TWh)	Total Loss Responsibility (TWh)	Sales (Twh)	Gross Generation Requirements (TWh)
High Voltage	0 61	0 11	0 72	5 39	6 12
Medium Voltage	0 99	0 62	1 61	8 32	9 93
Low Voltage	2 35	4 30	6 65	15 63	22 28
Total	3 96	5 03	8 99	29 34	38 33

28

2 2 4 Energy Demand by Tariff Category

Figure 2-6 shows the estimated breakdown in demand by tariff category, HV, MV, LV Household and LV Non-household The Household class is the largest (38% of total consumption), followed by the MV (26%), LV Non-household (19%) and HV industrial (17% of total annual load)

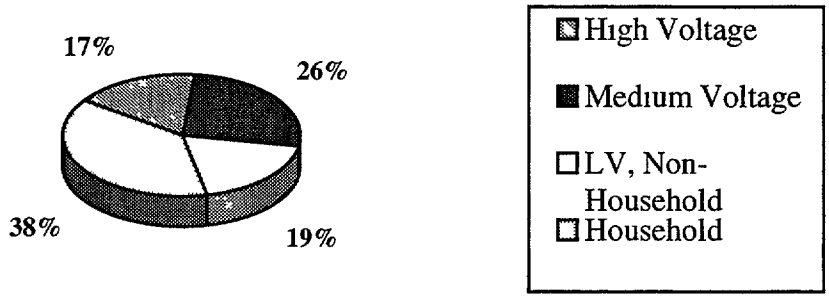


Figure 2-6 Forecast Percentage of Annual Electric Energy Consumption by Tariff Category

2 2 5 Pattern of Demand

The pattern of demand for each non-household tariff category was postulated based on the assumptions in Table 2-4 The Household load shape was taken to be the residual of the overall load shape and the sum on the load shapes of the non-household tariff category loads Figures 2-6 and 2-7 depict typical daily load forecasts for each of the four tariff categories for typical winter and summer days

Table 2-4
Load Shape Assumptions for Non-household Tariff Categories

	hours	load factor
High Voltage		
1st shift	40	100 0%
2nd shift	40	95 0%
3rd shift	88	92 7%
Medium Voltage		
1st shift	40	100 0%
2nd shift	40	85 0%
3rd shift	88	78 2%
Low Voltage Non household		75 0%

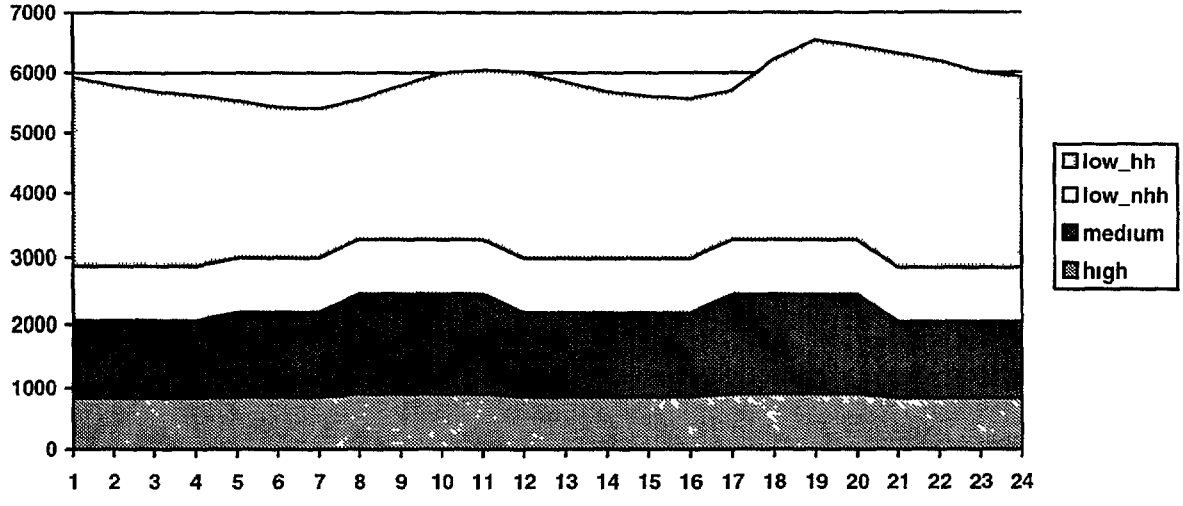


Figure 2-7 Demand by Tariff Category for a Typical Winter Day January 1995

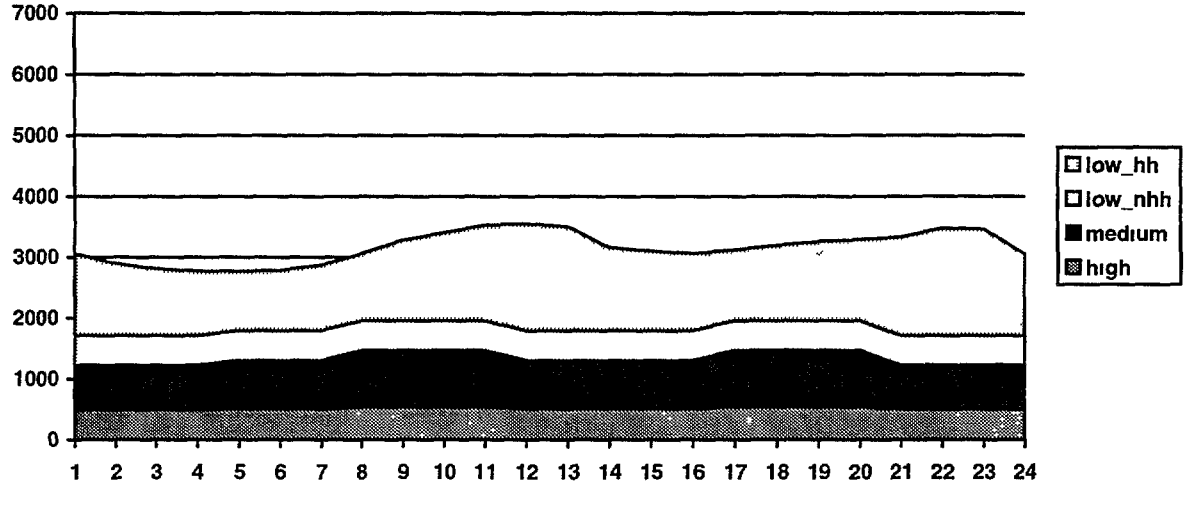


Figure 2-8 Demand by Tariff Category for a Typical Summer Day July 1995

30

Section 3
Review of Bulgarian Power System

The objective of this section is to identify the major factors associated with the existing and planned Bulgarian power supply system affecting electricity pricing and tariff structure This section describes the expected system operating and cost characteristics for three alternative power supply plans differentiated based on the timing for the shut down of several units at Kozloduy These three scenarios underlie the marginal cost scenarios presented in Section 6 of this report

3 1 THE GENERATION SYSTEM

3 1 1 Characteristics of Existing Bulgarian Power Plants

Electric energy in Bulgaria comes mainly from NEK nuclear, thermal and hydroelectric power plants Energy is also supplied by local district heating plants, industrial plants and imports Table 3-1 summarizes the operating characteristics of the existing nuclear and thermal power plants in the Bulgarian system Tables 3-2 and 3-3 summarize the operating characteristics of hydroelectric and pumped storage power plants in the Bulgarian system

3 1 2 Fuel Prices

A comparison of various fuel price projections for fuels used in nuclear and thermal power plants are shown in Table 3-4 Three different fuel price projections made within the last five years are compared with NEK's current forecast These forecasts are taken from the following publications

- *Evaluation of Energy Price Subsidies for Gabrovo, Bulgaria* (Gilbert/Commonwealth, May 1995)
- *Bulgaria Energy Strategy Study* (World Bank, December 1991)
- *Power Complex Rehabilitation Project in Bulgaria* (Bechtel, October 1993)

NEK's current forecasts for the prices of fuels, which are used for the tariffs developed in this report, are at the low ends of the ranges defined by the various studies Gilbert/Commonwealth's forecasts define the high ends of the ranges for fuel prices For tariff setting, coal prices are the most critical of the fuel prices because coal generation typically defines the marginal costs for the Bulgarian system

Table 3-4
Comparative Fuel Price Projections

Fuel Type	NEK 1995 $/kcal	Real fuel price esc 1996 on	NEK 1995 $/GJ	Gilb/Com 1995 $/GJ	Bechtel 1993 $/GJ	WBank 1991 $/GJ
Nuclear	5 00	0%	1 2		0 5	
Lignite for Maritsa East 1,2,3	3 89	1 0%	0 9	1 8	1 1	1 1
Lignite for Maritsa West	2 47	0%	0 6		2 1	
Imported brown coal for other plants	7 26	1 2%	1 7	2 7	1 9 2 1	up to 2 5
Heavy fuel oil	13 16	0%	3 1	4 7		
Natural gas	13 24	1%	3 2	3 8	3 3	3 @ brdr

3 1 3 Imported Power Costs

The Bulgarian power system is strongly interconnected with power systems of neighboring countries Capacity or energy deficiencies could be met with long term, short term or emergency imports At this time NEK does not have any long or short term power purchase contracts The synchronized operation of the interconnected power systems allows exchanges of energy on an emergency basis when one power system, due to unplanned plant outages, has capacity deficiencies

For system modeling purposes, we estimate that around 600 MW of imports could be supplied during the high demand season from October to April and 300 MW in the low demand season from May to September The variable component of the import price was set at $US 70 per MWh, and the fixed component at about $US 17 per kW-yr

3 1 4 O&M Costs

Non-fuel production expenses associated with the operation of power plants are called operating and maintenance costs (O&M costs) These costs are generally split into two categories variable O&M costs that are dependent and incurred as a consequence of plant operation, and fixed O&M costs that are invariant with the electrical output of the plant Calculating both fixed and variable components of O&M cost is important for tariff setting because variable O&M costs and fuel expenses are recovered in energy charges, while fixed O&M is recovered in capacity charges

We analyzed O&M costs in the NEK dataset against the U S experience For 1994, the O&M cost for nuclear units in Bulgaria was 10 $/MWh while average U S cost was 15 $/MWh The O&M cost for most of the coal units in Bulgaria was set around 10 $/MWh while the average U S cost was 5 $/MWh

The original NEK generating unit data has O&M costs for each power plant presented as a simple fixed value in $/kW We judged this an acceptable representation for nuclear and hydro units However for fossil units it is known that O&M costs include both fixed and variable components U S and European experience shows that about half to two thirds of the O&M cost for the typical base loaded coal power plant is in the fixed category Therefore we split the NEK O&M costs between variable and fixed components, with two thirds of the O&M cost put into the fixed category For new units, we used the EPRI Technical Assessment Guide breakdown of fixed and variable costs

Table 3-5 summarizes the O&M costs used in this report

3 2 GENERATION DEVELOPMENT AND INVESTMENT PLANS

3 2 1 Capacity Development

The power system development plan is a critical determinant of revenue requirements and LRMC-based tariffs At the present, several alternative development plans are under consideration in Bulgaria The alternative supply plans contain varying timing and need assumptions for several power projects that have been identified for the Bulgarian system The key developments that will impact tariffs within the next five years include

- rehabilitation of each of the major coal-fired power plants
- addition of new peaking combustion turbines
- shut down of Kozloduy Units 1-4

Debate over nuclear and gas capacity expansion alternatives and financing constraints makes it impossible to select a supply plan that is acceptable to all It is beyond the scope of this Project to examine the myriad of resource planning choices available and to evaluate the tariff implications of each one

We have chosen to evaluate three scenarios in this report, Plans A, B and C Capacity additions for the three plans for the period 1995-2005 are shown in Table 3-6 Table 3-7 summarizes the operating characteristics and required investments for the capacity additions

Plan A, which is used as the base case for the tariffs developed in this report, is based on a shutdown of Kozloduy 1 and 2 in 1998 and Kozloduy 3 and 4 in 2004 The Plan A resource schedule resembles plans that have been acknowledged in discussions between the World Bank and NEK Plan B assumes a delay in the shutdown of Kozloduy 1 and 2 to 2001 and 2002, respectively The shutdown of Kozloduy 3 and 4 is beyond the tariff planning horizon in Plan B Plan C assumes that Kozloduy 1 and 2 are shut down by yearend 1997, and units 3 and 4 are shut down by yearend 1998 The Plan C assumptions regarding Kozloduy are the preferred alternative from the perspective of the World Bank

Each of the three alternative scenarios has been developed to meet the long term reliability requirements of the power system by gradually adding generating resources It should be noted that there is concern regarding the ability of NEK to finance additional capital projects due to the current poor financial condition of the utility In this regard, the plans are idealized projections, and tariffs based on these plans are likewise idealized

3 2 2 Capital Requirements

The investments required for power plant rehabilitation and new hydro projects, which are shown in Tables 3-8 and 3-9, are based on estimates provided by NEK The capital cost estimates for power plant rehabilitation projects appear generally consistent with previous studies The principal previous studies of rehabilitation include *Power Complex Rehabilitation Project in Bulgaria* (Bechtel, 1993) and *Project 200/07 Bulgaria Generation Plant - A Review of Performance Improvement Opportunities and the Preparation of Electricity Supply Investment Plans* (PowerConsult, April 1994)

Table 3-8
Power Plant Rehabilitation Projects

Rehabilitation Projects	Investment Cost (1995 $/kW)	Years to Implement
Maritza	64 3	1
Varna	139 0	2
Bobov Dol	99 1	2

Table 3-9
New Hydro Projects

New Hydro Projects	Investment Cost (1995 $/kW)	Years to Implement	Installed Capacity	Operation in Year
Gorna Arda	837	6	156	2002
Sreden Iskar	975	2	44	2002

3 3 FUTURE GENERATING MIX AND ASSOCIATED PRODUCTION COSTS

Accurate projections of the future resource mix, fuel costs and other operating assumptions are critical to the tariff analysis because operating costs are a significant portion of revenue requirements and an important determinant of power system marginal costs

Tariffs developed on the basis of forecasted system operations and fuel prices are subject to significant forecast risk, for example the risk that future fuel prices will vary from the forecast One means of avoiding forecast risk for tariff-setting is the use of indexation or the fuel price adjustment clause mechanism In the case of fuel prices, indexation would be used to recover fuel costs in tariffs Under the indexation approach, tariffs increase directly in response to fuel price increases, and thus the fuel-related cost components of tariffs reflect actual costs rather than forecasted costs

3 3 1 Capacity and Energy Balances

Tables 3-10 and 3-11 show the forecasted capacity and energy balances for the Bulgarian electrical system for years 1994-2000 for Plan A Results for 1994 are based on data supplied by NEK Results for 1995-2000 are based on IRP Manager simulations of the electricity production process

3 3 2 Current and Future Mix of Fuels Used to Generate Electricity

In 1994 approximately 49 percent of generation used coal, 43 percent used nuclear fuel, about 4 percent used heavy fuel oil or natural gas, and the remaining sources included

35

hydroelectric, pumped storage and imports In 1994, over 80 percent of the coal used for power generation was low quality domestic lignite

There are several significant trends projected for the future mix of fuels used for power generation With rehabilitation of coal plants and the eventual shutdown of some Kozloduy units, the share of coal in the mix will increase while nuclear will decline Also, oil and gas use for electric generation will increase, although coal and nuclear will continue to dominate An important trend is the increasing use of imported coal at the coal-fired power plants Varna, Bobov Dol and Rousse are projected to add increasing amounts of imported coal to their fuel mixes, while Maritsa East 1,2,3 and Maritsa West are expected to continue to burn indigenous lignite Several factors support the increasing use of imported coal, including its higher quality, cost competitiveness and availability advantages

By year 2000, under Plan A assumptions, approximately 50 percent of generation will use coal, 37 percent will use nuclear fuel, 7 4 percent will use heavy fuel oil or natural gas, and hydroelectric, pumped storage and imports will generate the remaining 5 6 percent

Table 3-1
Operating Characteristics of Existing Thermal Power Plants

Station	Install Capacity (MW)	Main fuel	First Year in Service	Maint Outage (days/yr)	Forced Outage (%)
Kozloduy					
Unit 1	400	Nuclear	1974	120	20
Unit 2	400	Nuclear	1975	120	20
Unit 3	400	Nuclear	1980	90	10
Unit 4	400	Nuclear	1982	90	10
Unit 5	950	Nuclear	1988	75	30/7 (1998 on)
Unit 6	950	Nuclear	1988	75	30/7 (1998 on)
Maritza East 1	180	Lignite	1966 69	30	10
Maritza East 2					
150 MW Units	480	Lignite	1966 69	60/45 (2002)	10
210 MW Units	585	Lignite		60/70 to 2000, 45 from 2001	10
New 210 MW Unit	195	Lignite	1998	45	10
Maritza East 3	780	Lignite	1978 81	55/45 (1999)	10
Maritza 3 Dimitrovgrad	80	Lignite	1971	180	15
Varna					
210 Units 1 3	585	Imported coal	1968 79	45	10/6 post rehab
210 Units 4 6	585	Imp coal, NG	1968 79	45	10/6 after rehab
Bobov Dol	570	Local lignite	1958 63	45	10/6 after rehab
Rousse	190	Imported Coal	1964 85	30	10
District Heating Plants					
Sofia	150	NG,HFO	1958 85	35	15
Plovdiv	60	HFO	1970 95	20	15
Other	100				15
Industrial Power Plants					
Burgas	120	HFO	1965 71	25	15
Devnia	170	Coal, NG	1965 70	25	15
Himko	50	NG	1966	25	15
Sviloza	70	Coal	1969	25	15
Other	100	HFO		25	15

Table 3-2
Operating Characteristics of Bulgarian Hydroelectric Power Plants

Stations or Cascades	Installed Capacity (MW)	Average Generation (GWh)	Fixed O&M Cost ($US/kW-yr)
Arda Cascade	274	210	13 2
Batak Cascade	228	358	13 2
Belmeken-Sestrimo Cascade	710	407	13 2
Dospat Vacha Cascade	380	289	13 2
Small Hydro	210	435	13 2

Table 3-3
Operating Characteristics of Bulgarian Pumped-Storage Power Plants

Station	Installed Capacity (MW)	Reservoir Limit (hours)	Round-Trip Efficiency (%)	Fixed O&M Cost ($US/kW-yr)
Chaira 1-4	210	8	75	16 56

Table 3-5
O&M Costs for Major Thermal Power Plants in Bulgaria
1995

Units	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Bobov Dol	29	6
Varna	24	6
Russe	41	9
Maritza East	41	3
Maritza 3	77	3
Sofia	24	3
Plovdiv	14	3
Burgas	22	3
Cogeneration	22	3
Devnia (cogen)	18	3
Devnia (conden)	7	3
Himko	14	3
Sviloza	6	3
Industrial	42	3
New Combined Cycle	5	4
New CT Plant	1	8

Table 3-6
Capacity additions for Plan A, B and C for the period 1995-2005

					Plan A		Plan B		Plan C	
Year	Action	Plant	Unit #	Nominal Unit Capacity (MW)	Increase in Capacity (MW)	Cumulative Capacity Increase (MW)	Increase in Capacity (MW)	Cumulative Capacity Increase (MW)	Increase in Capacity (MW)	Cumulative Capacity Increase (MW)
1996	Commission	Maritsa East 2	8	195	195		195		195	
	Commission	Gas Turbine		50	0		100		600	
	Initiate rehabilitation	Varna	1	210	195	0	195	100	195	600
1997	Initiate rehabilitation	Bobov Dol	1	210	190		190		190	
	Complete rehabilitation	Maritza East 3	1	210	15		15		15	
	Initiate rehabilitation	Varna	2	210	195	370	195	270	195	230
1998	Initiate rehabilitation	Bobov Dol	2	210	190		190		190	
	Commission	Gas Turbine		300	300		0		0	
	Complete rehabilitation	Kozloduy	5&6	2 x 950	0		0		0	
	Complete rehabilitation	Maritza East 3	2	210	15		15		15	
	Complete rehabilitation	Varna	1	210	210		210		210	
	Initiate rehabilitation	Varna	3	210	195		195		195	
	Retire	**Kozloduy**	**1**	**440**	-400		0		-400	
	Retire	**Kozloduy**	**2**	**440**	-400	1030	0	-430	-400	730
1999	Initiate rehabilitation	Bobov Dol	3	210	190		190		190	
	Commission	Gas Turbine		100	0		100		0	
	Retire	**Kozloduy**	**3**	**440**	0		0		-400	
	Retire	**Kozloduy**	**4**	**440**	0		0		-400	
	Complete rehabilitation	Bobov Dol	1	210	210		210		210	
	Complete rehabilitation	Maritza East 3	3	210	15		15		15	
	Complete rehabilitation	Varna	2	210	210	785	210	85	210	1285
2000	Complete rehabilitation	Bobov Dol	2	210	210		210		210	
	Complete rehabilitation	Maritza East 2	5	210	15		15		15	
	Complete rehabilitation	Maritza East 3	4	210	15		15		15	
	Commission	New Coal		300	300		0		300	
	Commission	Sofia Coal		200	200		0		200	
	Retire	Maritza 1	1 4	50	180		180		180	
	Complete rehabilitation	Varna	3	210	210		210		210	
	Initiate rehabilitation	Varna	4	210	195	150	195	350	195	350

40

Table 3-6
Capacity additions for Plan A, B and C for the period 1995-2005 (cont)

					Plan A		Plan B		Plan C	
Year	Action	Plant	Unit #	Nominal Unit Capacity (MW)	Increase in Capacity (MW)	Cumulative Capacity Increase (MW)	Increase in Capacity (MW)	Cumulative Capacity Increase (MW)	Increase in Capacity (MW)	Cumulative Capacity Increase (MW)
2001	Complete rehabilitation	Bobov Dol	3	210	210		210		210	
	Complete rehabilitation	Maritza East 2	6	210	15		15		15	
	Retire	**Kozloduy**	**1**	**440**	0		-400		0	
	Retire	Maritza East 1	1 7	7 x 40	180		180		180	
	Commission	New Coal		300	300		0		300	
	Initiate rehabilitation	Varna	5	210	195	300	195	200	195	200
2002	Commission	Combined Cycle		240	240		240		240	
	Commission	Combined Cycle		240	240		240		240	
	Retire	**Kozloduy**	**2**	**440**	0		-400		0	
	Initiate rehabilitation	Maritsa East 2	1	150	120		120		120	
	Complete rehabilitation	Maritza East 2	7	210	15		15		15	
	Initiate rehabilitation	Maritsa East 2	1	150	0		0		0	
	Commission	Sreden Iskar		44	44		44		44	
	Complete rehabilitation	Varna	4	210	210		210		210	
	Initiate rehabilitation	Varna	6	210	195	734	195	166	195	234
2003	Complete rehabilitation	Maritsa East 2	1	150	170		170		170	
	Initiate rehabilitation	Maritsa East 2	2	150	120		120		120	
	Complete rehabilitation	Varna	5	210	210	994	210	94	210	494
2004	Commission	Gas Turbine		120	120		120		120	
	Retire	**Kozloduy**	**3**	**440**	-400		0		0	
	Retire	**Kozloduy**	**4**	**440**	-400		0		0	
	Complete rehabilitation	Maritsa East 2	2	150	170		170		170	
	Initiate rehabilitation	Maritsa East 2	3	150	120		120		120	
	Complete rehabilitation	Varna	6	210	210	574	210	474	210	874
2005	Complete rehabilitation	Maritsa East 2	3	150	170		170		170	
	Initiate rehabilitation	Maritsa East 2	4	150	120	624	120	524	120	924

41

Table 3-7a
Operating Characteristics of New Capacity Additions

Type	Fuel	Net Cap (MW)	Min Load (MW)	Heat Rate Min Load Fuel (kJ/KWh)	Heat Rate Max Load Fuel (kJ/KWh)	Forced Outage Rate (%)	Planned Outage Rate (days/yr)
Coal 300	Lignite	300	210	11,200	11,050	6	45
Coal 100	Lignite	100	70	9,375	8,790	5	30
Combined Cycle	Nat Gas	240	170	7,210	6,000	4	60
Combustion Turbine	Nat Gas	50	10	11,175	11,135	5	30

Table 3-7b
Cost Characteristics of New Capacity Additions

Type	Non-Fuel O&M Fixed ($US/kW-yr)	Non-Fuel O&M Variable ($US/ MWh)	Capital Cost Without IDC ($US/kW)	Construction Time (years)
Coal 300	41	3	1,276	4
Coal 100	41	9	829	4
Combined Cycle	5	3	572	2
Combustion Turbine	1	8	436	1

42

Table 3-10
Capacity Balance in MW for NEK (Plan A)
(Operating Installed Capacity)
1994-2000

Station\Year	1994	1995	1996	1997	1998	1999	2000
Kozloduy							
Unit 1	400	400	400	400			
Unit 2	400	400	400	400			
Unit 3	400	400	400	400	400	400	400
Unit 4	400	400	400	400	400	400	400
Unit 5	950	950	950	950	950	950	950
Unit 6	950	950	950	950	950	950	950
Maritza East 1	180	180	180	180	180	180	
Maritza East 2							
150 MW Units	480	480	480	480	480	480	480
210 MW Units	585	585	585	585	585	585	600
New 210 MW Unit			195	195	195	195	195
Maritza East 3	780	780	780	795	810	825	840
Maritza 3 Dimitrovgrad	80	80	80	80	80	80	80
Varna							
210 Units 1-3	585	585	390	195	210	420	630
210 Units 4-6	585	585	585	585	585	585	390
Bobov Dol	570	570	570	380	190	210	420
Rousse	190	190	190	190	190	190	190
Chaira	420	420	420	420	840	840	840
Other Thermal and CHP	820	820	820	820	820	820	820
Imports	600	600	600	600	600	600	600
Hydro	1802	1802	1802	1802	1802	1802	1802
New Units							
Simple Cycle					300	300	300
Sofia Coal 100							200
Lignite 300							300
Total		**11177**	**11177**	**10807**	**10567**	**10812**	**11387**
Peak Load		**7180**	**7402**	**7632**	**7868**	**8112**	**8364**

43

Table 3-11
Energy Balance in GWh for NEK (Plan A)
1994-2000

Station\Year	1994	1995	1996	1997	1998	1999	2000
Kozloduy							
Unit 1		1882	1882	1882			
Unit 2		1882	1882	1882			
Unit 3		2376	2376	2376	2376	2376	2376
Unit 4		2376	2376	2376	2376	2376	2376
Unit 5		4626	4625	4628	6149	6149	6149
Unit 6		4626	4624	4628	6149	6149	6149
Maritza East 1		1253	1248	1276	1287	1297	
Maritza East 2							
150 MW Units		2278	2492	2410	2827	2863	2704
210 MW Units		3624	3695	3724	3793	3702	3777
New 210 MW Unit			1234	1267	1337	1344	1342
Maritza East 3		4366	4432	4753	5149	5377	5282
Maritza 3 Dimitrovgrad		301	301	301	301	301	301
Varna							
210 Units 1-3		1662	852	646	1076	2025	2470
210 Units 4-6		1655	1607	2056	2369	2446	1055
Bobov Dol		513	791	708	640	988	1732
Rousse		515	486	554	761	703	596
Chaira (gener./ pumping)		126/168	201/268	316/422	419/580	394/540	287/392
Other Thermal and CHP		3474	3617	3766	4035	3916	3920
Imports		270	371	793	460	437	311
Hydro		1700	1700	1700	1700	1700	1700
New Units							
Simple Cycle					326	310	174
Sofia Coal 100							1389
Lignite 300							2166
Unserved Energy		**158**	**195**	**362**	**333**	**312**	144
Total Generation*		**39495**	**40719**	**41982**	**43283**	**44625**	**46008**
Sales		**31596**	**32575**	**33585**	**34626**	**35700**	**36806**

Note Generation includes power plant own use and transmission and distribution losses

44

Section 4
Electric System Operating Cost Structure

The objective of this section is to review the energy- and capacity-related costs for the Bulgarian power system Our analysis is differentiated for time-of-day and seasonal cost variations The forecasted cost structure is based on simulation of the Bulgarian generating system

4 1 MARGINAL COSTING USING PRODUCTION SIMULATION

The operation of the generation system is simulated using the IRP-Manager model This model has been developed by the U S company, EPS Solutions, and the software is licensed by NEK and CoE It is a commonly used model for power system production simulation for tariff analysis

Marginal energy cost The purpose of production simulation is to project the operation of plants under a given set of assumptions in order to forecast future outcomes such as fuel use, the reliability of the generation system, and the marginal generating units that would respond to increased electric consumption (A unit is considered "on the margin" or "marginal" if its output responds to small changes in demand) *Short run marginal cost*, SRMC, which is based on the operating costs associated with the marginal units, 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 that are fixed in the short term and do not vary with changing demand

Marginal capacity cost Production simulation is also used to forecast *marginal capacity cost* Marginal capacity cost is the change in capital requirements associated with capacity additions to serve an increase in peaking requirements (Some utilities also account for customer unserved energy costs in marginal capacity cost) Marginal capacity cost is a function of the reliability of the generation system The reliability of the generation system varies by time of day and by season because of changing load demand, and the variations in the generating resources available to serve load Common measures of generation reliability include loss-of-load probability (LOLP) and expected unserved energy (EUE) The contribution of a particular time period to LOLP or EUE provides the basis for estimating the marginal capacity cost associated with an increase in demand in that period

Factors influencing marginal costs Chapters 2 and 3 describe the attributes of the Bulgarian power sector that impact system operations and associated marginal costs In summary, key factors that affect the operation of the system include

- Technical characteristics of the generating units including capacity, reliability, maintenance requirements, and the need to provide heat as well as electric power
- Cost characteristics of generating units, including operation and maintenance (O&M) cost and efficiency as a function of total output
- Fuel prices
- Peak demand
- Daily and seasonal shape of loads
- Import/export power agreements

4 2 MARGINAL CAPACITY COST STRUCTURE

Methodology The amount of generation system expected unserved energy (EUE) by time period was calculated using the IRP-Manager model EUE is an indication of the likelihood of the generation system not meeting system demand based on the outage probability of individual units This calculation indicates the relative value of capacity in each time period

Results Figure 4-3 shows the projected contribution to generation system EUE by season and time-of-day for 1996 The winter season, which includes the annual peak consumption month of January, contributes about 46 percent to the annual EUE The summer season contributes around 54 percent to the annual EUE We find that the seasonal breakdown of marginal capacity cost is consistent for all years of the study period This seasonal distribution of contribution to EUE is a function of many factors, and two important factors are electric consumption level and generation maintenance scheduling

The Bulgarian system has its highest loads in the winter Generally this situation results in more unserved energy in the winter Therefore, our findings seem counter-intuitive However, it appears that our results reflect real operational difficulties during summer months due to nuclear refueling scheduling and minimum load operating restrictions for a large portion of the installed generation Note that current tariffs, which are higher in the winter than in the summer, are apparently counter to the seasonal economic cost structure for the Bulgarian power system

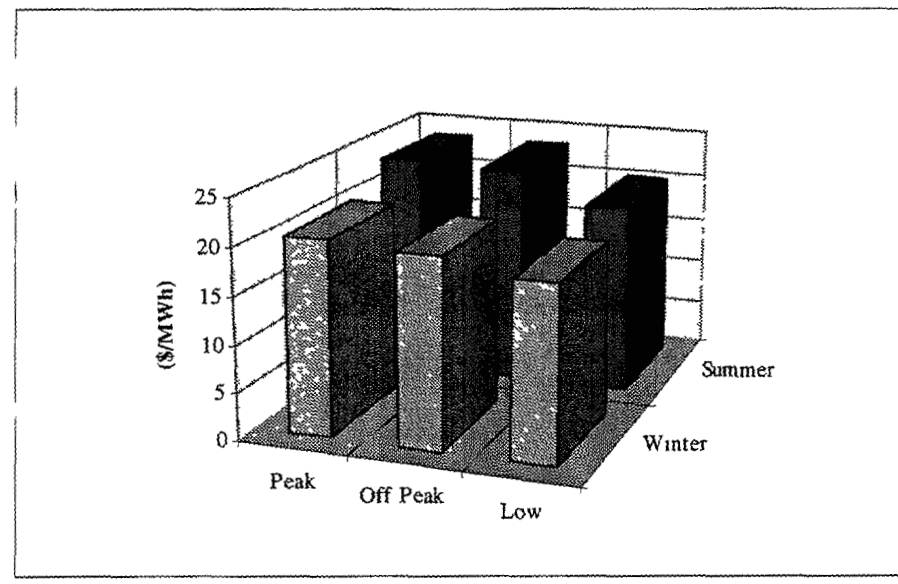


Figure 4-3 Projected Contribution to Expected Unserved Energy by Time Period for 1996

Daily peak periods (1560 hours per year) account for 41 percent of the EUE The daytime non-peak period (3967 hours per year) is responsible for 38 percent of the EUE As would be expected, nighttime and non-peak weekend hours (3233 hours per year), contribute less to EUE at 22 percent

The seasonal contribution to EUE provides a rationale for varying the capacity-related component of tariffs by season to provide customers with signals of the marginal cost of capacity If time-of-day metering of energy is used, the contribution to EUE by time period provides a basis for allocating capacity-related costs to time-differentiated tariffs

4 3 MARGINAL ENERGY COST STRUCTURE

Methodology Marginal energy cost, or SRMC, is a function of the cost of operating the marginal generating resource to meet a small change in electric demand Figure 4-4 illustrates how IRP Manager identifies the marginal generating resource The figure shows a monthly load curve for the system and the method of meeting the load with various generating sources Electric generation from nuclear, coal, industrial and combined heat and power (CHP) units covers the baseload portion of the electric demand curve In general, hydro, pumped-storage units and peaking units cover the daily peaks and valleys Imports, if any, are the most expensive source of power and are used only in event of insufficient Bulgarian generating resources When required, the more flexible CHP, coal and oil fired units are cycled to match demand requirements

47

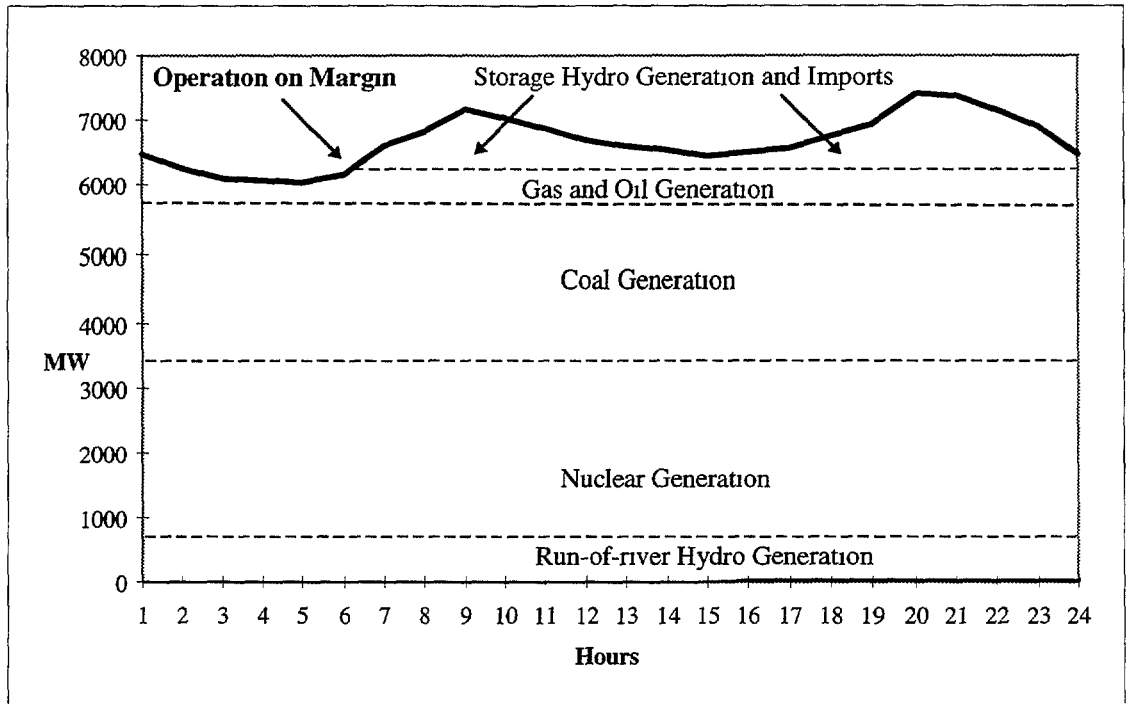


Figure 4-4 Illustration of Marginal Energy Cost (SRMC)

The marginal energy cost for the system for a given month is given by the incremental cost of operating the marginal units weighted by the percent of time that each unit operates on the edge (or margin) of the load curve Our projections indicate that in the future gas, oil and partly coal fired units, as well as imports will operate in the margin The marginal energy cost will thus be affected by prices for gas, oil, coal and imported energy

In contrast to marginal energy cost, the *average generating cost* is based on the average operating costs of all units that contribute to meeting load, including the nuclear, thermal and hydro units, the CHP and industrial unit costs allocated to electricity generation, the price and amount of imports, and the operating cost of the condensing units

Results Figure 4-5 shows SRMC by year, compared with average generating cost All values are 1995 USD SRMC is projected to vary between $US 20 and $US 28 per MWh Average generating cost is projected to vary between $US 13 and $US 14 per MWh The increase in SRMC in years 1998 and 1999 is driven by the shut-down of Kozloduy Units 1 and 2 and introduction of new peaking units

48

Seasonal and time-of-day SRMC are shown in Figure 4-6 for 1996 Seasonal SRMC is projected to be higher in the summer and lower in the winter, with the winter SRMC about 10 percent lower than in the summer Seasonal differences in SRMC are counterintuitive, as usually higher loads would result in higher SRMC In this case higher SRMC in summer is a result of maintenance scheduling of nuclear and coal units and decreased capacity of some units, all happening in the summer season

Time-of-day differences in SRMC average about 10-15 percent between the daytime and the nighttime periods This is a relatively small level of variation for an electric system with significant residential and commercial loads The difference in SRMC on a time-of-day basis can be explained by the system's relatively flat daily load curve and relatively small differences in operating costs among the generating units that contribute the most to marginal energy cost

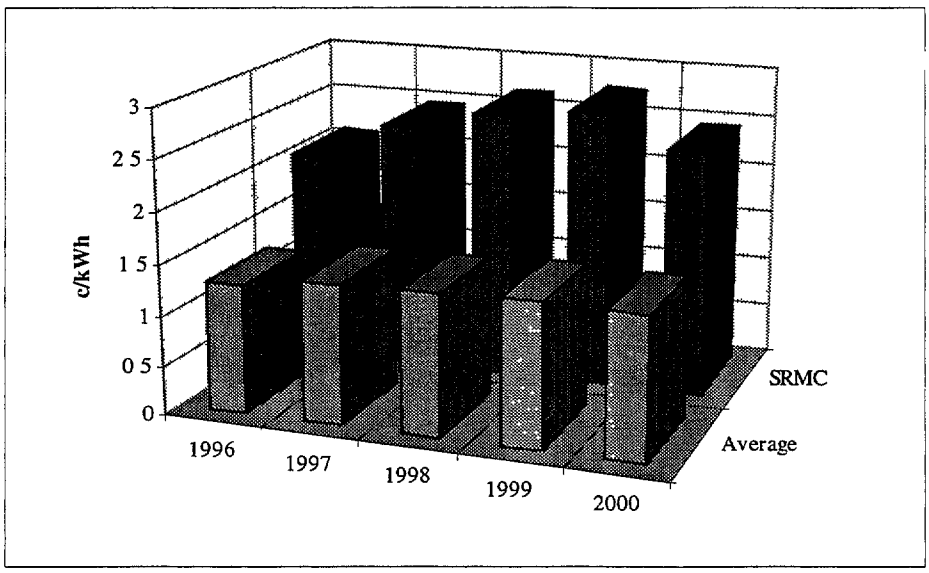


Figure 4-5 Comparison of Projected Average Variable Generating Cost and Short-Run Marginal Cost for Plan A

49

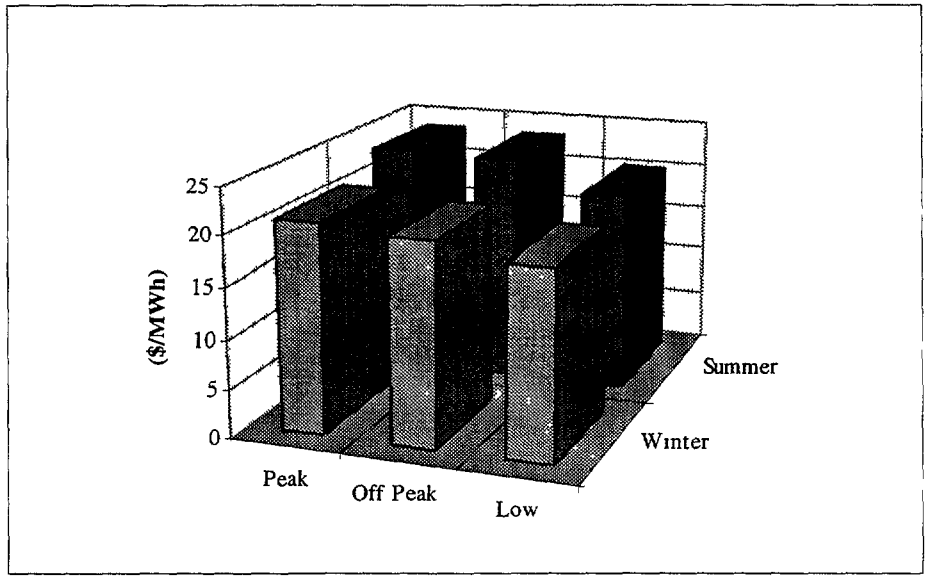


Figure 4-6 Projected Short-Run Marginal Cost by Time Period for 1996

50

Section 5
Review of Existing Tariffs

The objective of this section is to present and evaluate the current pricing of electricity in Bulgaria We evaluate pricing structures (i e , the pricing relationships among customer categories), price levels, and the regulation of prices

5 1 CURRENT TARIFF SETTING AND REGULATION

Electricity prices are set by the Commission of Pricing (COP) under the category of "fixed" prices, the most controlled form of pricing regulation in Bulgaria Other items in this regulatory category are residual fuel oil, natural gas and district heating for households

The organizations that play principal roles in electric pricing include

- NEK, which has primary responsibility for the generation, transmission and distribution of electricity
- Industries and district heating companies that generate electricity and sell power in excess of their own needs to NEK, at regulated prices
- COE, which has regulatory authority over the general energy policy including electricity

The formal procedure is that NEK suggests tariffs to COE COE then accepts or rejects NEK's proposal If proposed tariffs are accepted, they are sent for final approval to the COP However, conditions of loans from the World Bank and EBRD are currently driving tariff increases The last tariff increase in September 1995 brought average electricity tariffs to $US 26 per MWh Based on agreements with the Banks, average tariffs are to rise to $US 30 per MWh by March 1996 and $US 35 per MWh by September 1996 The World Bank has threatened cancellation of existing loans to the power sector if these targets are not met EBRD has threatened loan suspension

5 2 CURRENT TARIFFS

Household tariff are differentiated by day and night use Non-household tariffs are differentiated by season (i e , winter and summer) and by time of day (peak, daytime and nighttime periods) As of September 1996, Household electricity tariffs are 1 56 leva/kWh ($US 23 per MWh) for daytime use and 0 83 leva/kWh ($US 12 per MWh) for nighttime use Table 5-1 shows the non-household tariffs Electric generation from industries and district heating companies can be sold to NEK at rates shown in Table 5-2

Table 5-1
Non-household Tariffs- September 1995 (leva/kWh)

	Winter				Summer			
	Peak	Day	Night	Single Zone	Peak	Day	Night	Single Zone
High Voltage	3 55	1 99	0 95	2 86	3 10	1 67	0 81	2 48
Medium Voltage	3 68	1 99	0 98	2 91	3 19	1 73	0 86	2 57
LV Non-HH	3 85	2 07	1 02	3 10	3 35	1 81	0 88	2 69

Note Published tariffs also contain power factor penalties for large users

Table 5-2
Electricity Buyback Rates for Industry and District Heating Companies

Time of Day	leva per kWh	$ per MWh
Peak	1 82	27 2
Day	1 01	15 1
Night	0 44	6 6

5 3 FINANCIAL REQUIREMENTS

Under current tariffs, NEK is experiencing a serious shortfall in revenues, even though current electricity tariffs generate enough revenue to meet the technical definition of financial requirements provided under Bulgarian accounting standards The key reasons for inadequate revenues include

- There is no allowance for nuclear waste fuel storage
- There is no allowance for nuclear plant decommissioning
- There is inadequate allowance for depreciation, because *book value* has not kept pace with *replacement cost* in Bulgaria's hyper-inflationary economy
- There is no direct subsidy of NEK from the state budget, although some subsidy reaches NEK indirectly through state subsidization of domestic coal production

52

Section 7 of this report reviews the financial requirements for NEK, and estimates additional revenue requirements to eliminate the aforementioned revenue shortfalls

5 4 ECONOMIC SIGNALS TO CUSTOMERS AND SUPPLIERS

The point has been made previously that, in the ideal, prices should reflect the marginal costs of providing electric service The sections below compare current prices with LRMC by tariff category and by time-of-day These comparisons measure the extent to which current pricing provides economic signals to customers and suppliers

5 4 1 Comparison by Tariff Category

Figure 5-1 compares the weighted average September tariffs for each tariff category with the estimate of LRMC by tariff category developed in Section 6 of this report Sales figures for 1994 were used in weighting the time-of-day (TOD) tariffs to obtain the weighted average by tariff category Both TOD and single zone tariffs are shown for non-household customers

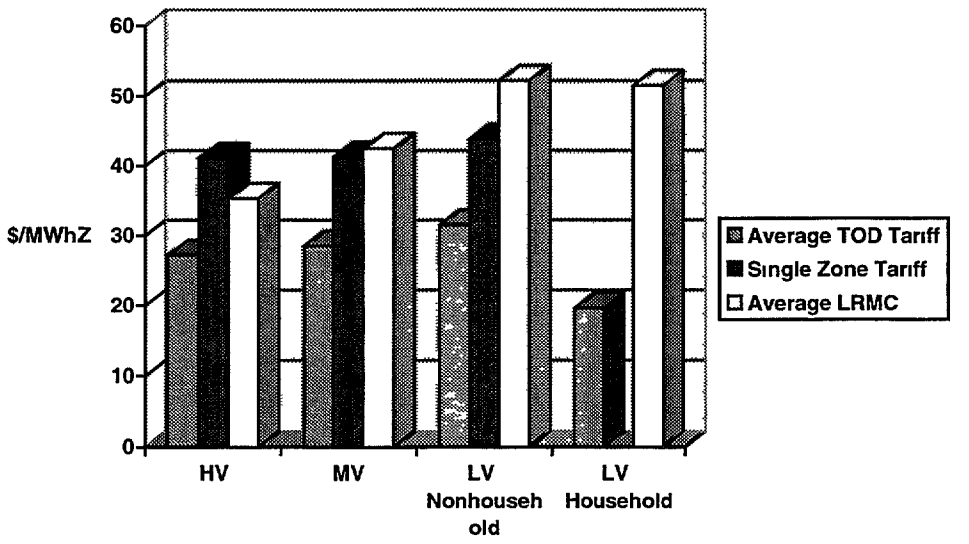


Figure 5-1 Comparison of Current Tariffs with LRMC

53

Based on the comparisons of current tariffs to LRMC in Figure 5-1, we make the following observations

- The current TOD High Voltage tariffs are about 75% of average LRMC Almost all 1994 High Voltage sales were TOD (i e , over 98%) The single zone High Voltage tariff is slightly more than average LRMC, but is used by very few customers
- The current TOD Medium Voltage tariff is about 67% of average LRMC As with High Voltage, almost all Medium Voltage sales are based on TOD pricing The single zone tariff appears to be very near average LRMC, but applies to few customers
- TOD Low Voltage- Non-household tariff is about 60% of average LRMC and the single zone tariff is about 85% of LRMC About 53% of Low Voltage- Non-household sales were under TOD tariffs in 1994 and 47% were single zone
- Household tariffs are about 40% of average LRMC

5 4 2 Comparison by Time-of-Day

In Bulgaria, time-of-day (TOD) tariffs are available to all customers By installing multi-zone metering, Household customers can use daytime and nighttime tariffs, and Non-household customers can use peak, daytime and nighttime tariffs

This section provides a comparison of TOD tariffs with time-differentiated LRMC Figures 5-2a, b and c depict the comparisons for the High Voltage, Low Voltage Non-Household and LV Household categories The values shown in the figures are weighted averages based on 1994 sales statistics

We make the following observations based on the comparisons in the figures

- **High Voltage Tariff Category** The peak period tariff is slightly higher than estimated LRMC, the daytime tariff is about 75% of LRMC, and the off-peak tariff is significantly less than LRMC The HV nighttime tariff is approximately 27% of the peak tariff, while nighttime LRMC is approximately 67% of peak LRMC Thus it appears that the HV TOD tariffs exaggerate the difference between economic costs in the peak and nighttime periods
- **Medium Voltage Tariff Category** The comparisons between TOD tariffs and LRMC for the MV category are similar to the HV, except that the TOD tariffs are lower than LRMC for all time periods The MV nighttime tariff is approximately 27% of the peak tariff, while nighttime LRMC is approximately 62% of peak LRMC

54

- **Low Voltage- Non-household** The tariff is significantly less than LRMC in all time periods, however, exaggerated time-differentiation in tariffs continues to be evident, in comparison to more moderate time-differentiation in LRMC
- **Low Voltage- Household** The tariff is so much less than LRMC in daytime and nighttime periods that analysis of time-differentiation is not useful

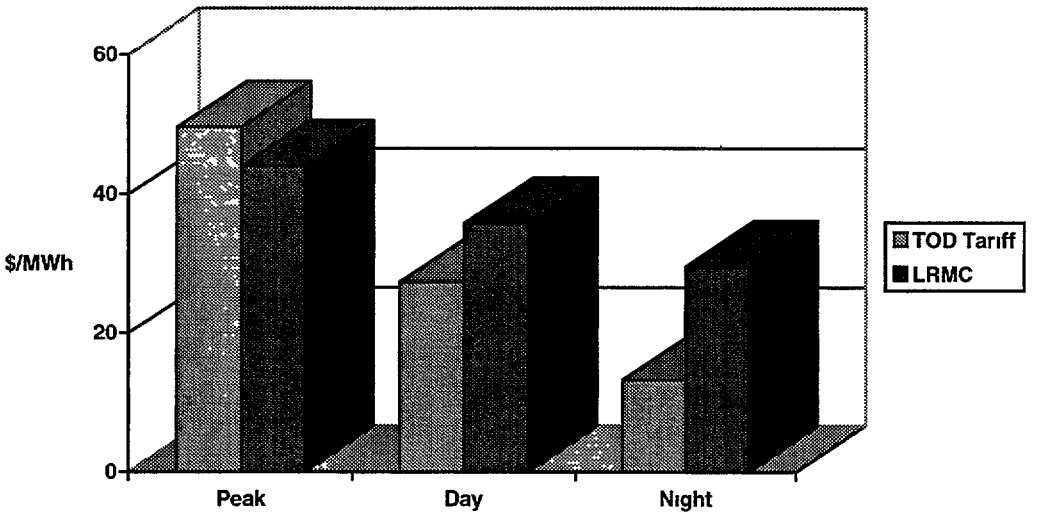


Figure 5-2a High Voltage Tariffs and LRMC by Time of Day

55

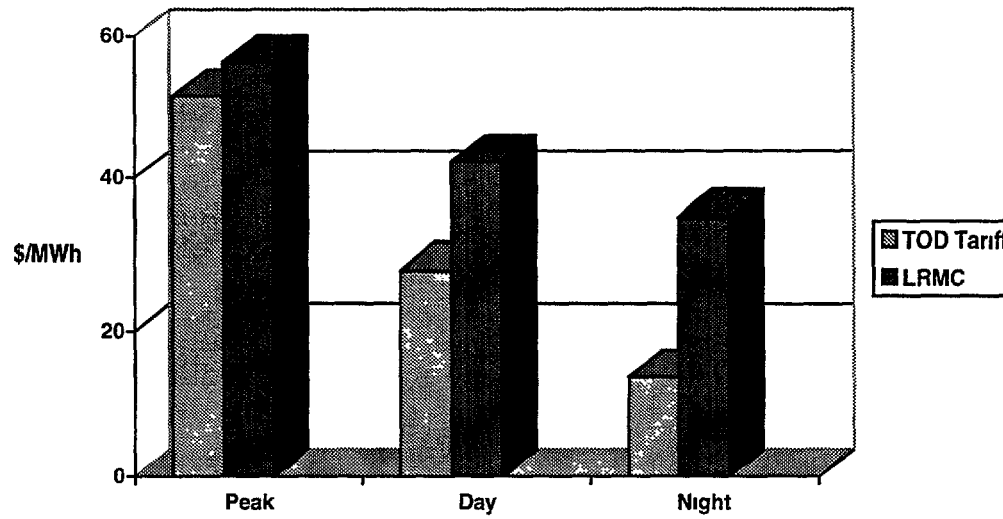


Figure 5-2b Low Voltage- Non-household Tariffs and LRMC by Time of Day

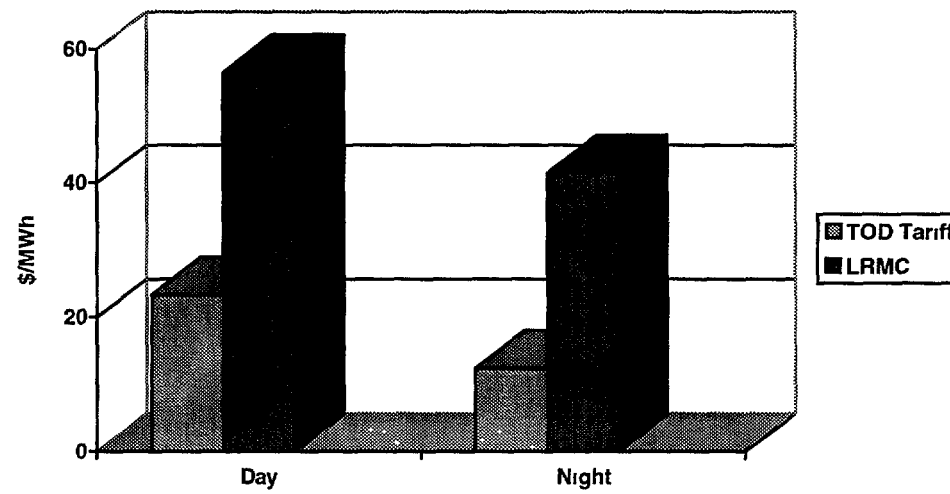


Figure 5-2c Household Tariffs and LRMC by Time of Day

5 4 3 Seasonal Tariffs

Seasonal tariffs apply to all non-household customers These tariffs are higher in the winter than the summer, for example the High Voltage peak winter tariff is 15% higher than the peak summer tariff The fact that loads are highest in the winter makes this

56

intuitively satisfying However our analysis indicates that SRMC and the shortage of capacity, as measured by the likely amount of energy that will not be served, are actually higher in the summer Tariffs based on these pricing signals would actually be higher in the summer than in the winter

Figure 5-3 illustrates the relationship between winter and summer prices and marginal costs for High Voltage customers As shown, the existing ratio of winter to summer tariffs for High Voltage is greater than 110% for each of the peak, daytime and nighttime periods The ratio of estimated winter to summer SRMC and LRMC is less than 100% Thus marginal costs analysis would indicate that High Voltage tariffs should be higher in the summer than the winter This relationship was found for the other tariff categories as well

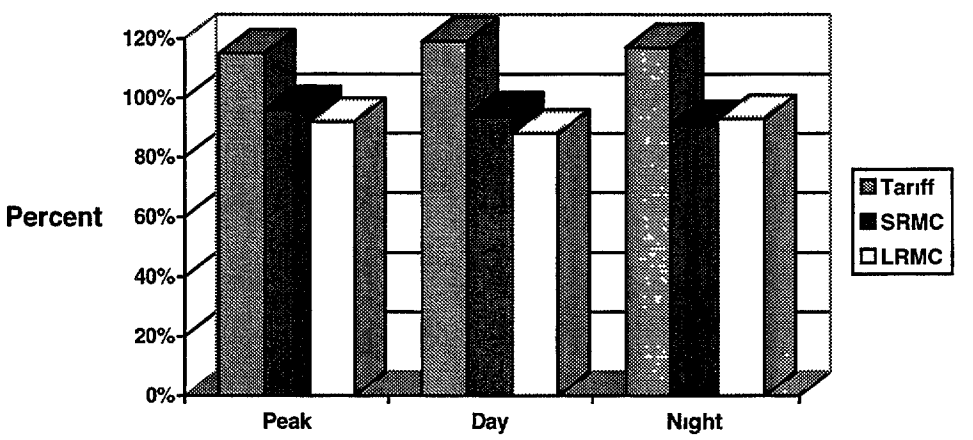


Figure 5-3 Ratio of Winter to Summer Prices and Costs- High Voltage

How can this counterintuitive result be explained? There are several possibilities all relating to operational difficulties of the generation system during the summer The system has been designed for greater demand than is now the case and for integrated operation with the former USSR The sizing of Kozluduy 5 and 6 at 1000 MW was done in the 1980's at a time of high projected growth and when the larger USSR system could be depended upon to supply backup capacity during emergency outages and to absorb excess generation during minimum load periods

This situation has clearly changed The decline in demand since 1989 has resulted in a system in which each of Units 5 and 6 at Kozluduy represent over 14% of the Bulgarian

57

peak load Transmission links exist to the larger system of the former USSR, but their use has been limited Combined with the inflexible operation of the coal and lignite-fired capacity, the Bulgarian system is limited in its ability to respond to load changes and unexpected outages This situation is particularly severe during the summer when loads are lower and the relative size of the largest generating units to total system output is greatest

It should be noted that many steps have been and are planned to increase the operational flexibility of the Bulgarian electric generation system The Chaira pumped storage plant is the most notable In addition, there are plans for rehabilitation of most of the coal and lignite-fired capacity, and system control has been improved to increase their operational flexibility Even with these improvements, our modeling of the Bulgarian system using IRP Manager indicates that the operational limitations during the summer will result in higher marginal costs than in the winter However, further investigation is warranted in assuring that the modeling accurately reflects the seasonal operation of the generating units In particular, we recommend investigating the effect of projected nuclear unit refueling schedules on the results

5 4 4 Pricing for Power Purchased from Industrial and CHP Plants

Pricing for generation sold to NEK by industry and district heating companies is compared with generation SRMC and LRMC in Figure 5-4 This comparison illustrates the extent to which prices reflect NEK's incremental cost savings associated with power purchases NEK's incremental cost savings fall somewhere between SRMC and LRMC, depending on the reliability of the power and the coincidence of power deliveries with the power system's requirements

Our comparisons indicate that the "buyback" rate is only as high as SRMC in the peak period Prices during other periods are significantly lower than even the marginal operating cost of NEK

53

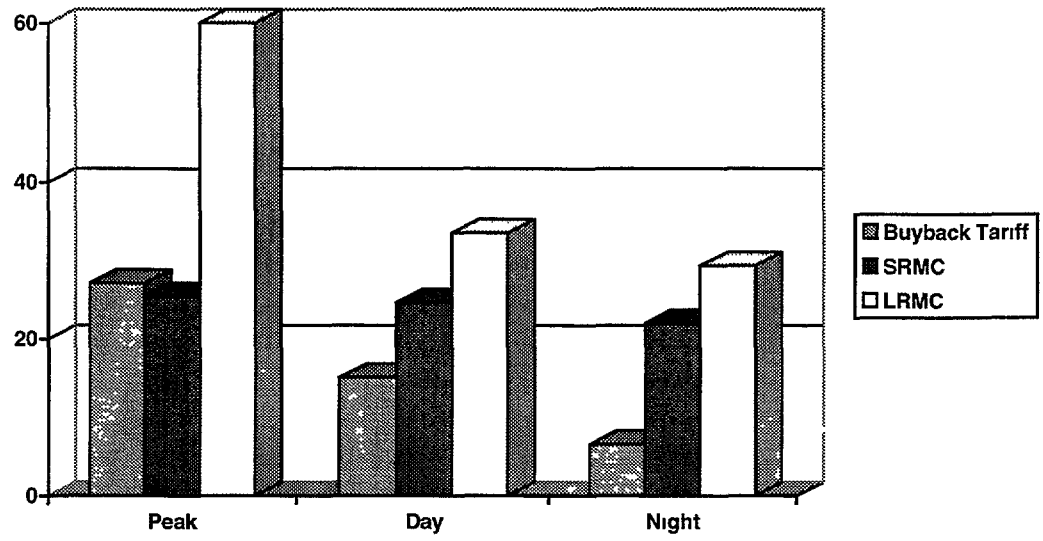


Figure 5-4 Comparison of Pricing for Power Purchased from Industrial and CHP Plants with SRMC and LRMC by Time of Day

The gap between the buyback rate for industries and district heating customers and the estimated generation LRMC will require further study of the following factors

- The degree to which generation from industrial and district heating companies can be used in peak periods of demand and in emergency situations
- The degree to which this generation can be used to defer capacity expansion by NEK
- Other costs and benefits associated with non-NEK generation
- Influence of avoided cost pricing for development of a competitive market for non-utility generation

The fact that generation from the CHP units is driven by heat demand and may not fully correspond to NEK needs may justify a price less than LRMC However, new Sofia and Sofia East CHPs have been proposed as partial replacement for the Kozluduy Unit 1-4 This proposal implies a capacity value and from a purely economic standpoint would justify a buyback price greater than SRMC

Section 6
Long Run Marginal Cost Forecast

The objective of this section is to develop the long-run marginal costs (LRMC) of supplying electricity 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) LRMC is used in Section 7 as a guide to structure tariffs to provide economic signals to electricity consumers

6 1 INTRODUCTION TO LRMC

The electric utility provides three main services (1) customer access to the utility system and associated meter reading and billing services, (2) electric energy, and (3) reliable power for meeting customers' peak loads *Marginal customer costs, marginal demand or capacity costs*, and *marginal energy costs* represent incremental changes in cost with respect to each respective service The marginal costs for providing utility services are important determinants of tariffs for those services

Marginal customer costs are those costs which change as a result of a change in the number of customers The marginal customer cost is essentially an access cost, and consequently, it does not vary according to when or how much electricity is used by the customer The cost is based on the utility's cost to provide all the equipment needed to deliver energy from the network to the customer site, plus the cost of servicing each customer account Marginal customer costs are relatively low compared to marginal energy and capacity costs, and are not addressed quantitatively in this report

Marginal energy and marginal capacity costs are instantaneous costs related to energy use Marginal energy costs are related to kilowatt-hours consumed, for example fuel expense Marginal capacity costs are those costs which change in relation to changes in kilowatt demand, for example the investment cost for new generating capacity *Generation* capacity costs reflect the need to provide sufficient generation capacity to meet system loads with an adequate degree of reliability, *transmission and distribution* capacity costs reflect the need to provide sufficient T&D facilities to supply the peak system demand Marginal costs are estimated separately for each voltage level

Marginal customer, energy and capacity cost estimates by voltage level are used as the building blocks for estimating LRMC to various customer tariff categories The reason for assessing energy and capacity marginal costs separately is that marginal energy costs provide a guideline to determining variable components of tariffs related to customer energy demand, and marginal capacity costs provide a guideline to relating tariffs to customer peak demand

6 2 GENERATION SYSTEM LRMC

Two methods of calculating generation system LRMC are used in this report to illustrate alternative methods and to demonstrate the sensitivity of results to methodological approach These methods are referred to as the *Incremental Plant Method* and the *Revenue Requirements Method* The analyses are conducted in constant 1995 U S currency for the period 1996-2005 We assume an opportunity cost of capital of 10 percent per year These methods and their results for the Bulgarian power system for Plans A, B and C (see Section 3) are discussed below

6 2 1 Incremental Plant Method

Overview The Incremental Plant Method is applied in the following way

- Marginal energy cost is estimated by the IRP Manager model within the generation system simulation Marginal energy cost, also known as *short-run marginal cost* (SRMC), is the change in variable operating costs, such as fuel, to serve a change in demand in any hour using the generating resources that have been committed to service for that hour
- Marginal capacity cost is estimated based on the investment cost of the *gas turbine proxy*, incurred at the time the *incremental plant* is added to meet system capacity requirements The technical and operating characteristics for the gas turbine are shown in Table 6-1

Table 6-1
Technical and Economic Characteristics of Gas Turbines

	Simple Cycle Gas Turbine		Gas Fired Combined Cycle	
Capital Cost without IDC	436		572	$/kW
Capacity	50		240	MW
Construction Time	1		2	years
	1st year	2nd year	1st year	2nd year
Investment Schedule	100 0%	0 0%	50 0%	50 0%
Fixed O&M Cost	0 84		4 68	$/kW-yr
Real Escalation for O&M	1%		1%	

61

- Levelized marginal capacity cost is calculated per unit of peak demand increase over the study time horizon
- Marginal energy and capacity costs are combined for total generation system LRMC

Marginal Capacity Cost Methodology The *incremental plant* is defined as the first unit in the development plan that can either be deferred in case of a decrease in demand or accelerated in case of an increase in demand We use the IRP Manager model to identify the incremental plant The methodology involves removing all discretionary capacity additions from the initial model run, and then testing capacity additions for cost-effectiveness to determine when capacity additions are first needed in order to ensure adequate system reliability

To calculate marginal capacity cost, the investment cost of a gas-fired combustion turbine-generator is used This generator has the lowest investment cost of any generator type, although its operating cost is relatively high The low investment cost of the gas turbine makes it an appropriate proxy for the marginal cost of "pure" generation capacity

The calculation of marginal capacity cost is performed in two steps The first step removes all discretionary resource additions from the plan The second step calculates the first year when new peaking units are needed in the system The calculation uses the IRP-Manager Iterative Cost Effectiveness Methodology (ICEM) ICEM performs a cost effective analysis and determines a year and total capacity of new unit additions

Generally there are two options to determine the year when new capacity is needed in the system One way is to build the system expansion plan to meet some target level of system reliability, e g loss-of-load probability (LOLP) or reserve margin However, economic theory suggests that reliability should be treated as a variable to be optimized, and both price and capacity levels should be optimized simultaneously The optimal price is then the marginal cost price, while the optimal reliability level is achieved when the marginal cost of capacity additions equals the expected value of economic cost savings to consumers due to electricity supply shortages avoided by those capacity increments For this second approach we use 70 $/MWh as an approximation of the consumer costs for system unreliability

Results Table 6-2 presents the calculation of the generation LRMC using the Incremental Plant Method for Plan A SRMC shown in Table 6-2 reflects IRP Manager's marginal energy costing

62

Table 6-2
Generation LRMC – Incremental Plant Method Plan A

Cost per kW of peak load increase ($)	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Investment	493										
Present Value in 1st year of operation		542									
Capital Recovery	0 0	59 7	59 7	59 7	59 7	59 7	59 7	59 7	59 7	59 7	59 7
Fixed O&M	0 0	1 0	1 0	1 0	1 0	1 0	1 0	1 0	1 0	1 0	1 0
Total Fixed Cost	0 0	60 7	60 7	60 7	60 7	60 7	60 7	60 7	60 7	60 7	60 7
Energy (GWh) (assuming 65% load factor)	0 0	5 7	5 7	5 7	5 7	5 7	5 7	5 7	5 7	5 7	5 7
Energy cost (SRMC) (from IRP-Manager)	21 0	20 9	24 5	26 5	27 5	24 3	21 5	25 3	24 9	26 5	26 8
Capacity cost	0	10 7	10 7	10 7	10 7	10 7	10 7	10 7	10 7	10 7	10 7
Total	21 0	31 6	35 2	37 1	38 2	35 0	32 1	36 0	35 6	37 1	37 4
Levelized cost (per MWh of generation)											
Variable	24 1	$/MWh									
Fixed per MWh	9 1	$/MWh									
Fixed per kW-yr	52 0	$/kW-yr									
Total	33 2	$/MWh									

We find that SRMC is highest for Plan C because the earlier retirement of Kozloduy units 3 and 4 causes units with higher variable costs to be more frequently on the margin, and there is also more expected unserved energy Plan A has later retirement of Kozloduy units, and new additions replace the retired capacity Later need for new additions for Plan A causes the overall LRMC to be slightly lower than for the other scenarios

6 2 2 Revenue Requirements Method

Overview As a verification of the results obtained using the Incremental Plant Method, the Revenue Requirements Method was also used Like the Incremental Plant Method, the Revenue Requirements Method makes use of the IRP Manager Model and the ICEM optimization routine within the model The Revenue Requirements Method uses the following procedure

- Develop optimized generation plan for a given electricity demand forecast Potential resource additions for the optimal plan are chosen from a menu of generic alternatives For simplicity, we make two potential supply-side additions available to ICEM, the simple-cycle combustion turbine and the

combined-cycle combustion turbine Technical and operating characteristics for these technologies are shown in Table 6-1

- Develop optimized generation plan for a given electricity demand forecast with a small increase/decrease in demand Based on some preliminary testing, we adopted a simple approach of increasing demand by 250 MW in all hours of the year Two main considerations affect the choice of demand increment damping of "lumpiness" impacts on system operation, and matching to the size of resource expansion alternatives

  In the interest of time, we adopted a load increment approach, however, a technically superior approach involves averaging results from incremental and decremental trials Another technical enhancement to our approach would involve multiple IRP Manager runs with load increments/decrements in time-of-day periods, rather than in all hours

- Calculate the revenue requirements for each optimized plan (investment and operating costs)
- Separate revenue requirements into energy- and capacity-related costs
- The difference in revenue requirements between the two plans yields the levelized cost per unit of demand increase for energy-related, capacity-related, and total costs

Results The following key results were obtained for the Revenue Requirements Method

- For Plan A, two new simple cycle combustion turbines are added in 1996 Table 6-3 illustrates the calculation of LRMC for the Revenue Requirements Method for Plan A
- For Plan B's higher loads, one combined cycle and two simple cycle units are added in 1996, and a combined-cycle unit was added in year 1999
- For Plan C, one combined cycle unit and two simple cycle units are added in 1996, and one combined cycle unit is added in 1997

Table 6-3
Generation LRMC – Revenue Requirements Method for Plan A

Increased Load Minus Reference Case	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Sales (GWh)	2,190	2,258	2 328	2 400	2 474	2,551	2,583	2,614	2,646	2,679	2,712
Peak (MW)	250	258	266	274	282	291	295	298	302	306	310
Incremental Load Factor	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%
(thousands US$)											
Fuel	31,480	34,570	40,850	44,490	44,990	49,820	47,760	50,100	51,570	53,430	55 500
Variable O&M	8 520	9 850	10,610	11,950	12 700	14,070	13,430	14 400	14,820	15,030	15,280
Fixed O&M	0	3 210	3 240	3,270	3 310	3,330	3,370	3 400	3 430	3 470	3 500
Total											
Variable	40 000	44,420	51,460	56 440	57,690	63,890	61 190	64 500	66 390	68 460	70 780
Fixed	0	3 210	3,240	3 270	3 310	3,330	3 370	3,400	3,430	3,470	3,500
Levelized Value											
Energy	18 6	$/MWh									
Capacity	1 2	$/MWh									
	10 5	$/kW-yr									
Total	19 8	$/MWh									

6 2 3 LRMC Summary for the Two Methods

Summary of Results The estimated generation system LRMC for the two methods for Plans A, B and C is summarized in Table 6-4

Table 6-4
Generation LRMC Summary

		Plan A	Plan B	Plan C
Incremental Plant Method				
Variable	$/MWh	24 1	24 1	26 4
Fixed	$/MWh	9 1	9 1	9 1
	$/kW-year	52 0	52 2	52 2
Total	$/MWh	33 2	33 2	35 5
Revenue Requirements Method				
Variable	$/MWh	18 6	20 7	22 0
Fixed	$/MWh	1 2	6 1	8 9
	$/kW year	10 5	53 3	78 3
Total	$/MWh	19 8	26 8	30 9

65

Note that there is a difference between the allocation of costs which are energy-related and those which are capacity-related for the two methods The variable part of the LRMC in the Revenue Requirements Method is lower than SRMC in the Incremental Plant Method This is expected because for the Revenue Requirements Method, higher-capital-cost, lower-energy-cost additions bias the allocation of LRMC toward fixed costs This introduces an added complexity for tariff setting, because the split between fixed and variable costs must be adjusted

6 2 4 Conclusions

The Incremental Plant Method provides a consistent measure of LRMC and a direct allocation between energy- and capacity-related costs Therefore the generation LRMC used in other sections of this report is based on the results obtained using the Incremental Plant Method

We found some inconsistent trends in our results for the Revenue Requirements Method We expected LRMC for this approach to exceed LRMC for the Incremental Plant Method, due to the addition of a sizable load increment, however the trend apparent in Table 6-4 shows lower LRMC Another unsettling result is the comparison between the exceptionally low LRMC for Plan A versus higher estimates for Plans B and C At this time we do not have a satisfactory explanation for these unexpected results Part of the difference could be attributed to the optimization routine in the planning model and to the sizes of the units additions used for the analysis The optimal plan is generally considered a plan that has optimal mixture and timing of new unit additions, taking into account system load forecast and the existing units The generation plans used for our analysis are constrained, and the timing and types of new additions are not fully optimized

6 3 LRMC OF T&D

Ideally, a forecast of LRMC for T&D would be based on projected demand growth-related investments for T&D, plus O&M For the transmission system, such investment costs would include expenditures for generation interconnections and line and substation projects to serve load growth For the distribution system, such investment costs would include primarily expenditures for distribution substations

Estimating such T&D investment costs is a relatively complex planning exercise outside the scope of this report Anyway, the increased precision that would come with a more detailed estimate is a marginal added value for the illustrative purposes that this study aims to achieve While a forecast of T&D LRMC based on planned investments is

beyond the scope of the current report, we recommend work in this area in order to improve LRMC estimates A possible starting point for a Bulgarian estimate of T&D LRMC is NEK's 5-year investment plan/budget

We are unaware of any previous estimates of LRMC for the Bulgarian transmission and distribution systems The Study on High Voltage Transmission Network (Fichner, January 1994) estimated transmission investments required in support of expanding the generation system, and this information can be used to estimate marginal costs for the high voltage (HV) system of 110 kV and up We have no Bulgarian data that could be used to estimate the marginal costs for the medium voltage (MV) network between 6 and 110 kV, or for the low voltage (LV) network below 6 kV The LRMC used in this study for the Bulgarian MV and LV networks is based on international comparisons

Table 6-5 shows estimates of T&D LRMC for Belarus and two U S utilities LRMC for the Bulgarian HV network, based on the Fichner "Option 2" investment plan, is also shown in the table Note that the voltage class aggregations shown in the table differ from the Bulgarian categorizations of HV, MV and LV, and thus any extrapolation of these marginal costs to the Bulgarian system is indirect The table can be used to gain an order-of-magnitude comparison of LRMCs for networks

Table 6-6 presents the marginal costs of T&D used in this study The HV network LRMC used in this study is based on the Fichner investment cost projections for the "Option 2" case which is in turn based on a hypothetical generation expansion plan that resembles the scenario plans presented in this report, but is not wholly consistent with them Table 6-7 shows Fichner's assumptions for transmission system expansion projects and associated costs, and illustrates the derivation of HV LRMC based on the Fichner estimated costs of expansion

The estimates used in this study for MV and LV are based loosely on the Bechtel study for Belarus We have reduced the Belarus estimates slightly based on the judgment that the distribution system in Bulgaria can accommodate significant demand growth without the requirement for investments due to the historic decrease in demand relative to levels once served by the system

Table 6-5
International Comparison of Estimates of LRMC for T&D ($US 1995 per kW-year)

	Fichner Study for Bulgaria	Bechtel Study for Belarus	Southern California Edison (USA)	Missouri Public Service (USA)
Extra High Voltage (EHV) (>200 kV)	7	2	–	–
EHV plus High Voltage (HV) (>30 kV)	–	7	36	23
EHV plus HV plus Medium (MV) (>1 kV)	–	13	–	–
EHV plus Trans plus Distr (T&D total)	–	45	95	51

Table 6-6
Assumptions for LRMC for Bulgarian T&D ($US 1995)

	LRMC $/kW-yr
High Voltage (>110 kV)	7
Medium Voltage (6 110 kV)	8
Low Voltage (<6 kV)	25
Total	40

Table 6-7
Derivation of HV LRMC from Fichner Study ($US 1995)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Project										
Vidin S/S	3 1	3 9	8							
Dobrich S/S			1 9	7 7	7 7	1 9				
TPP Jambol A		2 8	9 8	9 8	2 8	2 8				
TPP Jambol - B								1 5	6 0	6 0
TPP Burgas A							3 0	10 4	10 4	3 0
NPP Belene							7 9	27 8	27 8	7 9
HV Investments, $MUSD	0 8	2 8	11 7	17 5	10 5	4 7	10 9	39 7	44 2	16 9
Peak Demand Growth, MW	220	240	230	240	250	110	110	110	110	110
Level Annual Invest, $MUSD	12 7									
Demand Growth, MW, '96-'05	1730									
Estimated LRMC, $/kW-yr	**7**									

68

6 4 LRMC LOSS ADJUSTMENT BY VOLTAGE LEVEL

Power loss is power that is produced by the power plants and delivered to the transmission system, but not delivered to customers because it is dissipated in the process of transmission along the T&D network Each voltage level service serves sales at that voltage level and is a conduit for sales at lower voltage levels Therefore, the peak experienced by the system at a given voltage level is affected by the load characteristics at that voltage and lower

For example, the Medium Voltage system serves Medium Voltage sales and distributes electricity to the Low Voltage system Therefore, the peak experienced at this level reflects both Medium and Low Voltage demand, but not High Voltage demand Marginal energy and capacity costs vary by the voltage level at which customers take service because higher power losses occur for service at lower voltage levels (See Section 3 for additional illustration of loss adjustment by voltage level)

6 5 LRMC BY VOLTAGE LEVEL

Table 6-8 illustrates a simplified estimate of average annual LRMC by voltage level consistent with the Plan A scenario This illustration accounts for the effects of losses by voltage level, and for the LRMC of network facilities attributed to each voltage level

Table 6-8
LRMC by Voltage Level

Point of Sale	Loss Fctr	SRMC $/MWh	Capacity Contribution to LRMC ($/kW-yr)					Avg Load Fctr	Cap Cost $/MWH	Total LRMC $/MWh
			Gen	HV	MV	LV	Total			
Generation	1 00	24 1	52 0				52 0	63%	9 4	33 5
High Voltage	1 12	26 9	58 1	7 0			65 1	73%	10 2	37 1
Medium Voltage	1 16	28 0	60 4	7 3	8 0		75 7	65%	13 3	41 3
Low Voltage Household	1 28	30 8	66 5	8 0	8 8	25 0	108 3	60%	20 6	51 4
Low Voltage Non HH	1 28	30 8	66 5	8 0	8 8	25 0	108 3	58%	21 3	52 1

Note
1 The load factor by voltage level is based on the customer class load factor assumptions The voltage level load factor is weighted by the contribution of the customer categories served at that voltage and levelized over the 1995-2000 time period
2 The average total LRMC includes the SRMC plus the capacity contribution at the average load factor for the voltage level

6 6 LRMC TIME-OF-DAY VARIATION

Each component of LRMC can be allocated to time periods SRMC by time period is found by averaging hourly marginal energy costs Time differentiation of peak demand-related components of LRMC, i e marginal generation capacity and network costs, is less straightforward A commonly accepted method of assigning demand-related marginal costs to time periods is according to the contribution of that time period to expected system unserved energy (EUE) EUE is a probabilistic measure of marginal system unreliability, the risk that the generation system will not to be able to meet the load over a given period of time It is a measure of the need for capacity higher EUE indicates more need for capacity

SRMC and EUE by time of day and by season are presented in Table 6-9

Table 6-9
Time-of-Day Variation in SRMC and EUE for 1995 for Plan A

	SRMC, Level $/MWh	EUE, % of Annual Total	Hours in Period
Winter			
Peak	25	19%	780
Daytime	24	16%	2002
Nighttime	21	11%	1586
Summer			
Peak	26	22%	780
Daytime	25 5	22%	1965
Nighttime	23	10%	1647
Total		100%	8640

70

Section 7
Financial Requirements and Cost of Electric Service

The costs currently reported by NEK fall short of full economic cost Notably, some of the domestic lignite purchased for generating electricity is subsidized, the allowance for utility asset depreciation does not reflect replacement cost, and there is inadequate allowance for nuclear plant decommissioning and waste fuel storage This section presents a preliminary estimate of the NEK financial requirements to meet the full economic cost of the utility

This section presents a *cost-of-service* study for the Bulgarian electric sector Cost-of-service is the utility financial requirements for meeting customers' electric service requirements Cost-of-service is an *average* cost, as distinguished from the *marginal* cost of electric service Tariffs usually are set at levels that allow the utility to collect its cost-of-service without generating either financial surplus or deficit Section 8 of this report will discuss reconciling marginal cost pricing principles and cost-of-service for final tariff design

7 1 UTILITY FINANCIAL REQUIREMENTS

7 1 1 Financial Objectives

A critical requirement of a tariff is that it produce adequate revenues to meet the financial requirements to operate, replace and expand the power system These requirements include the out-of-pocket operating expenses, an adequate allowance for depreciation to provide funds for replacing the system as the economic life of equipment comes to an end, and a reasonable return on investment

We have assumed the following key idealized objectives for NEK financial planning

- Cash flow from electric sales will provide for all operating expenses plus the costs of construction and replacement programs
- NEK will self-finance capital projects with only minor amounts of external debt
- There will be no direct external subsidization of NEK finances
- NEK will pay its bills when due
- There will be negligible customer default on bill payments
- Regulation of NEK will allow 5% return on net fixed assets to be used for retained earnings, shareholder dividends or capital expenditures

71

7 1 2 Financial Assumptions for NEK

The financial outlook provided by NEK in the IRP Manager dataset of October 1995 was evaluated for its adherence to the financial objectives described above This dataset was used as a starting point As described in the following sections, some variables within the IRP Manager dataset were changed in order to meet financial objectives

In addition to analyzing the IRP Manager NEK financial statements for the Plan A scenario, we also considered two other key financial statements for NEK, the 5-year forecast used within NEK for financial planning and the Arthur Andersen audit of NEK for year 1994 It is important to note that the financial scenario analyzed in this report, the IRP Manager Plan A scenario, differs significantly from the NEK 5-year plan and the Arthur Andersen audit in the following key aspects

- Most importantly, a higher amount of forecasted depreciation sets the IRP Manager forecast apart from the NEK 5-year forecast and the Arthur Andersen audit, which are based on the book value of NEK assets determined in the 1992 revaluation
- The IRP Manager scenario expects significantly higher fuel, O&M, tax and capital expenditures than the NEK 5-year plan We found that the NEK 5-year plan anticipates *decreasing* real costs for fuel and O&M, when these costs are corrected for inflation, in contrast to nearly flat cost trends in the IRP Manager dataset
- In summary, the IRP Manager scenario anticipates revenue requirements up to 50% higher than the NEK 5-year financial plan that was examined for this study

The key assumptions and findings of our financial analysis for the Plan A scenario are discussed below

Capital expenditures For this Interim Report we have used the capital expenditures provided by NEK in the IRP Manager database (see Table 7-1) At this time we have *not* thoroughly reviewed these assumptions with the Tariff Project Working Group

Cash flow An adequate supply of cash is considered a key financial objective for NEK because in its current poor financial state NEK has limited prospects for borrowing One measure of cash flow is the ***cash generation ratio***, the ratio of after-tax cash generation (operating revenues - operating expenses excluding depreciation - taxes - principal payments) to total annual investment and debt service requirements If the cash generation ratio is high enough, the utility is in a strong position to carry out construction programs to maintain a reliable power system For NEK in the near term we feel that the

72

cash generation ratio should be between 0 6 and 1 We have used this ratio as a key determinant of the appropriate level of revenues required by NEK

Borrowing Due to NEK's limited prospects for additional borrowing, we assume no new borrowing from year 1998 onward, and only small amounts of debt prior to 1998 Essentially this means that NEK will be paying cash for operating expenses as well as for construction and replacement programs The ratio of long-term debt to total capital for NEK is forecast to be less than 3% through year 2000, which is very low by international standards In contrast, for U S utilities this ratio is typically close to 50% A higher level of debt would enable NEK to amortize capital expenditures, reducing electric service tariffs in the near term

Depreciation Depreciation is an accounting mechanism intended to reflect the loss in value of tangible assets In the context of utility finance, depreciation expense is the mechanism by which the utility recovers from customers the funds previously provided for the construction or acquisition of utility plant These recovered funds are available to replace utility plant as it ages

In a hyper-inflationary economy such as Bulgaria's, the depreciation reserve quickly loses its purchasing power and in time the depreciation fund is inadequate for the capital requirements of the utility To ensure adequate depreciation expense, asset revaluation is advisable in a hyper-inflationary economy In Bulgaria, the last asset revaluation was conducted in 1992 Inflation subsequent to the 1992 asset revaluation has decreased the purchasing power of the Bulgarian leva by an estimated factor of 32 Therefore accounting depreciation based on the 1992 asset revaluation is currently inadequate for financing utility capital programs

Our financial analysis treats depreciation as a variable that is optimized to ensure adequate revenue requirements to meet the utility's financial requirements The amount of depreciation is determined using a trial and error approach of evaluating financial outcomes assuming different overall levels of depreciation For the Plan A scenario we determined that optimal depreciation would require restatement of asset values about 4 times the valuations determined in the 1992 revaluation

7 1 3 Financial Results

Tables 7-2a, b and c present the IRP Manager Balance Sheet, Income Statement, and Funds-Flow Profile for the base case Plan A scenario All financial figures in this report are presented in 1995 U S dollars The annual financial requirements underlying the tariff forecasts developed in this report are taken from the Income Statement shown in Table 7-2b

Utility Revenue Requirements Overall annual revenue requirements associated with the Plan A scenario range from 1 5 billion USD in 1996 to 1 8 billion USD in 2000 In levelized 1995 dollars over the period 1995-2000, the associated average cost of sales to consumers would be 43 $/MWh In comparison, the average electric tariff effective September 1995 was 26 $/MWH, or sixty percent of the anticipated levelized cost to the utility

Financial indicators Key indicators for the Plan A financial outlook for the period 1995-2000 are summarized in Table 7 3 below

Table 7-3
Key Financial Ratios

	1996	1997	1998	1999	2000	Accepted Value
Debt to Total Capital	<5%	<5%	<5%	<5%	<5%	up to 50%
Return on Net Assets	2%	2%	2%	3%	3%	up to 16%
Cash Generation Ratio	73	63	69	78	1 24	greater than 0 6

Based on the financial ratios, we make the following conclusions regarding NEK's financial outlook under the Plan A scenario

- The low debt to capital ratio is indicative of a cash operation in which electric consumers pay in advance for plant that will be placed in service to meet future electric requirements A higher debt to capital ratio would have the impact of deferring tariff impacts of the costs associated with facilities under construction
- The low return on net assets ratio is consistent with a public enterprise not expected to provide return incentives that would attract private investment
- The relatively high cash generation ratio is indicative of a cash operation that operates free of financial deficits and is in strong position to finance capital additions

7 1 4 Financial Uncertainties

Future capital requirements for generating resources The future capital requirements associated with expansion and replacement of generating resources is the major financial uncertainty that NEK faces Future capital requirements depend on factors such as future

74

electric consumption, the timing for retiring Kozloduy units, the need for rehabilitation of existing plant and the choice of new generating technologies to meet anticipated resource requirements

Nuclear decommissioning costs At the time of this report there is no reliable estimate of the costs required for the decommissioning of Kozloduy However, comparison of international estimates of decommissioning costs indicate that such costs will be an important component of NEK's financial requirements Table 7-4 presents the estimated costs of future decommissioning for two nuclear plants the Bodorik Nuclear Power Plant in Slovakia, which is similar in design to Kozloduy, and the Diablo Canyon Nuclear Power Plant in California For these two examples, the estimated cost of decommissioning is between $US 300 and $US 400 per kW of installed capacity

Table 7-4
Examples of Cost of Nuclear Decommissioning

Plant	Location	Type, Vintage	No units and MW per Unit	Estimated Cost of Decom	$ per kW Installed Capacity
Bodorik	Slovakia	Russian VVER	2-440 MW units	$285 Million	$323 per kW
Diablo Canyon	California	Press Water, 1985	2-1080 MW units	$ 839 Million	$388 per kW

U S accounting standards require utilities to establish decommissioning funds that accumulate beginning when the nuclear plant is commissioned In Bulgaria, there is no such fund, which means that decommissioning will have to be financed at the time of the decommissioning Only small decommissioning costs are accounted in the IRP Manager dataset Essentially the financial results shown in this section assume that decommissioning costs will be financed sometime after year 2000

As a sensitivity study, we evaluated the impact on average costs to customers under the following assumptions

- decommissioning activities would begin immediately
- total cost of 500 million USD (1995 dollars)
- cost of decommissioning financed over five years

75

Under the foregoing assumptions the impact on the average cost of electricity is approximately $US 4 per MWh of sales in 1995 dollars

Disposal of spent nuclear fuel The costs associated with disposal of spent nuclear fuel from Kozloduy, like the costs associated with Kozloduy decommissioning, are not certain at this time However, it is likely that such costs will be an important component of NEK's future financial requirements For comparison, in the U S, utilities pay a surcharge to the federal government of $1 per Mwh of nuclear generation In exchange, the federal government is developing a disposal site and ulimately will take possession of the spent fuel currently stored in temporary facilities adjacent to the nuclear plants At the time of this interim report, it is not clear if any costs associated with disposal of spent nuclear fuel are included in the data assumptions underlying our estimates of NEK's cost-of-service

Environmental costs There is considerable uncertainty regarding expenditures that will be required to bring NEK coal and nuclear generating facilities into compliance with increasingly stringent environmental regulations Our financial analysis does not consider this contingency

Operating costs Unless there is a mechanism to adjust utility revenues to meet changes in the cost of production, the utility is subject to the possibility of significant financial deficits or surpluses depending on the cost expectations built into the tariffs Bulgaria is currently implementing *tariff indexation* to minimize such risk The *adjustment clause* is another possible approach that is used in many countries

7 2 COST-OF-SERVICE BY CUSTOMER CATEGORY

7 2 1 Introduction

Once the total revenue requirement for the utility is determined, that amount must be allocated among the various customer classes (a process known as revenue allocation), and then converted into the rates that appear in the utility's tariffs The use of marginal costs in allocating cost responsibilities to customer classes, and in formulating tariff schedules to recover these costs, is in accord with fundamental microeconomic theory when the prices buyers are paying equal the marginal costs of supply, productive efficiency is maximized and a commensurate increase in total welfare is realized

Under a strict LRMC-based tariff design process, the individual cost-of-service for each customer class is not used Customer class cost-of-service is important only if tariffs are to be designed subject to the constraint that each class' tariffs should collect that class' cost-of-service Even if an LRMC-based tariff design process is to be used, cost-of-

service for each customer class is an important point of comparison for evaluating LRMC-based tariffs For example, cost-of-service for household consumers can be used to set an upper bound on LRMC-based tariffs for that class, if the goal is to minimize household tariffs but still recover utility costs to serve that class of customer

7 2 2 Cost-of-Service Methodology

A detailed cost-of-service study requires two key elements 1) each utility account must be assigned to utility services on the basis of causality, for example fuel costs are considered energy production-related costs, and 2) each customer class' consumption of each utility service must be evaluated in order to relate utility costs to consumption

In the past, Bulgarian pricing of electric services has not required detailed cost-of-service accounting, and there is no existing allocation of historic costs to electric services This lack of information limits the possible scope of cost-of-service studies If cost-of-service is to play a role in future Bulgarian tariff setting, it would be advisable for NEK to implement a company-wide integrated billing and accounting system to track historic costs, and a related system for forecasting future cost-of-service

Due to time and data constraints, we adopted several simplifying judgments for allocating the overall forecasted costs provided by NEK in the IRP Manager database For illustrative purposes we have used only two cost categories, energy- and capacity-related costs, which are much larger than the other categories including customer costs, reactive power costs, etc After we determined the allocation of financial requirements between energy- and capacity-related costs, the IRP Manager model was used to calculate cost-of-service by customer class, taking into account relative sales by customer class and T&D losses

One key aspect of cost-of-service is that in general fixed costs are a higher percentage of total cost than for LRMC because existing assets are accounted as sunk costs In this regard, the relative allocations of costs to variable and fixed components in the cost-of-service study are irrelevant for designing the split between fixed and variable components of economically efficient tariffs

7 2 3 Cost-of-Service Results

Table 7-5 summarizes the results of the simplified cost-of-service study by customer class, and compares the results with LRMC In summary, for the Plan A scenario the cost-of-service for electric sales is forecast to average $47 per MWH of sales, in levelized 1995 dollars over the period 1995-2000 The comparable LRMC for the Bulgarian system is about the same, $46 per MWH of sales This relationship is characteristic of a

utility facing the need to expand and replace its existing system The class-by-class comparisons of LRMC with cost-of-service indicate that for each individual coustomer class, cost-of-service and LRMC are nearly the same, suggesting that strict LRMC pricing may be appropriate for all classes

Table 7-5
Comparison of Cost-of-Service and LRMC for NEK
USD per MWh of Sales Level over 1995-2000 (1995 dollars)

Customer Class	Variable Cost	Fixed Cost	Total Cost of Service	Marginal Energy Cost	Marginal Capacity Cost	Total LRMC
HIGH	16	19	36	24	10	34
MEDIUM	17	23	40	25	14	39
LOW_HH	20	35	55	29	24	53
LOW_NHH	18	33	51	29	25	54
Average			47			46

78

Table 7-1
Forecasted Capital Expenditures

Project	Plant Added into Service $US Millions						Construction Work in Progress (CWIP) $US Millions					
	1995	1996	1997	1998	1999	2000	1995	1996	1997	1998	1999	2000
HV Network	7	7	7	7	7	8	0	0	0	0	0	0
LV Network	34	34	34	34	34	34	0	0	0	0	0	0
MV Network	8	8	8	8	9	9	0	0	0	0	0	0
KOZ1_4	0	0	0	0	0	0	0	0	0	0	0	0
KOZ5_6	23	112	67	7	6	6	0	0	0	0	0	0
KOZ5_6C	0	0	0	0	0	0	0	0	0	0	0	0
CHAIRA	0	0	40	0	0	0	17	40	0	0	0	0
CWIP	0	0	0	0	0	0	672	672	672	672	672	672
DISPATCH	0	0	57	0	0	0	25	57	0	0	0	0
MI8	0	74	58	0	0	0	74	58	0	0	0	0
SMALL	42	165	129	63	71	72	0	0	0	0	0	0
SMALL2	0	0	0	0	0	0	0	0	0	0	0	0
RB_1BBD	0	0	0	0	21	0	0	0	6	21	0	0
RB_2BBD	0	0	0	0	0	21	0	0	0	6	21	0
RB_3BBD	0	0	0	0	0	0	0	0	0	0	6	21
ARDA02	0	0	0	0	0	0	0	4	13	42	90	121
ISKAR02	0	0	0	0	0	0	0	0	0	0	0	13
LIGN_FX0	0	0	0	0	0	402	0	24	129	322	402	0
LIGN_FX1	0	0	0	0	0	0	0	0	24	130	325	406
SOF00A	0	0	0	0	0	87	0	5	28	70	87	0
SOF00B	0	0	0	0	0	87	0	5	28	70	87	0
TFEC02A	0	0	0	0	0	0	0	0	0	0	0	41
TFEC02B	0	0	0	0	0	0	0	0	0	0	0	41
TFEC04	0	0	0	0	0	0	0	0	0	0	0	0
RC_1VAR	0	0	0	29	0	0	0	10	29	0	0	0
RC_1VAR	0	0	0	0	29	0	0	0	10	29	0	0
RC_2VAR	0	0	0	0	0	29	0	0	0	10	29	0
RC_2VAR	0	0	0	0	0	0	0	0	0	0	0	10
RC_3VAR	0	0	0	0	0	0	0	0	0	0	0	0
Total	115	399	400	148	177	755	789	876	939	1371	1720	1325
Change in CWIP		87	63	432	349	394						
Cash Requirements		486	463	580	526	361						

79

Table 7-2a
Balance Sheet

Electric Power Software Inc IRP-Manager

Company BULGARIA
IRP-Manager

BALANCE SHEET
(Millions of Current Dollars)

	ASSETS	1994	1995	1996	1997	1998	1999	2000
1	Gross Plant in Service	4700 00	4814 56	5213 80	5614 04	5762 18	5939 38	6694 37
2	+CWIP	730 35	789 15	876 06	939 03	1370 74	1719 57	1325 36
3	TOTAL UTILITY PLANT	5430 35	5603 71	6089 86	6553 07	7132 92	7658 95	8019 73
4	-Accumulated Depreciation and Amortization	1100 00	1337 72	1585 75	1857 49	2142 88	2437 63	2761 34
5	NET UTILITY PLANT	4330 35	4265 99	4504 11	4695 58	4990 04	5221 32	5258 40
6	+Capitalized Leases	0 00	0 00	0 00	0 00	0 00	0 00	0 00
7	+Investment in Non-Regulated Subsidiaries	4 04	4 04	4 04	4 04	4 04	4 04	4 04
8	+Deferred Revenues	0 00	0 00	0 00	0 00	0 00	0 00	0 00
9	+Net Deferred Debits	0 00	0 00	0 00	0 00	0 00	0 00	0 00
10	+Net Deferred Fuel	0 00	0 00	0 00	0 00	0 00	0 00	0 00
11	+Short Term Investments	0 00	228 06	251 33	198 40	90 52	63 01	221 95
12	+Deferred Income Taxes	0 00	0 00	0 00	0 00	0 00	0 00	0 00
13	+Other Assets	0 00	0 00	0 00	0 00	0 00	0 00	0 00
14	+Current Assets	317 52	364 53	460 86	496 06	476 03	436 06	412 66
15	TOTAL ASSETS	4651 91	4862 61	5220 34	5394 07	5560 61	5724 43	5897 04
	LIABILITIES							
16	Common Stock	4400 00	4400 00	4400 00	4400 00	4400 00	4400 00	4400 00
17	+Retained Earnings	0 00	99 25	293 88	499 60	698 96	890 05	1090 22
18	TOTAL COMMON EQUITY	4400 00	4499 25	4693 88	4899 60	5098 96	5290 05	5490 22
19	PREFERRED STOCK	0 00	0 00	0 00	0 00	0 00	0 00	0 00
20	LONG TERM DEBT	28 01	93 15	205 40	186 39	170 89	155 02	138 75
21	TOTAL CAPITAL	4428 01	4592 40	4899 28	5085 99	5269 84	5445 07	5628 97
22	+Other Long Term Liabilities	41 45	41 45	41 45	41 45	41 45	41 45	41 45
23	+Short Term Debt	67 25	1 00	1 00	1 00	1 00	1 00	1 00
24	+Deferred Income Taxes	0 00	0 00	0 00	0 00	0 00	0 00	0 00
25	+Deferred Investment Tax Credit	0 00	0 00	0 00	0 00	0 00	0 00	0 00
26	+Other Deferred Items	2 50	2 50	2 50	2 50	2 50	2 50	2 50
27	+Liabilities not Elsewhere Classified	113 10	225 66	276 51	263 53	246 22	234 80	223 52
28	TOTAL LIABILITIES	4652 31	4863 01	5220 74	5394 47	5561 02	5724 83	5897 44
	RATE BASE ITEMS							
29	Rate Base Plant-In Service		1738 92	3552 45	3692 30	3687 92	3560 52	3717 39
30	+Rate Base Deferred Debits		0 00	0 00	0 00	0 00	0 00	0 00
31	+Rate Base CWIP		0 00	0 00	0 00	0 00	0 00	0 00
32	+Other Rate Base Items		292 12	335 37	423 99	456 37	437 94	401 18
33	-Rate Base EXCLUSIONS		0 00	0 00	0 00	0 00	0 00	0 00
34	-Deferred Taxes EXCLUDED from Rate Base		0 00	0 00	0 00	0 00	0 00	0 00
35	-ITCs EXCLUDED from Rate Base		0 00	0 00	0 00	0 00	0 00	0 00
36	Rate Base		2031 04	3887 81	4116 29	4144 30	3998 47	4118 57

80

Table 7-2b
Income Statement

Electric Power Software Inc — IRP-Manager

Company BULGARIA
IRP-Manager

INCOME STATEMENT
(Millions of Current Dollars)

		1995	1996	1997	1998	1999	2000
1	Base Revenues	1258 18	1491 27	1582 21	1617 55	1659 44	1730 39
2	+Adjustment Clause Revenues	0 00	0 00	0 00	0 00	0 00	0 00
3	+Other Revenues	58 56	58 91	59 26	59 62	59 98	60 34
4	TOTAL OPERATING REVENUES	1316 73	1550 18	1641 47	1677 17	1719 42	1790 73
5	-Fuel Expenses	391 45	405 87	419 48	446 56	474 02	499 09
6	-Purchased Power Expenses	32 37	38 34	67 38	96 46	95 06	47 91
7	-Operation/Maintenance Expenses	433 83	442 85	440 21	411 78	430 12	470 68
8	- Network Expense	12 00	12 00	12 00	12 00	12 00	12 00
9	-Deferred Fuel Expense	0 00	0 00	0 00	0 00	0 00	0 00
10	-Depreciation Expense	237 72	248 03	271 74	285 39	294 75	323 70
11	-Amortization Expense	0 00	0 00	0 00	0 00	0 00	0 00
12	TOTAL OPERATING EXPENSES	1107 37	1147 09	1210 81	1252 19	1305 94	1353 39
13	-Operating Revenue Tax	0 00	0 00	0 00	0 00	0 00	0 00
14	-Property Taxes	0 00	0 00	0 00	0 00	0 00	0 00
15	-Other Taxes	0 21	0 37	0 40	0 48	0 46	0 50
16	-Income Taxes	107 60	208 34	224 44	217 29	213 09	230 91
17	-Income Tax Deferrals (Dr)	0 00	0 00	0 00	0 00	0 00	0 00
18	-Income Tax Deferrals (Cr)	0 00	0 00	0 00	0 00	0 00	0 00
19	-Investment Tax Credit (ITC)	0 00	0 00	0 00	0 00	0 00	0 00
20	TOTAL OPERATING EXPENSES AND TAXES	1215 18	1355 79	1435 66	1469 95	1519 49	1584 80
21	OPERATING INCOME	101 55	194 39	205 81	207 21	199 92	205 93
22	+Deferred Revenues	0 00	0 00	0 00	0 00	0 00	0 00
23	+Other Taxable Income	0 00	0 00	0 00	0 00	0 00	0 00
24	+Interest Income	3 42	7 19	6 75	4 33	2 30	4 27
25	+Other Net of Tax Items	0 00	0 00	0 00	0 00	0 00	0 00
26	-Other Expenses	0 00	0 00	0 00	0 00	0 00	0 00
27	-Income Taxes	0 00	0 00	0 00	0 00	0 00	0 00
28	-Deferred Taxes	0 00	0 00	0 00	0 00	0 00	0 00
29	INCOME BEFORE INTEREST EXPENSES	104 97	201 58	212 56	211 55	202 23	210 20
30	-Interest on Long Term Debt	4 36	6 91	6 80	12 15	11 09	10 00
31	-Interest on Short Term Debt	1 37	0 04	0 04	0 04	0 04	0 04
32	+AFUDC Borrowed	0 00	0 00	0 00	0 00	0 00	0 00
33	INCOME AFTER INTEREST EXPENSES	99 25	194 63	205 72	199 36	191 10	200 16
34	+Subsidiary Income	0 00	0 00	0 00	0 00	0 00	0 00
35	-Extraordinary Expenses	0 00	0 00	0 00	0 00	0 00	0 00
36	NET INCOME	99 25	194 63	205 72	199 36	191 10	200 16
37	-Preferred Dividends	0 00	0 00	0 00	0 00	0 00	0 00
38	Earnings Available to Common	99 25	194 63	205 72	199 36	191 10	200 16
39	-Common Dividends	0 00	0 00	0 00	0 00	0 00	0 00
40	RETAINED EARNINGS	99 25	194 63	205 72	199 36	191 10	200 16
41	Return on Rate Base	5 00	5 00	5 00	5 00	5 00	5 00
42	Return on Average Equity	2 23	4 23	4 29	3 99	3 68	3 71
43	Book Value per Share of Common Stock	0 04	0 05	0 05	0 05	0 05	0 05
44	Common Stock--Shares Outstanding (year end)						
45	Dividends Per Share	0 00	0 00	0 00	0 00	0 00	0 00
46	Dividend Payout Ratio (%)	0 00	0 00	0 00	0 00	0 00	0 00
47	Market to Book Ratio	0 00	0 00	0 00	0 00	0 00	0 00
48	Common Stock Earnings Per Share	0 00	0 00	0 00	0 00	0 00	0 00

41

Table 7-2c
Funds-Flow Profile

Electric Power Software Inc

Company BULGARIA
IRP-Manager

IRP-Manager

FUNDS-FLOW PROFILE
(Millions of Current Dollars)

		1995	1996	1997	1998	1999	2000
	FUNDS PROVIDED BY OPERATIONS BEFORE CAPITAL SERVICE						
1	Income Before Capital Service	104 97	201 58	212 56	211 55	202 23	210 20
2	Depreciation and Amortization	237 72	248 03	271 74	285 39	294 75	323 70
3	ITCs and Deferred Income Tax	0 00	0 00	0 00	0 00	0 00	0 00
4	AFUDC Other Net of Tax & Def Rev	0 00	0 00	0 00	0 00	0 00	0 00
5	Other Non-Cash Expenses	0 00	0 00	0 00	0 00	0 00	0 00
6	TOTAL	342 70	449 61	484 30	496 94	496 98	533 91
	CAPITAL SERVICE PAYMENTS						
7	Interest	-5 72	-6 95	-6 84	-12 19	-11 13	-10 04
8	Preferred Dividends	0 00	0 00	0 00	0 00	0 00	0 00
9	TOTAL	-5 72	-6 95	-6 84	-12 19	-11 13	-10 04
10	FUNDS FROM OPERATIONS	336 97	442 65	477 47	484 75	485 85	523 87
	OTHER CASH SOURCES						
11	Sale of Assets	0 00	0 00	0 00	0 00	0 00	0 00
	NET CAPITAL REQUIREMENTS						
12	Plant Subsidiary Investments	-173 36	-486 15	-463 21	-579 85	-526 03	-360 78
13	Short Term Investments	-228 06	-23 28	52 93	107 88	27 51	-158 95
14	Lease Payments	0 00	0 00	0 00	0 00	0 00	0 00
15	Investment in Working Capital	65 55	-45 47	-48 18	2 72	28 55	12 12
16	Debt and Preferred Stock Retirements	-12 26	-6 47	-112 81	-15 50	-15 87	-16 27
17	Deferred Fuel	0 00	0 00	0 00	0 00	0 00	0 00
18	TOTAL	-348 13	-561 37	-571 27	-484 75	-485 85	-523 87
19	EXTERNAL FINANCING REQUIRED	-11 16	-118 72	-93 80	0 00	0 00	0 00
	EXTERNAL SOURCES						
20	Common Stock Issued	0 00	0 00	0 00	0 00	0 00	0 00
21	Preferred Stock Issued	0 00	0 00	0 00	0 00	0 00	0 00
22	Long Term Debt Issued	77 41	118 72	93 80	0 00	0 00	0 00
23	Short Term Debt Issued	-66 25	0 00	0 00	0 00	0 00	0 00
24	Other Long Term Liabilities	0 00	0 00	0 00	0 00	0 00	0 00
25	EXTERNAL FINANCING PERFORMED	11 15	118 72	93 80	0 00	0 00	0 00

82

Section 8
Tariff Design

The objective of this section is to illustrate fundamental aspects of tariff design for the Bulgarian power sector This tariff design reflects the LRMC by voltage level estimated in Section 6, the balancing of LRMC and financial requirements, and the protection of low income groups

8 1 LRMC-BASED REVENUE ALLOCATION

8 1 1 Overview of Revenue Allocation

Tariffs based on strict LRMC may produce more or less revenues than required for financial reasons It has been suggested by some economists that this need not cause a problem for a government-owned utility since surpluses and deficits can be adjusted by taxation and subsidization, respectively From a strict economic point of view this solution is considered the most efficient However, it has serious shortcomings

- The scarcity of public funds makes strict LRMC-based revenues unacceptable if they produce less than financial requirements
- If strict LRMC-based revenues produce surpluses over financial requirements, consumer resistance generally prevents their use even if the surpluses are recycled back to consumers by way of public coffers
- The goals of increased efficiency and competition in the power sector go hand-in-hand with financial autonomy, which requires that financial requirements be met

8 1 2 Comparison of Current Tariffs with LRMC and Financial Requirements

Figure 8-1 shows a comparison of current tariffs, financial requirements and LRMC for HV, MV and LV consumers The comparisons are based on the Plan A scenario developed in previous sections of this report We make the following conclusions from the comparisons in Figure 8-1

- Current tariffs are set too low to fully recover NEK's financial requirements This situation inhibits the utility from making essential operating and capital expenditures This indicates the need for Bulgaria to transition to cost-based electric tariffs
- Comparing LRMC with financial requirements, for Bulgaria strict LRMC-based tariffs would produce revenues roughly equal to financial requirements Unaccounted nuclear costs would push financial requirement

above LRMC Under these circumstances there is little room for gradual transitioning to LRMC-based tariffs

- Class-by-class comparison of financial requirements with LRMC shows that LRMC and cost-of-service are fairly close for all classes As mentioned above, unaccounted nuclear costs would push financial requirement above LRMC

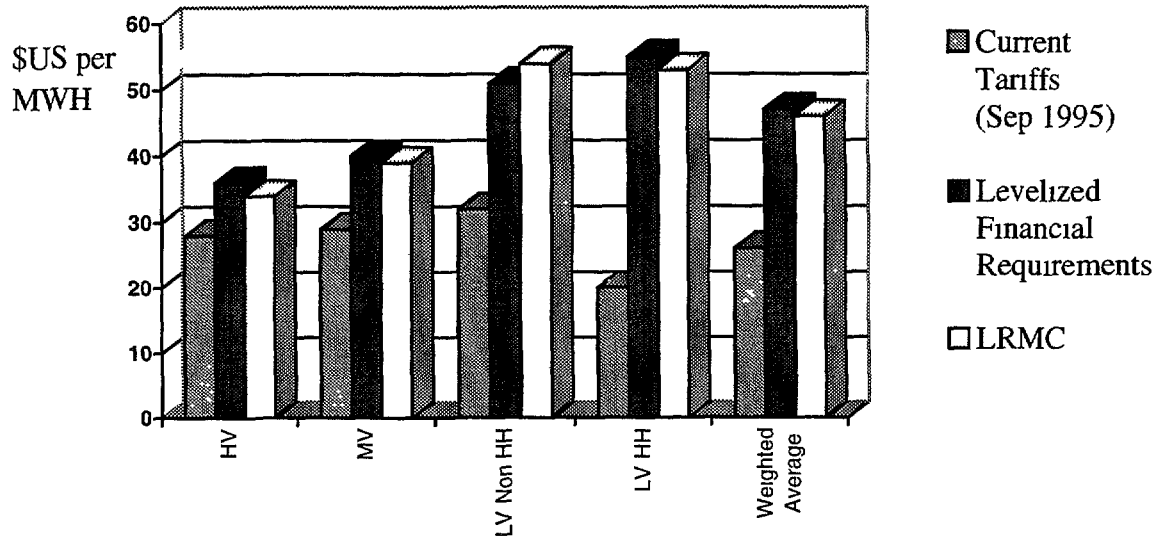


Figure 8-1 Comparison of Current Electricity Tariffs, Financial Requirements, and LRMC

8 1 3 Revenue Allocation to Customer Class

Based on the forecasted relationships between LRMC and financial requirements over the period 1995-2000, we conclude that tariffs by customer class should be set such that revenues for each class equal the cost of service for that class Any cross subsidies among customer classes will raise others above LRMC Any delay raising tariffs up to economically viable levels will subsidize today's consumption at the cost of future consumers

8 1 4 Revenue Allocation to Customer Classes Illustration

For purposes of illustration, we describe a revenue allocation alternative known as *equal percentage of marginal cost* (EPMC), which is used to allocate revenue requirements to

84

each customer class based on its relative LRMC in comparison to the other classes This method retains the relative structure of LRMC for tariffs to various categories In our illustration, the objective is to achieve the overall financial requirements for expansion Plan A, as described in Section 7

Table 8-1 summarizes the EPMC revenue allocation results, and compares these results with strict LRMC and with September 1995 tariffs The allocation produces average tariffs meeting financial requirements of $US 47 per MWH of sales, compared to $US 46 per MWH LRMC It can be seen from the table that with LRMC so close to cost of service, EPMC is a relatively minor tariff design adjustment

Table 8-1
Alternative Revenue Allocation to Customer Classes
Level 1995 Dollars over the Period 1995-2000

Customer Class	Cost of Service $MUS	LRMC Based Revenue $MUS	EPMC Allocation $MUS	Average EPMC Tariff $/MWH	LRMC $/MWH	Current Tariff (Sep 95) $/MWH
HV	214	202	206	35	34	28
MV	352	339	346	39	39	29
LV HH	693	669	683	54	53	20
LV NHH	277	295	301	55	54	32
Total	1536	1506	1536	47	46	26

8 1 5 Capacity and Energy Components of Tariffs

In much of the utility world, revenue requirements are allocated to energy costs in $/MWH, capacity costs in $/kW-month, and customer costs in $/month Including all three cost components in tariffs allows a greater degree of *unbundling* of the three services provided by a utility, and thereby provides more accurate pricing signals For the illustrative purposes of this report, we ignore the relatively small customer cost component

The capacity component of tariffs can be assessed as either a demand charge on the basis of the consumer's contribution to the system's peak load, or as an energy charge allocated among the billing periods The latter method is typically applied for consumers without demand meters, which is the case for all customer classes in Bulgaria, and in the situation

85

of a utility with marginal capacity cost not concentrated in a particular billing period, which is also the case for Bulgaria IRP Manager modeling of the Bulgarian power sector indicates that increased consumption in any billing period increases system capacity requirements Therefore for the illustrative purposes of this study we have allocated NEK's anticipated capacity-related financial requirements to time periods as a $/MWH component of tariffs

We recommend that the split between capacity- and energy-related components of tariffs should be proportional to LRMC's for capacity and energy As was pointed out in Section 7, in general fixed costs are a higher percentage of total cost for cost-of-service than for LRMC because existing assets are accounted as sunk costs In this regard, the relative allocations of costs to variable and fixed components in the cost-of-service study are irrelevant for designing the split between fixed and variable components of economically efficient tariffs

8 1 6 LRMC-based Seasonal Allocation

We recommend that seasonal tariffs should be proportional to seasonal LRMC, consistent with the economic efficiency rationale for LRMC-based tariffs The seasonal allocations of capacity- and energy- related components of tariffs are based on the following logic

- The capacity-related component of tariffs is allocated to time period based on proportionate system unserved energy during that time period Unserved energy measures system reliability, and therefore it is reasonable to allocate marginal capacity cost across hours or time periods according to the relative system unserved energy in each hour or time period In general, unserved energy is concentrated in peak load periods, and therefore the capacity-related component is highest for sales during the peak period
- The variable energy-related component of tariffs is allocated to time periods proportionate to seasonal marginal energy cost Marginal energy costs are a function of system operations and can vary significantly by time period

8 2 SUMMARY OF TARIFF RESULTS

Bulgaria has a good basic electric tariff structure The current tariff structure in Bulgaria is appealing because it is simple, and yet it enables essential cost-based differentiation among customers Current electric tariffs differentiate among customers based on the following factors

- Households are differentiated from all other customers, which are grouped together as "industrial and public sector" Household tariffs are

86

differentiated only for 2 zones, peak and off-peak Currently the winter and summer tariffs are the same

- Peak, daytime and nighttime time-of-use is recognized
- Summer and winter seasons are differentiated for non-household tariffs
- HV, MV and LV service levels are differentiated
- Tariffs are provided for non-household customers having 1-, 2- and 3-zone meters

Using the existing Bulgarian tariff structure, we have developed strict LRMC-based tariffs for the Plan A scenario The resulting LRMC-based tariffs were compared with current Bulgarian tariffs in Section 5 of this report Two general conclusions are repeated below

- In general current tariffs are low relative to LRMC-based tariffs This is especially true in the nighttime, and this large differential between day and night is not justifiable based on cost Peak pricing is currently close to cost-based
- Low voltage customers' tariffs are particularly low relative to LRMC-based tariffs, while higher voltage customers' tariffs are closer to cost-based

8 3 BLOCK PRICING STRUCTURE

An *block tariff structure* provides a means of maintaining marginal cost pricing for marginal consumption even if the consumer's overall bill varies from strict LRMC for electric service A two block pricing structure attempts to price consumption in the second (marginal) block at LRMC The first block is priced such that total revenues for the customer class meet the utility's revenue objectives for that class The attractiveness of this structure is that it provides the proper economic signals for marginal electricity usage, provides a flexible mechanism for adjusting revenue to financial requirements, and mimics the underlying cost structure of the power system

8 4 PROTECTION OF THE POOR FROM HIGH ELECTRIC PRICES

The most obvious application of the inverted block tariff structure is pricing for poor households The block tariff could be designed to lower household electricity bills for some consumers, while bringing revenues from the category as a whole closer to the cost of service and while giving more realistic pricing signals for marginal usage

Lifeline tariffs provide an extreme low-cost block for subsistence household use of electricity A difficulty with this structure is that it does not protect the poor household

87

with high subsistence use of electricity for space heating Another form is a special low price electric tariff that is offered to poor consumers who qualify on the basis of income or some other measure of wealth

Other systems that can be used include vouchers, use of the existing social assistance systems, cash payments on behalf of at-risk groups and cross subsidization by other electric consumers A key consideration for the appropriate mechanism is distortion of consumer choices of fuel for their energy requirements

8 5 OTHER ISSUES

- **Transitional pricing** The comparison of current tariffs with cost-based tariffs shown in Figures 8-1 shows that there is a need to transition to higher tariffs Ideally, tariffs would be increased immediately to cost-based levels, and the transition would be managed through subsidies provided direct to consumers from the government At this stage the tariff Working Group has not developed a consensus recommended transition pricing plan
- **Energy Substitution Considerations** It has been established that in some instances the low price of electricity drives electricity consumption above economically efficient levels For example, household use of electric space heating would decrease in response to LRMC-base electricity tariffs because some consumers would switch to other fuels such as oil The impacts of constrained prices for alternative fuels must be considered in electricity tariff design
- **Revenue Adjustments for Regional Distribution Units** Cost of service varies by region due to area specific power system constraints This introduces the possibility of tariff differentiation by region
- **Transfer pricing** NEK and each of the regional distribution units are vertically integrated so that there are no direct bulk power sales With restructuring of the Bulgarian power sector, generation, transmission and distribution may each become more autonomous with arms-length agreements among entities One means of achieving this structure is through use of a transfer pricing mechanism Transfer prices would reflect LRMC The transfer pricing mechanism provides a transparent framework for pricing on the basis of full economic cost, and also for performance-based incentives to operating entities
- **Pricing for Non-utility Generation** The power industry should encourage competition and reduce the need for price regulation wherever possible A step in this direction would be to reflect system LRMC in the buyback tariff for generation from industrial and combined heat and power producers The next step would be to introduce direct competition In most places where the

88

electric utility acts as a central purchasing agency, prices to independent power producers are based on the successful bid among competing producers in a solicitation process Key considerations for pricing for individual independent power providers include location, service voltage, reliability of the generating resource, delivery guarantee, term of contract etc

- **Inflation Adjustment of Tariffs** The Study has been conducted in constant 1995 $US However, tariffs will be issued in leva and will be subject to the high inflation currently existing in Bulgaria Prices will have to be adjusted on a regular basis and should include an allowance to reflect anticipated inflation Bulgaria is currently introducing an *indexation* approach that will include the effects of inflation as well as other variables such as fuel prices

  We recommend the introduction of *current purchasing power* (CPP) accounting in order that adjustments for changes in the general price level are reflected in the value of assets and depreciation allowances

89

Bulgaria Tariff Implementation Project

Interim Report: District Heating Tariffs

February 1996

Prepared under Contract to

U.S. Agency for International Development

Regulatory Reform and Energy Sector Restructuring in Central and Eastern Europe and the Baltics

Contract No EHR-0030-C-00-5016-00

LECHTEL
International Consulting Group

90

Contents

District Heating Tariffs

1 Introduction

1 1 Background and Objectives 1-1

1 2 Guidelines for Tariff Design Development 1-1

1 3 Guide to the Tariff Study Report 1-2

2 District Heating Supply and Demand

2 1 Overall Supply/Demand Structure 2-1

2 2 The Sofia District Heating Company 2-2

2 3 References 2-6

3 Review of Existing District Heating Tariff Structure, Pricing and Regulation

3 1 Regulation of District Heating 3-1

3 2 District Heating Tariffs 3-1

3 3 Metering and Control 3-3

3 4 Impact of Combined Heat and Power Operation 3-3

4 Long-Run Marginal Cost Estimate

4 1 Overall Approach and Assumptions 4-1

4 2 Generation LRMC 4-1

4 3 Transmission 4-3

4 4 Distribution 4-4

4 5 Pricing 4-6

4 6 Comparison With Existing Tariffs 4-6

4 7 References 4-7

5 Implementation Issues

5 1 Financial Impact 5-1

5 2 Competition With Other Heat Sources 5-2

5 3 Impact on Economically Disadvantaged Groups 5-4

5 4 Proposed Price Regulation 5-5

5 4 1 LRMC Pricing Formula 5-5

5 4 2 Rate-of-Return Alternative 5-6

5 5 Transition Pricing 5-7

5 6 References 5-8

Illustrations

Figure		Page
2-1	Heating Mode by Floor Area (1985)	2-1
2-2	Share of Sales by Customer Category- 1994	2-3
3-1	Evolution of Household District Heating Prices	3-2
3-2	Revenue by Customer Category- 1994	3-2
5-1	Summary of Revenue Requirements Analysis for Hot Water Supply	5-2
5-2	Relative Heating Costs from Various Sources	5-3
5-3	Contribution of Energy to Household Budget as a Function of Income- 1993	5-4

Tables

Table		Page
2-1	Characteristics of Sofia District Heating Plants	2-2
2-2	Sofia District Heating Production and Sales Statistics- 1994	2-2
2-3	Projected Hot Water Supply and Demand- Sofia System (Mwt)	2-4
2-4	Projected Hot Water Energy Demand by Customer Category (Tcal)	2-4
2-5	Projected Steam Supply and Demand- Sofia System (Mwt)	2-5
2-6	Projected Steam Demand by Customer Category (Tcal)	2-5
3-1	Buyback Rates for Electricity Generated by District Heating Companies	3-3
4-1	Natural Gas Price Forecast for District Heating	4-1
4-2	Characteristics of Incremental Plants	4-2
4-3	Generation LRMC Calculation	4-2
4-4	SRMC as a Function of Projected Natural Gas Price	4-3
4-5	Capacity-Related Costs as a Function of Need for New Capacity	4-3
4-6	Transmission LRMC Calculation	4-4
4-7	Distribution LRMC Calculation	4-5
4-8	LRMC Pricing- Hot Water	4-6
4-9	LRMC Pricing- Steam	4-6
4-10	LRMC-Based Tariff	4-7
5-1	Hypothetical Impact of LRMC Tariff on 1994 Income Statement	5-1
5-2	Effect of Transition Pricing on Finances	5-8

93

Section 1
Introduction

1 1 BACKGROUND AND OBJECTIVES

This is the Volume 2 of the Interim Report of Bulgaria Energy Tariff Implementation Project It addresses district heating in Bulgaria Volume 1 of the Interim Report addresses electricity This work has been performed under funding from the US Agency for International Development (USAID) under its project for Regulatory Reform and Energy Sector Restructuring in Central and Eastern Europe and the Baltics Bechtel is prime contractor for this project and Arthur Andersen is a subcontractor

The primary objectives of the district heating analysis presented in this report were to

- To investigate the existing cost and pricing of district heating
- To estimate the level and structure of tariffs based on long-run marginal cost (LRMC)
- To estimate financial requirements of the Sofia District Heating Company
- To make recommendations on tariffs taking into consideration LRMC, financial requirements of Sofia District Heating, impact on energy-intensive industries, and protection of economically disadvantaged groups

The analysis was performed with the cooperation of the Committee of Energy (COE), the Commission of Pricing (COP), the Ministry of Finance, and the various district heating companies, including Sofia District Heating

The tasks of this analysis are

- Task 1- Evaluate district heating demand
- Task 2- Evaluate the existing Sofia District Heating supply system
- Task 3- Analyze economic cost structure of district heating supply
- Task 4- Evaluate existing district heating tariffs
- Task 5- Formulate pricing strategy based on LRMC
- Task 6- Conduct financial analysis of Sofia District Heating Company
- Task 7 Adjust LRMC tariffs to reflect financial analysis and protection of the poor
- Task 8- Develop district heating tariff structure and implementation plan

1 2 GUIDELINES FOR TARIFF DESIGN DEVELOPMENT

The objectives of tariff design are identified below

- Objective 1 – Provide clear economic signals to customers on the long-run costs of district heating supply

- Objective 2 – Provide adequate funds to operate the Sofia District Heating and provide a reasonable return on investment
- Objective 3 – Address social equity and economic development issues such as protection of economically disadvantaged groups and consideration of economic competitiveness

The first objective generally calls for LRMC-based pricing as developed in Section 4 However, metering and control limitations in most Central European district heating systems constrain both the ability of Sofia District Heating to provide clear signals to individual customers and their ability to respond Objective 2 ensures that the power system can meet its financial obligations The current financial condition of Sofia District Heating and most other Bulgarian district heating companies providing residential district heating gives high priority to this objective Objective 3 requires that some method be devised to ensure heat supply to poor families

1 3 GUIDE TO THE TARIFF STUDY REPORT

The Study Report is organized so as to answer the following questions

What are the basic demand and resource characteristics of district heating in Bulgaria (Tasks 1 and 2)	Section 2
What are the reported costs of district heating compared to the existing prices? (Tasks 3)	Section 3
What is the LRMC of the various components of district heating supply? (Task 5)	Section 4
How must tariffs based on LRMC be modified to meet other tariff-setting goals? (Tasks 7 and 8)	Section 5

A financial analysis of Sofia District Heating Company is currently in progress and will be contained in the Final Report It will contain an analysis of the financial requirements of Sofia District Heating through the year 2000 (Task 6) The preliminary results of the financial analysis are used in Section 5 in a comparison of the revenues projected on the basis of strict LRMC pricing and the financial requirements of the company

95

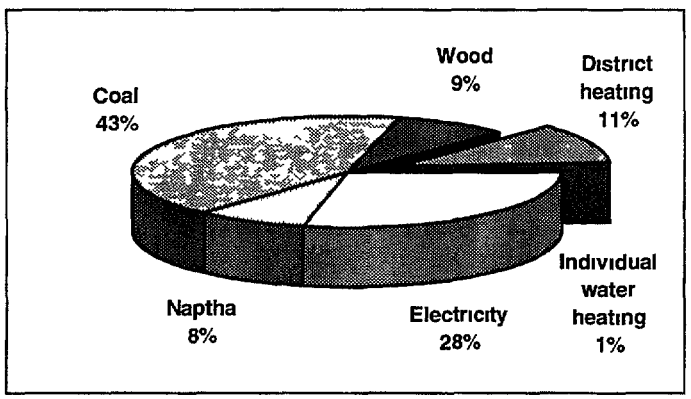
Section 2
District Heating Supply and Demand

The objective of this section is to review overall district heating supply and demand situation in Bulgaria focusing on the Sofia region

2 1 OVERALL SUPPLY/DEMAND STRUCTURE

Bulgaria has well-developed district heating systems in most major cities and towns These systems provide steam and hot water to industry and hot water to households for heating and general use Some sources estimate that 58% of the 1990 heat consumption of industry was provided by centralized district heating systems These systems provided 22% of the household and public sector's requirements (Reference 1) The share of the population using district heating was 16% in 1990 and earlier statistics from 1985 indicate the share of floor space heated by district heating only 11% (Reference 2) However, district heating customers use more heat per capita and per square meter of floor space than average The city of Sofia, served by the Sofia District Heating Company accounts for nearly half of the district heat production of the country

Figure 2-1
Heating Mode by Floor Area (1985)



Coal and electric heating are the dominant types of heating in Bulgaria as shown in Figure 2-1 (Reference 2) Electricity is the fastest growing heating mode Pricing of electricity and district heating is such that they result in a roughly equivalent cost to the consumer However, district heating prices cover less than half of costs and direct subsidies are required from the government As discussed in Volume 1, the price of electricity to household customers does not cover true costs either, cross-subsidies with other electricity users has prevented the need for direct subsidies of electricity Natural gas is not currently available for residential heating, but extension of the gas system to household consumers is under consideration for a number of communities Pricing of gas to residential users is undetermined at this time

96

District heat is supplied from a variety of combined heat and power (CHP) and heat-only plants with a combined heating capacity of about 8 GWt The principle owners/operators of district heating are

- the National Electric Company (NEK)- produces heat at the Kozluduy Nuclear Plant and the Maritsa East I Plant
- several district heating companies- operate twelve major CHP plants which are primarily heat producers and eight major heat-only plants
- industry- supply steam for their own use with some sold to near-by industries, meeting most of industry steam demand

2 2 THE SOFIA DISTRICT HEATING COMPANY

The Sofia District Heating Company is municipally owned COE approves budgets for operation and maintenance and the Committee for Prices sets prices for district heat from these companies The Sofia system is served by two plants having a combination of CHP and heat-only equipment and two heat-only boiler plants The characteristics of these facilities is shown in Table 2-1

Table 2-1
Characteristics of Sofia District Heating Plants

Plant Name	Capacity (MW)		CHP Capacity		Age		Fuel
	Electric	*Heat*	*(MWt)*	*(%)*	*Electric*	*Heat*	
Sofia	125	1162	465	40 0%	37	15-20	fuel oil
Sofia East	186	1453	523	36 0%	31	15-20	gas
Zemliane	-	622	-	-	29	15-20	fuel oil
Liulin	-	622	-	-	4	8-20	gas

Approximately 200 MWt of the heat capacity is for steam with the remainder for hot water

The transmission system is made up of 960 km of hot water lines, 60 km of steam lines, 5,656 direct and 7,575 indirect substations The indirect substations are connected to the primary loop of the district heating system and customers are served by a secondary loop by means of a heat exchanger Less than half of the household customers are served by indirect substations The heat exchanger and secondary loop are consumer owned The remainder of consumers are served by direct substations in which hot water from the primary loop flows directly into the building space heating elements and domestic hot water is taken directly from the primary loop supply Industrial trunk pipelines are owned by industrial consumers The 1994 sales statistics are summarized in Table 2-2

91

Table 2-2
Sofia District Heating Production and Sales Statistics- 1994

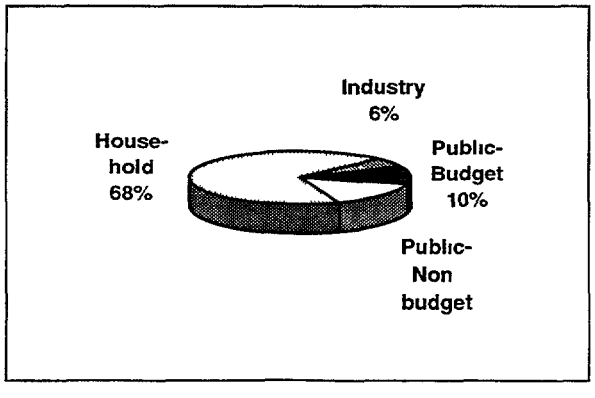
	Gcal
Heat Generation	6,709,187
Transmission Losses	1,277 467
Sales	5,431 720
Steam	323 153
Hot water	5,108,567

There has been virtually no metering at substations so that transmission losses are only calculated The calculated losses of 19% are approximately double what should be expected There is no metering of individual customers so that there is no measure of distribution losses Sofia District Heating supplies heat to substations, owning and operating generation, transmission, and substation facilities Ownership and operation of distribution facilities is unclear at this time

The steam sales shown in Table 2-2 represent sales to industry Hot water sales were made to Households and two categories of Public Sector customers- Budget and Non-budget The share of each customer category is shown in Figure 2-2

In 1993-95, a feasibility study was conducted for a number of options for the Sofia system (Reference 3) Existing equipment was inspected, projections of future demand made, investment options were evaluated, and investment plans developed Equipment condition of generating units was found to be poor, primarily as a result of inadequate funding for maintenance and operation outside equipment specifications The transmission and distribution system was found to be unreliable due to the low quality of the piping material and inappropriately selected insulation material, experience high leakage from "gasket type" compensators and at substations, and having low thermal efficiency

Figure 2-2
Share of Sales by Customer Category- 1994



98

The conclusions of that study was to rehabilitate existing generating units for safety, environmental impact, and immediate reliability, while deferring investments in generation for increasing efficiency and replacement Lack of capital, current and projected overcapacity were cited as major reasons for this conclusion The projected supply/demand balance used in Reference 3 is shown in Table 2-3

Expected growth in demand from Household and Public Sector customers is projected to be more than offset by demand reductions resulting from conservation and reduction in transmission losses The result is that there is no immediate need for capacity additions, although investment will be required for rehabilitation of generation and the transmission system and environmental improvements

The energy planning data provided by COE and NEK indicate the installation of CHP capacity at Sofia and Sofia East early in the next century with a electric generation capacity of 240 MW each This size is larger than any of the options considered in the Reference 3 feasibility study This plants may well be needed in the context of the overall energy system In particular, the need to replace decommissioned capacity at the Kozluduy Nuclear Plant will require additional electricity capacity as discussed in Volume 1 However, the need for these units is not driven by the requirements of the Sofia district heating system

Table 2-3
Projected Hot Water Supply and Demand- Sofia System (MWt)

	1994	1995	1996	1997	1998	1999	2000
Historical peak demand	1 598	1,598	1 598	1,598	1 598	1,598	1 598
Adjustment for design ambient -15 degrees C	266	266	266	266	266	266	266
Cumulative new household customers	18	36	53	71	89	105	122
Cumulative new public sector customers	13	25	39	52	65	80	95
Effect of conservation	(9)	(24)	(45)	(76)	(118)	(174)	(232)
Transmission losses	442	446	420	391	362	331	313
Gross peak demand	2 327	2,346	2,331	2,303	2 261	2,206	2,162
Capacity	3,359	3,359	3,359	3 359	3,359	3 359	3,359

The adjustment for -15 degrees C is a reliability requirement ensuring adequate spare capacity

Table 2-4 shows the projected hot water energy demand by customer category This was developed using the Reference 3 projection for total hot water energy demand and allocating among customer categories according to 1994 statistics

99

Table 2-4
Projected Hot Water Energy Demand by Customer Category (Tcal)

	1994	1995	1996	1997	1998	1999	2000
Households	3,711	3,730	3,811	3,869	3,902	3,899	3 857
Public Sector	-	-	-	-	-	-	-
Budget	561	570	590	607	619	630	633
Non-budget	837	851	881	906	924	940	945
Industry	-	-	-	-	-	-	-
Total Sales	5,109	5,152	5 282	5,382	5,446	5,469	5 435
Network losses	1,081	1,090	1,026	957	885	809	767
Generation	6,190	6,242	6 308	6,339	6 330	6,278	6 201

The demand for steam on the Sofia system is much smaller than for hot water The projected supply/demand balance for steam on the Sofia system from Reference 3 is shown in Table 2-5 It is not clear what the reduction in public sector demand is, although it appears to represent a shifting of some heating customers from steam to hot water The reductions in steam demand represented by this shift, conservation and reduction in transmission losses more than off-sets projected increases in industrial demand Table 2-6 translates the capacity projection to steam energy demand by customer category assuming all steam sales are to industry

Table 2-5
Projected Steam Supply and Demand- Sofia System (MWt)

	1994	1995	1996	1997	1998	1999	2000
Historical peak demand	236	236	236	236	236	236	236
Adjustment for design ambient -15 degrees C	39	39	39	39	39	39	39
Cumulative new industrial customers	-	-	-	-	-	6	14
Cumulative reduction in public sector demand	(6)	(17)	(28)	(33)	(33)	(31)	(28)
Effect of conservation	(0)	(1)	(2)	(4)	(6)	(7)	(9)
Transmission losses	80	77	65	59	55	53	52
Gross peak demand	349	334	310	297	291	296	303
Capacity	500	500	500	500	500	500	500

100

Table 2-6
Projected Steam Demand by Customer Category (Tcal)

	1994	1995	1996	1997	1998	1999	2000
Households	-	-	-	-	-	-	-
Public Sector	-	-	-	-	-	-	-
Budget	-	-	-	-	-	-	-
Non-budget	-	-	-	-	-	-	-
Industry	323	309	295	286	283	292	303
Total Sales	323	309	295	286	283	292	303
Network losses	196	188	159	145	135	130	126
Generation	323	309	295	286	283	292	303

2 3 REFERENCES

1 World Bank Bulgaria Energy Strategy Study December 1991
2 Danish Energy Group Study on Identification of Guideline Projects for the Sustainable Development of the District Heating Sector of Bulgaria, February 1993
3 Gilbert/Commonwealth International, Inc , Bulgarian District Heating System Feasibility Study February 1995

10

Section 3
Review of District Heating Tariff Structure, Pricing and Regulation

The objective of this section is to present and evaluate the current pricing of district heating in Bulgaria, including the structure (i e , the pricing relationship between customer categories), the level of pricing, and the regulation of prices

3 1 REGULATION OF DISTRICT HEATING

As discussed in the previous section, the following three types of entities provide district heating the National Electric Company, industry, and district heating companies The final type of entity provides all of the non-industrial district heating Prior to 1992, the district heating companies were under the COE There are now independent legal entities The law allows for a variety of ownership possibilities including state ownership, limited liability companies and joint stock companies At present, the only municipally owned company is Sofia District Heating

COE has regulatory authority over the general strategy of the companies and approves budgets for operations and maintenance In general, the companies are unprofitable because of low prices to non-industrial customers An exception is the small Trjavna system which primarily supplies industry As a result, direct subsidies are required under the direction of COE and the actual independence of these companies is limited Direct subsidies have continued to Sofia District Heating after municipal ownership

Prices for Households and Public Sector- Budget (made up of entities funded by the government budget) are set by the Commission of Pricing (COP) under the category of "fixed" prices, the heaviest form of price regulation Electricity, residual fuel oil and gas prices are also in this category Beginning in July 1994, prices for Public Sector- Non-budget (primarily private offices) went to a less regulated price category called "supervised" prices Bread and milk are in this category Steam prices to industry are not regulated

3 2 DISTRICT HEATING TARIFFS

While district heating remains heavily subsidized, progress has been made in increasing prices over the past five years Figure 3-1 shows this increase for the Households and Public Sector- Budget, the customer categories receiving heavy price regulation Although, there was a nominal price increase in March 1995, prices for these categories have remained unchanged in real terms since April 1994

The current tariffs (September 1995) for Households and Public Sector- Budget are as follows Option 1- 610 leva / Gcal and 1 6 leva / m^3 of heating space per month, and Option 2- 810 leva / Gcal (12 1 $/Gcal at 67 leva/$) This compares with a LRMC at the for district heating at the from the substation estimated at 1880 leva/Gcal (28 1 $/Gcal) Thus current tariffs cover slightly more than 40% of cost The losses experienced by Sofia District Heating in 1994 reflect this situation

The average revenue collected in 1994 by tariff category is shown in Figure 3-2 compared with the estimate long-run marginal cost (LRMC) for that category as calculated in Section 4

Figure 3-1
Evolution of Household District Heating Prices (1995 $/Gcal)

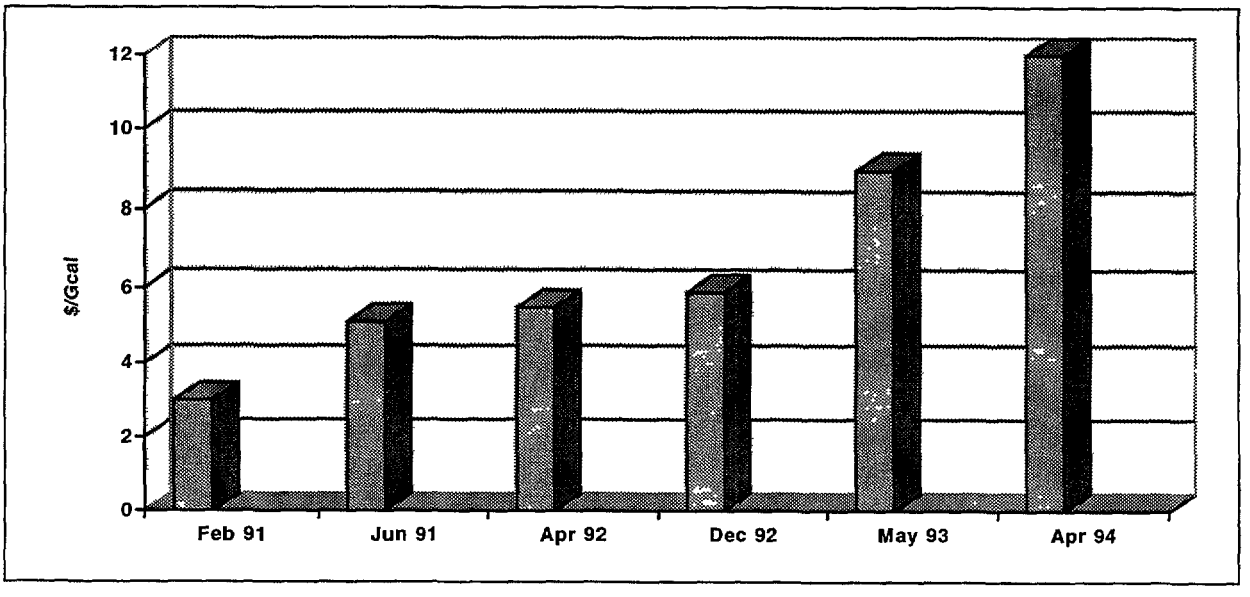
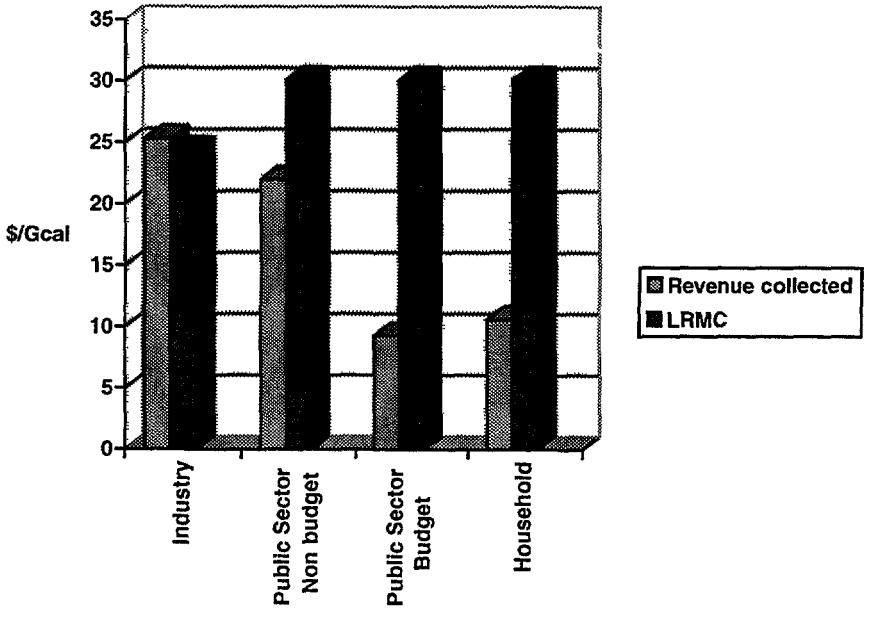


Figure 3-2
Revenue by Customer Category- 1994



103

3 3 METERING AND CONTROL

In the past, district heating has been unmetered Plant production was measured, losses were calculated and costs were allocated to customers on the basis of the floor area of their flats There was no metering or control for individual flats Temperature could only be controlled through the opening of windows Heat distribution follows the radial design with radiators connected in series throughout flats so that future metering and control of individual flats will be very complicated and costly

The situation is largely the same today However, under Phase I of a program administered by COE, 2,500 substations now have meters All substations are targeted to have meters by the end of 1997 In the interim, customers served by metered substations pay on the basis of actual delivered energy to the substation Interviews with district heating managers have indicated that this is resulting in a 10-25% reduction in price to these customers As part of this program rehabilitation of the network is being funded in order to reduce system losses

From the point of view of the district heating service, the customer is the substation A signed contract is associated with each substation for supply to surrounding buildings It is technically possible to disconnect a building, but not individual flats The district heating companies bill individual flats If individuals do not pay their bills, there is not way to disconnect them with disconnecting the entire building Current regulations do not allow this Interviews with district heating managers indicate that the rate of non-payment is approximately 26% Most managers feel that they should have the control to disconnect buildings if some of the individuals living there are delinquent However, even if they were given this authority, we feel that companies would be unlikely to exercise this prerogative given the importance of heating to survival

Under Phase II of the above-mentioned program, some flats will be equipped with thermostats and controls However, this will have no effect in the near term Any district heating tariff and billing procedure reforms will have to reflect the significant metering and control constraints which exist

3 4 IMPACT OF COMBINED HEAT AND POWER OPERATION

District heating companies can sell electricity generated by CHP plants to NEK The buyback rates currently in effect are shown in Table 3-1

Table 3-1
Buyback Rates for Electricity Generated by District Heating Companies

Time of Day	leva/kWh$_t$	\$/MWh$_t$
Peak	1 82	27 2
Day	1 01	15 1
Night	0 44	6 6

104

In the near term, the effect of this is that the district heating companies loss money for every kWh sold because the buyback rates do not cover fuel costs except in the peak period In the long term future CHP projects ,such as those envisioned at Sofia and Sofia East and part of the overall energy plan of Bulgaria, cannot be justified

To illustrate, the reported fuel requirements for producing electricity by Sofia District Heating in 1994 was 7,874 kJ/kWh At 3 13 $/GJ for gas, the fuel cost was 24 6 $/MWh Thus, the buyback rate is inadequate to cover fuel costs even in the peak period The actual reported revenue from electricity sales was 720 leva/Gcal (19 2 $/Gcal at 37 5 leva/$ in 1994) indicating that some significant sales were made outside the peak period

This situation exacerbates the already financially strained condition of the district heating companies Either the buyback rate is fair and the generation of electricity by CHP units should be discouraged or the rate is too low, reflecting less that the value of CHP electricity generation to NEK

These buyback rate are less than the Short Run Marginal Cost for the electricity system calculated in Volume 1 in all periods except the peak and significantly less than the LRMC for generation The fact that generation from the CHP units is driven by heat demand and may not fully correspond to NEK needs may justify a price less than LRMC However, new Sofia and Sofia East CHPs have been proposed as partial replacement for the Kozluduy Unit 1-4 This proposal implies a capacity value In any case, we see no justification for buyback rates less than SRMC

105

Section 4
Long-Run Marginal Cost Estimate

The objective of this section is to present a pricing strategy for district heating 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) for an indefinite period of time One component of LRMC is short-run marginal cost (SRMC) This is defined as those parts of LRMC that vary immediately with demand The remainder of LRMC varies with demand in the long term, but the variation is delayed by fixed cost components of the system

4 1 OVERALL APPROACH AND ASSUMPTIONS

The overall approach to district heating LRMC estimation was to estimate LRMC of each component of the system (i e , generation, transmission from the generating plants to substations, and distribution of heat from substations to individual customers) The concept of "opportunity cost of capital" was used in the calculations This is defined as the value of an incremental amount of capital Economies with more severe capital constraints have higher opportunity costs of capital A value of 10% was used in the calculations

Natural gas firing was assumed with the 1% real price escalation The result fuel price forecast is shown in Table 4-1

Table 4-1
Natural Gas Price Forecast for District Heating

	1995	1996	1997	1998	1999	2000
$/Gcal	13 24	13 37	13 50	13 64	13 77	13 91
$/GJ	3 16	3 19	3 23	3 26	3 29	3 32

4 2 GENERATION LRMC

A theoretically ideal way of estimating generation LRMC is to develop a least-cost investment plans for a reference forecast of demand and an incremental increase in demand, estimate fixed and variable costs for both, and estimate LRMC based on the differential fixed and variable costs between the two plans This approach is based on an assumption of current economically efficient operation Price subsidies and investment, maintenance and operating cost constraints have distorted the operation of district heating in Bulgaria and limit the practical application of this approach

An alternative is termed the Incremental Plant Approach 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) For purposes of this estimate only fuel costs were assumed to contribute to SRMC Some part of non-fuel operating and maintenance costs is often included in this value as well, however for

106

purposes of the calculations in this section all non-fuel costs were considered to be capacity-related

- Capacity-related costs (i e , fixed) costs were estimated based on the investment and non-fuel operating and maintenance costs of the incremental plant A planning reserve margin of 20% was used
- Levelized capacity-related costs were calculated per unit of peak demand increase and per unit of energy demand increase
- Energy- and capacity-related costs per unit of energy demand increase were combined for a total generation system LRMC

The incremental plants were assumed to be a stand-alone hot water heater for the hot water system and a stand-alone steam boiler for the steam system The assumed characteristics of this plants are summarized in Table 4-2

Table 4-2
Characteristics of Incremental Plants

	Water Heater	Steam Boiler
Thermal Capacity (MWt)	20	30
Capital Cost (million $)	0 75	1 55
Construction Time (years)	1	1
Economic Life (years)	25	25
Overall Efficiency	85%	85%
O&M (thousands $/year)	22 5	46 5

The resulting LRMC calculation is show in Table 4-3

Table 4-3
Generation LRMC Calculation[1]

	Water Heater	Steam Boiler	
Capacity-Related Costs ($/kWt)			
Investment	4 13	5 69 A	Per unit capital cost/PMT(10%,25 1)
O&M	1 13	1 55 B	Annual O&M/ Capacity
Planning Reserve	1 05	1 45 C	(A+B)*20%
Total	6 31	8 69 D	A+B+C
Expressed in Terms of Energy Production ($/Gcal)			
Levelized Fuel Cost	13 53	13 53 E	from Table 4-1
Levelized SRMC	15 92	15 92 F	E/ 85%
Capacity-Related Costs (assuming 25% capacity factor)	3 41	2 48 G	D/(8 76*25%)
Total LRMC	19 33	18 40 H	E+F+G

1 Based on the assumption that generation capacity additions are required immediately with an incremental demand increase

107

The SRMC varies over time depending by time-of-day and season depending on the fuel price and the characteristics of the facilities providing incremental demand The data necessary to make the calculation of SRMC by time of day is not readily available There is currently no seasonal pricing for natural gas so that there should be significant seasonality to district heating SRMC Table 4-4 shows the projected average SRMC as a function of time based on the projection of natural gas cost

Table 4-4
SRMC as a Function of Projected Natural Gas Price

	1995	1996	1997	1998	1999	2000
NaturalGas Price ($/Gcal)	13 24	13 37	13 50	13 64	13 77	13 91
SRMC($/Gcal)	15 58	15 73	15 88	16 05	16 20	16 36

If capacity is not required immediately, the contribution of capacity-related costs is diminished In Table 4-3, it is assumed that new capacity is need immediately The existing overcapacity in the generation system of Sofia District Heating suggests that this is not the case Table 4-5 shows the effect of a delayed need for new generation capacity on LRMC

Table 4-5
Capacity-Related Costs as a Function of Need for New Capacity ($/kWt/year)

Year Capacity Needed	Water Heater	Steam Boiler	
1995	6 31	8 69	A
1996	5 73	7 90	A/(1 1)
1997	5 21	7 18	$A/(1\ 1)^2$
1998	4 74	6 53	$A/(1\ 1)^3$
1999	4 31	5 94	$A/(1\ 1)^4$
2000	3 92	5 40	$A/(1\ 1)^5$

Because of the overcapacity in the Sofia District Heating generation system, the year 2000 for new investment requirements was used in our estimate

4 3 TRANSMISSION

Transmission costs are generally considered to be fixed (i e , capacity-related) since the design of these facilities is primarily determined be peak demand (kWt) Generally, the Average Incremental Cost (AIC) Method is used to estimate transmission LRMC The formula for this calculation is as follows

$$AIC = \left[\sum_{1}^{T}(I_t + OM_t - OM_{t-1})/(1+occ)^t\right]\left[\sum_{L+1}^{T+L}(D_t - D_{t-1})/(1+occ)^t\right]$$

where

IC = average incremental cost (proxy for LRMC)

T = planning period (years)

L = time delay between investment and commissioning of facilities (years)

102

I_i = annual investment in year i

OM_i = fixed O&M in year i

D_i = demand in year i

occ = opportunity cost of capital

Data required to make this calculation was not readily available Therefore, an estimate was made based on an estimate of replacement cost

- Existing transmission assets were revalued according to replacement value
- The revaluation was discounted to reflect the average number of years until replacement Because of the need for immediate rehabilitation of the transmission system, immediate need for replacement was assumed
- The theoretical design peak for the size generation system was estimated (The system is overcapacity so that the design peak is much high than the actual 1994 peak of 2890 MWt)
- The replacement value as a function of peak load was estimated

The application of this procedure is shown in Table 4-6

Table 4-6
Transmission LRMC Calculation[1]

	Physical units		per unit cost		Total Cost (millions $)		
Lines	1027 1	km	121 3	$/meter (Ref 1)	249	A	
Substations	4420	substations	41 7	$/kWt (Ref 2)	184	B	
Total					433	C	A+B
Generating capacity	4420	MW_t				D	
Theoretical design peak	3683	MW_t				E	D/(1 2)
Per unit investment	117 63	$\$/kW_t$ of peak				F	C*1000/E
LRMC ($\$/kW_t$/year of peak)							
Investment	12 03	$\$/kW_t$/year				G	F * PMT(10% 40 1)
Fixed O&M	1 18	$\$/kW_t$/year				H	F * 1%
Total LRMC	13 21					I	G + H

1 Based on the assumption that transmission capacity additions are required immediately with an incremental demand increase

As with generation LRMC, this value is discounted if capacity is not immediately needed as a result of a demand increase Because of the immediate investment required in the transmission system to reduce losses, no discounting was applied

139

4 4 DISTRIBUTION

The AIC Method, described in the previous section, can be applied to the distribution system The data to apply the method was not readily available so a method utilizing replacement cost was applied This is illustrated in Table 4-7

As with generation LRMC, the estimated value is discounted if capacity is not immediately needed as a result of a demand increase Because most new customers would require extensions of the distribution system, no discounting was applied

Table 4-7
Distribution LRMC Calculation[1]

Description	Value	Label	Explanation
Reference distribution cost (1982 $)[2]	1335	A	
based on			
heating density (kWh/m^2)	200	B	
peak (MW$_t$)	200	C	
Adjusted to 1995 $	1960	D	A* (1 03)[13]
Expressed as a function of non-simultaneous demand ($/MW$_t$)	9 80	E	D / C
Sofia heating density (kWh$_t$/m^2)	263	F	1994 Statistics
Adjusted to Bulgarian heating density ($/MW$_t$)	7 46	G	E * B / F
Sofia diversity factor	85%	H	
Expressed in terms of simultaneous demand ($/MW$_t$)	8 78	I	G / H
LRMC ($/kW$_t$/year of peak)			
Investment	0 93	J	I * PMT(10% 30 1)
Fixed O&M	0 09	K	I * 1%
Total LRMC	1 02	L	J + K

1 Based on the assumption that distribution capacity additions are required immediately with an incremental demand increase
2 Swedish example in Reference 3

4 5 PRICING

The LRMC pricing structure is summarized in Tables 4-8- and 4-9 The losses assumed for the calculation correspond to the projected 2000 loss rate as discussed in Section 2

Table 4-8
LRMC Pricing- Hot Water

Point of Sale	Loss Factor[1]	Energy Contribution[2] ($/Gcal)	Capacity Contribution to LRMC ($/kW$_t$ yr) Generation	Primary	Secondary	Total	Average Load Factor	Average Capacity Contribution ($/Gcal)	Average Total LRMC ($/Gcal)	(lev/Gcal)
Generation	1 00	15 9	3 9			3 9	25%	2 1	18 0	1206
Substation level	1 17	18 6	4 6	13 2		17 8	25%	9.4	28 1	1880
Household	1 23	19 6	4 8	13 9	1 0	19 7	25%	10.5	30 1	2016
Public Sector	1 23	19 6	4 8	13 9	1 0	19 7	25%	10 5	30 1	2016

1 Loss factors are based on hot water system loss goals for 2000 (14 5% for the primary loop and 5% for secondary loop)
2 Energy contribution is based on the projected levelized cost of natural gas through 2000 adjusted by production efficiency

110

Table 4-9
LRMC Pricing- Steam

Point of Sale	Loss Factor[1]	Energy Contribution[2]	Capacity Contribution to LRMC ($/kW$_t$ yr)				Average Load Factor	Average Capacity Contribution	Average Total LRMC	
		($/Gcal)	Generation	Primary	Secondary	Total		($/Gcal)	($/Gcal)	(lev/Gcal)
Generation	1 00	15 9	8 7			8 7	60%	1 9	17 8	1196
Substation level	1 20	19 2	10 5	13 2		23 7	60%	5 2	24 4	1636
Industry	1 20	19 2	10 5	13 2	0 0	23 7	60%	5 2	24 4	1636

1 Loss factors are based on steam system loss goals for 2000 (17% for the primary loop) with Industry served directly from primary loop
2 Energy contribution is based on the projected levelized cost of natural gas through 2000 adjusted by production efficiency

4 6 COMPARISON WITH EXISTING TARIFFS

The exising tariff is based on customer ownership of facilities downstream of the substation Therefore, the tariff is at the substation level However, economic comparisons of alternative heating costs should include the cost of these facilities

The tariff can take the form

Revenue = A x Energy + B x Maximum Heating Demand

Maximum heating demand

Table 4-10 shows the LRMC for hot water expressed in comparable terms to existing tariffs

Table 4-10
LRMC-Based Tariff

Energy component (A)=	18 6 $/Gcal
=	1248 leva/Gcal at 67 leva/$
Capacity component of LRMC =	17 8 $/kW$_t$/year
1995 System peak =	2 346,173 kW$_t$
Estimated heat load (m^3) =	83,842 223 m^3 (based on area from Reference 3 and 2 5 meter ceilings)
Demand component (B) =	0 055 $/m^3 of heating space
=	3 7 leva/m^3 at 67 leva/$

4 7 REFERENCES

1 Bechtel Corporation, Reconstruction of the Trnava Municipal and Industrial District Heating Plant, December 1995
2 Gilbert/Commonwealth International Inc Bulgarian District Heating System Feasibility Study, February 1995
3 International Energy Agency, District Heating and Combined Heat and Power Systems- A Technology Review, 1993

112

Section 5
Implementation Issues

The objective of this section is to investigate the financial impact associated with this proposed price increase, approaches to assuring that economically disadvantaged groups receive heat, treatment of non-payers, and proposed changes in price regulation

5 1 FINANCIAL IMPACT

The LRMC tariff as estimated would have covered the financial costs of Sofia District Heating as reported in 1994 This is illustrated in Table 5-1 Revenues based on steam system LRMC are estimated to be slightly lower than what was actually collected in 1994, however, revenues from hot water sales are estimated to be more than twice as large under LRMC pricing Under such pricing no subsidies would have been required, Sofia District Heating would have contributed income taxes to the government and would have earned a profit which could be applied to its investment requirements

Table 5-1
Hypothetical Impact of LRMC Tariff on 1994 Income Statement

	as reported (1995 $)	with proposed tariff increase and full payment
Revenue		
Hot water	64,073	143,375
Steam	8,321	7 892
Electricity	12 580	12,580
Other	5 083	5,083
Total Revenue	90 057	168 930
Expenses		
Fuel	122,107	122,107
Depreciation	10,778	10,778
Other	26,504	26,504
Total Expenses	159 389	159,389
Operating Income	(69 331)	9 541
Interest	114	114
Income Taxes	-	3 959
Subsidies	28 571	0
Net Income	(40 875)	5 468

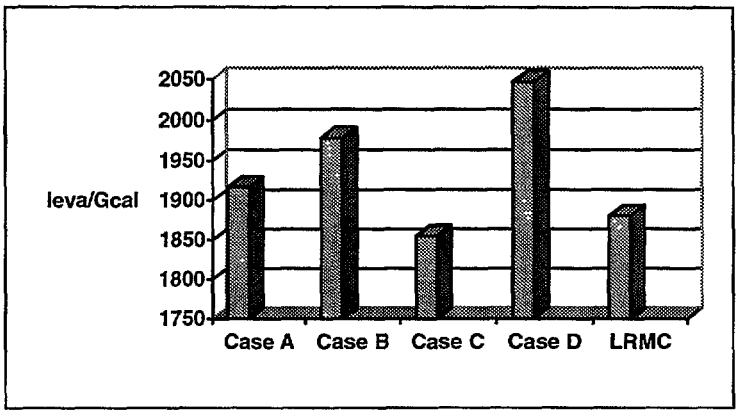
We evaluated four different cases to assess revenue requirements under different future assumptions The four cases include

- Case A- Revenue requirements estimate was made based on extrapolation of 1994 financial data and investment plan from Reference 5-1 No adjustments were made to the value of existing assets or to electricity buyback rates
- Case B- Same as Case A except that net asset values were adjusted to replacement cost

113

- Case C- Same as Case B except that electricity buyback rates were increased to electric system marginal cost
- Case D- Same as Case C except an allowance was made for nonpayment by some customers amounting to 10% of operating cost

Figure 5-1
Summary of Revenue Requirements Analysis for Hot Water Supply



The Case A revenue requirement estimate was slightly higher than hot water LRMC However, this tariff was found to be insufficient to support the proposed investment plan Asset values were adjusted to reflect replacement cost in Case B and this was found to support the proposed investment plan However, the resulting tariff would be substantially higher than LRMC (i e , more than 5%) Higher buyback rates for electricity would reduce the revenue requirements for hot water supply and there is reason to believe that higher buyback rates are economically justified In Case C the future buyback rates are set at the LRMC of generation on the electricity system The result was to reduce the projected revenue requirements to slightly less than the hot water LRMC

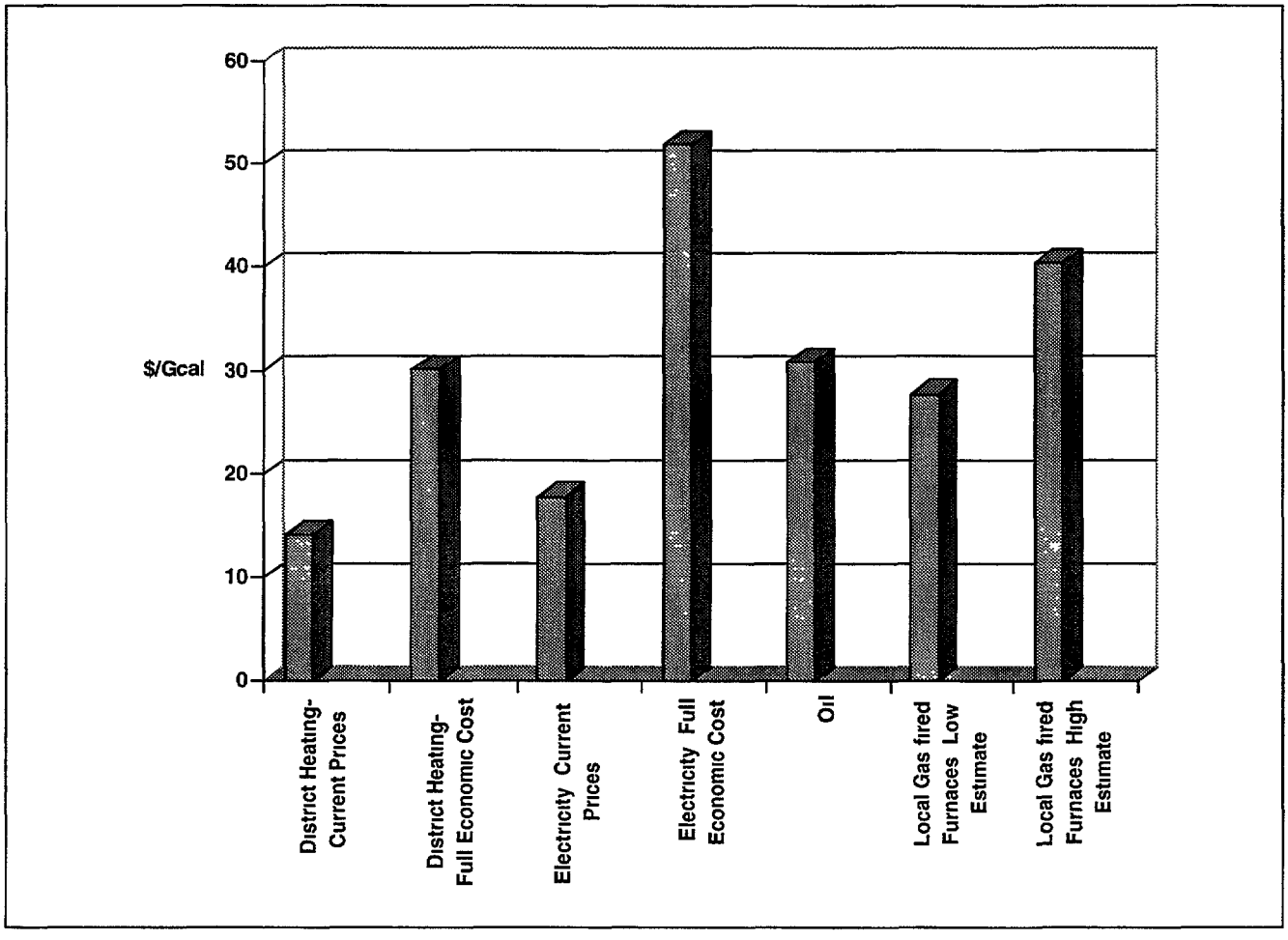
Cases A through C are based on the assumption that there is full payment from all customers If some customers do not pay and are allowed to receive service then the cost has to be borne by the remaining customers Case D was based on an assumption of nonpayment amounting to 10% of operating cost Discussions with district heating managers indicate that nonpayment is currently higher than this The resulting revenue requirements for paying customers would be almost 10% greater than LRMC

Based on this analysis, one can conclude that future tariffs to Household and to Public Sector- Budget based on LRMC would be adequate to meet the financial requirements of Sofia District Heating only if the buyback rate for electricity can be increased to the electric generation system LRMC and non-payment by district heating customers can be severely reduced Otherwise, it will be impossible to support investment requirements without subsidies even with LRMC pricing

5 2 COMPETITION WITH OTHER HEAT SOURCES

As market forces increasingly affect energy pricing, competition between fuels and heat supply systems will become increasingly important Figure 5-2 shows relative heating costs from a variety of sources in Bulgaria Natural gas is not currently used for household heating and a range of potential heating costs is presented based on a price of natural gas delivered to the household of between 150 $ per thousand cubic meter (tcm) and 260 $/tcm This range represents potential variations in future pricing policy for gas to households and distribution costs between communities The full economic cost of district heating and electricity is based on LRMC to households, including distribution Electricity LRMC is addressed in detail in Volume 1 Oil heating costs are based on a delivered cost of fuel oil to households of 6 $/GJ and represent full economic cost

Figure 5-2
Relative Heating Costs from Various Sources



115

The following observations can be made base on these estimated heating costs

- District heating and electric heating are the least expensive modes of heating under current pricing This is due to direct subsidies in the case of district heating and cross-subsidies in the case of electricity The deregulation of oil prices has made oil heating uncompetitive
- Current price distortions are the greatest for electricity Current pricing makes it the heating source of choice for anyone without access to a district heating system It is by far the most expensive source when full economic costs are considered
- When full economic costs are considered, oil is competitive with other forms of heating
- Natural gas will be competitive with other forms of heating for communities with the lowest distribution costs

The distortions in electricity pricing have already resulted in a massive shift away from oil heating (i e , from approximately 1200 thousand tonnes per year in 1985 to a negligible amount in 1995) Its replacement with electric heating represents a large economic cost to the country The lesson is that while it is important to increase district heating prices, it is important that this be done in conjunction with electricity price reform Otherwise, district heating consumers will incorrectly perceive that electric heating is less expensive than from their district heating systems

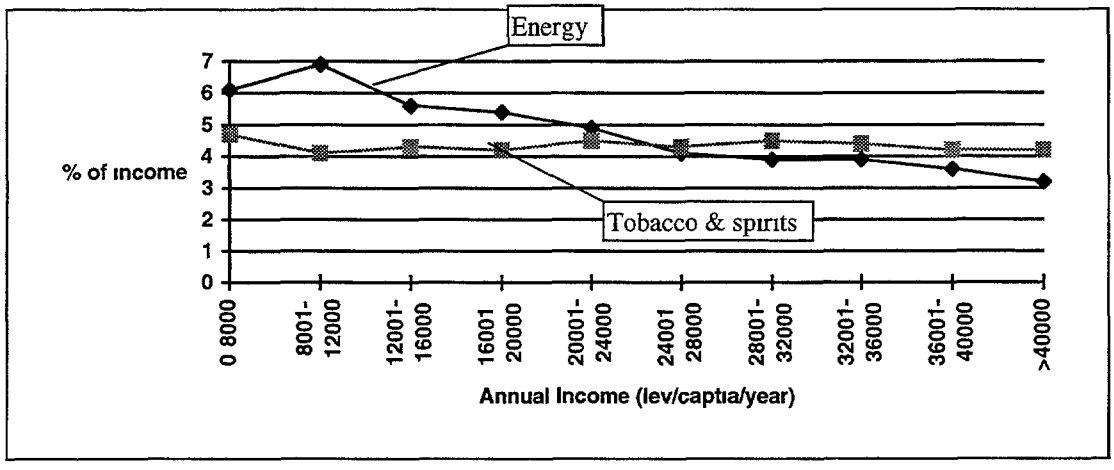
Under pricing based on full economic costs, district heating will remain competitive with other forms of heating However, if Sofia District Heating is to maintain its current customer base it will be important to reduce costs and gradually offer customers greater control over their usage

5 3 IMPACT ON ECONOMICALLY DISADVANTAGED GROUPS

Generally energy for household use should make up no more than approximately 10% to 15% of a household budget As shown in Figure 5-3, this criterion was met for all income groups in 1993

116

Figure 5-3
Contribution of Energy to Household Budget as a Function of Income- 1993



Source Reference 5-2

The proposed district heating household tariff increase is more than 300% higher than the 1993 levels A similar tariff increase has been recommended for household electricity tariffs in Volume 1 Had these tariff levels existed in 1993, expenditures for energy would have represented would have approximately 20% of their income This group represented 17 6 percent of the population This is the segment of the population to which protection from tariff increases should be provided There are a variety of ways that relief can be provided, with varying degrees of effectiveness in protecting low-income customers The current method of providing direct subsidies to the district heating companies reduces tariffs for all customers and provides the largest subsidy to those who heat the most, usually those with higher incomes Cross-subsidies between customer classes are not an option because the price to other customer classes (i e , Industrial and Public Sector- Nonbudget) is no longer heavily regulated Cross-subsidies within the Household customer class would result in tariffs greater than LRMC and would most likely result in district heating becoming more expensive to paying customers than oil heating This leaves some form of direct assistance to the poor

5 4 PROPOSED PRICE REGULATION

Price regulation for district heating should have the following characteristics

- Regional or municipal administration to allow for geographic differences in fuel prices and district heating system cost
- Oversight at the national level to coordinate district heating tariffs with electricity price reform
- A formula for automatic adjustment to reflect inflation and fuel price changes

117

The formula should provide incentives for efficient operation The formula could either be based on LRMC or be based on cost-of-service or a hybrid of the two All pricing approaches will be limited by metering The following discussion is based on the assumption that all substations will be metered Calculated usage will have to substitute for unmetered substations

5 4 1 LRMC Pricing Formula

For metered substations, the tariff would take the form

$$R_{ij} = A_i x E_{ij} + B_i x D_j$$

where

R_{ij} = payment in month i for substation j

A_i = coefficient based on SRMC for month i

E_i = usage in month i for substation j

B_i = demand charge in month i (leva/cubic meter of heating space connected to substation) based on capacity component of LRMC

D_j = heating space connected to substation j

The energy coefficient, A_i, should be adjusted to reflect changed in fuel costs as shown by the following formula

$$A_i = A_o x F_i / F_o$$

where

F_i = per unit fuel cost in month i

F_o = per unit fuel cost in month in base month o

The demand charge, B_i, should be adjusted to reflect general inflation as shown by the following formula

$$B_i = B_o x CPI_o / CPI_i$$

where

CPI_i = Consumer price index in month i

CPI_o = Consumer price index in base month o

The demand coefficient, B, is based on the capacity component of LRMC and expressed as a function of cubic meters of heating space Therefore the initial coefficient, B_o, is calculated as follows

$$B_o = LRMC_c x P_o / H_o$$

where

118

$LRMC_c$ = the capacity component of LRMC including generation and transmission divided by 12 ($/kW$_t$/month)

P_o = projected peak in first year (kW$_t$)

H_o = connected heating space in first year (m^3)

It is expected that the coefficients A and B will vary among district heating systems reflected cost differences

The energy coefficient, A_t, should be revised periodically (e g , 5 years) to reflect changes in system losses In between revisions, the utility will have an incentive to reduce losses in order to reduce costs and maximize profits The period between revisions should be long enough to allow the utility to recover investments in loss reduction

The demand coefficient, B, should be revised on a periodic basis to reflect structural changes in cost and the performance of the utility in providing service

5 4 2 Rate-of-Return Alternative

Pricing based on a "fair" rate-of-return on an historical value of assets is the most common regulated energy utility pricing in the U S This approach results in coefficients for energy and demand (A and B) The difference with the LRMC approach is primarily with the treatment of the demand coefficient Under this approach,

$$B_t = \left(FOM_k + D_k + NFA_k xR\right) / 12 / H_t$$

where

FOM_k = projected annual fixed operating and maintenance costs for year *k*

D_k = projected annual depreciation for year *k*

NFA_k = net fixed assets for year *k*

R = fair rate of return

The primary problem with rate-of-return price regulation is that energy companies are rewarded for capital investment, but not necessarily for increasing operating efficiencies There is a trend to move away from rate-of-return price regulation where competition is technically feasible (e g , electricity generation) and in situations in which the approach has resulted in prices which deviate significantly from LRMC

The approach depends upon a reliable valuation of assets In the U S , most energy utilities are privately owned so that their value is subject to market forces In addition, low inflation allows historical accounting value to be meaningful in most cases Neither of these conditions is true in Bulgaria As a result, analytical approaches can be used to estimate asset value, these estimates are not subject to the discipline of the market Furthermore, constant revision is required for net fixed assets and depreciation to reflect inflation

In the U S , value of R is usually a weighted average of cost of capital of the enterprise It is then applied to historical asset values (i e , historical value of fixed assets minus historical accumulated depreciation) A portion of R is "real" return and the remainder is intended to adjust the return for inflation The following formula expresses this relationship

R = (1+real return) x (1+general inflation rate)

If net asset values are periodically corrected for inflation, as will be the case in Bulgaria, only the "real" portion of R should be applied to the corrected net asset values "Real" rate-of-return is usually in the range of 2% to 5%

5 5 TRANSITION PRICING

Sofia District Heating tariffs to Households and Public Sector- Budget should rise from the current 810 leva/Gcal (12 1 $/Gcal) to approximately 1880 leva/Gcal (28 1$/Gcal) delivered to substations to fully reflect economic cost How quickly should this change be made? The factors which support a quick transition are

- Continue low district heating tariffs cannot support investment in the district heating systems
- Direct subsidies are straining the budget
- Customers have little incentive to conserve

On the other hand, the disadvantages of a rapid change to higher tariffs are

- A rapid change could damage economically vulnerable groups unless accompanied by some form of assistance
- The change could actually contribute to overall price distortions if not accompanied by electricity price reform
- It could appear unjust because of the low degree of control that customers have over their usage

In Volume 1, transitional pricing approaches to the electricity sector are proposed resulting in household electricity tariffs being in line with LRMC by 2000 Table 5-2 shows the effect of a similar transition pricing plan Sofia District Heating A linear increase in tariffs in real terms unitl LRMC is reached in 2000 is shown The revenue requirements estimates used in the table are preliminary The shortfall shown represents required subsidies from the government in order to meet revenue requirements Even with LRMC pricing, ther is some shortfall due to an assumption that there will continue to be a non-payment problem In this analysis it was estimated at 10% of operating expenses

The advantages of this pricing plan are that it is with proposed electricity tariff increases and it is accompanied by investments in metering The primary disadvantage is that is calls for continuing although declining, subsidies from the government

120

Table 5-2
Effect of Transition Pricing on Finances

	1995	1996	1997	1998	1999	2000	Label	Explanation
Total Revenue Requirements (thousands $)	150 229	163 924	163 081	164 428	165 124	166 053	A	
Adjust for Public Sector-Nonbudget								
Public Sector-Nonbudget LRMC ($/Gcal)	28 1	28 1	28 1	28 1	28 1	28 1	B	
Demand (Tcal)	851	881	906	924	940	945	C	
Total Adjustment	23 891	-24 718	25 418	-25 936	26 372	-26 520	D	-(B*C)
Revenue Requirements for Household and Public Sector Budget (thousands $)	126 338	139 206	137 663	138 492	138 752	139 533	E	A+D
Proposed Tariff ($/Gcal)	12 1	15 3	18 5	21 7	24 9	28 1	F	
Demand (Tcal)	4 300 278	4 401 574	4 476 182	4 521 418	4,528 991	4 489,808	G	
Revenue (thousands $)	51 988	67 277	82 720	98 002	112 638	126 009	H	F*G
Shortfall (thousands $)	74 349	71 929	54 943	40 490	26 114	13 524	I	E H

5 6 REFERENCES

1 Gilbert/Commonwealth International, Inc , Bulgarian District Heating System Feasibility Study, February 1995

2 Republic of Bulgaria, Statistical Yearbook, 1994

121