PN-ABJ-742

Report No. 91-12

Report of the

Office of Energy
Bureau for Science and Technology
United States Agency for International Development

COSTA RICA: POWER SECTOR EFFICIENCY ASSESSMENT

Technical Volume

Prepared by:

RCG/Hagler, Bailly, Inc.
370 L'Enfant Promenade, SW, Suite 700
Washington, D.C. 20024
Reference HBI No. 91-4312-211
and
Oak Ridge National Laboratory

with

International Development and Energy Associates, Inc.
Florida Power & Light
International Institute for Energy Conservation
International Resources Group, Ltd.
Stone & Webster Engineering Corp.
National Rural Electric Cooperative Association
Centro de Investigaciones Sociales, Ambientales y Tecnológicas

Energy Policy Development and Conservation Project, 936-5728
Energy Conservation Services Program
DHR-5728-Z-00-7014-00

June 1991

ACKNOWLEDGEMENTS

This study was financed by the Office of Energy (S&T/EY) of the U.S. Agency for International Development (A.I.D.) and USAID/Costa Rica. The project team members responsible for the demand-side analysis of this report included: Ignacio Rodriguez, team leader/project economist (RCG/Hagler, Bailly, Inc.); Juan Gonzalez, load management specialist (Florida Power & Light); Michael MacDonald, residential and general sector specialist (Oak Ridge National Laboratory); Alan Pashkevich, industrial sector specialist (RCG/Hagler, Bailly, Inc); Mark Cherniack, institutional and program specialist (International Institute for Energy Conservation); Peter Meier, ELECTROPLAN (International Development and Energy Associates, Inc.), Jose Maria Blanco, local coordinator (Centro de Investigaciones Sociales, Ambientales y Tecnológicas); and Bernal Muñoz and Arturo Molina, local consultants. For the supply-side analysis, the team members included: Daniel Waddle, team leader (Oak Ridge National Laboratory); Robert Chronowski, thermal specialist (International Resources Group Ltd.), Lou Conklin, hydro specialist (Stone & Webster Engineering Corp.); and Ross Turner, transmission and distribution specialist (National Rural Electric Cooperative Association).

The team members would like to thank the Instituto Costarricense de Electricidad, particularly Hernan Robles, and the Direccion Sectorial de Energia for their collaboration and support during the project. We would also like to express our appreciation to Carlos Yermoli (RCG/Hagler, Bailly, Inc.) for his technical review of the supply-side analysis, and to Wynne Cougill (RCG/Hagler, Bailly, Inc.) for her editing for this report.

ACRONYMS

BOP	Balance of payments.
CFIA	Colegio Federado de Ingenieros y Arquitectos de Costa Rica. An independent entity created to ensure, stimulate, promote, and defend the practice of engineering and architecture.
COOPE-GUANACASTE	Cooperativa de Electrificación Rural Guanacaste R.L. The second-largest cooperative in terms of sales and energy volume, serving the Guanacaste Peninsula region of Costa Rica.
COOPELESCA	Cooperativa de Electrificación Rural San Carlos R.L. The largest of Costa Rica's four electric distibution cooperatives, serving the north-central part of the country.
CNFL	Compañia Nacional de Fuerza y Luz. The National Power and Light Company responsible for generation, transmission, and distribution, mainly in the San Jose area.
CPI	Consumer price index.
DSE	Direccion Sectorial de Energía. The body within MIRENEM that is mandated to perform and coordinate national energy planning.
DSM	Demand-side management.
ECM	Energy conservation measure.
ESPH	Empresa de Servicios Públicos de Heredia. The municipal company serving the Heredia district of the San Jose metropolitan area with electricity and other public services.
ECODES	Estrategia de Conservación para el Desarrollo Sostenible de Costa Rica. The Costa Rican National Conservation Strategy for Sustainable Development.
FODEIN	Fondo de Desarrollo Industrial. The Industrial Development Fund.
GDP	Gross domestic product.

ACRONYMS

JASEC	Junta Administrativa de Servicios Eléctricos de Cartago. A municipal organization that provides electric services to the municipality of Cartago and its immediate surrounding area.
ICE	Instituto Costarricense de Electricidad. The national electric utility of Costa Rica.
ICETICO	The "energy conservation mascot" of ICE. A talking lightbulb that appears in posters, television, and newspapers to promote energy conservation.
INTECO	The Institute of Technical Standards. A non-profit organization created as a private association to stimulate efficiency in the industrial sector, and to protect the consumer as well.
IRP	Integrated resource plan.
LRMC	Long-run marginal cost.
MEIC	Ministerio de Economía, Industria, y Comercio. The Ministry of Economy, Industry, and Commerce.
MICIT	Ministerio de Ciencias y Tecnología. The Ministry of Science and Technology.
MIDEPLAN	Ministerio de Planificación Nacional y Política Económica. The Ministry of National Planning and Economic Policy.
MIRENEM	Ministerio de Recursos Naturales, Energía y Minas. Ministry of Natural Resources, Energy, and Mines.
RECOPE	Refineria Costarricense de Petroleo, S.A. The Costa Rican Petroleum Refinery.
SNE	Servicio Nacional de Electricidad. The regulatory body providing oversight and approval of rate adjustments and water rights for Costa Rica's electric utilities.
SNI	Sistema Nacional Interconectado. The National Interconnected System.

LIST OF TERMS

bbl	barrel
Btu	British thermal unit
giga	1,000,000,000
GW	gigawatt
GWh	gigawatt hour
hp	horsepower
HV	high voltage
kcal	kilocalorie
km	kilometer
kV	kilovolts
kVA	kilovolt ampere
kW	kilowatt
kWh	kilowatt hour
l	liter
ln	natural logarithm
LPG	liquefied petroleum gas
LV	low voltage
m^3	cubic meter
mega	1,000,000
MV	medium voltage
MVA	megavolt ampere
MW	megawatt
MWh	megawatt hour

Costa Rica: Key Economic Indicators
(in millions of US $ unless noted)

	1987	1988	1989	Estimated 1990
Domestic Economy				
Population (thousands, July)[1]	2,606	2,762	2,735	2,801
Population growth (%)	2.4%	2.5%	2.4%	2.4%
GDP (mill. current $)	4,536	4,762	5,230	5,510
Per capita GDP (current $)	1,741	1,769	1,912	1,989
Real GDP (1966 colones, mill.)	10,851	11,193	11,825	12,298
percent change	5.1%	3.2%	5.6%	4.0%
Consumer price index change (Dec. to Dec.)	16.4%	25.3%	10.0%	25.0%
Production and Employment				
Labor force (thousands, July)	978	1,006	1,026	1,051
Unemployment	5.6%	5.5%	3.8%	5.0%
Balance of Payments				
Exports (FOB)	1,194.8	1,286.9	1,456.6	
Imports (CIF)	1,380.2	1,404.7	1,743.0	
Trade balance	-185.4	-117.8	-286.4	
Current account balance	-257.0	-179.0	-382.0	
Foreign official debt (year-end)	3,923.6	3,833.9[2]	3,746.8	
Debt service paid	265.2	218.2	255.5	
Debt service unpaid/resched.	369.2	579.8	442.9	
Total debt service as % of merchandise exports	53.1%	62%	47.9%	
Net official foreign exchange reserves (year-end)	376.0	604.9	752.2	
Average exchange rate for year (colones per US$1)	69.8	80.0	84.9	100.0
Central Government Finances (mill. Colones)				
Revenues	44,025	53,435	63,764	72,770
Expenditures	49,936	58,965	77,850	98,000
Deficit (-) or Surplus	-4,911	-5,430	-14,086	-25,300
Deficit as % of GDP	1.7%	1.5%	3.3%	4.6%
U.S.-Costa Rica Trade				
Costa Rican Exports to US (FOB)	508.0	493.9	578.5	
Costa Rican Exports to US (CIF)	512.8	544.3	705.0	
Trade Balance	-4.8	-150.4	-126.5	
U.S. Share of Costa Rican Exports	42.5%	38.4%	39.7	
US Share of Costa Rican Imports	37.2%	38.7%	40.4	
U.S. Bilateral Aid	155.8	105.2	110.0[3]	

Notes

1 Bureau of Statistics and Census from "Encuesta de Hogares" survey. Based on a revision to the 1984 national census, the Bureau estimates about 3 million by mid-1990, plus approximately 200,000 undocumented foreign residents.

2 Beginning in 1988, USD 150 million in "Presa" CDs -- dollar denominated Central Bank bonds -- were reclassified as a domestic liability, thereby producing a drop in reported foreign official debt.

3 Only partially disbursed. Includes USD 65 million in Economic Support Funds.

ABSTRACT

In an effort to demonstrate the advantages of integrated resource planning, and to promote the adoption and implementation of electric utility conservation and efficiency programs, the U.S. Agency for International Development initiated a joint effort with Costa Rica's Instituto Costarricense de Electricidad (ICE) and the Direccion Sectorial de Energia (DSE) of the Ministerio de Recursos Naturales, Energia y Minas (MIRENEM) to demonstrate the benefits of these programs. As part of that effort, this study was carried out in 1990 to identify the likely economic potential to save capacity and energy, and the costs that will be incurred to realize these savings.

The recommended capacity deferral (real reduction) programs under this study, which include the implementation of daylight savings time, interruptible tariffs, and commercial/small industrial load management, could provide a coincident peak demand savings of 183.6 MW in the year 2005 (a reduction of 11 percent of the forecast system peak). The recommended energy-efficiency programs for the industrial, general, and residential sectors result in an estimated energy saving of 624 GWh in the year 2005 (an energy reduction of more than 8 percent). The implementation of a demand-side management (DSM) program (load management and energy conservation) as recommended would result in a peak demand reduction of 213 MW, or 12 percent of the forecasted system peak for the year 2005. This represents a 16 percent reduction of the incremental capacity requirements (1,298 MW) under the ICE expansion plan for the period 1990-2005.

Based on a net present value of ICE financial flows to the year 2005, the financial impact of the recommended DSM program would result in an increase in net income of $103 million, considering the financial impact of capacity and energy savings, including investments in generation and transmission and distribution equipment, fuel costs, revenue losses from decreased electricity sales, and associated administrative costs for the implementation of the DSM program. The program's impact on Costa Rica's balance of payments is substantial, with a net present value to the year 2005 of the foreign exchange savings for Costa Rica of 14 percent over the base case (no DSM program). This impact is a result of 1) reduced external debt service due to the deferral of capacity expansion, 2) reduced oil import bill due to energy savings, and 3) increased import bills associated with the need to import equipment for the energy conservation measures. The DSM programs also have important environmental benefits by reducing energy production requirements, which mitigate the negative environmental impacts of energy resources exploration, development, and production.

CONTENTS

SUMMARY VOLUME

(bound under separate cover)

TECHNICAL VOLUME

CHAPTER 1 INTRODUCTION

1.1	Background	1.1
1.2	Economic Trends in Costa Rica	1.2
1.3	The Electric Power Sector in Costa Rica	1.4
1.4	Integrated Resource Planning	1.6
	The Concept of Integrated Resource Planning	1.6
	Steps in Integrated Resource Planning	1.8

CHAPTER 2 DEMAND-SIDE ENERGY EFFICIENCY IMPROVEMENTS

2.1	Characterization of Energy Use	2.1
2.2	Demand-Side Management Study Methodology	2.4
	The Cost of Conserved Energy/Demand	2.4
	The ELECTROPLAN	2.6
	General Study Assumptions	2.6
2.3	Load Management Measures and Savings	2.10
	Daylight Savings Time	2.13
	Interruptible Tariff Modification	2.15
	Load Control Program for the Commercial and industrial Sectors	2.23
	Load Control Program for the Residential Sector	2.23
	Summary and Conservation Supply Curve	2.28
2.4	Energy and Demand Savings for the Industrial Sector	2.28
	Low Cost/No Cost Measures	2.31
	Synthetic Lubricants	2.32
	Cogged V-Belts	2.33
	Lighting Technologies	2.34
	Energy-Efficient Motors	2.39

	Synchronous Belts	2.39
	Variable-Speed Drives	2.41
	Summary and Conservation Supply Curve	2.42
2.5	Energy and Demand Savings for the Residential Sector	2.46
	Water Heater Tank Insulation	2.47
	Energy-Efficient Refrigerators	2.49
	Spiral Burners	2.52
	Solar Water Heating for Tanks and Termo Duchas	2.53
	Compact Fluorescent Lighting	2.54
	Summary and Conservation Supply Curves	2.55
2.6	Energy and Demand Savings for the General Sector	2.59
	Lighting	2.61
	Energy Management	2.62
	Summary and Conservation Supply Curve	2.64

CHAPTER 3 SUPPLY-SIDE EFFICIENCY IMPROVEMENTS

3.1	Analysis of the Generating System	3.1
	Thermal Generation	3.2
	Hydroelectric Generation	3.21
3.2	Analysis of the Transmission and Distribution Systems	3.27
	Transmission System Overview	3.27
	Distribution System Overview	3.30
	Areas of Analysis	3.33
	Planned Transmission System Changes	3.35
	Planned Distribution System Changes	3.37
	Effects of New Technologies on Losses	3.39
3.3	Summary of Findings	3.40

CHAPTER 4 ANALYSIS OF THE IMPACTS ON THE UTILITY AND BALANCE OF PAYMENTS

4.1	Basic Assumptions	4.2
	Load Curves	4.2
	Hydroelectric Seasonality	4.4
	Load Curve Linearization	4.6
	Losses	4.7
	Load Shape Projections	4.8

4.2 Load Curve Impacts and the Demand-Side Management Plan 4.9
4.3 Impacts on ICE 4.15
Impact on the Demand Forecast 4.15
Impact on the Capacity Expansion Plan and the ICE Investment Plan 4.17
Impact on Fuel Costs 4.19
Impact on ICE's Financial Plan 4.21
Impacts on the Balance of Payments 4.26

CHAPTER 5 IMPLEMENTING AN INTEGRATED RESOURCE PLAN

5.1 Institutional Roles 5.1
5.2 Financing Conservation Programs 5.3
5.3 Regulations and Standards 5.5

CHAPTER 6 CONCLUSIONS, RECOMMENDATIONS, AND ACTION PLAN

6.1 Conclusions and Recommendations 6.1
The Demand Side 6.1
The Supply Side 6.7
6.2 Demand-Side Action Plan 6.9
Institutional Coordination and Program Evaluation 6.9
New Buildings 6.11
New Residential Appliances 6.13
Existing Appliances 6.15
Existing Residential Lighting 6.16
Existing General Sector Lighting and Energy Management 6.17
Industrial Sector 6.18
Load Management Program 6.19

CONTENTS

APPENDICES

Appendix 1	Calculations for Daylight Savings Program
Appendix 2	Calculations for Commercial/Industrial Interruptible Rate Program
Appendix 3	Calculations for Commercial/Industrial Load Control Program
Appendix 4	Calculations for Water Heater Load Control Program
Appendix 5	Calculations for Residential Time-of-Use Program
Appendix 6	Calculations for Residential Refrigerator Load Control Program
Appendix 7	U.S. Experience with Demand Limiting Systems
Appendix 8	Economic Analysis of Energy Conservation Measures
Appendix 9	Financial Analysis of Energy Conservation Measures
Appendix 10	Projected Demand Reductions for Energy Conservation Measures in the Residential and General Sectors
Appendix 11	Rehabilitation Program Description
Appendix 12	Locations and Characteristics of ICE Hydroelectric Plants
Appendix 13	Output Tables for Utility and Balance of Payments Impacts Analysis

Glossary

EXHIBITS

2-1	Costa Rican Electricity Consumption by Sector - 1989	2.2
2-2	Costa Rican Forecasted Electricity Consumption by Sector for the Year 2005	2.2
2-3	Impact on Residential Customers of Energy Conservation Awareness Campaign and Tariff Increases, 1986-1989	2.3
2-4	EPRI Penetration Rate Curve	2.7
2-5	ICE System Load Profile for the 1989 System Peak Day	2.11
2-6	Coincidence of Residential Sector Cooking Peak and Lighting Peak	2.14
2-7	Sample Profile for an Interruptible Customer	2.16
2-8	Hydro Availability and Plant Maintenance in Costa Rica, 1990	2.18
2-9	Firestone Load Profile on the Time-of-Use Tariff	2.20
2-10	Firestone Simulated Load Profile on the Interruptible Tariff	2.21
2-11	Potential Demand Reduction from a Sample of Industrial Customers	2.22
2-12	Estimated Conservation Supply Curve for Load Management Measures	2.28
2-13	Peak Reduction Program Implementation by Year	2.30
2-14	Estimated Energy Savings for Various Energy Conservation Technologies in MWh per Year, Industrial Sector	2.41
2-15	Estimated Energy and Demand Savings for the Industrial Sector, with Target Penetration Rates	2.42
2-16	2005 Conservation Supply Curve -- Costa Rica Industrial Sector	2.43
2-17	Residential End-Use Breakout	2.47
2-18	Data Used to Develop Conservation Resource Supply Curves for U.S. Refrigerators	2.50
2-19	Comparison of Efficiency Potentials for U.S. and Costa Rican Refrigerators	2.51
2-20	Estimated Energy Savings for Various Energy Conservation Technologies in MWh per Year, Residential Sector	2.56
2-21	Estimated Energy and Demand Savings for the Residential Sector, with Target Penetration Rates	2.57
2-22	2005 Conservation Supply Curve -- Costa Rica Residential Sector	2.58
2-23	Commercial End-Use Breakout	2.60
2-24	Estimated Energy Savings for Various Energy Conservation	

EXHIBITS

2-24	Estimated Energy Savings for Various Energy Conservation Technologies in MWh per Year, General Sector	2.65
2-25	Estimated Energy and Demand Savings for the General Sector, with Target Penetration Rates	2.66
2-26	2005 Conservation Supply Curve - Costa Rica General Sector	2.67
3-1	Thermal Generation Unit Nameplate and Derated Capacity	3.2
3-2	Energy Production Growth from 1980 Through 1989	3.4
3-3	Thermal Plant Efficiencies and Availabilities, 1987-1989	3.9
3-4	ICE Expansion Plan: Medium-Case Load Growth Scenario	3.10
3-5	Probable Energy Output of Existing and Future Plants	3.12
3-6	Comparison of New Equipment to Existing Turbine Cycle Life Cycle Costs	3.14
3-7	Potential Savings for Present Diesel and Combustion Turbine Units	3.15
3-8	Characteristics of Different Types of Thermal Units Suitable to ICE's System	3.17
3-9	Characteristics of Different Types of Thermal Units Suitable to ICE's System	3.18
3-10	Life Cycle Costs of Various Combustion Technologies	3.19
3-11	Standard STIG Configuration	3.20
3-12	Nominal Hydro Power Plant Ratings and Efficiencies	3.23
3-13	Hydro Power Plant Operating Statistics	3.24
3-14	National Interconnected System	3.28
3-15	Distribution Company Characteristics	3.30
3-16	Moin-Siquirres Line Losses with Increased Load and No Modification	3.36
3-17	Moin-Siquirres Line Losses with 230 kV Conversion	3.37
3-18	Effect of Distribution Line Upgrade	3.38
4-1	Demand-Side Management Program Measures Included in the Second-Stage Analysis	4.2
4-2	Daily Load Curves for the Week of April 3, 1989	4.3
4-3	Load Curves for Wednesday April 5 and September 27, 1989	4.4
4-4	Monthly Hydroelectric Production by Plant, 1989	4.5
4-5	Linearization of the Dry Season Load Duration Curve	4.6
4-6	Average Dry Season Load Curve Partition	4.7
4-7	Losses for the Peak System Day of 1989	4.8
4-8	Projection of the System Load Curve for the Peak Day of 2005	4.9
4-9	Typical Hypothesized Load Curve Impacts for 2005	4.11

EXHIBITS

4-10	Impacts on the Linearized Load Curve	4.12
4-11	Impact of Daylight Savings Time, 2005	4.13
4-12	Impact of Daylight Savings Time on the Load Curve of the 2005 System Peak Day	4.14
4-13	Impact of the Complete Plan	4.15
4-14	Impact of the DSM Plan on ICE's Peak Load	4.16
4-15	Impact of the DSM Plan on Energy Requirements	4.17
4-16	Comparison of ELECTROPLAN and ICE Base Case Expansion Plan	4.19
4-17	The Impact of the Planning Reserve Margin Assumption	4.20
4-18	Impact of the DSM Plan on Capacity Expansion Requirements	4.21
4-19	Annual Investment Requirements	4.22
4-20	Impact of Daylight Savings Time	4.23
4-21	Impact of the Full DSM Plan	4.24
4-22	ICE Base Case Fuel Cost Scenarios: September 1989	4.25
4-23	Impact of the DSM Plan: ICE Base Case Fuel Cost Scenarios	4.26
4-24	Impact of the DSM Program on Net Income	4.27
4-25	Financial Impacts of the DSM Plan	4.28
4-26	Impact of the DSM Program on Debt Service Ratio	4.29
4-27	Foreign Exchange Flows Associated with the Power Sector	4.30
4-28	Impact of the DSM Plan on the Balance of Payments	4.31
6-1	Estimated Demand Savings Under a Load Management Program and Estimated Energy Savings Under a Full DSM Program, 2005	6.2
6-2	Estimated Peak Demand Reduction for a Full DSM Program for the Year 2005	6.6

CHAPTER 1: INTRODUCTION

1.1 BACKGROUND

The demand for electric power in Costa Rica, as in many developing countries, has grown at an average rate of over 6 percent per year in the past decade, well above the rates forecast. While increased electricity supply may greatly enhance the industrialization and modernization of society, it can also place great demands on the capital resources needed to finance capacity expansion programs and associated investments.

If present growth rates are maintained, the capital requirements for financing new capacity for developing countries may be as high as US $200 billion per year for the next twenty years, totalling more than $4 trillion over this period. The foreign exchange available to developing countries to amortize a capital cost of this magnitude of investment, and to cover recurring fuel and maintenance costs, may well be very limited.

The investment requirements of the power sector thus pose a major financial challenge for developing countries. In some Central American countries, these requirements account for up to 50 percent of public-sector investment programs and up to 25 percent of public sector external debt service. Alternatives are thus needed to the conventional approach to capacity expansion. These alternatives can include 1) private sector participation, where an influx of private capital will help to reduce the heavy burden the power sector places on public financing, and 2) the development of conservation and efficiency programs to make more effective use of electric power conversion, transmission, and end- use systems. The latter is the focus of this study.

In coordination with other development institutions, including the World Bank, the Inter-American Development Bank, and the Asian Development Bank, the United States Agency for International Development (A.I.D.) has played a leading role in addressing the problems faced by electric utilities. A.I.D. has also been a leading proponent of integrated resource planning (also called least-cost utility planning), wherein electric utilities consider all resource alternatives, including investments in conservation, when they plan for the future provision of electricity services. In this type of planning, the selection criteria for satisfying electricity demand are based on the most economic use of investment capital.

In an effort to demonstrate the viability of integrated resource planning, and to promote the adoption and implementation of electric utility conservation and efficiency programs, A.I.D. initiated a joint project with the Instituto Costarricense de Electricidad (ICE) and

the Direccion Sectorial de Energia (DSE) of the Ministerio de Recursos Naturales, Energia y Minas (MIRENEM) to demonstrate the benefits of these programs in Costa Rica. The purpose of this study was to assess the extent to which energy conservation and efficiency programs can play a viable role in ICE's economic delivery of services to its customers, as well as the extent to which improved technologies can be employed to decrease the rate of growth of electricity demand in future years.

The project was sponsored by ICE, MIRENEM, the A.I.D. Office of Energy, and USAID/San Jose. Most of the field and analytical work was carried out in 1990. Counterparts from all four institutions have contributed substantively to the project and worked closely to produce this report.

The project focused on primary and secondary conversion technologies and processes, in both electric power generation and the use of electric energy. Consumer conservation programs, line loss reduction (high and low voltage), load management, and improvements in the efficiency of electric power generation are included in this assessment.

This two-volume report describes an assessment performed as a part of this project. The assessment focused on the potential to save demand and energy, and on the costs that will be incurred to realize these savings. With costs and benefits quantified, technical and managerial alternatives are compared against the primary investment alternative, the ICE supply expansion plan.

The methodology developed in this process is intended to be used by other countries in the future. Although clearly defined at the outset of the project, the methodology was refined to satisfy the project's evolving needs. All project participants have gained valuable insights during the project, and it is hoped that their experiences will be useful to others working on activities that are similar in scope and nature.

1.2 ECONOMIC TRENDS IN COSTA RICA

In the early 1980s, the Costa Rican economy was severely affected by external shocks, including deteriorating terms of trade and rising international interest rates. These shocks had a drastic impact on the economy, and the country plunged into its worst recession in 30 years: real Gross Domestic Product (GDP) dropped over 7 percent in 1982 and inflation reached 90 percent. The economy recovered strongly after the crisis, as more balanced fiscal policies and a flexible exchange rate, helped by improvements in the terms of trade and increased capital inflows, stabilized the economy. GDP grew at an annual

average rate of almost 5 percent during 1983-1989, while inflation was reduced sharply to an average of 15 percent per annum.

The largest contributor to Costa Rica's GDP in 1989 was industry (22 percent), followed by agriculture (19 percent) and commerce (17 percent). The most dynamic industrial activities are food processing, the manufacture of plastic products, and the production of industrial chemical substances. Other industries include textile and clothing manufacture, leather products, and non-metallic minerals production. Employment in industry is estimated at 185,900 persons (19 percent of total employment in 1989).

Industry is undergoing great changes in its structure. When Costa Rica's highly protectionist tariffs were lowered, many companies switched from the production of goods destined for internal consumption and exports to the rest of Central America, to exporting new or improved products to third markets.

With respect to Costa Rica's balance of payments, the 1989 current account deficit is estimated at US $382 million. The goods Costa Rica exported during 1989 were valued at $1,457 million, while those it imported were valued at $1,743 million. Thus, Costa Rica's overall trade deficit amounted to $286 million.

Costa Rica faces a heavy long-term external debt burden. The huge public sector deficits of the early 1980s were financed largely by borrowing abroad. Costa Rica's public sector external debt was estimated to be approximately $3.75 billion at year-end 1989. Servicing this debt fully would have required about 50 percent of the income derived from its total exports.

Deteriorating public finances is a major concern for the economy's future. During 1989, the central government's fiscal deficit increased by almost 60 percent with respect to the previous year, reaching $165 million. This sum exceeds Costa Rica's agreement with the International Monetary Fund by approximately $77 million. Losses incurred by the Central Bank helped raise the overall public sector deficit to a sum equivalent to 5.4 percent of GDP. These losses stem from actions taken by the Central Bank in the early 1980s when the Bank ran large debts while trying to defend the exchange rate, and assumed debts owed by the private and public sectors. Currently, the Bank maintains a policy of frequent, small devaluations of the colon. Gradual devaluation helps the country to maintain a competitive export advantage without setting off inflationary spirals or uncertainty about future exchange rate moves. During 1989, the colon was devalued by 6.2 percent with respect to the US dollar. The average exchange rate in 1989 was 85 colones to the dollar, and in 1990 it was 92 colones to the dollar.

In 1989, credit to the private sector from private banks grew by 59 percent while it remained stagnant for state banks. However, state banks continue to hold a predominant share of the lending to both the private and public sectors. Borrowers paid state commercial banks an average 31.5 percent yearly for industrial, commercial, and personal loans. Home loans cost an average 25 percent in interest. State commercial banks paid their depositors 22.5 percent interest rates on 6-month certificates of deposit and 8.9 percent for dollar-denominated deposits in 1989.

Costa Rica's Consumer Price Index (CPI) increased by 10 percent during 1989, which was an improvement over the 25 percent CPI increase during 1988. For a labor force of slightly more than one million workers (out of a population of 2.7 million), official statistics indicate a rate of unemployment of 3.3 percent.

For 1990, Costa Rica's economic growth was slightly less than in 1989, estimated by the Central Bank at about 4 percent. Estimates of the increase in the CPI during 1990 vary between 20 and 30 percent. The country's international reserve position weakened in 1990 as a result of its increasing trade deficit and the use of official reserves to implement the buyback of Costa Rica's official debt with private international commercial banks. 1990 was a period of increases in import tariffs, fuel prices, utility rates, and the prices of basic foodstuffs.

1.3 THE ELECTRIC POWER SECTOR IN COSTA RICA

The development of the infrastructure to provide reliable and affordable electricity to industries, commerce, and households has been instrumental to the economic and societal development of Costa Rica. The Instituto Costarricense de Electricidad (ICE) was formed in 1949 with the primary goal of establishing this infrastructure to develop hydroelectric resources and to interconnect supply and demand centers through the construction of an integrated national electric grid.

In addition to ICE, the electric power sector includes two other major institutional bodies. Servicio Nacional de Electricidad (SNE) is a regulatory body, providing oversight and approval of rate adjustments and water rights for electric utilities in Costa Rica. Within the Ministry of Energy, Mines, and Natural Resources, the Direccion Sectorial de Energia (DSE) is mandated to perform and coordinate national energy planning. To execute this responsibility, DSE conducts energy sector studies to determine the extent to which new technologies could affect the energy market, to characterize the changing complexion of the market, and to determine the impact that technologies and energy programs will have on the demand for power. DSE and ICE collaborate on selected projects and programs in the electric power sector, but DSE's mandate goes beyond electric power to energy

issues in general, as they affect the development of the Costa Rican economy and national security.

Currently, ICE, like other electric utilities in the Central American region is suffering a financial crisis. In 1988 its debt service ratio (net income/debt service) was estimated at 0.64 instead of the minimum of 1.5 that is recommended by the World Bank and others. ICE's debt/equity ratio is also estimated at 1.8 instead of the maximum recommended 0.65. ICE has very limited capital available to finance new projects. Further, because the time required to bring a new plant on line is rarely less than three years and the country may be unable to secure financing within that period, an energy crisis could arise in the near future.

While the nation's electricity service is reliable, load growth could eventually deplete capacity reserves, resulting in a loss of system reliability. Also, the cost of electricity will increase as the demand exceeds the production of the most-economic sources, and financial constraints may force the implementation of suboptimal projects that can be brought on-line quickly. Such projects would rely on imported petroleum fuels for generation, creating further pressure on the country's balance of payments.

At present, ICE operates a total installed capacity of 858 MW, consisting of five major hydroelectric plants (717 MW) and four thermal power stations (141 MW). Over 1,300 km of high-voltage transmission lines, with an installed capacity of 3,200 MVA, connect these power stations to load centers. Fifteen thousand kilometers of distribution line provide approximately 85 percent of Costa Rica's residents with electric power, through the combined resources of ICE, two municipal distribution companies, and four rural electric cooperatives.

For several years after the completion of the Arenal/Corobici hydroelectric complex, ICE enjoyed significant surplus capacity, and rarely used thermal power plants. In recent years, however, ICE's ability to meet growing demand for electric power has diminished, due to delays in the development of major new geothermal and hydroelectric generating projects. The addition of three combustion turbines, combined with the rehabilitation of existing thermal power stations and the completion of the Sandillal and Toro hydroelectric projects, should enable the utility to meet near-term demand increases.

Costa Rica's energy consumption in 1989 totalled 3,493 GWh, with a maximum demand of 658 MW. Assuming a medium scenario growth in demand (about 6 percent per year on average), consumption is expected to rise to 8,561 GWh and maximum demand to 1,644 MW by 2005. ICE has developed an expansion plan to meet these needs, with the majority of generation relying on the continued exploitation of hydroelectric resources (858 MW of new capacity is planned). This plan also includes the expansion of

geothermal energy resources (165 MW of new capacity) and a significant increase in fossil-fired thermal power stations (272 MW of new capacity). These plants will range in cost from $378/kW (Moin gas turbines) to $2,863/kW (Miravalles I, geothermal).

The planning process has become much more problematic over the past decade, when several uncharacteristically dry years had a pronounced effect on ICE's ability to generate electric power from existing hydroelectric power stations. The probability of experiencing "average" annual rainfall is more suspect than ever before, after Costa Rica experienced in succession two of the driest years in its history. Indeed, ICE will need to carefully weigh supply mix, magnitude of capacity expansion, and demand reduction alternatives in future years.

1.4 INTEGRATED RESOURCE PLANNING

Integrated resource planning refers to the process of developing and implementing a power resource acquisition strategy for an electric power system. This process will enable Costa Rica to meet its electricity needs reliably and at the least possible total system cost, taking into account the uncertainty of forecasts, environmental considerations, and the compatibility of new resources with the existing power system.

1.4.1 The Concept of Integrated Resource Planning

Unlike conventional utility supply planning, in integrated resource planning, conservation (the efficient end-use of electricity) competes directly with generating resources for consideration in meeting the utility's future load growth requirements. Both supply and demand (energy and capacity savings) are considered formally in the utility's planning and resource acquisition processes. Because it recognizes the need to combine supply- and demand-side resources, integrated resource planning is sometimes called least-cost utility planning.

Least-cost utility planning has in part been associated with the lowest-cost mix of generating resources for a power system. However, the lowest system cost cannot be achieved without the full consideration of demand-side resources. Conservation or energy efficiency can be viewed as a resource for the electric power system. It can be estimated, forecast, scheduled, and purchased to help meet future load growth requirements for the entire power system.

In the electric power industry in general, the demand for electricity is assumed to be fixed. Power planners strive to forecast the future demand for electricity in all end-use

sectors (residential, commercial, and industrial) and to develop supply options to meet the given power demand. The supply options are usually in the form of power generating plants fueled by a variety of fossil, renewable, or nuclear fuels.

The options available to ICE for meeting electricity demand have expanded in recent years. The new options include conventional supply-side resources such as cogeneration from non-utility owned electricity generation. Furthermore, a range of new resources is also available on the demand side.

The implementation of a conservation acquisition program as part of an integrated resource plan can be accomplished directly by the utility or by designated agents of the utility, such as MIRENEM/DSE. However, the systematic effort to acquire conservation for meeting loads requires an integrated process of program design, demonstration, and evaluation to establish conservation as a resource that is available and reliable for the power system.

There are six reasons why ICE should promote efficiency in the end use of electricity:

1. **Efficiency will allow ICE to operate at the lowest possible cost of production.** This will help keep tariffs stable and will support national development efforts. Costly investments in new power plants will be delayed for as long as possible or avoided completely. Efficiency savings will also reduce the need for both peak and base load generation. Last, the costs of transmission/distribution system expansion, operation and maintenance, and fuel will be delayed or avoided.

2. **Through efficiency, ICE can help reduce customers' bills.** This will free up money that can then be spent elsewhere in the economy. It also ensures customer satisfaction with the cost of the service that ICE provides.

3. **ICE can reduce the uncertainty in projecting future electricity demand.** This will occur because a portion of future load growth is managed through efficiency investments.

4. **The risk of underbuilding or overbuilding new power plants will be reduced.** ICE's investments in new generating plants are usually large and have long construction lead times. Efficiency investments can be made in smaller amounts (with smaller tariff impacts) and more quickly adjusted to meet changes in demand.

5. **ICE will reduce environmental impacts caused by power plant construction and operation, regardless of the type of plant.** By decreasing energy use, energy conservation reduces energy production requirements, which mitigates the negative environmental impacts of energy resource development and production. Reducing the need for new power plants while assuring an adequate supply of electricity services will help enable a positive consensual approach to environmental management in the energy sector.

6. **ICE will reduce social conflict over natural resource utilization.**

1.4.2 Steps in Integrated Resource Planning

In order to carry out integrated resource planning, ICE and DSE will need to expand their existing forecasting and planning models to an integrated end-use forecasting model. ICE and DSE should examine all resources within the integrated resource planning analytical framework. The framework consists of a number of steps; these are described in general terms below.

Step One: The Load Forecast

The forecasting process begins with the recognition that because the future is uncertain, it is not possible to forecast electricity growth with precision. ICE and DSE have acknowledged this uncertainty by defining plausible boundaries for the likely growth of energy within the country. Most utilities develop sensitivity cases for load growth and usually choose a base growth scenario and high growth scenario. With integrated resource planning, the utility's planning flexibility would be enhanced by increasing the range of potential load forecasts from the current two, to three or four (e.g. low, medium low, medium high, and high). A probability analysis would then be conducted to determine the most likely range of future load growth.

There are many uncertainties involved in developing the load forecast. The current method of econometric forecasting cannot usefully reflect structural changes in the composition of demand in each sector. Uncertainty in the load forecast could be reduced by thoroughly analyzing the end-use of electricity for all uses in the residential, commercial, and industrial sectors. This end-use forecast provides more information to the forecasters on which specific loads might grow and improves the overall quality of the forecast.

ICE and DSE have already conducted some important analyses on end-use through the end-use metering of appliances. The end-use analysis can be expanded.

Step Two: Initial Resource Assessment

On a continuing basis, ICE (and DSE at a more limited level) already reviews the availability, reliability, and costs of all existing and potential generating resources. Integrated resource planning would simply expand ICE's resource review to consider demand-side resources. This approach explicitly recognizes that there is no demand for electricity per se. Rather, electricity provides services such as lighting, cooling and drive power. These services can be provided by increasing the supply of electricity through the addition of new generation. However, these service needs can also be met in part, at a lower cost, by increasing the efficiency of customers' electricity use.

Examples of Utility Resource Options

Supply-Side Options

Conventional plants:
- Large fossil-fueled (oil, gas, lignite, coal)
- Hydroelectric
- Nuclear
- Small combustion turbines
- Life extension of existing plant
- Transmission expansion or upgrade

Non-utility owned generation:
- Cogeneration
- Independent power producers

Renew le
- Geothermal
- Solar, biomass
- Wind, others

Import purchases

Demand-Side Options

Energy efficiency options (customer):
- Efficient building design
- Efficient appliances
- Efficient lighting
- Efficient air conditioning
- Efficient motors
- Efficient industrial processes

Minimum equipment efficiency standards:
- Solar hot water heating

Energy efficiency options (utility):
- Increased boiler efficiency
- Reduced transmission losses
- Advanced transformers
- Load management
- Utility direct control of appliances

Tariffs:
- Time-of-day
- Interruptible
- Incentive

The environmental impacts of both supply- and demand-side resources are also analyzed under this planning approach. The environmental impacts of efficiency are obviously different than those of any generating option. Every time a new power plant is built, regardless of its type, there is a degrading impact on the environment. Efficiency reduces the need for more power plants and therefore reduces environmental impacts as a direct benefit, without additional cost. Environmental benefits begin immediately with efficiency. A number of U.S. utilities explicitly recognize the environmental cost benefit of efficiency and give efficiency a bonus credit when analyzing the comparative costs of supply and demand resources.

The products of this resource assessment are "generation supply curves" for each resource. These supply curves estimate how many megawatts of a resource are available across a range of costs.

All quantifiable costs of supply resources are examined, including construction, operation, maintenance, transmission, distribution, decommissioning, and environmental cost components. Because the utility will have to finance the conservation (just as it does generation) to ensure its availability, demand-side costs are fully examined, including capital costs, installation, replacement, and related costs of technologies and programs that would be operated to acquire the efficiency resources. The program-related costs include administration, marketing, and evaluation.

Resources can be divided into "cost-effective" and "promising" categories. Cost-effective resources must use commercially available technologies, have predictable and competitive costs and performance, and must use a demonstrated resource base. The resource must not have institutional constraints (legal, financial, regulatory, or political) and it must be environmentally acceptable according to current laws, policies, and social conditions. The promising categories would be those resources that are not commercially available but should be followed closely in the future.

These criteria provide a consistent basis for comparing the costs and benefits of both supply- and demand-side resources.

Step Three: Efficiency Supply Curves

Generation supply curves serve as the models for developing efficiency supply curves, which are also called conservation supply curves. These supply curves simply describe the amount of energy or capacity available at a given cost. Efficiency supply curves can define the technical potential of cost-effective demand-side resources and are the focus of

this report (see Chapter 2). The procedure for developing these supply curves involves four major steps:

- Defining the baseline of current energy use intensities, load shapes, equipment saturations, and stocks, disaggregated by individual end-use.
- Developing an inventory of demand-side savings measures, including cost data, per unit savings, load shape impacts, and interactive effects among measures (e.g., the heat from lighting can affect air conditioning requirements).
- Combining this inventory with end-use based growth projections to develop a series of macro supply curves of the demand-side resource over time.
- Determining projections of market potential and penetration rates of savings measures to calculate the expected efficiency to be gained over time.

Step Four: Integrated Resource Analysis

This step combines all the information known about potential supply- and demand-side resources and analyzes the lowest-cost combination of all resources that would be needed to meet a range of future energy needs. The compatibility of each resource with the existing power systems is determined. Risk management is also analyzed in this step.

Several resource characteristics can be identified as important in providing flexibility to adapt to uncertainties and risk in the future. Resources with short construction lead times, small plant sizes, and low capital costs can reduce risk. Resources that can be brought into operation quickly give the utility a much better chance of matching supply to energy needs. These "efficiency resources" reduce the uncertainty of future load growth. In addition, efficiency, when built into the construction of new buildings, provides savings over the life of the building. Efficiency resources come in smaller units and are on-line immediately when installed. All of these characteristics point toward the benefits of choosing efficiency resources.

Step Five: Policy Considerations

This step formally recognizes that while system analysis is an important component of decision making, informed judgment is ultimately the most important factor. Policy considerations include resource diversity; fuel cost escalation; national, regional, or local

economic development policy; and financial and environmental constraints; all of which play a part in the decision making for final resource selection.

Step Six: Power Plan and Resource Portfolio

The power plan is complete after the integrated resource process is defined. A range of supply- and demand-side resources are identified to meet future load scenarios. The resources are ranked so that the most cost-effective ones are developed first. The plan includes a resource portfolio that describes a schedule and sequence for resource acquisition. The costs of the plan are also finalized and presented. These costs determine the total system costs to the utility and therefore determine how tariffs must be structured to recover the utility's total costs.

This approach may not result in the lowest electricity tariffs in the short run, but it will result in the lowest total long-term cost of providing electricity services to all customers. This, in turn, will enhance the possibility that tariffs will be lower than they would have been under a generation-based system plan.

Step Seven: Action Plan

Based on the final power plan, specific actions are identified that are necessary to meet the plan's objectives. Actions are specified for ICE, DSE, other government agencies, and the private sector. Implementation schedules and budgets are then negotiated within the timeframe and power requirements identified in the resource portfolio.

CHAPTER 2: DEMAND-SIDE ENERGY EFFICIENCY IMPROVEMENTS

2.1 CHARACTERIZATION OF ENERGY USE

In 1989, Costa Rica's total electricity consumption was 3,100 GWh, with a peak demand of 658 MW. The industrial sector accounted for almost 28 percent of the total consumption. The general sector, which comprises the commercial and public sectors, consumed about 23 percent, public lighting about 3 percent, and the residential sector about 47 percent. Exhibit 2-1 shows the breakdown of sectoral electricity consumption for 1989.

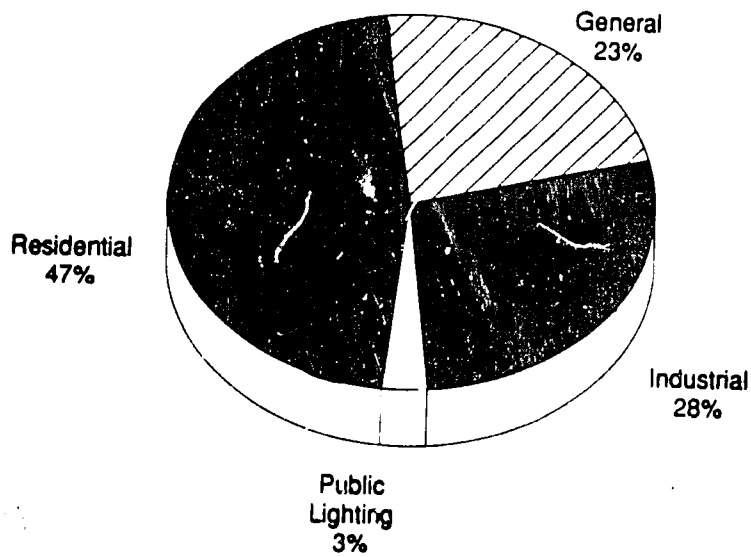
For the year 2005, ICE has estimated that the electricity demand for the industrial, general, and public lighting sectors will decline in relative terms, consuming 26 percent, 17 percent, and 2 percent, respectively (see Exhibit 2-2). The share for the residential sector will increase to 55 percent, indicating its importance in Costa Rica's power sector.

From 1965 until 1981, the industrial sector's energy consumption increased steadily, both in real terms and in percentage of the nation's energy use (although it experienced a brief decline in the mid-1970s). Since that time, its share of total energy consumption has steadily decreased, although in absolute terms, it has been increasing. ICE projects that industrial sector energy consumption will reach 1,500 GWh by the year 2000 and surpass 2,000 GWh by 2005. The average annual growth rate for the industrial sector is expected to be 5.8 percent to the year 2005.

In 1984, Costa Rica's residential sector consisted of 400,632 customers. This sector grew to 552,193 customers in 1989 (an increase of approximately 38 percent in five years). The average annual consumption per customer has increased from 2,588 kWh in 1982 to 2,820 kWh in 1987, when consumption peaked. The average consumption per customer has decreased to 2,710 kWh in 1988 and to 2,641 kWh in 1989.

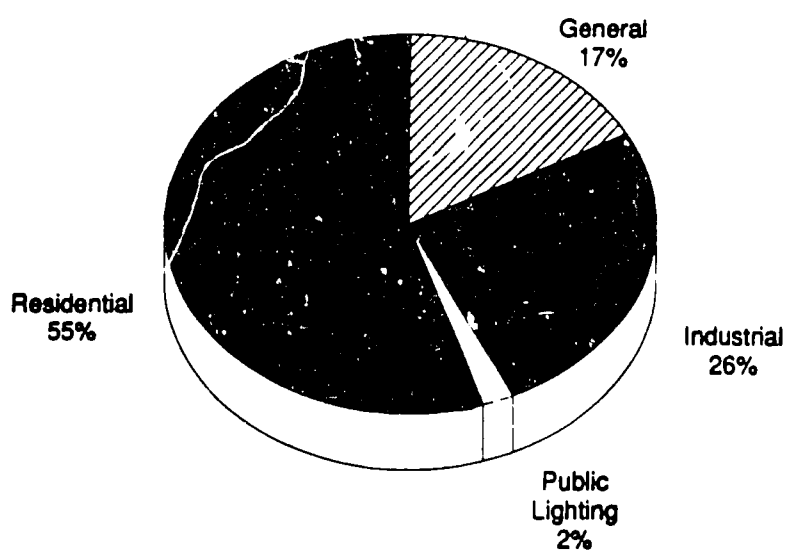
This reduction resulted from a combination of factors. In October 1987 ICE started an energy conservation awareness campaign geared to making its customers conscious of energy conservation and to avoid the waste of electricity. At the same time, there was an increase in tariffs. Exhibit 2-3 shows the impact of these actions on CNFL (the National Power and Light Company) customers. For the period 1984-1989, CNFL did not undertake an expansion of the distribution system to rural or marginal areas, therefore eliminating the possibility of adding new lower-income customers to the grid.

Exhibit 2-1
Costa Rican Electricity Consumption by Sector, 1989



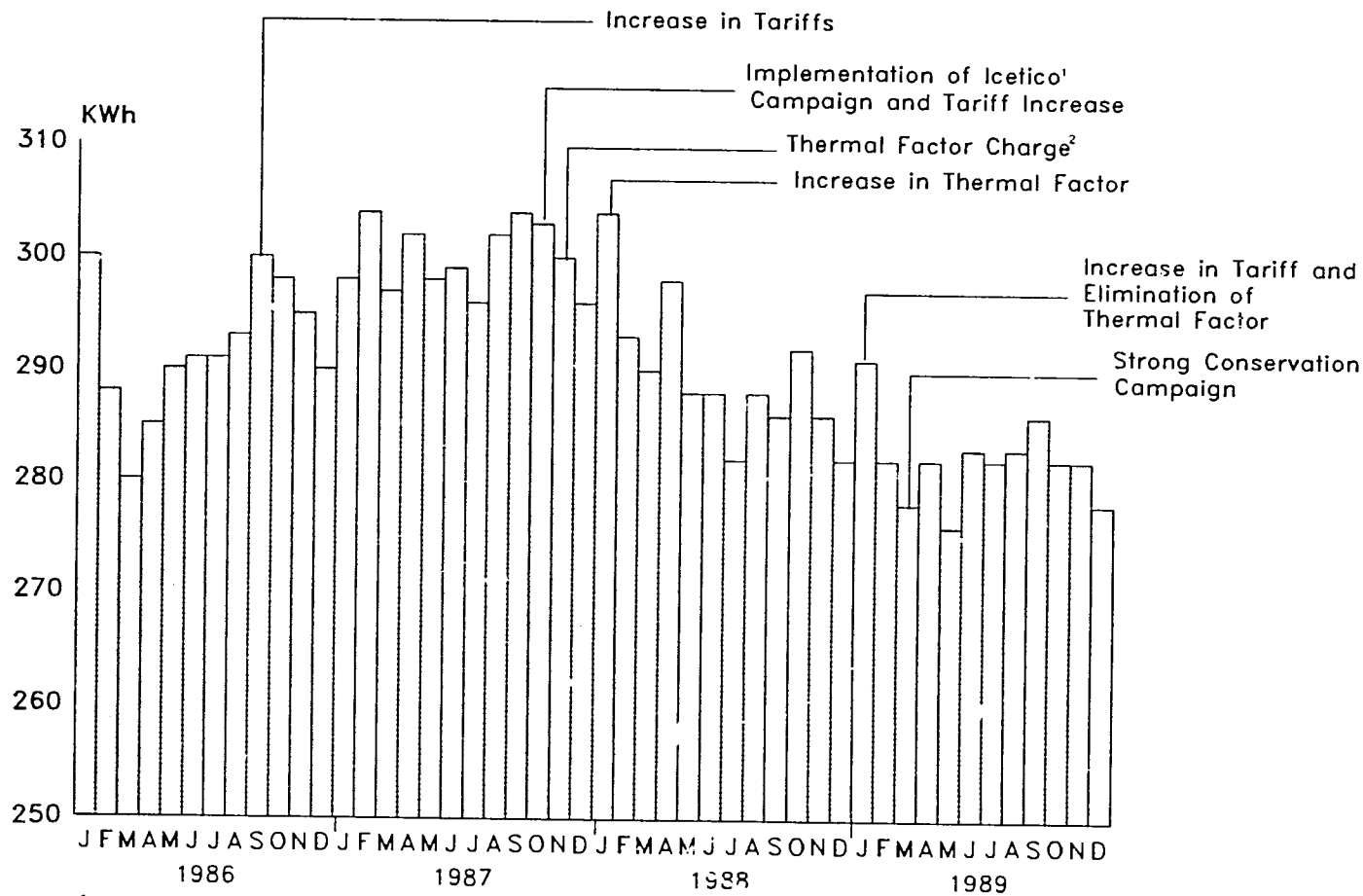
Source: ICE.

Exhibit 2-2
Costa Rican Forecasted Electricity Consumption by Sector for the Year 2005



Source: ICE Mercado Electrico, Medium Scenario, September 1989.

Exhibit 2-3
Impact on Residential Customers of Energy Conservation Awareness Campaign and Tariff Increases, 1986-1989



[1] Icetico is the ICE mascot for energy conservation.

[2] During periods of high thermal cost and/or above normal use of thermal power generation (e.g., drought) a thermal charge is used

Source: ICE

The residential sector's consumption in 1989 was over 1,400 GWh and is projected by ICE to increase to over 3,100 GWh by the year 2000 and surpass 4,300 GWh by the year 2005. The average annual growth rate for the residential sector is projected to be about 7 percent to the year 2005.

The public and commercial sectors have been combined to form what is termed the general sector. Much less is known about this sector than the other sectors in Costa Rica. The general sector's electricity consumption in 1989 was close to 700 GWh and is projected by ICE to increase to almost 1,100 GWh by the year 2000, and to over 1,300 GWh by 2005. The average annual growth rate for the general sector is expected to be 4.3 percent to the year 2005.

2.2 DEMAND-SIDE MANAGEMENT STUDY METHODOLOGY

In this study, a power sector efficiency assessment was conducted to identify the most appropriate target areas for improving energy efficiency in Costa Rica -- from generation, to transmission and distribution, and to end use. This is only a first attempt within the concept of integrated resource planning, and this study should provide a framework for developing pilot programs and technical assistance in this area.

In the benefit/cost analysis of the energy conservation and load management measures identified in this study, two approaches were used in order to 1) rank key conservation technologies or load management programs, and 2) examine the impact of alternative measures on both ICE and on the overall foreign exchange balance. The Cost of Conserved Energy/Demand approach was used for the ranking and the ELECTROPLAN model was used for the impact evaluation.

2.2.1 The Cost of Conserved Energy/Demand

For the purposes of ranking and as a first approximation of the economic viability of each demand-side conservation measure, an annualized factor called the cost of conserved energy/demand (CCE or CCD) was utilized. The CCE or CCD can be determined using the following formula:

$$\text{CCE or CCD} = \frac{\text{Incremental ECM Cost x CRF}}{\text{Amount of Energy or Demand Conserved Annually}}$$

where

ECM = The energy conservation measure
CRF = The capital recovery factor = $\frac{r}{1 - (1+r)^{-n}}$

Here, r is the discount rate and n is the number of years over which the investment is amortized.

The incremental ECM cost is the differential between the net present value (NPV) of the ECM and the NPV of the alternative (the currently used technology or procedure). The NPV calculations consider the change in operation and maintenance costs related to that measure. For measures that will require full replacement to achieve a significant penetration rate (e.g., stove burners with a life over 10 years), then only the full replacement cost was considered. For ECMs with lives that are not equal to a multiple of the present technology life, the NPV was taken over two or more ECM lifetimes so that a multiple was reached.

The capital recovery factor (CRF) spreads the incremental cost of the ECM over the life of the measure, giving an annualized or levelized cost. Any changes, including changes in related labor costs, are included in the NPV calculations. The amount of energy or demand conserved annually is the energy saved in kWh or kW per year by one unit of the ECM. The CCE or CCD is given in US cents per kWh. This can be compared to the ICE avoided cost. ICE has estimated the average overall long-run marginal cost (LRMC) of the system at US 6.5¢/kWh. At times of system peak, the avoided cost has been estimated by ICE at up to US 10¢/kWh.

In principle, any measure represented at a cost below the ICE avoided cost is attractive and should be evaluated in greater detail. For the energy conservation programs, the CCEs illustrated in the conservation supply curves do not include program implementation and administration costs and therefore, a margin needs to be considered. The program implementation costs are, however, included in other parts of the analysis. For the CCD conservation supply curves, some of the associated administrative costs (e.g., program implementations costs) are included because programs like daylight savings time and the interruptible tariff are more institutional than technology driven and are larger in scope.

As a next step in this study, the programs should be evaluated in greater depth, with the proper voltage-level LRMC per customer class and more refined end-use data and cost estimates.

2.2.2 The ELECTROPLAN

Based on 1) the assumed penetration rate for each measure, 2) a detailed technical analysis of the likely energy savings and use patterns of the technology (in the case of a conservation measure) or user response to a load management measure, and 3) using the ELECTROPLAN spreadsheet model, we quantified a measure's impact on the load curve. Groups of individual programs (or measures) were combined into a plan, and the aggregate impacts on the load curve were determined.

The impact on the system peak was then used to estimate the impact on the capacity expansion plan, and plants were modeled to seasonal load-duration curves to assess the impact on fuel consumption. The financial consequences of these impacts were analyzed in a financial model. ICE's administrative costs for a demand-side management program and any revenue losses associated with kWh savings from conservation measures were also included in the model.

Finally, the assessment of the foreign exchange impacts is compared with the need for increased equipment imports associated with the demand-side management (DSM) measures, with savings in oil imports that follow from conservation measures, and savings in foreign debt service associated with lower investment requirements for supply-side expansion.

2.2.3 General Study Assumptions

Cost of Capital and Penetration Rates

The real discount rate (net of inflation) used in this analysis is 12 percent, which is the same rate used by ICE and the multilateral lending agencies in Costa Rica. A higher discount rate (e.g., 20 percent) could have been used for the financial analysis of the residential sector (see below) due to this sector's more risk-averse nature. However, because this analysis was conducted from the point of view of the national economy, for the purpose of simplification, the discount rate utilized was the same for all sectors based on the estimated cost of capital to the economy.

The economic analysis was based on costs net of taxes and at the ICE estimated long-run marginal cost. Shadow prices for labor and the local currency (the colon) were estimated at the ratio of 1 due to the low unemployment rate and the open-market colon exchange rate. In addition to conducting a benefit/cost analysis from the national economic

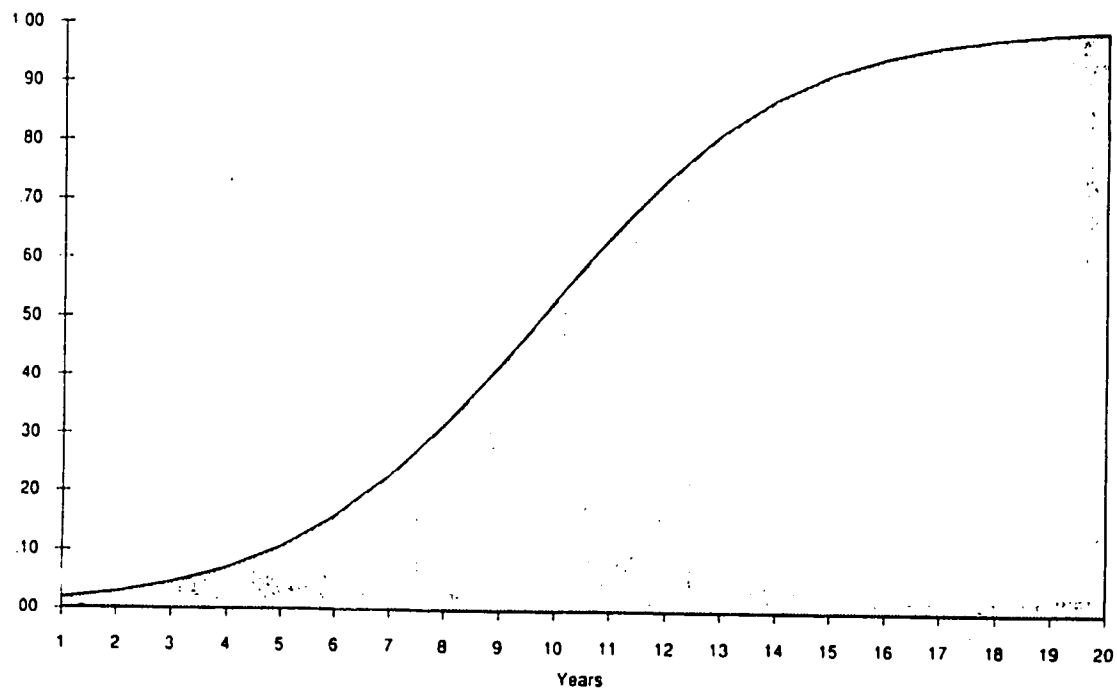
perspective, a financial analysis was carried out to rank the ECMs in terms of their financial attractiveness to the end-user, considering taxes and current electricity tariffs.

Penetration rates were also estimated based on the extent of acceptance of an ECM. These rates can vary greatly depending on how the technology is introduced and financed. Factors affecting penetration rates are previous experience with the ECM, financial incentives and costs, user confidence, availability of spare parts, and perceived usefulness, to name a few.

Another aspect of penetration rates is the rate at which maximum penetration is achieved. Typically, the rate of penetration of a new technology is very slow at first because of the lack of confidence in the technology. As it gains acceptance, the rate increases substantially. At about 70 percent of maximum penetration, the rate of penetration again slows until maximum penetration is reached.

The penetration rate curve used by the Electric Power Research Institute (EPRI) to project penetration rates for new technologies is widely accepted and was used in this analysis. This curve is depicted in Exhibit 2-4 and can be modeled by the following formula:

Exhibit 2-4
EPRI Penetration Rate Curve



Source: Electric Power Research Institute.

$$\text{Rate of Penetration} = \frac{1}{1 + e^{A+Bt}}$$

$$A = \text{Ln}\left\{\frac{1 - P_1}{P_1} - (Bt_1)\right\}$$

$$B = \frac{\text{Ln}\left(\frac{1-P_1}{P_1}\right) - \text{Ln}\left(\frac{1-P_2}{P_2}\right)}{t_1 - t_2}$$

P_1 = Assumed penetration at time t_1
P_2 = Assumed penetration at time t_2

Payback and Energy/Demand Savings

The payback period for each technology was calculated to assist in estimating the penetration rate. Two paybacks were calculated. The first was the simple payback. It included only the differences in costs between the two measures; the life of the measures was not considered here. In the second, where the energy-conserving technology replaced an existing technology (such as energy-efficient lamps), the difference in terms of NPV of the installed cost between the technologies was used as the investment for the payback calculation.

To determine the total energy conservation potential for all ECMs, the individual contributions of each ECM were summed on an annual basis. A curve was then developed with the additive energy conservation potential, by ECM, plotted against the cost of conserved energy or demand. This yields a supply curve for energy conservation. It shows how much conservation can be "purchased" for a given cost per kilowatt-hour or kilowatt as if it were new generating capacity.

Generally, energy savings for each measure were determined on a country-wide basis by some of the sample calculations given below:

kWh saved = % energy saved by ECM x % of total energy consumed by given technology x penetration rate x total estimated consumption for a given year

kWh saved - motors = motor hp x 0.746 kW/hp x hours of operation x motor load % x (1 - (STD EFF % / EE EFF %)

Where: STD EFF = efficiency rating of standard-efficiency motor
EE EFF = efficiency rating of energy-efficient motor

kWh saved - belts = motor hp x 0.746 kW/hp x hours of operation x motor load % x (savings % / motor efficiency)

kWh saved - lights = (STD wattage draw - EE wattage draw) x hours of operation / 1000 W/kW

The demand savings (MW) are coincident peak demand savings: the demand reduction that can be anticipated to coincide with times of peak system demand. Peak demand savings were calculated in two ways. The first involved recreating, in half-hour segments, the end-use load profile for a 24-hour period as attempted in the ELECTROPLAN model. The second used average demand savings (consumption savings divided by the number of hours in the year). Then, the end-use non-coincident peak load factor was divided into the average demand savings, which yields the maximum demand savings. Finally, the maximum demand savings was multiplied by the coincident peak factor to obtain the coincident peak demand savings.

Demand Forecasting, Elasticities, and Equipment Cost Estimates

ICE and DSE carry out demand forecasting independently. ICE projections to the year 2005 are based on an econometric model developed by the Inter-American Development Bank (IDB) in 1984. The main variables in the model include: GDP, number of residential customers, size of commercial sector, value added for the commercial and industrial sector, retail price of electric appliances, electricity prices, and fuel substitution. Projections for the industrial sector are largely based on an aggregated historical trend rather than on one disaggregated by major industries with their expansion programs and a sensitivity analysis. DSE projections are based on a macroeconomic model and are more empirical. They include a more detailed end-use breakdown.

With respect to consumption elasticities, based on the IDB study, ICE uses a GDP elasticity of +0.50 for the general sector and +0.20 for the residential sector. This means that if GDP would increase by 10 percent, the electricity consumption for the residential sector would increase by 2 percent. The consumption elasticity for prices is

estimated at -0.5. Therefore, a price increase of 10 percent would be accompanied by an electricity consumption decrease of 5 percent.

The sectoral electricity demand projections used in this analysis were taken from the medium scenario of ICE's *Mercado Electrico*, published in September 1989. The projections consider the above elasticities and the tariff increases necessary for ICE to be able to finance its own investment program and cover its debt. For the end-use consumption breakdowns and current penetration rates, DSE data were utilized.

Cost figures used in the calculations were based on prices in Costa Rica when available, or in U.S. prices if not. The prices are only approximations since there is a large variation in prices and sizes (e.g., motor belts). Costa Rican labor costs are based on US $4 per hour.

2.3 LOAD MANAGEMENT MEASURES AND SAVINGS

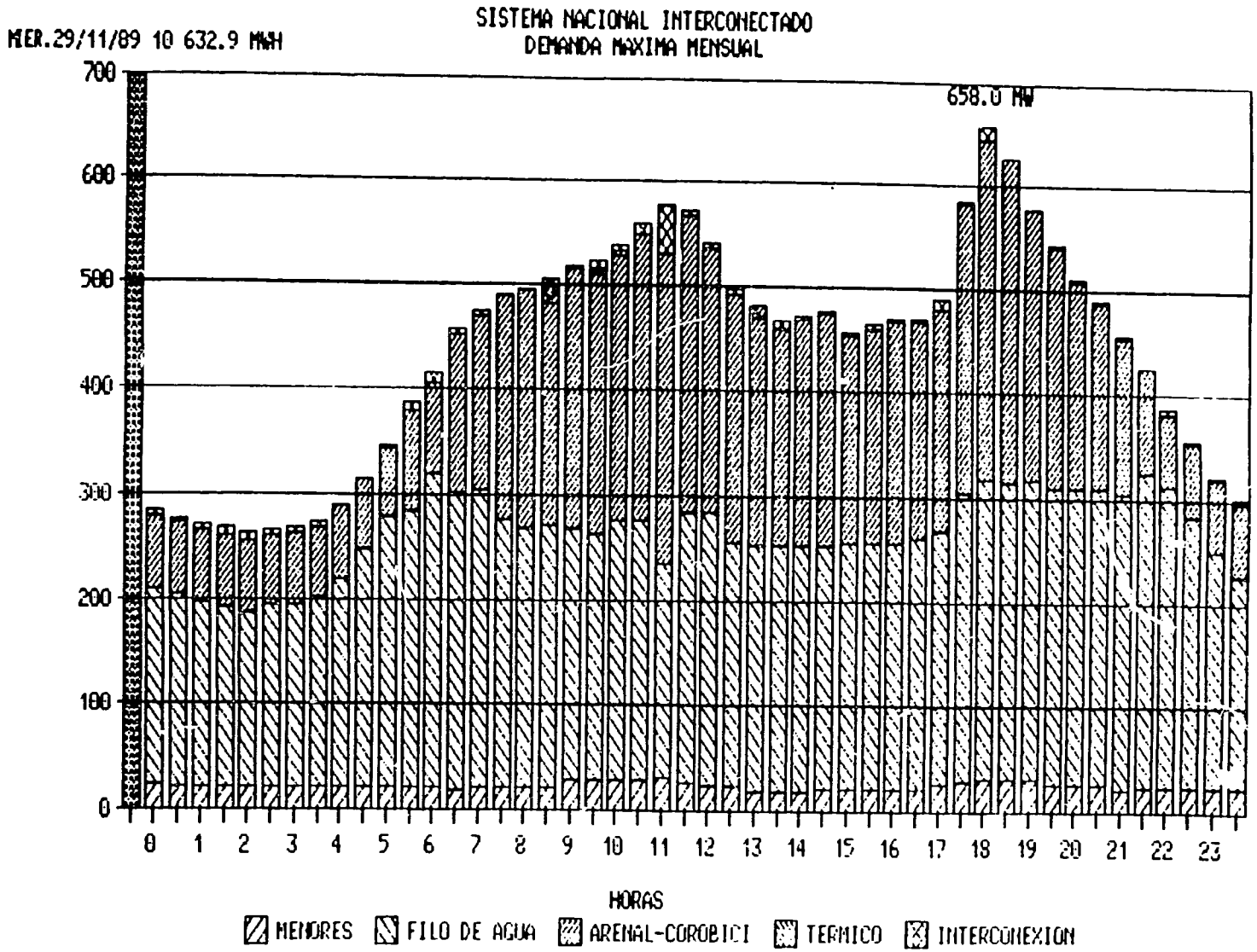
Load management is defined as those activities or actions that utilities take to influence the timing and magnitude of their customers' use of electricity. Utilities use load management in order to modify the utility load profile to the most efficient configuration.

ICE's system load profile for the day of system peak in 1989 is shown in Exhibit 2-5. This curve has a morning peak at approximately 11:00 a.m. and a more pronounced afternoon peak at 6:30 p.m. The morning peak on this day is approximately 93 percent of the afternoon peak's maximum demand.

Between 1981 and 1985, Costa Rica's electric power sector experienced a steady rise in annual peak demand, mainly due to a rapidly increasing use of electricity for cooking and lighting. Other major contributors to the system's evening peak are other household loads, multi-shift industrial high load factor facilities, and retailing operations. Statistics for 1986 through the first quarter of 1988 indicated that peak demand was rising at an annual rate of close to 10 percent. It thus became necessary to modify ICE's 1987 expansion plan because it was based on a projected total system demand growth of around 5 percent annually.

In response to a request from ICE, A.I.D. financed the pilot Load Control Demonstration Project in 1988 to demonstrate that the coincident peak demand of a sample of industrial and commercial customers can be reduced by 10 percent. An analysis of 24 companies participating in the project showed that these companies reduced their evening peak demands by 3 MW. Since the combined demand for this group of customers was 21 MW

Exhibit 2-5
ICE System Load Profile for the 1989 System Peak Day



Source: ICE Small Hydro Plants Run of the River Thermal Interconnection

during peak hours in 1987, they achieved a total demand reduction of 14 percent compared to the same time period in 1988.

A key element of the demonstration was the monitoring of customers' load profiles to evaluate the impact of the project and to provide feedback to guide the energy management efforts of participating customers. This was to be accomplished by means of Sangamo DataStar electronic pulse recorders linked by telephone lines to a central computer situated in the ICE meter laboratory in Colima (near San Jose). The recorders can be interrogated centrally, and hard copy demand data, including graphics, can subsequently be generated by the computer. This equipment consisted of meters with a capability to record daily load data on a magnetic tape cartridge. Data from these recorders were transferred to computers at ICE for analysis and billing.

By and large, the project participants relied on manual load control to achieve their demand savings. Typically, they used their own technical staff to study load reduction priorities and to conduct trials with manual controls, using little or no equipment. Some companies proceeded to a second manual control stage by installing simple systems, such as signal lights and alarms, to remind plant staff to implement load control procedures. In a small number of cases, a limited degree of automatic control equipment was installed.

The peak reduction proposals and programs evaluated in this study including the following:

- Implementation of daylight savings time to displace the lighting peak from the cooking peak.

- Modification of the interruptible tariff for industrial and large commercial customers with monthly billing demands over 100 kW and/or monthly consumption over 20,000 kWh.

- Development of a load control program for commercial and small industrial customers with demands between 10 kW and 100 kW.

- Implementation of a residential load control program for customers with electric water heater tanks.

- Implementation of a residential load control program for customers with electric refrigerators. Duty cycling can be used to reduce demand during peak days.

- Implementation of a mandatory residential time-of-use rate for customers with monthly consumption over 500 kWh per month.

A discussion of the implementation of a demand limiting system, which allows the utility to limit the household demand that may be imposed by the customers, is also covered at the end of this section, but in less detail because of the lack of data and the uncertainties involved.

2.3.1 Daylight Savings Time

In Costa Rica, the afternoon meal preparation time and the beginning of the illumination period tend to coincide. This results in the coincidence of the residential cooking peak and the lighting peak (see Exhibit 2-6).

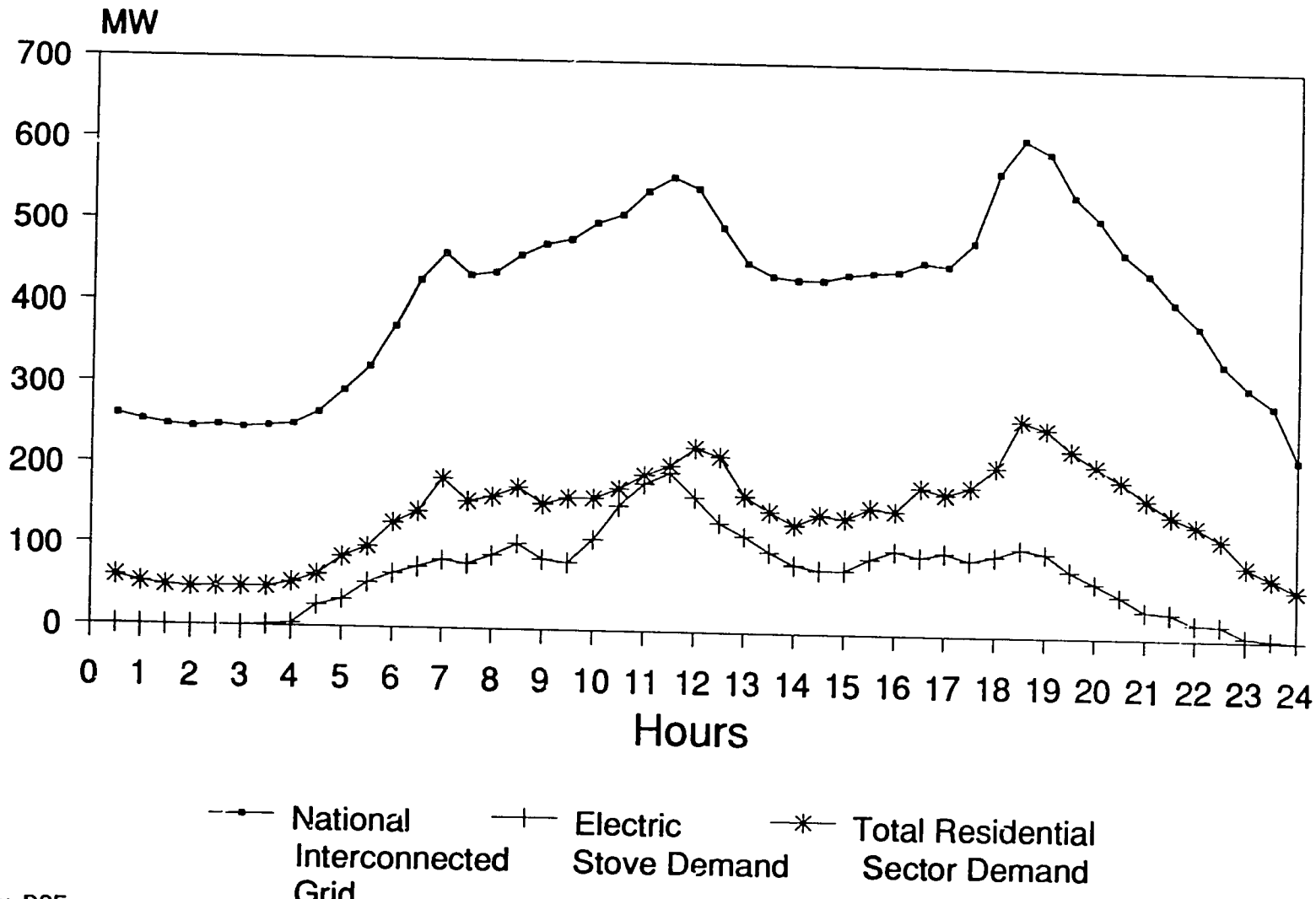
In analyzing Costa Rica's load profile and observing the occurrence of illumination needs, it appears that moving the clock forward by one hour could have a significant impact on displacing the lighting peak so that it no longer coincides with the cooking peak.

The public lighting sector accounted for over 20 MW of the nation's system peak in 1989. Assuming that one third of the residential sector's contribution to lighting energy use is shifted at the time of system peak, it is conservatively estimated that this would reduce at least 23 MW of additional demand from the peak. This displacement of the lighting peak represents a potential demand reduction of 43 MW at the time of system peak. Significant energy savings could also be achieved due to the reduced need for illumination in the early evening hours. The potential for peak demand reduction from implementing daylight savings time in the year 2005 is 87.6 MW based on an annual program. The analysis for determining the demand contribution for the public lighting sector and the projections and calculations for daylight savings time are included in Appendix 1.

The implementation of daylight savings time will require minimal expenditures, principally for the promotion costs associated with convincing the public of its merits. The estimated cost of conserved demand for this program is US $0.26/kW compared to the ICE estimated long-run marginal cost of $64/kW to $80/kW per year.

However, before such a program is implemented, there are many other issues that need to be analyzed in detail. These include the important issues of labor, transportation, and

Exhibit 2-6
Coincidence of Residential Sector Cooking Peak and Lighting Peak



Source: DSE

safety.[1] Therefore, a socio-economic study should be carried out before implementing daylight savings time.

In marketing a daylight savings time program to the general public, it should be emphasized that this program will help to reduce the amount of future tariff increases plus the need to burn fossil fuels.

2.3.2 Interruptible Tariff Modification

Under interruptible service, the utility provides customers with an incentive (usually in the form of reduced demand charges) for allowing the utility to interrupt all or part of their load during "critical days" for the utility. (Critical days are defined as those days during which the utility's generation is not sufficient to meet the expected utility load while maintaining normal operating reserves.)

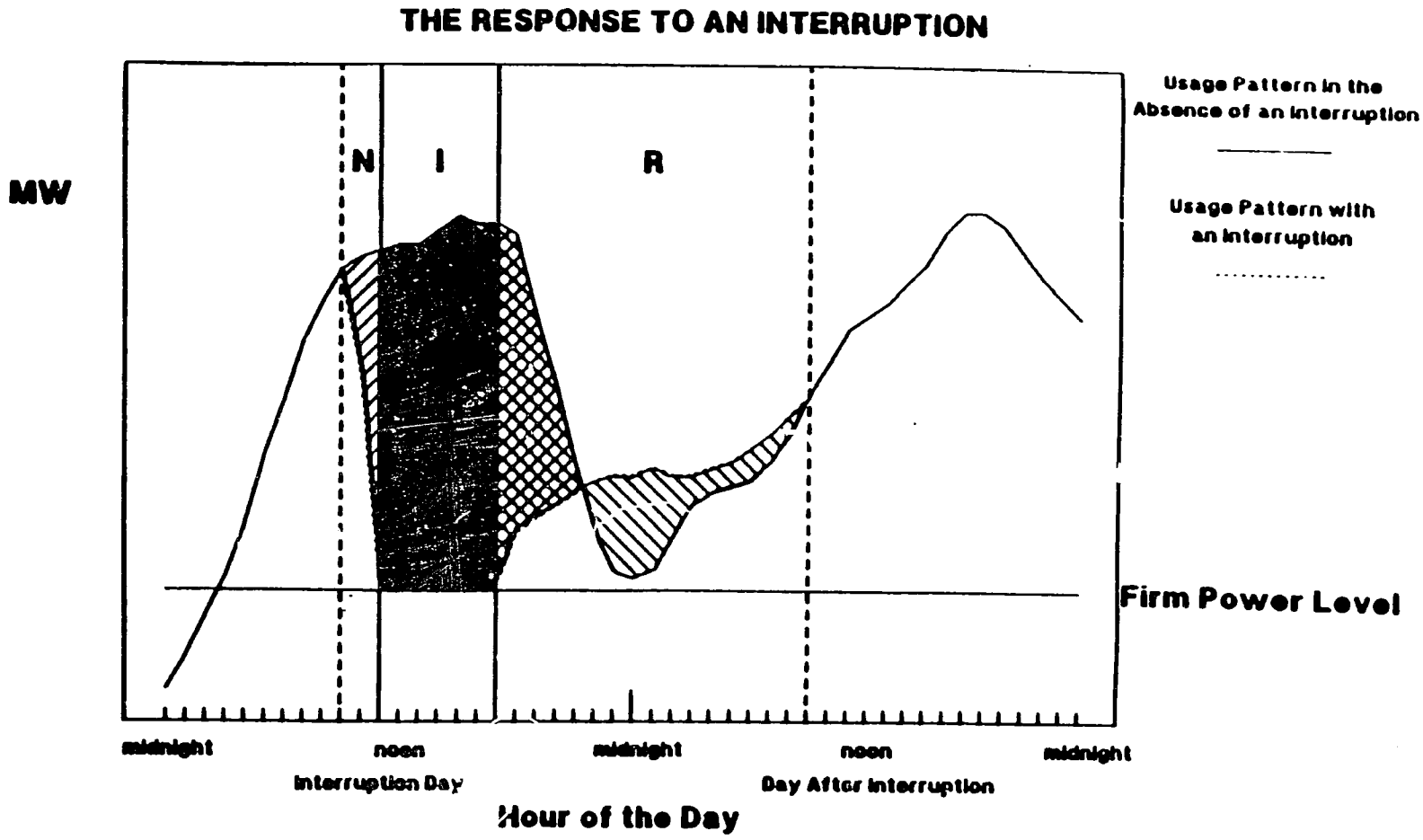
Utilities have found that the industrial sector usually has the potential to provide a large amount of reduction from very few customers in a very short period of time. Several studies have been performed on interruptible rates in the United States. A sample profile for an interruptible customer used in these studies would be similar to the graph shown in Exhibit 2-7.

ICE has established an interruptible rate (*tarifa interrumpible*, T-11), available to customers with demands of 500 kW and higher, as well as a time-of-use tariff T-8 for industrial customers to encourage energy use during off-peak hours. The maximum number of hours that the customer may be interrupted is 300 hours a year, with interruptions not to exceed six hours per day. This could represent 50 days if loads are interrupted for six hours per day, or 100 days if they are interrupted for three hours per day.

However, based on its experience over the past few years, there should not be any need to control customer loads for more than two to four days (approximately 6 to 12 hours) per year. The present minimum operating reserve target that ICE maintains on a daily basis is 10 percent according to the ICE System Control Center (Centro de Despacho). Assuming that reserve margins were reduced over the next ten years, it is possible that the interruptible period may be needed as much as 10 days (30 to 60 hours) per year.

[1] As this report was being prepared, ICE implemented daylight savings time on a seasonal basis.

Exhibit 2-7
Sample Profile for an Interruptible Customer



N = Notification Period
I = Interruption Period
R = Recovery Period

Source: Electric Power Research Institute

Power interruptions are most likely to occur during March-April and August-November on an annual basis. These are the months during which plant maintenance is performed and consequently, the reserve margins are at their lowest levels (see Exhibit 2-8).

Currently, however, there are no customers on this interruptible tariff for three reasons:

- most customers are not aware of this tariff
- the tariff has a very large number of maximum control hours, which tends to discourage customers due to the potential for significant impacts on their production
- ICE has not promoted this rate in the past.

During the Costa Rica Load Control Demonstration Project, Firestone (also known as Industrias Accron) was informed of the availability of this rate and received an explanation of how interruptible rates are used in the United States to reduce the utility's peak demands during "critical days."

Firestone solicited this rate for their facility from ICE. ICE has been studying the situation to determine how interruptible rates should be handled in order to inform Firestone of whether they should or can participate in the interruptible tariff. Firestone is very anxious to start on this tariff due to the potential for savings on this rate.

The difference in kW demand charges between the industrial tariff (T-3) and the interruptible tariff (T-11) is:

T-3 for demand charges over 87 kW	$11.68/kW
T-11 for interruptible demand	$ 5.81/kW

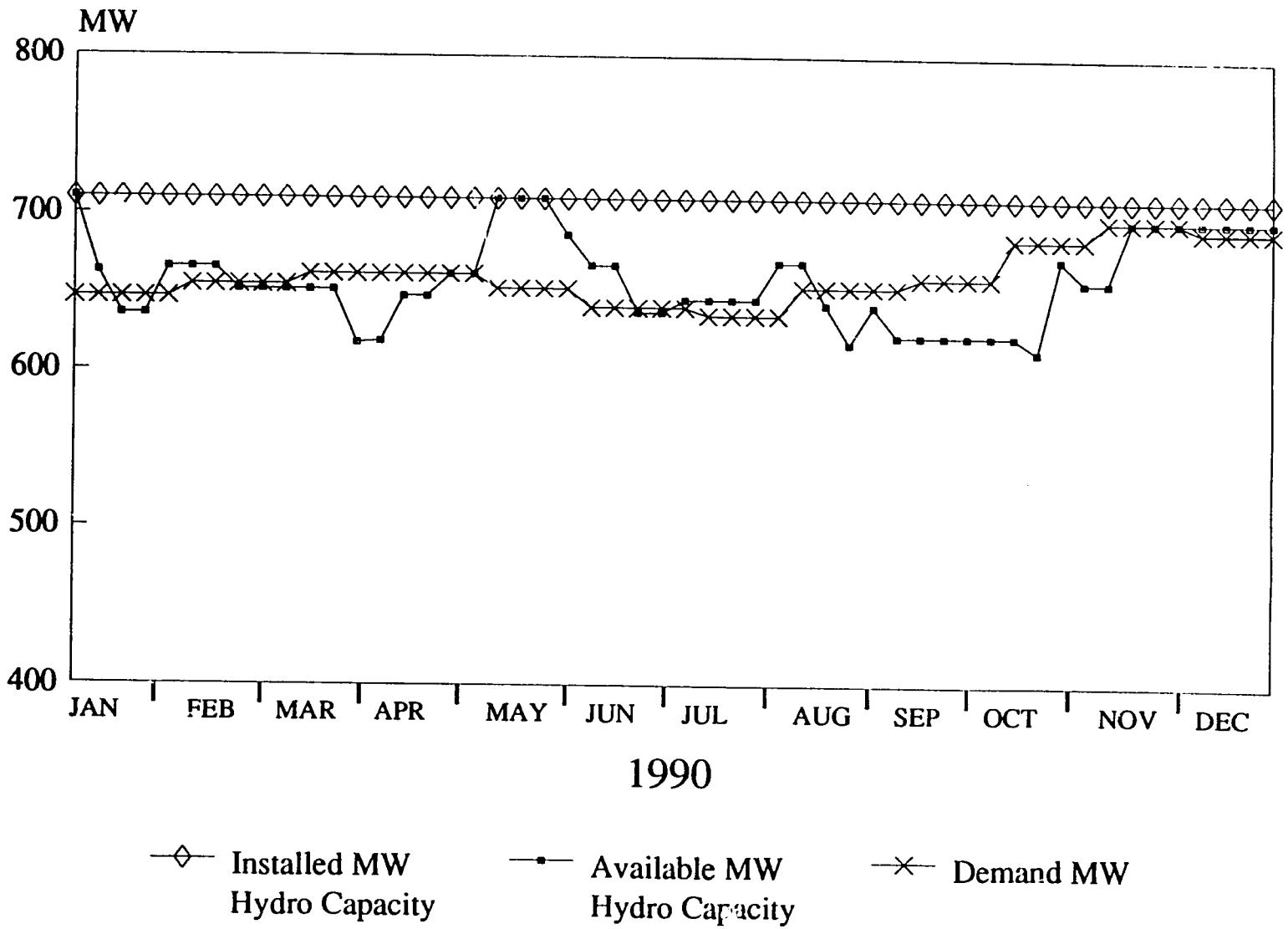
Savings per kW of interruptible load	$ 5.87/kW

If Firestone were to reduce its demand by 1,000 kW on critical days, then it would receive the following financial benefit:

1,000 kW x $5.87/kW = $5,870/month.

This calculation is based on an exchange rate of 85.95 colones per dollar (the exchange rate as of April 1990).

Exhibit 2-8
Hydro Availability and Plant Maintenance in Costa Rica, 1990



Source: ICE

Assuming that Firestone reduces its demand by 300 kW during peak periods on the time-of-use rate (the T-8 tariff), the savings would be $3,504/month. Then, the additional savings on the interruptible tariff would be $2,366/month.

Exhibit 2-9 shows a recent load profile for Firestone, which continues to participate in the T-8 tariff. Firestone has experienced an estimated reduction of 250-300 kW during peak hours under this tariff. Exhibit 2-10 shows a simulated load profile during a control day for Firestone if they were to participate in the proposed interruptible . iff. Firestone has estimated that they can achieve a reduction of approximately 1,000 kW on the interruptible rate.

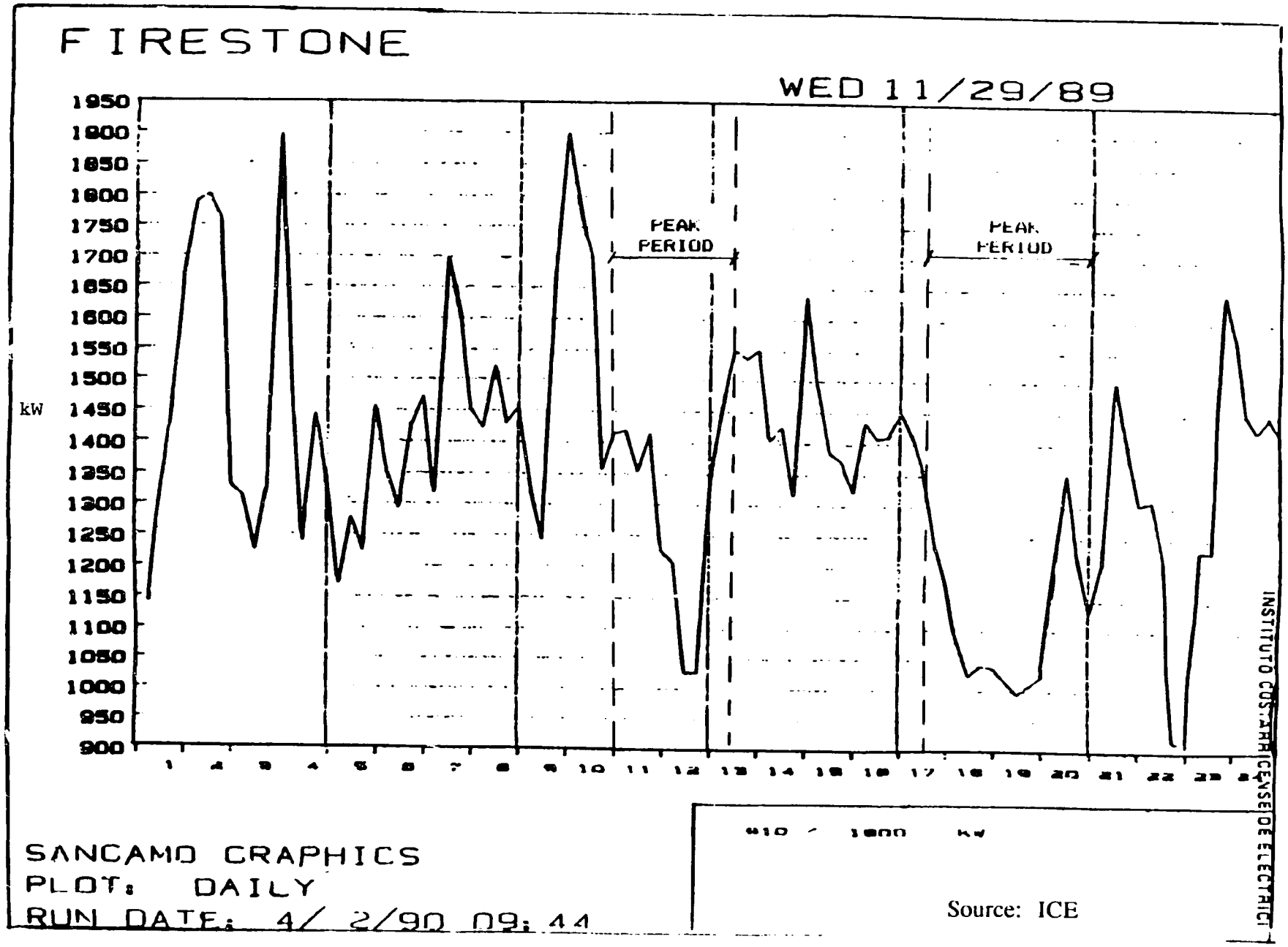
During the Load Control Demonstration Project in 1988, many of ICE's industrial customers indicated that based on their production and/or operational needs, they could not participate in the time-of-use rates, or if they did, they could only provide small demand reductions. However, they indicated that they could participate in a load control or interruptible rate and provide more significant demand reductions.

ICE estimated the reduction that could be achieved from a sample of customers under a revised interruptible rate. These customers received an explanation of how an interruptible tariff would be implemented and the expected frequency of control periods. Exhibit 2-11 lists various customers that expressed interest in the load control or interruptible tariffs and their estimate of the potential reduction if they were to participate in the interruptible tariff.

A potential area of caution in the implementation of an interruptible rate in Costa Rica is that some customers may change from the time-of-use rate to the interruptible rate. As a result, these customers may increase their demands during peak periods, thus increasing the daily peaks during days when an interruption of their loads is not requested. This problem could be avoided by incorporating peak hours as part of a revised interruptible rate. The maximum billing demand would then be based on the maximum peak occurring during peak hours. This would not be a major obstacle because the reductions to be obtained from the interruptible rate would normally be two to three times greater than those achieved through the time-of-use rate.

The interruptible rate should eventually be revised to allow customers with billing demands exceeding 100 kW/month to participate in this tariff. The target market for this program consists of large commercial and industrial customers with monthly consumption levels of at least 20,000 kWh or a maximum monthly billing demand exceeding 100 kW. The target population, as of 1989, consists of approximately 480 accounts with an

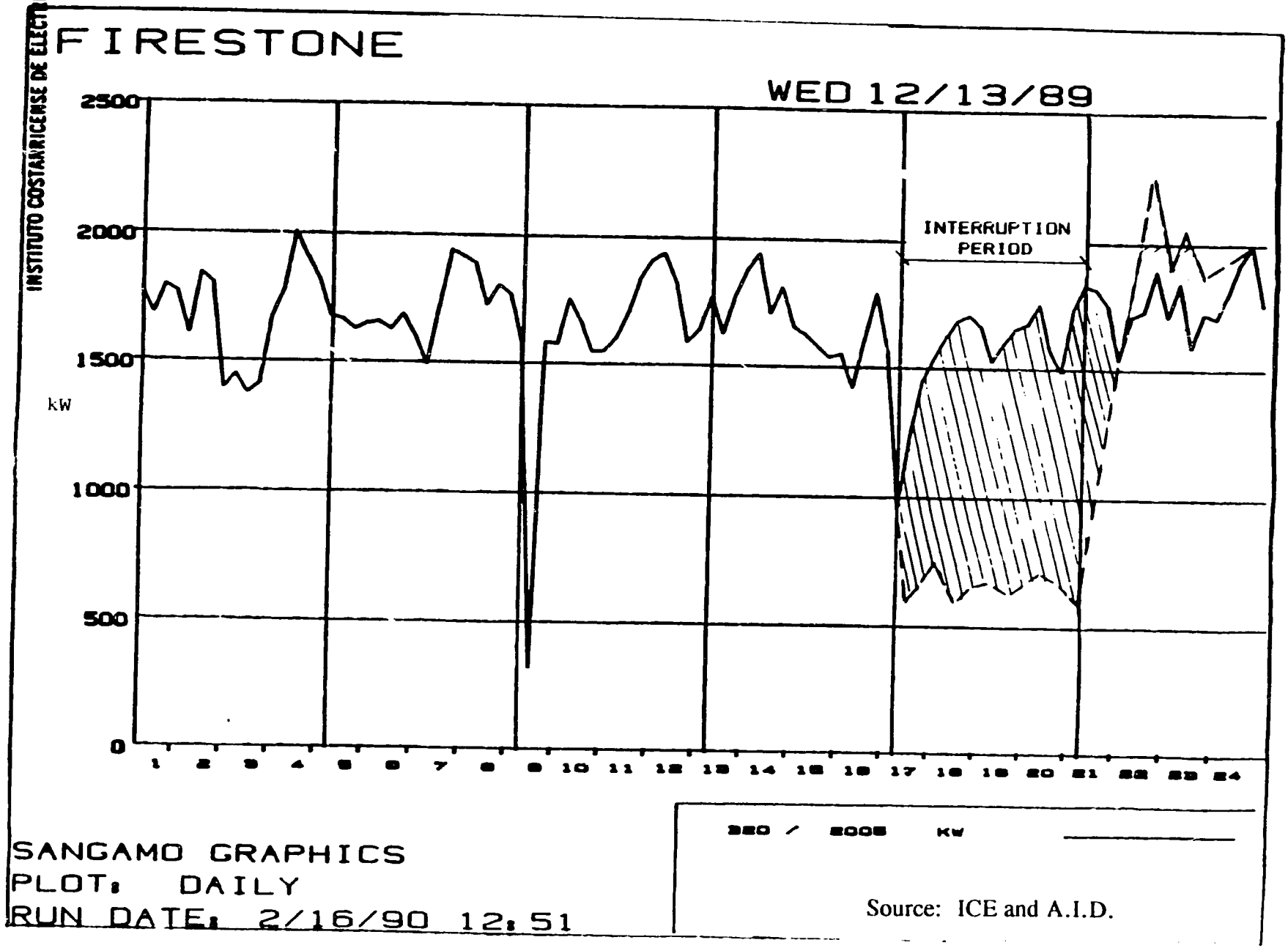
Exhibit 2-9
Firestone Load Profile on the Time-of-Use Tariff



Source: ICE

47.

Exhibit 2-10
Firestone Simulated Load Profile on the Interruptible Tariff



Source: ICE and A.I.D.

estimated aggregate coincident peak demand of 132 MW (20 percent of the 1989 system peak of 658 MW).

Exhibit 2-11
Potential Demand Reduction from a Sample of Industrial Customers

Potential Participant (kW)	Maximum Demand (kW)	(1) TOU Tariff Demand Reduction (kW)	(2) Interruptible Tariff Demand Reduction (kW)
Firestone	2142	330	1000
Conducen 1 & 2	1040	100	300
Ricalit	931	0	600
Coope-Montecillos Alajuela	1007	130	300
Fertica	4280	427	2000
Molinos de Costa Rica	1659	50	1000
Carnes de Centroamerica	1000	50	400
Scott Paper	4635	200	1000
Gerber* (Plant 2)	260	0	200
CoopeVictoria Beneficio	912	60	200
Totals	17,866	1347	7000
Percent of Load		7.54%	(3) 39.2%

* Gerber has two plants at the same site. One of them is on the CNFL time-of-use rate and the other (plant #2) is not.

(1) This represents the reductions being achieved by customers on the time-of-use rate, or the projected reduction if they were to participate in this rate.

(2) This represents the reduction potential achievable by these customers if they were to participate in the interruptible rate. The reduction estimates are based on the customers' estimate of how much load they could reduce on this rate. For customers currently on the time-of-use rate, the net reduction is the difference between the interruptible rate reduction and the time-of-use rate reduction.

(3) The 39 percent was used as the basis for the maximum potential reduction of 40 percent achievable for an interruptible rate program (see Appendix 2).

The potential for peak demand reduction in 2005 for the "critical" days is almost 70 MW. Appendix 2 shows some of the assumptions and calculations used to estimate the impact of implementing an interruptible tariff program. The estimated cost of conserved demand for the interruptible tariff ranges around $4.28/kW, which would cover the implementation costs of the program.

2.3.3 Load Control Program for the Commercial and Small Industrial Sectors

A disadvantage of implementing a load control program in this customer group (commercial and small industrial customers with demands between 10 kW and 100 kW) relates to the wide variation in equipment used, even within one end-use type. This makes the design, implementation, and evaluation of these programs more complex.

The candidate end uses for load control in this sector are: motors and compressors, water heating, and refrigeration. These three end-uses account for over 27 percent of these customers' electricity consumption, with an estimated contribution of over 30 percent to the coincident peak demand of the general sector.

The maximum coincidental demand reduction potential for this sector is estimated at 22.7 MW as of 1990. However, because program implementation will be more complex for this sector, a 50 percent penetration is probably the most that could be achieved. This would result in an 11.2 MW reduction in real demand at 1990 levels of consumption.

The peak demand savings reduction for the year 2005 is estimated at 27 MW, assuming this 50 percent penetration rate. Appendix 3 shows the sample calculations and assumptions. The cost of conserved demand for the load control program for the commercial and small industrial sector is estimated at $13.14/kW.

2.3.4 Load Control Programs for the Residential Sector

None of the load control programs identified in this study for Costa Rica's residential sector have shown to be economically viable with the exception of the demand limiting systems, which require further analysis. The programs analyzed below are electric water heating, refrigerators, and a residential time-of-use tariff. This will be followed by a discussion on the demand limiting systems.

The most cost-effective system for performing one-way load control in Costa Rica would be a radio-based system. These systems have a low initial cost because receivers can be purchased for about $40 to $50 per point. The simpler central station computer and software can normally be purchased at much lower prices than central stations for other technologies.

Electric Water Heater Load Control

The residential loads most often controlled by U.S. utilities are electric water heaters and central air-conditioners. The most viable residential load that can be controlled in Costa Rica is the water heater tank, which is found in approximately 4 percent of the nation's homes, according to the 1984 *Censo Nacional de Viviendas*. Thus, an estimated 22,000 water heater tanks can be controlled in a residential load control program.

Based on the appliance consumption data provided by ICE, the average diversified demand reduction of a water heater is approximately 0.25 kW at the time of system peak. This would provide a potential controllable load of 5.5 MW at the time of system peak using off-the-shelf residential load control equipment.

Based on these data, the potential for peak demand savings for the year 2005 is estimated at 16 MW. The cost of conserved demand is estimated at $91.92/kW for the residential water heater load control program.

The most common demand water heater in Costa Rica is an in-line, instantaneous water heating shower head called the *termo ducha*. This heater provides hot water only to the shower. The *termo ducha* can save energy by eliminating tank losses, but it can lead to increased electric demand if used during peak hours.

In 1988-89, DSE performed a study entitled *Encuesta de Opinion Sobre Consumo Energetico en el Sector Residencial Urbano*, which examined customer opinions on consumption in the urban residential sector. This study focused on the metropolitan region of San Jose, and the cities of Alajuela, Heredia, and Cartago, which hold 40 percent of Costa Rica's dwellings and about 80 percent of its urban residences.

This study revealed that 13 percent of the households in the Central Valley of San Jose have water heater tanks and over 37 percent of the households have *termo duchas* (demand water heaters). The electric water heater tanks have an average connected load of 3 kW and the *termo duchas* of 1.5 kW.

Based on this information, it was determined that an estimated 34,100 urban residences have water heater tanks, representing an estimated peak reduction potential of 8.5 MW. Because these homes are located in the urban areas where the populace has easier access to equipment installation services, program implementation could be more cost-effective. Appendix 4 shows the calculations used to estimate the demand potential reduction for both estimates, and the projections for the base case.

Information obtained from local water heater manufacturers in Costa Rica indicates that between 3,420 and 4,800 water heaters are being sold in the country each year. If this is true, then the figures presented above are understated. With a growth rate of 4,000 water heater tanks per year, there would be approximately 100,000 water heater tanks in Costa Rica by the year 2005. The potential demand reductions for this scenario would thus be as high as 25 MW.

Residential Time-of-Use Rates

Because most of the residential sector's consumption of electricity is for cooking, refrigeration, and lighting, there are few loads available for control under a load control program. In this situation, a potential strategy to reduce residential demand at the time of system peak would be to use a residential time-of-use rate.

The target market for this program would consist of residential customers with an average consumption of over 500 kWh per month. This customer class consisted of approximately 30,370 customers in 1989, representing 5.5 percent of the residential sector and 20 percent of the energy use in this sector. This customer class's estimated contribution to the residential sector's coincident peak is 64 MW, which represents 17.6 percent of the total contribution to the residential peak.

A properly designed residential time-of-use rate, targeted to this customer class as a mandatory tariff, can provide savings in the range of almost 19 MW in the year 2005 (see Appendix 5 for the calculations and projections). The cost of conserved demand is estimated at $99.59/kW for the residential time-of-use program.

Refrigerator Load Control

In principle, there is significant potential in Costa Rica to interrupt power to refrigerators in the residential sector, since refrigerators are one of the large energy users in homes. Refrigerators can be cycled in a way similar to cycling central air conditioners. The

results would also be similar in nature and would help to reduce demand during peak periods and shift it to off-peak periods.

Refrigeration consumes 335 GWh of electricity annually in Costa Rica, and represents about 23 percent of total residential sector electricity consumption. The saturation of refrigerators in this sector was approximately 54 percent in 1990. The coincidental peak demand from residential refrigeration is estimated to be between 48.9 and 66.9 MW for 1990.

The average diversified demand of the typical refrigerator is approximately 0.16 kW at the time of system peak. For customers who consume over 500 kWh per month, this demand is estimated to be approximately 0.32 kW. The estimated demand reduction from a residential refrigeration load control program in the year 2005 is expected to be approximately 10.6 MW, based on a 60 percent to 75 percent duty cycling of refrigerators for a period of one to two hours during critical days.

For the year 2005, we estimate potential peak demand savings of 10.8 MW for refrigerator cycling. Appendix 6 shows the calculations and projections used to obtain these estimates. The cost of conserved demand is estimated at $102.12/kW for this refrigerator program.

Such a program must be carefully tested in order to determine customer acceptance and to ensure that there is no significant effect on food preservation. However, a 60 percent cyclic control for a period of 1-1/2 hours should have little effect on refrigerator performance; this would normally only occur a few days a year.

Demand Limiting Systems

A demand limiting system limits the total household demand that a customer can impose on the utility system. This technique is similar to direct load control, except that instead of controlling an end-use load, such as water heaters, this method reduces the residential demand contributed by all of the appliances and loads in the home.

As part of implementing such a system, the utility installs equipment at the customer's meter which monitors the customer's demands. In addition, this equipment can interrupt the customer's service if the subscribed demand level (the demand level agreed to between the customer and the utility) is exceeded. Appendix 7 shows the U.S. experience with this concept.

Two different methods can be used to limit customer demand: demand subscription service and time-activated demand limiting meters. The demand subscription service is implemented by installing a remote module at the customer's home, which can be remotely activated (using a radio signal) by the utility system. When an activation period begins, customers must reduce their electrical loads to the subscribed level. A customer "alert device" is installed inside the home to warn the customer when an activation period has begun. If the customer's electrical loads exceed the subscribed level and no action is taken to reduce the load, all electrical service to the home is interrupted. After the customer has turned off enough loads to reduce demand to, or below, the subscription level, the customer can then restore the electrical service by pressing a reset button on the equipment. At the end of the activation period, if the customer's load was interrupted and the customer has not restored his service, then the services will be restored automatically.

The time-activated demand limiting meter is similar to the demand subscription service, but it can be programmed much like a time-of-use meter so that the demand limiting feature is activated during pre-programmed hours of the day and days of the week.

The demand subscription service may be the simplest and least complicated method of reducing residential demand. This program would be most effective if targeted to the largest residential users. One major advantage is that the customer is limited to the subscribed demand level, thus providing a more positive means of control than, for example, time-of-use rates. Under time-of-use rates, customers are penalized for use during peak periods, but if they are willing to pay for it, they can use as much electricity as they want during peak hours.

If the U.S. experience is applied to Costa Rica for customers who use over 500 kWh/month, then the potential reduction from a demand limiting program would be approximately 0.57 kW per customer. Based on the target market of 30,370 customers with usage over 500 kWh per month in 1989, the maximum potential reduction achievable in 1989 would be approximately 17.3 MW at the time of system peak.

While demand limiting systems may be the most effective means of controlling demand in the residential sector, they have two major disadvantages at this point in time. Based on U.S. experience, the cost of the equipment available for this technology is high and the experience with such systems is limited. In France, there is more experience with this technology, but this would need to be examined in detail to see how it could be applied to Costa Rica and how its costs would compare. For these reasons, our analysis did not include the savings and costs of such programs in the conservation supply curves.

2.3.5 Summary and Conservation Supply Curve

The programs analyzed in this study provide savings that result in a marginal cost of conserved demand between US $0.26 and $102.2 per kilowatt of demand per year. The first three programs compare favorably with the equivalent ICE-estimated long-run marginal cost of $64/kW to $80/kW.[2] Exhibit 2-12 shows the conservation supply curve for the load management measures for the year 2005. Exhibit 2-13 shows the peak reduction program implementation by year.

The most cost-effective program is the proposal to implement daylight savings time. This program can provide an estimated savings of 44.9 MW in 1990, and 87.6 MW in 2005 at the time of system peak, and requires minimal expenditures to implement. The principal expenditure would be for the promotion costs associated with convincing the public of the program's merits. The cost of conserved demand for this program is $0.26/kW.

The next two most cost-effective programs are the interruptible rates program and the commercial/industrial load control program. The costs of conserved demand for these programs are $4.28 and $13.14/kW, with savings of almost 70 MW and 27 MW, respectively, for the year 2005. The costs of conserved demand for the remaining programs are above the ICE-estimated avoided capacity cost, at $91.92/kW for the residential water heater load control program, $99.59/kW for the residential time-of-use program, and $102.2/kW for the residential refrigerator load control program.

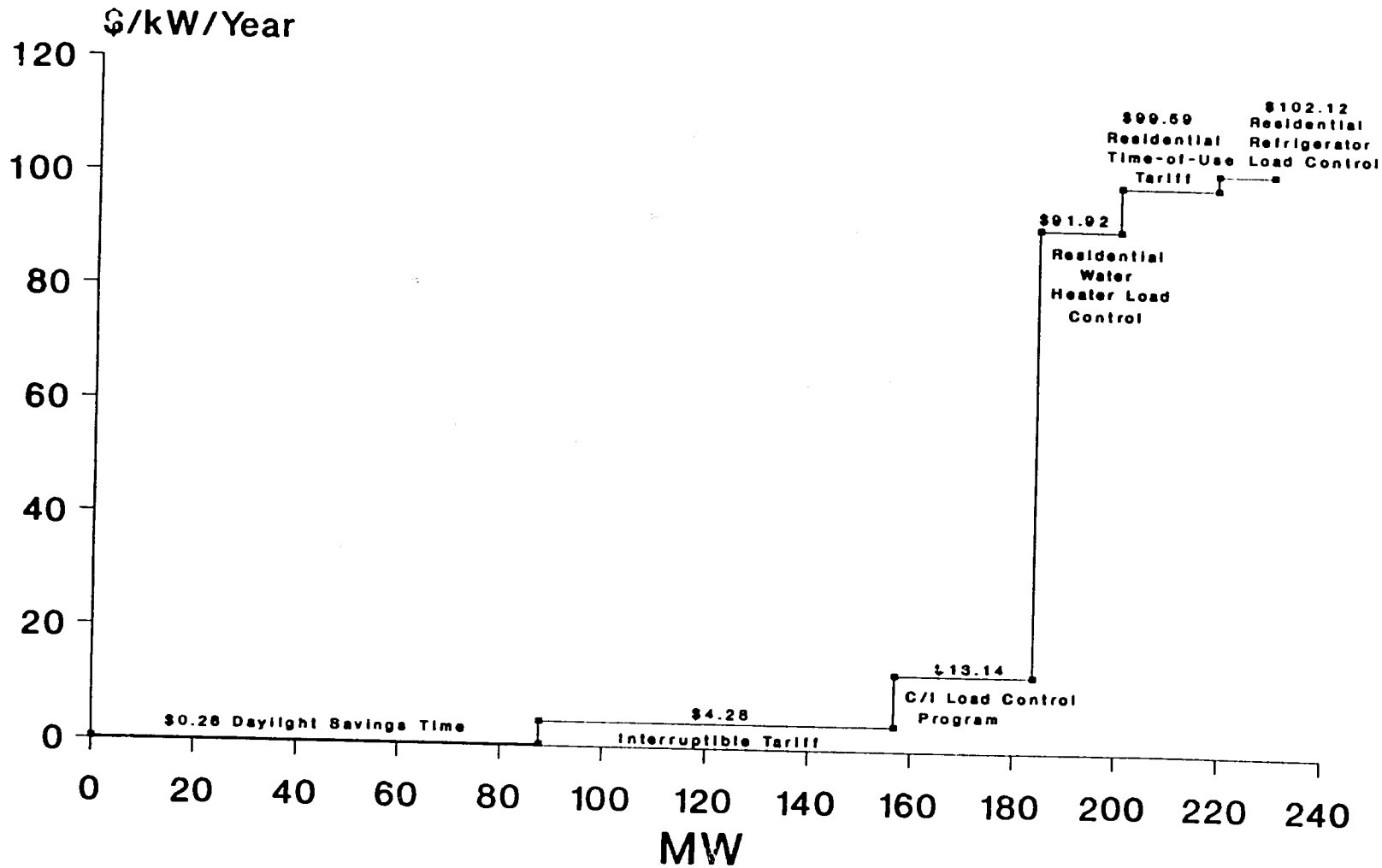
One must keep in mind that the estimates for the water heater and refrigerator load control programs are based on estimates of the end-use contribution to the coincident peak. End-use research is needed to verify the actual demand contribution and then if needed, the costs of conserved demand can be re-calculated to determine their cost-effectiveness compared to the other programs. The same applies to the projected savings for the residential time-of-use program, since the estimated savings can vary when a pilot project is performed.

2.4 ENERGY AND DEMAND SAVINGS FOR THE INDUSTRIAL SECTOR

In its 1983 report, *Encuesta de Consumo Energetico en el Sector Industrial*, DSE states that electricity is used primarily in five industrial processes: motors, illumination, process heat, steam, and refrigeration (process and air conditioning). Electric motors are by far

[2] Avoided capacity costs were determined in the study *Tarifas de Generacion Privada*, prepared by Electricite de France, June 1990.

Exhibit 2-12
Estimated Conservation Supply Curve for Load Management



At Year 2005 With Target Penetration Rates

Source: *Costa Rica Power Sector Efficiency Assessment*/A.I.D.

Exhibit 2-13
Peak Reduction Program Implementation by Year

Year	Implement Daylight Savings Time (MW)	Interrup-tible Rates Program (MW)	C/I Load Control Program (MW)	Res. WH Load Control Program (MW)	Refrig. Load Control Program (MW)	Res. Time-of-Use Tariff (MW)	Annual Reduction All Programs (MW)	Cumulative Reduction All Programs (MW)
1990	44.9	0	0	0	0.0	0.0	44.9	44.9
1991	1.7	2	0	0	0.0	0.0	3.7	48.6
1992	1.7	2	1	0	0.0	0.0	4.7	53.3
1993	2.0	4	1	0	0.0	0.0	7.0	60.3
1994	2.2	5	2	1	0.8	1.4	12.4	72.7
1995	2.4	5	2	1	0.8	1.4	12.6	85.3
1996	2.5	5	2	1	0.8	1.4	12.7	98.0
1997	2.9	6	2	2	1.6	2.8	17.3	115.3
1998	2.9	8	3	2	1.6	2.8	20.3	135.6
1999	3.1	7	3	2	1.6	2.8	19.5	155.1
2000	3.5	7	3	2	1.6	2.8	19.9	175.0
2001	3.2	4	3	2	1.0	1.8	15.0	190.0
2002	3.4	3	2	1	0.2	0.4	10.0	200.0
2003	3.8	4	1	1	0.4	0.7	10.9	210.9
2004	3.7	4	1	1	0.2	0.4	10.3	221.2
2005	3.7	3	1	0	0.2	0.4	8.3	229.5
	87.6	69	27	16	10.8	19.1	229.5	

Source: Costa Rica Power Sector Efficiency Assessment/A.I.D.

the largest energy user in this sector, accounting for nearly 95 percent of its energy use. Lighting, the next-largest user, consumes only 2.6 percent. Refrigeration consumes 1.7 percent, process heat 1 percent, and steam 0.2 percent. According to a 1983 DSE study, electrical energy accounted for 20 percent of Costa Rica's industrial energy consumption.

Because motor energy consumption was assumed to account for the remainder of energy use after all other consumption was subtracted, there was no disaggregation of motor energy use. To calculate energy savings, an average motor size and efficiency were determined. An overall average motor size of 7.8 horsepower (hp) was chosen. Efficiencies for a standard motor and an energy-efficient motor were 0.842 and 0.910, respectively.

The demand-side efficiency measures discussed for this sector are: low cost/no cost measures, synthetic lubricants, cogged V-belts, lighting (energy-efficient fluorescent lamps, hybrid electro-mechanical ballasts, compact fluorescent lamps, electronic ballasts, and fluorescent fixture reflectors), energy-efficient motors, synchronous belts, and variable-speed drives.

The cost assumptions and calculations for all these programs are shown in Appendix 8, based upon economic parameters and Appendix 9, based upon financial parameters. The economic analysis is discussed below.

2.4.1 Low Cost/No Cost Measures

Low-cost and no-cost measures are energy conservation measures that typically involve operation and maintenance improvements, improved housekeeping, and a little extra vigilance to turn off unneeded equipment and lights. The costs of these measures are minimal. Some of these measures include:

- Turn off lights when not needed
- Turn off unused equipment
- Use equipment only when fully loaded (e.g., heat treat furnaces)
- Keep door closed to refrigerated space
- Repair damaged or missing insulation
- Use most efficient equipment when more than one piece could be used
- Reduce compressed air pressure
- Repair compressed air leaks
- Repair water leaks (pump energy)

- Install compressed air intakes in coolest location
- Lubricate equipment on schedule
- Keep equipment clean and cool (especially motors)
- Use natural light as possible
- Use fans and blowers instead of compressed air for personnel and process cooling.

U.S. experience indicates that a 10 percent energy savings can be achieved by implementing these and other low/no cost measures.[3] A demand savings of only 5 percent from low cost/no cost measures can be anticipated because many of these measures apply outside of peak demand times. Based on Costa Rica's industrial consumption, we have estimated that using the recommended measures could save over 202 GWh in the year 2005 (10 percent of total industrial energy use), assuming a penetration rate of 100 percent. The peak demand reduction as a result of these measures is estimated at 15.5 MW for the year 2005.

2.4.2 Synthetic Lubricants

Description. Synthetic lubricants are man-made lubricants specially formulated for a given application. Although mineral oils have similar properties, they also have impurities that compromise the long-term quality of the oil. Synthetic lubricants have only the required properties without the impurities. On the average, they save 2 to 5 percent of energy use (some claims are as high as 15 percent for specific applications) and last four times longer than mineral oils, but on average, cost four times more.

Model. Synthetic lubricants were designed originally for use in gearboxes. The Rocky Mountain Institute has estimated that 10 to 30 percent of electric motors in the U.S. employ gearboxes, an estimate confirmed by several lubricant manufacturers. Based on the experience of the Energy Analysis and Diagnostic Center and on conversations with lubricant manufacturers, a typical gearbox would hold about 8 quarts of oil, with the oil being changed quarterly. The calculations for these lubricants assume an average of 3 percent energy savings on 20 percent of the sector's motor population.

[3] Some energy engineers place this number as high as 30 percent, but 10 percent is probably a more attainable number given the many demands on the time and attention of the average plant engineer in Costa Rica.

Since the cost of the mineral oil changes over the life of the synthetic lubricant, this was included in the net present value calculations. A drawback to synthetic lubricants is that when they are first used in a gearbox, the old oil must be completely purged. This is typically done by flushing the gearbox with synthetic lubricants up to four times. This cost is treated as part of the initial cost of the synthetic oil.

The cost of conserved energy of synthetic lubricants is negative: -2.1¢/kWh. This is due to the high savings in maintenance costs over the medium- to long-term. If only the up-front costs are considered, the simple payback is 5.3 years. However, when the NPVs of the two measures are considered over a 15-year period, an immediate payback is shown. Synthetic lubricants have had a slow entry into the U.S. market because of consumer skepticism. The calculations assume that it will take 20 years to reach a maximum penetration of 30 percent; therefore, the savings for the year 2005 are based on a 25 percent penetration rate.

In the year 2005, we have estimated an energy savings potential of over 2.6 GWh for synthetic lubricants. Because synthetic lubricants apply to all motor sizes, the efficiencies and costs used in the calculations are for a 7.8 hp motor. The peak demand reduction for this measure is estimated at 0.4 MW for the year 2005.

2.4.3 Cogged V-Belts

Description. Cogged V-belts have notches formed into the face of the belt. This allows greater flexibility and heat dissipation, resulting in an efficiency improvement of approximately 2 percent. Cogged V-belts do not require sheave changes and can replace a standard V-belt when it wears out or breaks. The life and price of cogged V-belts are estimated to be twice those of standard V-belts.

Model. As discussed in Section 2.3.6, cogged V-belts and synchronous belts have similar applications. Cogged V-belts are generally applied to motors of 5 hp or less. Efficiencies and costs used in the calculation are for a 2.7 hp motor.

By installing these belts, industrial facilities will reap maintenance and replacement cost savings that are greater than the discounted cost of the cogged V-belt. It was assumed that either belt can be replaced in 20 minutes. The cost of replacing a standard V-belt once during the life of a cogged V-belt is included in the net present value calculations. The cost of conserved energy is for this energy conservation measure is negative: -1.7¢/kWh due to the operation and maintenance (O&M) savings. The simple payback is 1.5 years.

Because the use of cogged V-belts is of obvious advantage to industrial concerns, its penetration rates are expected to reach 90 percent. This does not mean that 90 percent of the belted motors of 5 hp and under will be retrofit with cogged V-belts, but that 90 percent of the potential energy savings due to cogged V-belts will be realized. The maximum penetration rate is expected to be reached within five years. In the year 2005, we have estimated an energy savings potential of over 7 GWh, assuming a saturation point/penetration rate of 90 percent. The peak demand reduction for this measure is estimated at 1.1 MW in the year 2005.

2.4.4 Lighting Technologies

According to DSE's *Encuesta de Consumo Energetico en el Sector Industrial*, illumination comprises 2.6 percent of the industrial sector's energy consumption. The DSE data allowed the disaggregation of lighting energy consumption into incandescent (three lamp sizes), fluorescent (three lamp sizes), and other. Incandescent lamps account for 4.1 percent of lighting energy consumption, fluorescents account for 85.4 percent, and all other lighting sources account for 10.5 percent. The two largest lighting energy consumers are 8-foot and 4-foot fluorescents, which draw 53.2 and 32.0 percent of Costa Rica's total lighting energy, respectively.

Energy-Efficient Fluorescent Lamps

Description. Energy-efficient fluorescent lamps are constructed using a mixture of rare elements and gases to give energy savings while minimizing the reduction in light output. Energy savings are typically in the 15 percent range, while lighting levels drop approximately 10 percent. Because of the low lighting levels evidenced in Costa Rica, the applicability of energy-efficient fluorescents may be somewhat reduced. In addition, research conducted by Lawrence Berkeley Laboratories indicates that energy-efficient lamps do not last as long as their standard counterparts, resulting in increased replacement costs and negating savings from reduced consumption. Conversations with several lighting manufacturers contradicted these findings.

More research must be done in this area before implementing a program for energy-efficient lamps in Costa Rica. To achieve the desired objective, a combination of technologies may be the answer. Some users have found that the proper combination of two lighting technologies (e.g., a fluorescent power reducer with a fixture reflector) has

enabled them to achieve substantial energy reductions while maintaining the desired illumination.

Model. In the DSE survey database, fluorescent lamps were disaggregated into 24-inch, 48-inch, and 96-inch lamp categories. Energy-efficient lamps are made for 48- and 96-inch lamps. No attempt was made by DSE to determine how many lamps are already energy-efficient. Sylvania/Costa Rica states that the total lamp market is about 10 percent energy-efficient, primarily in the commercial sector. The model currently does not take into account any effect from energy-efficient lamps already installed in the industrial sector.

Standard fluorescent lamps can be replaced by energy-efficient models as they fail or as a group. In either case, the calculations are based on the incremental cost of the energy-efficient lamps over the standard lamp. Because the lifetimes of standard and energy-efficient fluorescents are assumed to be equal based on the best data available, O&M costs for both lamps types are the same.

The costs of conserved energy for the 48-inch and 96-inch energy-efficient lamps are 0.3¢/kWh and 0.7¢/kWh, respectively. The payback periods for these lamp sizes are 0.2 and 0.4 years, respectively.

In the year 2005, we have estimated an energy savings potential of about 3.6 GWh for these lamps. The penetration rate of energy-efficient lamps in U.S. conservation programs without financial incentives has been on the order of 80 percent. This was also the penetration rate assumed for Costa Rica in the year 2005. Because of the relatively short lifetimes of fluorescent lamps and the favorable payback periods, full penetration is expected to be reached in eight years. The peak demand reduction estimated for this measure is 0.6 MW for the year 2005.

Compact Fluorescent Lamps

Description. Compact fluorescent lamps are low-wattage, self-ballasted fluorescent lamps that can screw into incandescent lamp sockets on a one-to-one replacement basis. On average, compact fluorescents draw 25 percent of the electricity of an incandescent for the same lumen output. They are available in a range of sizes to replace 25 to 100 watt incandescent bulbs. New introductions to the market may allow the direct replacement of 150 and 200 watt bulbs. Configurations of the compact fluorescent include two and four parallel tubes ranging from 4 to 8 inches in length, depending on the lamp wattage.

Model. Within the conservation supply model for the Costa Rican industrial sector, compact fluorescents are applied as replacements for 50, 75 and 100 watt incandescent lamps. These three lamp sizes comprise 0.2, 1.0, and 2.9 percent, respectively, of the lighting energy total. The selected replacement compact fluorescents are nominally sized at 11, 18 and 26 watts, which with ballast energy requirements, draw 14, 21, and 29 watts, respectively. Energy savings were calculated by multiplying the percent reduction in energy draw for each size by the amount of energy consumed in each size category.

In the year 2005, we have estimated an energy savings potential of almost 0.7 GWh for compact fluorescents. Sylvania/Costa Rica has tentative plans to import compact fluorescents for the local market, but anticipates poor sales because lights are purchased on a first-cost basis, not on life-cycle cost. Lamp life is assumed to be that listed in manufacturers' catalogs. The calculated costs of conserved energy for the 11, 18, and 26 watt compact fluorescents are 2.0¢/kWh, 1.9¢/kWh, and 2.8¢/kWh, respectively. The simple payback period ranges from 2.1 to 1.3 years. If the longer life of the compact fluorescents is considered, the payback of the NPV is more attractive, at 0.9 to 1.2 years.

Because compact fluorescents will not fit some industrial fixtures (most notably explosion-proof), the penetration rate is estimated to be 50 percent for each lamp size for the year 2005. Based on 10 hours per day of lamp operation, the average incandescent lamp will fail in 3.5 months. Although incandescent lamp life is short, presenting opportunities for lamp replacement by compact fluorescents, the moderate payback makes it probable that full market penetration will be reached in 10 years. The peak demand reduction for this measure is estimated to be 0.1 MW for the year 2005.

Hybrid Electro-Mechanical Ballasts

Description. Hybrid electro-mechanical ballasts are standard electro-mechanical ballasts with electronic circuitry that switches off the lamp cathode once ignition has occurred, allowing energy consumption to be reduced to nearly the same level as that of electronic ballasts. Hybrid electro-mechanical ballasts cost half to two-thirds as much as electronic ballasts, but twice as much as the standard electro-mechanical ballast. Their estimated lifetime is 50 percent more than that of electro-mechanical ballasts, but about one-third less than that of electronic ballasts. Their noise levels are on the order of standard electro-mechanical ballasts. It is anticipated that hybrid electro-mechanical ballasts will become the most widely accepted ballast in industry due to their lower capital cost and significant energy savings.

Because hybrid electro-mechanical ballast energy savings are on the order of those of electronic ballasts (see the next section), all 48-inch fluorescent lamps are treated under hybrid electro-mechanical ballasts (these ballasts apply only to the 48-inch fluorescent).

Model. Because the lifetimes of the two technologies are different, the net present value was calculated over two lifetimes of the hybrid ballast (three lifetimes of the standard ballast). The cost of conserved energy calculated for hybrid electro-mechanical ballasts is 0.93¢/kWh. The simple payback period is 1.6 years.

Actual energy savings from hybrid electro-mechanical ballasts will vary according to whether the ballast drives standard or energy-efficient lamps. The calculation of savings for these ballasts accounts for the effect of energy-efficient lamp penetration rates. In the year 2005, we have estimated an energy savings potential for these ballasts of about 2.3 GWh, assuming a penetration rate of 55 percent. The peak demand reduction for this measure is estimated to be 0.4 MW in the year 2005.

Electronic Ballasts

Description. Electronic ballasts use electronic circuitry to regulate the energy coming into lamps. These ballasts typically operate at 20 to 25 kilohertz, while standard electro-mechanical ballasts operate at line frequency (60 hertz). They apply to both 48- and 96-inch lamps, but only 96-inch lamps are used in the model below. Energy savings from these ballasts are 15 to 20 percent. Because of their solid-state electronic components and lower operating temperatures, electronic ballasts are said to operate for 25 years or more.

When electronic ballasts were first introduced, their failure rate was unacceptably high. Through the efforts of the Northwest Power Planning Council, Bonneville Power Administration, and others, manufacturers reduced their failure rate to equal or below the rate of electro-mechanical ballasts.

Model. The energy savings of electronic over standard ballasts are approximately 23 percent. Electronic ballasts are about three and a half times more expensive than standard electro-mechanical ballasts, but their lifetimes are estimated to be two and a half times longer. Because the lifetimes of the two technologies are different, the net present value calculation is based on two lifetimes of the electronic ballast and five lifetimes of the standard ballast.

The cost of conserved energy calculated for electronic ballasts is 2.35¢/kWh for 96-inch lamps. (Equivalent energy savings can be achieved at a lower capital cost for 48-inch

lamps by the use of hybrid electro-mechanical ballasts.) The simple payback period is 3.4 years.

Like hybrid electro-mechanical ballasts, electronic ballast energy savings vary according to whether they drive standard or energy-efficient lamps. The calculations in this analysis account for the interactive effect of energy-efficient lamps.

In the year 2005, we have estimated an energy savings potential of about 3.4 GWh for electronic ballasts, with a penetration rate of 59 percent. The peak demand reduction for this measure is estimated to be 0.5 MW for the year 2005.

Fluorescent Fixture Reflectors

Description. Fluorescent fixture reflectors are polished or reflectorized metal inserts that are placed in an existing fixture. The reflectors direct more light out of the fixture and toward the work surface, sometimes permitting half of the lamps in a room to be removed. On the average, installing reflectors and removing half of the lamps will result in lighting levels of 60 to 80 percent of the design light level. Current reflector technology uses clips to secure the reflector to the fixture. The reflector also serves as the ballast cover in lay-in fixtures.

Model. Savings for installing reflectors and removing half the lamps are affected by the type of lamp and ballast used in the present fixture. In the calculations, it was assumed that lamp and ballast improvements would be made first. Reflector savings were based on 50 percent of the energy consumption of the energy-conserving lighting system.

The cost of conserved energy for fixture reflectors is 3.6¢/kWh for 48-inch fixtures and 4.0¢/kWh for 96-inch fixtures. The payback periods based on the initial costs of reflectors (no existing technology is being replaced) are 4.2 and 4.6 years for the 48-inch and 96-inch applications, respectively.

Assuming a moderate rate of penetration, a maximum penetration of 10 percent is expected to be reached in 15 years. The moderate rate of penetration is anticipated despite the high payback periods because reflectors are a simple technology to comprehend and to retrofit. Most lighting levels observed in Costa Rica, however, were marginal for the tasks. There were some brightly-illuminated areas in some of the facilities visited, but this is thought to be the exception rather than the rule, and accounts for the low maximum penetration rate. In the year 2005, we have estimated an energy

savings potential of about 1.7 GWh for fluorescent fixture reflectors. The peak demand reduction for this measure is estimated to be 0.3 MW for the year 2005.

2.4.5 Energy-Efficient Motors

Description. Energy-efficient motors are made with higher quality materials, improved bearings and fans, and superior windings. Energy savings with such motors vary from 2 to 10 percent, with the larger savings being in the smaller horsepower ranges. Energy-efficient motors can be retrofit to all but specialty motors. Standard motors are typically replaced by energy-efficient motors as the standard motors burn out.

Model. As mentioned above, a 7.8 horsepower (hp) standard average motor size was selected for study; the efficiencies selected were 84.2 percent for the standard motor and 91.0 percent for the energy-efficient motor.

Average motor life was estimated at 24,000 hours. (Motor life is greatly affected by moisture, load, application, and dirt, and can vary substantially from this average.) The motor load factor was assumed to be 75 percent. The hours of operation assumed for these motors is the same as for lighting: 10 hours per day, 21.6 days per month. This seems to correlate with the hours use of demand data available from the DSE industrial survey.

Based on these assumptions, the cost of conserved energy for energy-efficient motors is estimated at 2.6¢/kWh.

Energy-efficient motors apply to most industrial applications except where specialty motors are required. The simple payback, based on the incremental cost of purchasing a new energy-efficient motor over a new standard motor, is 1.2 years. Because of the moderate payback and because motors have relatively long lives, full implementation (around 80 percent) is expected to take up to 20 years. We have estimated an energy saving potential for the year 2005 of 94 GWh, with a penetration rate of 73 percent for that year. The peak demand reduction for this measure is estimated to be 14.5 MW for the year 2005.

2.4.6 Synchronous Belts

Description. Synchronous belts, sometimes called high-torque drive (HTD) belts, are flat belts with rounded teeth. They resemble timing belts, but can run at higher velocities

with less noise. Synchronous belts transmit drive power 4 to 10 percent more efficiently than standard V-belts because they have greater flexibility and less slip. They can be applied to any V-belt application except those requiring slip for shock loadings and those used with belt clutches. Synchronous belts require that the sheaves be replaced along with the belt and, therefore, they cannot be installed whenever a V-belt breaks. They are generally cost-effective for drives above 7.5 hp. The average motor size in this category is 22.6 hp.

Model. The calculations for synchronous belts assume a 5 percent energy savings, a figure typically used by the industry to estimate savings. The Rocky Mountain Institute estimates that about 40 percent of the U.S. motor population is connected to the load by a belt or chain. Synchronous belts can replace both.

It is assumed that synchronous belts have lives that are four times longer than V-belts. Figures of 8,000 hours for synchronous belts and 2,000 hours for V-belts are used. (The lives of belts vary greatly depending on application, grit, tensioning, shock loading, and other factors.) Because synchronous belts have longer lives than V-belts, the cost of replacing V-belts over the life of the synchronous belts was annualized. It was assumed that the average V-belt drive with three belts can be replaced in 45 minutes, while synchronous drives require two man-hours. The cost of conserved energy for synchronous belts is estimated at 5.45¢/kWh.

Synchronous belts and cogged V-belts have similar applications. Because synchronous belts provide larger energy savings, they are preferred. However, they are not very cost-effective below the 7.5 to 10 hp range. The calculations here assume that synchronous belts can be applied to motors at 22.6 hp. Cogged V-belts are used below this horsepower.

The simple payback period for synchronous belts is 2.8 years. V-belts tend to be viewed as the "way we've always done it," which resulted in synchronous belts meeting a fair amount of resistance when first introduced into the U.S. market. In the year 2005, we have estimated an energy savings potential of over 5 GWh, with a penetration rate of 60 percent. The peak demand reduction for this measure is estimated to be 0.8 MW for the year 2005.

2.4.7 Variable-Speed Drives

Description. Variable-speed drives modulate the speed of driven equipment. Reducing the speed of a fan by 50 percent, for example, can reduce power consumption by 87.5 percent.

Older AC variable-speed drives used clutches and other mechanical means that were frequently unwieldy, costly, and hard to maintain. Early variable-frequency drives also proved troublesome and costly. The current generation of electronic variable-speed drives is significantly more reliable and less expensive.

Model. Discussions with variable-speed drive vendors indicate that up to 60 percent of the motor population could benefit from these drives. Many of these applications are on equipment that require variable speed for reasons other than energy savings. Concern for energy savings would account for about 25 percent of the motor population applications.

Variable-speed drives for energy efficiency are more cost effective on motors over 5 horsepower. Average savings are estimated to be 8 percent of the motor energy draw. The load factor is estimated to be 75 percent. The average variable-speed drive costs $4,100 for the motor population above 5 hp.

The cost of conserved energy (CCE) for variable-speed drives is 18.7¢/kWh, clearly above the desired CCE if conservation is to offset new generating capacity. The payback period is almost 20 years. It must be remembered that these figures are averages for the segment of the entire motor population over 5 hp in size, regardless of application and operating hours.

There are applications for variable-speed drives for which energy conservation is the motivating factor, but these are buried in the aggregation of the motors. Once the motor population is disaggregated, cost-effective applications will be found. It is expected, however, that variable-speed drives will play only a marginal role in the integrated resource plan. For the purposes of this analysis, we estimated an average motor size of 22.6 hp.

In the year 2005, we have estimated an energy savings potential of nearly 0.8 GWh. A maximum penetration rate of 10 percent is expected to be reached in 20 years, but this could be improved if adequate financing were to be provided.

2.4.8 Summary and Conservation Supply Curves

The estimated energy savings for the energy conservation measures for Costa Rica's industrial sector are shown in Exhibit 2-14. The savings for the low cost/no cost measures are listed first because these measures are typically implemented first and represent the greatest savings. The savings for the measures that follow reflect the implementation of the low/no cost measures first.

Eliminating the non-viable measure (variable-speed drive, whose cost of conserved energy falls well above the ICE avoided cost level), the total energy conservation potential in the year 2005 is 323.1 GWh (see Exhibit 2-15). The reduction in peak demand from these measures is estimated at 34.1 MW in the year 2005.

Exhibit 2-16 shows the estimated conservation supply curve for the industrial sector for the year 2005. In the supply curve, low cost/no cost measures, synthetic lubricants, and cogged V-belts are treated as having a cost of conserved energy (CCE) of zero. In practice, the CCE of the low cost/no cost measures will be slightly positive because some of the measures in this category do have a nominal cost. Synthetic lubricants and cogged V-belts have negative CCEs (-2.1¢/kWh and -1.7¢/kWh, respectively) because the user will gain significant maintenance savings in excess of the cost of these conservation measures.

Like the low cost/no cost measures, coggged V-belts can probably be introduced and widely adopted on a voluntary basis just by active marketing. Since they provide a negligible CCE, their acceptance can be based on maintenance savings alone. The utility should not have to "purchase" this conservation measure. Because synthetic lubricants have a long payback period (5.3 years) due to their high front-end costs (including cleaning/retrofitting of the gear box), the implementation of this measure may require some financial assistance, even though it has a negligible CCE.

The bulk of these measures are simply improved operation and maintenance. The implementation of these measures will result in energy savings as well as improved equipment performance and life.

Variable-speed drives have only limited application because their average CCE is nearly 20¢/kWh or more. There will be applications, however, for this technology in drives with large horsepower motors and long hours of operation. These will have to be evaluated on an individual basis. Because the CCE is so high on these two energy conservation measures, significant effort to identify the segment of applicable drives can be postponed until the more attractive measures have been implemented.

Exhibit 2-14

Estimated Energy Savings for Various Energy Conservation Technologies in MWh per Year, Industrial Sector

MEASURES	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
LOW/NO COST MEASURES	0	1,820	13,840	58,702	97,113	110,088	117,558	124,782	132,498	140,700	149,400	158,600	168,500	179,100	190,400	202,200
SYNTHETIC LUBRICANTS	0	31	49	76	117	184	286	433	633	885	1,180	1,497	1,818	2,126	2,415	2,683
COGGED V-BELTS	0	78	585	2,367	3,771	4,234	4,503	4,761	5,029	5,309	5,601	5,908	6,242	6,604	6,996	7,411
48" EE LAMPS	0	19	62	183	434	752	988	1,128	1,226	1,311	1,395	1,482	1,575	1,674	1,780	1,890
96" EE LAMPS	0	17	57	167	396	688	903	1,031	1,121	1,199	1,276	1,355	1,440	1,530	1,627	1,728
HYBRID E-M BALLASTS	0	26	42	64	98	153	237	359	527	742	996	1,272	1,552	1,824	2,079	2,315
13-W COMPACT FLUOR	0	2	4	10	23	44	68	89	104	115	124	132	141	150	159	169
11-W COMPACT FLUOR	0	0	1	2	5	9	15	19	22	25	27	29	30	32	34	37
ELEC BALLAST FOR 96"	0	38	61	94	143	223	344	522	767	1,078	1,448	1,849	2,257	2,652	3,023	3,366
EE MOTORS	0	1,028	1,639	2,530	3,911	6,157	9,590	14,579	21,426	30,169	40,476	51,682	63,092	74,130	84,506	94,097
26-W COMPACT FLUOR	0	5	12	30	65	125	195	255	287	328	353	377	402	428	455	483
48" REFLECTORS	0	8	14	24	41	70	113	171	239	306	363	409	446	478	509	540
96" REFLECTORS	0	13	23	41	72	123	204	317	452	590	717	826	920	1,005	1,084	1,161
SYNCRONOUS BELTS	0	53	135	324	710	1,360	2,120	2,751	3,191	3,502	3,752	3,982	4,217	4,466	4,733	5,015
VARIABLE SPEED DRIVES	0	9	14	22	33	52	81	123	180	251	335	425	516	603	685	761

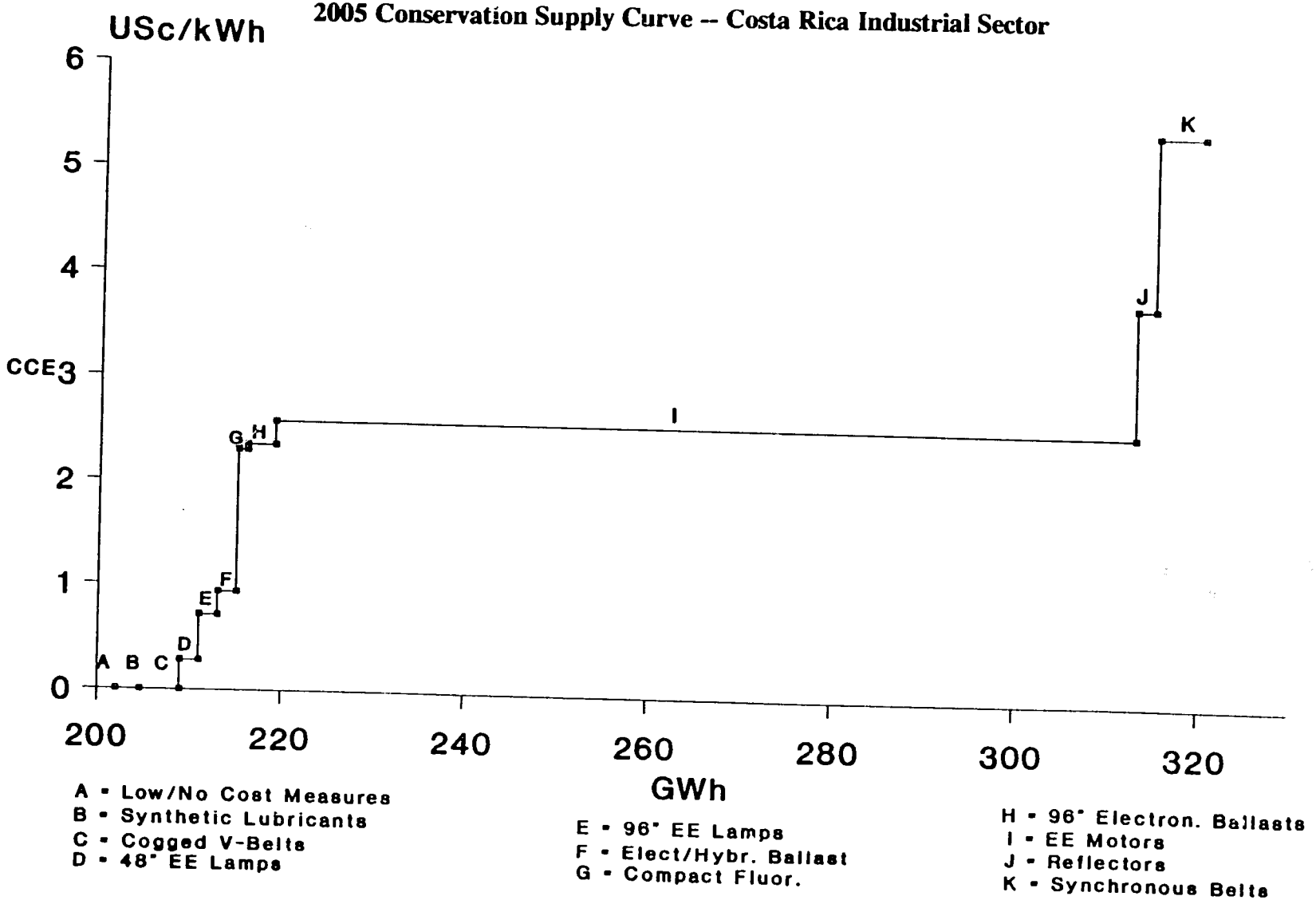
Exhibit 2-15

Estimated Energy and Demand Savings for the Industrial Sector, with Target Penetration Rates

	Penetration	Savings in GWh/yr	Avg. MW Savings	NCP Load Factor	Maximum MW	Coincidence Factor	Peak MW Savings
Low/No Cost Measures:	100%	202.2	23.1	0.8	30.4	0.5	15.5
• Synthetic Lubricants	25%	2.7	0.3	0.6	0.54	0.8	0.4
• Cogged V-Belts	90%	7.4	0.8	0.6	1.48	0.8	1.1
• Energy-Eff. Fluor	80%	3.6	0.4	0.6	0.72	0.8	0.6
• Hybr Electro-Mech Ballasts	55%	2.3	0.3	0.6	0.46	0.8	0.4
• Compact Fluor.	50%	0.7	0.1	0.6	0.14	0.8	0.1
• Electronic Ballasts	59%	3.4	0.4	0.6	0.67	0.8	0.5
• High Eff. Motor	73%	94.1	10.7	0.6	18.84	0.8	14.5
• Fluor. Fixt. Reflect	10%	1.7	0.2	0.6	0.34	0.8	0.3
• Synchronous Belts	60%	5.0	0.6	0.6	1.00	0.8	0.8
TOTAL SAVINGS		323.1	36.9		54.6		34.1

Exhibit 2-16

2005 Conservation Supply Curve -- Costa Rica Industrial Sector



Source: *Costa Rica Power Sector Efficiency Assessment*/A.I.D.

All of the other energy conservation measures (lighting technologies, energy-efficient motors) should be actively promoted with financial incentives. To achieve the penetration rates estimated in the sections above, it may be necessary to compensate the industries for part or all of the incremental cost of the energy conservation technology. This means paying a portion of the cost differential between the technology currently in use and the recommended energy-saving technology.

Energy-efficient motors should be strongly promoted since their savings potential is an order of magnitude greater than that of any other specific measure. Industry confidence in energy-efficient motors is growing in the U.S. However, like electronic ballasts, energy-efficient motors have significant replacement costs, which may be a hindrance to their acceptance.

The driving forces behind all the measures will be low initial cost, simple installation, low replacement costs, and low maintenance. Lighting measures are very attractive for this reason. If incremental costs are offset, initial costs will be less of an issue. All of the viable energy conservation measures identified are uncomplicated to specify and install.

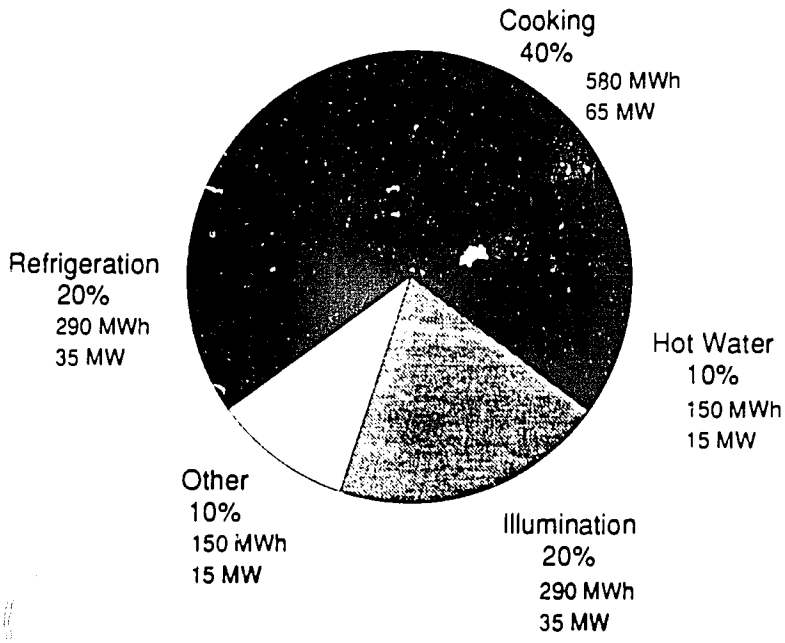
2.5 ENERGY AND DEMAND SAVINGS FOR THE RESIDENTIAL SECTOR

Residential loads accounted for almost 50 percent of Costa Rica's electricity use in 1989 (1,460 GWh out of a total of 3,100 GWh). Cooking, lighting, and refrigeration consumed about 80 percent of this fraction. Exhibit 2-17 shows the percentages of electricity consumption and average demand (based on 8,760 hours) for residential sector end uses in 1989. This figure is based on a study performed under the direction of DSE (1989).

DSE estimated that 62 percent of all residences used electricity for cooking in 1989, which made it the sector's major electrical end use. In the same year, refrigerators were present in 54 percent of all residences. Twenty four percent of all residences had electric hot water heater heaters; 16 percent of this fraction was represented by hot water tanks and the other 84 percent was *termo duchas* (in-line water heaters). Electric lighting is found in 88 percent of all homes.

The cost assumptions and calculations for all the residential sector programs are shown in Appendix 8 from the economic (national) perspective and Appendix 9 from the financial (end-user) perspective. As indicated previously in this report, the analysis here is based on the economic perspective.

Exhibit 2-17
Residential End-Use Breakout



Source: Direccion Sectoral de Energía.

2.5.1 Water Heater Tank Insulation

Description. The total energy use for water heating in Costa Rica is about 150 GWh/yr. Options for saving hot water energy include insulating hot water tanks; using in-line, instantaneous water heaters; and using solar systems. In the U.S., water heater tank insulation can be expected to typically save 500 kWh/yr.[4]

DSE estimates that about 24,000 water tanks were installed in Costa Rican households in 1989 (about 4 percent of all households). However, other DSE data indicate that there

[4] Usibelli, A. "Monitored Energy Use of Residential Water Heaters." *Proceedings of the ACEEE 1984 Summer Study on Energy Efficiency in Buildings*. p. E-266.

may be about 40,000 hot water tanks in the central valley alone (540,000 customers x 60 percent of the population x 13 percent with hot water tanks). Also, local manufacturers indicate that 10,000 tanks are being sold each year in Costa Rica. Of these, 70 percent (7,000/yr) are of 30 or 40 gallon capacity, which are typical sizes for a household. Some of the total number of tanks are installed in hotels, motels, and *apartotels*, but these units typically have water heaters smaller than 30 gallons.

Although there is significant uncertainty regarding the actual number of water heater tanks installed in Costa Rican residences, the savings estimated here are based on the official estimate of 24,000 tanks. If future data indicate a larger number of tanks, the results can be scaled upward to reflect the new information. This analysis also assumes that the percentage of the total population with water heater tanks will remain at 4 percent through the year 2005.

Tank losses can have a considerable range depending on tank temperature, ambient temperature, and tank insulation: 500-2,000 kWh/yr for a 66 gallon tank with an ambient temperature all year of 70° F, water temperatures ranging from 110-170° F, and 2" of insulation.[5] An approximate value for the tank losses for Costa Rican water heater tanks, at 30-40 gallons with 1.5" of insulation and a temperature of 140° F (based on data obtained from a local manufacturer), is estimated to be about 900-1,000 kWh/yr. Increasing the tank insulation will save part of these losses.

In Costa Rica, demand water heaters are more commonly used than tanks. Demand water heaters are often called tankless or instantaneous water heaters (or "geysers" in Britain). These water heaters are common in Europe and Japan, and were once common in the United States, but they fell into disfavor because they could not provide the amount of hot water used by many households. These types of water heaters are now being considered more seriously in America because of their potential to cut fuel bills.

Currently, the ICE demand peak occurs at noon and in the evening, and most use of *termo duchas* is considered to be in the morning. If this is the case, their use should not increase system peaks. The *termo ducha* saves energy and is less costly than a hot water tank, and thus is preferable to hot water tanks in a rational economic sense if having hot water available at other water outlets is not considered more important. The *termo ducha* costs about one-tenth as much as a hot water tank, and the most common type is of Italian license, which is imported from Brazil.

[5] Slaughter, G.G. and D.E. Spann. *An Efficiency Evaluation of Consumer Economic Analysis of Domestic Water Heaters*. ORNL report ORNL/CON-5. 1978.

Model. Domestic water heating consumes a small but significant percentage of Costa Rica's electricity use. Energy losses can be minimized by insulating water heater tanks. Current tank energy losses are estimated to be 950 kWh/yr on average. Energy savings for adding additional insulation are estimated to be 400 kWh/yr for each tank. For the year 2005, we estimate an energy conservation potential of 10.3 GWh, with a penetration rate of 60 percent. The peak demand reduction for this measure is estimated to be 2.1 MW for the year 2005.

The cost of conserved energy estimated for water heater tank insulation is US 0.44¢ /kWh, which is well below the ICE avoided cost. The simple payback is estimated at 0.4 years.

The use of *termo duchas* presents an analytical dilemma because these units must be compared with hot water tank heaters. The *termo ducha* offers much lower cost and lower energy use, but lower-quality service. Thus, while there are energy savings, the incremental cost is negative compared to a tank unit. *Termo duchas* will always provide a benefit in energy savings since less water is heated (some water is probably heated on the stove). The lower cost makes them very attractive to cost-conscious consumers. These units will always be chosen by consumers when they meet their needs, and efforts to increase penetration would lower amenity within the economy while saving energy. Therefore, no analysis is presented on these types of water heaters.

2.5.2 Energy-Efficient Refrigerators

Description. Considerable attention in the United States has been focused on refrigerators, and this experience could be valuable for Costa Rica. According to current estimates, U.S. refrigerator efficiency can be improved as much as 50 percent. The National Appliance Energy Conservation Act has led to the development of formal regulations affecting the efficiency of U.S. refrigerators. Although standards are usually needed to ensure the reasonable success of refrigerator efficiency measures, Costa Rica currently has no testing or labeling standards.

An example of the type of data used to develop a conservation "resource" supply curve for U.S. refrigerators is shown in Exhibit 2-18. These data were developed by Lawrence Berkeley Laboratory as part of an overall assessment of energy savings potential. In Figure 2 of this exhibit, the annual units of electricity consumption (UEC) decrease as the consumer price increases. Based on results for U.S. refrigerators, significant savings appear to be possible for refrigerators in Costa Rica.

Exhibit 2-18

Data Used to Develop Conservation Resource Supply Curves for U.S. Refrigerators

Figure 1: ENERGY CONSUMPTION AND COSTS FOR REFRIGERATOR ENHANCEMENTS

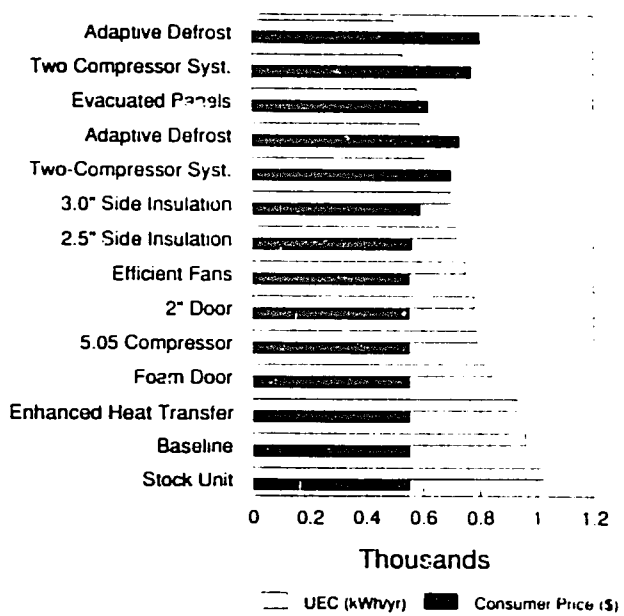
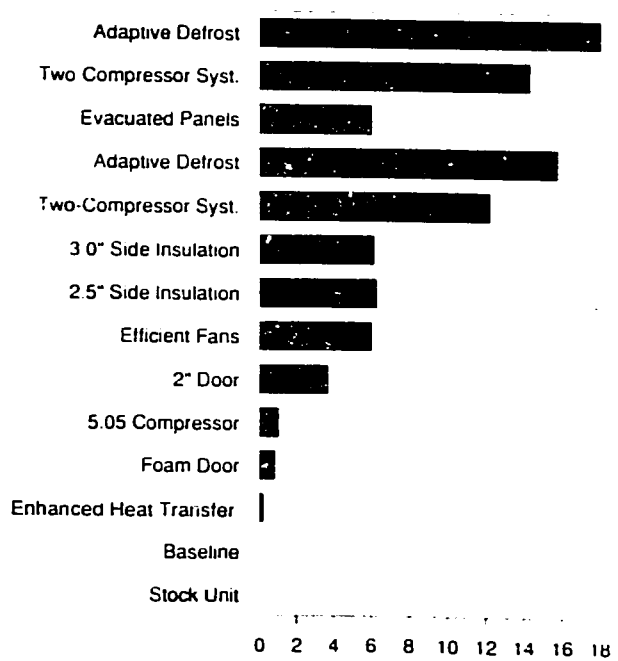


Figure 2: COST OF CONSERVED ENERGY ($/KWh X 100)



Source: Lawrence Berkeley Laboratory.

Model. Estimating the energy savings from increasing refrigerator efficiency depends on extrapolating U.S. experience to Costa Rican refrigerators and estimating a probable efficiency increase. The factors used to scale the U.S. experience to Costa Rica are shown in Exhibit 2-19. Average annual field power is based on measured data for residential refrigeration units (refrigerators and freezers) in California and the estimated total GWh consumption for refrigerators in Costa Rica. The total energy consumption (GWh) is divided by 8,760 h/yr, multiplied by one million GW/kW, and divided by the estimated number of refrigerators in 1989 (290,000) to obtain the average power of field units.

Exhibit 2-19
Comparison of Efficiency Potentials for U.S. and Costa Rican Refrigerators

	U.S.	Costa Rica
Average size of new units, liters	590	270
Field power, average yearly kW per home for existing units	0.23	0.10
New power, average kW of units sold now	0.12	*0.07 (est.)
Efficient power, average yearly kW*	0.09	0.55
Efficiency improvement, %	27.00	21.00
Incremental improvement cost to consumer, $/unit	19.00	25.00

* Efficiency improvements, based on estimated cost of conserved energy being less than $0.065/kWh with a 12% discount rate, include: enhanced heat transfer, improved door insulation, and a compressor with a COP of 5.05.

For Costa Rica, the savings estimated to result from improvements in enhanced heat transfer, improved door insulation, and a compressor with a coefficient of performance (COP) of 5.05 is 21 percent of refrigerator energy. With an estimated energy savings of approximately 200 kWh/year, the estimated cost of conserved energy for this technology is 1.84¢/kWh, which is less than ICE's estimated long-run marginal cost of 6.5¢/kWh. The simple payback is estimated at 1.9 years. In the year 2005, we have estimated an

energy conservation potential of about 56.1 GWh, with a penetration rate of 50 percent. The peak demand reduction for this measure is estimated to be 8.0 MW.

2.5.3 Spiral Burners

Description. Cooking is the major residential end use of electricity in Costa Rica. In the United States, cooking is much less important, accounting for less than 10 percent of total residential energy use in the late 1980s and consuming only about two-thirds of the energy used by refrigerators and freezers. In addition to being a small end use, U.S.-manufactured electric stoves and ovens are considered to be efficient; there is little that can be done to improve their efficiency.

In contrast, it appears that significant savings for electric stoves in Costa Rica can be attained by substituting spiral burners for the disc burners now prevalent. According to initial tests performed by ICE, spiral burners may be 25 percent more efficient than the flat disc-type burners.

However, acceptance of changes to the preferred disc burners may be difficult according to the local manufacturer, Atlas Eléctrica. Spiral burners are typically not used because they cost about 25 percent more, allow food to fall through, and are not as durable. The quality standards of the spiral-type burners should therefore be examined.

Model. A number of assumptions were made to estimate the potential energy savings for this end use. For domestic cooking, the economic impacts are based on a 25 percent energy savings in rangetop use. Electric stoves with disc-type burners were further assumed to account for 90 percent of electric stoves, and 1 percent of homes already have spiral burners. Rangetop use was assumed to account for 85 percent of total cooking energy for electric stoves, which is estimated at 440 GWh/yr in 1989 and forecast to be 860 GWh/yr in 2005. The energy savings per stove is estimated to be 300 kWh/year.

The cost for this measure to achieve any reasonable penetration should be based on total replacement and full cost, since replacement is not likely to be needed for most burners. The cost is estimated at $60 for four burners on one stove, and the total number of households that could have replacement burners is 340,000 (610,000 x 0.62 x 0.9).

The estimated cost of conserved energy with the full cost assumption is 3.23¢/kWh, while the replacement value (e.g., an option to purchase a flat spiral disc) would be 0.54¢/kWh. Both measures indicate the spiral burners are economically attractive due to their 25 percent energy savings. However, this savings potential needs to be further

investigated. In the year 2005, we have estimated an energy conservation potential of 59.5 GWh, with a penetration rate of 30 percent. The simple payback for the incremental cost of the spiral burner is 0.5 years. The peak demand reduction for this measure is estimated to be 10.7 MW for the year 2005.

2.5.4 Solar Water Heating for Tanks and Termo Duchas

Description. Although solar water heating could be important for the future, solar systems are still generally too expensive for the energy saved. Another problem with solar system applications is reliability, which continues to present difficulties in the United States. Many solar systems have been installed in Israel, accounting for 65 percent of that nation's domestic water heating. These systems require only $25/yr for supplemental electric heating, and the systems pay for themselves in less than four years. A 1980 law in Israel requires the use of solar systems on all residential buildings up to nine stories high.[6] Solar water heating systems in Hawaii, with the high electricity prices there, are enjoying reasonable success and can save 100 percent of water heating energy use in many cases. However, these systems cost $3,000-4,000.

Costa Rica could realize important benefits from solar systems if reasonable efforts are made to duplicate the Israeli experience with standardization, simplification, and cost reduction for these systems. The use of solar energy in Costa Rica is less popular than some researchers had hoped several years ago, with lack of confidence in the buying public and high cost being key limiting factors.[7] Based on current prices, ICE and DSE have estimated a simple payback of 10 years for solar hot water systems based on Alcatel collectors.

Model. For this study, we assumed that a lower-cost, lower-efficiency, reliable solar hot water system is used (similar to Israeli systems). The estimated average savings from solar for a home with a hot water tank is 80 percent of 2,100 kWh/yr, or about 1,700 kWh/yr. The savings for a home with a *termo ducha* is 90 percent of 650 kWh/yr, or about 600 kWh/yr (savings may be more if energy for heating wash water on the stove is displaced), which has a value of about $40. The total installed cost of a solar system for a home with a hot water tank is estimated to be $600 (with some development effort). The cost of a system for a home with a *termo ducha* should be less, an estimated $450.

---

[6] Shea, C.P. "The Promise of Renewable Energy, Part II." *Sunworld*, vol. 12(2), 1988, p. 42.

[7] SUNSPOTS. "Costa Rica Celebrates Sun Day." *Sunworld*, vol. 10(3), 1986, p. 67.

For the year 2005, we estimated an energy conservation potential for solar in homes with hot water tanks of 29.1 GWh with a penetration rate of 40 percent. For homes with a *termo ducha*, the energy conservation potential is estimated to be 30.3 GWh, with a penetration rate of 20 percent. Based on current costs, the cost of conserved energy for tanks is 5.18¢/kWh and for *termo duchas* is 11.01¢/kWh, which is close to or above the ICE avoided cost. Thus, these measures would require close examination on a case-by-case basis. The simple payback for the solar water heater tank is 5.4 years, while the simple payback for the termo ducha is 11.5 years.

2.5.5 Compact Fluorescent Lighting

Description. Lighting used about 290 GWh/year in Costa Rica's residential sector in 1989; about 90 percent of this energy was used for incandescent and 10 percent for fluorescent lighting (based on data from the 1984 DSE residential survey).

Changes in residential illumination may be beneficial to Costa Rica. In the U.S., Southern California Edison Company (SCE) is conducting a major residential relamping program. In this program, three 15 watt, compact, self-ballasted fluorescent lamps are installed in fixtures that typically use 2,000 h/yr or more (5.5 h/day) to replace existing incandescent lamps of up to 60 watts in the average customer's home. This program has been in operation since 1985, and over 800,000 lamps have been installed for about 250,000 customers. Their current annual savings are over 70 GWh/yr and the average power savings is 30 MW. SCE is now evaluating methods to provide replacement lamps as the lamps reach their 9,000 hour operating life. The SCE program has demonstrated dramatic savings and received much recognition. The use of compact fluorescent lamps has been shown to have important benefits when installed in a fixture used (typically) at least five hours per day. The SCE relamping program has also had important ancillary benefits. Customer surveys show that participating households become more aware of energy conservation and develop an increased appreciation for the utility.

Model. Lighting energy savings estimates are based on replacing an average of three incandescent lamps averaging 50 watts each in each household. The replacement lamps are 15 watt, compact, screw-in, self-ballasted fluorescent lamps. The savings per lamp is 35 watts. With three lamps per residence, approximately 1.620,000 lamps would be installed in 540,000 residences in Costa Rica. Current data on the use of electric lighting indicate that on average, lighting is used three hours per day. Some effort is probably needed to confirm lighting energy use habits in Costa Rica and the number of lamps that may be used for more hours each day. Furthermore, a program to install the lamps in the most appropriate fixtures in homes is needed.

The incremental cost estimated for these compact self-ballasted fluorescent lamps is about US $14 each. The cost of conserved energy is estimated at US 6.43¢/kWh. If the administrative and implementation costs related to this program were added to this amount, the cost of conserved energy (CCE) would rise to about 12¢/kWh. This is well above ICE's avoided cost estimate. However, this estimate is based on a lamp utilization of only three hours per day. Thus, the CCEs of the compact fluorescent lamps for the residential sector would need to be estimated according to specific circumstances such as lamps that would be on for five or more hours per day, increasing the economic viability of the measure. In the year 2005, we have estimated an energy conservation saving potential of about 51 GWh, based on a penetration rate of 50 percent. The simple payback is 5.5 years. The peak demand reduction for this measure is estimated to be 15.8 MW in the year 2005.

2.5.6 Summary and Conservation Supply Curves

The analysis of potential demand-side measures for Costa Rica's residential sector revealed a number of attractive possibilities. These include water heating, refrigerator, cooking, and lighting energy efficiency.

One area of concern is the cost of running any demand-side management (DSM) program. These costs per kWh saved are generally considerably higher for the residential sector than other sectors because of its diversity.

Program costs (as separate from the measure costs) are affected by the way in which a measure is introduced. For example, more efficient refrigerators and solar water heaters could be mandated by law after an initial testing period to determine their feasibility. The program costs for this approach would then depend on the effort needed to certify performance and to develop any required information to support potential legislation. As another example, the water heater insulation measure could be introduced as a service provided by ICE. In this case, program costs could include such items as customer mailings, tracking appointments, scheduling work crews, etc. The costs of running a program for installing measures or for introducing a measure through legislation must be considered in an analysis of potential demand-side energy savings.

The estimated energy savings for the energy conservation measures for Costa Rica's residential sector are shown in Exhibit 2-20. The overall estimated savings potential for the residential sector is about 177 GWh/yr for the spiral burners, the water tank insulation, the refrigerator efficiency, and the compact fluorescent programs, which are all below the ICE-estimated avoided cost (see Exhibit 2-21). Exhibit 2-22 shows the

Exhibit 2-20

Estimated Energy Savings for Various Energy Conservation Technologies in MWh per Year
Residential Sector

MEASURE	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Water Heater Tank Insulation	0	100	210	300	430	610	870	1230	1720	2380	3250	4310	5590	7070	8680	10270
EE Refrigerators	0	640	1200	1680	2360	3300	4590	6360	8760	11970	16260	21650	28470	36300	46080	56060
Spiral Burners	0	1110	1880	2540	3380	4480	6010	7940	10440	13880	18120	23310	30230	38280	47870	59540
Solar Water Heater for Tanks	0	577	790	1082	1480	2015	2734	3706	4991	6670	8876	11590	11590	19100	23890	29110
Compact Fluorescent Lighting	0	620	1170	1640	2300	3210	4460	6180	8490	11560	15600	20590	26740	34060	42370	51080
Solar for Termo Ducha	0	990	1280	1640	2110	2820	3610	4620	5900	7490	9930	12470	15610	19440	24960	30350

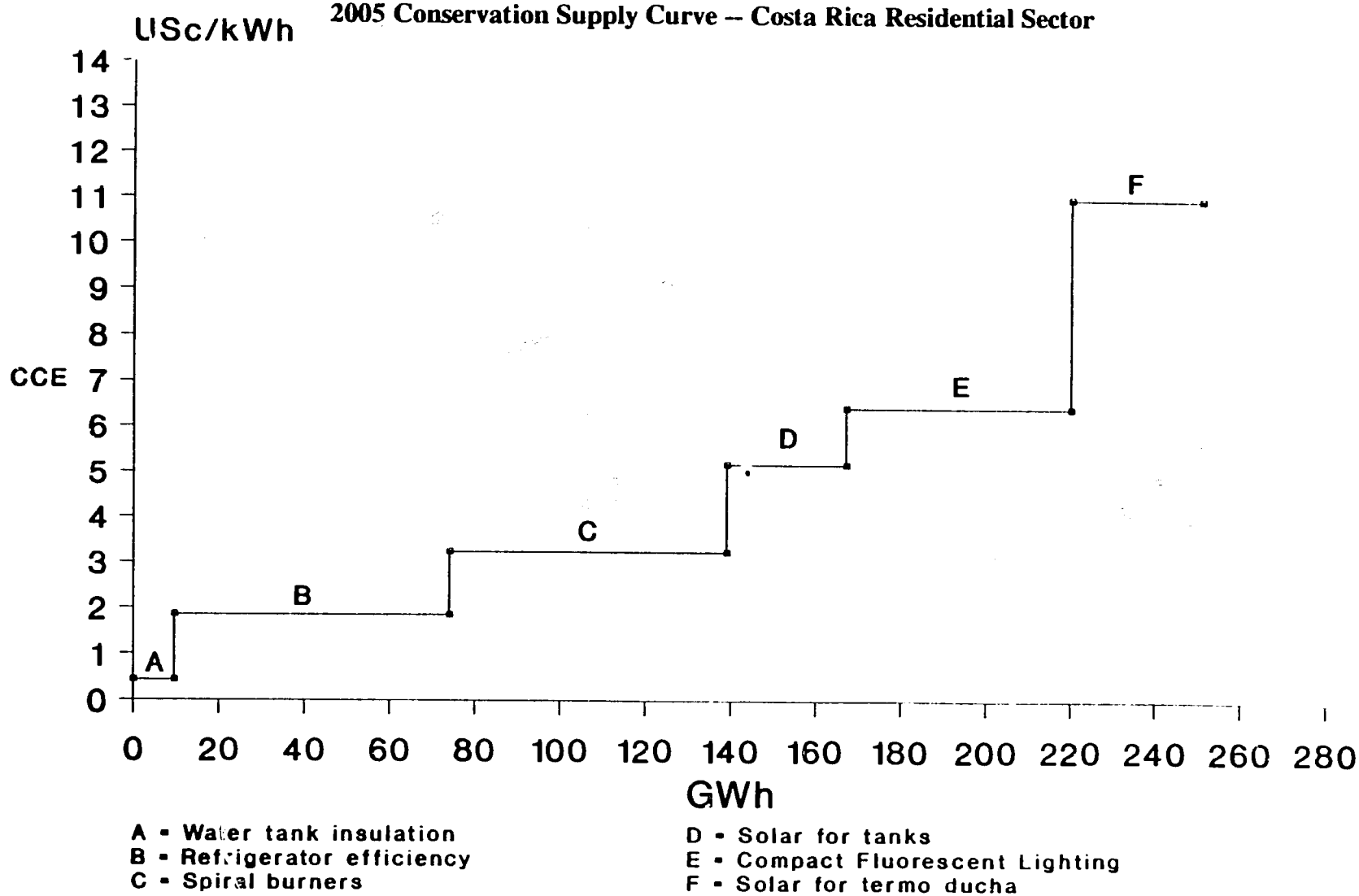
Exhibit 2-21

Estimated Energy and Demand Savings for the Residential Sector, with Target Penetration Rates

	Penetration	Savings in GWh/yr	Avg. MW Savings	NCP Load Factor	Maximum MW	Coincidence Factor	Peak MW Savings
• Water Tank Insulation	60%	10.3	1.2	0.5	2.34	0.90	2.1
• EE Refrigerators	50%	56.1	6.4	0.8	8.42	0.95	8.0
• Spiral Burners	30%	59.5	6.8	0.4	19.42	0.55	10.7
• Compact Fluorescent	50%	51.1	5.8	0.4	16.66	0.95	15.8
TOTAL SAVINGS		177.0	20.2	2.0	46.8	3.4	36.6

Exhibit 2-22

2005 Conservation Supply Curve -- Costa Rica Residential Sector



Source: *Costa Rica Power Sector Efficiency Assessment*/A.I.D.

conservation supply curve for all the identified programs for the year 2005.

On the other side of the balance sheet, the savings for avoided generating capacity resulting from the installation of these DSM measures have been estimated at a very preliminary level of about 36.6 peak MW for the year 2005 (see Exhibit 2-21). For instance, more efficient water heater tanks can reduce the need for hot water energy during the evening system peak, assuming the heaters are not on a load control program where they are switched off during this period by utility control. Similarly, increased refrigerator efficiency could help reduce system peaks. Solar water heating could have benefits for the evening peak demand by helping to reduce electricity consumption during this time for heating water. The use of higher-efficiency lamps might have the largest impact on peaks, so long as the periods for cooking and illumination coincide. Moving to daylight savings time to allow more daylight when evening meals are cooked could have an important impact, but if this change is not possible, the more-efficient lamps could help.

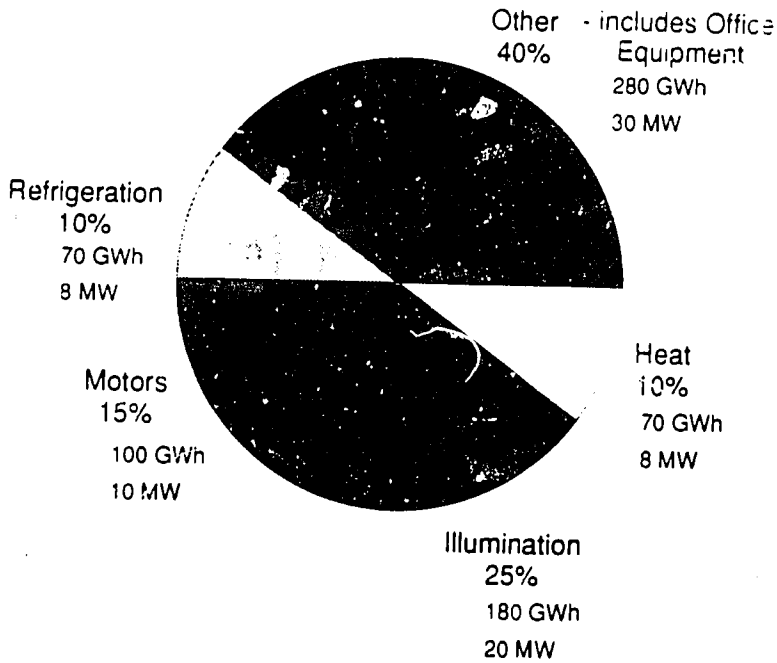
2.6 ENERGY AND DEMAND SAVINGS FOR THE GENERAL SECTOR

General sector (commercial and public buildings) loads account for approximately 20 percent (700 GWh/yr) of Costa Rica's electricity consumption. Much less is known about this sector than the others. The characterization, identification of potential conservation measures, and estimation of energy savings thus become more difficult for the general sector of Costa Rica.

Data are not directly available on the end-use breakdown for this combined sector. Two different studies by DSE have estimated the end-use breakdown for the commercial and public sectors, respectively, but the end uses are different in the two studies. An estimate of the electrical end-use breakdown was prepared based on the results of the DSE studies, but necessitated significant judgment. Exhibit 2-23 shows the resulting breakdown, which identifies illumination as the major known load, but the "Other" category accounts for 40 percent of the total.

The DSE study on commercial buildings estimated that office equipment accounts for 38 percent of this sector's total consumption. The study on public buildings uses a different breakout that makes comparisons almost impossible. The actual consumption of the office equipment category appears questionable, and is thus included here in the "Other" category to indicate the uncertainties. Lighting (illumination) is estimated to account for 40 percent of total consumption in public buildings, while accounting for only 20 percent of total consumption in the commercial sector study. Since the commercial sector is

Exhibit 2-23
Commercial End-Use Breakout



Source: Direccion Sectoral de Energía.

larger, the overall general sector lighting consumption is estimated here to be about 25 percent.

In its recent work on a national energy plan, DSE estimates end-use energy consumption for the residential sector, but estimates only total consumption for the general sector. More data are needed on the general sector as a whole to address DSM measures for this rapidly growing part of the economy.

In its report *Mercado Electrico*,[8] ICE has included the energy savings of converting all public lighting to high-pressure sodium lighting, with Inter-American Development Bank (IDB) financing. For this reason, it is unnecessary to include any more detail on public

[8] ICE. *Mercado Electrico*. Instituto Costarricense de Electricidad report, Direccion de Planificacion Electrica, 1989.

lighting in this report. Based on ICE and CNFL data, approximately 3.2 MW of energy savings have yet to be realized from this conversion, which should be completed in the next two years.

Potential electricity use savings in the general sector could result from many different measures, but the calculations here focus on improved energy management and lighting. The cost assumptions and calculations for all general sector programs are shown in Appendix 8 from the economic (national) point of view and in Appendix 9 from the financial (end-user) point of view.

2.6.1 Lighting

Description. Lighting efficiency changes, including the increased use of daylighting, could lead to important savings. Although many buildings in Costa Rica do not appear to have excessive lighting, significant lighting savings are still possible.

Although data on commercial sector lighting equipment were collected as part of the DSE surveys, the data on these types of equipment were apparently not coded in the final computer data set. Thus, the actual distribution of the equipment is not known. Without knowing the distribution of lighting technologies in general sector buildings, the estimation of savings is somewhat speculative.

Observations of buildings in San José indicate that older buildings benefit greatly from daylighting contributions (because they are architecturally open, while newer buildings are often more closed). The uses of daylighting in the older buildings could be studied to determine if their designs are more energy efficient.

Model. As in the industrial and residential sectors, lighting technologies are applicable in Costa Rica's general sector.

Based on assumptions similar to those made for the industrial sector, the cost of conserved energy has been estimated for each technology as follows:

Measure	CCE (US¢/kWH)	Savings (GWh, 2005)
Energy-Efficient Fluorescent	0.05	14.94
Hybrid Electro-Mechanical Ballast	0.09	5.45
Electronic Ballasts	2.3	11.27
Compact Fluorescents	2.4	3.24
Fixture Reflectors	4.7	11.56

For the year 2005, we estimated an energy conservation potential of almost 46.5 GWh from the adoption of these technologies, with a penetration rate of 35 percent. The peak demand reduction for these measures is estimated to be 6.8 MW in the year 2005.

2.6.2 Energy Management

Description. In the U.S., energy management can account for 10-40 percent savings or more, including significant amounts of heating and cooling energy. However, because these are not major uses in Costa Rica, its energy management savings will be smaller. Energy management can also be used for load control to reduce power requirements during system peaks, and with some types of systems, utilities can exercise remote control of building loads.

Savings can also result from better control of motors (use only when needed) for fans and pumps, control of periods when lighting is used, reducing the use of refrigeration equipment, and better control of the heat energy used in commercial buildings. Energy monitoring programs, where the energy use of different buildings is measured and studied, would allow simple standards to be developed that describe expected energy consumption for different building types. Buildings exceeding these standards could be targeted for additional efforts to reduce their consumption. The exact form of such standards and support efforts requires additional study.

Model. General sector savings are not as amenable to presentation on a per-customer basis. The buildings and the energy-using systems in this sector are not as homogeneous as the residential sector. There is significant variation in the size of the buildings also. Because of these variations, general sector buildings must be analyzed in more depth than residential buildings. The analysis is particularly important for larger buildings, where

significant system interaction effects must be understood, while a relatively standard package of DSM improvements can generally be applied to smaller buildings. Because of the nature of these types of changes, detailed descriptions of the specific DSM improvements cannot be given.

ICE will realize the greatest benefit in the general sector if larger buildings receive DSM improvements first, followed by progressively smaller buildings. Larger buildings more often have staff responsible for their use who can assist in developing and implementing DSM measures. Also, opportunities for energy management are usually greater for larger buildings because of the number and complexity of their energy-using systems.

The savings results are presented as though they accrued to a "typical" (average) customer, when the savings will mainly come from larger buildings. The representation using a typical customer allows further analysis of the savings in a format similar to that used for the residential sector. To provide some perspective, the average general sector customer consumes 10,000 kWh/yr, and this customer's lighting consumption would be 2,500 kWh/yr. (The average commercial building in the United States consumes about 175,000 kWh/yr.) A further breakdown would lead us to estimate that the average customer uses about 1 kW of lighting about 7 h/day.

Energy management measures are estimated to result in a 10 percent savings of energy for the average general sector customer. There are no hard data on the maximum savings, but this is an informed judgment. Energy management studies in the United States show that savings can be 15 percent from operations and maintenance changes alone. Energy audits performed for large general sector customers in Costa Rica also show significant opportunities for energy management. Thus, our estimate of potential savings is 10 percent, for a penetration rate of 50 percent.

For the year 2005, we estimated an energy conservation potential of over 77 GWh from energy management measures. The peak demand reduction estimated for energy management is 8.0 MW for the year 2005. The cost for achieving these savings is estimated to be $200 per customer, which is $7,000,000 for 50 percent of the approximately 70,000 customers in this sector (70,400 as of December 1989, ICE). The cost of conserved energy could range from nearly US 0¢/kWh from adopting low/no cost measures such as in the industrial sector to well above the ICE avoided cost. For the purposes of this analysis, the average cost estimated based on U.S. experience is 5.5¢/kWh, which is below the ICE avoided cost. This indicates that the implementation of such a program would need to be site specific.

2.6.3 Summary and Conservation Supply Curves

The uncertainty about the actual distribution of end uses of energy in the general sector means that this study's estimates of lighting costs and savings must be viewed with caution. The level of knowledge about general sector energy end uses should be improved to facilitate demand-side planning efforts.

As with the industrial and residential sectors, a number of issues are raised. Technical assistance on program implementation, the assessment of program costs, and the estimation of benefits from avoided power at system peak are again issues for the general sector.

There is a need for better characterization of the end uses of energy for the whole sector. Public buildings should not be treated separately, so that a consistent data set is obtained for the sector. Energy consumption guidelines to evaluate general sector buildings against a common "standard" should be established. This type of comparison can significantly increase the benefits of energy management programs by identifying the buildings needing the most assistance.

Furthermore, one could identify additional measures through improved data. For example, insulating 30-40 gallon commercial water heater tanks would save as much energy as insulating residential tanks. Refrigeration systems also could probably benefit from efficiency improvements, but no data are available to characterize this potential.

Also, one could identify the ways in which the use of daylighting could be increased. Daylighting should be a major priority for all new general sector buildings; lighting controls (including simple switches) to take advantage of daylighting in existing buildings should also be aggressively promoted.

The estimated energy savings for the energy conservation measures for Costa Rica's general sector are shown in Exhibit 2-24. The overall estimated savings potential for the general sector for the year 2005 is estimated at about 124 GWh and 14.7 peak MW, considering the energy management program and the lighting technologies that are below the ICE-estimated avoided cost (Exhibit 2-25). Exhibit 2-26 shows the conservation supply curve for all the identified programs for the year 2005.

The potential savings for the general sector are tentative, but better field data and more study of these buildings could indicate further potential savings. As with the industrial and residential sectors, the work needed to achieve these savings requires careful thought and technical assistance, and the benefits should extend beyond the energy savings.

Exhibit 2-24

Estimated Energy Savings for Various Energy Conservation Technologies in MWh per Year
General Sector

MEASURE	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Energy Efficient Fluorescent	0	330	560	750	990	1330	1770	2340	3060	3980	5150	6580	8280	10250	12470	14940
Hybrid Electro-Mech Ballasts	0	80	130	180	250	340	470	640	860	1160	1550	2060	2690	3460	4380	5450
Electronic Ballasts	0	130	280	380	520	710	970	1320	1780	2390	3210	4250	5560	7160	9060	11270
Compact Fluorescent	0	60	100	130	180	240	310	420	550	720	950	1240	1600	2050	2590	3240
Fixture Reflectors	0	160	280	390	530	730	1000	1350	1830	2450	3290	4360	5710	7350	9300	11560
Energy Management	0	720	1400	2020	2910	4200	6020	8560	12030	16660	22900	30810	40450	51670	64130	77400

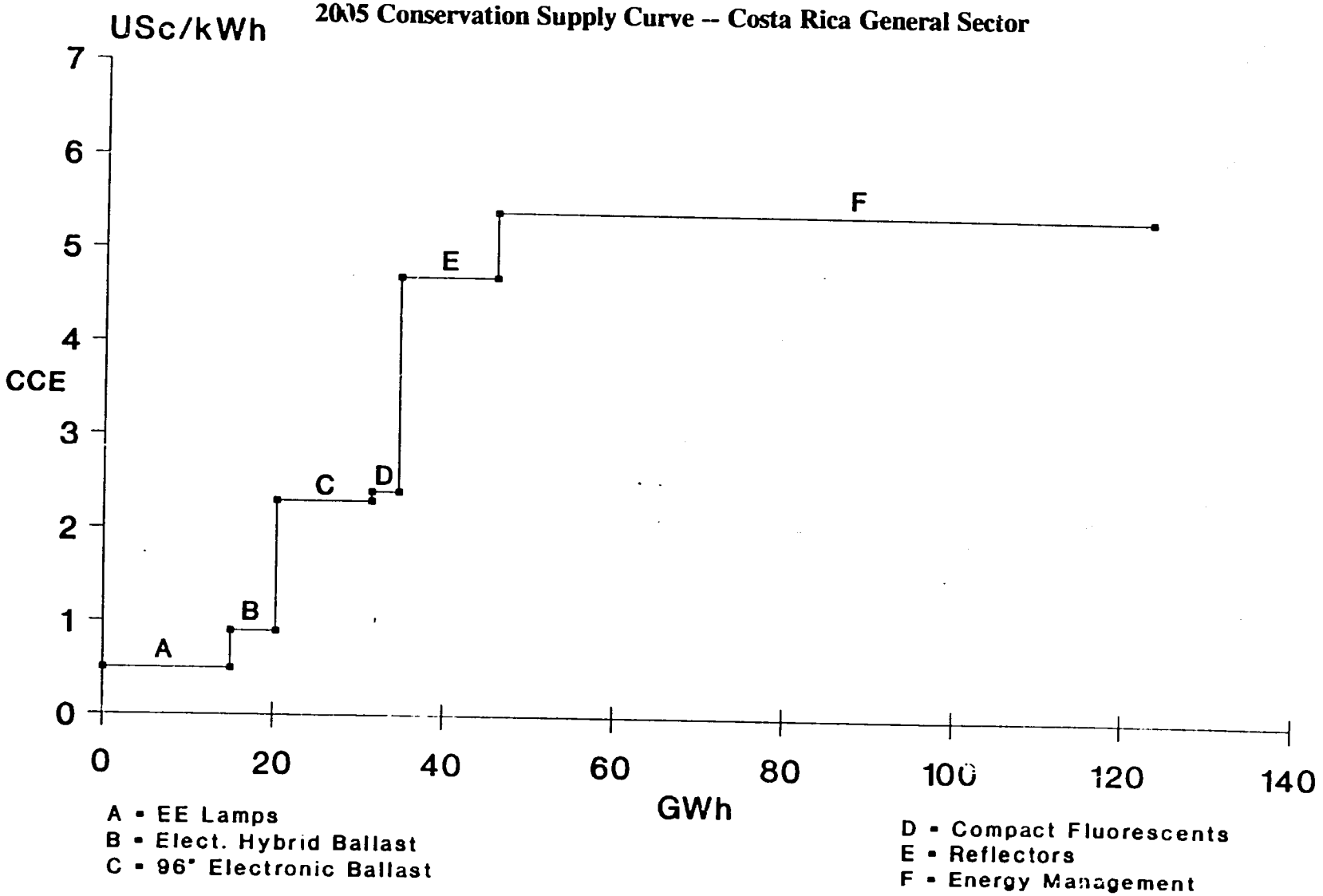
Exhibit 2-25

Estimated Energy and Demand Savings for the General Sector, with Target Penetration Rates

	Penetration	Savings in GWh/yr	Avg. MW Savings	NCP Load Factor	Maximum MW	Coincidence Factor	Peak MW Savings
GENERAL							
• Energy Management	30%	77.0	8.8	0.6	15.98	0.50	8.0
Lights:							
• Energy-Eff. Fluor	35%	14.9	1.7	0.6	3.10	0.70	2.2
• Hybr Electro-Mech Ballasts	35%	5.5	0.6	0.6	1.13	0.70	0.8
• Electronic Ballasts	35%	11.3	1.3	0.6	2.34	0.70	1.6
• Compact Fluor.	35%	3.2	0.4	0.6	0.67	0.70	0.5
• Fluor. Fixt. Reflect	35%	11.6	1.3	0.6	2.40	0.70	1.7
TOTAL SAVINGS		123.5	14.1		25.6		14.7

Exhibit 2-26

2005 Conservation Supply Curve -- Costa Rica General Sector



Source: *Costa Rica Power Sector Efficiency Assessment*/A.I.D.

CHAPTER 3: SUPPLY-SIDE EFFICIENCY IMPROVEMENTS

3.1 ANALYSIS OF THE GENERATING SYSTEM

ICE installed its first thermal power station at San Antonio in 1954, followed by the Colima station, which was constructed in 1956. La Garita, Costa Rica's first major hydroelectric plant, was commissioned in 1958. These facilities are located in San Jose, and for many years, provided power only to the national capital region. As demand for electricity grew in Costa Rica, however, ICE expanded its capacity. Rio Macho and Cachi, hydroelectric stations with a combined installed capacity of 94 MW (later expanded to 221 MW), were commissioned in 1963 and 1966, respectively.

To meet the power needs of the coastal areas, the Barranca and Moin thermal stations were constructed in the mid 1970s. These plants were used extensively during their first years of service, prior to the construction of the Arenal and Corobici hydroelectric complex in 1980. This hydroelectric complex, representing nearly 40 percent of Costa Rica's total installed capacity, is the backbone of ICE's system.

For several years after they were commissioned, the thermal plants were placed on standby service, and were used sparingly until the 1987 dry season. A combination of uncharacteristically dry weather, coupled with high load growth and delays in ICE's ability to expand hydroelectric capacity, led to a return of these thermal power stations to active service.

ICE's expansion plan calls for a variety of technologies to be commissioned over the next twenty years, including several thermal power units. A combination of the new and existing thermal equipment will play an increasingly important role in the delivery of reliable electric energy, as ICE increasingly relies on thermal energy to satisfy dry season power and energy requirements. Thus, the efficient conversion of fuel to electric energy will grow in importance to both ICE and to the Costa Rican economy in general.

The purpose of this chapter is to quantify the degree to which efficiency measures can be taken to improve the technical and economic performance of ICE's power plants. To execute this objective, members of the project team visited Costa Rica to gather data and hold discussions with ICE management and power plant operations staff. The Arenal/Corobici complex was visited, as were two of the four thermal plant sites, to conduct extensive interviews with plant operating staff and management, and to collect detailed data on unit performance. Interviews with central ICE maintenance and generation staff provided the input for the analysis of the two plants that were not visited.

3.1.1 Thermal Generation

All ICE thermal power plants are located at four power stations. The two oldest of these stations are located in San Jose (San Antonio and Colima). The Colima station has six medium-speed diesel units, whose nameplate capacity totals 19.5 MW. San Antonio has two gas turbines (19 MW each) and two 5 MW boiler/steam turbines. Units from both stations have been derated, as described later in this chapter.

In addition to San Antonio and Colima, ICE operates two other thermal power stations. The Barranca station was commissioned in 1974, and consists of two gas turbines, with nameplate capacities of 20 MW each. Slow-speed diesels were installed at the Moin station in 1977, with a total installed capacity of 32 MW. Their nameplate and derated capacities are listed in Exhibit 3-1, together with those of the Colima and San Antonio plants.

Exhibit 3-1
Thermal Generation Unit Nameplate and Derated Capacity

Station	Plant	Nameplate Capacity (kW)	Derated Capacity (kW)	Available Capacity (kW)
San Antonio	Steam Gas Turbine	2 x 5000 2 x 20,800	2 x 5,000 2 x 18,000	13,000
Colima	Nordberg Diesel Sulzer Diesel	4 x 2,970 2 x 3,830	4 x 2,000 2 x 3,830	10,000
Barranca	Gas Turbines	2 x 18,000	2 x 18,000	18,000
Moin	Pielstick Diesel	4 x 8,000	4 x 6,500	26,000
Total		141.240	120,000	70,000

Due to an increased demand for electric energy, ICE has recently purchased three additional gas turbines to be installed at the Moin station. The turbines will arrive between December 1990 and February 1991. The turbines will add 108 MW of capacity to the ICE system, and similar to the existing thermal plants, they will be used primarily

in the dry season during periods of low river flows. As demand increases, they may be used to provide peak power at other times of the year. The new gas turbines are Japanese-manufactured GE Frame 6 units, which are essentially larger and more modern versions of the gas turbines installed at Barranca and San Antonio.

Thermal generation has grown in importance in recent years in Costa Rica. Due to a combination of high growth in demand, insufficient investment capital, and uncharacteristically dry weather, ICE has experienced power shortfalls from its hydroelectric plants. Exhibit 3-2 illustrates the energy production by generation type for a ten-year period (1980 through 1989). As this exhibit shows, ICE did not have to utilize its thermal capacity for an extended period beginning in 1980, when the Arenal/Corobici plants were commissioned. In fact, from 1981 through 1986, the thermal plants lay dormant, producing a cumulative total of 10 GWh during that period.

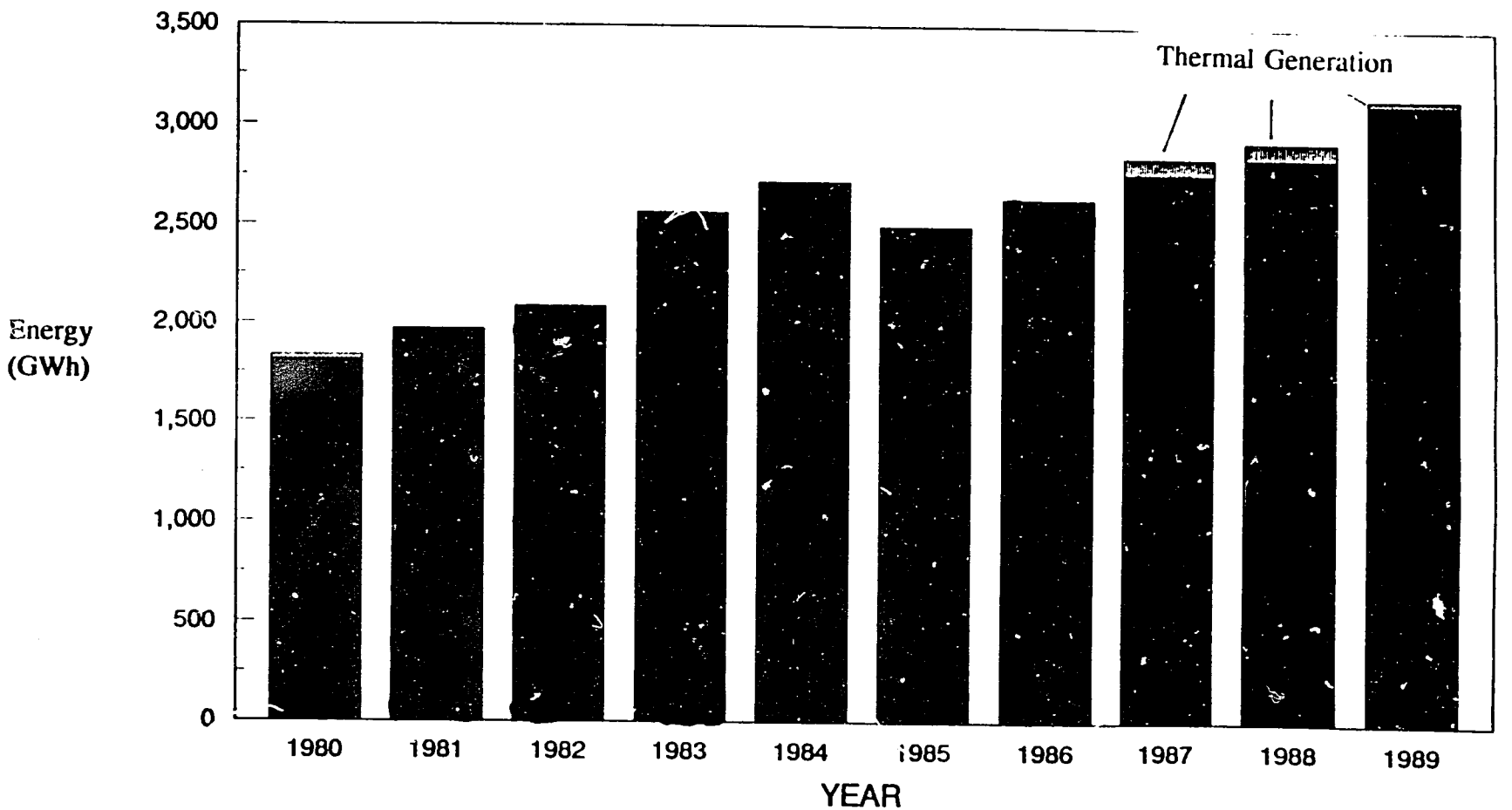
Beginning in 1987, however, the thermal plants were brought back into service. In response to the growing need to expand capacity, negotiations for the three new Moin gas turbines were initiated shortly thereafter. In addition to purchasing the new turbines, ICE management decided to initiate a rehabilitation program to purchase spares and refurbish gas turbines, boilers and boiler controls, and diesels that had fallen into a state of disrepair during the period of low use levels in preceding years.

At the time this assessment was conducted, the available capacity of the thermal equipment had fallen to 70 MW from a total installed capacity of 141 MW. The rehabilitation program will result in 120 MW of available thermal capacity by 1992, with spares provided through this activity to satisfy maintenance needs for the following eight operating years. This program will not only result in increasing the available capacity, but should also increase the efficiency of operations of some of the power units benefiting from the program. With the inclusion of the three new gas turbines, ICE will have 249 MW of installed capacity (228 MW available capacity) by 1992.

3.1.1.1 Operating Issues

Availability. Due to the cyclical and sometimes intermittent use of the thermal power plants, their number of actual operating hours is much lower than one would expect for units of this age. For example, the Colima diesel units were installed in 1956, but have been operated for only 45,000 hours per machine, the equivalent of 10 years of service at a 0.5 plant factor. Similarly, the Barranca combustion turbines have seen only 12,000

Exhibit 3-2
Energy Production Growth from 1980 Through 1989



hours of service since 1974, or 4.6 years of service at a 0.3 plant factor (average plant factor for peaking units).

The combustion turbines were often cycled several times per day during periods of high use (i.e., from 1974 through 1979 and from 1987 through 1989). As are all thermal power plants, combustion turbines are very sensitive to thermal stress associated with frequent cycling (start up and shut down), and it is therefore preferable to maximize operating hours per engine start. Aero-derivative turbines are much less sensitive to frequent cycling, due to the enhanced materials used in their construction, but the advanced alloys used in aero-derivative turbines have not yet been introduced in industrial combustion turbines or internal combustion engines.

Due to metal fatigue and other related factors, multiple starts have the effect of increasing the incidence of forced outages, often requiring more frequent major maintenance procedures and sometimes reducing plant life. For example, it has been estimated that decreasing operating hours per start from 100 hours per start to 10 hours per start will increase maintenance costs by approximately 20 percent. All ICE combustion turbines have been operated less than six hours per start, with one machine running on average only four hours per start. Maintenance schedules, including major maintenance (hot section overhauls) need to be adjusted if units experience multiple starts daily. ICE experience has shown that these units have required overhauls at more frequent intervals than industry standards, usually a major overhaul per 30,000 hours of operation or per 1,000 starts.

A review of equipment records revealed that the availability of the thermal plants in the most recent period of use is much lower than in preceding years. While it is impossible to determine the actual causes of this decline in reliability, it can be ascribed in part to a combination of factors including less experienced staff, scarcity of spare parts, obsolescence of some of the oldest equipment, and to a change of the heavy oil specification supplied by RECOPE (the Costa Rican Petroleum Refinery).

RECOPE's change in heavy oil specification is thought to have contributed significantly to the increase in downtime for diesel plants at Colima and Moin, as well as the boiler/steam turbines at San Antonio. Both the slow-speed diesel units at Colima (Nordberg and Sulzer) and the medium-speed diesel gensets at Moin (Pielstick) can be operated with heavy oil and were operated as such throughout most of their history.

ICE fuel quality analyses indicate that the vanadium content of the fuel increased significantly in 1987, a factor that can cause increased wear on upper combustion chamber components. Maintenance records reflect an increased incidence of exhaust valve failure

during the period approximating the introduction of the new RECOPE heavy oil specification.

In 1988 after a series of problems at both Moin and Colima, heavy oil use was discontinued and the remaining heavy oil shipped to San Antonio for use in the steam plant boilers. The oil had to be heated to an elevated temperature to allow adequate atomization and ignition. The boilers experienced serious slagging, and the steam atomization systems were unable to keep the burner tips clean. The tips had to be removed for cleaning on a daily basis, and sometimes several times per day. Boiler control systems were also affected, due to fouling of control point taps in the boiler, resulting in inaccurate readings from the monitoring equipment.

There is also reason to believe that the density of the oil was much higher than permissible for use in fuel cleaning and/or conversion equipment. Although the density of the heavy oils was not tested, it is possible that the fuel density may have reached a value as high as 1.0, causing severe problems in the fuel pre-treatment facility. Due to these problems, the plant manager has elected to use diesel oil only (distillate) after problems continued with fuel handling equipment. This has resulted in significantly higher fuel costs for the heavy oil-compatible equipment: diesel sold for US $0.11 more per liter than heavy oil in 1989.

During the March 1990 mission, RECOPE issued a revised heavy oil specification for performance trials. The results of the trials have not yet been received.

Data Collection, Instrumentation, and Controls. ICE has historically maintained detailed records of maintenance and operating data. In a relatively recent development, its Operation Management (the Gerencia de Generacion) has begun to track component replacement intervals, calculating mean time to failure by component. Unit performance is routinely recorded, including fuel and oil consumption, power and energy output, relevant temperatures and pressures, and qualitative remarks provided by shift supervisors regarding performance or maintenance required.

However, in spite of a rather impressive data set available at each plant, it is clear that at the time of the plant visits carried out for this study, plant staff and management have not had sufficient time or computing hardware to take full advantage of the data collected. It was also clear that some of the data monitoring systems were antiquated, and if replaced with digital systems, could result in a more efficient data collection and analysis process, as well as a system that would ultimately be of much greater use to ICE management.

In an earlier discussion with management regarding the rehabilitation program, it was noted that a data logging system may be purchased to provide trending analysis for the new combustion turbines. This is certainly a step in the right direction, but it may be useful to consider data logging systems for each of the power stations (one each for the stations should be sufficient to record and analyze data for all plants in that station). These systems can be as simple as a PC-based data logging system, with a companion data analysis package to perform trending analysis on- or off-line. If the prime mover is being used in a cogeneration application, a more versatile and powerful package would be preferred to allow system optimization with changes in heat and electric energy loads. Systems of a more simplified nature will allow the manager to quickly detect a drop in performance, but will not allow real-time adjustments to optimize efficiency. However, this capability will in all likelihood be unnecessary and unwarranted for the conditions under which the gas turbines and diesel engines will be operated by ICE.

The age of ICE thermal plants is such that the control hardware is to a great extent obsolete. The performance of analog instrumentation is affected by wear in cams and mechanical linkages, resulting in poor performance. Due to inevitable wear, these components need to be periodically replaced to ensure response and control to varying operating conditions. The rehabilitation program will provide some replacement parts for turbine and engine controls, but at least in the case of the combustion turbines, the availability of higher-performance control systems should be requested from equipment suppliers. In some cases, many components may not be available. Where and when possible, these systems should be replaced with more modern components.

3.1.1.2 Cost and Potential Savings

Rehabilitation Program. The rehabilitation program has been designed to provide ICE with additional standby power to avert significant load shedding during peak consumption periods in dry season months. The program provides sufficient spare parts to allow major overhauls of the power generating units, calls for overhaul or replacement of all major accessories, and provides technical assistance to maintenance staff for selected tasks in the rehabilitation process.

Improvements for the San Antonio plant will include replacement of voltage regulators, boiler controls, governors, condensate and recirculation pumps and motors, and switchgear for the boiler/steam units. Parts for a major overhaul of the steam turbines and generators will also be purchased. In addition, fuel systems, starter motors, voltage

regulators, governors, and parts for hot section overhauls will be purchased for each of the combustion turbines.

Parts and services purchased for the Barranca combustion turbines will include voltage regulators, governors, complete starter motor overhaul kits, switchgear, one turbine rotor, one starter motor, and all parts to allow complete turbine and generator overhauls for both machines. The Colima plant will receive overhaul kits for each of the Nordberg and Sulzer engines and generators, parts for renovation of the oil and engine cooling systems, overhaul of the centrifuges, and parts for the renovation of the voltage regulator and governors.

The Moin plant will receive four complete engine overhaul kits, low-pressure cutout protection, four new turbochargers, and replacement parts for the renovation of the engine cooling systems. Auxiliary motors and switchgear will also be renovated.

Technical assistance has been budgeted to allow the plant maintenance personnel to receive training on critical systems or procedures for which expertise may be lacking. The technical assistance budget is relatively small, so it can be assumed that it will provide essential services only. A full description of the rehabilitation program is provided in Appendix 11.

Benefits of the Rehabilitation Program. The improvements resulting from the rehabilitation program should result in increases in operating efficiency and subsequently reduce operating costs. As Exhibit 3-3 illustrates, the performance of the thermal plants has fallen short of rated capacity and efficiency, with some years yielding dramatically low operating efficiencies. These problems occurred from a combination of factors, many of which are being addressed in the rehabilitation program. As improvements are made in the mechanical, electrical, and control systems, and the ICE maintenance team trains and becomes more familiar with the equipment and control systems, availability and operating efficiency can be expected to improve. After the rehabilitation process has been completed and the training programs have been accomplished by maintenance staff, the power units should operate at or near expected levels of fuel consumption, energy, and power output.

In the longer term, energy demand is expected to increase dramatically, requiring a substantial investment in capacity to keep pace with this growth. Thermal power plants will need to contribute significantly more power and energy to the interconnected system in response to this increase in demand. If new plants are added according to the expansion plan and demand does not increase faster than expected (see Exhibit 3-4 for the

Exhibit 3-3
Thermal Plant Efficiencies and Availabilities, 1987-1989

Plant	Derated Capacity	Rated Eff	Actual Eff	77-79 POR	77-79 UOR	87-89 POR	87-89 UOR
Colima Disel	14,000	35.0	31.1	8.2	11.1	2.8	35.5
San Antonio Stm	10,000	22.4	21.2	26.9	7.4	22.9	12.5
San Antonio Gas	34,000	24.4	20.4	5.0	8.7	1.1	81.8
Barranca Gas	36,000	25.4	20.1	2.6	9.6	6.1	79.8
Moin Diesel	26,000	40.0	34.3	13.4	12.1	10.3	22.2

Legend: POR = planned outage rate
UOR = unplanned outage rate

Source: Values provided by ICE maintenance staff.

June 1990 ICE expansion plan) then the older, less efficient plants will produce less and less energy, and will for all practical purposes provide reserve margin to the system. Under this scenario, measures taken now to improve efficiency on existing combustion turbines and steam cycles will result in almost insignificant energy savings in the future. Rehabilitation measures are being made primarily to provide capacity and energy over the short term only, not to provide additional energy over the longer run.

An analysis was performed to forecast the extent to which the existing thermal power plants will be used in future years as ICE commissions additional hydro, geothermal, and thermal power plants to meet demand. This analysis took into consideration the data provided in the June 1990 ICE expansion plan, and the historical data on plant performance and reliability. Exhibit 3-5 illustrates the results of this analysis.

A "normal" year rainfall scenario was used, and an average energy production of 3,450 GWh was assumed for the existing hydro plants. Plant factors of 0.7 and 0.6 were assigned to new geothermal and run-of-river hydro plants, and a plant factor of 0.55 was assigned to new hydroelectric plants with significant storage. Maximum energy production for the diesel plants was estimated at 175 MW, based upon a plant factor of 0.5 over one year of operation. This analysis indicates that the existing combustion turbines will be needed only sparingly in the future, while the diesel units will see service on an annual basis for almost all years under this normal rainfall scenario.

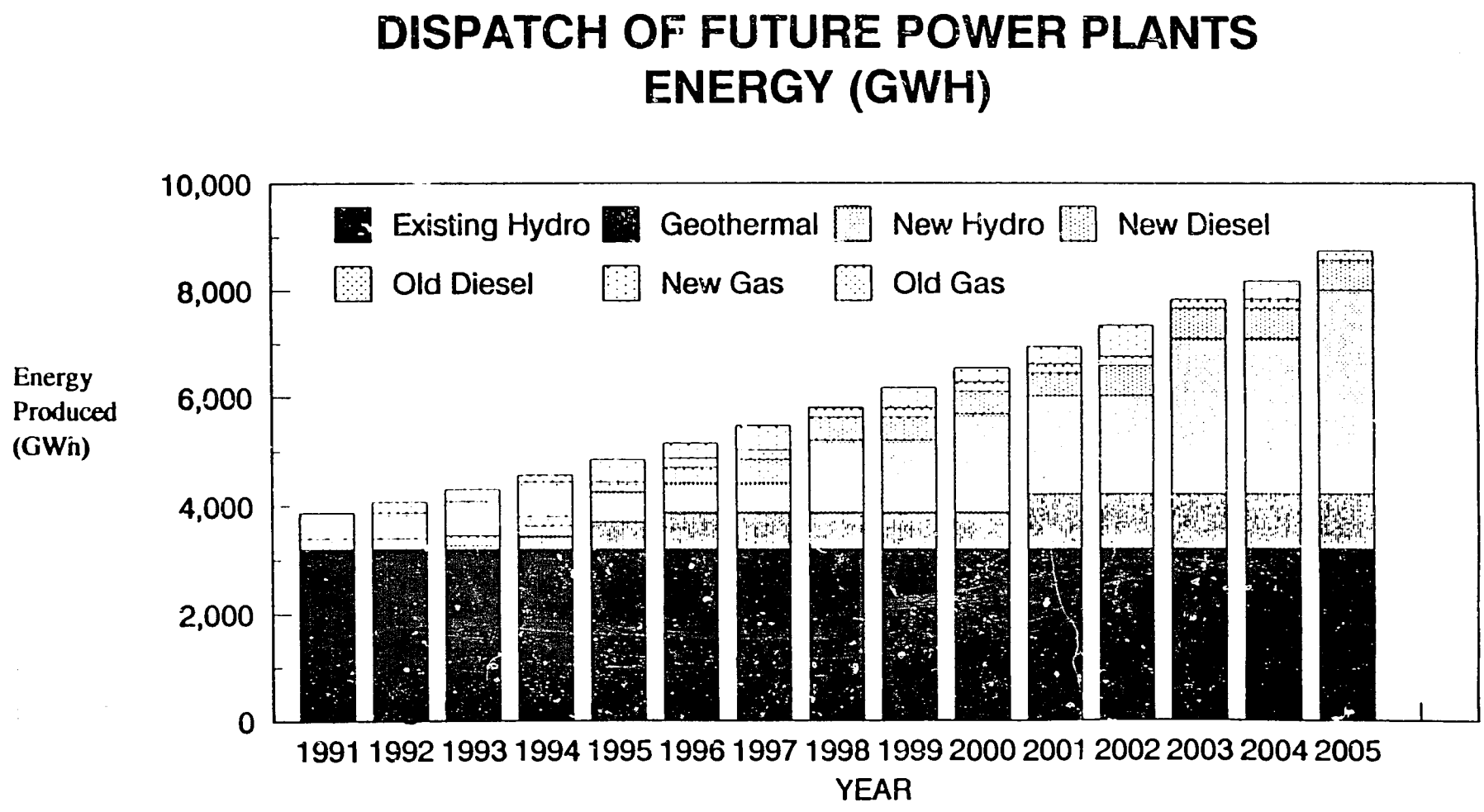
Exhibit 3-4
ICE Expansion Plan - Medium Case Load Growth Scenario

Year	Energy Demand (GWh)	Increase (%)	Peak Demand (MW)	Increase (%)	Planned Additions	Planned Commissioning Date (Year/Month)
1987	3,246					
1988	3,324	2.4	613			
1989	3,498	5.1	658	7.3		
1990	3,681	5.4	707	7.4	P H Nagatac (4.2 MW)	1990/3
1991	3,878	5.4	744	5.2	Small Hydro P T Gas (3x36 MW)	1991/1 1991/1
1992	4,072	5.0	781	5.0		
1993	4,304	5.7	626	5.8	P H Sandhill (32 MW) P T Gas (1x36 MW)	1993/7 1993/1
1994	4,556	6.1	877	6.2	P H Toro I (24 MW) PG Miravalles I (55 MW)	1994/9 1999/7
1995	4,858	6.3	933	6.4	P H Toro II (65 MW) P G Miravalles II (55 MW)	1995/1 1995/7
1996	5,155	6.2	991	6.2	Slow-Speed Disel (2x32 MW)	1996/1

Exhibit 3-4 (continued)
ICE Expansion Plan - Medium Case Load Growth Scenario

Year	Energy Demand (GWh)	Increase (%)	Peak Demand (MW)	Increase (%)	Planned Additions	Planned Commissioning Date (Year/Month)
1997	5,479	6.3	1,054	6.4	Slow-Speed Diesel (1x32 MW)	1997/1
1998	5,813	6.1	1,119	6.2	P H Angostura (177 MW)	1998/1
1999	6,172	6.2	1,188	6.2		
2000	6,550	6.1	1,261	6.1	P H Pirris (110 MW)	2000/1
2001	6,941	6.0	1,336	5.9	P G Miravalles III (55 MW)	2001/1
2002	7,342	5.8	1,413	5.8	Slow-Speed Diesel (1x32 MW)	2002/1
2003	7,751	5.6	1,491	5.5	P H Guayabo (245 MW)	2003/1
2004	8,167	5.4	1,570	5.3		
2005	8,561	4.8	1,644	4.7	P H Siquirres I (206 MW)	2005/1
2006	8,941	4.6	1,715	4.8		
2007	8,889	4.8	1,789	4.8	P H Siquirres II (206 MW)	2007/1
2008	9,756	4.8	1,866	4.8	Slow-Speed Diesel (1x32 MW)	2008/1
2009	10,192	4.8	1,847	4.8	Slow-Speed Diesel (2x32 MW)	2009/1
2010	10,649	4.8	2,081	4.8	Slow-Speed Diesel (2 x 32 MW)	2010/1

Exhibit 3-5
Probable Energy Output of Existing and Future Plants



An additional analysis was performed to estimate the financial benefits of the rehabilitation program to ICE through enhanced conversion efficiency. As part of this analysis, the expected life cycle cost of the existing power plants after rehabilitation was compared with the expected life cycle cost of various available new thermal power plants.

Exhibit 3-6 shows that the life cycle cost of rehabilitated equipment in some cases was higher than the estimated life cycle cost of investments in high-efficiency combustion turbines and medium-speed diesel units. In this analysis, it was assumed that the rehabilitation loan ($10 million) was allocated to all machines according to the estimates provided by the rehabilitation program plan, that these costs were amortized over a 30-year period, and that the units returned to name plate conversion efficiency. Estimated costs for new diesel and combustion turbines, performance ratings, and estimated operating costs were provided by equipment suppliers.

At plant factors above 0.3, rehabilitation of the lower-efficiency units may not be cost effective. Rehabilitation of the slow- and medium-speed diesels appears to be cost effective under all plant factor scenarios, and of course are more attractive if residual oil can be used. This analysis assumes, however, that the utility is indifferent to the capital cost of expansion/rehabilitation, which may not be the case.

Exhibit 3-7 shows the estimated magnitude of fuel savings resulting from efficiency improvements effected by the rehabilitation program. Two energy demand scenarios were explored for this analysis indicating years of "low" versus "high" demand for power from the existing thermal plants. The high scenario assumed an energy output of 175 GWh from the diesel units and 25 GWh for the combustion turbines, while the "low" demand scenario assumes 100 GWh for the diesels and 12 GWh for the combustion turbines.[1] In addition, these units have operated in the past on residual oil (Bunker C), and should RECOPE provide a fuel with acceptable specifications, this could result in substantial additional savings for these machines.

The above calculations indicate that the first priority should be to return to the use of residual oil, and that total savings from efficiency improvements could reach $1.75 million per year. A combination of efficiency improvements and conversion to heavy oil would result in a maximum annual savings of $4,839,000.

In summary, the rehabilitation program will benefit ICE in two important ways. First and perhaps most important, it will provide ICE with additional reserve capacity to avert load shedding that might occur if one of the primary hydroelectric power stations experiences a

[1] The high demand scenario corresponds to the energy output illustrated in Exhibit 3-5.

Exhibit 3-6
Comparison of New Equipment to Existing Turbine Life Cycle Costs

Machine	Life Cycle Costs ($/kWh) for Indicated Plant Factors			
	Fuel	0.3	0.5	0.7
Rehab IFCT*	Dist	0.116	0.114	0.113
Rehab SSD*	Dist	0.090	0.079	0.074
Rehab MSD*	HO	0.063	0.053	0.048
New IFCT**	Dist	0.103	0.096	0.093
New ADCT**	Dist	0.091	0.083	0.079
New STIG**	Dist	0.089	0.078	0.073

* Details of rehabilitation program are shown in Appendix 11.
** Values derived using data from Exhibit 3-8.

Legend: IFCT = industrial frame combustion turbine
SSD and MSD = slow- and medium-speed diesel, respectively
ADCT = aero-derivative combustion turbine
STIG = steam-injected gas turbine

Assumptions: Discount rate = 12 percent
Distillate fuel price = $6.77/MBtu (using 2 percent per year fuel price escalation)
Bunker fuel price = $3.54/MBtu (using 2 percent per year fuel price escalation)
Rehab machines reflect capital recovery for rehabilitation cost only
New machines reflect full capital recovery for cost of new equipment

Exhibit 3-7
Potential Savings for Present Diesel and Combustion Turbine Units

Plant Type	Type of Improvement	Annual Production			
		12 GWh	25 GWh	100 GWh	175 GWh
Diesel	Efficiency 33 to 37%	N/A	N/A	$573,000	$1,003,000
Diesel	Conversion to Bunker	N/A	N/A	$1,763,000	$3,086,000
Diesel	Eff & Con to Bunker	N/A	N/A	$2,336,000	$4,089,000
Turbine	Efficiency 18 to 23%	$360,000	$750,000	N/A	N/A

Assumptions: Fuel costs: $6.14/MBtu for distillate, $3.54/MBtu for heavy oil.

failure during dry season months. Second, the program will allow efficiency improvement measures to be undertaken that will result in cost savings on an annual basis to the utility.

3.1.1.3 Future Thermal Generation

Responding to Expansion Requirements. From 1990 through 2005, ICE will need to expand its thermal capacity by 384 MW to meet demand growth under a "medium" growth scenario. The expansion plan includes four 36 MW combustion turbines and nine 32 MW slow-speed diesel units. Three of the four combustion turbines are already on order, and will be installed in the late-1990 to early-1991 time frame.

The thermal power plants are projected to grow from 10 percent of total installed capacity in 1990 to 22 percent in 2000. Consequently, the value of the efficiency optimization

activities for both the existing and future thermal plants will grow in importance, and the potential financial impacts of efficient operations may affect ICE's financial condition. While the need for thermal power plants is clear, analysis suggests that the technology selection process should be revisited. Recent experiences with aero-derivative combustion turbines has shown that this technology could be ideally suited to the changing seasonal and daily duty cycles required in ICE's system, with a combination of elevated efficiency and competitive costs in comparison to industrial frame combustion turbines.

The gas turbines indicated in the expansion plan have a capacity of 36 MW. Both aero-derivative and industrial machines are available in this size. For example, General Electric produces the Frame 6 industrial machine and the LM 5000 aero-derivative machine. The LM 5000 is available in a simple-cycle configuration and in a steam-injected configuration. The Frame 6 can similarly be purchased in simple- or combined-cycle configurations. Exhibit 3-8 provides a summary of the data characterizing the operation and cost of several types of thermal generation, including industrial frame combustion turbines, aero-derivative combustion turbines, slow-speed diesels, combined-cycle units, and steam-injected combustion turbines.

Exhibit 3-9 shows the estimated life cycle cost of operation of each type of plant as a function of the expected plant factor.[2] Life cycle costs include both fixed and variable costs associated with operation, as affected by fuel cost, maintenance, and capital costs. Normalizing each technology in this fashion, the technologies can be "screened" in a common framework known as a screening curve. This is a simplified analysis, disregarding several operational conditions, but it allows a the utility planner to determine which technologies should be considered much more carefully in a detailed generation expansion plan.

Aero-derivative turbines appear to be the most attractive technology for future ICE thermal power plant additions for capacity factors up to 0.3. The simple-cycle industrial frame machines do not appear to be as financially attractive.

As capacity factors increase, steam injected aero-derivative combustion turbines (STIGs) become increasingly attractive. Exhibit 3-11 provides a schematic diagram of a STIG. While the capital cost may be marginally higher with a STIG than a simple-cycle machine, the benefits of the elevated efficiencies from these turbines may well outweigh these costs.

[2] These values are plotted in Exhibit 3-10.

Exhibit 3-8
Characteristics of Different Types of Thermal Units
Suitable to ICE's System

Machine	Capacity	Fuel	Heat Rate Btu/ kWh	POR (%)	UOR (%)	O&M Fixed	O&M Var	Cost $/kW
ADCT	38,858	Dist	9348	5	4	1.36	6	430
STIG	51,620	Idst	7907	5	4	1.91	6	557
IFCT	38,100	Dist	11376	5	4	1.06	4	385
CC	41,600	Dist	8302	5	2	4.83	2	696
SSD	11,200	HO	7768	5	.6	7.31	5	1442

Legend:
IFCT = industrial-frame combustion turbine
ADCT = aero-derivative combustion turbine
CC = combined cycle combustion turbine
STIG = steam-injected combustion turbine
SSD = slow-speed diesel
POR = planned outage rate
UOR = unplanned outage rate
Dist = distillate fuel
HO = heavy oil (bunker)

Assumptions:
All plants evaluated on 30-year life
Capacities are gross
Costs are total installed costs (1990 dollars) including allowance for funds during construction (AFDC)
O&M costs are in mills/kWh

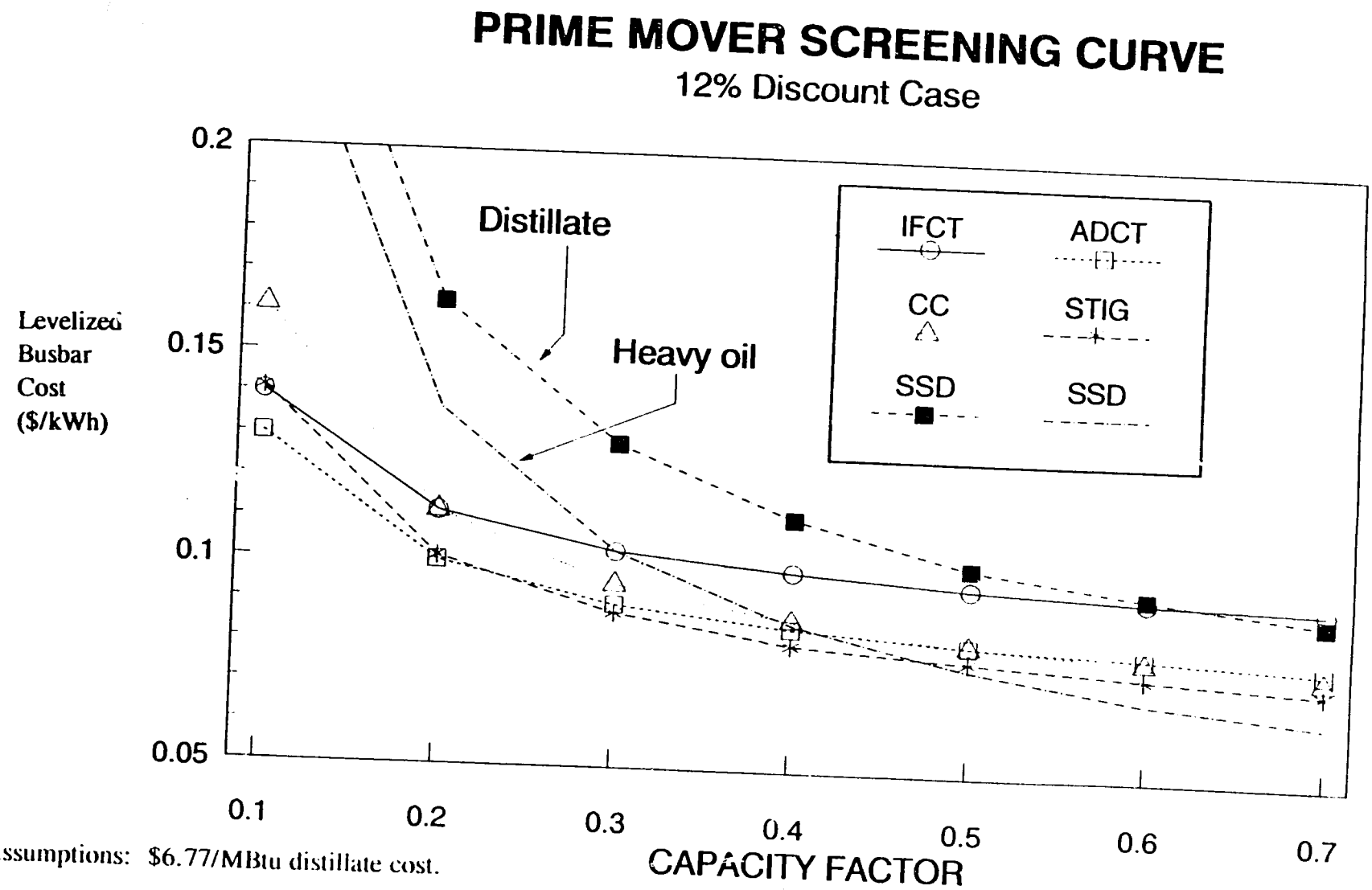
Exhibit 3-9
Characteristics of Different Types of Thermal Units
Suitable to ICE's System

Machine	Life Cycle Costs ($/kWh) for Indicated Plant Factors			
	Fuel	0.3	0.5	0.7
IFCT	Dist	.103	.096	.093
ADCT	Dist	.091	.083	.079
CC	Dist	.096	.082	.076
STIG	Dist	.089	.078	.073
SSD	Dist	.130	.102	.090
SSD	HO	.105	.077	.065

Legend:
IFCT = industrial-frame combustion turbine
ADCT = aero-derivative combustion turbine
CC = combined cycle combustion turbine
STIG = steam-injected combustion turbine
SSD = slow-speed diesel
Dist = distillate fuel
HO = heavy oil (bunker)

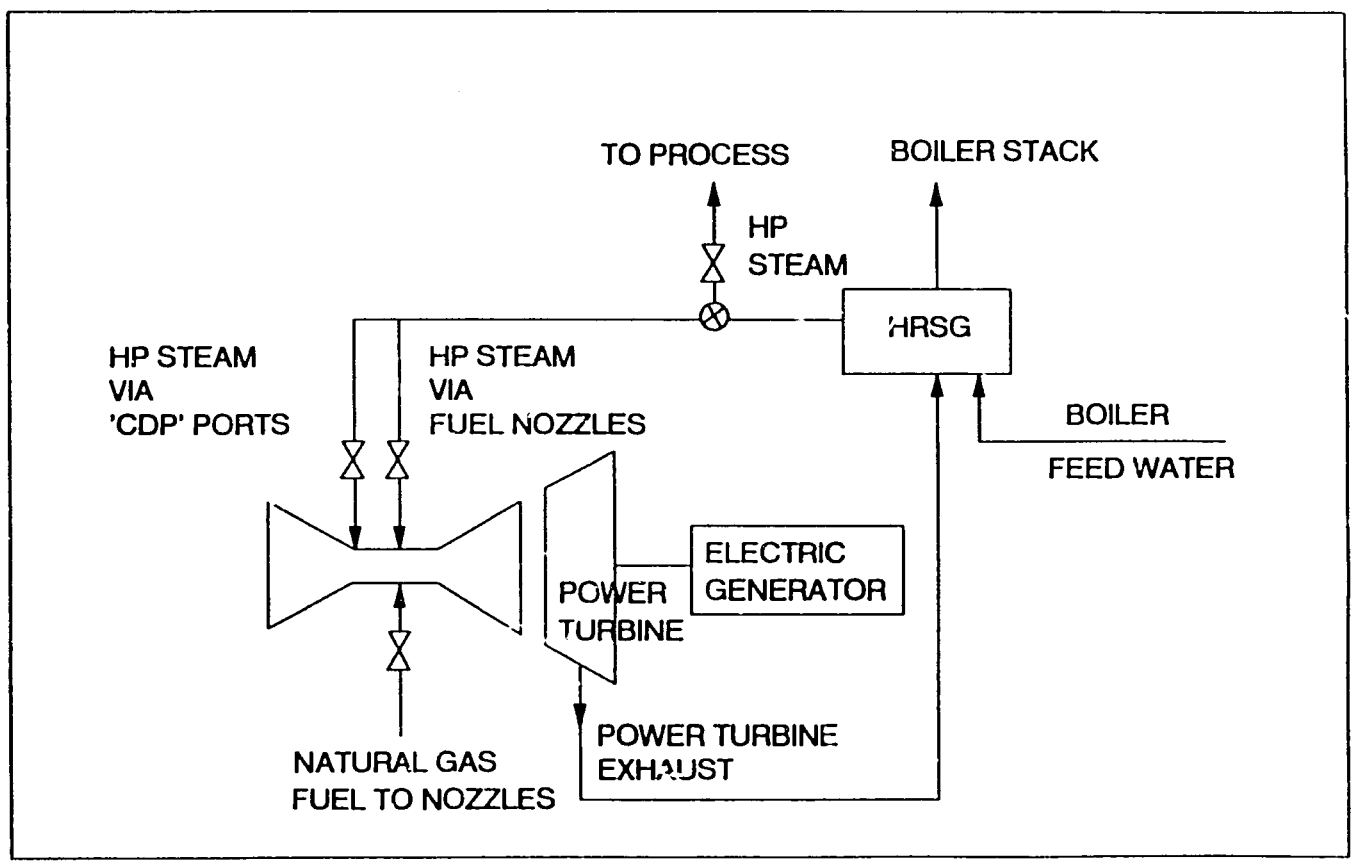
Assumptions:
All plants evaluated on 30-year life, discount rate = 12 percent, with characteristics specified in Exhibit 3-8
Distillate fuel price = $6.77/MBtu
Heavy oil fuel price = $3.54/MBtu

Exhibit 3-10
Life Cycle Cost of Various Combustion Technologies



Assumptions: $6.77/MBtu distillate cost.

Exhibit 3-11
Standard STIG Configuration



Technology Innovations. As new and improved technologies become available, they will need to be evaluated for possible inclusion in future expansion plans. The latest generation aero-derivative combustion turbine, for example, will have significant cost and efficiency savings over all present units, and will be available for delivery in early 1992. This will be a 52 MW machine (the LM-6000), with an estimated installed cost of $387/kW ($480/kW combined cycle), and an overall efficiency of 43 percent in a simple-cycle mode and 52 percent in a combined-cycle mode.

Efforts are underway in the U.S. to couple advanced combustion turbines with solid-fuel gasifiers, such as coal and biomass. The Cool Water project demonstrated the technical viability of a coal-fired integrated gasification/combined-cycle power plant. More recently, the Department of Energy initiated a program to demonstrate the use of a combustion turbine in conjunction with a biomass gasification system, with a field demonstration scheduled to be completed by the end of 1993.

Detailed technology assessments indicate that a biomass gasification steam-injected gas turbine (BSTIG) system could be a very attractive power system. With fuel cost estimated at $2 per million Btu (including all harvesting, transportation, and conditioning costs), this technology could produce power for as low as $0.042/kWh with a 0.7 plant factor. Even with a more likely plant factor of 0.3, the energy costs would only rise to $0.064/kWh. Traditionally, bagasse has been burned in low-pressure boilers at very low efficiencies to produce steam to assist in the sugar making process, and to produce electricity for sugar mills. Recent studies in Costa Rica, Thailand, Jamaica, and the United States suggest the conversion efficiency could be improved from levels as low as 8 percent overall thermal efficiency to as high as 47 percent. At present sugar production levels, 400-500 million kilowatts of energy per year could be produced if investments in improved equipment were made. This is equivalent to approximately 50 to 55 MW of installed capacity operated at base load throughout the year.

3.1.2 Hydroelectric Generation

The development of hydroelectric resources has played a prominent role in ICE's energy delivery strategy since the first decade of the utility's existence. As additional hydroelectric capacity was brought into service, ICE came to depend increasingly on these plants to provide virtually all energy required for ten to twelve months out of the year, totalling as much as 97 percent of the energy sold annually.

The first hydroelectric station commissioned in Costa Rica was the La Garita plant in 1958. This facility was expanded from its original capacity of 30 MW to 127 MW in

1987. Rio Macho and Cachi were constructed in the 1960s, providing a combined total of 221 MW of capacity (after expansions at both plants in the late 1970s). Reservoir storage at both plants is limited, and for all practical purposes, they operate on a run-of-river basis.

The most recent addition to the hydroelectric system is the Arenal-Corobici complex, which constitutes the backbone of ICE's generation capacity. It produces more than 40 percent of current energy requirements and is capable of meeting up to 46 percent of the peak load. This two-staged complex went into service in 1979, with the first 65 MW commissioned at Arenal. Capacity was increased to 157 MW the following year, and finally to 331 MW as Corobici was commissioned downstream of Arenal in 1982. This project has sufficient reservoir storage for seasonal flow regulation and is therefore central to ICE's strategic generation planning.

The characteristics of power generating equipment at ICE hydroelectric plants are shown in Exhibit 3-12 and the most recent operating statistics of these plants are shown in Exhibit 3-13. Locations and project characteristics for these plants are shown in Appendix 12.

Hydroelectric energy will continue to play an important role in ICE's power mix, but due to the cost of construction and lead time necessary to bring new plants on line, ICE will have to rely increasingly on other generation alternatives.

This section provides an analysis of opportunities for increasing the efficiency of the hydroelectric system. There are three aspects of a hydroelectric system that can lead to opportunities for improvements in efficiency; these are related to generating equipment, civil works, and reservoir operations.

3.1.2.1 Generating Equipment

In contrast with a thermal machine, the hydraulic turbine is a rugged, slow moving machine operating without any significant temperature gradients and is mechanically insensitive to rapid start-ups or other unsteady load conditions. The hydraulic efficiency of the turbine does not change appreciably, even over very long periods of time, except in cases where severe cavitation (short bursts of negative pressure in a solid-liquid interface) causes erosion in the turbine blades. The generator rating is selected with consideration of the turbine output for a range of different reservoir elevations. It is unusual for this range to vary sufficiently to suggest a different turbine-generator match than that selected at design time.

Exhibit 3-12
Nominal Hydro Power Plant Ratings and Efficiencies

	Turbine Data					Generator Data			
Plant	No. of Units	Capacity (kW)	Rated Head (M)	Rated Design Flow (M3/5)	Nominal Effi-ciency	Capacity (KVA)	Capacity (kW)	Power Factor	Total Capacity (kW)
Garita 1 & 2	2	17,358	151	13.2	86.13	18,750	15,000	.80	30,000
Garita 3 & 4	2	48,694	220	25.2	85.85	54,100	48,700	.90	97,400
Macho 1 & 2	2	17,358	450	4.37	87.30	18,750	15,000	.80	30,000
Macho 3, 4 & 5	3	35,304	450	8.92	86.99	37,500	30,000	.90	90,000
Cachi 1 & 2	2	34,789	219	17.75	80.52	40,000	32,000	.80	64,000
Cachi 3	1	36,113	219	17.33	94.11	46,000	36,800	.80	36,800
Arenal 1,2 & 3	3	52,470	210	31.61	78.18	61,720	52,470	.85	157,410
Corobici 1, 2 & 3	3	57,802	234	32.5	75.18	68,240	58,000	.85	174,000
Total	18	299,888				345,060	287,970		679,610

Exhibit 3-13
Hydro Power Plant Operating Statistics

Plant	Capacity (MW)	Energy Output (MWh) 1987	1988	1989	Plant Factors 1987	1988	1989
La Garita	127.4	319,645	327,883	564,547	.29	.56	.51
Rio Macho	120	557,992	571,069	594,106	.53	.54	.57
Cachi	100.8	567,742	614,855	644,412	.64	.70	.73
Arenal	157.4	616,041	468,519	620,479	.45	.34	.45
Corobici	174	709,921	550,606	703,293	.47	.36	.46
Total	696.6	2,771,341	2,832,932	3,126,837	.47	.48	.53

During the last twenty years, there have been advances in turbine design that offer some improvements in hydraulic turbine efficiency. However, the change of a turbine runner is only justified either in very old plants when a comprehensive rehabilitation effort is made or when a mechanical breakdown or a drastic change in hydrologic regime warrants a redesign of the equipment.

Based on observations at the plants and the maintenance procedures followed by ICE, there does not appear to be any opportunity for economically improving the efficiency of the existing equipment.

3.1.2.2 Civil Works

Civil works can affect the efficiency of a hydroelectric project in several ways. Faulty design or deterioration of the dam can result in substantial water losses through seepage; unlined tunnels or tunnels with damaged concrete linings can have excessive hydraulic losses; and sometimes it is possible to increase the sill of ungated spillways or install flashboards in gated spillways to increase power production with the same volume of water during periods of low flood probability.

Seepage does not appear to be a problem at ICE's dams. At La Garita, it has been estimated that tunnel repairs could increase power production by 26 MWh, but there are no firm cost estimates that would indicate the feasibility of this improvement. All run-of-river plants have gated spillways. ICE has considered installing flashboards at some of them, but abandoned the idea after consultation with the project designers regarding dam stability at higher heads.

3.1.2.3 Reservoir Operations

A hydroelectric power plant offers three products in terms of power generation: firm energy, secondary energy, and dependable capacity. These products have different values in different power systems. Firm energy is the energy that the project can generate under adverse water conditions and is often expressed as the minimum annual energy that can be produced under the worst condition on record. Secondary energy is the difference between the average annual energy production and the firm energy production. Dependable capacity is the amount of thermal capacity that the system would need to have to meet its reliability targets if the hydroelectric project were not in it.

Bearing in mind that the power produced by a plant is a function of both the amount of water captured to pass through the turbines and the difference in water elevation upstream and downstream of the plant, the optimization of the operation of a hydroelectric system to maximize the combined value of all three products presents a complex problem related to the probability of too much or too little water entering the reservoir over time. To illustrate this point, consider the following example:

To maximize firm energy and dependable capacity, it is often necessary to keep the reservoir surface at higher elevations than those that would allow complete storage of wet season runoff. Therefore, what could, at first sight, be interpreted as an inefficient operation because it leads to more spill than necessary could be, in fact, a very prudent and economic choice since it avoids investments in thermal capacity by ensuring production under dry water conditions.

The full evaluation of the soundness of a reservoir operation strategy is a formidable task, but through conversations with ICE staff and a review of data on power plant performance, there is every indication that all the elements of a sound strategy are being considered and that ICE is constantly monitoring the probability of water inflows to provide the operators with reservoir elevation guidelines to optimize the reliability and quantity of power from the hydroelectric system.

3.1.2.4 Data Collection, Power Dispatch, and Flow Measurement

ICE employs a very thorough data collection system to record energy and plant output, fuel consumption of auxiliary equipment, water flows, reservoir levels, and maintenance activities for each power plant.

Data collection and analysis for hydro plants fall into two categories: hydrologic and plant performance data. ICE collects streamflow data at each plant based on energy production, storage change, and spill records. ICE is also responsible for the collection and dissemination of hydrologic data for the Republic of Costa Rica. In addition to water quality and sedimentation records, ICE maintains an extensive network of rainfall and stream gaging stations.

The hydro power plants are dispatched at the ICE Control Center in San Jose. Reservoir water levels and water use are monitored as a means of regulating and dispatching energy supply resources from the Control Center. The Center controls generation at all power stations and supervises the linkages with other utilities inside and outside the country. It also performs a centralized data collection function for all records of generation. The data

are collected here for making an assessment of daily hydro generation capability and for evaluating the availability of hydro generation reserves.

3.1.2.5 Potential for Efficiency Improvement

Except for the tunnel at La Garita, there does not appear to be any opportunity for significant energy gain through improvements in generating equipment and civil works at ICE's hydroelectric power plants. Operational improvements are always possible in any system, but there is an indication that ICE staff are well aware of the operational considerations, and regularly revise the reservoir operating guidelines at Arenal-Corobici in accordance with good practice.

3.2 ANALYSIS OF THE TRANSMISSION AND DISTRIBUTION SYSTEMS

3.2.1 Transmission System Overview

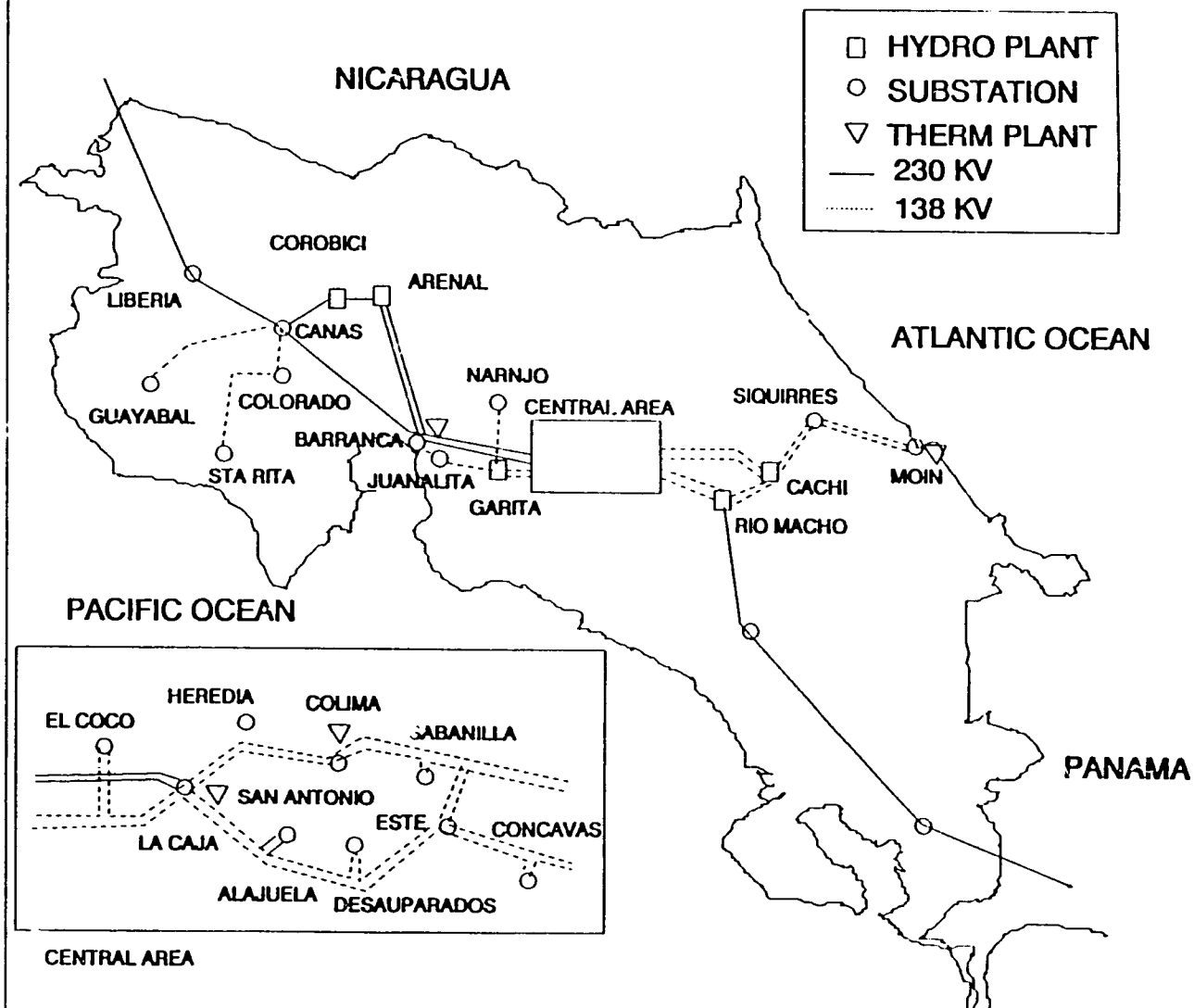
In addition to its mandate to generate electric energy, ICE is responsible for developing, maintaining, and operating the national electric transmission system. This integrated system is composed of all generating plants, transmission substations, and transmission lines that form the Sistema Nacional Interconectado (national interconnected system), or SNI.

The SNI, with power transmission lines operating at voltages of 138 kV and 230 kV, links the electric power generation sources on the northwestern and southeastern portions of the country to the main load centers located in its central plateau, encompassed by a double circuit 138 kV ring or loop. This 138 kV loop connects the various transmission and distribution substations serving the other parts of the country, as illustrated in Exhibit 3-14. The transmission system consists of approximately 670 kilometers of 138 kV circuits and 667 km of 230 kV circuits.

ICE has invested heavily in the transmission system in recent years, and has upgraded and maintained transmission lines on a regular basis. The northwest portions of the country in particular have seen significant improvements in the last five years. Much of the investment was made with reliability, rather than loss reduction, as the primary goal, but certainly the energy savings were an important additional benefit.

Exhibit 3-14
National Interconnected System

LINE	VOLT	DIST
ARENAL BARANCA	230	88
ARENAL COROBICI	230	11
BARANCA JUANILAMA	138	70
BARANCA LA CAJA	230	62
CACHI ESTE	138	18
CACHI RIO MACHO	138	15
CACHI SABANILLA	138	34
CACHI SIQUIRRES	138	49
CANAS BARANCA	230	70
CANAS COLORADO	138	26
CANAS GUAYABAL	138	59
CANAS LIBERIA	230	45
COLIMA ESTE	138	18
COLIMA HEREDIA	138	7
COLORADO SANTA RITA	138	30
CONCAVAS EL-ESTE	138	16
COROBICI CANAS	230	7
EL COCO LA CAJA	138	16
ESTE ALAJUELITA	138	19
ESTE DESAMPARADOS	138	10
GARITA EL COCO	138	19
GARITA LA CAJA	138	22
GARITA NARANJO	138	17
JUANILAMA GARITA	138	35
LA CAJA ALAJUELITA	138	12
LA CAJA COLIMA	138	8
LA CAJA DESAMPARADOS	138	10
LA CAJA HEREDIA	138	8
LIBERIA BRASILES	230	73
RIO CLARO PROGRESO	230	30
RIO MACHO CONCAVAS	138	9
RIO MACHO EL ESTE	138	26
RIO MACHO SAN ISIDRO	230	65
SABANILLA COLIMA	138	13
SAN ISIDRO RIO CLARO	230	110
SIQUIRRES MOIN	138	42



The Costa Rican transmission system, as well as the Central American transmission network, is constrained by the longitudinal geography of the Central American isthmus, as well as the nature and location of major population centers. Thus, system loading is concentrated along a northwest-southeast corridor, with the heaviest load in San Jose, and relatively light loads on the extremities of the system. Only when power is purchased from Honduras via Nicaragua, or sold to Panama or Nicaragua are the lines at these extremes used to capacity.

In one respect, it would seem that this would tend to increase losses and cost of service, due to the relatively non-uniform nature of system loading. But the distances from border to border are relatively short, and San Jose, the main load center, is centrally located with respect to major hydroelectric generating plants. During the dry season. the Arenal/Corobici complex provides most of the energy generation required, while during the wet season, the run-of-river plants south and east of San Jose, including Rio Macho and Cachi, provide most of the energy required.

The net electrical energy generated by ICE in 1989 was 3,493 GWh, with the total energy distributed during the same period equivalent to 3,126 GWh. This represents calculated system losses of 10.5 percent, with 2.6 percent losses assigned (from substation measurement) to the transmission system. The maximum demand in 1989 was 658 MW, with an annual load factor of 60.6 percent.

In addition to connecting Costa Rican generation sources with the country's electrical loads, the SNI serves in an important role to interconnect neighbors in Panama and Nicaragua with ICE's system, and ultimately, to interconnect ICE with all other Central American utilities. Costa Rica can import surplus energy from the hydroelectric plants in Honduras and can also transfer power to Panama. In 1989, total imports were 241 GWh and total exports of electrical energy were 98 GWh.

ICE's laudable efforts to design and maintain a reliable and cost-effective transmission system have resulted in relatively low line losses. These efforts, undertaken primarily to maintain acceptable levels of reliability, have provided direct cost saving benefits, and enabled ICE to develop and retain a cadre of experienced transmission analysts to continually upgrade its transmission network. For these reasons, the analyses that follow provide overview material only, as line loss reduction analyses must be performed on a line-by-line basis. The purpose of this section is to identify, where possible, the areas that require further detailed numerical analysis by ICE staff.

3.2.2 Distribution System Overview

In contrast to the transmission system in Costa Rica, which is totally owned and operated by ICE, electric energy is distributed by ICE and a number of municipal distribution companies and rural electric cooperatives, each serving a specific geographic service area. In some cases, these companies pre-date ICE (e.g., CNFL), and have small but independently owned and operated generation facilities. Rural electric cooperatives were established 25 years ago to assist in the extension of electric energy services to areas beyond the reach of ICE distribution services, and have slowly developed small but important systems for users in their service areas. The characteristics of some of these companies are shown in Exhibit 3-15.

Exhibit 3-15
Distribution Company Customers, 1989

	ICE	CNFL	ESPH	JASEC	COOPS	TOTAL
Customers (thousand)	238	255	36	24	57	610
Line Length (km)	9265	1900	748	300	3367	15,580
Transformer Capacity (MVA)	571	680	93	42	100	1486
Energy Purchased and Produced (GWh)	1198	1608	116	174	191	3359
Energy Sold (GWh)	1069	1617	104	161	174	3125
Losses (%)	10.8	3.7	9.7	7.2	8.9	7.0

Note: Individual loss percentages calculated before rounding

As mentioned above, ICE distributes electric power to approximately one third of all connected consumers in Costa Rica, providing power to residential, commercial, and industrial consumers. Moreover, ICE sells bulk power to its sister distribution companies

and shares its plans for system expansion with these utilities to assist in their expansion planning processes. The following is a very brief description of each of the various companies involved.

Instituto Costarricense de Electricidad. ICE serves approximately 40 percent of the electric customers in Costa Rica directly. Standard distribution voltages for ICE are 13.2 kV and 34.5 kV. In a few areas, 4.16 kV is still being used.

The customers served by the ICE distribution system include residential, general, small industrial, and public lighting customers. Total sales in this category were 1,069 GWh in 1989. Energy input from the transmission system for this category was reported as 1,198 GWh, resulting in calculated distribution losses of 10.8 percent. This figure is reasonable given the variety of customers and distances served by the ICE system, and suggests that individual lines may well need to be reviewed for excessive energy losses, but that the system as a whole is in good condition. ICE serves customers in two other catetories: large industrial customers and construction projects, directly from the transmission system. The energy usage of these customers is not included in the distribution loss calculations.

A number of communities far from transmission corridors are served by ICE as local isolated systems, and not as part of the national grid. These small communities have a total power supply capacity of approximately 1 MVA, and are supplied by diesel generation units.

Compañia Nacional de Fuerza y Luz. CNFL is the retail distribution company serving greater metropolitan San Jose, and is 95 percent owned by ICE. CNFL is in the process of converting all of its distribution lines to ICE's standard 34.5 kV voltage. Total sales in 1989 were 1,817 GWh. Purchases from ICE were 1,562 GWh, while CNFL also produced 118 GWh from its own power plants. Calculated distribution losses are 3.7 percent for the year, a very low loss number. This loss level is possible, given the high load density and short distances between customers in the urban areas served, but it is perhaps more possible that the number does not reflect the total losses because the voltage conversion program is not yet completed. Further investigation into this number may be warranted.

Empresa de Servicios Públicos de Heredia. ESPH is a municipal company that serves the Heredia district of the San Jose metropolitan area, with electricity and with other public

services. Sales for 1989 amounted to 104 GWh, with an energy input of 17 GWh generated by ESPH and the balance (99 GWh) purchased from ICE. Distribution losses were estimated at 9.7 percent. ESPH uses both 13.2 and 34.5 kV distribution voltages.

Junta Administrativa de Servicios Eléctricos de Cartago. JASEC, as its name implies, is a municipal organization providing electric services to the municipality of Cartago and its immediate surrounding area. This company has been aggressively pursuing the development of small hydro generation on the Birris River to reduce its dependence on ICE for future power supply. JASEC has sections of 2.4, 4.16, 13.8, and 34.5 kV lines. Its total 1989 sales were 161 GWh. JASEC generated 35 GWh from its own power plant, and 139 GWh were purchased from ICE. System losses for the year were 7.2 percent.

Cooperativa de Electrificación Rural San Carlos R.L. COOPELESCA, as the company is generally known, is the largest of four rural electric distribution cooperatives in the country, in terms of number of customers and energy distributed. The service area of COOPELESCA is the San Carlos region of north-central Costa Rica. In 1989, its sales totalled 76 GWh. COOPELESCA generated 17 GWh internally, while 66 GWh were purchased from ICE. The system losses were 8.3 percent. The standard system voltage is 24.9 kV.

Cooperativa de Electrificación Rural Guanacaste R.L. COOPEGUANACASTE is the country's second-largest cooperative in terms of sales and energy volume, although it serves the largest geographic area of all cooperatives. COOPEGUANACASTE provides service to customers in most of the Guanacaste Peninsula region. With no generation capacity, ICE supplies all of the company's energy needs, amounting to 64 GWh in 1989. Sales totalled 59 GWh, resulting in distribution losses of 8.6 percent. The standard voltage is 24.9 kV.

Cooperativa de Electrificación Rural Los Santos R.L. COOPESANTOS has a small service area to the south of the city of San Jose. This cooperative, as the others previously mentioned, uses a standard distribution voltage of 24.9 kV. Total energy supply, all purchased from ICE, was 35 GWh in 1989. Total sales were 32 GWh. Distribution losses in 1989 were approximately 9.7 percent.

Cooperative de Electrificación Rural Alfaro-Ruiz R.L. The smallest of the cooperatives and of all the distribution companies in the country, COOPEALFARO has a very small service area in the mountains of central Costa Rica. Its total sales for 1989 were approximately 7 GWh, with purchases of approximately 9 GWh. Distribution losses were calculated to be 15.4 percent. The distribution voltage at COOPEALFARO is 13.2 kV.

The total energy delivered to all of the distribution companies in the country in 1989 was 3,359 GWh, with total sales during the same year of 3,125 GWh. The combined distribution losses for all of the companies was 7.0 percent. It should be noted that the arithmetic sum of distribution losses (7.0 percent) and transmission losses (2.8 percent) is not equal to calculated losses for the total electrical system (9.4 percent): the dividend for each of these loss calculations differs due to the fact that the energy supplied to the transmission network is higher than that supplied to the distribution network.

3.2.3 Areas of Analysis

In general, the information gathered during this study indicated that both the transmission and distribution portions of the Interconnected Power System Network of Costa Rica are relatively efficient in terms of power losses. The transmission losses of 2.6 percent are very low for a longitudinal system such as that found in Costa Rica. The distribution system losses of 7.0 percent, while much larger, are still acceptable when compared to other systems, especially since individual distribution transformers and secondary service drops normally account for around 3 percent losses. For this reason, the analysis focused on issues or areas with a reasonable potential for efficiency improvement, or in which care should be taken to maintain the benefits of ICE's recent system improvements. As the availability of financial resources becomes more problematic and pressures increase to minimize system investments, it will become increasingly important to closely examine opportunities to improve system reliability and efficiency.

3.2.3.1 Energy Measurements

In March 1990, ICE's Energy Transmission Department prepared a study that addressed the metering needs of the transmission system. Included in this study was a careful analysis of metering accuracy and data acquisition needs. The efforts to assemble an integrated and computer-controlled network are commendable. However, it was noted in other conversations concerning individual metering points that some of the information was not as clear cut as it might seem at first. For example, it was not clear if substation transformer losses were included in the transmission losses or in the distribution loss

estimates, i.e., whether the metering points were on the low-voltage side or on the high-voltage side of the transformer. In the field, it is difficult to measure parameters consistently when transformers for different voltages and loads, and from different manufacturers, must be considered. Having a very accurate meter is not an advantage if one does not know which side of the transformer is being measured.

Another potential problem could arise in measuring demand from various metering points without accounting for the time of day the meter readings were taken. Energy demand at each respective metering point must be correlated against time to allow the construction of a composite demand profile.

Coordination of monthly billing times to the distribution companies in order to match various sales and usage measurements is also very important, and has been a source of problems in the past. The efforts now being made to automate and centralize the meter readings should help in this respect.

Distribution metering equipment can also be a problem. Accurate and consistent distribution metering is very expensive, principally because there are so many points to deal with, but it is difficult to obtain reliable information and identify losses without investing heavily in equipment and manpower. The correct mix of equipment and procedures is very much a judgmental decision, but needs to be considered carefully.

3.2.3.2 Distribution Loss Calculations

As mentioned above in the descriptions of the distribution utilities, some of the distribution losses reported bear further study. These include the loss figure reported by CNFL (3.7 percent) and the figure calculated for COOPEALFARO (15.4 percent).

The main reason for doubting the 3.7 percent figure is that if it represented true system losses there would not be a good justification for undertaking the voltage conversion program now underway. If the level is verified to be true, CNFL should give courses to the other companies in Costa Rica on how such impressive results were achieved.

Different factors seem to explain the relatively high percentage of losses for COOPEALFARO. The cooperative serves a low-density agricultural area with a system voltage supplied at 13.2 kV. Additionally, an extra transformation is necessary to step down from 34.5 kV to 13.2 kV, though it was not confirmed that the extra losses incurred in this transformation were charged to the cooperative. Moreover, because the amount of energy sold is relatively small, differences in billing and reading cycles between ICE and

COOPEALFARO could be causing distortions in reported losses. Last, because the service area is quite small, the loss number suggests that a problem may exist with overloaded line conditions or possibly with non-technical losses.

3.2.4 Planned Transmission System Changes

Construction is planned for a new 230 kV single-circuit transmission line to connect the northwestern generating facilities to the central valley by 1992. This will significantly reduce future losses between Arenal and La Caja, and holds the potential, through new substation improvements, to dramatically reduce losses on lines now serving the Naranjo-Quesada area. Because it will follow a completely different route, the new line should also improve reliability for the metropolitan area, in view of the fact that the existing double-circuit 230 kV line is vulnerable to outages due to severe weather conditions.

In association with the previously mentioned transmission line project, a new 230 kV transmission link through the central valley is under consideration that would complete the longitudinal corridor at 230 kV across the country. It appears, however, that the costs of this proposed project would be very high relative to its benefits. Perhaps the principal benefit would be an increased capability to wheel power between Nicaragua and Panama. It is suggested that ways be explored to incorporate international financing, if this project progresses, to account for the benefits to neighboring countries. An analysis on this basis will involve projections of supply and use from Honduras, Nicaragua, and Panama, in addition to those from Costa Rica.

New gas turbine plants located at Moin, on the Atlantic Coast, will greatly affect the losses on the double-circuit 138 kV line between Moin and the central area. Since these lines have only a 336 MCM conductor, the losses may be quite high, depending on the amount of energy the new turbines are called upon to deliver annually. Calculations for this have been performed assuming relatively few hours per year of projected operation. True losses should be followed closely, based on experience after the units begin operation.

To illustrate the extent to which increases in line loading from the addition of generation sources can affect line losses, a simplified case study of the transmission line section between Moin and Siquirres substations was performed. This section is 41.5 km in length, with double-circuit 138 kV construction and 336 MCM aluminum conductor.

The Moin plant is used to provide power to the San Jose metropolitan area during the dry season. The present installed capacity is approximately 40 MW. Energy losses from

present practices are not excessive. If the line section is carrying 20 MW of power, balanced between the two circuits and equally distributed along the three phases, then the current in each conductor at a power factor of 85 percent would be about 49 amperes. Energy losses in this case would be 1.29 kW per km for each circuit, or 104 kW for the entire line section. Peaking operation for three hours per day would result in energy losses valued at $1,600 per year in this line section at an energy value of $0.65/kWh. Non-peaking operation for 18 hours per day would result in energy losses valued at $45,600 per year.

Plans have been made to install three new gas turbines between December 1990 and February 1991, increasing ICE's total installed capacity by 108 MW. A study performed by ICE indicated that in all likelihood, the turbines will be used during dry season months for a 14-hour period daily. They will be used at full load capacity for four hours during periods of daily maximum load, and for ten hours between these two peak periods at 60 percent capacity. Exhibit 3-16 illustrates the expected transmission losses resulting from this level of use if the line is not modified.

Exhibit 3-16
Moin-Siquirres Line Losses with Increased Load and No Modification

Power (MW)	Current (amps)	Loss/km Circuit (kW)	Energy Loss (kW)	Annual Cost (US$)
25	61.5	1.93	160.2	15,620
45	110.7	6.53	542	52,845
65	159.9	13.04	1082	105,495
85	209.1	22.3	1851	72,189
105	258.3	34.03	2824	110,136
125	307.5	48.2	4000	156,000

As demand and power delivery levels grow, it will become increasingly important to review options to reduce transmission line losses. Reductions can be made by increasing conductor size (decreasing line resistance), voltage conversion, constructing additional circuits, and moving the generator sets closer to San Jose (decreasing line distances).

Perhaps the most practical way of reducing losses will be to increase the transmission voltage to 230 kV. Exhibit 3-17 contrasts the estimated losses and associated savings for the same rates of power transfer and conductor size, with a 230 kV transmission voltage upgrade on the Mion-Siquirres line illustrated above.

Exhibit 3-17
Moin-Siquirres Line Losses with 230 kV Conversion

Power (MW)	Current (amps)	Loss/km Circuit (kW)	Energy Loss (kW)	Annual Cost (US$)	Annual Savings (US$)
25	36.9	0.69	57.3	5,587	10,033
45	66.42	2.25	186.8	18,213	24,632
65	95.94	4.69	389.3	37,957	67,538
85	125.46	8.03	666.5	25,993	46,196
105	154.98	12.25	1016.8	39,655	70,481
125	184.50	17.36	1440.9	56,195	99,805

Note: Assumed 10 hours operation at 25-65 MW, 4 hours operation at 85-125 MW capacity.

Both of the above analyses are simplified, and the values are presented for illustrative purposes only. In actual practice, a line load distribution curve would be used to determine probable losses, costs, and benefits. Moreover, the losses shown above merely show the savings potential for the Moin to Siquirres line only, not the savings potential for other parts of the ICE system.

3.2.5 Planned Distribution System Changes

During the 1990-1993 period, the Distribution System Project will result in the replacement or upgrading of 300 km of distribution line per year to 34.5 kV. Several utilities will be involved in this project in addition to ICE. The replacement of 270 MVA in distribution transformers is also included in this project. This investment should make

it possible to approximately maintain or slightly lower the loss ratios, while serving additional new loads and expanding system capacity.

The importance of these improvements can be shown in the following example. A typical three-phase distribution line in Costa Rica could be constructed with a 1/0 ACSR conductor and might be operating at an effective voltage of 13.2 kV. The resistance of the 1/0 conductor in this line is 0.59 ohms per km. Given the load pattern indicated, a 1 km section of 13.2 kV would yield the losses illustrated in Exhibit 3-18.

Exhibit 3-18
Effect of Distribution Line Upgrade

Number of Hours/Day	Annual Value of Losses, $USS/km			
	kVA Load	1/0 Conductor, 13.2 KV	336 MCM, 13.2 kV	1/0 Conductor, 34.5 kV
5	1800	1301	375	191
3	2300	1275	367	187
3	2000	864	277	141
4	2800	2519	726	369
9	1200	1041	300	152
Total		$7000	$2045	$1040

In order to reduce these energy losses, either the line resistance or current must be reduced. Changing conductor size from 1/0 to 336 MCM (both sizes are used in Costa Rica) reduces the resistance from 0.590 to 0.170 ohms per km for each phase. In this case, the losses and energy costs would be reduced as indicated in Exhibit 3-18.

At an energy cost of $0.065/kWh, the annual savings from reduced losses would be $5,055 per kilometer. There are no reduced revenues from this change. If anything, revenues would increase slightly because with reduced losses, the delivered voltage, and hence, customer energy consumption, would tend to increase.

A second and often more practical way to reduce energy losses is to increase the operating voltage. Using the same specifications in the example distribution line, but upgrading line voltage from 13.2 to 34.5 kV instead of reconductoring, the current and losses would change as shown in the right-most column of Exhibit 3-18. The annual savings from reduced energy losses due to voltage conversion would be $6,060/km.

The cost of increasing conductor size or of increasing the operating voltage can vary widely, from a minimum of approximately $4,500/km up to $50,000/km or more. Each energy loss reduction project must be analyzed individually, in terms of specific energy savings potential over a projected line load distribution and growth, and the specific construction costs for the conversion. However, it is easy to see that the proposed project to upgrade 300 km of lines per year can yield significant energy savings, with a very short payback period.

In 1989, a new policy was introduced in Costa Rica to allow private power producers to participate in the production of electricity for the national grid. While this policy is intended to allow small independent power producers to supply power to ICE only, the total effect is projected to be significant within a few years. The effects will be most apparent in the distribution systems, since producers of hundreds of kilowatts to a few megawatts will connect to the utility distribution voltage lines rather than to transmission voltage lines. Losses on a particular distribution line could be greatly increased or greatly decreased, depending on plant size, line capacity, and relative location of plant, line loads, and substation.

In some cases, the effects of a small generation plant on line losses can be very beneficial. In the case of the example distribution line described earlier, a small 1 MVA generation plant connected to the end of the line would result in annual energy cost savings amounting to $5,122/km, assuming the generation plant was privately owned with very little investment on the part of the utility company.

The net effect of all small producers should be to reduce system losses, since the flow of their energy into the system should tend to be opposite to (and thus subtracted from) the general energy flow from the centralized transmission sources. However, it is too early to form an overall idea of the total effects of this additional energy source.

3.2.6 Effects of New Technologies on Losses

Perhaps the technology with the greatest potential for reducing losses in Costa Rica is amorphous core distribution transformers. These new transformers, which use a magnetic

core of amorphous alloys instead of the more traditional and commonly used crystalline materials, have core losses that are 20-30 percent lower than other new transformers of equivalent capacity. These losses are often less than half those of transformers manufactured some years ago. A reduction of 25 watts, for example, results in a saving of about 220 kWh per year for each distribution transformer. The purchase cost premium of these transformers has prevented their widespread use in the past, but the cost difference has narrowed in recent years, and will continue to do so in the future.

Another technology growing in importance is time-of-day metering equipment. As this equipment becomes less costly and easier to use, time-of-day rate structures will become more attractive and important for mitigating dramatic daily system peaks. This practice will result in a more efficient use of generation resources, and concurrently, in lower energy transmission and distribution losses, given that energy can be transported with decreasing losses as demand is levelized.

3.3 SUMMARY OF FINDINGS

The results of the previous analyses illustrate clearly that the attractiveness of energy efficiency improvements for existing ICE generating plants is limited. This is due to a number of factors. Thermal power plants have been used to provide energy on a seasonal basis only -- less than 5 percent for most years over the operating history of the utility. Even if significant improvements could be made to the plants, the results would be minimal with respect to system costs. Maximum cost savings were estimated at $4,849,000 per year for improvements to existing thermal equipment.

Cost savings can be accomplished via a return to the use of lower-cost heavy oil and/or through the rehabilitation of existing plant and equipment. The cost savings accrued from the use of heavy oil would merely reflect financial benefits, and would not result from any appreciable improvements in energy efficiency. The rehabilitation program, on the other hand, may in fact result in efficiency improvements, but these benefits will be relatively minor with respect to system energy demand.

An analysis of the hydroelectric generating plants yielded similar results, although for a very different set of reasons. As a hydro-based utility, ICE has invested much time and effort in optimizing reservoir management. Maintenance for mechanical and electrical systems is well planned and executed. Performance and maintenance records indicate that plant performance has been maintained at adequate levels throughout the period of record, and that maintenance procedures have been followed on regular intervals. As a result, the hydroelectric generating plants appear to be functioning extremely well, and there is room

for only marginal improvements to energy output at these facilities: a mere 26 GWh per year of additional energy. This represents only 1 percent of the hydroelectric energy produced in 1989. Determining the cost of this measure will require a full engineering analysis, a task beyond the scope of this study.

Similar to the hydroelectric plants, ICE has continuously upgraded its transmission system in an effort to keep pace with the changes in load characteristics and the overall needs of the National Interconnected System. System upgrades have resulted in high line reliability and relatively low line losses. Distribution losses are higher, but certainly within acceptable margins for most of the distribution companies. Total system losses approximate 9.4 percent, with 2.5 percent attributable to transmission losses and 7.0 percent of the energy delivered to the distribution system being lost for technical or non-technical reasons.

Certainly, there is technical potential for line loss reduction in various transmission and distribution spurs. Determining the costs and benefits of such a potential does not lend itself to global approximation, however. Each line upgrade project must be evaluated separately, analyzing loading characteristics, the value of losses, and the costs of the improvements. The cost of line improvements is greatly dependent upon topography, and can vary by a factor of five. Due to these uncertainties, the transmission and distribution analysis noted the types of measures that could be taken to reduce line losses, including illustrative examples of the benefits of these measures (increasing voltage or line conductor upgrades). Without a comprehensive analysis of each distribution system, and a similar review of each major transmission link, it is impossible to accurately quantify the costs of line improvements, and the benefits those improvements might yield. Moreover, due to the low relative losses ICE has experienced in their system, in all probability, the financially attractive improvements identified (beyond those already planned) would be minimal.

This last point can be applied perhaps to virtually all phases of the generation, transmission, and distribution system. ICE's focus has always been on the sound management of its capital assets, with the primary objective of providing reliable and affordable electric energy. ICE is acknowledged to be one of the best-managed utilities in Latin America.

The purpose of this analysis was to determine if there were any areas of ICE's system where energy efficiency improvements could obviously play an important role in maintaining reliability, increasing financial and technical efficiency, and allowing ICE to reduce its cost of production in the process. In general, while systems can always be improved technically, there appears to be little evidence that significant improvements can

be made in the generation, transmission, and distribution systems to increase efficiency in a cost-effective manner.

Perhaps the only area where more attention appears merited is the comparative analysis of the generation expansion program. The existing thermal plants are old and will perhaps need to be retired some time over the next ten years. Replacing these plants and supplementing the thermal capacity with new equipment should be reviewed quite carefully by ICE planning personnel. Recognizing that energy derived from thermal facilities may never approach that produced by hydro facilities, these thermal plants and the cost of their operation will represent increasing financial outlays for ICE. And with the very uncertain nature of the world oil markets, it would be very wise to seriously consider more efficient, albeit higher capital cost conversion systems, which will yield fuel savings for many years to come.

Advanced combustion turbines, combined-cycle combustion turbines, slow-speed diesel engines, and biomass conversion technologies should all be carefully considered and compared to conventional combustion turbines. As commercial experience grows with these technologies, and ICE's need for additional thermal capacity grows, these options should be analyzed by the planning and operations staff at ICE.

CHAPTER 4: ANALYSIS OF THE IMPACTS ON THE UTILITY AND BALANCE OF PAYMENTS

The analyses performed and reported on in the two previous chapters generated information needed to determine the extent to which efficiency measures could be undertaken to reduce growth in system demand. However, in order to determine the interactions that energy efficiency measures may have on one another, these measures must be integrated into a common analytical framework, allowing the measures to be compared in both financial and economic terms.

This process was performed in the project through the use of ELECTROPLAN, a model developed specifically to determine the relative benefits of supply and demand efficiency options and their effect on the utility, as well as the national economy. ELECTROPLAN operates by accepting data generated through load control and conservation measure analyses input in spreadsheet format, together with expansion plan data to generate a series of scenarios for providing energy at the lowest possible cost to consumers.

ELECTROPLAN also allows several economic calculations to be made regarding the effect of implementing an energy efficiency program on the national economy, as well as its financial effects on the utility.

Based on the measures identified and analyzed in Chapter 2, the energy conservation measures that passed the first screening analysis and have been included in this second stage are shown in Exhibit 4-1. Among the measures that were rejected for the purposes of this analysis were solar water heaters in the residential sector, load control programs for residential refrigerators and water heaters, and the variable-speed drives for the industrial sector because their costs were well above the ICE-estimated avoided cost. The model ELECTROPLAN was used in this second stage of the analysis.

Each of these proposed measures has its own worksheet within the ELECTROPLAN model, which specifies market penetration assumptions and the cost of implementation, and quantifies the impact on the load curve. This chapter first provides the basic assumptions used in the analysis, then the load curve impacts on the demand-side management plan, and finally, the impacts on ICE.

Exhibit 4-1
Demand-Side Management Program Measures
Included in the Second-Stage Analysis

Residential Sector
- Water Heater Insulation (DSMP4)*
- Compact Fluorescent Lights (DSMP13)
- Spiral Burners (DSMP11)
- Higher-Efficiency Refrigerators (DSMP8)

General Sector
- Lighting (DSM 14, 7, 9, 3)
- Energy Management (DSMP10)

Industry Sector
- Lighting (DSMP12)
- Motors and Belts (DSMP1)

Load Management Measures
- Daylight Savings Time (DSMP6)
- Small Industry/Commercial Load Control (DSMP2)
- Interruptible Rates (DSMP14)

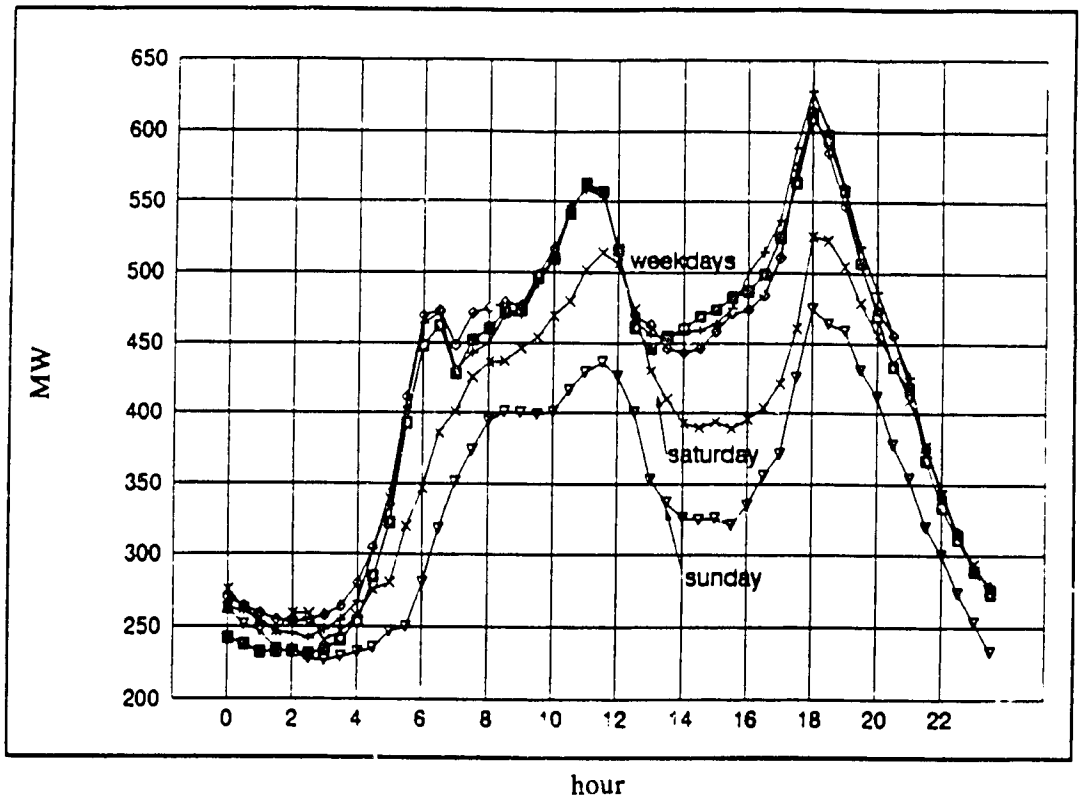
* The ELECTROPLAN file names are indicated in parentheses.

4.1 BASIC ASSUMPTIONS

4.1.1 Load Curves

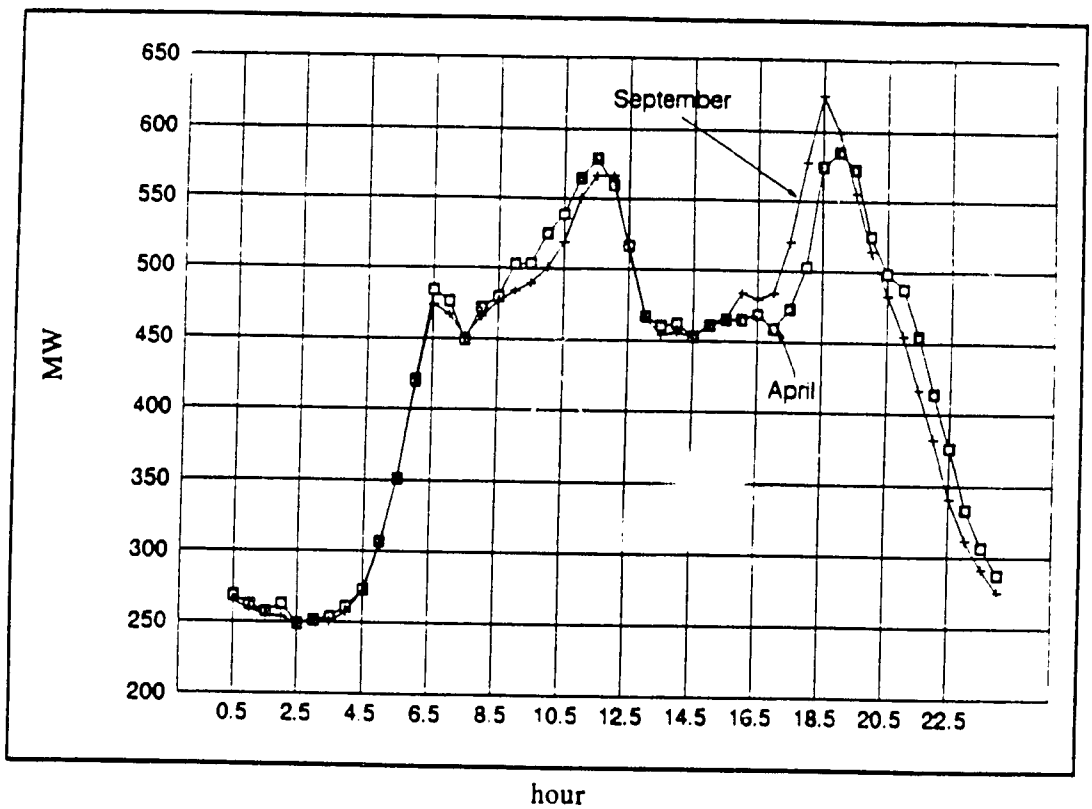
The bi-hourly system load data for 1989 served as the basis for the impact analysis. As indicated in Exhibit 4-2, weekday loads are substantially higher than loads on Saturdays and Sundays. In the analysis of the detailed load data, we used the same representative weeks that were used in the recent Electricite de France (EDF) tariff study.

Exhibit 4-2
Daily Load Curves for the Week of April 3, 1989



Important seasonal differences exist in the load shapes. Exhibit 4-3 shows the load curves for a typical Wednesday in the wet and dry seasons. As this exhibit shows, in the dry season (April), the morning and evening peaks are fairly close (589 MW and 585 MW, respectively). In the wet season (September), however, the evening peak is substantially greater (625 MW and 567 MW). This has important implications for the impact of daylight savings time on the load curve; all other things being equal, daylight savings time in the dry season could shift the peak from evening to morning, whereas in the wet season, the impact would be to bring the evening peak closer to the morning peak.

Exhibit 4-3
Load Curves for Wednesday, April 5 and September 27, 1989



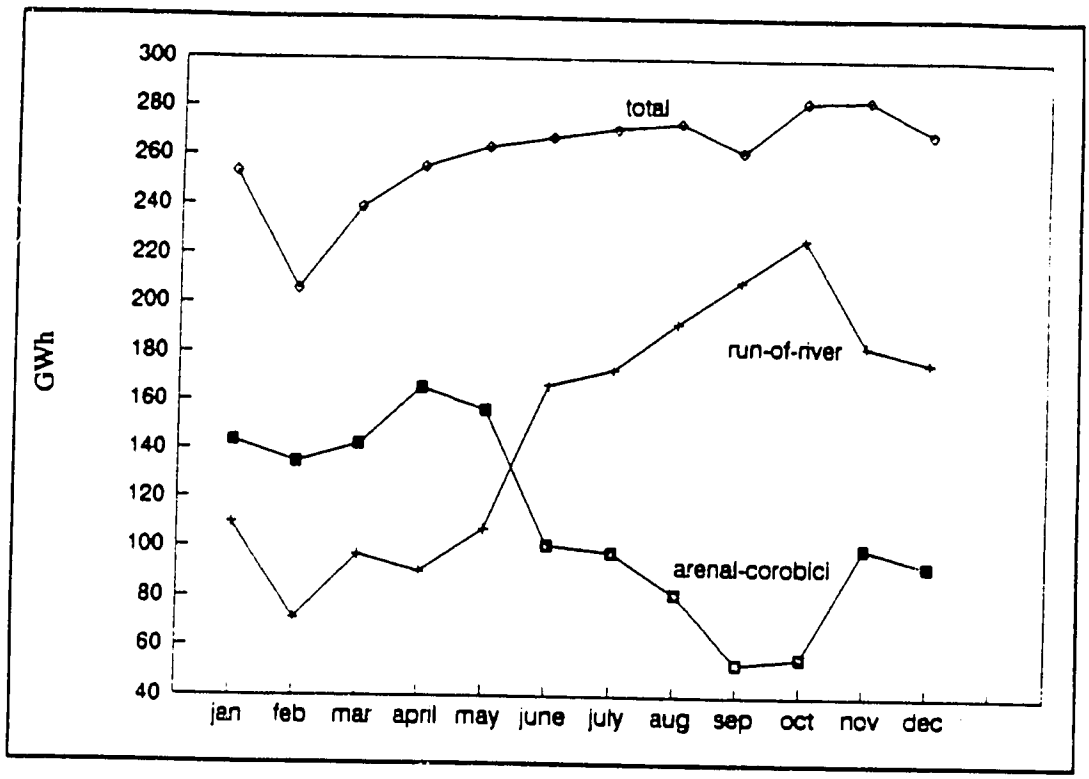
4.1.2 Hydroelectric Seasonality

The fuel requirements were calculated by modeling plant dispatch in merit order into load-linearized duration curves. Because there are substantial seasonal variations in hydroelectric output, which in turn significantly affect the dispatching of thermal plants, two seasons need to be defined. Where only run-of-river hydro plants are present, rainfall regimes can be used for this purpose ("wet" and "dry" seasons). In Costa Rica, however, a number of hydro plants have inter-seasonal storage, which means that what matters for the thermal dispatch calculations is the total output of all hydro plants combined.

Exhibit 4-4 shows the month-by-month hydro generation from the run-of-river hydro plants, and from the Arenal-Corobici plants, which have significant inter-seasonal storage. The output of the run-of-river plants reflects the rainfall regime, with a dry season from

January to April. The Arenal-Corobici plants are run in such a way as to make the total hydro production relatively constant.

Exhibit 4-4
Monthly Hydroelectric Production by Plant, 1989



Whether this can be maintained into the future is unclear. The next hydro plants to come on line, Angostura (with firm energy of 1,412 GWh/yr) and Sandillal (140 GWh/yr) have minimal storage volumes (11 and 4.82 Hm^3, respectively). Only Siquirres I and II, with a total storage volume of 900 Hm^3, will add significantly to the 3,800 Hm^3 of the Arenal-Corobici plants.

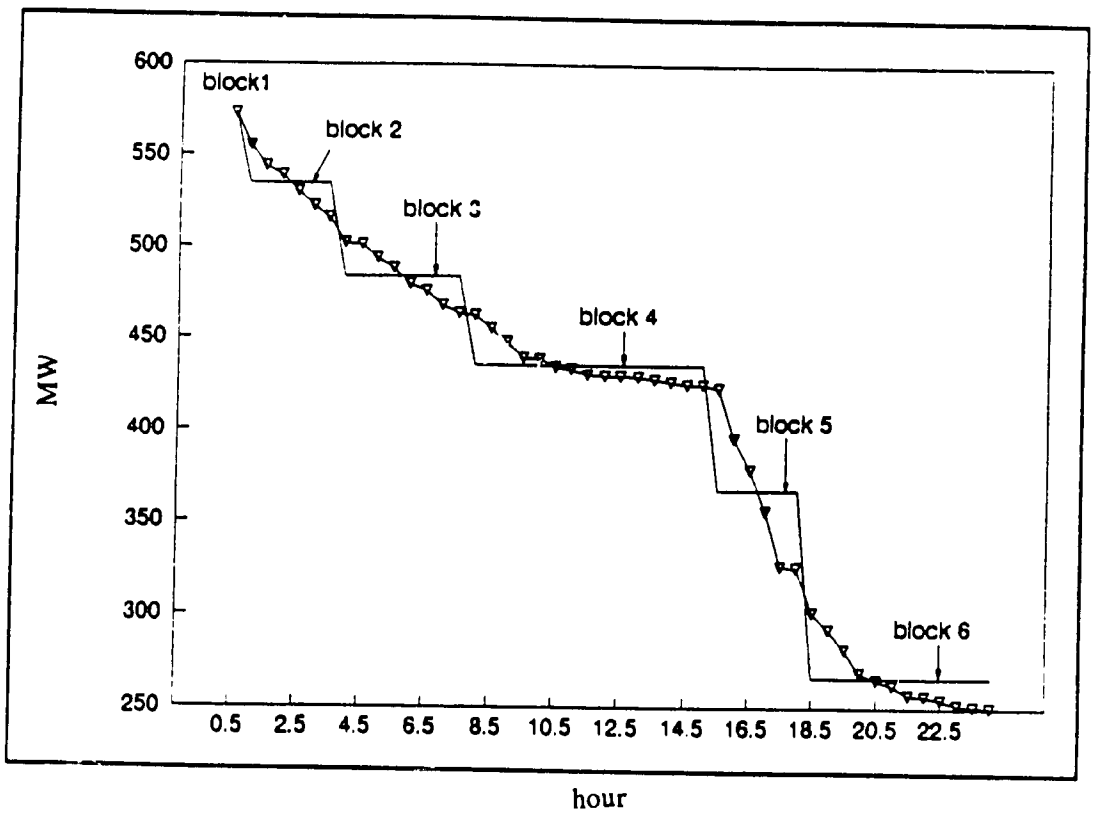
The "dry season" is defined as January to May, and a "wet season" is defined as June through December.

141

4.1.3 Load Curve Linearization

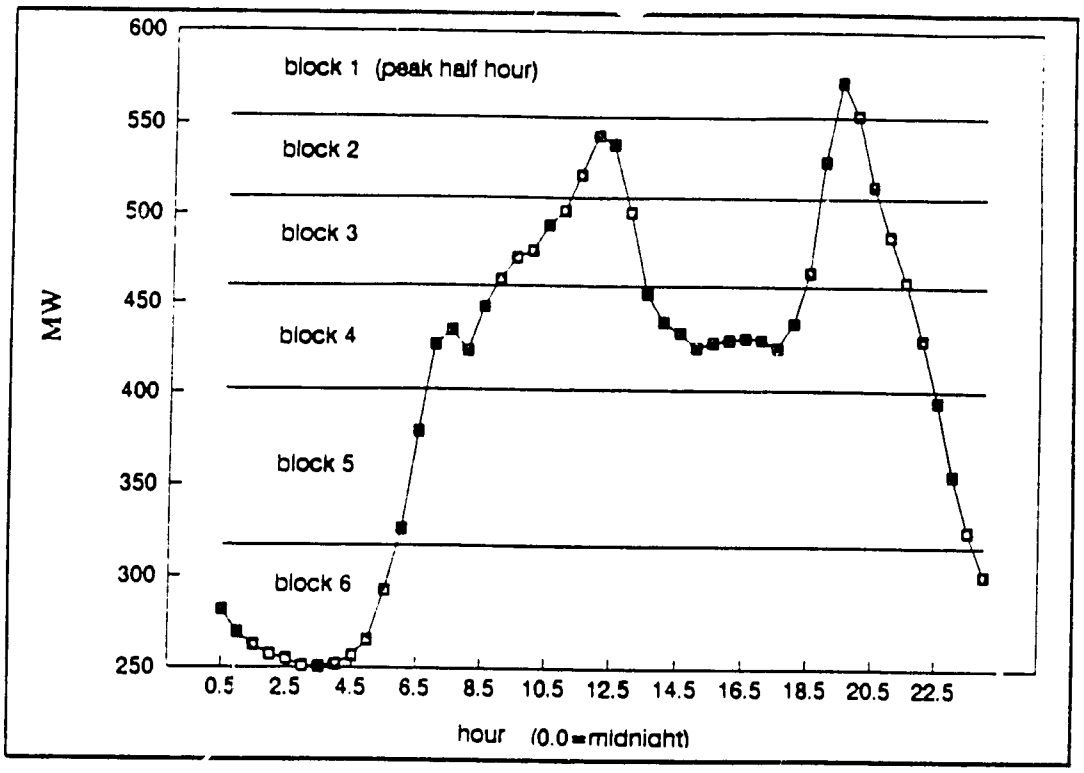
As indicated in Exhibit 4-5, we linearized the seasonal load duration curve (or its equivalent, the average day in this season) into six blocks. The first block is always defined as the peak half-hour. This ensures that the system load factors of the actual and linearized approximations are always identical. A similar linearization was done for the wet season.

Exhibit 4-5
Linearization of Dry Season Load Duration Curve



In effect, this linearization partitions the instantaneous system demand curve into a series of horizontal blocks (see Exhibit 4-6). In the ideal case, each block corresponds to a group of like generation units: block 3, for example, corresponds to the operation of intermediate cycling units, and block 6 to baseload plants.

Exhibit 4-6
Average Dry Season Load Curve Partition

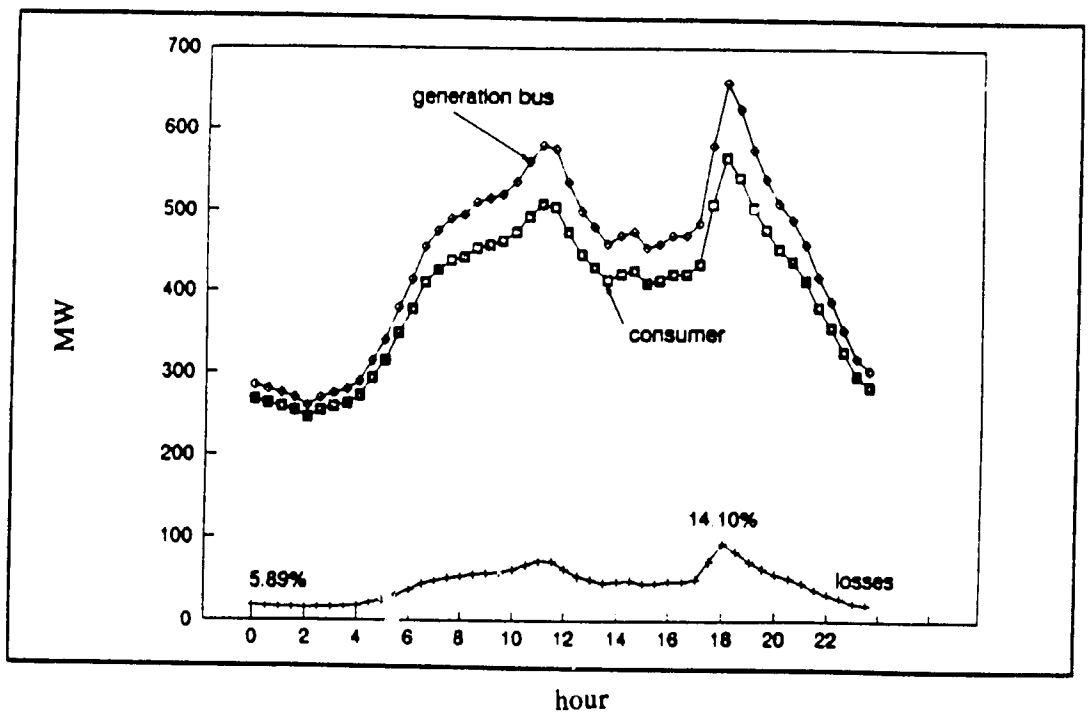


4.1.4 Losses

Average technical transmission and distribution (T&D) losses are assumed to be 10 percent of net generation on an annual basis. However, one cannot simply apply this average rate across the entire load curve because losses vary with the *square* of the load. Thus, losses during the peak hours are very much greater than the average, and losses during the off-peak hours are much smaller. As indicated in Exhibit 4-7, when one calculates the period-by-period losses for the peak day, during the evening peak losses are in excess of 14 percent, whereas in the middle of the night they fall to 6 percent. Consequently, every kW saved by residential consumers due to conservation or load management during the evening peak period reduces the generation requirement by an additional 14 percent. Because losses in the high voltage system are lower, similar

savings by industrial customers supplied at high voltage would have a smaller impact on loss rates.

Exhibit 4-7
Losses for the Peak System Day of 1989

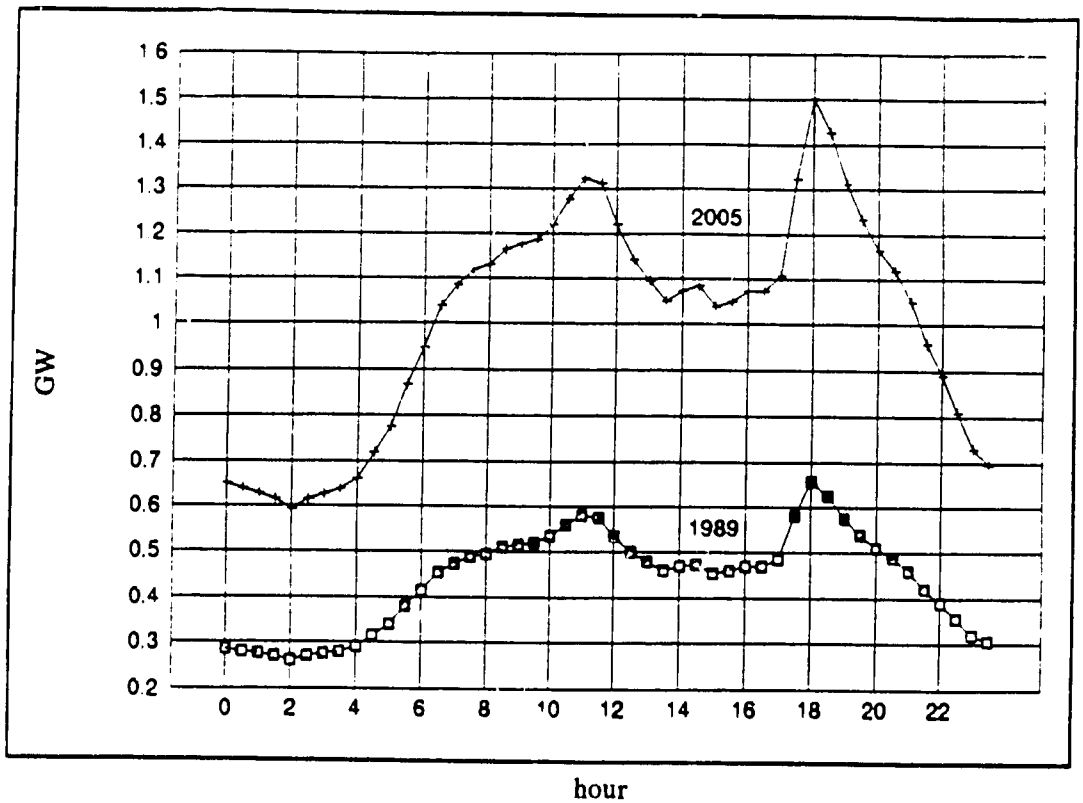


4.1.5 Load Shape Projections

For the base case, we assumed no significant changes to the load profile, and that annual and daily system load factors are held constant. Thus, the load curve for 2005 has the same shape as that for 1989, as shown in Exhibit 4-8.

There will, of course, be changes to the load profile and to the system load factors as a result of the impact of the load management and conservation measures recommended in this report. The measures will have the general impact of increasing system load factors, particularly as a result of the load management measures, which have the effect of flattening out the peaks.

Exhibit 4-8
Projection of System Load Curve for the Peak Day of 2005



4.2 LOAD CURVE IMPACTS AND THE DEMAND-SIDE MANAGEMENT PLAN

The fundamental problem in assessing the impact of both load control and conservation measures is the lack of data, particularly in terms of evaluating the impact, by hour, on the load curve. In the case of conservation measures, for example, reasonable estimates can be made of the total annual energy savings. One option, which was employed in deriving the estimates in Chapter 2, is to roughly estimate the load factor, and the coincident peak factor, which permits an evaluation of the impact at the time of system peak. Unfortunately, such simple expedients are of limited value in the case of such measures as daylight savings time, where the impact is concentrated over single hours at dusk and dawn, and where the key question is whether the result is simply a shift in peak

from the evening to the morning, or whether the evening peak is simply shifted to an hour later.

In short, there is a need to examine the likely impact of each measure on an hour-by-hour basis. Given the absence of data, the approach we took in this second stage was to make a series of reasonable hypotheses for each measure based on our collective knowledge about lifestyles in Costa Rica.

For example, in the case of residential water heater insulation, we reasoned that the main benefit will come during the hours in which water is not being used. During the hours of main use, whether or not tanks are insulated makes less difference because the main source of heat loss is by water withdrawal. The result is the load curve impact shown in Figure A of Exhibit 4-9. On the other hand, for improved residential refrigerator efficiency, the rationale is that the savings are proportional to compressor use hours: the more the doors are opened (during times of meal preparation), the shorter the time between compressor cycles, and the greater the savings during these time periods. The result is the hypothesized load curve shown in Figure B of Exhibit 4-9.

In any event, the spreadsheets in the ELECTROPLAN model can be easily modified. If and when data on device-specific load profiles are available, the spreadsheets can be readily updated.

When one aggregates the half-hourly blocks into the six-block linearized load curve discussed above, then the impact of typical measures on this load curve is illustrated in Exhibit 4-10. In the case of residential water heater insulation, there is no hypothesized impact in the peak period; instead, the impact is concentrated in the off-peak periods (with the greatest impact occurring at night). This follows from the hypothesis that the greatest benefit of insulation occurs when no water is withdrawn (i.e., at night). The least benefit occurs during the peak water use periods when water is withdrawn, which also coincides with the system's demand peak.

On the other hand, the impact of compact fluorescent lighting is concentrated in the peak (since peak lighting use also coincides with the evening electricity peak). There is also, however, a large impact in the early morning hours (before dawn) when there is extensive use of lighting in the residential sector. This impact is felt in the 5th (baseload) block.

Of all the measures examined, daylight savings times has the potential for the largest impact on the evening peak. However, as indicated in Exhibit 4-11, the reduction in the

Exhibit 4-9
Typical Hypothesized Load Curve Impacts for 2005

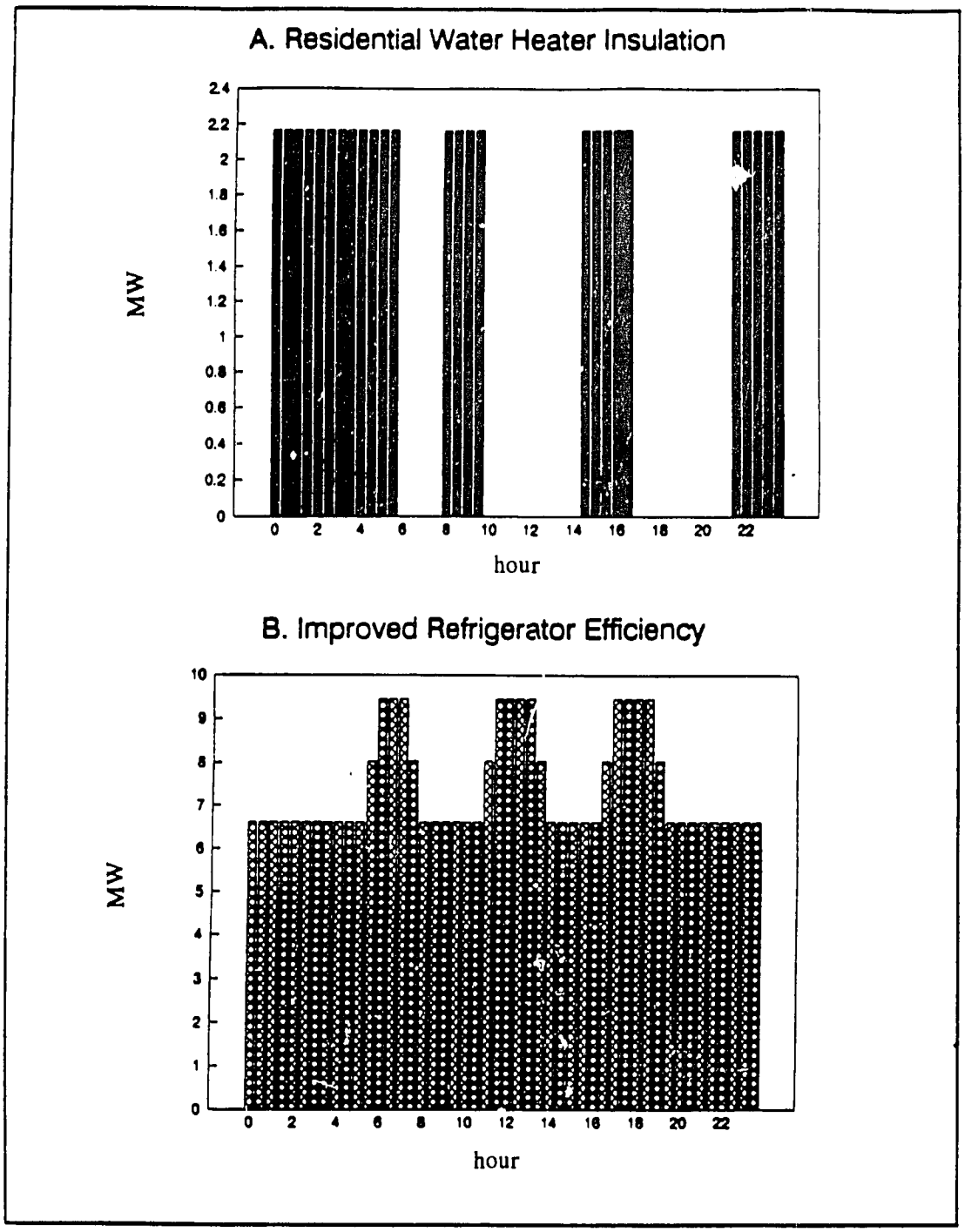


Exhibit 4-10
Impacts of the Linearized Load Curve

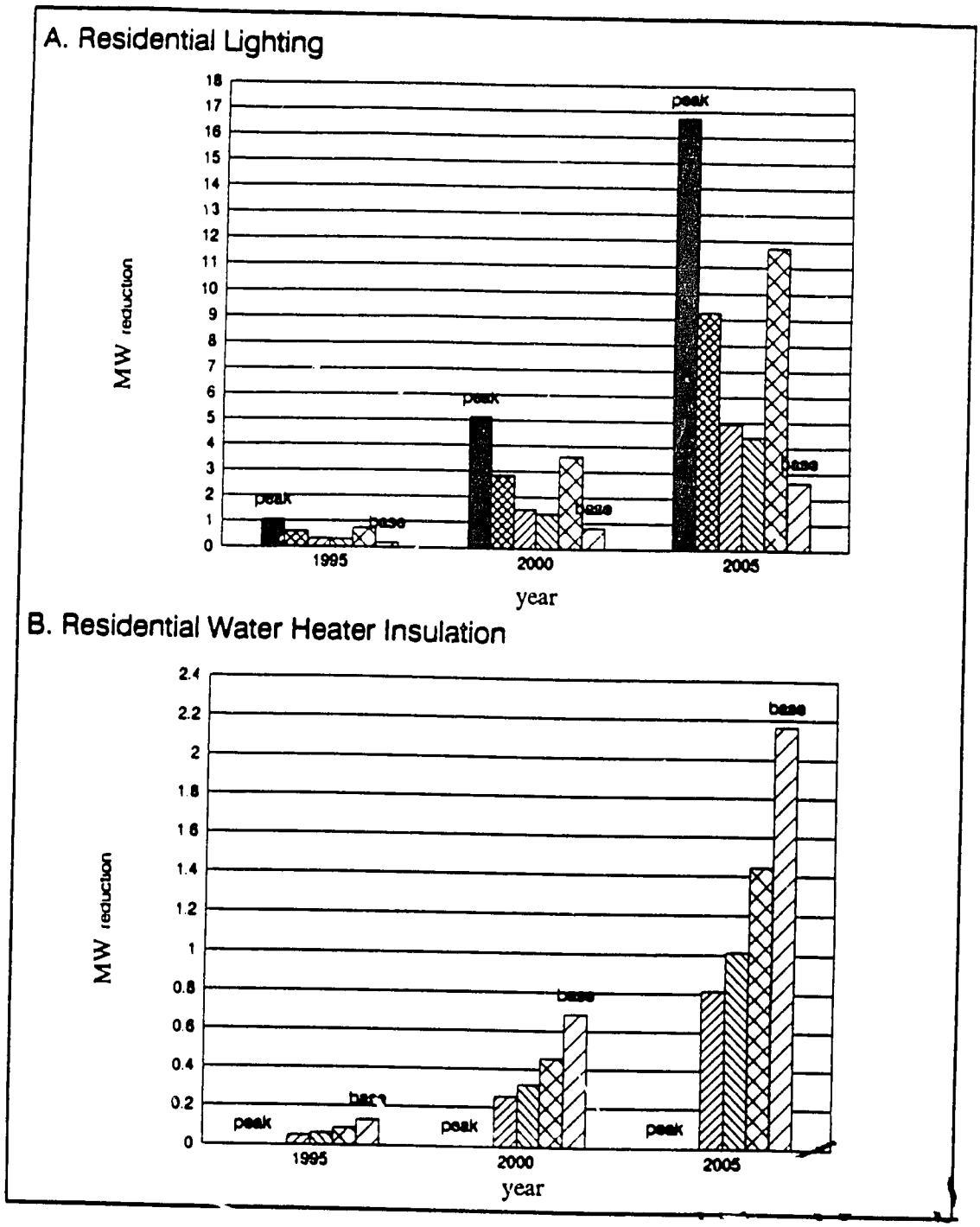
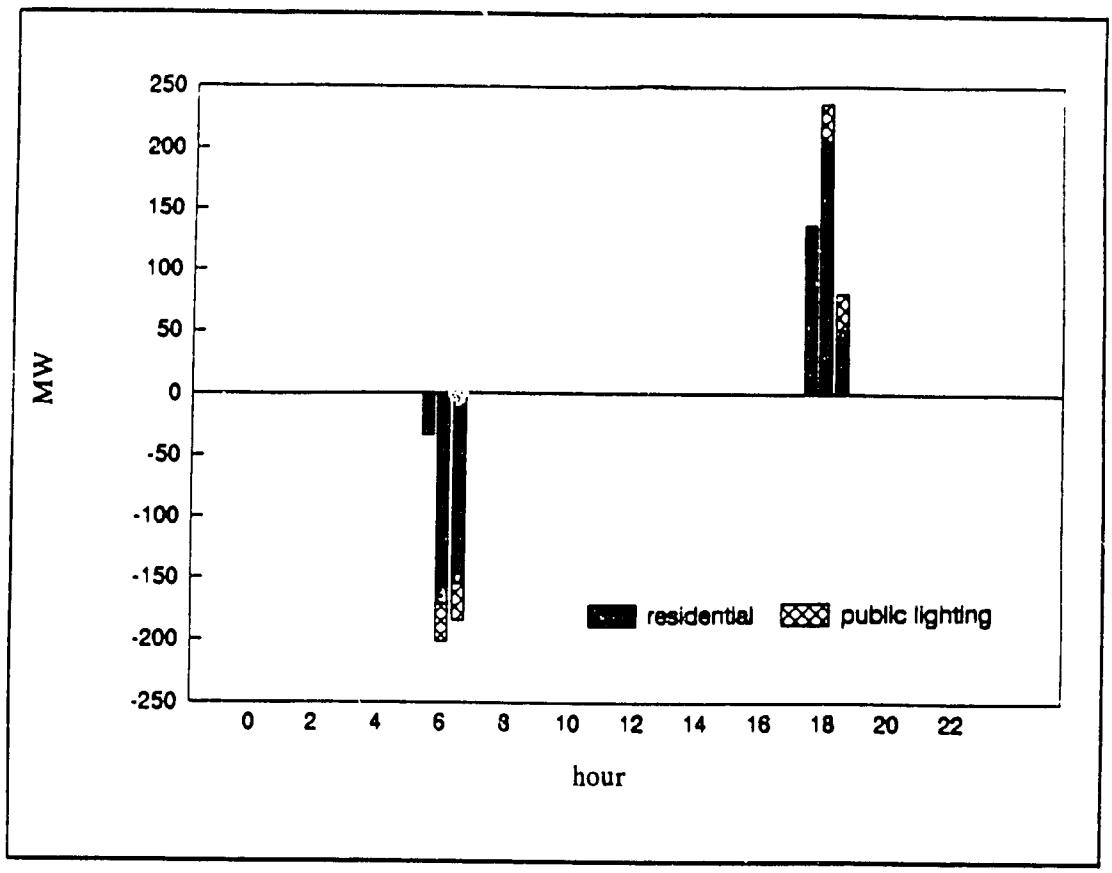


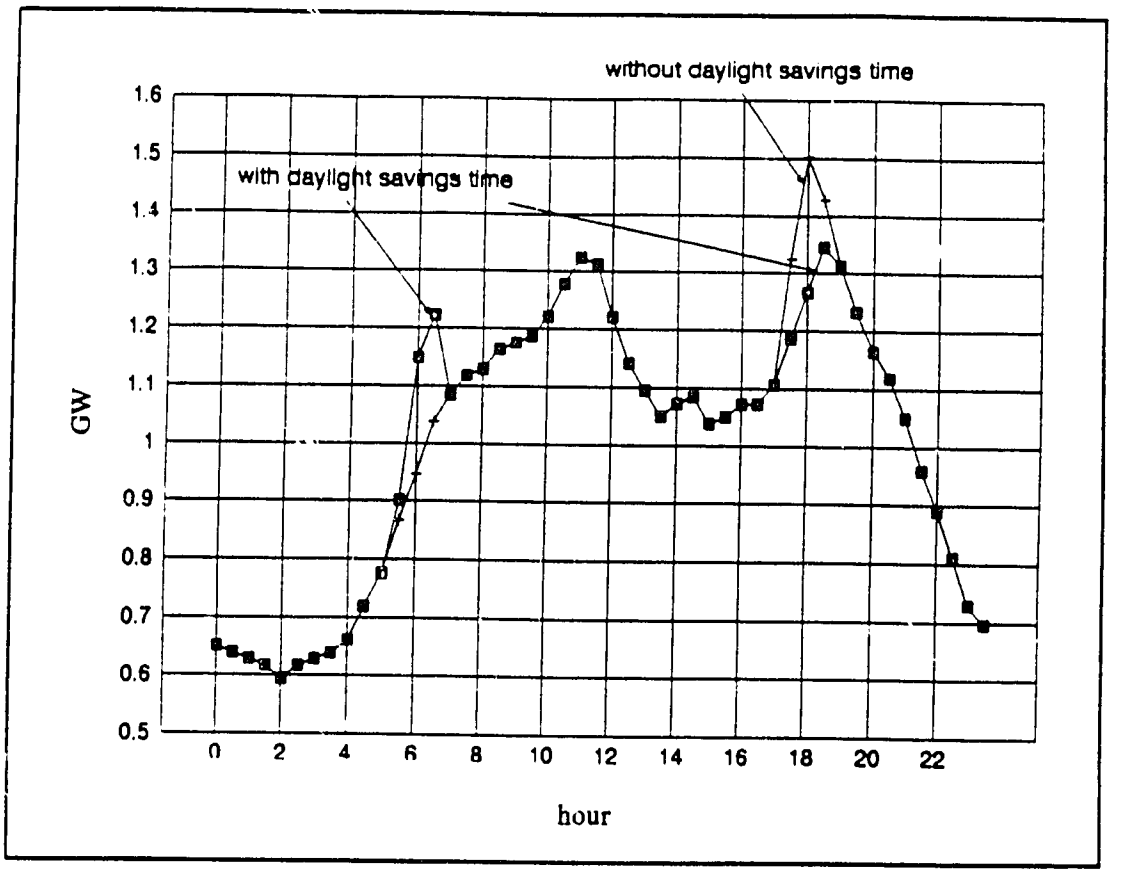
Exhibit 4-11
Impact of Daylight Savings Time, 2005



evening peak is offset by increased lighting loads in the morning, which creates a small demand peak at that time.

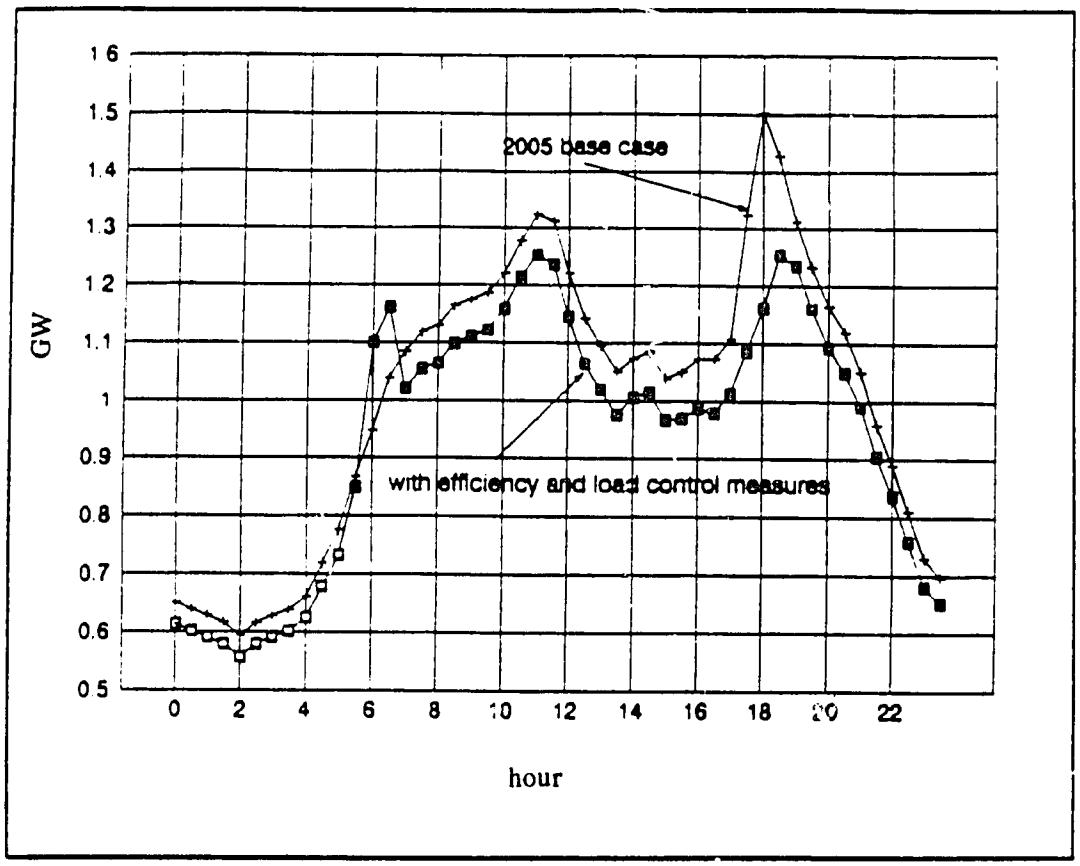
The real question, however, is whether this sharp load reduction at dusk simply shifts the peak to a later hour, or to the morning peak. As can be seen from Exhibit 4-12, about 170 MW of load can be eliminated from the evening peak before the morning peak dominates. The spike at dawn reflects the need for increased lighting loads when people rise and prepare for work in the morning. This spike, which would occur during darkness under daylight savings time, is substantial, however. It is obvious from these exhibits that although much additional research needs to be done to reduce the uncertainties, the potential for very large reductions of the peak load is present.

Exhibit 4-12
Impact of Daylight Savings Time on the Load Curve of the 2005 System Peak Day



When all the measures from Exhibit 4-1 are aggregated, the impact on the year 2005 load curve is that shown in Exhibit 4-13.

Exhibit 4-13
Impact of the Complete Plan



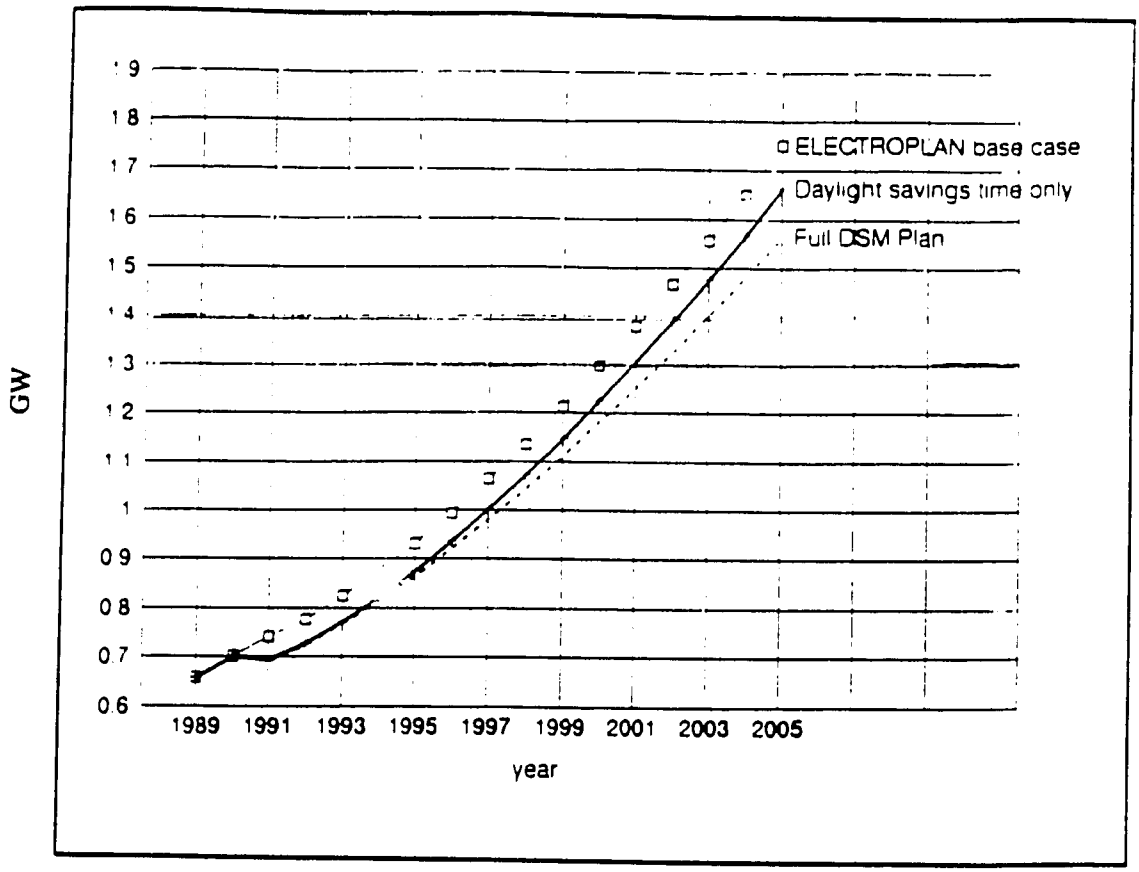
4.3 IMPACTS ON ICE

4.3.1 Impact on the Demand Forecast

As indicated in Exhibit 4-14, the impact of the DSM plan on ICE's peak load is over 200 MW by the year 2005, a reduction of about 12 percent in the system peak. However, of this total peak reduction, almost 50 percent (about 90 MW) is attributable to the introduction of daylight savings time. In light of the potential importance of this measure, additional field work is required to assess the exact relationship between lighting loads and

151

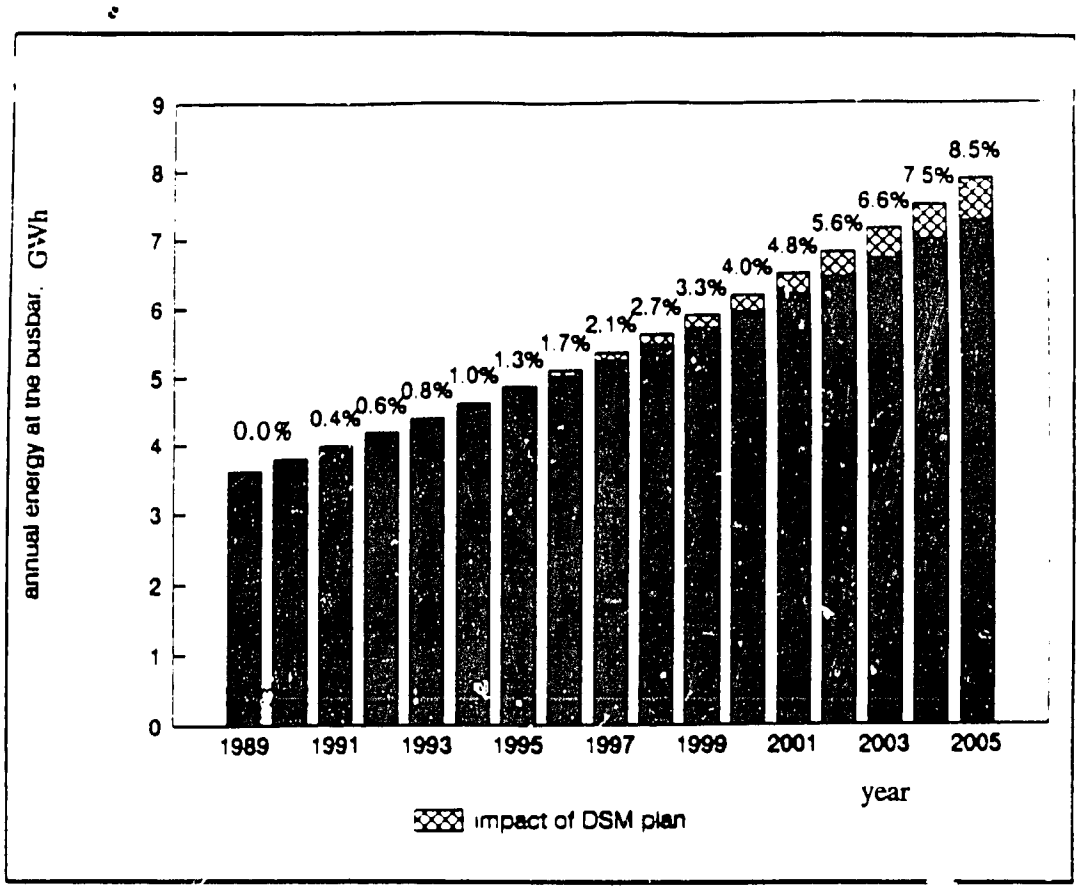
Exhibit 7-14
Impact of the DSM Plan on ICE's Peak Load



the timing of dusk and dawn. Because daylight savings time amounts to a single one-hour shift, and the sharpest evening peak load is only of about 1.5 hours in duration, the assumptions here are critical.

The impacts on energy generation requirements are shown in Exhibit 4-15. Daylight savings has a very small impact on energy requirements, since much of the energy saved during the evening peak is made up by the additional lighting needs in the morning, as darkness extends for an additional hour. Nevertheless, for the full DSM plan, the conservation measures result in energy savings by 2005 that are on the order of 8 percent, or over 600 GWh.

Exhibit 7-15
Impact of the DSM Plan on Energy Requirements



4.3.2 Impact on the Capacity Expansion Plan and the ICE Investment Program

The ICE capacity expansion plan is based on a projection of the system peak load. For the purposes of this assessment, we have used the ICE base case demand projection of June 1989, and the ICE base case capacity expansion plan specified in ICE's September 1989 report.

ELECTROPLAN incorporates a capacity expansion algorithm that adjusts some exogenously specified schedule of capacity additions in such a way that a given planning

reserve margin is met.[1] This means that whenever the reserve margin would otherwise fall below the specified percentage, the next unit is brought on line. Because of the lumpy nature of capacity increments, the actual reserve margin will vary from year to year (as will the LOLP), and will be higher than the planning reserve margin (PRM) because the algorithm ensures that the PRM is always at least met or exceeded.

Thus, if demand increases relative to the base case, the timing of capacity additions is accelerated; if demand decreases, unit start-up dates are delayed. The basic concept is to maintain the overall level of reliability, while adjusting capacity. Alternatively, if one left start-up dates unchanged in the face of lower demand, then the consequence would be to increase the reserve margin and reliability (implying, in turn, a decrease in the LOLP). Obviously, if we maintain constant system reliability levels, the impact of conservation and load management measures is to permit a delay in start-up dates.

Exhibit 4-16 shows a comparison of the ICE capacity expansion plan (of September 1989) and the results of the ELECTROPLAN algorithm for a planning reserve margin of 5 percent. The results are seen to be in very close agreement with the ICE WASP results.[2]

If the planning reserve margin is increased, say to 15 percent, then ELECTROPLAN adjusts the capacity expansion plan in such a way that unit start-up dates are advanced, as indicated in Exhibit 4-17. If we assume, then, a 5 percent PRM to ensure alignment with ICE's WASP results, the results of the ELECTROPLAN simulations of the impact of the DSM plan on the capacity expansion schedule are shown in Exhibit 4-18.

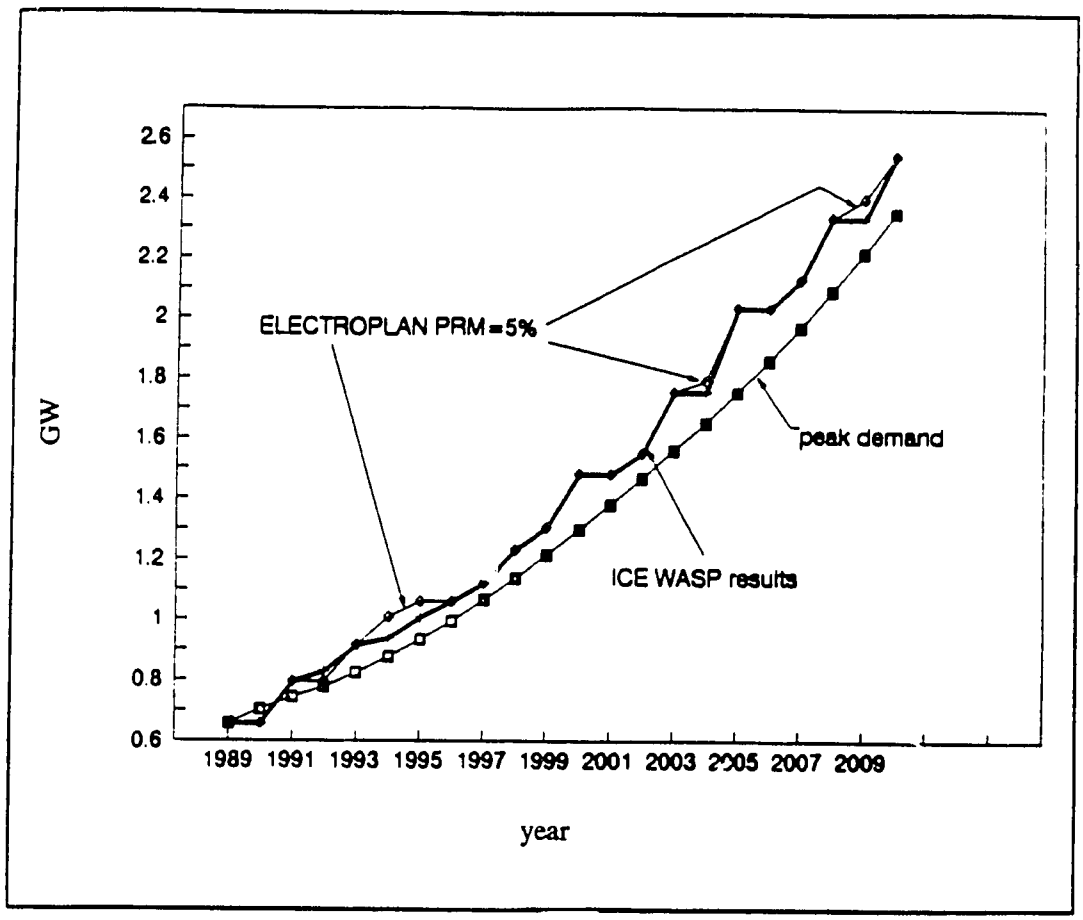
When one examines the year-by-year investment outlays (shown in Exhibit 4-19), the impact of the capacity deferments is less clear. Obviously, in view of the lumpy nature of construction outlays, even under the DSM program, construction outlays will be higher in some years and lower in others. Consequently, in order to quantify and compare the impacts of the DSM programs and plans, we used the Net Present Value (NPV) of the financial flows, through 2005, and a discount rate of 12 percent, as the criteria for evaluating alternatives.

---

1 For a detailed discussion of this approach, which is similar to that used in the EPRI OVER/UNDER and MIDAS models, see the technical report on ELECTROPLAN.

2 Indeed, the results are so close that it is unlikely that this is mere coincidence. One suspects that the LOLP used in the WASP runs that generated the ICE capacity expansion plan was selected in such a way as to result in a 5 percent average reserve margin.

Exhibit 4-16
Comparison of ELECTROPLAN and ICE Base Case Expansion Plan

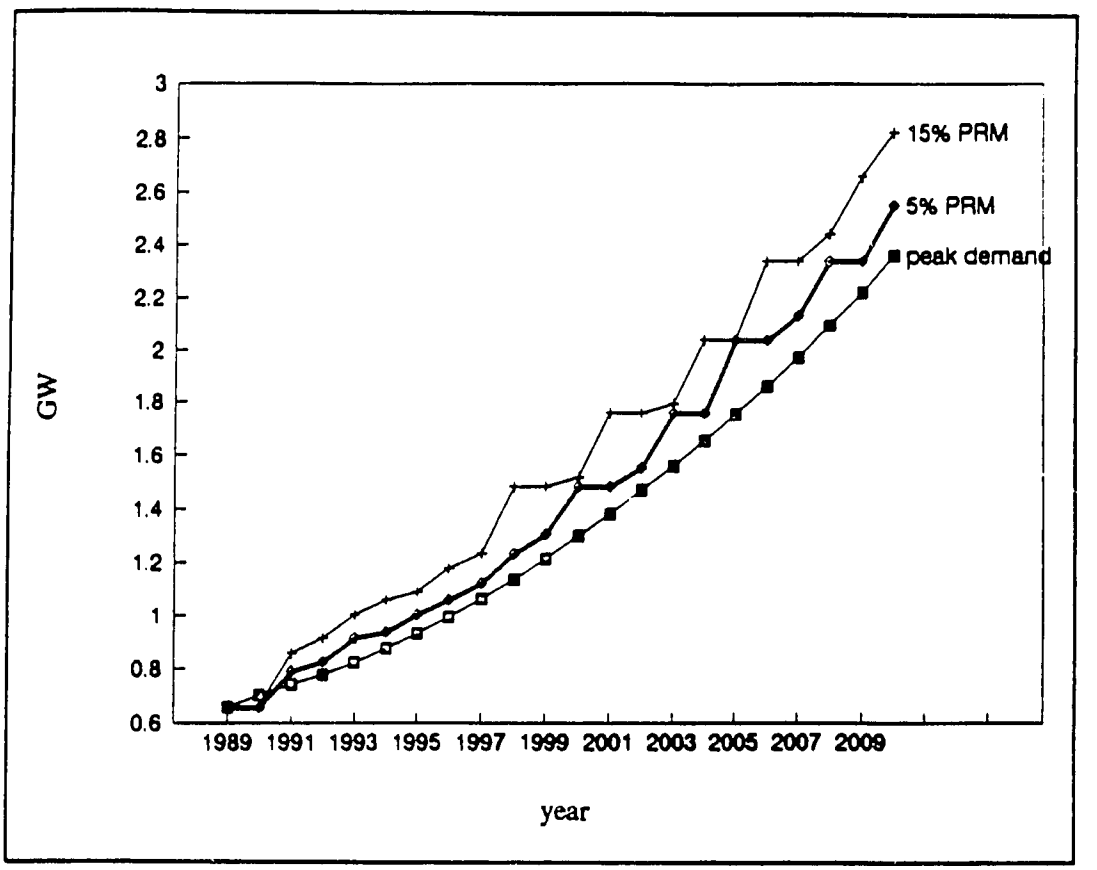


Appendix 13 includes a complete set of output tables that give the year-by-year financial flows to 2005, and the corresponding NPVs, for the base case, for daylight savings time only, and for the full DSM plan. Exhibit 4-20 shows the impact of daylight savings time, which is simply the difference between the financial flows in the base case and the flows in the daylight savings time case. Exhibit 4-21 shows the corresponding impacts for the full DSM plan.

4.3.3 Impact on Fuel Costs

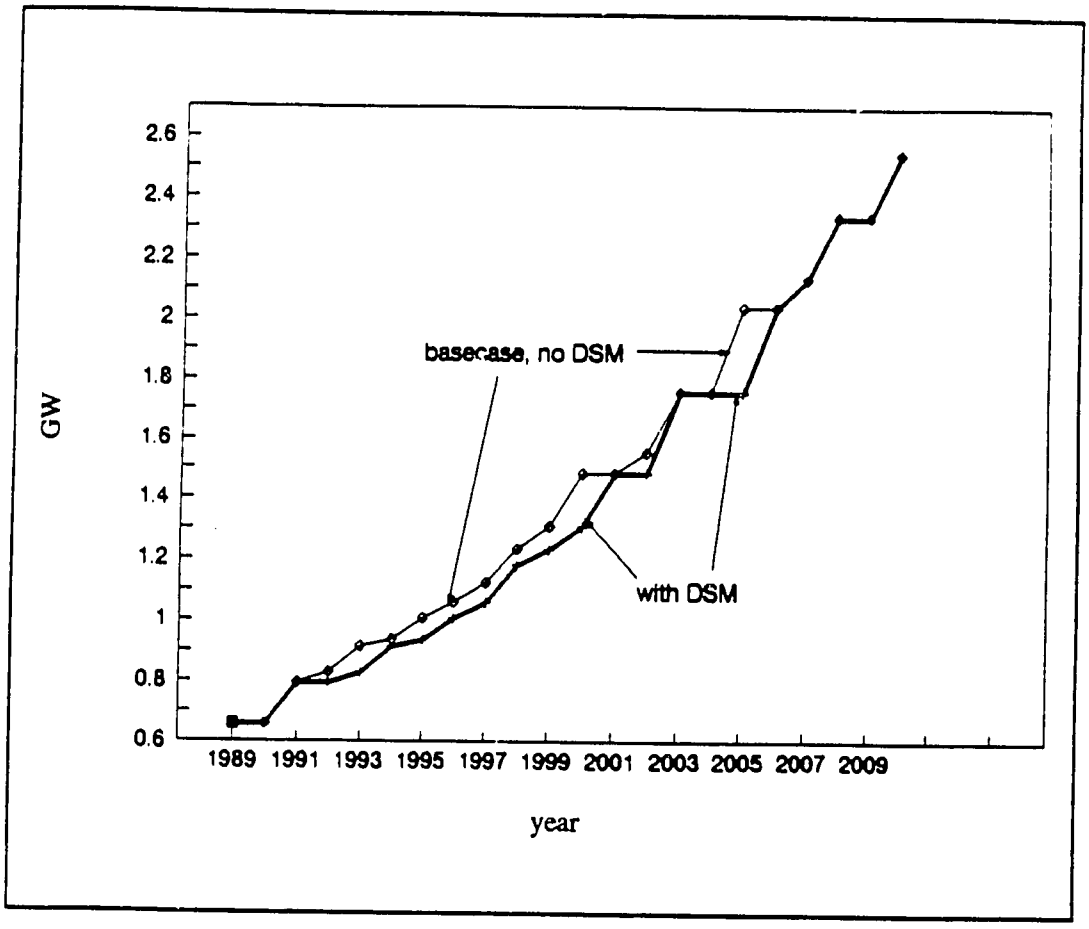
The fuel cost scenarios used by ICE for the WASP runs reported in September 1989 are portrayed in Exhibit 4-22. By the mid-1990s, oil prices are estimated to increase in real terms by a few percentage points per year, as assumed by ICE.

Exhibit 4-17
The Impact of the Planning Reserve Margin Assumption



As indicated in Exhibit 4-23, the fuel cost savings by 2005 will be substantial. We view these savings as fairly robust because they are dependent only upon the conservation measures, whose impact is less dependent on uncertain assumptions than some of the load management measures such as daylight savings time. Obviously, these savings are directly proportional to the assumed fuel price: a 2005 fuel oil price of $44/bbl rather than $33/bbl simply increases the savings by 33 percent.

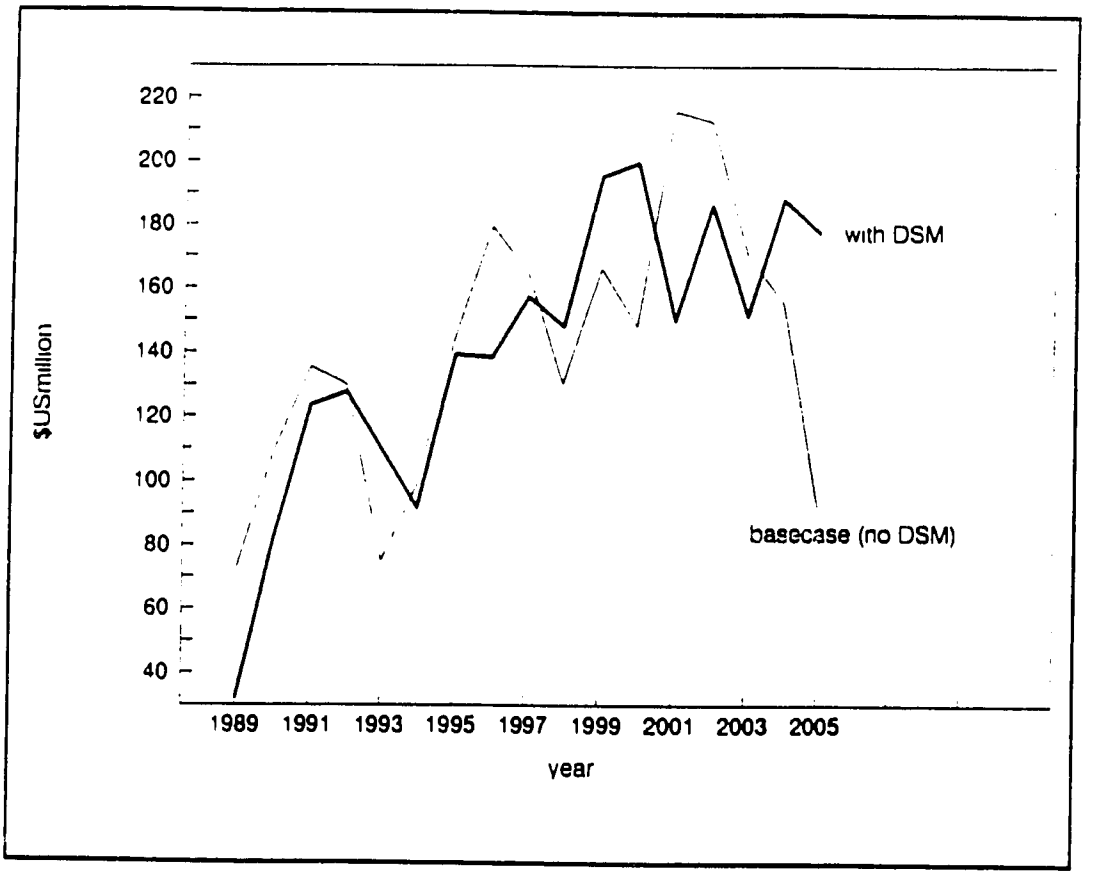
Exhibit 4-18
Impact of the DSM Plan on Capacity Expansion Requirements



4.3.4 Impact on ICE's Financial Condition

Despite the revenue losses associated with the conservation measures and the costs of administration of the DSM plan, the savings in fuel costs and interest payments outweigh the losses, resulting in an increase in net income. Exhibit 4-24 shows the impact of the DSM plan on ICE's net income. Exhibit 4-25 summarizes the key results in terms of the change in NPV of the associated changes in financial flows.

Exhibit 4-19
Annual Investment Requirements



The impact on balance sheet ratios is similarly beneficial. For example, Exhibit 4-26 shows the impact on the debt service coverage ratio.[3]

The broad conclusion from this analysis is that the financial impacts of the proposed DSM plan on ICE are beneficial. While there is some revenue loss associated with both conservation and load management measures, and significant administrative costs are

[3] Defined as funds from internal sources, often meeting operating expenses (before depreciation), debt service, taxes, dividends, increases in working capital and other significant cash outflows, excluding capital expenditures, as a ratio to capital expenditures.

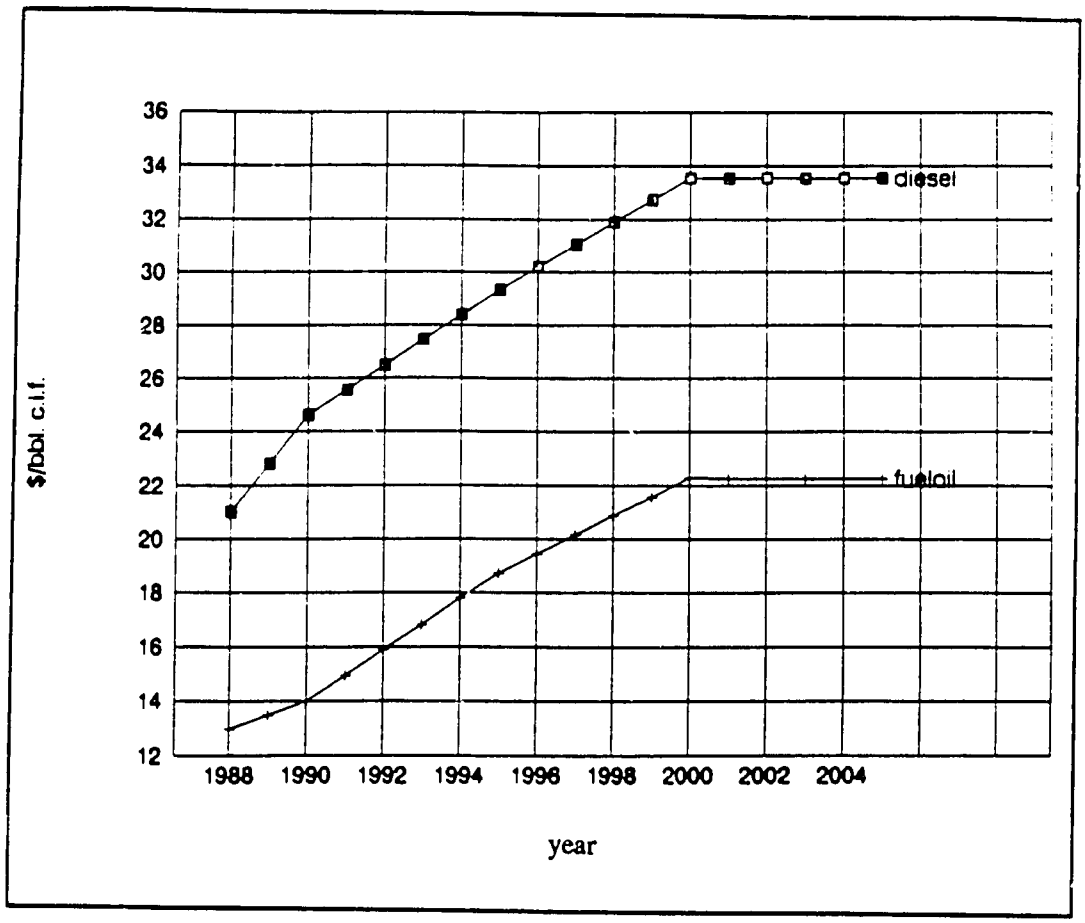
Exhibit 4-20. Impact of Daylight Savings Time

			1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Capacity Expansion														
peak demand	MW		0	0	-47	-48	-50	-63	-55	-57	-60	-63	-66	-70
installed capacity	MW		0	0	0	-36	-87	-24	-66	-53	-64	-55	-72	-177
Investment Program	NPV $mil.	of base												
foreign investment	-35	-8.53%	-28	-18	-7	-2	23	-7	-6	-27	-3	13	20	35
generation investment	-51	-8.50%	-40	-27	-12	-2	34	-7	-6	-41	-7	18	29	52
total investment	-51	-5.57%	-40	-27	-12	-2	34	-7	-6	-41	-7	18	29	52
DSM equip. imports	0		0	0	0	0	0	0	0	0	0	0	0	0
fuel imports	0	0.23%	0	0	0	0	0	0	0	0	0	1	0	0
int. on foreign debt	-27	-12.12%	-3	-5	-5	-6	-3	-3	-3	-6	-6	-4	-2	2
principal repayments	-13	-21.22	0	0	0	0	-7	-1	-1	-3	-1	-3	-2	-4
total foreign exchange impact	-39	-7.99%	-3	-5	-5	-6	-9	-4	-5	-10	-7	-6	-4	-1
ICE Impacts														
fuel bill	3	1.12%	0	0	2	0	0	0	0	0	0	2	0	2
revenue loss	0		0	0	0	0	0	0	0	0	0	0	0	0
DSM expend./admini.	0		0	0	0	0	0	0	0	0	0	0	0	0
DSM expend./equip.	0		0	0	0	0	0	0	0	0	0	0	0	0
interest on debt	-27	-12.12%	-3	-5	-5	-6	-3	-3	-3	-6	-6	-4	-2	2
depreciation	-26	-14.46%	0	0	0	0	-10	-2	-2	-4	-1	-4	0	-15
ICE income state. impact	50	7.49%	-3	-5	-4	-6	-12	-6	-5	-11	-7	-6	-2	-11
principal repayments	-13	-21.22%	0	0	0	0	-7	-1	-1	-3	-1	-3	-2	-4
self-finance invest. cost	-15	-3.11%	-12	-9	-4	0	11	0	0	-14	-4	4	9	17
ICE cash flow impact	-104	-7.41%	-15	-14	-8	-6	-18	-7	-8	-32	-14	-8	5	-13

Exhibit 4-21. Impact of the Full DSM Plan

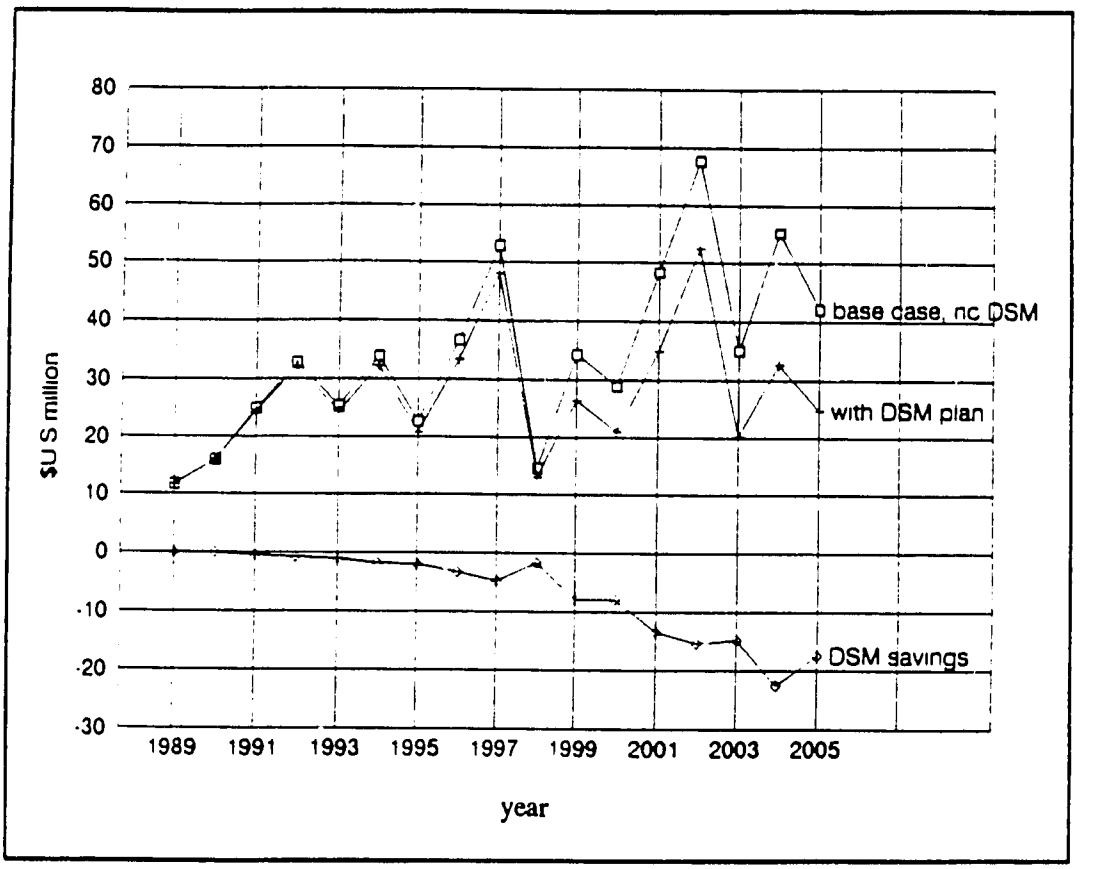
			1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Capacity Expansion														
peak demand	MW		0	0	-49	-52	-55	-60	-66	-72	-81	-91	102	-114
installed capacity	MW		0	0	0	-36	-87	-79	-90	-53	-64	-110	-127	-213
Investment Program	NPV $mil.	of base												
foreign investment	-56	-13.57%	-28	-40	-23	-4	34	4	-21	-34	4	33	-7	15
generation investment	-80	-13.45%	-40	-57	-34	-6	49	9	-25	-50	2	45	-16	20
total investment	-80	-8.81%	-40	-57	-34	-6	49	9	-25	-50	2	45	-16	20
DSM equip. imports	19		0	0	1	1	1	1	2	2	3	4	5	6
fuel imports	-26	12.68%	0	0	0	-1	-1	-2	-2	-3	-5	2	-8	-8
int. on foreign debt	-42	-19.11%	-3	-7	-9	-9	-5	-4	-6	-9	-9	-5	-5	-3
principal repayments	-20	-33.56	0	0	0	0	-7	-7	-2	-3	-1	-6	-4	-6
total foreign exchange impact	-70	-14.32%	-3	-7	-8	-10	-13	-11	-8	-14	-11	-8	-12	-10
ICE Impacts														
fuel bill	-30	11.51%	0	0	0	-1	-1	-2	-2	-4	-5	-2	-8	-8
revenue loss	34		0	0	1	1	1	2	3	4	5	7	9	12
DSM expend./admini.	3		0	0	0	0	0	0	0	0	1	1	1	1
DSM expend./equip.	0		0	0	0	0	0	0	0	0	0	0	0	0
interest on debt	-42	-19.11%	-3	-7	-9	-9	-5	-4	-6	-9	-9	-5	-5	-3
depreciation	0	-0.0%	0	0	0	0	-10	-9	-4	-4	-1	-9	-4	-15
ICE income state. impact	103	15.53%	-3	-7	-10	-11	-16	-17	-15	-21	-20	-22	-26	-37
principal repayments	-20	-33.56%	0	0	0	0	-7	-7	-2	-3	-1	-6	-4	-6
self-finance invest. cost	-24	-4.87%	-12	-17	-11	-1	15	5	-3	-16	-2	11	-9	6
ICE cash flow impact	-147	-10.50%	-15	-24	-21	-13	-19	-28	-24	-44	-25	-26	-44	-51

Exhibit 4-22
ICE Base Case Fuel Cost Scenarios: September 1989



imposed on ICE for program administration and promotion, these costs are far outweighed by the benefits of lower fuel import costs, and reductions in debt service associated with deferments in capital outlays. The impact on all financial ratios is beneficial, including return on assets. Although the asset base is somewhat smaller (because there is less generation capacity), the increased net income is proportionally much higher, resulting in an increase in return on assets.

Exhibit 4-23
Impact of the DSM Plan: ICE Base Case Fuel Cost Scenario



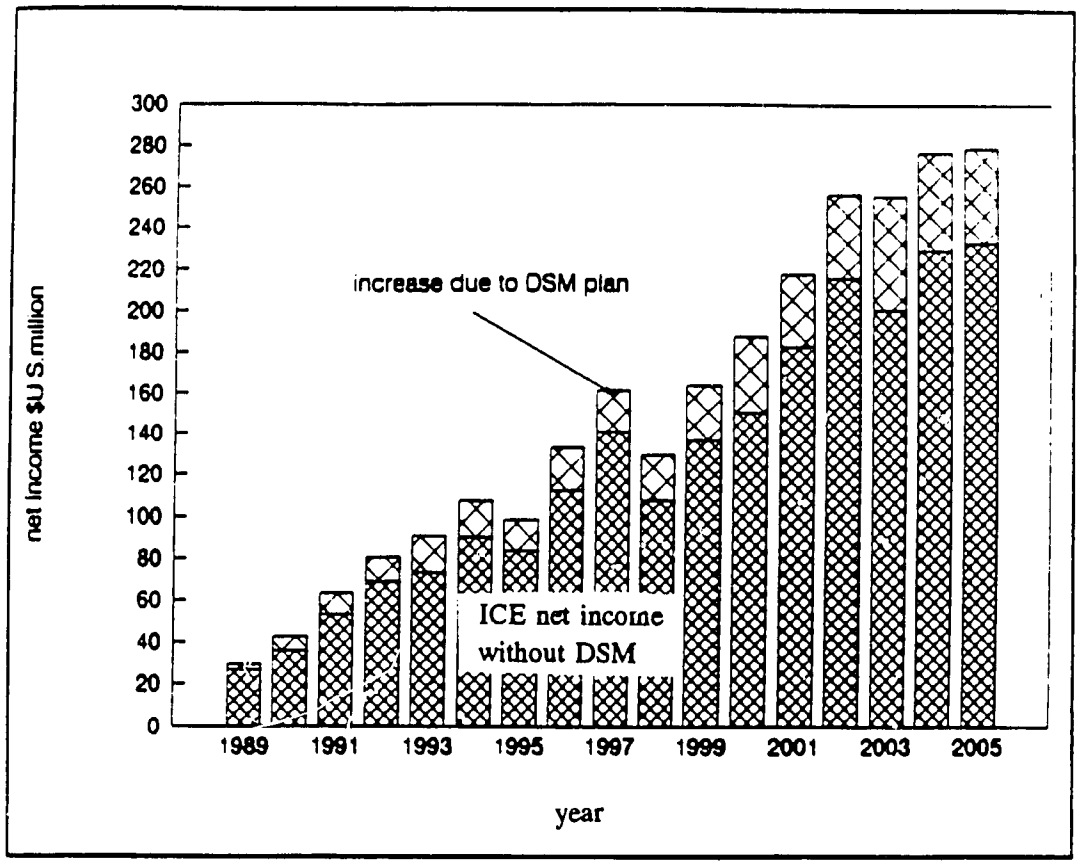
4.4.5 Impacts on the Balance of Payments

The DSM program has three potentially important impacts on the balance of payments:

1. reduced debt foreign debt service associated with the defrayal of capacity expansions (both interest and principal)

2. reduced oil import bill associated with energy savings (which at the margin displace oil-fired generation)

Exhibit 4-24
Impact of the DSM Program on Net Income



3. increases in the import bill associated with the need to import equipment for the DSM measures (such as more costly light bulbs, load control equipment, etc.).

As is evident from Exhibit 4-27, the increased equipment imports necessary for the DSM plan are relatively small compared to fuel imports and debt service payments. Moreover, we have made the conservative assumption that imports make up all of this equipment, which is certainly true for some measures, but not necessarily true for others.

Exhibit 4-28 illustrates the impact of the full DSM plan on the net balance of payments. Over the period of the planning horizon, the net present value of the foreign exchange

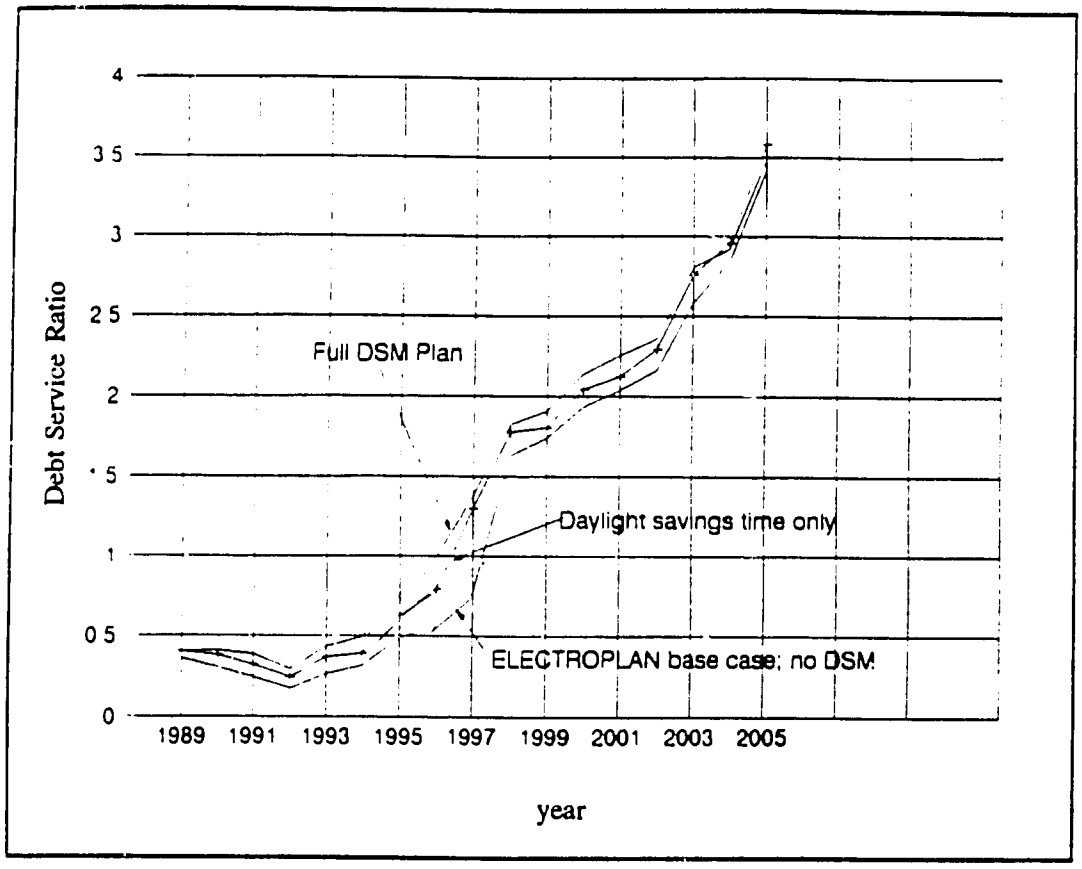
Exhibit 4-25
Financial Impacts of the DSM Plan
(as NPV of Financial Flows to 2005 at 12 Percent Discount Rate)

	Base Case	Impact of Daylight Savings Time Only	Impact of Full DSM Plan	As % of Base Case
Total Investment	909	-51	-80	-8.8%
Foreign Investment	412	-35	-56	-14%
DSM Equipment Imports	0	0	19	
Fuel Imports at cif	206	0	-26	-12%
ICE Revenue Losses	0	0	34	
ICE Administrative Costs	0	0	3	
ICE Income Statement Impact	0	50	103	15%

savings is 14 percent of the base case, which is significant. However, we have excluded from this calculation debt service associated with the current debt, given the uncertainties over its rescheduling. Nevertheless, even if this is added into the base case, the foreign exchange savings associated with implementation of the DSM plan are substantial.

Exhibit 4-26

Impact of DSM Program on Debt Service Ratio



165

Exhibit 4-27

Foreign Exchange Flows Associated with the Power Sector

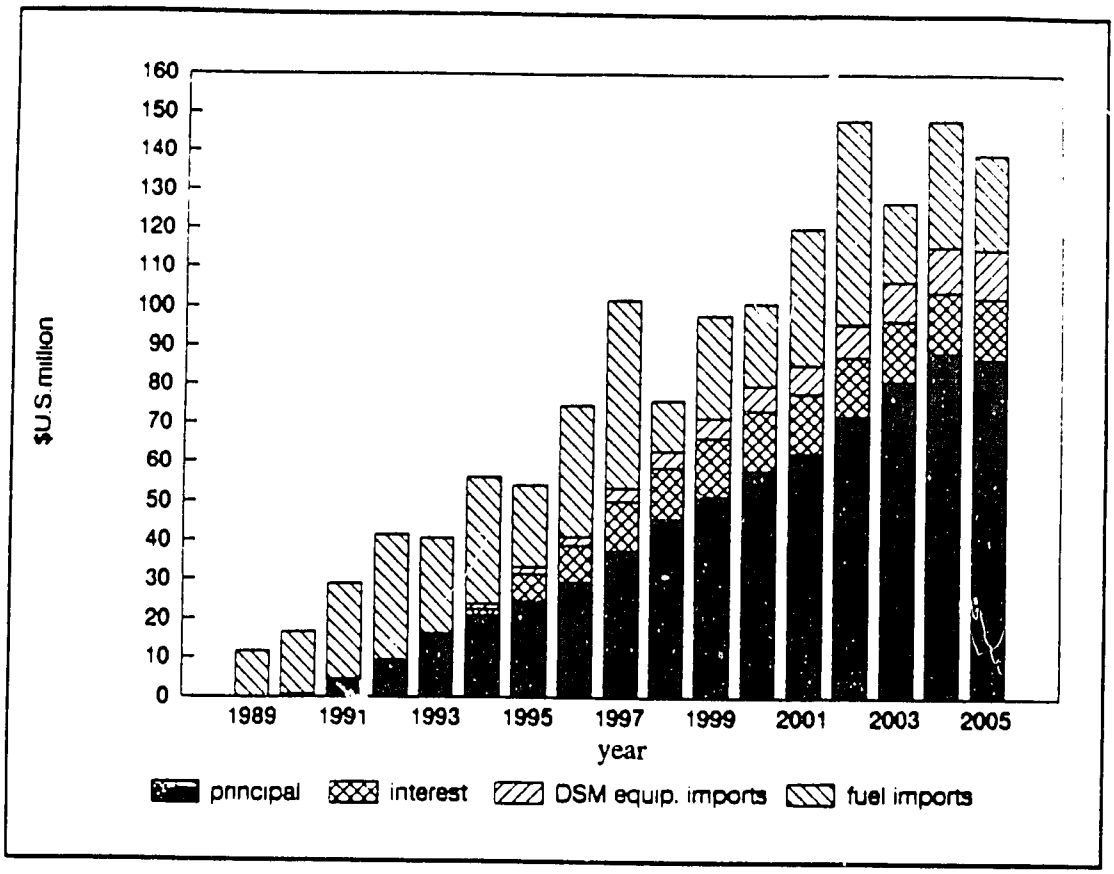
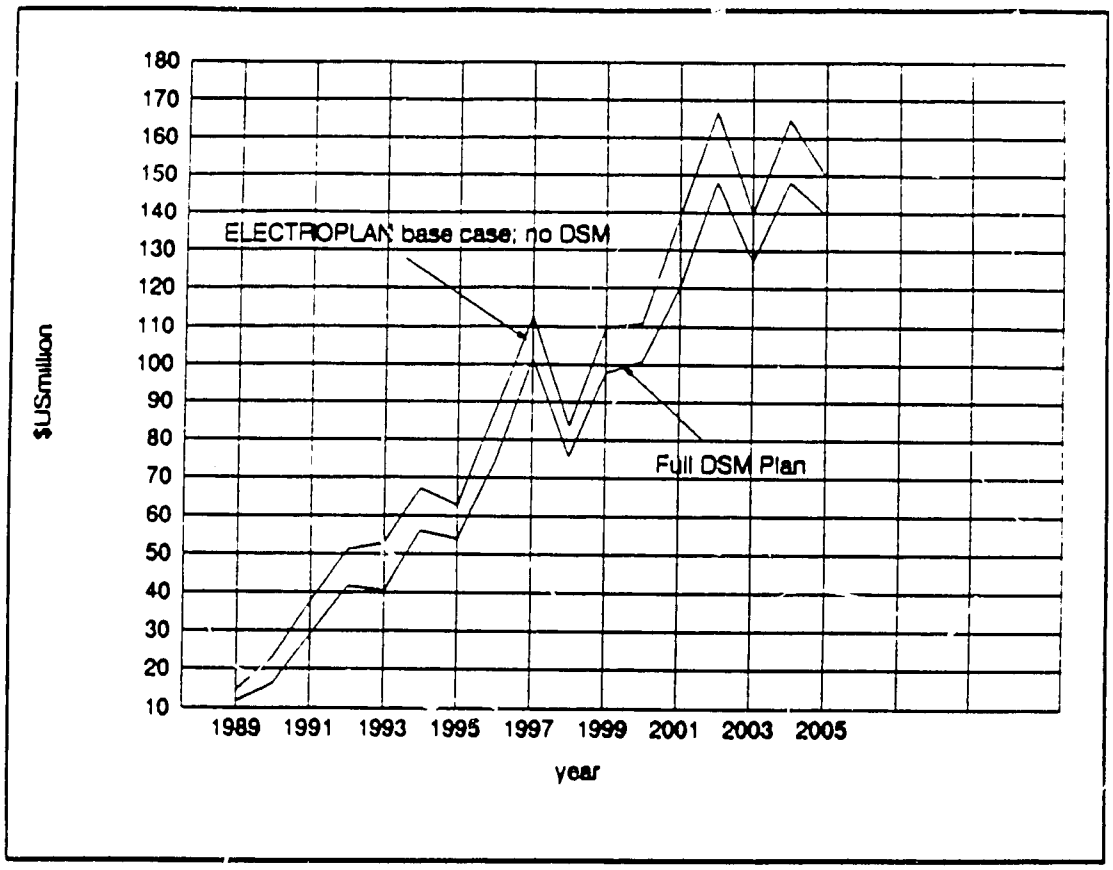


Exhibit 4-28

Impact of the DSM Plan on the Balance of Payments



CHAPTER 5: IMPLEMENTING AN INTEGRATED RESOURCE PLAN

This chapter discusses three issues surrounding the implementation of an integrated resource plan for Costa Rica. The first is the roles to be played by the nation's public and private institutions in such a plan. The second concerns tariff and revenue questions that will arise during program implementation, and the third concerns issues on the establishment of a full regulatory process for supporting energy efficiency.

5.1 INSTITUTIONAL ROLES

Because conservation resources are dispersed, a variety of actions must be taken to ensure that programs designed to save energy are developed and implemented successfully. Each of these programs will require financing strategies, regulatory actions, and different types of analytical and technical assistance services. Thus, the development and implementation of an integrated resource plan (IRP) must include the participation of a wide variety of public and private sector institutions, many of which have not traditionally played a direct role in the electric power sector.

ICE. Because it has the primary legal responsibility for providing electricity to meet Costa Rica's economic development objectives, ICE would play the central role in the implementation of the IRP. In addition to ICE, the other electricity agencies--including the National Power and Light Company (CNFL), the three Municipality Boards, and the three electric cooperatives--are expected to participate because their customers will be targeted for efficiency programs, thus affecting these agencies' tariffs and revenues.

DSE/MIRENEM. This is the lead government agency in assisting in the development of programs, efficiency standards, and data bases, program evaluation, public education, and other areas essential for an IRP. MIRENEM's main function is to elaborate, manage, and control natural resources, energy, and mining policies.

MIDEPLAN. The Ministry of Planning and Economic Policy (MIDEPLAN) is responsible for coordinating the National Development Plan with other public institutions. It also has the authority to approve public investments, external financing, and technical assistance support for public institutions. Its Division of International Technical Cooperation would have to approve the use of foreign assistance in several activity areas.

MIDEPLAN should be closely involved in the development and coordination of an IRP in Costa Rica.

SNE. The National Service of Electricity (SNE) regulates the tariffs of ICE and is responsible for establishing requirements for electrical design, installations, and hookups to the distribution system. SNE would have to approve any tariff-related activity for demand-side management program financing.

Hacienda. The Ministry of the Treasury (Hacienda) is responsible for coordinating monetary, credit and treasury policy. This includes all aspects related to taxes and import duties. This Ministry would be involved in decisions affecting import duties on energy-efficient (and inefficient) products. It would also need to understand the relationship between financing efficiency and the impacts on balance of payments and external debt.

MEIC. The Ministry of Economy, Industry and Commerce (MEIC) is responsible for formulating and planning national economic policy, stimulating the consumption of locally produced products, and for achieving economic integration of Costa Rica with other Central American countries.

The Bureau of Census. The Bureau is under the Ministry of Economy and Commerce, and is responsible for conducting a national census every ten years, especially of housing, agriculture, and population. It also serves as a national and international center of statistics, which is needed in the development of an IRP.

MICIT. The Ministry of Science and Technology (MICIT) is a new ministry created in 1986, whose main function is to define and promulgate guidelines for scientific and technology policies. MICIT could participate in the research of energy-efficient technologies and their applications in Costa Rica.

FODEIN. The Industrial Development Fund (FODEIN) may play a role in financing industrial efficiency development. This is a special line of credit managed by the Central Bank to finance industrial investments, including new construction projects, rebuilding, equipment, furnishings, etc. The total amount available per loan varies from $250,000 to $5 million. This loan allows up to 10 years for repayment and a favorable interest rate is fixed by the Central Bank (about 20 percent in colones).

CFIA. The Colegio Federado de Ingenieros y Arquitectos de Costa Rica (CFIA) is an independent public entity created to ensure, stimulate, promote, an defend the practice of engineering and architecture. It would participate in any discussions to develop building energy codes.

The Chamber of Industries and Chamber of Commerce. The Chambers have provided logistic support to the Costa Rican Institute of Technical Standards (INTECO). Under an IRP, they would act as representatives of the private sector in any regulatory and program design process that might involve or affect their members.

INTECO. This non-profit organization, the Institute for Technical Standards, was created as a private association to stimulate efficiency in the industrial sector and to protect the consumer as well. Its objectives are to 1) develop proper standards for local industry in conjunction with the public sector, 2) train staff of the main industries at all levels of production in the use and application of adequate standards, and 3) provide quality control. INTECO could play a role in an IRP if appliance efficiency standards are developed.

The University of Costa Rica and the National Training Institute. These institutions could be involved in training and technical assistance efforts on efficiency.

ECODES. The Costa Rican National Conservation Strategy for Sustainable Development (ECODES) is an effort to incorporate the concept of sustainability into the socio-economic and cultural development of the country. For the energy sector, it has recommended the execution of a national energy plan with special emphasis on efficiency and energy savings aspects and control of the environmental impacts of energy projects. It could provide the context for carrying out an IRP in Costa Rica.

Overall, new institutional relationships and communications networks will have to be established in order to provide ICE the necessary support to implement the integrated resource plan.

A number of valuable lessons have been learned by U.S. utilities, who have taken wide variety of approaches to integrated resource planning. They have found that the utilities and agencies with the most successful program results have had a strong senior management commitment to the programs, and have committed adequate funding and staff to program implementation. Second, utilities have found that careful documentation of the program costs and savings is critical to program success. Information on participation rates, kWh and kW savings, and administrative and marketing costs must be collected on a systematic basis in order to evaluate programs properly.

5.2 FINANCING CONSERVATION PROGRAMS

Integrated resource planning assumes that conservation is a resource that can be used by the power system to meet future load growth. Therefore, the utility can directly finance the

conservation measures and programs for customers, and recover the costs through the tariff structure, just as it would if it were to build a generating resource.

There may, however, be disincentives for ICE to promote conservation because if ICE succeeds with conservation programs, its current tariffs and revenues will be affected. First, a near-term impact of a successful conservation program financed by ICE is a potential tariff increase, which would be needed to pay for the costs of financing the programs. Full conservation costs are incurred immediately (savings are also realized immediately), unlike generation investments, which can be paid out over time as construction is carried out. Second, future impacts on ICE include the loss of expected revenues required to meet fixed system costs.

There are also two major financing issues that need to be considered in order to implement a DSM action plan: (1) how can utilities structure DSM programs such that end users will want to invest in conservation and (2) how can incentives be structured for utilities that will encourage them to invest in DSM programs. In the United States, state regulatory agencies and investor-owned utilities have been developing options for utilities to address these questions. The options include separating sales from profits, allowing for recovery of lost revenues, and allowing rate-of-return treatment for conservation investments. In some cases, utilities are receiving additional returns on conservation spending above the allowable return on other capital investments. One flexible accounting mechanism that has been developed is the Electric Rate Adjustment Mechanism (ERAM), which has been utilized in California. The ERAM automatically adjusts utility tariffs on an annual basis to correct for overcollection and undercollection of revenues due to unforseen reasons, including changes in weather, economic cycles, and conservation expenditures. It does not provide a direct incentive to utilities to conduct conservation programs, however.

In the non-profit utility sector, incentives for conservation spending are usually seen in the allowance of tariff increases to account for conservation program spending and the recovery of lost revenues to ensure that system operating costs are fully covered. In addition, long-term system costs and tariffs are kept lower because new generating plants are deferred or avoided.

The macroeconomic incentives of integrated resource planning for Costa Rica are clear: reduced imports of fossil fuel, reduced investment and debt for new generation, and increased environmental benefits. However, the issue of what direct incentives can be developed for ICE, CNFL, and the cooperatives must still be addressed. The analysis carried out in Chapter 4 of this report was only an attempt to address this issue.

The IRP experience of U.S. utilities provides three other lessons in the area of financing conservation programs:

- Financial incentives increase program participation. The availability of financing for implementing energy audit recommendations is fundamental to achieve higher efficiency and penetration rates. Energy audits to help customers to identify conservation opportunities without appropriate financing mechanisms for carrying out recommendations can result in significantly lower implementation rates.

- There are a variety of approaches for financing efficiency programs in different market segments in each end-use sector, and a combination of approaches is especially useful. Equipment rebate programs are good for basic equipment, but will not be effective for promoting improvements involving complex interactions of multiple pieces of equipment. Loan programs only reach a minority of customers. Direct installation programs achieve the highest penetration rates, but at a generally higher cost.

- Comprehensive programs may result in higher participation rates and higher savings. For example, a program for new commercial construction could include design assistance, financial incentives, a building code, and training of architects/engineers. A commercial sector retrofit program would include a comprehensive approach to total building energy use, rather than a piecemeal approach such as a lighting rebate program only.

5.3 REGULATIONS AND STANDARDS

The United States has the world's most extensive system of energy-related regulations, which take the form of building energy codes (residential, commercial) and minimum efficiency standards for appliances (electric, oil, and gas). Codes and standards are established on a state-wide or national basis, with the participation of equipment manufacturers, builders, architects, energy/environmental advocates, code enforcement agencies, and other interested representatives. In addition to establishing codes and standards, institutional and financial resources are required to enforce them and to certify compliance on a continual basis. Independent testing laboratories have been established to certify appliance efficiency standards.

As U.S. electric utilities moved toward integrated resource planning, they discovered that building codes and appliance efficiency standards were developed at levels that were less

than optimum for utility resource planning. Efficiency levels are set by consensus based on consumer cost-effectiveness criteria, not on utility marginal cost criteria. This means that savings that are technically possible are lost due to the restrictive financial criteria used to evaluate the costs of the codes or standards. For example, a new commercial building program sponsored by the federal Bonneville Power Administration in the Pacific Northwest demonstrated that new commercial buildings of various types could be constructed to use 30 percent less electricity than the current building energy codes required, with minimum construction cost increases (with lower first costs in some cases) and existing off-the-shelf technology. This provides an example of a "lost opportunity" for the utility.

U.S. utility experience has shown that a critical target for programs lies in new construction and equipment. The potential "lost opportunities" include new residential and commercial construction, where there is a one-time opportunity to achieve savings at a much lower cost than through a retrofit.

Similar concerns exist about appliance efficiency standards. Lost opportunities may occur when major equipment is being replaced, when buildings are remodelled, or when process lines in industry are replaced or modernized.

In the U.S., new standards for refrigerators will go into effect in 1993, which will result in a decrease in electricity use of nearly 30 percent from the more recent standards. However, there is growing interest by several major U.S. utilities in motivating refrigerator manufacturers to make a technological leap to units that would exceed the 1993 standards by an additional 30 percent. The utilities would provide financial incentives directly to the manufacturers to produce the minimum number of units, which would "jump start" the market for high energy efficiency models.

These issues bring into question the assumption that Costa Rica should establish a full regulatory process for supporting energy efficiency. DSE is interested in proposing building energy codes and appliance standards. However, there may be other alternatives to achieve significant efficiency savings that acknowledge the limits to institutional and financial resources, which currently characterize the Costa Rican public sector. There may be a unique opportunity in Costa Rica for a less administratively complex and costly approach to obtaining refrigerator and electric stove efficiency because of the single manufacturing source for the majority of these appliances in Costa Rica.

As for building energy codes in the general sector, an ICE hookup standard that requires each new building design to be reviewed, combined with financial incentives for incremental construction costs and training of architects, may prove to be a cost-effective

alternative to establishing a more elaborate building energy code and enforcement procedure.

CHAPTER 6: CONCLUSIONS, RECOMMENDATIONS, AND ACTION PLAN

6.1 CONCLUSIONS AND RECOMMENDATIONS

6.1.1 The Demand Side

The forces driving the selection of energy conservation measures (ECMs) for a demand-side management program are low initial cost, simple installation, low replacement costs, and low maintenance. Low cost/no cost measures and lighting technologies are very attractive when weighed against these criteria. If incremental costs between the existing and energy-efficient technology or measure are offset, initial costs will become less important for measures with simple paybacks of more than two years.

All of the energy conservation measures discussed below are uncomplicated to specify and install, and those that are economically viable should be actively promoted. To achieve the penetration rates estimated in this study, it may be necessary to compensate the end-user for part or all of the incremental cost of the energy conservation technology. This means paying a portion of the cost differential between the technology currently in use and the recommended energy-saving technology. At the same time, establishing minimum energy efficiency standards would also assist in achieving the maximum conservation potential.

The recommended load management programs, which include the implementation of daylight savings time, interruptible tariffs, and commercial/industrial load management, would provide a peak demand savings of 183.6 MW in the year 2005. This is an 11 percent system peak demand reduction for the year 2005. The recommended energy-efficiency programs for the industrial, general, and residential sectors result in an estimated energy saving of 624 GWh in the year 2005. This is an energy saving of over 8 percent per year for the year 2005. Exhibit 6-1 shows the savings. The implementation of a full recommended DSM program (load control and energy conservation) would result in a peak demand reduction of 213 MW, or 12 percent of system peak for the year 2005. This represents a 16 percent reduction of the capacity requirements (1,298 MW) under the ICE expansion plan for 1990-2005.

The sections below provide discussions of the savings and costs associated with each ECM, and an estimate of the impact on ICE and on Costa Rica's balance of payments of a full load control and conservation program.

Exhibit 6-1
Estimated Demand Savings Under a Load Management Program and Estimated Energy Savings Under a Full DSM Program, 2005

Estimated Demand Savings Under a Load Management Program for the Year 2005	
Measure	Savings in MW
Daylight Savings Time	87.6
Interruptible Rates Program	69.0
C/I Load Control Program	27.0
Total	183.6

Estimated Energy Savings Under a Full DSM Program for the Industrial, General, and Residential Sectors for the Year 2005			
Sector	Consumption in GWh*	DSM Savings in GWh	DSM Savings in %
Industrial	2,171	323	15
General	1,350	123	9
Residential	4,319	177	4
Total	7,840	623	8

* Medium Scenario Forecast, ICE, 1989.

Peak Demand Savings from Load Management Measures

The most cost-effective program is the proposal to implement daylight savings time. This program can provide an estimated savings of 44.9 MW in 1990 and 87.6 MW in 2005 at the time of system peak, and requires minimal expenditures to implement. These savings are based on implementing the measures on an annual basis rather than a seasonal basis. The principal expenditure for implementing daylight savings time would be for the promotion costs associated with convincing the public of its merits. The cost of conserved demand for this program is estimated at US $0.26/kW.

The next two most cost-effective programs are the interruptible rates program and the commercial/industrial load control program. The implementation of an interruptible rate program could achieve peak demand savings of over 69 MW in 2005, and the savings that could be achieved by the commercial/industrial load control program are in the range of 27 MW. The costs of conserved demand for these programs are $4.28/kW and $13.14/kW, respectively.

The costs of conserved demand for the remaining programs are above the ICE-estimated avoided capacity cost. They range from $91.92/kW for the residential water heater load control program, to $99.59/kW for the residential time-of-use program, and to $102.12/kW for the residential refrigerator load control program.

The priorities for the continued development of a load management program for Costa Rica should be to: 1) adopt daylight savings time,[1] 2) implement a revised interruptible tariff, and 3) carry out a commercial/industrial load control program.

Energy and Demand Savings in the Industrial Sector

The total potential energy savings for the ECMs selected for the industrial sector is roughly estimated to be over 320 GWh in the year 2005. The reduction in peak demand is roughly estimated at 33 MW in 2005, based on assumed load and coincidence factors.

The low cost/no cost measures savings should be implemented first and represent the greatest savings (202 GWh and 15 peak MW in 2005). The savings resulting from the other conservation measures for the industrial sector reflect the implementation of the low/no cost measures first.

After the implementation of the low-no cost measures, the other low-cost measures (such as energy-efficient belts and some lighting technologies and ballasts) can probably be introduced with wide implementation on a voluntary basis, simply by active marketing. Because some of these measures provide a cost of conserved energy (CCE) that is close to US 0¢/kWh with a quick payback (less than six months), their acceptance can be based on maintenance savings alone. The utility should not have to "purchase" this conservation.

Energy-efficient motors represent the next-largest market for potential savings (94 GWh and roughly 14 peak MW in 2005), with an estimated CCE of 2.6¢/kWh. Energy-efficient

[1] During the preparation of this report, ICE implemented daylight savings time on a seasonal basis (dry season).

motors should be strongly promoted because their savings potential is an order of magnitude greater than that of any other measure. Industry confidence in energy-efficient motors is growing in the U.S., and Costa Rica can build upon this confidence. However, like electronic ballasts, energy-efficient motors have significant replacement costs, which may be a hindrance to their acceptance. Establishing minimum energy efficiency standards for this category of measures would be extremely helpful.

Variable speed drives have only limited application, with the average CCE being almost 19¢/kWh or more. There will be applications, however, for this technology in drives with large horsepower motors and long hours of operation. These applications will have to be evaluated on an individual basis. Because the CCE is so high on this ECM, significant effort to identify the segment of applicable drives can be postponed until the more attractive measures have been implemented.

The recommended priorities for continued development of a demand-side management (DSM) program for the industrial sector of Costa Rica should be to: 1) implement the low/no cost measures, and 2) promote energy efficient lighting technologies, belts, and motors through advertising campaigns and the establishment of minimum energy efficiency standards and codes if appropriate.

Energy and Demand Savings in the Residential and General Sectors

The overall estimated energy savings potential for the residential sector as a result of implementing the ECMs selected is estimated at about 139 GWh in the year 2005. The reduction in peak demand is estimated at roughly 23 MW in 2005, based on assumed load and coincidence factors.

The efficiency measures identified for the residential sector cover refrigeration, cooking, lighting, and water heating. Improving energy efficiency in refrigerators and cooking represents the most significant savings. The measures identified to improve the energy efficiency of the refrigerators could represent savings of 65 GWh, roughly 9 peak MW, for the year 2005. Savings for cooking through the use of spiral burners instead of the flat burners currently in use could represent savings of almost 65 GWh, roughly 11.6 peak MW. The potential for reducing cooking energy use with spiral burners is very large, but additional knowledge on performance and reliability is needed.

The use of solar energy for water heating has potentially important impacts, but some research and development is needed for these options. Lighting replacements for the residential sector will depend on the actual hours of use.

The uncertainty about the actual distribution of end uses of energy in the general sector precludes meaningful estimates of energy and demand savings. The level of knowledge about general sector energy end uses should be improved to facilitate demand-side planning efforts.

The overall estimated savings potential for the general sector for the year 2005 is estimated at about 124 GWh, roughly 14.7 peak MW. The two principal measures to be implemented are an energy management program and lighting technologies. The energy management program could achieve savings of 77 GWh, roughly 8 peak MW, for the year 2005. The lighting technologies could represent savings of over 46 GWh, or 6.8 peak MW. The potential savings for the general sector are tentative, but better field data and study of these buildings could indicate further potential savings.

The recommended priorities for the continued development of a demand-side management (DSM) program for the residential and general sectors of Costa Rica should be to: 1) identify methods for implementing water heater tank and refrigerator standards that reduce heat loss and increase efficiency, 2) determine the energy savings and durability possible with spiral burners, 3) investigate the actual and expected penetration of water heater tanks in the residential and general sectors, 4) implement an energy management program for the general sector, 5) promote-energy efficient lighting technologies for the residential and general sectors, 6) proceed with efforts to develop daylighting guidelines and standards for commercial buildings, 7) obtain better data on general sector electricity end uses, including detailed data on lighting equipment, 8) study the energy management equipment and methods most appropriate to commercial buildings, and 9) study the distribution of hours of use of residential incandescent lamps.

Impact on ICE and Balance of Payments of a DSM Program

The impact of a full demand-side management program (DSM), based on a simulation using the ELECTROPLAN model, produces a total saving of over 200 MW by the year 2005. This represents a reduction of about 12 percent in the system peak. However, of this total peak reduction, almost 50 percent (almost 90 MW) is attributable to the introduction of daylight savings time. Caution must be exercised, however, because daylight savings time amounts to a single one-hour shift, and the sharpest evening peak load is only about 1.5 hours in duration; the assumptions here are thus critical. The impact on energy generation requirements is an energy saving by 2005 on the order of 8 percent or over 600 GWh. Exhibit 6-2 shows the estimated real demand reductions for the full DSM program for the year 2005.

Exhibit 6-2
Estimated Peak Demand Reduction for a Full DSM Program for the Year 2005

	Peak Demand Savings
Total Savings from Load Management and Conservation	213 MW
Projected Peak Demand Before Conservation*	1743 MW
Projected Peak Demand Reduction	12%
New Capacity Requirements (1990-2005)**	1298 MW
Projected Capacity Savings with Full Program	16%

* Medium Scenario Forecast, ICE, 1989
** Medium Scenario Expansion Plan, ICE, 1989

The financial impact of the DSM plan on ICE is as follows:

Total investment	decreased by US $80 million
Foreign investment	decreased by US $56 million
DSM equip. imports	increased by US $19 million
Fuel imports	decreased by US $26 million
ICE revenue losses	increased by US $34 million
ICE administrative costs	increased by US $3 million
ICE income statement	increased by US $103 million

The above estimates are based on a net present value of financial flows to the year 2005 at a 12 percent discount rate. The total investment and associated foreign investment decrease as a result of the decrease in demand from conservation programs. The increase in DSM equipment imports results from the assumption that ICE would finance the incremental cost of the ECM. The fuel imports decrease is based on the ICE scenario of US $33/bbl for diesel in 2005, and is a result of the reduction in energy demand. The increase in ICE revenue losses is the result of the losses in electricity sales from the reduced energy demand. The increase in the ICE administrative costs is due to the assumption that ICE would finance all the associated DSM administrative and promotion costs. The end result of a full DSM program is a cash flow increase of $103 million in the year 2005.

The DSM program has three important impacts on the country's balance of payments:

1) reduced external debt service due to the defrayal of capacity expansion
2) reduced oil import bill due to energy savings
3) increase in the import bill associated with the need to import equipment for the ECM.

The impact of a DSM program on the balance of payments is substantial, with a saving of roughly $10 million in 2005 according to this scenario. Therefore, the net present value of the foreign exchange savings is 14 percent over the base case (no DSM program).

6.1.2 The Supply Side

The analysis of the generation, transmission, and distribution systems of ICE indicates that opportunities for improving the efficiency of existing equipment are very limited. This is essentially due to the overwhelming contribution of hydropower to energy production in Costa Rica and the fact that ICE hydroelectric plants are in good order and competently managed.

Thermal power plants have been used to provide energy on a seasonal basis only: less than 5 percent for most years over the operating history of the utility. Cost savings of approximately US $5 million per year can be achieved by ICE's current rehabilitation and a return to heavy oil, but it is questionable if this rehabilitation is cost effective with respect to new generation on the basis of economic analysis.

As a hydro-based utility, ICE has invested significant time and effort to optimize reservoir management. Maintenance for mechanical and electrical systems is well planned and executed. Performance and maintenance records indicate that plant performance has been maintained at adequate levels throughout the period of record, and that maintenance procedures have been followed on regular intervals. Opportunities for efficiency improvements in the hydro operation were investigated in three areas: mechanical-electrical equipment, civil works, and reservoir operation. A specific opportunity exists for increasing the output by 26 GWh per year through the repair of civil works at La Garita, but estimates of the cost of these repairs are not available.

ICE has continuously upgraded its transmission system in an effort to keep pace with the changes in load characteristics and the overall needs of the National Interconnected System. System upgrades have resulted in very high line reliability and relatively low line losses.

Distribution losses are higher, but certainly within acceptable margins for most of the distribution companies. Total system losses approximate 10.5 percent, with 2.6 percent attributable to transmission losses, and 8.7 percent to distribution losses.

Certainly, there is technical potential for line loss reduction in various transmission and distribution spurs. Determining the cost and benefits of such a potential does not lend itself to global approximation, however. Each line upgrade project must be evaluated separately, analyzing loading characteristics, the value of losses, and the costs of the improvements. The cost of line improvements is greatly dependent upon topography, and can vary by a factor of five. Due to these uncertainties, the transmission and distribution analysis noted the types of measures that could be taken to reduce line losses, including illustrative examples of the benefits of these measures (increasing voltage or line conductor upgrades). Without a comprehensive analysis of each distribution system, and a similar review of each major transmission link, it is impossible to accurately quantify the costs of line improvements, and the benefits those improvements might yield. It is, however, unlikely that improvements beyond those already planned by ICE would prove financially attractive.

The most promising area for efficiency improvements on the supply side is the planning of new generation capacity in light of the greater contribution that thermal generation will gradually have in meeting future energy demands. Two aspects must be considered: one is the large variety of closely competing thermal generation alternatives, and the other is the strategic operation of the hydroelectric system.

Advanced combustion turbines in both industrial and aeroderivative designs, combined-cycle combustion turbines, slow-speed diesel engines, and biomass conversion technologies should all be carefully considered and compared to conventional combustion turbines. As commercial experience grows with these technologies, and ICE's need for additional thermal capacity grows, these options should be analyzed by the planning and operations staff at ICE.

The strategic operation and planning of the hydroelectric system involve a delicate balance between the need to save as much fuel as possible in the thermal system by maximizing the energy production in years of normal hydrology while, at the same time, minimizing thermal investments by operating hydro reservoirs in a manner that will provide guaranteed hydroelectric energy during dry periods. This compromise between fuel and capital savings under uncertain conditions of both fuel cost and hydrology is a challenge that ICE planners must meet for an efficient and economic operation of their system.

It is recommended that a cost estimate for the repairs at La Garita be obtained and compared with the expected fuel savings due to additional hydro generation over the

lifetime of the project. Also, it is recommended that particular attention be given to the selection of thermal alternatives and the strategic operation and planning of the hydroelectric system.

6.2 DEMAND-SIDE ACTION PLAN

This action plan is a description of actions that is intended to serve as a basis for extensive discussions between Costa Rica and the study team to arrive at a set of concrete and specific technical and institutional recommendations to implement an IRP in Costa Rica.

6.2.1 Institutional Coordination and Program Evaluation

Goal: Carry out effectively an integrated resource plan.

Action 1: Strengthen DSE and ICE technical capabilities in evaluating and implementing demand-side management programs. This will involve a transfer of U.S. experience to Costa Rica.

Action 2: Develop program evaluation standards. An assessment and evaluation of current experience and needs in DSE and ICE should be conducted.

Action 3: Involve public and private sector institutions in a collaborative steering committee to discuss and analyze barriers and opportunities, and to make recommendations for specific actions. DSE should be the lead coordinating agency.

The development and implementation of an integrated resource plan (IRP) for Costa Rica will require the cooperation and participation of several key agencies, both public and private. DSE has already taken the lead in the coordination effort. It should continue to have a principal role, jointly with ICE. The IRP issues that must be addressed include:

- assessment of financial and personnel needs at DSE and ICE and other public agencies to implement the plan
- identification of priorities for action in each end-use sector
- identification of financing options and incentives for ICE and consumers
- selection of pilot/demonstration projects
- identification of needs for external financial and technical assistance
- data collection requirements
- identification of training needs
- selection of financial screening criteria for cost-benefit analyses of measures and programs.

In addition, a consensus much be reached on the criteria for evaluating the variety of conservation programs that will be designed and implemented. In general, conservation program evaluation should provide a rigorous basis for determining the market acceptance, economic impacts, and load impacts associated with program actions when compared to baseline conditions. Often, two types of evaluation need to be conducted: 1) an impact evaluation, which measures the energy saved, the costs (measure, administrative, marketing), and other quantifiable data such as the time it takes to design and implement the program; and 2) a process evaluation, which describes how the program operates and provides the subjective information necessary to understand the program and the reasons for its successes and problems. Where appropriate, program evaluation should include:

- Documentation of the program process, including all stages of the design, offer, market response, program management and marketing.

- A complete accounting of all costs associated with the program including: utility (or other operator) administration, financing costs, marketing, customer and third party out-of-pocket expenses, and other non-monetary burdens such as time spent by program beneficiaries.

- Measurement of changes in energy use that result from the program's operation. The measurement should be based on at least actual billing data, and be drawn from a subset of participants and non-participants, and sub-metering data in pre-and post program periods. Weather and use or business cycle adjustments should be made.

- Characterizations of the physical and behavioral attributes of both respondents and non-respondents to the program offering.

- Macroeconomic benefit-cost analysis of the program offering, including an assessment of economic impacts on affected customers, non-respondents, utilities, and the national economy.

6.2.2 New Buildings

Residential Sector Goal: Develop energy-efficient housing designs.

General Sector Goals:

1. Increase electricity efficiency in new commercial and public buildings.
2. Initiate research and demonstration of energy-efficient building techniques and technologies.
3. Build a data base on commercial electricity end-uses.
4. Assess the need to establish minimum building energy standards.

Action 1: Create an ongoing design workshop for housing designs that maximize both natural ventilation and daylighting potential. In addition, a design competition should be initiated among the professional and building communities to produce energy-efficient designs. Prizes should be awarded to the winners and their designs published.

Action 2: Prepare energy-efficiency information packets for developers.

Action 3: Review the institutional and financial requirements necessary to establish an energy building standard in Costa Rica, including a training, technical assistance, and enforcement program. The current U.S. ASHRAE 90.1 standard may serve as a useful model. Determine the appropriateness of establishing an energy code.

Action 4: Create an ongoing design workshop for establishing a set of new commercial and public building design and equipment guidelines for a variety of building categories. The workshop would include training for architects and builders in daylighting techniques, lighting system design, and control strategies.

Action 5: Sponsor a design competition for high energy-efficiency commercial and public buildings.

Action 6: Develop a data base of electrical end-uses in the commercial sector. Conduct some end-use metering projects for several building types to estimate baseline electricity use.

New housing construction continues to grow throughout the country, especially near San Jose and in several beach areas. The type of residential construction and its ventilation, cooling, heating, and lighting requirements will affect future electricity demand.

DSE has already recognized the value in passive ventilation design and daylighting design in new construction, and has proposed a design project with French government support. However, more information needs to be collected on current construction practices. Some of the housing designs are imported, and the use of air conditioning is increasing.

Most new buildings built today will last twenty years or longer. It is appropriate to capture all cost-effective conservation available in the construction of new commercial buildings in order to avoid lost opportunities and expensive retrofits. Baseline information on commercial end-uses is still limited. While some end-use energy consumption has been estimated (lighting), there are no meaningful estimates of whole building energy use for a variety of building types, or of the potential for efficiency from good building design, use of efficient glazings, and efficient central ventilating and air conditioning systems.

When new buildings are opened, energy management procedures should be established, especially in large buildings such as office, retail establishments, hotels, and government structures.

One method of managing new load growth in buildings is to establish building energy standards or codes. These standards can be performance based, which allows the designer to meet a goal with as much flexibility as possible for architectural design and power equipment selection. As discussed above, building codes require institutional support, financing and enforcement.

Other options for ensuring high levels of energy efficiency in new buildings, without establishing formal building codes are: 1) pre-qualified efficiency measures, especially for small/medium sized buildings, and 2) design assistance for architectural and engineering elements.

6.2.3 New Residential Appliances

Sector Goal: Assess the options for increasing appliance efficiency.

Action 1: Determine the appliances' actual electricity consumption through either direct measurements or information from a reliable source, and assess the existing institutions/laboratories in Costa Rica to carry out the measurements effectively.

Action 2: Define the financial incentives to the manufacturer and/or end-user that are necessary to promote higher-efficiency appliances through the new proposed law on rational energy use.

Action 3: Determine the economic and technical criteria and costs for establishing energy efficiency standards for refrigerators, electric stoves, electric hot water heaters, and air conditioners manufactured in or imported into Costa Rica. This will include elaborating proposals for establishing codes for each appliance, discussing with the manufacturers and importers of appliances the terms of the codes and efficiency levels, and the methodology for determining the energy consumption of each appliance. The latter would be obtained either through direct measurements or certified information from well-known manufacturers.

Action 4: Evaluate current national appliance efficiency labeling systems from various countries. Analyze the benefits of implementing a labeling system if standards are to be adopted.

Action 5: Review technical claims, cost-effectiveness, and market acceptability of the utilization of spiral burner heads for electric stoves. Conduct a pilot project in at least 100 homes to evaluate consumer response. If the analysis indicates a positive response, offer a program with financial incentives to replace the existing burner tops.

Energy-efficient appliances--especially refrigerators, electric stoves, and hot water heaters--represent major sources of conservation potential in Costa Rica's residential sector at present and in the future. Cost-effective technological improvements can be made to increase the efficiency of these appliances.

One option for increasing appliance efficiency is to establish minimum efficiency standards. Costa Rica can choose an existing standard (such as the forthcoming 1993 U.S. appliance standards) or develop a new one based on local conditions. If new standards are to be developed, a close working relationship between the appropriate government regulatory agency and the appliance manufacturing industry needs to be developed. Once standards are established, ongoing independent testing and certification procedures are required. In addition, a consumer rebate program and labelling program may be appropriate.

Another option for increasing appliance efficiency standards is for ICE to negotiate directly with the appliance manufacturers to establish a cost-effective level of efficiency for all units produced. ICE would then provide direct financial incentives to the manufacturer to offset the incremental costs of making the appliances more efficient. ICE could pay a lump sum or pay on a per-unit basis for a predetermined period until the market accepts the new price levels and financial support from ICE is no longer required. This approach would not require the establishment of a regulatory process, but would require that products be tested and certified. A consumer rebate program would not be necessary.

6.2.4 Existing Appliances

Sector Goals:

1. Provide education, technical, and financial assistance to ensure the efficient use of existing appliances.
2. Replace inefficient appliances with efficient ones.

Action 1: Continue with the ICETICO campaign, focusing on two themes. 1) existing appliances can be made to run optimally if they are properly maintained and repaired, and 2) the two critical areas for refrigerator maintenance are the door seals and the refrigerant system.

Action 2: Offer a program to provide new refrigerator door gaskets at no cost to the consumers. A public relations program with ICETICO can assist people in identifying the condition of their door seals. The seals can be distributed by ICE district offices and through the municipal utilities and cooperatives. Offer a second program that would provide at low cost (partially funded by ICE) a refrigerant check and recharging of the cooling system.

Action 3: Adjust the temperature of electric hot water heater tanks, e.g., to 120 degrees Fahrenheit, for residences participating in an ICETICO campaign to turn down the temperature of water heaters.

Action 4: Offer a no-cost service to insulate residential electric hot water heater tanks. The demand-side analysis indicates that at least 24,000 tanks should be insulated. Where possible, a bottom insulating board should be placed under the tank.

6.2.5 Existing Residential Lighting

Sector Goal: Install energy-efficient lamps in homes.

Action 1: Offer compact fluorescents at a competitive price (which still must be determined) to residences in Costa Rica. Contact various suppliers of compact fluorescent lamps to determine product availability and price. Develop a public relations program with ICETICO to prepare for launching the program. The program would be targeted to installing lamps throughout an entire community. This would provide excellent publicity for the program. Conduct sample billing analyses, pre- and post-relamping, for evaluation purposes.

Savings in energy use for lighting can be achieved through the use of more-efficient fluorescent lamps and the installation of compact fluorescent lamps (CF) to replace incandescent lamps.

The most effective method of installing the lamps is to have ICE make a wholesale purchase and then directly distribute the lamps to customers and to the other utilities (with delivery scheduled according to ICE's ability to distribute the lamps). ICE can pay for the lamps and recover all or a portion of the cost through customers' bills each month. ICE can calculate a payback amount equal to the monthly bill savings and keep the customers' bills the same until the required cost recovery is completed. CNFL, the municipal board, and cooperatives can assume delivery responsibilities in their own service territories.

6.2.6 Existing General Sector Lighting and Energy Management

Sector Goals:

1. Install more energy-efficient equipment in the sector.
2. Develop energy management training programs.

Action 1: Analyze the economic benefits of energy-efficient technology options. Inventory available equipment in the local market and select the most cost-effective combinations of equipment. Develop a program to finance entire building lighting retrofits. Conduct a pilot project on one public and one private-sector commercial building, and end-use meter the project for evaluation purposes.

Action 2: Develop a training curriculum for building energy managers. Procedures should include the identification of an energy coordinator, baseline energy use, an ongoing energy reporting system, an operation and maintenance checklist, and senior management briefings.

In order to make significant gains in general sector lighting efficiency, a comprehensive program to replace lamps, ballasts, and fixtures is required. Lighting rebate programs for individual bulb purchases are not efficient to manage. Larger-scale projects (whole building lamp, fixture and ballast) are more effective and result in greater savings. More information must be gathered about the availability of various lighting products in the market and various other conditions in the Costa Rican market.

Building owners and operators can utilize electricity more efficiently in their buildings and facilities by establishing regular operation and maintenance schedules. Building energy managers can be trained to optimize equipment operation. Savings from energy management activities can be significant.

6.2.7 Industrial Sector

Sector Goals:

1. Increase motor efficiency.
2. Increase process efficiency.

Action 1: Develop an industrial lighting program similar to that described in Action 1 for existing general sector buildings.

Action 2: Develop an industrial process energy efficiency program. This would include technical assistance on design engineering and plant modification or construction.

Action 4: Develop a comprehensive motor program that will include financial incentives for energy-efficient motors and efficient belts (synchronous and cogged V-belts). Develop a technical assistance program for motor control applications.

In Costa Rica, industrial electricity use is largely for motors. However, motors have different sizes and applications. There are also savings to be gained in some process use of electricity. Because of the variation of energy use in major industries, programs to reach both end-use and process efficiency are required.

6.2.8 Load Management Program

Sector Goal:	Reduce peak demand.
Action 1:	Evaluate the impact of implementing daylight savings time.
Action 2:	Carry out a detailed analysis on the impact of an interruptible tariff.
Action 3:	Assess the costs and benefits of a direct load control program, including a market study, an equipment analysis, and load and revenue impacts analyses.

Load management is a critical tool for ICE's management of its peak demand. In the A.I.D. load management study completed in 1989, a pilot project reduced peak loads in the project sample by over 14 percent. (ICE staff are continuing to work individually with customers on reducing their peak demands.) The study concluded that a full-scale load control program should be implemented; this program would result in a 35 MW annual demand reduction by the mid-1990s at a cost of $4-5 million. Three additional measures were recommended in this study: 1) change to daylight savings time, 2) implement direct load control for commercial and industrial customers, and 3) modify the existing interruptible tariff.

APPENDIX 1: CALCULATIONS FOR DAYLIGHT SAVINGS TIME PROGRAM

DEMAND CONTRIBUTION FOR THE PUBLIC LIGHTING SECTOR

Costa Rica's public lighting sector consumed 89,271 MWh in 1989. This represented approximately 3 percent of the total energy consumed in the country.

89,271 MWh / 365 days = 244.6 MWh/day

The average demand due to public lighting is:

244.6 MWh/day / 12 hrs/day = 20.4 MW

Source: Information on the consumption of the public lighting sector was obtained from the Direccion de Planification Electrica, Oficina de Tarifas y Mercado Electrico, "Informe Mensual Ventas de Energia - Acumulado," Diciembre 1989.

PROJECTIONS FOR THE IMPLEMENTATION OF DAYLIGHT SAVINGS TIME

YEAR	SYSTEM PROJECTED DEMAND (MW)	ANNUAL INCREASE (MW)	PERCENT INCREASE (%)	PUBLIC(1) LIGHTING CONSUMP-TION (GWH)	PUBLIC(2) LIGHTING COINCIDEN DEMAND (MW)(3)	RESIDENTIAL LIGHTING DEMAND REDUCTION (MW)(4)	PROJECTED PROGRAM SAVINGS (MW)
1987	612	--	--		--	--	
1988	613	1	0.2%	92	--	--	
1989	658	45	7.3%	94	20.4	22.5	42.9
1990	703	45	6.8%	96	20.8	24.0	44.9
1991	742	39	5.5%	98	21.3	25.4	46.6
1992	778	36	4.9%	100	21.7	26.6	48.3
1993	825	47	6.0%	102	22.1	28.2	50.3
1994	876	51	6.2%	104	22.6	30.0	52.5
1995	932	56	6.4%	106	23.0	31.9	54.9
1996	994	62	6.7%	108	23.4	34.0	57.4
1997	1064	70	7.0%	110	23.9	36.4	60.3
1998	1136	72	6.8%	112	24.3	38.8	63.2
1999	1214	78	6.9%	114	24.7	41.5	66.3
2000	1298	84	6.9%	117	25.4	44.4	69.8
2001	1380	82	6.3%	119	25.8	47.2	73.0
2002	1467	87	6.3%	121	26.3	50.2	76.4
2003	1558	91	6.2%	124	26.9	53.3	80.2
2004	1653	95	6.1%	126	27.3	56.5	83.9
2005	1743	90	5.4%	129	28.0	59.6	87.6

(1) Source: ICE Mercado Electrico, September 1989.

(2) See page 1 of this appendix for the calculation of public lighting coincident demand in 1989.

(3) Assumes that the ratio of public lighting peak demand to public lighting consumption remains constant.

(4) See page 3 of this appendix for the calculation of demand reduction in the residential sector.

ESTIMATED REDUCTION DUE TO IMPLEMENTATION OF DAYLIGHT SAVINGS TIME

Total consumption for residential sector in 1989 = 1,479 GWh

Illumination in the residential sector represents 20 percent of total residential consumption, or 295.8 GWh.

Assume that 75 percent of the residential lighting use occurs during the hours of 5 p.m. and 5 a.m.:

295.8 GWh x 75% = 221.85 GWh

Divide by 365 days per year:

221.85 GWh / 365 days per year = 607.8 MWh/day

Assume that two-thirds of the nighttime lighting consumption occurs during the hours of 5 p.m. to 11 p.m.:

607.8 GWh x 2/3 = 405.2 MWh

Then the average demand during the six-hour period of 5-11 p.m. is:

405.2 MWh / 6 hrs = 67.5 MW average

Assuming that only one-third of this load is shifted, then the residential sector lighting reduction is:

<u>22.5 MW at the time of system peak.</u>

1973 DAYLIGHT SAVINGS TIME ANALYSIS

In an analysis performed on the load profiles in 1973 comparing the load during the week of May 21 to May 27, 1973 (on daylight savings time) to the week of May 28 to June 2, 1973 (without daylight savings time), the following observation can be made:

Average peak load, May 28 to June 2, 1973	=	204.6 MW
Average peak load, May 21 to May 27, 1973	=	184.5 MW
Difference in peak demand	=	20.1 MW
Based on a maximum demand of 208 MW	=	9.66% reduction.

Based on this analysis, the earlier estimate is very conservative.

SUPPLY CURVE CALCULATION FOR IMPLEMENTATION OF DAYLIGHT SAVINGS TIME

Assumptions:

Program	6	Incentives	$0.00 per kW
Cost of Equipment	$0 per customer	Conserved Demand	1000.00 kW per customer
Installation Cost	$0 per customer	Fixed Costs Begin	1990
O&M Costs	$0 per customer	Real Discount Rate	12%
Salaries	$15,000 per year	Tax Rate	0%
Promotion Costs	$0 per year		

Calculations:

YEAR	# OF NEW CUST.	CUM CUST	ANNUAL MW	CUM. MW	EQUIPT. COSTS	INSTALL COSTS	SALARIES	PROMO. COSTS	O&M	TOTAL ANNUAL IMPLEMENT. COSTS	ANNUAL INCREM. COSTS	MARGINAL COST OF CONSERV. DEMAND ($/KW)	CUM NPV COST OF CONSERV. DEMAND ($/KW)
1990	44.9	44.9	44.9	44.9	$0	$0	$15,000	$0	$0	$15,000	$15,000	$0	$0.33
1991	1.7	46.6	1.7	46.6	$0	$0	$15,000	$0	$0	$15,000	$15,000	$9	$0.33
1992	1.7	48.3	1.7	48.3	$0	$0	$15,000	$0	$0	$15,000	$15,000	$9	$0.32
1993	2	50.3	2.0	50.3	$0	$0	$15,000	$0	$0	$15,000	$15,000	$8	$0.32
1994	2.2	52.5	2.2	52.5	$0	$0	$15,000	$0	$0	$15,000	$15,000	$7	$0.31
1995	2.4	54.9	2.4	54.9	$0	$0	$15,000	$0	$0	$15,000	$15,000	$6	$0.31
1996	2.5	57.4	2.5	57.4	$0	$0	$15,000	$0	$0	$15,000	$15,000	$6	$0.30
1997	2.9	60.3	2.9	60.3	$0	$0	$15,000	$0	$0	$15,000	$15,000	$5	$0.30
1998	2.9	63.2	2.9	63.2	$0	$0	$15,000	$0	$0	$15,000	$15,000	$5	$0.29
1999	3.1	66.3	3.1	66.3	$0	$0	$15,000	$0	$0	$15,000	$15,000	$5	$0.29
2000	3.5	69.8	3.5	69.8	$0	$0	$15,000	$0	$0	$15,000	$15,000	$4	$0.28
001	3.2	73	3.2	73.0	$0	$0	$15,000	$0	$0	$15,000	$15,000	$5	$0.28
002	3.4	76.4	3.4	76.4	$0	$0	$15,000	$0	$0	$15,000	$15,000	$4	$0.27
003	3.8	80.2	3.8	80.2	$0	$0	$15,000	$0	$0	$15,000	$15,000	$4	$0.27
004	3.7	83.9	3.7	83.9	$0	$0	$15,000	$0	$0	$15,000	$15,000	$4	$0.27
005	3.7	87.6	3.7	87.6	$0	$0	$15,000	$0	$0	$15,000	$15,000	$4	$0.26
NPV				446						$117,163			

Results:

Cost of Conserved Demand — Annualized Implementation Costs/Annualized Conserved kW Demand

Cost of Conserved Demand — $\frac{\text{(PV Implementation Costs) x (Capital Recovery Factor)}}{\text{(PV Conserved KWD) x (Capital Recovery Factor)}}$

Cost of Conserved Demand — $\frac{\text{($117163) x (0.1468)}}{\text{(445743 kW) x (0.1468)}}$

Cost of Conserved Demand = $0.26 per kW per year

APPENDIX 2: CALCULATIONS FOR COMMERCIAL/INDUSTRIAL INTERRUPTIBLE RATE PROGRAM

POTENTIAL MARKET

1987 -- Population of large commercial/industrial customers is defined as customers with monthly consumption levels of 20,000 kWh or maximum demand exceeding 100 kW. This customer segment consists of approximately 425 accounts with a 1987 aggregate demand of 175 MW and a coincident load of 122.5 MW, or about 20 percent of the coincident system peak.

1987 Maximum Demand	=	612 MW
1987 Target Market	=	425 Accounts
1989 Maximum Demand	=	658 MW
1988 Target Market:		
425 accounts x 1.075	=	457 Accounts
1989 Target Market:		
457 accounts x 1.047	=	478 Accounts
1987 Aggregate Demand of Target Market	=	175 MW
1989 Aggregate Demand of Target Market:		
175 MW x 1.07516	=	188 MW
1987 Coincident Demand of Target Market	=	122.5 MW
1989 Coincident Demand of Target Market:		
122.5 MW x 1.07516	=	132 MW

POTENTIAL REDUCTION FROM INTERRUPTIBLE RATE PROGRAM

The potential reduction achievable from an interruptible rate program has been determined to be approximately 40 percent from site visits performed for a sample of customers.

Interruptible Rate Potential	(40 percent)	52.8 MW

Information on the 1987 target market was obtained from the *Costa Rica Load Control Demonstration Project*, final report.

PROJECTIONS FOR AN INTERRUPTIBLE RATE PROGRAM

The target market for this program consists of customers with demands of over 100 kW or consumption over 20,000 kWh/month.

YEAR	SYSTEM PROJECTED DEMAND (MW)	ANNUAL INCREASE (MW)	PERCENT INCREASE (%)	TARGET(1) MARKET (# CUST.)	TARGET(2) MARKET COINCIDENT DEMAND* (MW)	INTERRUPTIBLE RATES PROGRAM POTENTIAL: MAXIMUM POTEN-TIAL(3) (40%) (MW)	INTERRUPTIBLE RATES PROGRAM POTENTIAL: PROJECTED PENETRA-TION (20%) (MW)	PERCENT PROGRAM REDUC-TION(4) (%)	PROPOSED PROGRAM IMPLEMEN-TATION(5) (MW)
1987	612	--	--	425	122.5	---	---		---
1988	613	1	0.2%	457	127.0	---	---		---
1989	658	45	7.3%	478	132.0	52.8	26.4	20.0%	---
1990	703	45	6.8%	509	140.6	56.2	28.1	20.0%	---
1991	742	39	5.5%	538	148.4	59.4	29.7	20.0%	2
1992	778	36	4.9%	564	155.6	62.2	31.1	20.0%	4
1993	825	47	6.0%	598	165.0	66.0	33.0	20.0%	8
1994	876	51	6.2%	635	175.2	70.1	35.0	20.0%	13
1995	932	56	6.4%	675	186.4	74.6	37.3	20.0%	18
1996	994	62	6.7%	720	198.8	79.5	39.8	20.0%	23
1997	1064	70	7.0%	771	212.8	85.1	42.6	20.0%	29
1998	1136	72	6.8%	823	227.2	90.9	45.4	20.0%	37
1999	1214	78	6.9%	880	242.8	97.1	48.6	20.0%	44
2000	1298	84	6.9%	941	259.6	103.8	51.9	20.0%	51
2001	1380	82	6.3%	1000	276.0	110.4	55.2	20.0%	55
2002	1467	87	6.3%	1063	293.4	117.4	58.7	20.0%	58
2003	1558	91	6.2%	1129	311.6	124.6	62.3	20.0%	62
2004	1653	95	6.1%	1198	330.6	132.2	66.1	20.0%	66
2005	1743	90	5.4%	1263	348.6	139.4	69.7	20.0%	69

(1) Assumes that the average demand (kW) per customer remains constant at 276 kW/customer.

(2) Assumes that the ratio of target market peak to system peak remains at approximately 20 percent.

(3) Average reduction of 110 kW per participant.

(4) Program reduction as a percent of the total target market coincident demand.

(5) The implementation plan assumes that all interested participants can be signed up on the interruptible rate by the year 2000. Then, the utility will continue to obtain participants from new customers coming into the system. Note that a more aggressive schedule can be achieved, if desirable, to defer a specific power plant.

APPENDIX 3: CALCULATIONS FOR COMMECIAL/INDUSTRIAL LOAD CONTROL PROGRAM

POTENTIAL MARKET

Customers with demand between 10 kW and 100 kW:

Utility	Total Industrial	Total General	Ind./Gen. 10 kW to 100 kW
ICE	3,483*	26,010	1,800**
CNFL	2,314	29,875	1,963
Others	1,776	13,022	903
Totals	7,573	68,907	4,666

* Source: Information on the number of customers for each sector was obtained from the Direccion de Planificacion Electrica, Oficina de Tarifas y Mercado Electrico, "Informe Mensual Ventas de Energia -- Acumulado," Diciembre, 1989.

** Source: "Creacion de la Unidad Ejecutora del Projecto para la Administracion de la Demanda de Energia," prepared by ICE, 1989.

PROJECTIONS FOR A SMALL COMMERCIAL AND INDUSTRIAL LOAD CONTROL PROGRAM

The target market for this program is customers with demands between 10 and 100 kW or consumption over 3,000 kWh/month.

YEAR	PROJECTED DEMAND (MW)	ANNUAL INCREASE (MW)	PERCENT INCREASE (%)	TARGET MARKET (NUMBER OF CUST.)	COINCIDENT DEMAND (MW)	PROJECTED PENETRA-TION (15%) (MW)	MAXIMUM POTEN-TIAL (30%) (MW)	PROPOSED PROGRAM IMPLEMEN-TATION (MW)
1987	612	--	--	--	--	---	---	---
1988	613	1	0.2%	--	--	---	---	---
1989	658	45	7.3%	4666	69.5	10.4	21.2	---
1990	703	45	6.8%	4968	74.5	11.2	22.7	---
1991	742	39	5.5%	5243	78.7	11.8	24.0	---
1992	778	36	4.9%	5498	82.5	12.4	25.2	1
1993	825	47	6.0%	5830	87.5	13.1	26.7	2
1994	876	51	6.2%	6190	92.9	13.9	28.3	4
1995	932	56	6.4%	6586	98.8	14.8	30.1	6
1996	994	62	6.7%	7024	105.4	15.8	32.1	8
1997	1064	70	7.0%	7519	112.8	16.9	34.4	10
1998	1136	72	6.8%	8028	120.4	18.1	36.7	13
1999	1214	78	6.9%	8579	128.7	19.3	39.2	16
2000	1298	84	6.9%	9173	137.6	20.6	42.0	19
2001	1380	82	6.3%	9752	146.3	21.9	44.6	22
2002	1467	87	6.3%	10367	155.5	23.3	47.4	24
2003	1558	91	6.2%	11010	165.1	24.8	50.4	25
2004	1653	95	6.1%	11681	175.2	26.3	53.4	26
2005	1743	90	5.4%	12317	184.8	27.7	56.4	27

(1) Assumes that the ratio of target market peak demand to system peak demand remains at approximately 10.6 percent.

(2) Assumes that the average demand (kW) per customer remains at approximately 15 kW/customer.

SUPPLY CURVE CALCULATION FOR IMPLEMENTATION OF LOAD CONTROL PROGRAM

Assumptions:

Program	2	Incentives	$0.00 per kW
Cost of Equipment	$75 per customer	Conserved Demand	5.00 kW per customer
Installation Cost	$50 per customer	Fixed Costs Begin	1992
O&M Costs	$15 per customer	Real Discount Rate	12%
Salaries	$50,000 per year	Tax Rate	0%
Promotion Costs	$10,000 per year		

Calculations:

YEAR	# OF NEW CUST.	CUM CUST	ANNUAL MW	CUM. MW	EQUIPT. COSTS	INSTALL COSTS	SALARIES	PROMO. COSTS	O&M	TOTAL ANNUAL IMPLEMENT. COSTS	ANNUAL INCREM. COSTS	MARGINAL COST OF CONSERV. DEMAND ($/KW)	CUM NPV COST OF CONSERV. DEMAND ($/KW)
1990	0	0	0.0	0.0	$0	$0	$0	$0	$0	$0	$0	NA	NA
1991	0	0	0.0	0.0	$0	$0	$0	$0	$0	$0	$0	NA	NA
1992	200	200	1.0	1.0	$15,000	$10,000	$50,000	$10,000	$3,000	$88,000	$88,000	$88	$88.00
1993	200	400	1.0	2.0	$15,000	$10,000	$50,000	$10,000	$6,000	$91,000	$91,000	$91	$60.76
1994	400	800	2.0	4.0	$30,000	$20,000	$50,000	$10,000	$12,000	$122,000	$122,000	$61	$44.61
1995	400	1200	2.0	6.0	$30,000	$20,000	$50,000	$10,000	$18,000	$128,000	$128,000	$64	$34.91
1996	400	1600	2.0	8.0	$30,000	$20,000	$50,000	$10,000	$24,000	$134,000	$134,000	$67	$28.88
1997	400	2000	2.0	10.0	$30,000	$20,000	$50,000	$10,000	$30,000	$140,000	$140,000	$70	$24.86
1998	600	2600	3.0	13.0	$45,000	$30,000	$50,000	$10,000	$39,000	$174,000	$174,000	$58	$22.12
1999	600	3200	3.0	16.0	$45,000	$30,000	$50,000	$10,000	$48,000	$183,000	$183,000	$61	$19.90
2000	600	3800	3.0	19.0	$45,000	$30,000	$50,000	$10,000	$57,000	$192,000	$192,000	$64	$18.13
2001	600	4400	3.0	22.0	$45,000	$30,000	$50,000	$10,000	$66,000	$201,000	$201,000	$67	$16.72
2002	400	4800	2.0	24.0	$30,000	$20,000	$50,000	$10,000	$72,000	$182,000	$182,000	$91	$15.50
2003	200	5000	1.0	25.0	$15,000	$10,000	$50,000	$10,000	$75,000	$160,000	$160,000	$160	$14.50
2004	200	5200	1.0	26.0	$15,000	$10,000	$50,000	$10,000	$78,000	$163,000	$163,000	$163	$13.74
2005	200	5400	1.0	27.0	$15,000	$10,000	$50,000	$10,000	$81,000	$166,000	$166,000	$166	$13.14
NPV				62						$819,239			

Results:

Cost of Conserved Demand — Annualized Implementation Costs/Annualized Conserved kW Demand

Cost of Conserved Demand — (PV Implementation Costs) x (Capital Recovery Factor) / (PV Conserved KWD) x (Capital Recovery Factor)

Cost of Conserved Demand — ($819239) x (0.1468) / (62349 kW) x (0.1468)

Cost of Conserved Demand = $13.14 per kW per year

APPENDIX 4: CALCULATIONS FOR WATER HEATER LOAD CONTROL PROGRAM

POTENTIAL REDUCTION

The saturation of water heater tanks is approximately 4 percent. Based on the number of residential customers in 1989:

552,193 residential customers x 4 percent = 22,088 customers

Potential reduction:

22,088 customers x .25 kW/customer = 5,522 kW

The "Encuesta de Opinion Sobre el Consumo Energetico en el Sector Residencial Urbano" revealed a 13.34 percent saturation of electric water heater tanks in the urban areas. Based on this information, the potential reduction would be as follows:

1989 residential customers = 552,193

46.3 percent urban:

552,193 customers x 46.3 percent = 255,665 customers

13.34 percent have water heater tanks:

255,655 customers x 13.34 percent = 34,106 water heater customers

Potential reduction:

34,106 water heater customers x .25 kW/customer = 8.53 MW

PROJECTIONS FOR A RESIDENTIAL WATER HEATER LOAD CONTROL PROGRAM

The target market for this program is customers with electric water heater tanks, which represent an estimated 4 percent of the total residential sector and an estimated 13 percent of the urban residences.

YEAR	SYSTEM PROJECTED DEMAND (MW)	ANNUAL INCREASE (MW)	PERCENT INCREASE (%)	PROJECTED RESIDENTIAL CUSTOMERS (# OF CUST)	TARGET MARKET (NUMBER OF CUST.) (4%RES)	(13%URB)	WH TANKS (4%RES) COINCIDENT DEMAND (MW)	WH TANKS (13%URB) COINCIDENT DEMAND (MW)	PROPOSED PROGRAM IMPLEMEN-TATION (MW)
1987	612	--	--			--	--	--	--
1988	613	1	0.2%	518,854		--	--	--	--
1989	658	45	7.3%	552,193	22,088	34,106	5.5	8.5	--
1990	703	45	6.8%	563,697	22,548	35,042	5.6	8.8	--
1991	742	39	5.5%	586,222	23,449	36,755	5.9	9.2	--
1992	778	36	4.9%	609,565	24,383	38,462	6.1	9.6	--
1993	825	47	6.0%	633,894	25,356	40,336	6.3	10.1	--
1994	876	51	6.2%	660,507	26,420	42,382	6.6	10.6	1
1995	932	56	6.4%	686,795	27,472	44,343	6.9	11.1	2
1996	994	62	6.7%	714,045	28,562	46,484	7.1	11.6	3
1997	1064	70	7.0%	744,084	29,763	48,737	7.4	12.2	5
1998	1136	72	6.8%	773,543	30,942	51,079	7.7	12.8	7
1999	1214	78	6.9%	804,254	32,170	53,429	8.0	13.4	9
2000	1298	84	6.9%	838,094	33,524	56,124	8.4	14.0	11
2001	1380	82	6.3%	866,028	34,641	58,342	8.7	14.6	13
2002	1467	87	6.3%	894,936	35,797	60,767	8.9	15.2	14
2003	1558	91	6.2%	924,857	36,994	63,168	9.2	15.8	15
2004	1653	95	6.1%	953,349	38,134	65,623	9.5	16.4	16
2005	1743	90	5.4%	972,892	38,916	67,488	9.7	16.9	16

(1) Assumes that the ratio of target market peak demand to system peak demand remains at approximately 1 percent.
(2) Assumes that the average coincident demand per customer from electric water heaters is 0.25 kW/customer.
(3) Assumes that this sector consists of number of residential customers from the "Mercado Electrico," ICE, September 1989.
(4) Uses the projections from DSE for the percentage of urban customers.

SUPPLY CURVE CALCULATION FOR IMPLEMENTATION OF RESIDENTIAL WATER HEATER LOAD CONTROL

Assumptions:

Program	3	Incentives	$0.00 per kW
Cost of Equipment	$65 per customer	Conserved Demand	0.25 kW per customer
Installation Cost	$40 per customer	Fixed Costs Begin	1994
O&M Costs	$2 per customer	Real Discount Rate	12%
Salaries	$25,000 per year	Tax Rate	0%
Promotion Costs	$10,000 per year		

Calculations:

YEAR	# OF NEW CUST.	CUM CUST	ANNUAL MW	CUM. MW	EQUIPT. COSTS	INSTALL COSTS	SALARIES	PROMO. COSTS	O&M	TOTAL ANNUAL IMPLEMENT. COSTS	ANNUAL INCREM. COSTS	MARGINAL COST OF CONSERV. DEMAND ($/KW)	CUM NPV COST OF CONSERV. DEMAND ($/KW)
1990	0	0	0.0	0.0	$0	$0	$0	$0	$0	$0	$0	NA	NA
1991	0	0	0.0	0.0	$0	$0	$0	$0	$0	$0	$0	NA	NA
1992	0	0	0.0	0.0	$0	$0	$0	$0	$0	$0	$0	NA	NA
1993	0	0	0.0	0.0	$0	$0	$0	$0	$0	$0	$0	NA	NA
1994	4000	4000	1.0	1.0	$260,000	$160,000	$25,000	$10,000	$8,000	$463,000	$463,000	$463	$463.00
1995	4000	8000	1.0	2.0	$260,000	$160,000	$25,000	$10,000	$16,000	$471,000	$471,000	$471	$317.17
1996	4000	12000	1.0	3.0	$260,000	$160,000	$25,000	$10,000	$24,000	$479,000	$479,000	$479	$244.41
1997	8000	20000	2.0	5.0	$520,000	$320,000	$25,000	$10,000	$40,000	$915,000	$915,000	$458	$219.39
1998	8000	28000	2.0	7.0	$520,000	$320,000	$25,000	$10,000	$56,000	$931,000	$931,000	$466	$190.24
1999	8000	36000	2.0	9.0	$520,000	$320,000	$25,000	$10,000	$72,000	$947,000	$947,000	$474	$166.51
2000	8000	44000	2.0	11.0	$520,000	$320,000	$25,000	$10,000	$88,000	$963,000	$963,000	$482	$148.07
2001	8000	52000	2.0	13.0	$520,000	$320,000	$25,000	$10,000	$104,000	$979,000	$979,000	$490	$133.68
2002	4000	56000	1.0	14.0	$260,000	$160,000	$25,000	$10,000	$112,000	$567,000	$567,000	$567	$118.80
2003	4000	60000	1.0	15.0	$260,000	$160,000	$25,000	$10,000	$120,000	$575,000	$575,000	$575	$108.13
2004	4000	64000	1.0	16.0	$260,000	$160,000	$25,000	$10,000	$128,000	$583,000	$583,000	$583	$100.10
2005	0	64000	0.0	16.0	$0	$0	$25,000	$10,000	$128,000	$163,000	$163,000	NA	$91.92
NPV				32						$2,953,474			

Results:

Cost of Conserved Demand — Annualized Implementation Costs/Annualized Conserved kW Demand

Cost of Conserved Demand — $\frac{\text{(PV Implementation Costs) x (Capital Recovery Factor)}}{\text{(PV Conserved KWD) x (Capital Recovery Factor)}}$

Cost of Conserved Demand — $\frac{\text{($2953474) x (0.1468)}}{\text{(32132 kW) x (0.1468)}}$

Cost of Conserved Demand = $91.92 per kW per year

APPENDIX 5: CALCULATIONS FOR RESIDENTIAL TIME-OF-USE PROGRAM

SUPPLY CURVE CALCULATION FOR IMPLEMENTATION OF RESIDENTIAL TIME-OF-USE PROGRAM

Assumptions:

Prograr	5	Incentives	$0.00 per kW
Cost of Equipment	$140 per customer	Conserved Demand	0.35 kW per customer
Installation Cost	$35 per customer	Fixed Costs Begin	1994
O&M Costs	$2 per customer	Real Discount Rate	12%
Salaries	$25,000 per year	Tax Rate	0%
Promotion Costs	$10,000 per year		

Calculations:

YEAR	# OF NEW CUST.	CUM CUST	ANNUAL MW	CUM. MW	EQUIPT. COSTS	INSTALL COSTS	SALARIES	PROMO. COSTS	O&M	TOTAL ANNUAL IMPLEMENT. COSTS	ANNUAL INCREM. COSTS	MARGINAL COST OF CONSERV. DEMAND ($/KW)	CUM NPV COST OF CONSERV. DEMAND ($/KW)
1990	0	0	0.0	0.0	$0	$0	$0	$0	$0	$0	$0	NA	NA
1991	0	0	0.0	0.0	$0	$0	$0	$0	$0	$0	$0	NA	NA
1992	0	0	0.0	0.0	$0	$0	$0	$0	$0	$0	$0	NA	NA
1993	0	0	0.0	0.0	$0	$0	$0	$0	$0	$0	$0	NA	NA
1994	4000	4000	1.4	1.4	$560,000	$140,000	$25,000	$10,000	$8,000	$743,000	$743,000	$531	$530.71
1995	4000	8000	1.4	2.8	$560,000	$140,000	$25,000	$10,000	$16,000	$751,000	$751,000	$536	$362.45
1996	4000	12000	1.4	4.2	$560,000	$140,000	$25,000	$10,000	$24,000	$759,000	$759,000	$542	$278.50
1997	8000	20000	2.8	7.0	$1,120,000	$280,000	$25,000	$10,000	$40,000	$1,475,000	$1,475,000	$527	$250.88
1998	8000	28000	2.8	9.8	$1,120,000	$280,000	$25,000	$10,000	$56,000	$1,491,000	$1,491,000	$533	$217.57
1999	8000	36000	2.8	12.6	$1,120,000	$280,000	$25,000	$10,000	$72,000	$1,507,000	$1,507,000	$538	$190.22
2000	8000	44000	2.8	15.4	$1,120,000	$280,000	$25,000	$10,000	$88,000	$1,523,000	$1,523,000	$544	$168.89
2001	5000	49000	1.8	17.2	$700,000	$175,000	$25,000	$10,000	$98,000	$1,008,000	$1,008,000	$576	$148.14
2002	1000	50000	0.4	17.5	$140,000	$35,000	$25,000	$10,000	$100,000	$310,000	$310,000	$886	$129.03
2003	2000	52000	0.7	18.2	$280,000	$70,000	$25,000	$10,000	$104,000	$489,000	$489,000	$699	$116.79
2004	1000	53000	0.4	18.6	$140,000	$35,000	$25,000	$10,000	$106,000	$316,000	$316,000	$903	$106.99
2005	1000	54000	0.4	18.9	$140,000	$35,000	$25,000	$10,000	$108,000	$318,000	$318,000	$909	$99.59
NPV				42						$4,190,239			

Results:

Cost of Conserved Demand — Annualized Implementation Costs/Annualized Conserved kW Demand

Cost of Conserved Demand — (PV Implementation Costs) x (Capital Recovery Factor) / (PV Conserved KWD) x (Capital Recovery Factor)

Cost of Conserved Demand — ($4190239) x (0.1468) / (42075 kW) x (0.1468)

Cost of Conserved Demand = $99.59 per kW per year

APPENDIX 6: CALCULATIONS FOR RESIDENTIAL REFRIGERATOR LOAD CONTROL PROGRAM

POTENTIAL REDUCTION

Refrigeration represents 23 percent of the total electric consumption of the residential sector.

The total electrical consumption in 1989 was 1,458,430 MWh for the residential sector.

The corresponding consumption for residential refrigeration in 1989 was:

1,458,430 MWh x 23 percent = 335,438 MWh

The average demand due to residential refrigeration was:

335,438,000 kWh / 8760 hrs/year = 38.298 MW

Assuming a load factor of 80 percent for refrigerators, then the maximum demand would be:

$$\frac{38.3 \text{ MW}}{\text{Max. Demand}} = 80 \text{ percent load factor}$$

Maximum Demand = 47.9 MW

Source: Direccion Sectorial de Energia, fax from Giovanni Castillo dated April 9, 1990.

PROJECTIONS FOR A RESIDENTIAL REFRIGERATOR LOAD CONTROL PROGRAM

The potential target market for this program is customers with refrigerators, which represent an estimated 54 percent of the total residential sector.

YEAR	PROJECTED DEMAND (MW)	ANNUAL INC. (MW)	PERCENT INC. (%)	PROJECTED RESIDENTIAL CUSTOMERS (# OF CUST)	TARGET MARKET (NUMBER OF CUST.) (54%RES)	(DSE #'s)*	REFRIG. (54%RES) COINCIDENT DEMAND (MW)	REFRIG. (DSE #'s)* COINCIDENT DEMAND (MW)	PROPOSED PROGRAM IMPLEMENTATION (MW)	PROPOSED PROGRAM PATICIPANTS (# CUST.)	POTENTIAL PROGRAM PATICIPANTS (# CUST.)	POTENTIA PROGRAM REDUCTIONS (MW)
1987	612	-	-	--	--	--	--	--	--	--	--	--
1988	613	1	0.2%	518,854	--	--	--	--	--	--	--	--
1989	658	45	7.3%	552,193	299,289	--	47.9	--	--	--	30,370	6.1
1990	703	45	5.8%	563,697	305,524	417,998	48.9	66.9	--	--	31,003	6.2
1991	742	39	5.5%	586,222	317,732	441,406	50.8	70.6	--	--	32,242	6.4
1992	778	36	4.9%	609,565	330,384	466,125	52.9	74.6	--	--	33,525	6.7
1993	825	47	6.0%	633,894	343,571	492,228	55.0	78.8	--	--	34,863	7.0
1994	876	51	6.2%	660,507	357,995	519,792	57.3	83.2	--	--	36,327	7.3
1995	932	56	6.4%	686,795	372,243	548,355	59.6	87.7	0.8	4,000	37,773	7.6
1996	994	62	6.7%	714,045	387,012	576,047	61.9	92.2	1.6	8,000	39,272	7.9
1997	1064	70	7.0%	744,084	403,294	605,137	64.5	96.8	2.4	12,000	40,924	8.2
1998	1136	72	6.8%	773,543	419,260	635,697	67.1	101.7	4.0	20,000	42,544	8.5
1999	1214	78	6.9%	804,254	435,906	667,799	69.7	106.8	5.6	28,000	44,233	8.8
2000	1298	84	6.9%	838,094	454,247	701,429	72.7	112.2	7.2	36,000	46,094	9.2
2001	1380	82	6.3%	866,028	469,387	735,799	75.1	117.7	8.8	44,000	47,631	9.5
2002	1467	87	6.3%	894,936	485,055	771,853	77.6	123.5	9.8	49,000	49,220	9.8
2003	1558	91	6.2%	924,857	501,272	809,674	80.2	129.5	10.0	50,000	50,866	10.2
2004	1653	95	6.1%	953,349	516,715	849,348	82.7	135.9	10.4	52,000	52,433	10.5
2005	1743	90	5.4%	972,892	527,307	890,445	84.4	142.5	10.6	53,000	53,508	10.7

(1) Assumes that the average coincident demand per customer from electric refrigerators is 0.16 kW/customer.

(2) Assumes that the average coincident demand per customer from refrigerators, for consumers above 500 kWh/month, is 0.4 kW/customer.

(3) Assumes that this sector consists of number of residential customers from the "Mercado Electrico," ICE, September 1989.

(4) Uses the projections from DSE for the percentage of urban customers.

(5) Number of electric refrigerators obtaine from DSE on April 3, 1990.

SUPPLY CURVE CALCULATION FOR IMPLEMENTATION OF RESIDENTIAL REFRIGERATOR LOAD CONTROL

Assumptions:

Program	4	Incentives	$0.00 per kW
Cost of Equipment	$65 per customer	Conserved Demand	0.20 kW per customer
Installation Cost	$30 per customer	Fixed Costs Begin	1994
O&M Costs	$2 per customer	Real Discount Rate	12%
Salaries	$25,000 per year	Tax Rate	0%
Promotion Costs	$10,000 per year		

Calculations:

YEAR	# OF NEW CUST.	CUM CUST	ANNUAL MW	CUM. MW	EQUIPT. COSTS	INSTALL COSTS	SALARIES	PROMO. COSTS	O&M	TOTAL ANNUAL IMPLEMENT. COSTS	ANNUAL INCREM. COSTS	MARGINAL COST OF CONSERV. DEMAND ($/KW)	CUM NPV COST OF CONSERV. DEMAND ($/KW)
1990	0	0	0.0	0.0	$0	$0	$0	$0	$0	$0	$0	NA	NA
1991	0	0	0.0	0.0	$0	$0	$0	$0	$0	$0	$0	NA	NA
1992	0	0	0.0	0.0	$0	$0	$0	$0	$0	$0	$0	NA	NA
1993	0	0	0.0	0.0	$0	$0	$0	$0	$0	$0	$0	NA	NA
1994	4000	4000	0.8	0.8	$260,000	$120,000	$25,000	$10,000	$8,000	$423,000	$423,000	$529	$528.75
1995	4000	8000	0.8	1.6	$260,000	$120,000	$25,000	$10,000	$16,000	$431,000	$431,000	$539	$362.48
1996	4000	12000	0.8	2.4	$260,000	$120,000	$25,000	$10,000	$24,000	$439,000	$439,000	$549	$279.54
1997	8000	20000	1.6	4.0	$520,000	$240,000	$25,000	$10,000	$40,000	$835,000	$835,000	$522	$250.70
1998	8000	28000	1.6	5.6	$520,000	$240,000	$25,000	$10,000	$56,000	$851,000	$851,000	$532	$217.39
1999	8000	36000	1.6	7.2	$520,000	$240,000	$25,000	$10,000	$72,000	$867,000	$867,000	$542	$190.31
2000	8000	44000	1.6	8.8	$520,000	$240,000	$25,000	$10,000	$88,000	$883,000	$883,000	$552	$169.30
2001	5000	49000	1.0	9.8	$325,000	$150,000	$25,000	$10,000	$98,000	$608,000	$608,000	$608	$149.09
2002	1000	50000	0.2	10.0	$65,000	$30,000	$25,000	$10,000	$100,000	$230,000	$230,000	$1,150	$130.61
2003	2000	52000	0.4	10.4	$130,000	$60,000	$25,000	$10,000	$104,000	$329,000	$329,000	$823	$118.76
2004	1000	53000	0.2	10.6	$65,000	$30,000	$25,000	$10,000	$106,000	$236,000	$236,000	$1,180	$109.28
2005	1000	54000	0.2	10.8	$65,000	$30,000	$25,000	$10,000	$108,000	$238,000	$238,000	$1,190	$102.12
NPV				24						$2,455,155			

Results:

Cost of Conserved Demand — Annualized Implementation Costs/Annualized Conserved kW Demand

Cost of Conserved Demand — (PV Implementation Costs) x (Capital Recovery Factor) / (PV Conserved KWD) x (Capital Recovery Factor)

Cost of Conserved Demand — ($2455155) x (0.1468) / (24043 kW) x (0.1468)

Cost of Conserved Demand = $102.12 per kW per year

APPENDIX 7: U.S. EXPERIENCE WITH DEMAND LIMITING SYSTEMS

The U.S. utility that has tested this concept most extensively is Southern California Edison Company (SCE,) under the name of Demand Subscription Service (DSS). SCE has performed various tests of this residential demand-side concept.

SCE promoted the DSS by inviting residential customers to subscribe to the program, at a level of demand of at least one kW less than their calculated level of demand. In return, SCE would provide a credit to the customers on their electric bill.

The tests performed by SCE in 1985 and 1987 consisted of approximately 3,745 participants. Of these, 2,533 were in the treatment groups and 1,212 were in the control groups. SCE solicited customers by mailing brochures to randomly selected customers within pre-selected test areas. The response rate to the mail brochures sent to randomly selected customers was in the range of 3 to 7.2 percent.

The tests performed by SCE consisted of participants from high, middle, and low electric usage households. The usage groups were classified based on the following monthly consumptions:

- high usage group = 1,200 kWh and greater
- middle usage group = 800 to 1,200 kWh
- low usage group = 400 to 800 kWh.

The results obtained from this test were very favorable. The reductions achieved by the three usage groups were as follows:

- high usage group = 2 kW per customer
- middle usage group = 0.66 kW per customer
- low usage group = 0.57 kW per customer.

APPENDIX 8: ECONOMIC ANALYSIS OF ENERGY CONSERVATION MEASURES

COST OF CONSERVED ENERGY – ECONOMIC ANALYSIS

Date of most recent revision: 20-Dec-90

See EA3 for Technologies with No Replacement Value

General Assumptions:

Real Discount Rate	12%	/year
	0.95%	/month
Estimated System LRMC US$/kWh a/	$0.065	/kWh
Labor Cost per hour in US$ b/	$4.00	/hr
ICE Admin. Costs, as % of Equip. Costs :		
Residential/General Sector	20.0%	
Industrial Sector	15.0%	

a/ ICE estimate. The coincidental LRMC is higher, particularly for the Residential.

b/ For purposes of this analysis, the shadow price of skilled labor is 1.

CALCULATION FOR TECHNOLOGY WITH REPLACEMENT VALUE

RESIDENTIAL COMPACT FLUORESCENT LAMPS

ECM Price per Unit in US$ (less tax)	$14.00	/lamp
Life of Proposed ECM	8	yrs
Price of Alt/Present Measure (less tax)	$0.32	/lamp
Life of Alternative Measure	1	yr
Net Present Value of Alternative	$1.76	
Incremental ECM Differential NPV Cost	$12.24	
Capital Recovery Factor	0.20	
Annual Levelized Cost in US$	$2.46	/yr
Savings of ECM in kWh	38	kWh/yr
CCE in USc/kWh without Admin Costs	6.43	c/kWh
Simple Payback on a 1 unit basis	5.5	yrs
Payback including NPV of Alternative in Years	4.9	yrs
ICE Installation Costs	$8.00	/lamp
ICE Administration Costs	$2.80	/lamp
Total Cost of Proposed Measure	$24.80	/lamp
Total Incremental ECM Differential NPV Cost	$23.04	/lamp
Annual Levelized Cost in US$	$4.64	/lamp
Total CCE (equip, inst, admin) in USc/kWh	12.10	c/kWh

INDUSTRIAL ENERGY EFFICIENT MOTORS

ECM Price per Unit in US$ (less tax) a/	$323.00	/motor
Life of Proposed ECM	9.3	yrs
Price of Alt/Present Measure (less tax)	$256.12	/motor
Salvage Value of Alternative	$51.22	/motor
Life of Alternative Measure	9.3	yrs
Net Present Value of Alternative	$256.12	
Incremental ECM Differential NPV Cost	$118.10	
Capital Recovery Factor	0.18	
Annual Levelized Cost in US$	$21.81	/yr
Savings of ECM in kWh	848	kWh/yr
CCE in USc/kWh without Admin Costs	2.57	c/kWh
Simple Payback on a 1 unit basis	1.2	yrs
Payback including NPV of Alternative in Years	1.2	yrs
ICE Installation Costs	$0.00	/motor
ICE Administration Costs	$48.45	/motor
Total Cost of Proposed Measure	$422.67	/motor
Total Incremental ECM Differential NPV Cost	$166.55	/motor
Annual Levelized Cost in US$	$30.76	/motor
Total CCE (equip, inst, admin) in USc/kWh	3.63	c/kWh

a/ Assuming a target of an avg. motor in CR of 7.5 HP

INDUSTRIAL SYNCHRONOUS BELTS

ECM Price per Unit in US$ (less tax) a/	$353.98	/drive
Life of Proposed ECM	3.1	yrs
Price of Alt/Present Measure (less tax)	$33.42	/drive
Life of Alternative Measure	0.8	yrs
Net Present Value of Alternative	$117.97	
Incremental ECM Differential NPV Cost	$236.01	
Capital Recovery Factor	0.41	
Annual Levelized Cost in US$	$95.86	/yr
Savings of ECM in kWh	1758	kWh/yr
CCE in USc/kWh without Admin Costs	5.45	c/kWh
Simple Payback on a 1 unit basis	2.8	yrs
Payback including NPV		

of Alternative in Years	2.1	yrs
ICE Installation Costs	$0.00	/drive
ICE Administration Costs	$53.10	/drive
Total Cost of Proposed Measure	$407.08	/drive
Total Incremental ECM Differential NPV Cost	$289.11	/drive
Annual Levelized Cost in US$	$117.43	/drive
Total CCE (equip, inst, admin) in USc/kWh	6.68	c/kWh

a/ Assumes a before CR tax cost of the following:
sync. belt US$ 31, two new pulleys US$ 314, and two-hour labor installation.
Average size motor of 22 HP.

INDUSTRIAL COGGED V-BELTS

ECM Price per Unit in US$ (less tax)	$20.05	/drive
Life of Proposed ECM	1.5	yrs
Price of Alt/Present Measure (less tax)	$11.47	/drive
Life of Alternative Measure	0.8	yrs
Net Present Value of Alternative	$22.01	
Incremental ECM Differential NPV Cost	($1.96)	
Capital Recovery Factor	0.75	
Annual Levelized Cost in US$	($1.47)	/yr
Savings of ECM in kWh	89.00	kWh/yr
CCE in USc/kWh without Admin Costs	-1.65	c/kWh
Simple Payback on a 1 unit basis	1.5	yrs
Payback including NPV of Alternative in Years	-0.3	yrs
ICE Installation Costs	$0.00	/drive
ICE Administration Costs	$3.01	/drive
Total Cost of Proposed Measure	$23.06	/drive
Total Incremental ECM Differential NPV Cost	$1.05	/drive
Annual Levelized Cost in US$	$0.79	/drive
Total CCE (equip, inst, admin) in USc/kWh	0.88	c/kWh

INDUSTRIAL SYNTHETIC LUBRICANTS

ECM Price per Unit in US$ (less tax) a/	$144.00	/drive
Replacement Cost of Measure in US$	$36.00	/drive
Life of Proposed ECM	1	yr
Price of Alt/Present Measure (less tax)	$14.40	/drive

Life of Alternative Measure	0.3	yr
Net Present Value of Measure	$399.31	
Net Present Value of Alternative	$458.77	
Incremental ECM Differential NPV Cost	($59.46)	
Life of Equipment	20	yrs
Capital Recovery Factor	0.13	
Annual Levelized Cost in US$	($7.96)	/yr
Savings of ECM in kWh	374	kWh/yr
CCE in USc/kWh without Admin Costs	-2.13	c/kWh
Simple Payback on a 1 unit basis	5.3	yrs
Payback including NPV of Alternative in Years	-2.4	yrs
ICE Installation Costs	$0.00	/drive
ICE Administration Costs	$5.40	/drive
Total Cost of Proposed Measure	$149.40	/drive
Total Incremental ECM Differential NPV Cost	($309.37)	/drive
Annual Levelized Cost in US$	($41.42)	/drive
Total CCE (equip, inst, admin) in USc/kWh	-11.07	c/kWh

a/ Includes 8 quarts of Synthetic Lub. which initially has to be passed through 4 times as a process of cleaning in a fill and drain operation.

INDUSTRIAL AND GENERAL SECTOR COMPACT FLUORESCENT LAMPS

	11-W LAMP		18-W LAMP		26-W LAMP	
ECM Price per Unit in US$ (less tax)	$14.80	/lamp	$19.80	/lamp	$26.80	/lamp
Life of Proposed ECM	3.9	yrs	3.9	yrs	3.9	yrs
Price of Alt/Present Measure (less tax)	$1.12	/lamp	$1.12	/lamp	$1.12	/lamp
Life of Alternative Measure	0.4	yrs	0.3	yrs	0.3	yrs
Net Present Value of Alternative	$9.23		$12.02		$12.02	
Incremental ECM Differential NPV Cost	$5.57		$7.78		$14.78	
Capital Recovery Factor	0.34		0.34		0.34	
Annual Levelized Cost in US$	$1.89	/yr	$2.64	/yr	$5.01	/yr
Savings of ECM in kWh	93	kWh/yr	140.00	kWh/yr	184.00	kWh /yr
CCE in USc/kWh without Admin Costs	2.03	c/kWh	1.88	c/kWh	2.72	c/kWh
Simple Payback on a 1 unit base	2.3	yrs	2.1	yrs	2.1	yrs
Payback including NPV of Alternative in Years	0.9	yrs	0.9	yrs	1.2	yrs
ICE Installation Costs	$0.00	/lamp	$0.00	/lamp	$0.00	/lamp
ICE Administration Costs	$2.22	/lamp	$2.97	/lamp	$4.02	/lamp
Total Cost of Proposed Measure	$17.02	/lamp	$22.77	/lamp	$30.82	/lamp
Total Incremental ECM Differential NPV Cost	$7.79	/lamp	$10.75	/lamp	$18.80	/lamp

Annual Levelized Cost in US$	$2.64 /lamp	$3.64 /lamp	$6.37 /lamp
Total CCE (equip, inst, admin) in USc/kWh	2.84 c/kWh	2.60 c/kWh	3.46 c/kWh

INDUSTRIAL AND GENERAL SECTOR ENERGY-EFFICIENT LAMPS

	48" LAMP	96" LAMP
ECM Price per Unit in US$ (less tax)	$4.57 /fixture	$8.94 /fixture
Life of Proposed ECM	7.7 yrs	4.6 yrs
Price of Alt/Present Measure (less tax)	$4.04 /fixture	$7.37 /fixture
Life of Alternative Measure	7.7 yrs	4.6 yrs
Net Present Value of Alternative	$4.04	$7.37
Incremental ECM Differential NPV Cost	$0.53	$1.56
Capital Recovery Factor	0.21	0.30
Annual Levelized Cost in US$	$0.11 /yr	$0.46 /yr
Savings of ECM in kWh	39 kWh/yr	65.00 kWh/yr
CCE in USc/kWh without Admin Costs	0.28 c/kWh	0.71 c/kWh
Simple Payback on a 1 unit base	0.2 yrs	0.4 yrs
Payback including NPV of Alternative in Years	0.2 yrs	0.4 yrs
ICE Installation Costs	$0.00 /fixture	$0.00 /fixture
ICE Administration Costs	$0.69 /fixture	$1.34 /fixture
Total Cost of Proposed Measure	$5.26 /fixture	$10.28 /fixture
Total Incremental ECM Differential NPV Cost	$1.21 /fixture	$2.90 /fixture
Annual Levelized Cost in US$	$0.25 /fixture	$0.86 /fixture
Total CCE (equip, inst, admin) in USc/kWh	0.64 c/kWh	1.32 c/kWh

INDUSTRIAL AND GENERAL SECTOR HYBRID ELECTRO-MECHANICAL BALLASTS

ECM Price per Unit in US$ (less tax)	$13.84 /4'bal.
Life of Proposed ECM	15.0 yrs
Price of Alt/Present Measure (less tax)	$9.18 /4'bal.
Life of Alternative Measure	10.0 yrs
Net Present Value of ECM (2 Periods)	$16.37 /2 periods
Net Present Value of Alternative	$13.08 /2 periods
Incremental ECM Differential NPV Cost	$3.28
Capital Recovery Factor	0.12
Annual Levelized Cost in US$	$0.41 /yr
Savings of ECM in kWh	44.00 kWh/yr
CCE in USc/kWh without Admin Costs	0.93 c/kWh

Simple Payback on a 1 unit base	1.6	yrs
Payback including NPV of Alternative in Years	1.1	yrs
ICE Installation Costs	$0.00	yrs
ICE Administration Costs	$2.08	yrs
Total Cost of Proposed Measure	$17.08	yrs
Total Incremental ECM Differential NPV Cost	$3.99	yrs
Annual Levelized Cost in US$	$0.50	yrs
Total CCE (equip, inst, admin) in USc/kWh	1.13	c/kWh

INDUSTRIAL ELECTRONIC BALLASTS

ECM Price per Unit in US$ (less tax)	$29.[illegible]	/8'bal.
Life of Proposed ECM	25.0	yrs
Price of Alt/Present Measure (less tax)	$9.18	/8'bal.
Life of Alternative Measure	10.0	yrs
Net Present Value of ECM (2 Periods)	$31.24	/2 periods
Net Present Value of Alternative	$13.49	/2 periods
Incremental ECM Differential NPV Cost	$17.75	
Capital Recovery Factor	0.12	
Annual Levelized Cost in US$	$2.14	/yr
Savings of ECM in kWh	91.00	kWh/yr
CCE in USc/kWh without Admin Costs	2.35	c/kWh
Simple Payback on a 1 unit base	3.4	yrs
Payback including NPV of Alternative in Years	3.0	yrs
ICE Installation Costs	$0.00	yrs
ICE Administration Costs	$4.13	yrs
Total Cost of Proposed Measure	$33.63	yrs
Total Incremental ECM Differential NPV Cost	$20.14	yrs
Annual Levelized Cost in US$	$2.42	yrs
Total CCE (equip, inst, admin) in USc/kWh	2.66	c/kWh

CALCULATION FOR TECHNOLOGY WITH NO REPLACEMENT VALUE

RESIDENTIAL

	Water Heater Tank Insul	Solar Water Heater Tank	Solar Water Termo Ducha	Refrigerator	Spiral Burners (full cost meas)
Cost of Equipment less tax in US$	$10.00 /unit	$600.00 /unit	$450.00 /unit	$25.00 /unit	$60.00 /unit
Life of Measure in Years	10.0 yrs	15.0 yrs	15.0 yrs	15.0 yrs	12.0 yrs
Capital Recovery Factor	0.18	0.15	0.15	0.15	0.16
Annual Levelized Cost in US$	$1.77 /yr	$88.09 /yr	$66.07 /yr	$3.67 /yr	$9.69 /yr
Savings of Measure in kWh	400 kWh/yr	1700 kWh/yr	600 kWh/yr	200 kWh/yr	300 kWh/yr
CCE in USc/kWh without Inst. & Admin Costs	0.44 c/kWh	5.18 c/kWh	11.01 c/kWh	1.84 c/kWh	3.23 c/kWh
Simple Payback in Years	0.4 yrs	5.4 yrs	11.5 yrs	1.9 yrs	3.1 yrs
Installation Costs	$8.00 /unit	$8.00 /unit	$8.00 /unit	$8.00 /unit	$4.00 /unit
ICE Administration Costs	$2.00 /unit	$120.00 /unit	$90.00 /unit	$5.00 /unit	$12.00 /unit
Total Cost of ECM	$20.00 /unit	$728.00 /unit	$548.00 /unit	$38.00 /unit	$76.00 /unit
Annual Levelized Cost in US$	$3.54 /unit	$106.89 /unit	$80.46 /unit	$5.58 /unit	$12.27 /unit
Total CCE (equip, inst, admin) in USc/kWh	0.88 c/kWh	6.29 c/kWh	13.41 c/kWh	2.79 c/kWh	4.09 c/kWh

	Spiral Burners (with replace. value)
ECM Pric	$60.00 /unit
Life ECM	12 yrs
Price Alte	$50.00 /unit
Life Alt	12 yr
Incremen	$10.00
CRF	0.16
An. Level	$1.61 /yr
Savings o	300 kWh/yr
CCE	0.54 c/kWh
S. Payba	0.5 yrs

INDUSTRIAL

—INDUSTRIAL AND GENERAL SECTOR—

Variable Speed Drives		Fluorescent 48" Fixture Reflectors		Fluorescent 96" Fixture Reflectors	
$3,526.00	/drive	$22.50	/fixture	$45.00	/fixture
15.0	yrs	20.0	yrs	20.0	yrs
0.15		0.13		0.13	
$517.70	/yr	$3.01	/yr	$6.02	/yr
2769	kWh/yr	83	kWh/yr	149	kWh/yr
18.70	c/kWh	3.63	c/kWh	4.04	c/kWh
19.6	yrs	4.2	yrs	4.6	yrs
$1,000.00	/drive	$2.00	/fixture	$2.00	/fixture
$528.90	/drive	$3.38	/fixture	$6.75	/fixture
$5,054.90	/drive	$27.88	/fixture	$53.75	/fixture
$742.18	/drive	$3.73	/fixture	$7.20	/fixture
26.80	c/kWh	4.50	c/kWh	4.83	c/kWh

APPENDIX 9: FINANCIAL ANALYSIS OF ENERGY CONSERVATION MEASURES

COST OF CONSERVED ENERGY - FINANCIAL

Date of most recent revision: 20-Dec-90

See EA3 for Technologies with No Replacement Value

General Assumptions:

Real Discount Rate	12%	/year
	0.95%	/month
Avg. Resid. Tariff US$/kWh	$0.040	/kWh
Avg. Gen. Sect. Tariff US$/kWh	$0.080	/kWh
Avg. Industrial Tariff US$/kWh	$0.065	/kWh
Labor Cost per hour in US$	$4.00	/hr
ICE Admin. Costs, as % of Equip. Costs (net of tax):		
Residential/General Sector	20.0%	
Industrial Sector	15.0%	

CALCULATION FOR TECHNOLOGY WITH REPLACEMENT VALUE

RESIDENTIAL COMPACT FLUORESCENT LAMPS

ECM Price per Unit in US$ a/	$16.94	/lamp
Life of Proposed ECM	8	yrs
Price of Alternative or Present Measure	$0.40	/lamp
Life of Alternative Measure	1	yr
Net Present Value of Alternative	$2.23	
Incremental ECM Differential NPV Cost	$14.71	
Capital Recovery Factor	0.20	
Annual Levelized Cost in US$	$2.96	/yr
Savings of ECM in kWh	38	kWh/yr
CCE in USc/kWh without Admin Costs	7.73	c/kWh
Simple Payback to End-User on a 1 unit basis	10.8	yrs
Payback to End-User including NPV of Alternative in Years	9.6	yrs
ICE Installation Costs	$8.00	/lamp
ICE Administration Costs	$2.80	/lamp
Total Cost of Proposed Measure	$27.74	/lamp
Total Incremental ECM Differential NPV Cost	$25.51	/lamp
Annual Levelized Cost in US$	$5.14	/lamp

Total CCE (equip, inst, admin) in USc/kWh	13.40	c/kWh

a/ Includes a 21% tax

INDUSTRIAL ENERGY EFFICIENT MOTORS

ECM Price per Unit in US$ a/	$400.52	/motor
Life of Proposed ECM	9.3	yrs
Price of Alternative or Present Measure	$337.00	/motor
Salvage Value of Alternative	$67.40	/motor
Life of Alternative Measure	9.3	yrs
Net Present Value of Alternative	$337.00	
Incremental ECM Differential NPV Cost	$130.92	
Capital Recovery Factor	0.18	
Annual Levelized Cost in US$	$24.18	/yr
Savings of ECM in kWh	848	kWh/yr
CCE in USc/kWh without Admin Costs	2.85	c/kWh
Simple Payback to End-User on a 1 unit basis	1.2	yrs
Payback to End-User including NPV of Alternative in Years	1.2	yrs
ICE Installation Costs	$0.00	/motor
ICE Administration Costs	$48.45	/motor
Total Cost of Proposed Measure	$448.97	/motor
Total Incremental ECM Differential NPV Cost	$179.37	/motor
Annual Levelized Cost in US$	$33.12	/motor
Total CCE (equip, inst, admin) in USc/kWh	3.91	c/kWh

a/ Includes a 24% tax and assuming a target of an avg. motor in CR of 7.5 HP.

INDUSTRIAL SYNCHRONOUS BELTS

ECM Price per Unit in US$ a/	$432.08	/drive
Life of Proposed ECM	3.1	yrs
Price of Alternative or Present Measure	$42.00	/drive
Life of Alternative Measure	0.8	yrs
Net Present Value of Alternative	$120.80	
Incremental ECM Differential NPV Cost	$311.28	
Capital Recovery Factor	0.41	
Annual Levelized Cost in US$	$126.43	/yr
Savings of ECM in kWh	1758	kWh/yr
CCE in USc/kWh without Admin Costs	7.19	c/kWh
Simple Payback to End-User on a 1 unit basis	3.4	yrs

Payback to End-User including NPV of Alternative in Years	2.7	yrs
ICE Installation Costs	$0.00	/drive
ICE Administration Costs	$53.10	/drive
Total Cost of Proposed Measure	$485.18	/drive
Total Incremental ECM Differential NPV Cost	$364.37	/drive
Annual Levelized Cost in US$	$148.00	/drive
Total CCE (equip, inst, admin) in USc/kWh	8.42	c/kWh

a/ Includes sync. belt, two pulleys, and two hour labor installation.

INDUSTRIAL COGGED V-BELTS

ECM Price per Unit in US$	$25.33	/drive
Life of Proposed ECM	1.5	yrs
Price of Alternative or Present Measure	$14.33	/drive
Life of Alternative Measure	0.8	yrs
Net Present Value of Alternative	$27.50	
Incremental ECM Differential NPV Cost	($2.17)	
Capital Recovery Factor	0.75	
Annual Levelized Cost in US$	($1.62)	/yr
Savings of ECM in kWh	89	kWh/yr
CCE in USc/kWh without Admin Costs	-1.82	c/kWh
Simple Payback to End-User on a 1 unit basis	1.9	yrs
Payback to End-User including NPV of Alternative in Years	-0.4	yrs
ICE Installation Costs	$0.00	/drive
ICE Administration Costs	$3.01	/drive
Total Cost of Proposed Measure	$28.34	/drive
Total Incremental ECM Differential NPV Cost	$0.84	/drive
Annual Levelized Cost in US$	$0.63	/drive
Total CCE (equip, inst, admin) in USc/kWh	0.71	c/kWh

INDUSTRIAL SYNTHETIC LUBRICANTS

ECM Initial Cost per Unit in US$	$168.64	/drive
Replacement Cost of Measure in US$	$43.92	/drive
Life of Proposed ECM	1	yr
Price of Alternative or Present Measure	$15.81	/drive
Life of Alternative Measure	0.3	yr

Net Present Value of Measure	$492.14	
Net Present Value of Alternative	$507.23	
Incremental ECM Differential NPV Cost	($15.08)	
Life of Equipment	20	yrs
Capital Recovery Factor	0.13	
Annual Levelized Cost in US$	($2.02)	/yr
Savings of ECM in kWh	374.00	kWh/yr
CCE in USc/kWh without Admin Costs	-0.54	c/kWh
Simple Payback to End-User on a 1 unit base	6.3	yrs
Payback to End-User including NPV of Alternative in Years	-0.6	yrs
ICE Installation Costs	$0.00	/drive
ICE Administration Costs	$5.40	/drive
Total Cost of Proposed Measure	$497.54	/drive
Total Incremental ECM Differential NPV Cost	($9.68)	/drive
Annual Levelized Cost in US$	($1.30)	/drive
Total CCE (equip, inst, admin) in USc/kWh	-0.35	c/kWh

INDUSTRIAL AND GENERAL SECTOR COMPACT FLUORESCENT LAMPS

	11-W LAMP		18-W LAMP		26-W LAMP	
ECM Price per Unit in US$	$17.74	/lamp	$23.79	/lamp	$32.26	/lamp
Life of Proposed ECM	3.9	yrs	3.9	yrs	3.9	yrs
Price of Alternative or Present Measure	$1.28	/lamp	$1.28	/lamp	$1.28	/lamp
Life of Alternative Measure	0.4	yrs	0.3	yrs	0.3	yrs
Net Present Value of Alternative	$10.62		$13.82		$13.82	
Incremental ECM Differential NPV Cost	$7.12		$9.97		$18.44	
Capital Recovery Factor	0.34		0.34		0.34	
Annual Levelized Cost in US$	$2.41	/yr	$3.38	/yr	$6.24	/yr
Savings of ECM in kWh	93	kWh/yr	140.00	kWh/yr	184.00	kWh/yr
CCE in USc/kWh without Admin Costs	2.59	c/kWh	2.41	c/kWh	3.39	c/kWh
Simple Payback (industrial) to End-User on a 1 unit basis	2.7	yrs	2.5	yrs	2.6	yrs
Simple Payback (general sect.) to End-User on a 1 unit basis	2.2	yrs	2.0	yrs	2.1	yrs
Payback to End-User (industrial) including NPV of Alternative in Years	1.2	yrs	1.1	yrs	1.5	yrs
Payback to End-User (general sect.) including NPV of Alternative in Years	1.0	yrs	0.9	yrs	1.3	yrs

ICE Installation Costs	$0.00 /lamp	$0.00 /lamp	$0.00 /lamp
ICE Administration Costs	$2.22 /lamp	$2.97 /lamp	$4.02 /lamp
Total Cost of Proposed Measure	$19.96 /lamp	$26.76 /lamp	$36.28 /lamp
Total Incremental ECM Differential NPV Cost	$9.34 /lamp	$12.94 /lamp	$22.46 /lamp
Annual Levelized Cost in US$	$3.16 /lamp	$4.38 /lamp	$7.61 /lamp
Total CCE (equip, inst, admin) in USc/kWh	3.40 c/kWh	3.13 c/kWh	4.13 c/kWh

INDUSTRIAL AND GENERAL SECTOR ENERGY-EFFICIENT LAMPS

	48" LAMP	96" LAMP
ECM Price per Unit in US$	$5.36 /lamp	$10.65 /lamp
Life of Proposed ECM	7.7 yrs	4.6 yrs
Price of Alternative or Present Measure	$4.04 /lamp	$7.37 /lamp
Life of Alternative Measure	7.7 yrs	4.6 yrs
Net Present Value of Alternative	$4.04	$7.37
Incremental ECM Differential NPV Cost	$1.32	$3.27
Capital Recovery Factor	0.21	0.30
Annual Levelized Cost in US$	$0.27 /yr	$0.97 /yr
Savings of ECM in kWh	39 kWh/yr	65 kWh/yr
CCE in USc/kWh without Admin Costs	0.70 c/kWh	1.49 c/kWh
Simple Payback (industrial) to End-User on a 1 unit basis	0.5 yrs	0.8 yrs
Simple Payback (general sect.) to End-User on a 1 unit basis	0.4 yrs	0.6 yrs
Payback to End-User (industrial) including NPV of Alternative in Years	0.5 yrs	0.8 yrs
Payback to End-User (general sect.) including NPV of Alternative in Years	0.4 yrs	0.6 yrs
ICE Installation Costs	$0.00 /lamp	$0.00 /lamp
ICE Administration Costs	$0.69 /lamp	$1.34 /lamp
Total Cost of Proposed Measure	$8.05 /lamp	$11.99 /lamp
Total Incremental ECM Differential NPV Cost	$2.01 /lamp	$4.61 /lamp
Annual Levelized Cost in US$	$0.41 /lamp	$1.[illegible]6 /lamp
Total CCE (equip, inst, admin) in USc/kWh	1.06 c/kWh	2.10 c/kWh

INDUSTRIAL AND GENERAL SECTOR HYBRID ELECTRO-MECHANICAL BALLASTS

ECM Price per Unit in US$	$18.00 /4'bal.
Life of Proposed ECM	15.0 yrs
Price of Alternative or Present Measure	$10.00 /4'bal.
Life of Alternative Measure	10.0 yrs

Net Present Value of ECM (2 Periods)	$21.29	/2 periods
Net Present Value of Alternative	$14.26	/2 periods
Incremental ECM Differential NPV Cost	$7.03	
Capital Recovery Factor	0.12	
Annual Levelized Cost in US$	$0.87	/yr
Savings of ECM in kWh	44	kWh/yr

CCE in USc/kWh without Admin Costs	1.98	c/kWh
Simple Payback (industrial) to End-User on a 1 unit basis	2.8	yrs
Simple Payback (general sect.) to End-User on a 1 unit basis	2.3	yrs
Payback to End-User (industrial) including NPV of Alternative in Years	2.5	yrs
Payback to End-User (general sect.) including NPV of Alternative in Years	2.0	yrs

ICE Installation Costs	$0.00	yrs
ICE Administration Costs	$2.08	yrs
Total Cost of Proposed Measure	$23.36	yrs
Total Incremental ECM Differential NPV Cost	$9.11	yrs
Annual Levelized Cost in US$	$1.13	yrs
Total CCE (equip, inst, admin) in USc/kWh	2.57	c/kWh

INDUSTRIAL AND GENERAL SECTOR ELECTRONIC BALLASTS

ECM Price per Unit in US$	$35.28	/8'bal.
Life of Proposed ECM	25.0	yrs
Price of Alternative or Present Measure	$10.00	/8'bal.
Life of Alternative Measure	10.0	yrs
Net Present Value of ECM (2 Periods)	$37.35	/2 periods
Net Present Value of Alternative	$14.70	/2 periods
Incremental ECM Differential NPV Cost	$22.65	
Capital Recovery Factor	0.12	
Annual Levelized Cost in US$	$2.73	/yr
Savings of ECM in kWh	91	kWh/yr

CCE in USc/kWh without Admin Costs	3.00	c/kWh
Simple Payback (industrial) to End-User on a 1 unit basis	4.3	yrs
Simple Payback (general sect.) to End-User on a 1 unit basis	3.5	yrs

Payback to End-User (industrial) including NPV of Alternative in Years	3.8	yrs
Payback to End-User (general sect.) including NPV of Alternative in Years	3.1	yrs
ICE Installation Costs	$0.00	yrs
ICE Administration Costs	$4.43	yrs
Total Cost of Proposed Measure	$41.77	yrs
Total Incremental ECM Differential NPV Cost	$27.08	yrs
Annual Levelized Cost in US$	$3.26	yrs
Total CCE (equip, inst, admin) in USc/kWh	3.58	c/kWh

CALCULATION FOR TECHNOLOGY WITH NO REPLACEMENT VALUE

RESIDENTIAL

	Water Heater Tank Insul	Solar Water Heater Tank	Solar Water Termo Ducha	Refrigerator	Spiral Burners (full cost meas)
Cost of Equipment in US$ with 21% CR Tax	$12.10 /unit	$726.00 /unit	$544.50 /unit	$30.25 /unit	$72.60 /unit
Life of Measure in Years	10.0 yrs	15.0 yrs	15.0 yrs	15.0 yrs	12.0 yrs
Capital Recovery Factor	0.18	0.15	0.15	0.15	0.16
Annual Levelized Cost in US$	$2.14 /yr	$106.59 /yr	$79.95 /yr	$4.44 /yr	$11.72 /yr
Savings of Measure in kWh	400 kWh/yr	1700 kWh/yr	600 kWh/yr	200 kWh/yr	300 kWh/yr
CCE in USc/kWh without Inst. & Admin Costs	0.54 c/kWh	6.27 c/kWh	13.32 c/kWh	2.22 c/kWh	3.91 c/kWh
Simple Payback to End-User in Years	0.8 yrs	10.7 yrs	22.7 yrs	3.8 yrs	6.1 yrs
Installation Costs	$8.00 /unit	$8.00 /unit	$8.00 /unit	$8.00 /unit	$4.00 /unit
ICE Administration Costs	$2.00 /unit	$120.00 /unit	$90.00 /unit	$5.00 /unit	$12.00 /unit
Total Cost of ECM	$22.10 /unit	$854.00 /unit	$642.50 /unit	$43.25 /unit	$88.60 /unit
Annual Levelized Cost in US$	$3.91 /unit	$125.39 /unit	$94.33 /unit	$6.35 /unit	$14.30 /unit
Total CCE (equip, inst, admin) in USc/kWh	0.98 c/kWh	7.38 c/kWh	15.72 c/kWh	3.18 c/kWh	4.77 c/kWh

	Spiral Burners (with replace. value)
ECM Pric	$72.60 /unit
Life ECM	12 yrs
Price Alte	$50.00 /unit
Life Al	12 yr
Incremen	$22.60
CRF	0.16
An. Level	$3.65 /yr
Savings o	300 kWh/yr
CCE	1.22 c/kWh
S. Payba	1.9 yrs

INDUSTRIAL

—INDUSTRIAL AND GENERAL SECTOR—

Variable Speed Drives	Fluorescent 48" Fixture Reflectors	Fluorescent 96" Fixture Reflectors	
$4,266.46 /drive	$27.23 /fixture	$54.45 /fixture	
15.0 yrs	20.0 yrs	20.0 yrs	
0.15	0.13	0.13	
$626.42 /yr	$3.64 /yr	$7.29 /yr	
2769 kWh/yr	83 kWh/yr	149 kWh/yr	
22.62 c/kWh	4.39 c/kWh	4.89 c/kWh	
23.7 yrs	5.0 yrs	5.6 yrs	Industrial
	4.1 yrs	4.6 yrs	General
$1,000.00 /drive	$2.00 /fixture	$2.00 /fixture	
$528.90 /drive	$3.38 /fixture	$6.75 /fixture	
$5,795.36 /drive	$32.60 /fixture	$63.20 /fixture	
$850.90 /drive	$4.36 /fixture	$8.46 /fixture	
30.73 c/kWh	5.26 c/kWh	5.68 c/kWh	

APPENDIX 10: PROJECTED DEMAND REDUCTIONS FOR ENERGY CONSERVATION MEASURES IN THE RESIDENTIAL AND GENERAL SECTORS

The following calculations describe the methodology used to determine the projected demand reductions associated with the projected energy savings (GWh/yr) for the energy reduction measures proposed in this study.

The glossary at the end of this report contains a list of definitions and formulas that describe the terms used in calculating the projected demand reductions.

These are the various energy reduction measures along with the corresponding calculations:

1) **SPIRAL BURNERS** - The Direccion Sectorial de Energia performed a study in December 1989 entitled *Estudio de Factibilidad para la Substitucion de la Energia Electrica por Gas Licuado*. The following information was obtained from this report:

- Residential cooking maximum peak for November 24, 1987 at 11:30 a.m. was: 194.8 MW
- Residential cooking coincident peak for November 24, 1987 at 6:30 p.m. was: 107 MW
- Daily consumption due to residential cooking for November 24, 1987 was: 1635.7 MWh
- Projected coincident peak due to residential cooking in the year 2005: 186 MW

In another study, *Costa Rica Power Sector Efficiency Assessment: Peak Reduction Programs*, performed by Qualtec, Inc. in July 1990, the following information was obtained:

- Residential sector coincident peak for 1987 was: 329 MW

From the above information, the following parameters were calculated:

- Coincident peak load factor due to cooking:

$$\frac{68.15 \text{ MW Average}}{107 \text{ MW Peak}} = 63.7\% \text{ Load Factor}$$

- Non-coincident peak load factor due to cooking:

$$\frac{68.15 \text{ MW Average}}{194 \text{ MW Peak}} = 35.1\% \text{ Load Factor}$$

- Coincident peak coincidence factor:

$$\frac{107 \text{ MW}}{194 \text{ MW}} = 55\%$$

Calculation of Demand Reductions:

1. The projected energy savings in the year 2005 are: 64.5 GWh/yr.

2. The average MW savings are:

$$\frac{64.5 \text{ GWh/yr}}{8{,}760 \text{ hrs/yr}} = 7.36 \text{ MW Average}$$

3. The maximum MW savings achieved at the time of cooking peak (11:30 a.m.) are:

$$\frac{7.36 \text{ MW}}{35.1\% \text{ Load Factor}} = 21 \text{ MW}$$

4. The coincident peak MW savings achieved at the time of system peak as a result of implementing this measure through the year 2005 are:

21 MW x 55% coincident peak coincidence factor = 11.55 MW

2) **WATER TANK INSULATION** - Approximately 4 percent of households in Costa Rica have water heater tanks.

-	water heater coincident demand per customer	=	0.25 kW
-	water heater average demand per customer	=	0.14 kW
-	water heater coincident peak load factor	=	56%
-	water heater non-coincident peak load factor	=	50%
-	coincident peak coincidence factor	=	90%

Calculation of Demand Reductions:

1. The projected energy savings in the year 2005 are: 9.6 GWh/yr.

2. The average MW savings are:

$$\frac{9.6 \text{ GWh/yr}}{8{,}760 \text{ hrs/yr}} = 1.1 \text{ MW Average}$$

3. The maximum MW savings achieved at the time of water heater peak are:

$$\frac{1.1 \text{ MW}}{50\% \text{ Load Factor}} = 2 \text{ MW}$$

4. The coincident peak MW savings achieved at the time of system peak as a result of implementing this measure through the year 2005 are:

2 MW x 90% coincident peak coincidence factor = 1.8 MW

3) **REFRIGERATOR EFFICIENCY** - The specific savings associated with refrigeration energy efficiency improvements are described below.

-	refrigerator coincident demand per customer	=	0.16 kW
-	refrigerator average demand per customer	=	0.13 kW
-	refrigerator coincident peak load factor	=	80%
-	refrigerator non-coincident peak load factor	=	76%
-	coincident peak coincidence factor	=	95%

Calculation of Demand Reductions:

1. The projected energy savings in the year 2005 are: 65 GWh/yr.

2. The average MW savings are:

$$\frac{65 \text{ GWh/yr}}{8{,}760 \text{ hrs/yr}} = 7.4 \text{ MW Average}$$

3. The maximum MW savings achieved at the time of refrigerator peak are:

$$\frac{7.4 \text{ MW}}{76\% \text{ Load Factor}} = 9.7 \text{ MW}$$

4. The coincident peak MW savings achieved at the time of system peak as a result of implementing this measure through the year 2005 are:

9.25 MW x 95% coincident peak coincidence factor = 8.8 MW

4) **LIGHTING** - The majority of the residential lighting needs are concentrated over a period of a few hours at night. Although some illumination occurs as outdoor lighting for security and beautification purposes, most of it occurs from sundown to bedtime. For calculation purposes, it is estimated that the majority of illumination needs occur over a six-hour period. Thus, the 310 GWh of lighting use in 1990 results in an estimated demand of:

$$\frac{310 \text{ GWh/yr}}{365 \text{ days/yr} \times 6 \text{ hrs/day}} = 141 \text{ MW Average}$$

The coincident peak coincidence factor for lighting is 70%.

- Non-coincident peak load factor due to lighting:

$$\frac{35.8 \text{ MW Average}}{141 \text{ MW Peak}} = 25\% \text{ Load Factor}$$

- Coincident peak load factor due to lighting:

$$\frac{35.8 \text{ MW Average}}{98.7 \text{ MW Peak}} = 35.8\% \text{ Load Factor}$$

Calculation of Demand Reductions:

1. The projected energy savings in the year 2005 are: 5.25 GWh/yr.

2. The average MW savings are:

$$\frac{52.5 \text{ GWh/yr}}{8{,}760 \text{ hrs/yr}} = 6 \text{ MW Average}$$

3. The maximum MW savings achieved at the time of lighting peak are:

$$\frac{6 \text{ MW}}{25\% \text{ Load Factor}} = 24 \text{ MW}$$

4. The coincident peak MW savings achieved at the time of system peak as a result of implementing this measure through the year 2005 are:

24 MW x 70% coincident peak coincidence factor	=	16.8 MW

APPENDIX 11: REHABILITATION PROGRAM DESCRIPTION

INSTITUTO COSTARRICENSE DE ELECTRICIDAD

DIRECCION PRODUCCION Y TRANSPORTE DE ENERGIA
DEPARTAMENTO DE GENERACION

PROGRAMA DE REHABILITACION DE PLANTAS TERMICAS

5 ENERO 1989
SAN JOSE, COSTA RICA

4. EL PROYECTO

4-1 Descripción del proyecto

Motivado por el alto crecimiento de la demanda de energía eléctrica, el Instituto Costarricense de Electricidad ha creído conveniente rehabilitar las unidades generadoras termoeléctricas, dado que éstas cumplirán una función muy importante en el futuro como complemento de la generación hidro-geotérmica.

El I.C.E. cuenta con cinco plantas termoeléctricas identificadas como Barranca, San Antonio Vapor, San Antonio Gas, Colima y Moín; cuyas unidades fueron instaladas en 1974, 1954, 1973, 1956 y 1977 respectivamente.

A pesar de que estas plantas han recibido mantenimiento preventivo y correctivo parciales y totales, es importante reacondicionarlas debido a que se estima una operación que se irá incrementando y se requerirá contar con ellas durante las 24 horas.

Se pretende, por tanto, justificar las necesidades propias de repuestos para una rehabilitación completa de las cinco plantas termoeléctricas con el fin de estar en capacidad de afrontar las demandas futuras de energía y brindar confiabilidad al Sistema Nacional Interconectado.

4-2 Justificación técnica

A- Planta San Antonio Vapor

a- Reemplazo de los reguladores de voltaje.

Los actuales reguladores de voltaje tienen más de 30 años de funcionamiento, por lo que actualmente no es posible obtener componentes de repuesto, lo cual obliga a cambiarlos.

b- Reemplazo de controles de caldera y gobernadores de velocidad.

Las unidades generadoras a vapor de esta planta, tienen más de 30 años de servicio, razón por la cual desde hace varios años, los equipos de

control que utilizan ya fueron descontinuados y no hay forma de conseguir repuestos, lo cual hace que las unidades operen con alto grado de riesgo y en caso de que la unidad falle, quedaría indisponible por tiempo indefinido. Siendo la solución óptima reemplazar los controles por otros más modernos y más eficientes.

c- Renovación de motobombas de condensado, alimentación y recirculación.

Se requiere contar con repuestos para el reacondicionamiento total de estos componentes y en muchos de los casos realizar la sustitución completa, ya que son elementos muy viejos y en la mayoría de ellos se dificulta conseguir repuestos por el hecho de estar descontinuados.

Estos equipos cumplen funciones muy importantes en la operación de la unidad y es conveniente incluso, contar con equipos sustitutos para su reemplazo inmediato en caso de eventuales fallas.

d- Renovación interruptores principales y auxiliares

Es necesario contar con interruptores principalmente más modernos, con sistemas de extinsión de arco al vacío que sean más eficientes. Es importante efectuar el cambio de los interruptores de los auxiliares (control de motores) por cuanto estos están obsoletos y la existencia de repuestos en bodega es mínima e insuficiente para realizar los mantenimientos en los próximos años.

e- Repuestos para turbina - generador

El objetivo es mantener un stock de repuestos para realizar los mantenimientos parciales y mayores, dado que estas unidades han acumulado más de 60 000 horas de funcionamiento.

Actualmente no hay repuestos en bodega para el reacondicionamiento general, siendo lo más conveniente la adquisición de partes vitales tales como:

Repuestos para calderas (tubos, generadores, boquillas, etc).

Repuestos para turbinas (toberas, diafragmas, cojinetes, etc.).

Intercambiadores de calor (tuberías, válvulas, etc.).

Repuestos varios para equipo auxiliar de los sistemas de lubricación, enfriamiento, aire de control, combustible, agua de alimentación, etc.

B- San Antonio Gas

a- Cambio de sistema actual de combustible

El sistema de control de combustible de estas unidades a gas está descontinuado, por lo cual el sistema empleado falla con frecuencia causando serios transtornos en la operación de las unidades.

Para evitar estos problemas lo más conveniente es reemplazarlo por el modelo actual.

b- Motor de arranque

El motor de arranque de estas unidades es una parte fundamental en la operación de las mismas. Por ser un aparato eléctrico y por las características propias de funcionamiento, está sujeto a eventuales fallas que provocan indisponibilidad de la unidad.

Es importante contar con un motor de repuesto para evitar períodos largos de indisponibilidad, lo anterior debido a que por las dimensiones y características de este motor, se requiere de un período considerable para sus intervenciones preventivas o correctivas.

c- Renovación de motores de torre de enfriamiento

Es indispensable la adquisición de motores de los abanicos de los intercambiadores de calor y motor del sistema de enfriamiento, por la razón de que no se cuentan con sustitutos y en una eventual falla implicaría indisponibilidad de al menos una unidad por ser éste un sistema común para las dos unidades de gas.

d- Repuestos para los reguladores de velocidad y de voltaje

Actualmente la Planta San Antonio solo cuenta con una cantidad reducida de repuestos menores para esos equipos, por lo que en la mayoría de los casos cuando ocurre un daño que involucra una tarjeta o un módulo electrónico, la unidad se tiene que parar por largos períodos mientras se buscan los componentes para repararla o en su defecto se envían al exterior. La única forma de solucionar este inconveniente es comprando un juego completo de repuestos.

e- Repuestos para turbina - generador

Se pretende mantener un stock de repuestos para realizar los mantenimientos parciales y mayores considerando el número de horas de servicio y las que acumulará de acuerdo a las nuevas necesidades del Sistema Nacional Interconectado.

Los principales componentes a adquirir son:

Partes principales de turbina (toberas y álabes de primera y segunda etapa, piezas de transición, canastas de combustión, toberas de combustible, tornillería, empaquetaduras, etc.).

Repuestos varios para equipos auxiliares de los sistemas de combustible, lubricación, enfriamiento, aire de control, hidráulico, arranque, etc.

Intercambiadores de calor - torres de enfriamiento.

Repuestos varios para equipo de control de turbina y generador.

C- Planta Barranca

a- Repuestos para los reguladores de velocidad y de voltaje

Actualmente la Planta de Barranca solo cuenta con una cantidad reducida de repuestos menores para esos equipos, por lo que en la mayoría de los casos cuando ocurre un daño que involucra una tarjeta o un módulo electrónico, la unidad se tiene que indisponer por largos períodos mientras que se buscan los componentes para repararla o en su defecto se envían al exterior para ello. La única forma de solucionar este incoveniente es comprando un juego completo de repuestos.

b- Juego completo para overhaul de motores de arranque

Se pretende tener un respaldo de repuestos para cubrir las necesidades de intervención de estos motores que debe efectuarse en 1994, para lograr la confiabilidad de su operación.

c- Interruptor principal de máquina

Con la intención de tener un respaldo para las dos unidades, se pretende instalar un interruptor completo con el fin de lograr mayor confiabilidad en la operación. Se tiene

mayores, considerando el número de horas de servicio y las que acumulará de acuerdo a las nuevas necesidades del Sistema Nacional Interconectado.

Los principales componentes a adquirir son básicamente los mismos indicados en el punto para las turbinas de gas de Planta San Antonio.

La repercución de no contar con los repuestos y la no ejecución de los trabajos de reacondicionamiento general, implicaría un mayor número de fallas y por consiguiente indisponibilidad de las unidades generadoras y el peligro de que partes fundamentales como turbina y compresor sufran daños severos e irreparables.

D- Planta Colima

a- Renovación de enfriadores de agua-aire-aceite

Estos equipos cumplen funciones muy importantes dentro de la operación de la unidad, de ellos depende obtener mejores rendimientos. Cabe mencionar que los actuales presentan un marcado deterioro.

b- Sustitución de centrifugas

Las centrífugas instaladas son muy viejas y no tienen la capacidad requerida para la purificación del búnker. La operación de estas centrífugas es deficiente dado que se producen muchos atascamientos, los cuales inciden directamente en indisponibilidad de la unidad.

La sustitución de estos equipos es indispensable por la razón de que cumplen una función muy importante para la generación de energía con búnker, ya que de lo contrario se deberá consumir diesel lo cual implicaría elevar los costos de generación.

La purificación deficiente del búnker produce un serio deterioro mecánico de las unidades, lo que representa costos adicionales en repuestos.

c- Renovación de interruptores de equipos auxiliares

El equipo de control (interruptores, contactores, relés) instalados en esta planta, se encuentran en mal estado, debido a los años de operación, agravándose el problema al no contarse con los repuestos requeridos debido a que los mismos están descontinuados. Por lo anterior es una necesidad sustituir estos equipos.

d- Renovación de los motores eléctricos

Los motores que se recomienda renovar, son de los sistemas de enfriamiento y lubricación los cuales cumplen funciones importantes dentro de la operación de la unidad.

En la actualidad no se cuenta con motores sustitutos para los casos de mantenimiento o fallas de los mismos, siendo lo óptimo contar con motores de repuestos para sustituir cuando sea necesario y bajar de esta forma el período de indisponibilidad, otra razón es que muchos motores se han deteriorado por los años de servicio.

e- Renovación de reguladores de velocidad

Los reguladores actuales se encuentran en condiciones inaceptables de funcionamiento, además son equipos obsoletos por lo que no es posible adquirir repuestos para ellos. Por la función que cumplen en las unidades, es indispensable disponer lo más pronto posible de reguladores nuevos.

f- Renovación de reguladores de voltaje

La situación de estos reguladores es similar a lo indicado en el punto anterior. Debido a las horas de operación acumuladas, no se encuentran en condiciones recomendables para la operación, por lo que es necesario realizar el reemplazo cuanto antes.

g- Repuestos para reparaciones parciales

La necesidad de contar con unidades generadoras que están en capacidad de operar las 24 horas del día y en forma confiable, obligan a realizar mantenimientos preventivos (parciales y overhaul), para obtener mayor disponibilidad para la operación del equipo y por consiguiente satisfacer las necesidades de energía del Sistema Nacional Interconectado.

Es importante destacar que de no efectuarse los trabajos en mención, tendrán implicaciones como indisponibilidades prolongadas del equipo e inclusive pueden ocurrir daños severos en partes importantes del motor, como son cigueñal, block, bielas, etc.

Los principales repuestos a adquirir son:

Equipo principal (cabezotes, bielas, camisas, pistones, empaques, anillos, cojinetes de bancada, biela, árbol de levas, inyectores, bombas de inyección, válvulas escape-admisión, etc.).

Equipo auxiliar (repuestos para sistemas de lubricación, enfriamiento, combustible, aire, calderas, centrífugas, compresores, filtros, reductores de velocidad, etc.).

Repuestos para centros de carga y arranque de motores.

E- - -Planta Moin

a- Motores Eléctricos

La renovación de motores eléctricos corresponde específicamente a los sistemas de enfriamiento y lubricación de las unidades. Estos motores cumplen funciones muy importantes en la operación de la máquina, una avería en ellos implica indisponibilidad de la unidad.

Actualmente no hay motores sustitutos para reducir el período de indisponibilidad tanto en los mantenimientos correctivos como preventivos. Debe mencionarse que algunos de ellos, operan a la interperie y están afectados por un ambiente salino el cual ha acelerado el deterioro del laminado.

b- Interruptor principal

La compra de un interruptor principal de máquina, es importante por las siguientes razones: disminuye en un 95% la indisponibilidad de la máquina ya sea por una falla propia del interruptor o por un mantenimiento preventivo.

El interruptor en sí, sería un sustituto para cualquier interruptor de las cuatros unidades, evitaría periodos prolongados de indisponibilidad en caso de falla severa.

c- Turbocargador

El turbocargador es una parte fundamental para el buen desempeño y eficiencia de los motores de combustión.

Contar con un turbocargador de repuesto por unidad, es indispensable por la razón de que en la instalación se cuenta con 8 turbocargadores funcionando y no existe

ninguno de repuesto. Lógicamente se reducen los tiempos de indisponibilidad de la unidad tanto por intervenciones correctivas o preventivas, de contar con estos componentes de repuesto.

d- Enfriadores de aire

Los enfriadores de aire son componentes vitales para el funcionamiento de la unidad, estos mantienen las temperaturas normales de operación.

Cada unidad cuenta con dos enfriadores, por lo que de contar con varios de reemplazo, facilitará los trabajos y permitirá un rol de mantenimiento preventivo de éstos.

e- Instalación de protecciones por baja presión de aceite en el motor principal

El sistema de protección de lubricación actual no es 100% eficiente, como se pudo ver en el caso de la falla de la Unidad No. 2 la cual no operó como debía, produciendo serios daños a la unidad.

Se requiere contar con un equipo más moderno y de mayor confiabilidad, que opere en el momento preciso y de esta forma evitar altos costos de reparación y lapsos prolongados de indisponibilidad.

f- Repuestos para unidades generadoras de pistón

Se pretende adquirir los repuestos necesarios para ejecutar los mantenimientos parciales y mayores de las unidades generadoras y sus equipos auxiliares instalados en las plantas generadoras.

Los principales repuestos a adquirir son similares a los indicados en el punto 8 de Planta Termoeléctrica Colima.

F- Asesoría Técnica

La renovación de conocimiento e intercambio de información técnica, es fundamental para que los técnicos puedan alcanzar su máximo nivel de conocimiento en la atención del mantenimiento de las centrales eléctricas.

Pese a que se ha considerado que durante los trabajos a ejecutar durante las mejoras, se obtendrá asistencia técnica como complemento de la adquisición de nuevos equipos, también es necesario disponer de una partida fija para solicitar asesoría técnica por eventualidades imprevistas.

Durante el período comprendido de 1989 a 1993 se mantendrán funcionando las unidades de acuerdo con las necesidades del Sistema Nacional Interconectado, esta situación obliga a considerar la necesidad de contratar de asesoría técnica en caso de una falla imprevista.

La partida solicitada sería distribuída equitativamente entre las cuatro Plantas Termoeléctricas San Antonio, Barranca, Colima y Moín.

4-3 Detalle de costos

A- Planta San Antonio Vapor Repuestos necesarios para dos turbinas de vapor, Marca General Electric, series 97878 y 97879 de 5 MW de fabricación estadounidense.

Reemplazo para reguladores de voltaje.	$	140 000.00
Reemplazo de controles de calderas.	$	400 000.00
Reemplazo de gobernadores de velocidad.	$	484 000.00

Renovación moto - bombas de condensado, alimentación y recirculación	$	70 000.00
Renovación interruptores principales y auxiliares	$	125 000.00
Repuestos para overhaul turbina generador. (Incluyen respuestos-reparaciones y asesoría)	$	700 000.00
SUB TOTAL	$	1 919 000.00
Contraparte local	$	65 000.00

B- San Antonio Gas

Repuestos necesarios para dos turbinas de gas, marca AEG-Kanis, modelo MS 5001 N, series 225993 y 225994 potencia efectiva por unidad 18 MW.

Cambio de sistema actual de combustible	$	40 000.00
Un motor de arranque	$	150 000.00
Renovación de motores de torre enfriamiento	$	20 000.00
Repuestos para regulador voltaje	$	120 000.00
Repuestos para regulador velocidad	$	140 000.00
Repuestos para overhaul de turbina gasgen. (Incluyen respuestos, repaciones y asesoría).	$	830 000.00
SUB TOTAL	$	1 300 000.00
Contraparte local	$	62 000.00

C- Planta Barranca

Repuestos necesarios para dos turbinas de gas, marca General Electric, modelo MS 5001 P, series 226268 y 226267 de 18 MW fabricación estadounidense

Repuestos para reguladores de velocidad	$ 120 000.00
Repuestos para reguladores de voltaje	$ 140 000.00
Dos juegos completos para overhaul de motores arranque	$ 40 000.00
Un interruptor principal de máquina.	$ 25 000.00
Un rotor de turbina	$ 700 000.00
Un motor de arranque	$ 250 000.00
Repuestos de turbina - generador (Incluye repuestos - reparaciones y asesoría)	$ 850 000.00
SUB TOTAL	$ 2 125 000.00
Contrapartida local	$ 116 000.00

D- Planta Colima

Repuestos necesarios para:

Cuatro motores de pistón, marca Nordberg, modelo TS-219-31, series, 2012, 0964 /5/6/7, 2 MW, cada una fabricación estadounidense.

Dos motores de pistón marca Sulzer, modelo 12 TAF-48, series 50726-37, 50738-49 de 3 MW cada una, fabricación suiza.

Renovación de enfriadores de agua - aire - aceite	$	400 000.00
Sustitución de centrífugas	$	100 000.00
Renovación de interruptores de equipos auxiliares	$	10 000.00
Renovación de motores eléctricos	$	30 000.00
Renovación de reguladores de velocidad	$	400 000.00
Renovación de reguladores de voltaje	$	180 000.00
Repuestos para overhaul de motor generador Nordberg	$	1 676 000.00
Repuestos para overhaul de motor generador Sulzer	$	760 000.00
SUB TOTAL	$	3 556 000.00
Contrapartida local	$	300 000.00

E- Planta Moín

Cuatro motores de pistón I.H.I. - Semt - Pielstick, modelo 18 PC 2.5 V, series 1D 1841-1/2/3/4 de 6.4 MW cada uno, fabricación japonesa, licencia francesa

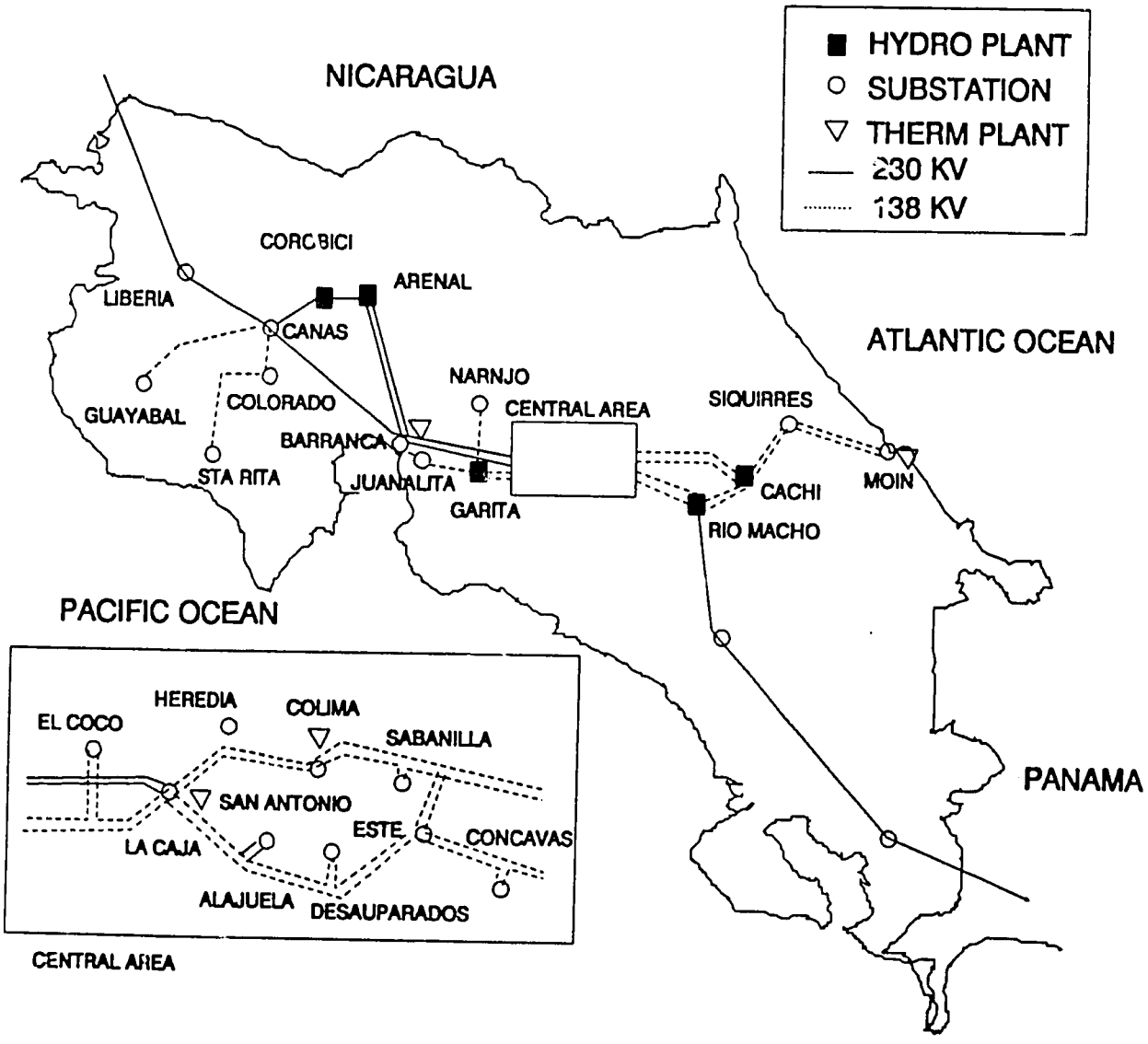
Renovación de motores eléctricos	$	30 000.00
Interruptores principal y auxiliares	$	35 000.00
Cuatro turbocargadores	$	100 000.00
Dos enfriadores de aire admisión	$	100 000.00

Instalación de protección por baja presión de aceite	$	20 000.00
Cuatro juegos para overhaul de motor-generador (Incluye reparaciones y respuestos).	$	1 060 000.00
SUB TOTAL	$	1 345 000.00
Contraparte local	$	320 000.00

F- Asesoría Técnica

Planta Térmica San Antonio	$	50 000.00
Planta Térmica Barranca	$	50 000.00
Planta Térmica Colima	$	50 000.00
Planta Térmica Moín	$	50 000.00
SUB TOTAL	$	200 000.00

APPENDIX 12: LOCATIONS AND CHARACTERISTICS OF ICE HYDROELECTRIC PLANTS



CARACTERISTICAS DEL EMBALSE

PLANTA : LA GARITA

NOMBRE DEL EMBALSE : EMBALSE

LOCALIZACION : PROVINCIA : ALAJUELA CANTON : CENTRAL DISTRITO: 13°

APORTE RIOS/LAGOS	FECHA DE ENTRADA
RIO GRANDE	2/5/58
POAS	2/5/58
RIO ALAJUELA	

AREA : 0,076 Km^2

VOLUMEN TOTAL : 0,564 508 MILLONES DE M^3

VOLUMEN UTIL : 0,500 119 MILLONES DE M^3

ELEVACION : 461,10 M.S.N.M.

NIVEL MAXIMO OPERACION : 461,10 M.S.N.M.

NIVEL MINIMO OPERACION : 455,72 M.S.N.M.

ENERGIA GENERABLE : 142,485 MWH

POTENCIA SOSTENIDA DE 1 M^3/s : 1,2 MW

CONSUMO PROMEDIO POR KWH : 3,000 M^3

CARACTERISTICAS DEL EMBALSE

PLANTA : RIO MACHO

NOMBRE DEL EMBALSE : EL LLANO

LOCALIZACION : PROVINCIA : CARTAGO CANTON : OROSI DISTRITO: 3°

APORTE RIOS/LAGOS : RIO MACHO FECHA DE ENTRADA : 28/7/63

RIO GRANDE DE OROSI (Tapantí) 8/7/74

PORRAS 8/7/74

VILLEGAS 8/7/74

HUMO 8/7/74

BLANCO 28/7/63

AREA : 0,05 Km^2

VOLUMEN TOTAL : 0,500 MILLONES DE M^3

VOLUMEN UTIL : 0,406 582 MILLONES DE M^3

ELEVACION : 1 573 M.S.N.M.

NIVEL MAXIMO OPERACION : 8,04 M.S.N.M.

NIVEL MINIMO OPERACION : 1 M.S.N.M.

ENERGIA GENERABLE : 389,908 MWH

POTENCIA SOSTENIDA DE 1 M^3/s : 3,4 MW

CONSUMO PROMEDIO POR KWH : 1,060 M^3

CARACTERISTICAS DEL EMBALSE

PLANTA	: CACHI		
NOMBRE DEL EMBALSE	: CACHI		
LOCALIZACION	: PROVINCIA : CARTAGO	CANTON : PARAISO	DISTRITO: 4°
APORTE RIOS/LAGOS	: REVENTAZON	FECHA DE ENTRADA :	7/5/66
	NAVARRO		7/5/66
	AGUA CALIENTE		7/5/66
	RIO MACHO		7/5/66

AREA	: 3,236	Km^2
VOLUMEN TOTAL	: 54	MILLONES DE M^3
VOLUMEN UTIL	: 51,306	MILLONES DE M^3
ELEVACION	: 990	M.S.N.M.
NIVEL MAXIMO OPERACION	: 990	M.S.N.M.
NIVEL MINIMO OPERACION	: 928	M.S.N.M.
ENERGIA GENERABLE	: 25 653	MWH
POTENCIA SOSTENIDA DE 1 M^3/s	: 2,2	MW
CONSUMO PROMEDIO POR KWH	: 1,636	M^3

CARACTERISTICAS DEL EMBALSE

PLANTA : LA GARITA (Ventanas-Garita)

NOMBRE DEL EMBALSE : SAN MIGUEL

LOCALIZACION : PROVINCIA : ALAJUELA CANTON : TURRUCARES DISTRITO: 11°

APORTE RIOS/LAGOS : VIRILLA FECHA DE ENTRADA :

CIRUELAS

AREA : 0,017000 Km^2

VOLUMEN TOTAL : 0,659 MILLONES DE M^3

VOLUMEN UTIL : 0,659 MILLONES DE M^3

ELEVACION : 545 M.S.N.M.

NIVEL MAXIMO OPERACION : 545 M.S.N.M.

NIVEL MINIMO OPERACION : 537 M.S.N.M.

ENERGIA GENERABLE : 384 MWH

POTENCIA SOSTENIDA DE 1 M^3/s : 2,12 MW

CONSUMO PROMEDIO POR KWH : 1,800 M^3

CARACTERISTICAS DEL EMBALSE

PLANTA	: COMPLEJO ARENAL - COROBICI		
NOMBRE DEL EMBALSE	: LAGUNA DE ARENAL		
LOCALIZACION	: PROVINCIA : GUANACASTE	CANTON : TILARAN	DISTRITO: 4º
APORTE RIOS/LAGOS (1) (2)	: ARENAL (1 y 2)	FECHA DE ENTRADA :	19/9/78
	CHIQUITO		19/9/78
	CAÑO NEGRO		19/9/78
	SABALO Y 5 MAS		19/9/78
	DE COTE (2)		29/7/82

AREA	: 87,8	Km^2
VOLUMEN TOTAL	: 2 416	MILLONES DE M^3
VOLUMEN UTIL	: 1 990	MILLONES DE M^3
ELEVACION	: 551	M.S.N.M.
NIVEL MAXIMO OPERACION	: 546	M.S.N.M.
NIVEL MINIMO OPERACION	: 522	M.S.N.M.
ENERGIA GENERABLE	: 887 685	MWH *
POTENCIA SOSTENIDA DE 1 M^3/s	: 1,75	MW *
CONSUMO PROMEDIO POR KWH	: 2,057	M^3 *

* DATOS CORRESPONDIENTES A PLANTA ARENAL

CARACTERISTICAS DEL EMBALSE

PLANTA : COROBICI

NOMBRE DEL EMBALSE : STA ROSA

LOCALIZACION : PROVINCIA : GUANACASTE CANTON : TILARAN DISTRITO: 7°

APORTE RIOS/LAGOS (1) (2) : ARENAL (2) FECHA DE ENTRADA : 15/2/83

STA ROSA (1) 15/2/83

AREA : 0,025 Km^2

VOLUMEN TOTAL : 0,143 670 MILLONES DE M^3

VOLUMEN UTIL : 0,097 132 MILLONES DE M^3

ELEVACION : 332 M.S.N.M.

NIVEL MAXIMO OPERACION : 330 M.S.N.M.

NIVEL MINIMO OPERACION : 326 M.S.N.M.

ENERGIA GENERABLE : 1 908 523 MWH

POTENCIA SOSTENIDA DE 1 M^3/s : 2,0 MW

CONSUMO PROMEDIO POR KWH : 1,800 M^3

CON EL APORTE DEL EMBALSE ARENAL

APPENDIX 13: OUTPUT TABLES FOR UTILITY AND BALANCE OF PAYMENTS IMPACTS ANALYSIS

Base Case Financial Flows

			1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Equilibrium tariff														
residential			0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0
commercial			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
small industry			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
large industry			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
public lighting			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
income items														
sales			171.4	187.0	203.7	213.9	253.2	278.7	310.7	340.4	392.2	432.4	476.7	525.6
operating costs (including fuel costs)			14.4	19.0	31.1	41.2	32.8	43.4	29.8	46.3	65.8	19.8	42.9	37.1
pre-tax income			35.5	43.0	43.3	38.8	74.6	83.8	122.4	123.4	147.1	220.4	235.0	270.1
after tax income			35.5	43.0	43.3	38.8	74.6	83.8	122.4	123.4	147.1	220.4	235.0	270.1
capacity expansion														
peak demand		Mw	658	702	741	777	824	875	931	994	1063	1135	1214	1297
installed capacity		Mw	656	656	792.6	828.6	915.9	920.9	1006.6	1058.6	1122.6	1232.6	1304.6	1481.6
investment program	NPV													
foreign investment/generatio	412.4	$USmillio	27.9	45.8	53.3	55.4	32.3	52.4	64.2	81.3	87.5	60.7	81.3	66.5
generation program investme	596.4	$USmillio	39.9	60.9	78.7	80.8	46.3	70.8	84.9	125.3	123.9	87.9	121.9	101.5
total investment	809.9	$USmillio	72.2	106.3	136.4	129.9	74.8	88.2	144.1	179.1	184.3	130.0	188.1	147.7
DSM equipment imports	0.0	$USmillio	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
fuel imports (at cif)	308.0	$USmillio	11.8	16.9	24.9	32.8	25.3	33.9	22.7	38.7	52.9	14.9	34.3	28.9
interest on foreign debt	221.7	$USmillio	2.8	7.4	12.7	18.2	20.8	25.2	30.7	36.8	45.9	50.1	56.3	60.9
principal repayments	58.9	$USmillio	0.0	0.0	0.0	0.0	7.0	8.0	9.3	12.7	13.7	19.1	19.1	21.1
total Foreign exchange	488.8	$USmillio	14.6	23.3	37.6	51.0	53.1	67.1	82.7	88.0	112.8	83.8	109.8	110.8
ICE Impacts														
fuel bill	260.6	$USmillio	14.4	19.0	31.1	41.2	32.8	43.4	29.8	46.3	65.8	19.8	42.9	37.1
revenue loss	0.0	$USmillio	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM expenditures/administra	0.0	$USmillio	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM expenditures/equipment	0.0	$USmillio	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
interest on debt	221.7	$USmillio	2.8	7.4	12.7	18.2	20.8	25.2	30.7	36.8	45.9	50.1	56.3	60.9
depreciation	180.1	$USmillio	9.9	9.9	9.9	9.9	19.9	21.3	23.4	27.9	29.2	38.1	38.1	52.8
ICE income statement impact	662.3	$USmillio	26.8	36.0	53.4	69.1	73.0	90.0	83.7	112.7	140.9	107.9	137.4	150.7
principal repayments	58.9	$USmillio	0.0	0.0	0.0	0.0	7.0	8.0	9.3	12.7	13.7	19.1	19.1	21.1
self-financed investment out	497.6	$USmillio	44.5	63.5	82.1	74.3	42.5	45.9	79.9	87.8	78.8	69.3	84.8	61.2
ICE cashflow impact	1398.8	$USmillio	80.6	109.0	145.1	153.1	142.1	165.1	198.3	241.1	260.7	234.4	279.4	305.9
ratios														
self-financing ratio		[]	-0.450	-0.718	-0.872	-1.332	-3.108	-2.263	-1.484	-0.883	-0.816	-0.994	-0.311	-0.363
debt service coverage (times)		[]	0.364	0.291	0.229	0.158	0.248	0.283	0.444	0.477	0.825	1.251	1.674	1.879
return on equity		[]	0.066	0.073	0.068	0.067	0.069	0.069	0.126	0.112	0.116	0.147	0.134	0.133
return on assets		[]	0.025	0.028	0.026	0.022	0.041	0.044	0.061	0.057	0.064	0.068	0.064	0.087
0														

262

Daylight Savings Time

			1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Equilibrium tariff														
residential			0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0
commercial			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
small industry			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
large industry			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
public lighting			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
income items														
sales			171.4	187.0	203.7	213.0	253.2	278.7	310.7	340.4	392.2	432.4	476.7	525.6
operating costs (including fuel costs)			14.4	19.0	32.8	40.9	32.8	43.8	29.7	46.0	65.8	22.1	42.9	38.9
pre-tax income			38.3	47.5	46.9	44.4	87.0	88.5	127.8	134.1	154.4	226.7	237.3	281.4
after tax income			38.3	47.5	46.9	44.4	87.0	88.5	127.8	134.1	154.4	226.7	237.3	281.4
capacity expansion														
peak demand		Mw	658	702	696	729	774	823	878	938	1003	1072	1147	1228
installed capacity		Mw	658	658	792.6	792.6	828.6	918.6	939.6	1005.6	1068.6	1177.6	1232.6	1304.6
investment program	NPV													
foreign investment/generatio	377.2	$USmillio	0.0	27.9	45.8	53.3	55.4	45.6	69.1	64.2	84.6	74.1	101.5	101.7
generation program investme	545.7	$USmillio	0.0	39.9	99.9	78.7	80.8	64.2	79.8	84.6	118.4	105.7	151.2	153.6
total investment	856.3	$USmillio	32.3	62.3	123.9	127.9	109.3	91.6	119.3	138.4	167.1	147.9	186.4	199.7
DSM equipment imports	0.0	$USmillio	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
fuel imports (a/ cif)	206.5	$USmillio	11.8	18.9	25.0	32.5	25.4	34.0	22.8	39.4	52.9	15.7	34.3	29.3
interest on foreign debt	194.8	$USmillio	0.0	2.8	7.4	12.7	18.2	22.1	27.2	32.7	39.9	45.7	54.1	62.5
principal repayments	46.4	$USmillio	0.0	0.0	0.0	0.0	0.0	7.0	8.0	9.3	12.7	15.9	17.6	17.6
total Foreign exchange	447.7	$USmillio	11.8	18.7	32.4	45.2	43.7	63.1	58.0	79.5	106.5	77.4	106.0	109.4
ICE impacts														
fuel bill	263.4	$USmillio	14.4	19.0	32.8	40.9	32.8	43.8	29.7	46.0	65.8	22.1	42.9	38.9
revenue loss	-0.3	$USmillio	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1
DSM expenditures/administra	0.1	$USmillio	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM expenditures/equipment	0.0	$USmillio	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
interest on debt	164.8	$USmillio	0.0	2.8	7.4	12.7	18.2	22.1	27.2	32.7	39.9	45.7	54.1	62.5
depreciation	154.0	$USmillio	9.6	9.6	9.9	9.6	9.6	19.9	21.3	23.4	27.9	33.7	38.1	38.1
ICE income statement impact	812.8	$USmillio	24.0	31.4	48.9	63.3	60.7	85.3	78.4	102.1	133.7	101.9	135.2	139.6
principal repayments	46.4	$USmillio	0.0	0.0	0.0	0.0	0.0	7.0	8.0	9.3	12.7	15.9	17.6	17.6
self-financed investment outl	482.1	$USmillio	32.3	54.3	77.6	74.6	53.8	45.9	80.2	74.2	72.5	73.8	93.9	94.1
ICE cashflow impact	1296.2	$USmillio	66.9	85.3	137.1	147.5	124.2	157.8	167.6	209.1	248.7	224.8	284.8	293.4
ratios														
self-financing ratio		[]	-1.007	-0.778	-0.725	-1.069	-1.676	-1.978	-1.106	-0.810	-0.496	-0.327	-0.256	-0.251
debt service coverage (times)		[]	0.392	0.371	0.302	0.219	0.343	0.361	0.864	0.867	0.866	1.746	1.738	1.964
return on equity		[]	0.070	0.060	0.073	0.064	0.111	0.101	0.126	0.118	0.117	0.145	0.131	0.133
return on assets		[]	0.028	0.033	0.030	0.027	0.049	0.048	0.065	0.064	0.066	0.090	0.094	0.088
0														

Full DSM Plan

			1988	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Equilibrium tariff														
residential			0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0
commercial			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
small industry			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
large industry			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
public lighting			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
income items														
sales			171.4	187.0	203.7	213.9	253.2	278.7	310.7	340.4	382.2	432.4	476.7	525.6
operating costs (including fuel costs)			14.4	19.0	30.6	40.4	31.5	41.5	27.5	42.7	80.6	17.8	34.4	28.6
pre-tax income			36.3	49.8	52.0	47.7	89.6	96.9	131.3	136.3	156.4	228.0	242.9	283.5
after tax income			36.3	49.8	52.0	47.7	89.6	96.9	131.3	136.3	156.4	228.0	242.9	283.5
capacity expansion														
peak demand		Mw	656	702	692	729	769	815	865	921	982	1045	1112	1183
installed capacity		Mw	656	656	792.6	792.6	828.6	860.6	915.6	1006.6	1058.6	1122.6	1177.6	1268.6
investment program	NPV													
foreign investment/generatio	356.4	$USmillio	0.0	5.6	30.7	51.3	96.6	58.5	42.9	57.5	91.3	94.2	74.1	81.3
generation program investme	518.2	$USmillio	0.0	10.0	44.9	75.2	95.7	79.7	80.0	75.6	125.3	132.5	105.7	121.9
total investment	829.7	$USmillio	32.3	62.3	101.6	124.3	124.2	107.1	119.5	129.5	166.0	174.7	149.9	168.1
DSM equipment imports	18.6	$USmillio	0.0	0.0	0.9	0.7	0.6	1.4	1.8	2.3	3.4	4.2	5.2	6.5
fuel imports (at cif)	179.9	$USmillio	11.8	15.9	24.5	32.0	24.3	32.2	20.7	33.5	48.2	13.0	26.4	21.0
interest on foreign debt	179.3	$USmillio	0.0	0.6	3.[illegible]	6.8	15.4	20.9	24.5	29.3	37.2	45.3	51.2	57.8
principal repayments	39.1	$USmillio	0.0	0.0	[illegible]	0.0	0.0	1.4	7.0	9.3	12.7	13.2	14.9	15.6
total Foreign exchange	416.9	$USmillio	11.8	16.5	29.1	41.5	40.4	56.0	54.0	74.4	101.5	75.7	97.7	100.8
ICE impacts														
fuel bill	230.5	$USmillio	14.4	19.0	30.6	40.4	31.5	41.5	27.5	42.7	80.6	17.8	34.4	28.6
revenue loss	33.9	$USmillio	0.0	0.0	0.6	1.0	1.3	2.0	2.9	3.9	5.4	7.2	9.3	11.7
DSM expenditures/administra	3.5	$USmillio	0.0	0.0	0.2	0.2	0.1	0.2	0.3	0.4	0.5	0.7	0.9	1.1
DSM expenditures/equipment	0.0	$USmillio	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
interest on debt	179.3	$USmillio	0.0	0.6	3.6	6.8	15.4	20.9	24.5	29.3	37.2	45.3	51.2	57.8
depreciation	180.1	$USmillio	9.6	9.6	9.6	9.6	9.6	12.1	19.6	23.4	27.9	29.2	33.7	38.1
ICE income statement impact	589.4	$USmillio	24.0	29.2	43.5	57.9	58.4	72.7	89.0	99.0	120.8	88.6	110.9	114.0
principal repayments	39.1	$USmillio	0.0	0.0	0.0	0.0	0.0	1.4	7.0	9.3	12.7	13.2	14.9	15.6
self-financed investment outl	473.3	$USmillio	32.3	46.7	70.8	73.0	57.7	50.6	78.6	72.0	74.7	80.5	75.6	86.8
ICE cashflow impact	1252.0	$USmillio	66.9	85.5	123.9	140.5	122.6	136.9	172.2	180.7	208.0	208.7	235.2	254.5
ratios														
self-financing ratio		[]	-1.007	-1.216	-0.785	-0.924	-1.260	-1.402	-1.064	-0.716	-0.272	-0.262	-0.316	-0.286
debt service coverage (times)		[]	0.382	0.386	0.387	0.267	0.400	0.441	0.670	0.829	1.288	1.799	1.852	2.096
return on equity		[]	0.070	0.083	0.080	0.066	0.112	0.106	0.127	0.115	0.116	0.143	0.131	0.132
return on assets		[]	0.028	0.035	0.035	0.029	0.052	0.063	0.066	0.066	0.066	0.069	0.065	0.069
0														

GLOSSARY

Actual demand	Maximum demand registered by the meter for the period (day, month, year).
Ampere	The unit of measurement of electric current produced in a circuit by one volt acting through a resistance of one ohm.
Appliance saturation	The ratio of the number of appliances to the total number of customers in the group, expressed as a percentage.
Average demand (kW) per customer	The average power requirement, calculated by dividing energy consumption per customer by the number of hours in the period.
Average kWh consumption	The total kilowatt hours used by a group of customers in a specific period (month, day), divided by the average number of customers in the group for the same period.
Average megawatts	The total energy consumption (MWh) over a specified period divided by the number of hours over the same period.
Baseload plant	A generating plant designed to operate at high capacity factor. Normally, a baseload plant operates several days or months at a time without interruption.
Billing demand	The demand upon which the billing is based, as specified in a rate schedule. The billing demand may be greater or less than the actual demand for a given billing period.
Capacity	The maximum rate at which energy can be produced by a generator. Because of the many factors that can limit this value, it is important to specify clearly the type of capacity involved. Installed capacity is normally the maximum electric output that the generator can deliver. Available capacity is the capacity taking into consideration the mechanical conditions of the machine or other external factors such as ambient temperature or hydroelectric reservoir elevation.

Capacity factor	The average power produced by a generator divided by its installed capacity.
Coincident peak MW Savings	Average MW savings / CP load factor or Maximum MW savings x CP coincidence factor
Coincident peak (CP) per customer	The total demand on the date and time the system peak occurred for a group of customers in a specific time period (day, month, year) divided by the average number of customers in the group for the same time period.
Coincidental demand	That load which occurs at the same time that the peak load of the electric system occurs.
Cooling degree day	A unit measuring the extent to which the outdoor mean daily dry-bulb temperature rises above a base temperature of 72 degrees (providing an opportunity for space cooling). One degree day is counted for each degree of excess over the 72 degrees for each calendar day on which such an excess occurs.
CP coincidence factor	The ratio of demand at the time of system peak to the sum of each individual customer's maximum demand, as calculated by dividing CP (coincident peak) over a designated period of time by NCP (non-coincident peak) for the same time period.
CP load factor	The ratio, in percent, of average demand over a designated period of time to the demand on the date and time the system peaked for the same time period. (kWh) x 100 / (CP demand in kW) x (hours in period)
Curtailable service	The rate tariffs that provide monetary credits to customers in exchange for voluntary load reduction (load shedding) upon request by the supplier on an infrequent basis in times of need such as extreme weather or an unexpected limitation of capacity. Compliance with the request for curtailment is voluntary except for any resulting predetermined monetary penalty.
Customer	An individual, firm, or organization who purchases services at one location under one class of service.

Customer appliance saturation	The ratio of the number of customers having a stated appliance to the total number of customers in the group, expressed as a percentage.
Customer non-coincident peak (NCP) per customer	The sum of each individual customer's maximum demands (day, month, year) divided by the average number of customers in the group for the same time period.
Demand (power requirements)	The rate at which electric energy is delivered at a given instant or averaged over a designated time interval such as 15, 30, or 60 minutes. It may be expressed in kilowatts, kilovolt-amperes, or other units for a system or group of customers, or on a per-customer basis.
Demand interval	The period of time during which the flow of energy is averaged in determining demand, such as 15, 30, or 60 minutes.
Distribution level	Power supply at medium voltage suitable for delivery across short distances. For example, customers who are served with power at a voltage stepped down from 240 kV to 138 kV, 115 kV, or lower.
Diversified demand (coincident demand)	The simultaneous demands of a group of appliances or customers taken as a whole for a specified date and time, such as the hour of the group peak or system peak.
Diversity factor (GCP or CP)	The ratio of the sum of the individual maximum demands of the components of a group, class, or system to the maximum diversified demand (GCP or CP) of the group, class, or system as a whole. The diversity factor is the reciprocal of the coincidence factor and as defined can never be less than one.
End-use	A load representing the final purpose for which electrical energy is used. Some examples of end-use categories are heating, air conditioning, refrigeration, and water heating.
Energy	Energy is a measure of the production or requirements of work. For the electric industry, energy is usually measured in

units of kilowatt-hours (kWh) supplied to or used by an individual customer, average customer, group of customers, or class of service.

Fiscal month — A reporting period that is consistent with that used to report monthly system peaks. A fiscal month starts on the 29th day of the previous calendar month and ends on the 28th day of the current calendar month. Fiscal February is the only exception since it ends on the 25th in a normal year and on the 26th in a leap year.

GCP coincidence factor — The ratio of demand at the time of the group peak to the sum of each individual customer's maximum demand as calculated by dividing GCP over a designated period of time, by the customer NCP for the same time period.

GCP load factor — The ratio, in percent, of average demand over a designated period of time to the demand on the date and time the group peak occurred for the same time period.
(kWh) x (100) / (GCP demand in kW) x (hours in period)

Geothermal capacity — Capacity of plants that use heat from the interior of the earth as a source of steam to run a turbine attached to a generator.

Giga — The prefix meaning billion.

Group coincident peak (GCP) per customer — The total demand for a group of customers on the date and time the group simultaneous peak occurred within a specific time period (day, month, year) divided by the average number of customers in the group for the same time period.

Heating degree day — A unit measuring the extent to which the outdoor mean daily dry-bulb temperature falls below a base temperature of 66 degrees (providing an opportunity for space heating). One degree day is counted for each degree of deficiency below the 66 degrees for each calendar day on which such a deficiency occurs.

Hour ending — The values reported are for the interval that ends at the time specified. For example, hour ending 8 a.m. represents the

value measured from 7:01 a.m. through 8 a.m. All times are shown in eastern standard time (EST) for November-March, and daylight savings time (DST) for April-October.

Housing type — The architectural configuration of the dwelling, such as single-family detached units, attached homes (apartments, townhouses, multiplex), or mobile homes.

Hydroelectric capacity — Capacity of hydroelectric plants.

Interconnection — The connection of one or more electric systems so that the loads of one system can be partially or totally met with the generating resources of other systems.

Interruptible service — The rate tariffs that provide monetary incentives to customers in exchange for the interruption of service to some specific load by the supplier on a pre-established basis in times of need, such as peak system load conditions or an unexpected limitation of capacity. The interruption is imposed by the supplier by means of remotely controlled switches.

Kilo — The prefix meaning thousand.

Load (demand) — The amount of power delivered or received at a given point over a specific time interval. It may apply to a total system, a part of a system, an individual customer, or a group of customers.

Load characteristics — Collectively, all or part of the features of electric service rendered, including: energy usage, demand, time of occurrence, coincidence factor, demand factor, load factor, and similar derivable relationships.

Load diversity — A measure of the variation between the sum of the peaks of two or more individual loads and the peaks of their combined load.

Load factor	The ratio, in percent, of average demand over a designated period of time to the demand on the date and time the system peaked for the same time period. (kWh) x (100) / (CP demand in kW) x (hours in period)
Load profile	As applied to a customer, group of customers, class or system, a load curve is a graph showing the power supplied during a specified period of time as plotted against the time of occurrence. Demands may be expressed in watts (W), kilowatts (kW), megawatts (MW), or as a percent of the average maximum load during the period in question. Time units may be 15, 30, or 60 minutes. Load curves normally cover a 24-hour period for a specific or average day and are plotted from midnight to midnight.
Load research	An activity embracing the measurement and study of the characteristics of electric loads to provide complete and reliable data on the general behavior of the load patterns of the more significant segments of loads served by the electric utility industry.
Load survey	The various steps and processes generally used in making load tests. It encompasses the selection of loads to be studied, the method of collecting and analyzing the load data, and the presentation of load characteristics in a useful form.
Maximum diversified demand	The maximum simultaneous power requirement from a group of energy-using devices or customers.
Maximum MW savings	Average MW savings / NCP load factor.
Mega	The prefix meaning million.
Non-coincident peak (NCP) load factor	The ratio, in percent, of average demand over a designated period of time to the sum of the individual customer's maximum demand for the same time period. (kWh) x (100) / (NCP demand in kW) x (hours in period)
Off peak	The hours of reduced system load as specified by the supplier.

On peak	The hours of high system load as specified by the supplier.
Peak load	The maximum load over a given period.
Peaking plant	A generating plant designed to operate at low capacity factor. Normally, a peaking plant only operates during the hours of highest load.
Power	The rate at which energy is produced. Thus, if 1000 kilowatt hours are produced in 10 hours, the average power involved is 100 kilowatts. However, this term is often used in a broad sense to denote electricity as a commodity, having only a general association with the scientific meaning.
Power factor	The ratio of real power (kW) to apparent power (kVA) for any given load and time, usually expressed as a percentage.
Residential	A customer, sales, or revenue classification covering electric energy supplied for residential (household) purposes.
Service area	The territory in which a utility system is required to or has the right to supply electric service to ultimate customers.
Standby service	Electric energy or capacity supplied by the company to replace all or part of energy or capacity ordinarily generated by the customer's own generation equipment during periods of either scheduled (maintenance) or unscheduled (backup) outages.
Stratum	A subgroup of a population that is homogeneous (like) in nature and does not overlap the other subgroups.
Subtransmission and distribution systems	The systems used to transmit power at medium to low voltage from the transmission system to the consumer.
Supplemental service	Electric energy or capacity supplied by the company to replace all or part of energy or capacity ordinarily generated by the customer's own generation equipment during periods of either scheduled (maintenance) or unscheduled (backup) outages.

Survey period	The entire time span during which the load characteristics are studied.
System maximum (system peak) demand	The maximum demand of an entire system. It is the maximum diversified (coincident) demand of all classes of customers measured at the point of total system supply.
Thermal capacity	Capacity of plants that operate by burning fuel. Includes steam plants (a boiler that produces steam to run a turbine attached to a generator), combustion gas turbines (similar to a jet engine but attached to a generator), and diesel (a diesel engine attached to a generator). The fuel can be oil, natural gas, coal, or uranium (nuclear plants only).
Transmission level	Power supply at high voltage suitable for delivery across long distances. For example, customers such as NASA, large cement companies, and phosphate mining companies that are served with power at 240 kV.
Transmission system	The system used to transmit power at high voltage from the generator to the distribution system. The high voltage is necessary to reduce losses, and the transmission system includes lines and the substations used to increase or decrease the voltage.
Volt	The unit of electromotive force which, if steadily applied, will cause a current of one ampere to flow through a conductor whose resistance is one ohm.
Volt-ampere	The mathematical product of one volt and one ampere; in a direct current, a volt-ampere is equal to one watt.
Watt	The unit of electric power equivalent to one ampere flowing under a pressure of one volt at unity power factor.
Watt-hour	The unit of electric energy that is expended in one hour when the power is one watt.
Wheeling	The act of transmitting power from a generating system to a consumer over lines owned by a third party.

The Office of Energy

The Agency for International Development's Office of Energy plays an increasingly important role in providing innovative approaches to solving the continuing energy crisis in developing countries. Three problems drive the Office's assistance programs: high rates of energy and economic growth accompanied by a lack of energy, especially power in rural areas; severe financial problems, including a lack of investment capital, especially in the electricity sector; and growing energy-related environmental threats, including global climate change, acid rain, and urban air pollution.

To address these problems, the Office of Energy leverages financial resources of multilateral development banks such as The World Bank and the Inter American Development Bank, the private sector, and bilateral donors to increase energy efficiency and expand energy supplies, enhance the role of private power, and implement novel approaches through research, adaptation, and innovation. These approaches include improving power sector investment planning ("least-cost" planning) and encouraging the application of cleaner technologies that use both conventional fossil fuels and renewable energy sources. Promotion of greater private sector participation in the power sector and a wide-ranging training program also help to build the institutional infrastructure necessary to sustain cost-effective, reliable, and environmentally-sound energy systems integral to broad-based economic growth.

Much of the Office's strategic focus has anticipated and supports recently-enacted congressional legislation directing the Office and A.I.D. to undertake a "Global Warming Initiative" to mitigate the increasing contribution of key developing countries to greenhouse gas emissions. This strategy includes expanding least-cost planning activities to incorporate additional countries and environmental concerns, increasing support for feasibility studies in renewable and cleaner fossil energy technologies that focus on site-specific commercial applications, launching a multilateral global energy efficiency initiative, and improving the training of host country nationals and overseas A.I.D. staff in areas of energy that can help to reduce expected global warming and other environmental problems.

To pursue these activities, the Office of Energy implements the following seven projects: (1) The Energy Policy Development and Conservation Project (EPDAC); (2) The Biomass Energy Systems and Technology Project (BEST); (3) The Renewable Energy Applications and Training Project (REAT); (4) The Private Sector Energy Development Project (PSED); (5) The Energy Training Project (ETP); (6) The Conventional Energy Technical Assistance Project (CETA); and (7) its follow-on Energy Technology Innovation Project (ETIP).

The Office of Energy helps set energy policy direction for the Agency, making its projects available to meet generic needs (such as training), and responding to short-term needs of A.I.D.'s field offices in assisted countries.

Further information regarding the Office of Energy's projects and activities is available in our Program Plan, which can be requested by contacting:

Office of Energy
Bureau for Science and Technology
U.S. Agency for International Development
Room 508, SA-18
Washington, D.C. 20523-1810
Tel: (703) 875-4052