Development Discussion Papers

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Development Discussion Paper No. 670
December 1998

Harvard Institute for
International Development

HARVARD UNIVERSITY

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Abstract

While the methodology for the evaluation of electricity generation investments is well developed, little work has been done on how to segregate and compare the costs and benefits of electricity distribution facilities.

Distribution projects have been usually treated as a required technical part of a power system, with their specific costs and benefits rarely evaluated. As electricity systems become unbundled through privatization and competition, this historical treatment of electricity distribution investments must change.

The purpose of this study is to develop and illustrate an integrated analysis of the electricity distribution investments where the financial, economic, stakeholder, and risks aspects of the investment are all carried out in a consistent fashion.

A major investment program that was undertaken to upgrade the distribution system of Commission Federal de Electricidad (CFE) of Mexico from 1990-94 will be the case to which this methodology is applied. Such projects produce a benefit stream that is multidimensional. It includes increased sales of electricity to new customers, a reduction of the rate of pilferage of electricity, energy savings due to reductions in transformers' losses and a reduction in incidence of power shortages. Each of these components represents different financial and economic values to customers as well as to the utility, hence, must be considered separately in an investment appraisal.

The results from this study indicate that this particular investment program was desirable from an economic perspective and from the point of view of the utility. In addition, the stakeholder analysis indicates that the economic externalities accrue largely to the government through a large positive fiscal impact, and to the electricity consumers who will now obtain access to a reliable service that is priced substantially below the amount they would be willing to pay for it. While the project makes some customers very much better off, those whose consumption was previously unmetered will be made worse-off.

Keywords: Mexico, rehabilitation, electricity, distribution, investment, appraisal
JEL Codes: D61, H43, L94

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*This study has benefited greatly from the collaboration and assistance of a number of people. Alfred Thieme has been a constant source of advice and encouragement. Luis E. Gutierrez, and Nissan Ceran spent a great deal of time to provide us with essential information from the World Bank archives and to provide us with a better understanding of the electricity sector in Mexico. The collaboration of our colleagues, George Kuo, Alberto Barreix, Mario Marchesini, Migara Jayawardena, Harmawan Rubino Sugana, and Raghavendra Narain was, as always, helpful and greatly appreciated. Any errors and omissions that remain are our responsibility. Comments on this paper may be addressed to: gjenkins@hiid.harvard.edu.

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I. Overview

CFE (Comission Federal de Electricidad), the national electric utility of Mexico, generates, transmits and distributes electricity to the whole country. In the decade of 1970's, with the oil boom, CFE was able to make sufficient investments in the power sector to meet the 6% to 7% annual growth in demand. The oil price fell in the next decade, investments in the power sector were greatly reduced. Consequently, the power system continued to deteriorate through out the decade. By 1989, the system's conditions had reached a point where substantial investments needed be made to reverse the deterioration trend or else the system's reliability would suffer badly. The power system might even fail to meet new demand, resulting in power shortages.

In the power distribution area, which is the focus of this study, the deferred investment caused the distribution substations to suffer overloading, causing substantial energy losses and power failures. New transformer substations and distribution equipment were needed to mitigate these problems.

There were also more than one million customers who were illegally connected to the power supply without meters. This pilfering of electricity became a severe financial drain on CFE. About one million meters were needed to substantially eliminate this financial loss. Increased efforts toward detection of pilferage had to be made.

As the monopoly provider of electricity, CFE had to install additional substations, distribution lines, hookups and meters to provide electricity to about 700,000 new customers annually during the 1990-1994 period. If not, these new customers would face a power shortage situation. The billing and collecting efficiency at CFE also suffered. New computers and training were needed to improve the efficiency. Routine repair and maintenance services had to be improved to reduce the down time of substations.

To address all of these issues, CFE, under the distribution project, made plans to undertake 14 separate investments costing a total of 5,926 billion pesos or US$ 1.93 billion in 1990 prices. The project was to be completed in 5 years, from 1990 to 1994.

This study will carry out an evaluation of these distribution investments from both the financial and the economic points of view using the data available before the project was implemented. Distribution projects have been usually treated as a required technical part of a power system, with their specific costs and benefits often overlooked. As electricity systems are becoming unbundled through privatization, the traditional appraisal methods of electricity distribution investments must change. The purpose of this study is to develop and illustrate a complete methodology that considers the financial, economic, stakeholder and risk aspects of such investments.

The financial analysis will ascertain the financial feasibility of the project, and determine if the project will be a financial drain to the utility**.**

The economic analysis provides an evaluation of the project from the public's or the economy's point of view. The economic analysis evaluates both the benefits and the costs of the project differently from the financial analysis. For instance, a power project may be financially profitable because of the heavily subsidized fuel price. The economic analysis will evaluate the fuel price at its economic opportunity cost and therefore expose the true net economic value of the project. Another example would be when the capital cost of a project is highly subsidized because the project is being done by a state owned utility. This highly subsidized capital cost often leads to over investment in the sector and the use of overly capital intensive technology[1].

The analysis undertaken in this study also includes a stakeholder analysis which attempts to allocate the net economic benefits or externalities of the project to various groups that gain or lose from the project. These groups usually include the producers, the various classes of consumers, the workers, the low income groups, the government, and the society at large. This study also estimates the poverty alleviation impact of the project.

The environmental costs of a project which are externalized in the financial analysis are internalized in the economic analysis. For some projects, the environmental costs, such as the decommissioning costs of a nuclear power plant, may critically affect the net economic benefits of the project.

As this study demonstrates, for a utility such as CFE operating in a high inflation and highly-regulated environment, the tariff policy of the utility is very important for its financial health. It also highlights the use of an integrated financial, economic, stakeholder and risk analysis of investments in the electricity sector. It is not a post evaluation, but an ex-ante analysis, using the information available at the time this investment was undertaken.

What follows gives a summary of the findings of this study.

Investment Cost and Financing

The project costs a total of Ps 5,926 billions pesos or $ 1,930 million in 1990 prices.

Of the total cost, about 60 % or $1,158 million is financed by CFE; 25% or US$474 million is financed by international lending agencies such as the World Bank; 12% or $230.4 million is financed by suppliers' credits; the rest is financed by government contributions of $38.8 million and consumer contributions of $29.3 million. The cost of foreign source debt is a nominal 11%. The required, or target, real rate of return on equity for CFE is 7%. The real economic discount rate is 12%.

[1] Jenkins, 1985.

Desirability of the Project[2]

The project is economically and financially feasible with an economic NPV of 239 billion pesos or US$ 78 million and a financial NPV of 193 billion pesos or US$ 63 million from the equity owner's perspective.

Major Financial Gains to CFE[3]

The largest financial gain comes from the sales to the one million previously connected but unmetered customers. It will add 2,484 billion pesos, in present value terms of extra revenue to CFE.

Sales to newly connected customers will bring in an additional 2,463 billion pesos of revenue.

A partial reduction in the consumption of those customers previously pilfering electricity will save 367 billion pesos in power production costs.

Savings in energy generation due to the reduction in transformer losses will amount to 481 billion pesos.

The present value of additional sales because of the reduction in power failures will add another 44 billion pesos to CFE's revenue.

Major Economic Costs, Benefits, and Distribution of Project's Net Benefits

The major economic benefits come from the supply of power to the newly connected customers and those affected by power failures.

The project's impacts on different stakeholders are as follows:

(i) Consumers

Newly Connected Customers

The biggest winners are the newly connected customers who stand to gain 2,488 billion pesos.

Previously Pilfering Customers

[2] All the figures quoted in the rest of this section are in present value terms at the level of 1990 prices unless stated otherwise.

[3] Annex 13a.

The biggest losers are the newly metered customers who previously did not pay for their electricity consumption. They will lose 1,833 billion pesos financially. On top of that they will also lose consumers surplus of 132 billion pesos because of their cutback in power consumption[4].

Power Failures Affected Customers

The consumers who have been affected by power failures will gain 182 billion pesos because of less frequent power failures.

(ii) Government and Fiscal Impact

The government will benefit because of the taxes and tariffs collected on the increase in the volume of electricity sales and imported material. This benefit will be partially offset by the government's fuel price subsidies. Overall the government will receive additional revenue of 725 billion pesos.

(iii) Employment and Labor Sector Gain

The labor sector will make a modest gain of 96 billion pesos due to its participation in the construction of the projects and the employment of operating workers by CFE.

(iv) Environmental Impact

The environmental costs of an electricity distribution project is usually minimal[5]. The environmental costs of 432 million pesos will be borne by society in general.

Poverty Alleviation

The low-income group among the newly connected customers will receive in present value terms a consumer surplus gain of 294 billion pesos.

[4] The amount of the electricity cutback is equal to the portion of previously free power consumption which is valued at less than the power tariffs. Annex 19.

[5] Distribution lines and substation structures can be unsightly and depress the property value of adjacent areas but have little environmental impacts such as wildlife habitat destruction, soil erosion or pollutants emission. A recent study has shown that power lines radiation has no significant health effect.

Private Or Public Sector Project

The normal criterion to decide whether a distribution system investment will be undertaken by the private sector is whether the financial NPV is positive with the proper private rate of return on equity. Projects may need to be subsidized, or the tariff structure changed, if the financial NPV is negative and the economic NPV is highly positive. The argument for public sector involvement is much stronger if there are also desirable distributive impacts to be realized by the project.

Any consideration for this particular project to be undertaken as a private project is out of the question. The reason is that the present project is essentially an upgrade of the existing distribution system of CFE, which is a public enterprise. Under the right conditions, the distribution system could be privatized, but isn't at the present time. Until the distribution system itself is privatized, there is no need to consider the current project as a private undertaking.

Sensitivity Analysis

The sensitivity analysis exposes the important variables that affect the final outcomes of the project. The results of the sensitivity analysis often signal the variables that must be considered in the risk analysis. They also tell us what are the important policy variables that management should monitor and evaluate carefully during project implementation.

The sensitivity analysis of the project demonstrates that CFE's tariff policy is crucial to its financial health and that the financial NPVs are sensitive to cost overruns, inflation, and electricity demand as well. The economic NPV is sensitive to our estimate of the willingness to pay for electricity, cost overruns, and the growth rates of electricity demand.

Risk Analysis

The project turns out to be quite risky with respect to the risk variables taken all together. There are a 25% chance for a negative economic NPV and a 37% chance for a negative financial NPV. Overall the project is worthwhile to undertake but keeping in mind that the control of investment costs, the willingness to pay estimates, and the growth of GDP are all critical variables determining its economic feasibility.

II. BACKGROUND

Mexico has two public electric utilities that operate in the country. CFE, is the major electric utility that involves generation, transmission and distribution throughout Mexico. A second minor utility, Compania de Luz y Fuerza del Centro, which is a former private utility and now wholly-owned by CFE, is in charge of the distribution in the area of Mexico city and vicinity.

During the 1970's, a decade of oil boom in Mexico, investment in the power sector was a sizable 13% of gross public investment. The economic crisis of the following decade led the government to reduce CFE's annual investment from US$2.0 billion (real, 1989 prices) to US$1.4 billion in 1988, a reduction of 30%. The investment restrictions imposed on CFE forced the company to postpone its expansion program in generation, transmission and distribution capacity. Although these restrictions did not have a significant negative effect on the quality of service as of 1989, it was anticipated that, if they were not corrected, the generation, transmission and distribution capacity all would soon suffer. This in turn would affect the reliability of the electricity service in Mexico. To correct this situation, the Mexican government along with the CFE decided to implement a ten year investment program called POISE 89 (Programa de Obras e Inversiones del Sector Electrico).

The installed capacity of CFE at the end of 1988 was 23,921 MW of generation plants, 56,000 km of high voltage transmission lines (400 KV, 230 KV and 115 KV), 255,000 km of distribution lines, and 16,500 MVA of distribution transformers. Although most of the country is interconnected through high voltage transmission lines, full exchange of power plant reserves is not possible because of the limitations in the interconnection of different regions.

For the decade 1988-98, electricity sales was expected to grow at 6.6% per annum.[6] Should the demand grow at a faster rate and the investment in the power sector remain stagnant, the reliability of the power supply in Mexico would deteriorate and eventually lead to a shortage situation. Consequently, as part of the ten-year Investment Program, CFE prepared four special subprograms to be implemented in a five-year period to address specific problems in the areas of generation, transmission, distribution and rehabilitation of old thermal plants.

During the period 1989-98, CFE planned to add 17,626 MW in new power plants of which 3,207 MW will be hydroelectric plants. The "Rehabilitation of Thermoelectric Plants" subprogram will renovate older thermoelectric power plants to improve the thermal efficiency and availability of CFE's main plants. The "Transmission" subprogram will expand and improve transmission installations rated 115 KV to 400 KV. Finally, the "Distribution" subprogram was designed to:

(1) reduce the distribution system's power losses,
(2) supply new customers with electricity (new connections),
(3) curtail electricity pilferage,
(4) improve the system reliability by reducing the power outage time,
(5) improve management, accounting and bill-collection efficiency by installing new computers, and
(6) improve maintenance of the distribution system through training and purchase of vehicles.

[6] Estimated by CFE using an econometric model which assumed that the population would grow at an average of 2.16% per year during the period, real public investment at 8.7% and real GDP at 5.1%.

III. PROJECT DESCRIPTION

A. Project Description and Scope

In 1988 the total demand recorded at the substations was 10,982 MW. At the projected demand growth, existing capacity would be insufficient to meet the demand by the year 1994. To overcome that shortfall, CFE plans to add through this project 2,080 MVA of new capacity to 109 substations, install 1,250 MVA in distribution transformers, and construct 18,000 km of secondary feeders. It will make 700,000 new connections per year during the five-year investment period.

In addition to the reduction of technical losses, the project will address the problem of non-technical losses. In the past, CFE was successful at maintaining a collection cycle of 60 days for its electricity bills and had reduced the uncollected accounts to only 0.1% of total billing. Despite this historical performance, the collection system at CFE deteriorated because of the increase in tariff complexity. The project design includes a component to assist the utility's collection system by setting up 665 computer billing stations to improve collection and administration efficiency. As of December 1988, 1,044,000 or about 7% of total customers were connected directly to the distribution lines without a meter. To address this problem, the project includes the purchase and installation of one million new meters on the premises of these customers.

B. Project Cost and Financing

Total investment cost of the project is 5,926 billion pesos or US$1,930 million in 1990 prices. Table 1 summarizes the components and the costs of this project.

Table 1 - Project Subprograms And Costs (Million Pesos, 1990)

Project Name	Total
Proj. 1: Substation Improvements	722,214
Subtransmission Lines	237,874
Primary Feeders	70,378
Proj. 2 Supervisory Control Equipment	50,454
Proj. 3 Distribution lines	427,923
Proj. 4 Capacitors	160,034
Proj. 5 Reclosing Equipment	356,512
Proj. 6 Secondary Network Improvement	1,004,611
Proj. 7 Voltage regulators	19,300
Proj. 8 Vehicles & Equipment	660,618
Proj. 9 Metering Equipment	911,893
Proj. 10 Computer Equipment	83,335
Proj. 11 Other equipment	67,885
Proj. 12 Buildings	349,807
Proj. 13 Maintenance	521,421
Proj. 14 Rural Electrification	281,561
Total	5,925,820
(Total in US$ million at 1990 exchange rate)	1,930

The financing of this project comes from both foreign and domestic sources. Foreign funds, amounting to US$704.4 million, are mainly from multinational development agencies, export credit agencies and suppliers. Table 2 summarizes the sources of funds.

Table 2 - Project Financing (Million 1990 US$)

Source of Financing	Local	Foreign	Total
IBRD Loan		162	162
IDB Loan		151.8	151.8
Eximbank Japan		28.5	28.5
Bank's Hydro Project		25.2	25.2
Turn-key Contracts		106.4	106.4
Suppliers' Credits		230.4	230.4
Consumer Contributions	29.3		29.3
Government Contributions	38.8		38.8
CFE	1,157		1,157
Total	1,225.1	704.4	1930

IV. SOURCES OF INCREMENTAL FINANCIAL AND ECONOMIC BENEFITS

A. Financial Benefits

There are four main sources of financial benefits in this project.

1. New Connections and Increase in Consumption

One objective of this project was to expand access to electricity in both urban and rural areas. Starting in 1990, CFE planned to provide connections to 700,000 new customers each year. Hence a source of financial benefits is the incremental sales from increase in electricity consumption from new connections to customers previously without electricity.

2. Reduction in Transformer Losses

Financial benefits also will arise from the cost savings from the reduction of technical losses at distribution substations. There are different types of technical losses in a distribution network. They range from transformer and subtransmission line losses to maintenance and outage losses. Since the installation of new distribution lines is mainly for connection to new customers, we shall assume the project did not have much impact on line losses. The major technical losses are transformer losses and outage losses.

In 1988, the demand at the substations of the distribution system was 10,982 MW. The increase of 2080 MVA in substation capacity and the addition of 1250 MVA of new transformers will reduce the demand factor of some transformers from 118% to 98%.[7] This will serve to reduce the level of technical losses, which translates into fuel and capacity savings to the utility.

3. Savings due to Curtailed Pilfered Electricity

When the meters are installed, some consumers who previously pilfered electricity will cut back a portion of their demand for electricity. The utility will no longer have to provide this electricity. The savings on capacity and fuel from this curtailed demand will be a financial benefit to CFE.

4. Reduction in Non-technical losses

A large increase in financial revenue will come from incremental sales due to the reduction of non-technical losses, which in this case means improved billing, collection and the metering of one million previously unmetered customers. In 1988, some 1,044,000 customers, equal to 7% of the all customers, were connected to the system but without a meter. Each year, during the 1990-1994 period, 200,000 meters were to be installed for these customers. With new computer systems and training, the efficiency of the accounting departments will be

[7] Demand factor is defined as the demand at the transformer divided by the transformer's rated capacity.

improved. We assume that the billing cycle will be reduced to one month and the amount of uncollected bills will be reduced to 0.1 of a month' billings per year.

5. Reliability Improvement And The Reduction Of Outage Losses

The lack of investment in the distribution network has affected the quality of service to customers. One of the objectives of this project is to reduce the total outage time. The total amount of outage time reduced by the project was estimated to be 12, 29, 55, 97 and 136 minutes for each year, respectively, from 1990 to 1994.[8] The reduction in outages means that CFE can sell more electricity for any given period, yielding additional revenue to CFE. The net financial benefit to CFE will be the additional revenue less the extra fuel cost required to generate this additional supply.

B. Economic Benefits

The economic impacts of this project will come from five areas: (1) additional consumption from new connections, (2) fuel and capacity savings from the reduction in transformer losses, (3) increased consumption due to reduction in outages, (4) curtailment of part of the consumption of the electricity previously pilfered by unmetered customers that will be a loss to the consumers but a fuel saving to the economy, and (5) an environmental impact that mainly includes the land area taken up by distribution lines and substations.

V. FINANCIAL ANALYSIS

A. Assumptions

1. Tariff Policy

There have been several proposals for the financial reform of CFE. One such proposal is for CFE to achieve a 7% real return on new assets. Another is to set electric tariffs on all energy to cover their long-run marginal costs (LRMC). This study has incorporated the "7% return on new assets proposal" through the use of a 7% real return on equity (ROE) in our evaluation.

In 1988, the ratio of the net of tax electric tariff to marginal cost of electricity supply for different customer groups ranged from 14% for the rural (agriculture) customers to 81% for the commercial customers (table 3). In this study, the proposal to equate power prices with marginal costs is incorporated through the use of a tariff adjustment mechanism[9].

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[8] Gutierrez, January 1991, p. 8.
[9] For more complete discussion, see the Sensitivity Analysis in the Financial section of this study.

Table 3 - Average Electricity Tariffs and LRMC in Mexico[10] (1988 US mills/kWh)*

	Tariff (Net of Tax)	LRMC	Price/LRMC Ratio (%)
Residential	27.2	80.9	33.6%
Industrial	32.0	49.9	64.1%
Commercial	57.1	70.4	81.2%
Rural	8.4	59.9	14.1%
Other	33.7	58.9	57.1%

*1988 exchange rate is 2273 pesos/US$.

2. Inflation

Predicting long-term inflation in Mexico is difficult. Inflation rates in Mexico have been volatile historically. Over the 1973-1996 period, the mean inflation rate was 40.7% per annum with a standard deviation of 35.1%. Inflation was 20% in 1988. For this study it is assumed that the rate of inflation will gradually decline over the long run. Based on this assumption, the long run rate of inflation is assumed to be 15% in Mexico.

3. Interest During Construction and Capital Cost

Accrued interest during construction (IDC) is not a cash flow item and hence does not enter the project analysis directly. It is, however, an important financial item for any electric utility because of the way the electric tariffs are set for a regulated utility. For utilities that pay income tax, the omission of IDC in the capitalized cost of the assets would lead to underestimation of depreciation and hence overestimation of income tax. For utilities whose rates are based on rate-of-return regulations, omission of the IDC in the capitalized cost of the assets will also underestimate the rate base and hence future tariffs and revenues.

4. Income Tax and Sales Taxes

The corporate income tax rate in Mexico was 35% in 1989. The VAT tax rate was 15%. Since CFE is not paying corporate income tax, the "Income Tax Status" parameter in the Table of Parameters of our financial and economic model of the project was set to zero[11].

5. Project and Economic Life

Our assumptions on the economic lives of the main types of equipment that make up the 14 different projects are as follows:

[10] Sectoral Electricity Demand Forecast, Mexico, World Bank, 1990, p. 27.

[11] Annex 1a: Table of Parameters. With reference to the set of EXCEL spreadsheets that accompany this case, the calculation of income tax and the impact of IDC and foreign exchange gains and losses that enter the income tax calculation for utilities that pay income tax can be activated easily by setting this parameter to one.

Table 4 - Economic Life of Main Types of Equipment in Projects

Project (project number refer to Table 1)	**Economic Life (Years)**
1, 3, 6, 14	25
2, 4, 5, 7, 9, 10, 13	15
8	6
11	3
12	50

Based on the average twenty years useful life of transformers and distribution substations, we assume a project life of twenty years for the analysis of this project.

6. Accounts Receivable, Accounts Payable, Cash balance

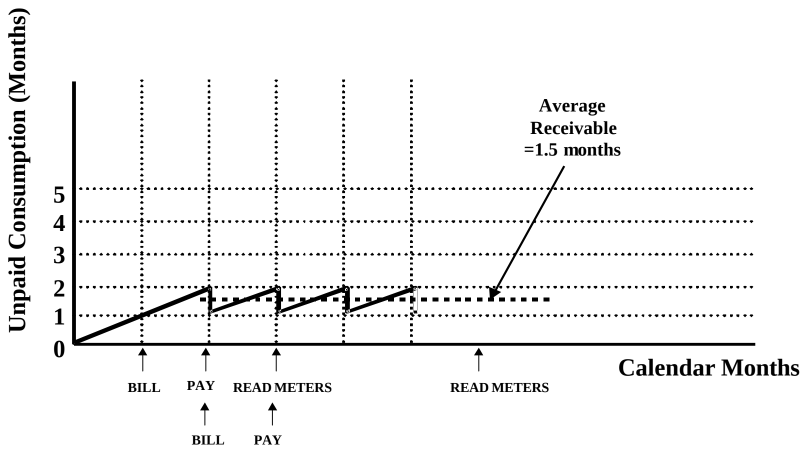
Accounts receivable in this study is determined by the length of billing cycle, collection period and bill collection efficiency[12].

For power companies that conduct quarterly meter readings and bill customers monthly, their estimated consumption will have an average unpaid consumption of 1.5 months of sales as shown in the graph below[13]. This is because when the monthly bill of a customer is sent, there must be at least one month worth of unpaid consumption. Assuming the customer is allowed one month to pay his bill, the unpaid consumption will have been increased by one more month by the time he pays his bill at the end of the month after he received his bill. The average unpaid bill is thus 1.5 months.

[12] Accounts receivable is often assumed to be a fixed percentage of sales.

[13] How often the customers' meters are read is not important. It is the billing cycle that decides this.

Figure 1 - Billing Cycles And Accounts Receivable



The relationship between the length of billing cycle and the level of accounts receivable expressed in months of sales can be written as [14]:

Average Accounts Receivable = Billing Cycle + Collection Cycle/2 (1)

The amount of bad debts written off each year will mean a net reduction of the potential cash flow for the year, hence bad debts written off during the period are reflected through a negative adjustment to the cash inflows for the period.

In this study, the billing cycle is assumed to one month. A customer has one month to pay after the bill is sent. It is also assumed that the bad debts written off each year will be equal to 0.1 month of sales.

Accounts payable are assumed to be one and a half months of expenses excluding labor costs. Cash balances which are held as working capital are assumed to be three months of operating expenses.

7. Construction Period

The construction period for the project is assumed to be 5 years. The total real construction costs are allocated proportionally to each year of the construction period.

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[14] In cash flow analysis, accounts receivable is equal to the unpaid sales whereas in accounting, accounts receivable only refer to unpaid bills. Unpaid consumption is always greater than the unpaid bills.

8. Cost of Capital

The real return on equity was taken as 7%. CFE expects the following funding mix for its projects: 47.4 % from external borrowings, 5.4% from the government and 47.2% from internal sources. The real interest cost of these sources of financing are estimated to be 7.17 %, 8.6% and 7% respectively. Based on this information, we estimated the real weighted average cost of capital (WACC) to be 7.17% and is used as the real discount rate in the analysis from the total investment perspective.

B. Points of View

The financial analysis was conducted from point of view of the utility taking both the perspectives of the equity being invested and the total investment made in the project. From the total investment perspective, the viability of the project is analyzed irrespective of financing arrangements, while from the equity perspective, the debt and its repayment is part of the project's cash flow.

C. Methodology

Share Of Tariff Attributable To Distribution Service

For an integrated electric utility, electricity is sold through "bundled" tariffs – no separate charges are levied for generation, transmission, and distribution. When evaluating the financial benefits of a distribution project, the question of how to apportion the utility's revenue to these various electricity supply components becomes a challenge. Setting internal prices for these components is therefore necessary.

One way to set this internal price for distribution is to multiply the weighted average tariff, less fuel and operating costs, by the share of the distribution capital cost in total marginal capital cost of the system. This internal price of distribution represents the contribution of distribution toward the utility's revenue from the sale of electricity to customers. The following formula is used in the case of the distribution project:

Financial Value of Distribution Service per kWh = (Weighted Average Tariff Net Of Fuel and Operating Costs[15])*[MCD/ (MCG+MCT+MCD)] (2)

where MCG: Marginal Capacity Cost of Generation per kWh
MCT: Marginal Capacity Cost of Transmission in per kWh
MCD: Marginal Capacity Cost of Distribution in per kWh

[15] Include Transmission and Distribution Loss.

Table 5 shows the estimates of marginal cost at CFE.

Table 5 - Marginal Supply Costs (1990 prices, US Cents/kWh)[16]

Marginal Transmission Cost	0.99
Marginal Distribution Cost	1.18
Fuel Cost	3.92
Marginal Generation Capacity Cost	1.26
Operating Cost	0.07
Total	7.42

Inflation and Tariff Policy

The analysis of this project has been conducted in both nominal and real prices to account for the impact of inflation which is assumed to be 15% in the base case. Inflation has both direct and indirect effects on the analysis. The indirect impacts, also known as the tax impacts, are relevant when the equity owner is subject to corporate income tax. The direct effects of inflation take place through changes in accounts receivable, changes in accounts payable and changes in cash balances and the real value of interest expenses.

Because of the high rate of inflation in Mexico, the power company's pricing and profit policy – i.e. whether its prices will cover its inflation-adjusted costs, is the prime determinant of the financial health of the company. An utility's tariff policy can be divided into three separate policy issues: (1) whether to set tariffs equal to their LRMC, (2) whether to index the tariffs fully and immediately to inflation, and (3) whether to set tariffs of different customer classes to reflect their LRMC or to permit cross-customer-class subsidies. We shall refer to the first issue as marginal cost adjustment, the second as inflation indexing and the third as class-tariff parity. A lag in the adjustment in any one of these three areas will mean tariffs lagging behind costs and a potential financial loss for the utility.

Electric tariffs in Mexico have not fully reflected the long run marginal costs of supplying power, including generation, transmission and distribution costs.[17] Nor have they been fully indexed to domestic inflation. In the base case of this study, it is assumed that the real electric tariffs, after they have been raised over 8 years to their marginal cost level by 1996, will be maintained at the current level of long-run marginal costs throughout the project life.[18] It is assumed that nominal tariffs adjusted immediately for changes in fuel costs and will be indexed monthly to the general price level with a three-month lag. Because the incremental nominal costs of supplying power reflect current market prices, and hence fully indexed to inflation with no lag, this lag in inflation adjustment of electricity tariffs will have a net negative impact on CFE's revenues.

[16] Based on Luis Gutierrez, January 1991, pg 5 and estimated data. The exchange rate for 1990 is 3071 pesos per dollar.

[17] When tariff are set to equal the LRMC, the LRMC of generation, fuel and operating cost should include the T&D loss.

[18] The government and CFE signed a new Financial Rehabilitation Agreement (FRA) on August 31, 1989 in which CFE agreed to raise its average electricity rate in eight years to reach the LRMC level by 1996.

Table 6 - Average Electricity Tariffs and LRMC in Mexico (1988 Pesos/kWh)[19]

	Tariff (Net of Tax)	LRMC	Price/LRMC Ratio (%)
Residential	61.28	183.4	33.6%
Industrial	72.7	113.4	71.3%
Commercial	130	160	81.2%
Rural	19	134.8	16.2%
Other	76.6	134.2	57.1%

Table 6 shows that in 1988, all tariffs were substantially lower then their LRMC. Tariffs may differ for different classes of customers for various reasons. This between-class difference may occur even if the weighted average tariff is set to its LRMC level. This can happen when some class-tariffs are higher than the LRMC while others are lower than the LRMC. However, it is assumed in this study, for the purpose of easy comparison, that real tariffs of all classes will reach their LRMC level in 1996. But these marginal-cost based tariffs are applied only to the incremental sales of the project[20].

Discounted Cash Flow

After constructing the cash flows in current pesos, the nominal cash flows then are deflated by the general price index to obtain the real cash flows in 1990 prices. The financial net present values from both the equity and total investment perspectives are then estimated by discounting the annual projected stream of real cash flows with their respective discount rates.

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[19] World Bank, 1990, pg 67.

[20] This is an effort to isolate the financial viability of the project from the impact of the tariff policy on the entire company sales. If these tariffs were to be applied to the entire sales of the company, it would have led to large revenue surpluses for CFE. This is because fully marginal-cost based tariffs would have meant all assets of the utility have to be valued at their replacement costs. With the large share of historical capacity costs that are fixed in lower nominal prices, replacement-cost or marginal-cost based tariffs would have created large amount of surplus revenue for the utility. For a highly controlled utility such as CFE, an all-asset-wide replacement-cost adjusted tariff policy is not likely to happen soon. Because of the "project only" marginal cost indexing assumption made in this study, the full financial impact of the marginal cost pricing principle on the entire sales of CFE is therefore not captured in this study. Better assumptions on nominal tariff escalation can only be based on some realistic financial reform plan of CFE - that is, to calculate future tariffs based on financial requirements necessary to satisfy the reform target. The company-wide marginal cost adjustment issue will therefore not be dealt with in this study.

The adaptation of the "project only" marginal-cost-adjusted and inflation-indexed tariffs for the base case in this study will provide an isolated environment for the evaluation of the financial profitability of the project. Because of the limitations imposed by the tariff issues, the results of the financial analysis must be appraised in the light of the various tariff policy assumptions made and options considered. For the same reason, the results of the economic analysis provide a much more useful investment guideline for the Mexican government, and CFE, or a public financial institution.

D. Results - Financial Analysis

Annexes 11 to 14 show the results of the projected real and nominal cash flow statements for the Distribution project from the total investment and equity perspectives. A summary of these results are given in Table 8a, 8b and 8c.

Revenue-Improving Items for CFE

The direct revenue improvements to CFE due to the Distribution program come mainly from the following:

(1) the elimination of pilfered electricity through the installation of meters on the one million previously unmetered electricity consumers,
(2) the saving in capacity and fuel costs due to the reduction in consumption by those previously pilfering demand,
(3) the reduction of power outage time through better maintenance of distribution facilities and expanded transformer capacity,
(4) the reduction in transformer losses through the installation of new substations and control equipment, and
(5) the sales to newly connected customers through the construction of new distribution lines and connections.

The present value of the incremental revenue, net of fuel and operating costs derived from these items are given in Table 7.

Table 7 - Present Value Of Revenue-Improving And Cost-Saving Items to CFE (1990 Prices)

	PV (Million Pesos)	**PV** (Million US$)
New sales due to Metered Pilfered Demand	2,484,480	809
New Connection Sales	2,463,247	802
Savings in cap & fuel cost (curtailed pilfered demand)	367,873	120
Transformer Loss Reduction	481,126	157
Reliability Improvement Sales (net of generation cost)	44,376	14
Total	5,841,101	1,902

It is clear from this analysis that it is the introduction of metering and the reduction of pilfered demand that has the greatest impact on the financial revenues, followed by the sales to newly connected customers.

Overall Financial NPV of the Project

The overall financial NPV of the base-case project, from the equity's point of view, is 193 billion pesos or US$ 63 million before the risk factors are considered (Table 8b).

~~TABLE 8a:CASH FLOW STATEMENT - Total Investment Perspective (million Pesos, real 1990 prices)~~

			1990	1991	1992	1993	1994	1995	1996	1997	1998	2014	2015
~~RECEIPTS~~													
REVENUE		NPV											
New Connection Sales		1643344	-7493	-5890	8942	39180	90810	143415	200972	199320	198927	202702	0
New sales due to Metered Pilfered Demand		2922917	23724	58656	102650	156649	226409	270426	313637	311173	310678	319235	0
Savings in capacity and fuel cost due to curtailed pilfered demand		432791	8362	17723	26534	34563	42038	42127	40856	40535	40471	41585	0
Savings from Transformer Loss Reduction		481126	27862	31425	35174	39693	45122	44621	44126	43637	43152	36098	0
Reliability Improvement		52207	-56	-44	135	672	1906	3049	4502	4703	4939	11353	0
Change in accounts receivable		-154580	-6578	-10555	-14373	-18814	-25258	-20547	-21969	-10795	-11264	-12096	78933
Government Contributions		98035	23865	23058	22278	21525	20797						
Consumer Contributions		74017	18018	17409	16820	16251	15702						
Total Net Revenue		5549857	87705	131781	198160	289720	417527	483092	582124	588572	586903	598877	78933
LIQUIDATION INCOME													
Building		7930											8499
Vehicles		0											0
Total Liquidation Income		7930											8499
		0											
Cash Inflow		5553219	87705	131781	198160	289720	417527	483092	582124	588572	586903	608651	87432
~~EXPENDITURES~~													
Investment Costs													
Substation Improvements		607321	156541	169135	149180	132087	73520						
Subtransmission Lines		197357	44603	59351	44786	37074	37265						
Primary Feeders		54070	5938	8687	12518	16885	20320						
Proj. 2 Supervisory Control Equip.		38786	4346	6242	8936	12062	14555						
Proj. 3 Distribution lines		318124	11887	40348	74095	115411	145484						
Proj. 4 Capacitors		123076	13832	19898	28382	38294	45964						
Proj. 5 Reclosing Equipment		274092	30486	44382	63305	85283	102589						
Proj. 6 Secondary Network Improvement		747290	28122	95601	174940	270867	339712						
Proj. 7 Voltage regulators		14881	1727	2431	3545	4490	5473						
Proj. 8 Vehicles & Equipment		532890	120218	103048	117249	135455	137656						
Proj. 9 Metering Equipment(project 9)		701427	78553	113962	162289	217940	261353						
Proj. 10 Computer Equipment		64191	7459	10464	14698	19968	23670						
Proj. 11 Other equipmemts(project 11)		52236	5878	8512	12097	16213	19401						
Proj. 12 Buildings		259145	10963	29762	58125	92746	124569						
Proj. 13 Maintenance		420852	80555	96370	103243	102126	102218						
Proj. 14 Rural Electrification		223460	38448	44635	51830	60198	65055						
Cost Overruns			0	0	0	0	0						
Total Investment		5447504	639556	852828	1079219	1357099	1518802						
Operating costs			119	293	513	783	1132	1352	1568	1556	1553	1596	0
Added Generation Costs for reliability improvement		0	0	0	0	0	0	0	0	0	0	0	0
Working capital													
Change in accounts payable		-165135	-16594	-20825	-22281	-23144	-24265	-11300	-8631	-10173	-10619	-11521	74897
Change in cash balance		165135	16594	20825	22281	23144	24265	11300	8631	10173	10619	11521	-74897
Total change in working capital			0	0	0	0	0	0	0	0	0	0	0
Bad Debt		54082	437	1081	1893	2891	4182	4996	5795	5751	5743	5935	0
Taxes													
Sales Taxes		855324	6864	16982	29766	45515	65934	78774	91424	90763	90678	94720	0
Income Tax			0	0	0	0	0	0	0	0	0	0	
Cash Outflow		5553218	646975	871185	1111391	1406288	1590051	85122	98787	98070	97975	102252	0
NET CASH FLOW		0	-559271	-739404	-913231	-1116569	-1172523	397969	483337	490502	488928	506399	87432
NPV @wacc real million peso	**7.17%**	**1**					IRR	7.17%					
NPV @wacc real billion US$)		**0.00**											

~~**TABLE 8b: CASH FLOW STATEMENT - Equity Perspective (million Pesos, real 1990 prices)**~~

	NPV	1990	1991	1992	1993	1994	1995	1996	1997	1998	2014	2015
Net cash flow from total investment		-559271	-739404	-913231	-1116569	-1172523	397969	483337	490502	488928	506399	87432
Debt, Consumer & Government Financing												
IBRD proposed loan		29819	183469	0	0	0	0	-107144	-103521	-100020	0	
IDB proposed loan		0	80706	78006	269757	0	0	0	0	-83005	0	
Eximbank Japan		0	28188	27235	26314	0	0	0	0	-6677	0	
Loan 3083-ME(hydro projects)		0	24993	24148	23332	0	0	0	0	-4812	0	
Turn-key Contract		0	105235	101676	98238	0	0	0	0	-67660	0	0
Supplier Credits		141518	97795	98591	98583	97947	-22333	-21578	-20849	-20144		
Total cash flow		171338	520387	329656	516224	97947	-22333	-128722	-124370	-282317	0	
Net Cash flow after finan	63	-387933	-219018	-583575	-600345	-1074577	375636	354615	366133	206611	506399	87432
NPV @ R(7.00%	**193111**		IRR =			7.8%						
NPV in million US$	**62.88**											

Table 8c - Summary Of Base Case Cash Flow Analysis (1990 Prices)[21]

	Total Investment Perspective [a]	Equity Perspective [b]
NPV (Million of Pesos)	1	193,111
NPV (Million US$)	0	63
P.V of Investment Cost (Million Pesos)	4,645,707	
P.V of Investment Cost (Million US$)	1,201	

[a] The discount rate for the total investment perspective is a real 7.17%
[b] The discount rate for the equity perspective is 7%.

E. Sensitivity Analysis - Financial

We conducted a sensitivity analysis to identify the key variables and to assess their impact on the project's financial NPV. Twelve key variables are identified. They are LRMC adjustment lag, inflation indexing lag, customer class tariff policy, the number of pilfering customers metered, the number of new customers added each year, domestic inflation, investment cost overrun, fuel cost escalation, billing period, GDP growth, foreign exchange rate, and transformer loss reduction.

1. Electric Tariff Policy - Long Run Marginal Cost Adjustment Lag

As mentioned earlier, a utility's tariff policy can be divided into three separate policy issues: (1) whether to set tariffs equal to their LRMC, (2) whether to index the tariffs fully and immediately to keep pace with inflation, and (3) whether to set tariffs of different customer classes to reflect their LRMC or to permit cross-customer-class subsidies. We shall first look at the sensitivity of the financial NPV's to the utility's policy on whether to set the tariffs at the LRMC level and how soon. Table 9 below presents these effects on the financial NPVs if the real tariffs are raised from their 1988 level to reach the LRMC level within different lengths of adjustment period.[22] The greater the length of adjustment, the lower the growth of the real tariff to reach the LRMC level. Such a lower growth in real tariff reduces the NPV. The sensitivity table below shows that for this project, the financial NPVs are sensitive to LRMC adjustment lag; setting the tariff level equal to LRMC later than eight years from the beginning of the reform will cause the financial NPV to become negative.

[21] Annex 10a.
[22] . The government and CFE signed a new Financial Rehabilitation Agreement (FRA) on August 31, 1989 in which the CFE agreed to raise its average electricity rate in eight years to reach the LRMC level by 1996.

Table 9 - The Effect Of LRMC-Adjustment Lag On NPV (Million Pesos)

Number of years to reach LRMC	**Total investment** NPV real	**Equity** NPV real
4	733,499	932,741
6	353,643	549,407
8	1	193,111
9	-660,855	-479,760
11	-1,493,837	-1,327,797
13	-1,995,653	-1,838,627
15	-2,330,378	-2,179,341

2. Electricity Tariff Policy - Inflation Indexing Lag

It was assumed in this study that the electric tariffs will be adjusted continuously to reflect the general inflation in the economy. Because the rate of inflation is not known beforehand, indexing is usually done after the rate of inflation is known and the information officially published. This means there will be a time lag between the adjustment in tariffs and the experience of inflation unless CFE can set tariffs in anticipation of the future inflation. It is rare that the government and consumers would allow electric tariffs to be set in anticipation of future inflation. In the base case of this study, the indexing lag is assumed to be three months.

As the following table shows, the financial NPVs are sensitive to the length of tariff indexing lag. A change in the indexing lag from 3 to more than 8 months will cause the NPV to turn from positive to negative.

Table 10 - The Effect Of Tariff Indexing Lag On NPV (million pesos)

Indexing Lag (months)	**Total investment** NPV real	**Equity** NPV real
0	162,590	358,582
3	1	193,111
6	-53,334	138,831
7	-106,243	84,984
8	-158,728	31,568
9	-210,793	-21,419
10	-262,440	-73,981

3. Electricity Tariff Policy – Customer Class Tariffs

Electricity prices for residential and rural customers are highly subsidized in Mexico. In 1988, the electricity tariff for residential customers was equal to 33% of the long run marginal costs (LRMC) of supply while agricultural users paid only 14%. To bring electricity tariffs in line with marginal costs, a large real increase for rural and residential customers will be required.

In this study, we nevertheless assume in the base case that the tariffs of all customer classes will reach their LRMC level by 1996.

As the sensitivity analysis presented in Tables 11 to 14 shows, the financial NPVs are sensitive to all four customer class tariffs – residential, industrial, commercial and rural electric tariffs. If the residential tariff and the industrial tariff are set at 80% and 90% of their LRMC respectively, it will lead to negative NPVs. This demonstrates that electric tariffs are an important policy variable in determining the financial impact of the project on the utility.

Table 11 - The Effect Of Residential Tariff On NPV (Million Pesos)

Tariff as % Marginal Cost	**Total investment** NPV real	**Equity** NPV real
40%	-458,855	-273,605
50%	-408,921	-222,861
60%	-349,155	-162,100
70%	-278,961	-90,715
80%	-197,750	-8,105
90%	-104,948	86,315
100%	1	193,111

Table 12 - The Effect Of Industrial Tariff On NPV (Million Pesos)

Tariff as % Marginal Cost	**Total investment** NPV real	**Equity** NPV real
60%	-945,200	-769,253
70%	-732,691	-552,903
80%	-504,999	-321,084
90%	-261,120	-72,771
100%	1	193,111

Table 13 - The Effect Of Commercial Tariff On NPV (Million Pesos)

Tariff as % Marginal Cost	**Total investment** NPV real	**Equity** NPV real
60%	-196,124	-6,493
70%	-152,202	38,203
80%	-105,021	86,220
90%	-54,363	137,778
100%	1	193,111

Table 14 - The Effect Of Rural Tariff On NPV (Million Pesos)

Tariff as % Marginal Cost	Total investment NPV real	Equity NPV real
20%	-424,741	-239,592
40%	-371,285	-185,162
60%	-291,108	-103,501
80%	-172,554	17,279
100%	1	193,111

4. The Number Of Pilfering Customers Metered

As we have noted before, the major sources of additional revenue to CFE are the metering of previously pilfering customers and the annual addition of new customers. As expected, Table 15 shows that the financial NPV is highly sensitive to the number of pilfering customers metered. If the total number of pilfering customers metered is reduced by 80,000 to 920,000, it will lead to a negative NPV for the project.

Table 15 - Effect Of The Number Of Pilfering Customers Metered On NPV

Number of Customers Metered	Total investment NPV real	Equity NPV real
1,000,000	1	193,111
960,000	-114,663	76,498
920,000	-229,326	-40,115
880,000	-343,989	-156,729
840,000	-458,653	-273,342

5. The Number Of New Customers Added Each Year

The annual addition of new customers is one of the major sources of additional revenue to CFE. The project plans to add 700,000 new customers annually from 1990 to 1994. Table 16 shows that the financial NPV is sensitive to the number of new customers added each year.

Table 16 - Effect Of The Number Of New Customers Added Each Year On NPV

Number Customers Added Each Year	Total investment NPV real	Equity NPV real
1		193,111
600,000	-152,866	37,135
500,000	-305,733	-118,841
400,000	-458,600	-274,816
300,000	-611,467	-430,792
200,000	-764,334	-586,768

6. Inflation

The real financial NPVs are quite sensitive to inflation because it directly impacts the real amount of cash balances required, and the real value of accounts receivable and accounts payable. In this study, because of the impact of indexing lag, a higher inflation rate will mean lower real electric tariffs which tend to reduce revenue due to the less than unitary price elasticities. The combined effects of these factors have led to the substantial impact of inflation on the financial NPVs.

Table 17 - Effect of Inflation On NPV (million pesos)

Inflation Rates	Total investment NPV real	Equity NPV real
5%	127,348	353,463
10%	57,788	267,195
15%	1	193,111
20%	-52,333	124,649
25%	-101,439	59,501

7. Cost Overrun

For any large and time-consuming construction project, cost overruns are likely to occur. As shown in Table 18, the project's financial NPVs are very sensitive to investment cost overruns. If a 5% cost overrun occurs, the NPV falls by about 231 billion pesos or $75 million.

Table 18 - Effect of Cost Overrun On NPV (million pesos)

Cost Overrun Factor	**Total investment** NPV real	**Equity** NPV real
-20%	925,840	1,122,252
-10%	462,920	657,681
0%	1	193,111
5%	-231,459	-39,175
10%	-462,919	-271,460
15%	-694,379	-503,745

8. Fuel Cost

Fuel costs for CFE account for about 52% of total power cost[23]. Table 19 shows the effect of the fuel cost on NPVs. The net present value of the project will improve as fuel price increases because the resulting increases in real tariffs will lead to a revenue rise because of inelastic demand. At the same time, the reduction in the quantity of electricity demanded will offset the higher fuel costs of generation. Furthermore the higher fuel costs means that the savings from the reduction in transformer losses are increased, hence the financial NPV of the project.

Table 19 - Effect of Fuel Cost On NPV (million pesos)

% Increase in average Level of real fuel cost	**Total Investment** NPV real	**Equity** NPV real
-15%	-160,822	28,939
-10%	-107,109	83,768
-5%	-53,502	138,492
0%	1	193,111
5%	53,400	247,625
10%	106,697	302,036
15%	159,893	356,344

9. Billing Period

The following table indicates that the financial NPV falls as the length of the billing period is increased. There is a clear trade-off between the costs of issuing bills more frequently, and the loss from less frequent billing.

[23] Annex 1b, Table of Parameters, section on Long Run Cost of Power Components.

Table 20 - Effect of Billing Period On NPV (million pesos)

Billing Period (months)	Total Investment NPV real	Equity NPV real
1	1	193,111
2	-154,580	36,934
3	-309,160	-119,242
4	-463,741	-275,418
5	-618,321	-431,595

10. GDP Growth

The demand for electricity in Mexico had been growing at around 6 to 7% per year for the past two decades. The forecasting models used in this study are based on income and price elasticities which project a 5% to 6% of electricity demand[24]. The rest of the historical growth is explained by other factors such as population growth and new connections which are captured by the constant terms used in the equations of the forecasting model. By changing the growth of income (GDP) in the model, we vary the growth of demand. We find that the NPV of the project is highly sensitive to GDP growth.

Table 21 - Effect of GDP Growth On NPV (million pesos)

GDP Growth	Total Investment NPV real	Equity NPV real
2%	-1,231,440	-1,064,939
3%	-864,320	-690,104
4%	-439,670	-256,286
4.9%	1	193,111
6%	599,859	806,570
7%	1,290,033	1,512,791
8%	2,066,255	2,307,489

11. Real Exchange Rate

This project has about US$704.4 million of foreign loans out of a total investment cost of US$2.3 billion. Given the volatile history of real exchange rates and the substantial share of financing through the use of foreign loans by this project, movements in exchange rates are expected to have an impact on the project's NPVs. A devaluation of the pesos tends to increase the debt burden of the project in local currency and diminishes the project's financial NPVs. At the same time, a real devaluation also increases the level of real electricity tariffs through its

[24] Annex 23l, Projected Electricity Demand Growth Rates 1989-2014.

impact on real fuel costs and the long-run marginal capacity costs. This leads to greater sales revenues because of the inelastic price elasticities of demand for electricity. This is offset by the higher power costs. The combined effect of a real devaluation of the pesos is a moderate reduction in the NPVs.

Table 22 - Effect of Changes in Real Exchange Rate On NPV (million pesos)

Change in Real Exchange Rate In year 0	Total Investment NPV real	Equity NPV real
-3%	36,206	224,543
-2%	24,157	214,085
-1%	12,088	203,608
0%	1	193,111
1%	-12,106	182,595
2%	-24,231	172,060
3%	-36,374	161,507

12. Transformer Loss Reduction

The estimation of the transformer loss reduction used in this study is highly uncertain. We have tested the sensitivity from 30% overestimate to 30% underestimate of the losses in the base case analysis. Table 23 summarizes the results of the sensitivity of NPV to transformer loss reduction. The transformer loss only moderately but not critically affects the project's NPVs.

Table 23 - Effect of Transformer Loss Reduction On NPV (million pesos)

Changes as percent Of Base Case Losses	Total Investment NPV real	Equity NPV real
-30%	-144,337	46,781
-20%	-96,224	95,557
-10%	-48,112	144,334
0%	1	193,111
10%	48,113	241,888
20%	96,226	290,664
30%	144,338	339,441

VI. ECONOMIC ANALYSIS

The economic analysis of the CFE Electricity Distribution Project conducted at the domestic price level to allow for the analysis of the project's externalities.[25] These externalities are estimated by taking the difference between the economic net benefit statement and the financial net benefit statement. The first step in conducting an economic analysis is to determine the economic value of electricity, the economic costs of foreign exchange and capital, and the economic conversion factors for all inputs used in the project. These conversion factors are then used to convert the financial statement of net benefits into the economic statement. The externalities are then distributed among different stakeholders in the stakeholder analysis.

A. The Economic Value of Electricity

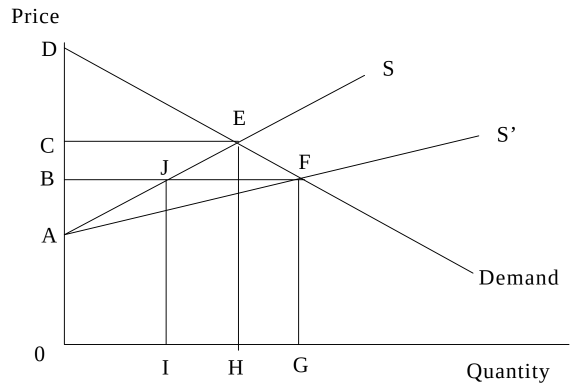
The measurement of the economic value of the output of a project differs markedly between a competitive industry and a regulated industry. A few countries have deregulated and introduced competition in their power industry. However, in most countries where the power industry remains regulated, a power project is typically the investment of a regulated power company within a regulated industry. In the following discussion, it is assumed that the power company concerned is such a regulated utility.

1. Economic Value of Electricity in a Competitive Industry

In a competitive market, when a project increases the industry's supply of electricity (supply curve AS shifts to AS' in Figure 2), the price of electricity falls, the quantity of electricity demanded rises. The production of existing producers decreases. The increase in consumer welfare or willingness to pay is equal to the area HEFG. The resources released by the reduction of production of the existing firms is given by the area IJEH. The economic value of the project's output is the sum of these two areas.

[25] For further discussion, see the Jenkins and Harberger (1997).

Figure 2 - The Impact Of A New Project In A Competitive Industry



IJEH = Saving in resources due to the production cut back of existing firms
HEFG = The incremental consumer welfare (willingness to pay) due to increase in demand

In the case of a *regulated* electric utility, the increase in supply from one of its new projects does not cause the price to change as it is regulated. A regulated utility typically increases its supply to meet a potential power shortage situation at a given price. The value of the electricity supplied by a regulated utility is considered below.

2. Value Of Electricity With Power Shortages

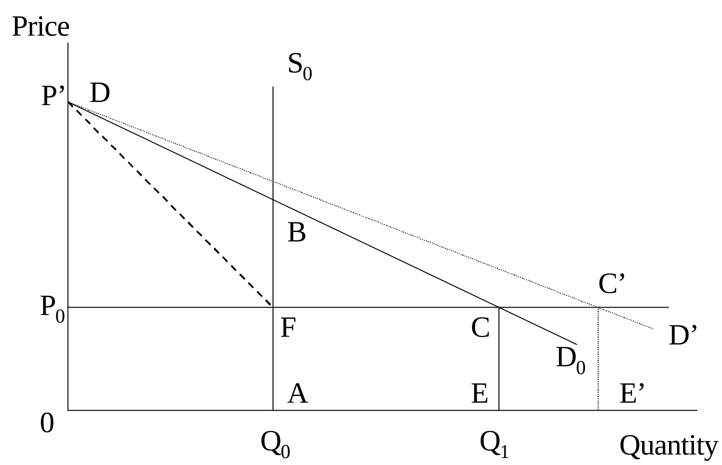
When a power shortage situation arises and persists for some time, some firms and residential customers may decide to install their own generators. Some would decide to conduct their business without electricity while others may simply cut back some of their activities that require electricity. Furthermore, some firms which otherwise would have located in the country or state may decide not to come. We shall refer to the potential demand for electricity in the state discouraged by the power shortages as the "deterred demand".

A power project providing electricity to customers during power shortages or to customers without a connection to power supply will have a direct impact on the consumers directly affected by the power shortages and an indirect impact on the economy by eliminating the deterrence to potential domestic and foreign investment in the state.

The direct benefits of providing electricity to the customers are measured by their willingness to pay for the power. In addition to the direct benefits accruing as a result of elimination of power shortages to those affected customers, there will be the added benefits due to reduction in the deterred demand. Because of the lack of a good measure of the quantity of deterred demand, these benefits are not included in this study. They nevertheless are an important consideration.

In Figure 3, the supply of power by the existing system is fixed at the level Q_0 in year 0, represented by the vertical supply curve, Q_0S_0. Based on the demand curve DD_0 , the demand for power would have been Q_1 at the prevailing tariff of P_0 at year 0. But because of the fixed supply at Q_0, a power shortage of AE persists. The valuation of electricity currently provided is given by the area 0DFA. The valuation of the entire demand (served and unserved), Q_1 , is given by the area ODCE. If the power shortage is *evenly distributed among all customers* through a rotating blackout, the valuation of the "unserved energy" or shortage power is given by the area AFDCE. After the deterred demand is added, the new demand curve is represented by the line DC'D'.

Figure 3 - Demand and Valuation of Electricity with Rotation Of Power Shortages



The highest value a customer is willing to pay can be estimated by the cost of the alternative power supply available to this customer, which usually means own-generation with a small gasoline or diesel electricity generator. For a rural farmer, the fuel cost of running a diesel water pump may provide an estimate of the highest level of willingness to pay. For rural residential usage, the cost of using a kerosene stove may be used.[26]

For the own-generated power to have the same degree of reliability as the power obtained from the electric utility, the own-generation will have to be backed up by another generator. The maximum willingness to pay for the shortage energy (P') with "similar to the utility" reliability can thus be estimated by the cost of own-generation plus the cost of maintaining a reserve generator. Assuming the capacity cost (cost of generator) takes up k% of the *total* self-generation cost, the maximum willingness to pay will be (1+k) times the own-generation cost with no backup.

[26] For example see World Bank, 1996.

Let the quantity of the shortage energy (AE) be S (kWhs), the gross of tax price of electricity ($0P_0$ or AF) be P_0 in year 0, and the cost of own-generation or alternative supply be G_0. The highest willingness to pay for shortage power is therefore

$$\text{Maximum WTP} = P' = 0D = (1+k)*G_0. \qquad (3)$$

We have

$$\text{Area } 0DFA = (P_t+(1+k)*G_0)*Q_0/2 \text{ and} \qquad (4)$$

$$\text{Area } 0DCE = (P_t+(1+k)*G_0)*(Q_0+S)/2\ . \qquad (5)$$

The valuation of the "unserved energy" is given by the area

$$AFDCE = 0DCE - 0DFA = S*(P_t+(1+k)*G_0)/2. \qquad (6)$$

Equation (6) can be rewritten as

$$WTP_S*S= S*(P_t+(1+k)*G_0)/2, \qquad (7)$$

where WTP_S is the average willingness to pay per unit of shortage power, S is the quantity of shortage power, P_t is the prevailing gross of tax price of electricity in year t, P_0 is the gross of tax price of electricity in year 0 when the alternative power cost is estimated or power price at the beginning of the project, k is the capacity cost as a percentage of the alternative power supply cost, and G_0 is an estimation of the alternative power cost.

From equation (7), the average willingness to pay per unit of shortage power is given by

$$\text{Average WTP} = WTP_S = (P_t+(1+k)*G_0)/2\ , \qquad (8)$$

that is, the maximum willingness to pay plus the prevailing tariff in year t divided by 2, or

$$\text{Average WTP} = (P_t+P')/2\ . \qquad (9)$$

For this study, the calculation of the average willingness to pay is given in Table 24.

Table 24 - Own-Generation Costs. Average Tariff and Willingness To Pay in Mexico (1990 Prices)[27]

Own-generation Cost ($/kWh)	0.210
Average Power Price in Mexico (Gross of Tax, 1990, M, Pesos/MWH))	0.114
Average Power Price in Mexico (Gross of Tax1990, $/kWh))	0.037
k (Capacity cost as a share of total own-generation cost)	0.403
Maximum Willingness To Pay (1990 $/kWh)	0.294
Maximum Willingness To Pay (1990 Millions Pesos/MWH)	0.904
Average Willingness To Pay (1990 $/kWh)	0.166
Average Willingness To Pay (1990 Millions Pesos/MWH)	0.509

It is important to note that the maximum willingness to pay will not be affected by the changes in electricity tariffs over time. For this study, the maximum real willingness to pay is assumed to stay constant in real terms at its year 0 (1990 in this case) level. The average willingness to pay for each year of the project is calculated as the average of the maximum willingness to pay and the prevailing real tariff**.**

3. Deterred Demand

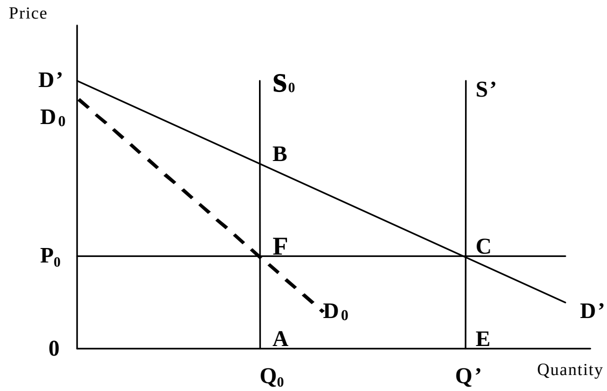
If a country or region's power shortages persist, there will be some potential businesses, investors and even residents being discouraged from settling in the region. We refer to this portion of the potential demand for electricity as the "deterred" demand. As long as the assumption that the deterred customers are of the types similar to the existing customers holds, the willingness to pay for the deterred demand can be represented by the area ECDC'E'. Equation (9) can be used to calculate the economic benefits per kWh when the deterred demand is considered in the study.

4. Value Of Electricity With Balanced Supply

With balanced power supply, there will be no potential demand discouraged. There will be no deterred demand. In Figure 4, the growth in potential electricity demand, due to population and income growth, represented by the shift of the demand curve D_0D_0 to D'D' was expected by the utility. The new power project is built to meet this potential demand. The initial supply of power, represented by Q_0S_0 will be shifted to Q'S'. The value of the additional power supplied by the project is thus represented by the area $AFD_0D'CE$.

[27] Annex 15a.

Figure 4 - Demand and Valuation of Electricity with Balanced Power Supply



If the difference between the maximum willingness to pay 0D' and $0D_0$ is small and negligible, equations (8) and (9) can be used to calculate the total willingness to pay for the newly supplied electricity.[28]

The above discussion is based on the assumption that new power supply does not affect power prices and that the demand curve for power shifts to the right over time. This situation often arises with a regulated electric utility which supplies to a captive market. In a competitive power market, however, a new power project from a competitive supplier may cause the power supply price to fall. This may lead the existing suppliers to reduce production and the demand for power to rise. In this case, the weighted average of the supply price and demand price for electricity should be used[29] to value the electricity.

5. Non-Technical Loss - Pilfered Electricity

There will always be some electricity being pilfered in any power system. We shall refer to the portion of demand that should be metered, but is not, as pilfered demand or pilfered electricity.

For pilfered electricity, consumers are likely to consume the electricity until the marginal utility for their electricity consumption becomes zero. The willingness to pay for the electricity consumed by these consumers is given by the entire triangular area under the demand curve (Figure 5). When meters are installed, these consumers will behave like any other electric consumers. Two things will happen. First, these newly metered consumers will continue to consume electricity but only to the point where the power price is equal to the marginal willingness to pay. To the utility, this will mean new "paid" customers and increased sales at no added costs, except for the meters and metering costs. Assuming that the pilferage behavior is evenly distributed among all groups of consumers, the reasoning and the estimation of the

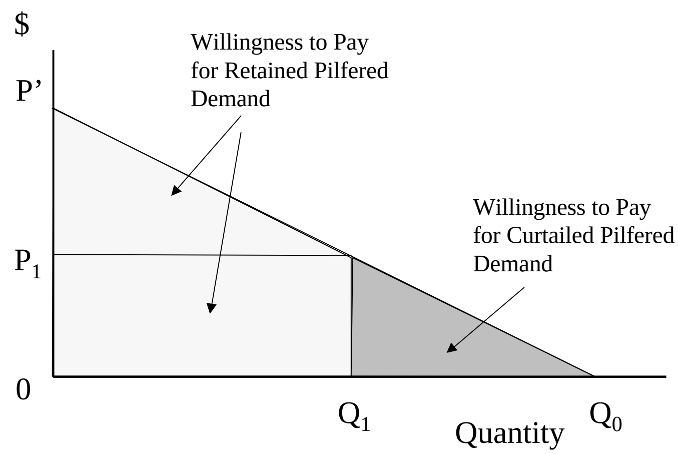
---

[28] The new maximum willingness to pay 0D' is likely to be greater than the initial maximum willingness to pay $0D_0$ as consumers' income level increases.

[29] Jenkins and Harberger, 1996, Ch. 8.

economic value of electricity for this portion of electricity demand is identical to the shortage case. Since the consumers already consumed this portion of pilfered electricity prior to the installation of new meters, this portion of "retained" pilfered electricity consumption adds no economic benefits to the consumers. What has occurred is the transfer of monetary payment from the consumers to the utility.

Figure 5 - Pilfered Electricity, New Meters Installation and Curtailed Demand



P_1: Price of Electricity
Q_0: Demanded before metered = Pilfered Demand
Q_1 : Demand after metered = Retained Pilfered Demand

Second, because the newly metered customers must now pay for the electricity they consume, the portion of electricity which they previously consumed but valued at less than the price will no longer be consumed. The newly metered consumers will lose the value of this portion of power previously available to them at no cost. The average value or willingness to pay for this "curtailed" pilfered electricity, assuming a straight-line demand curve which intersects the horizontal axis, is equal to one half the electricity tariff now charged.

When new meters are installed for those previously unmetered electricity consumers, the quantity of the retained demand or consumption is estimated as the number of new meters installed times the average consumption per customer (Q_1 in Figure 5).

We shall assume the second portion or the curtailed portion of the pilfered electricity to be A% of the retained consumption (the first portion of the pilfered electricity, Q_1) [30]. The total willingness to pay for the curtailed portion of the pilfered demand (WTP_{CPD}) should therefore be

$$WTP_{CPD} = AQ_1(0.5P_1) = 0.5AP_1Q_1 \qquad (10)$$

where P_1 is the price of electricity.

Since the utility no longer has to generate the curtailed portion of the previously pilfered demand, it will mean a fuel and capacity saving to the utility.

6. Technical Loss - Transformer Loss

The new project will reduce previous power losses due to transformer overload. After the project, the power company is no longer required to generate the power previously lost. The saving from the avoidance of generation of the power will mean a saving in fuel and generation capacity to the utility. A financial gain accrues to the utility equal to the marginal generation cost times the reduction in power losses.

There are two main transformer losses, namely the iron loss and the copper loss. At a given level of voltage the iron loss is constant while the copper loss is a function of the square of the current. An overloaded transformer entails more current in the transformer and therefore more copper loss. One can reduce the transformer losses in overloaded substations by installing new transformers. By doing so, the reduced loads of transformers decrease the copper loss while the iron loss remains constant. Since the iron loss remains constant, the incremental benefits from technical losses come only from the reduction of the copper loss.

To evaluate the loss, we calculate the overall running cost of the transformers before and after the project. The overall annual running cost of a transformer equals the annualized capital cost plus the fuel cost. The annual cost of power loss is given by the following:

$$\text{Annual cost of iron loss} = L_I *(C+ 8760 * FC), \qquad (11)$$

$$\text{Annual cost of copper loss} = L_C * D^2 *(C+ 8760 * FC *DLF* TLF), \qquad (12)$$

where L_I = Iron loss in system in kW
L_C = Copper loss in system in kW
C = Annual charge per kW of maximum demand.
FC = Fuel cost (Ps/kWh)
D = Demand Factor = Maximum demand/ Full-load rating of transformer

[30] Let Q_0 be the quantity of electricity pilfered before the project and let Q_1 be the quantity of electricity consumed and paid by the consumers who previously pilfered electricity. Let P' and P_1 be the maximum willingness to pay and the tariff respectively. Assume a linear demand curve, the following equation holds: $A= P_1/ (P' - P_1) = 24.04\%$ where P'= 0.652 Million Pesos/Mwh, and P_1 =0.126 Million Pesos/Mwh in 1990.

capacity
TLF = Transformer Load factor
DLF = Demand Load Factor .

The incremental annual cost of iron loss is zero since the iron loss, the fuel cost and the capital charge per kW are constant with or without the project. The incremental annual cost of copper loss varies with the square of the demand factor.

As of 1988, 29% of the substations were operating at 118% of their nominal capacity. This project aims at reducing that load of substations to 98% in 1994. Without this project, CFE has estimated the loss to be 623.38 MW in 1994. If we assume that the transformers have a ratio of copper loss to iron loss of 4/1, the copper loss is therefore 498.7 MW (0.8* 623.38 MW). The copper loss with the distribution project in 1994 can therefore be calculated as follows.

New Copper Loss = 498.7*[(.98/1.18)^2].

The annual reduction in energy loss will be given by

Reduction In Energy Loss = (Old Copper Loss – New Copper Loss) *

8760*Load Factor. (13)

The reduction in energy loss means CFE will be able to supply the same electricity demand with less power generation and transmission. This is a saving in fuel and capacity costs to the utility.

B. The Economic Costs of Capital and Foreign Exchange

1. Economic Cost of Capital

The economic cost of capital for Mexico was estimated to be 12.3%.[31] This cost was determined as a weighted average of the different domestic net-of-tax saving rates, the gross-of-tax returns on investment for the different sectors and the marginal costs of foreign borrowing.

2. Economic Cost of Foreign Exchange

The economic cost of foreign exchange was found to be 10.61% higher than the official exchange rate.[32] This premium is due partly to the impact of net import tariffs and value added taxes. We also assume that the current account deficit will be sustainable.

[31] Annex 15b.
[32] Annex 15c.

C. Conversion Factors for Inputs

1. Basic Conversion Factors

Investment and operating costs components are made of individual items such as: freight, insurance, non- tradable, and tradable materials and equipment, and tradable fuel costs. Before calculating the conversion factors for the investment and operating items, we have to determine the basic conversion factors of the above individual items.

The following assumptions were made for import tariff, local freight and insurance, and non-tradable material.

Import Tariff

The import tariff used in this study is 10%. This rate is admissible given the prevailing rates applicable after the March 1989 Trade Tariff Regime[33].

Local Freight and Handling

The local freight and insurance costs were also estimated to be 10% of the CIF value. The supply and demand weights for freight and handling were assumed to be 80% and 20% respectively; we also considered that freight and handling were 50% tradable.

Non-tradable material

We assumed 50% and 50% weights for the supply and demand, and 20% content of tradable components. The proportions of the quantity of non-tradable purchased by the project that are accommodated by increased supply and decreased demand are assumed to be 50% and 50% respectively. The foreign exchange content of the non-tradable material is assumed to be 20 percent.

With the above assumptions, we calculated the basic conversion factors, adjusted by the foreign exchange premium, for freight and handling, tradable material and equipment, non-tradable material, and tradable fuel. The calculations and results of the basic conversion factors are summarized in Annex 15.

The next step was to calculate the conversion factors for investment and operating items.

2. Investment Cost Items

For each component of the Distribution Subprogram we broke down the investment cost into tradable and non-tradable materials, skilled and non-skilled labor (Annex 15, 16a-c). We then calculated the conversion factor for tradable and non-tradable materials. The conversion

[33] Mexico Tax Reform for Efficient Growth, World Bank Report No 8097-ME, pg 78

factors for the labor came from a study done by the InterAmerican Development Bank.[34] Finally, we estimated the conversion factor for each investment line as the weighted average of the conversion factors of its components. For instance the cost of Primary Feeders is made of 68% of tradable materials, 15% of non-tradable materials, 11% of skilled labor and 6% of unskilled labor. Given these respective cost shares and the respective 0.999, 0.944, 0.734, 0.482 conversion factors for tradable materials, non-tradable materials, skilled and unskilled labor, we calculate the conversion factor for the Primary Feeders to be 0.931. Tradable materials and equipment are also adjusted for the foreign exchange premium.

3. Operating Costs Items

The operating costs in this study consist of such items as wages, maintenance and repair materials but exclude generating costs such as fuel costs. The conversion factor for operating and maintenance is the weighted average of the conversion factors for labor and material as estimated for maintenance.

4. Generation Cost Items

Generation costs consist mainly of fuel and capacity costs. The conversion factor for generation of 1.094 is calculated based on the following shares and conversion factors.

Table 25 - Shares and Conversion Factors of Generation Cost Components

Cost Item	**Share**	**Conversion Factor**
Fuel	0.5	1.253
Material (tradable, equipment)	0.3	0.999
Material(non tradable, civil work)	0.1	0.944
Skilled Labor	0.1	0.734
Generation		1.094

D. Results - Economic Analysis

The conversion factors were applied to the real cash flow from the total investment point of view to obtain the economic cash flow statement (Table 26). The overall economic NPV of the distribution project is 239 billion pesos or US$ 78 million. The project is economically justifiable because it earns more than the 12.3% real economic cost of capital in Mexico.

[34] Los precios de cuenta en Mexico 1988, 2nd ed. (Mexico city: National Finananciera, 1988).

~~TABLE 26: STATEMENT OF ECONOMIC BENEFITS AND COSTS (million Pesos, real 1990 prices)~~

		NPV	*1990*	*1991*	*1992*	*1993*	*1994*	*1995*	*1996*	*1997*	*1998*	*2014*	*2015*
~~RECEIPTS~~													
REVENUE	3												
New Connection Sales*		3460275	82778	180737	279855	378734	482686	510362	526330	522334	521647	539243	
Retained Pilfered Demand	0.000	0	0	0	0	0	0	0	0	0	0	0	
Consumers loss from Curtailed Pilfered Demand		-132591	-1716	-4243	-7425	-11331	-16376	-19560	-22686	-22507	-22472	-23091	
Savings due to curtailed pilfered demand	1.094	312171	9151	19396	29039	37825	46006	46103	44712	44361	44290	45510	
Savings from Transformer Loss Reduction	1.094	364837	30492	34390	38494	43439	49381	48833	48291	47755	47225	39504	
Reliability Improvement	3.071	211022	2045	5090	9890	16734	25689	26430	27211	28447	29902	69940	
Change in accounts receivable	1.000	-115760	-6578	-10555	-14373	-18814	-25258	-20547	-21969	-10795	-11264	-12096	78933
Government Contributions	0.000	0	0	0	0	0	0						
Consumer Contributions	0.000	0	0	0	0	0	0						
Total Net Revenue		4099953	116173	224816	335479	446589	562128	591621	601889	609595	609329	659012	78933
LIQUIDATION INCOME													
Building	1.000		0	0	0	0	0	0	0	0	0	0	8499
Vehicles	1.000		0	0	0	0	0	0	0	0	0	0	0
Total Liquidation Income			0	0	0	0	0	0	0	0	0	0	8499
Cash Inflow			116173	224816	335479	446589	562128	591621	601889	609595	609329	659012	87432
~~EXPENDITURES~~													
Investment Costs													
Project 1: Substation Improvements	0.933		146037	157786	139170	123224	68586						
Subtransmission Lines	0.931		41521	55250	41691	34513	34690						
Primary Feeders	0.931		5528	8087	11653	15719	18916						
Proj. 2 Supervisory Control Equip.	0.950		4129	5930	8490	11459	13828						
Proj. 3 Distribution lines	0.931		11065	37560	68975	107437	135432						
Proj. 4 Capacitors	0.999		13825	19888	28368	38274	45940						
Proj. 5 Reclosing Equipment	0.999		30470	44358	63272	85238	102535						
Proj. 6 Secondary Network Improvement	0.915		25718	87430	159987	247715	310675						
Proj. 7 Voltage regulators	0.955		1650	2322	3387	4289	5228						
Proj. 8 Vehicles & Equipment	0.999		120155	102994	117188	135385	137584						
Proj. 9 Metering Equipment	0.973		76445	110904	157935	212092	254340						
Proj. 10 Computer Equipment	0.986		7356	10320	14495	19693	23343						
Proj. 11 Other equipment	0.999		5875	8508	12091	16204	19390						
Proj. 12 Buildings	0.905		9927	26948	52630	83977	112792						
Proj. 13 Maintenance	0.661		53257	63712	68256	67518	67578						
Proj. 14 Rural Electrification	0.932		35824	41589	48292	56089	60614						
Cost Overrun	0.879		0	0	0	0	0						
total Investment			588782	783587	995880	1258825	1411475						
Operating Expenses for Metering of Previou	0.661		78	194	339	518	748	894	1037	1029	1027	1055	0
Added Generation Costs for reliability im	1.094		0	0	0	0	0	0	0	0	0	0	
Working capital													
Change in accounts payable	1.000		-16594	-20825	-22281	-23144	-24265	-11300	-8631	-10173	-10619	-11521	74897
Change in cash balance	1.000		16594	20825	22281	23144	24265	11300	8631	10173	10619	11521	-74897
Total change in working capital			0	0	0	0	0	0	0	0	0	0	0
Bad Debt	0		0	0	0	0	0	0	0	0	0	0	0
Taxes													
Sales tax	0												
Income Tax	0												
Cash Outflow		3,860,276	588860	783781	996219	1259343	1412223	894	1037	1029	1027	1055	0
Environmental Impact		435	50	50	50	50	50	50	50	50	50	50	50
NET CASH FLOW		239,713	-472737	-559015	-660790	-812805	-850145	590677	600803	608516	608252	657906	87382
NPV @ Econ. Disc. Rate (real in million p	**12.3%**	**239713**			IRR	13%							
NPV (real in billion US$)		**0.08**			In Billion Pesos (for risk simulatio			239.7					

* The economic value of power to be allocated to new connection sales should be net of the economic costs of fuel and operating expenses.

E. Sensitivity Analysis - Economic

The economic NPV is affected by similar variables to those that impact the financial NPVs. However, because the economic values of different revenue and cost items are measured differently from their financial prices, the resulting economic NPV will differ substantially from the financial NPV. In the economic sensitivity analysis presented below we shall look at how various variables affect the economic NPV.

We conducted a sensitivity analysis to identify the key variables and to assess their impact on the project's economic NPV. Six key variables are identified. They are investment cost overruns, domestic inflation, fuel cost escalation, GDP growth, real foreign exchange rate, and alternative power supply cost.

1. Cost Overruns

For any large and time-consuming construction project, cost overruns might occur. As shown in Table 27, the project's economic NPV is sensitive to investment cost overruns.

Table 27 - Effect of Cost Overrun ON NPV (million pesos)

Cost Overrun Factor	**Economic NPV real**
-20%	972,917
-10%	606,315
0%	239,713
5%	56,411
10%	-126,890
15%	-310,191

2. Inflation

Items such as cash balance, accounts receivable, accounts payable, and electric tariffs will be affected by inflation and will in turn affect the economic NPV. Although, the economic NPV increases with greater inflation[35], the overall impact of inflation on economic NPV is small in this project. Table 28 summarizes the effect of inflation on the economic NPV.

[35] Inflation affects the economic NPV because of its impacts on the real amount of cash balances accounts receivable, and accounts payable. Also, due to the impact of indexing lag, a higher inflation rate reduces real electric tariffs which lower the average willingness to pay but increase the quantity of electricity demanded. The combined effects of these factors on economic NPV is uncertain – the economic NPV may go up or down..

Table 28 - Effect of Inflation On NPV (million pesos)

Inflation Rates	Economic NPV real
5%	229,908
10%	234,367
15%	239,713
20%	245,080
25%	250,218

3. Fuel Cost

Higher fuel costs will increase the savings from the transformer loss reduction and hence improve the economic NPV. But higher fuel costs also mean higher tariffs which depress demand. A smaller demand means smaller benefits for newly connected customers. These two effects tend to offset each other, leaving a moderate negative impact on the economic NPV.

Table 29 - Effect of Fuel Cost On NPV (million pesos)

% Increase in Real fuel cost	Economic NPV real
-15%	389,617
-10%	338,919
-5%	288,962
0%	239,713
5%	191,139
10%	143,213
15%	95,907

4. GDP Growth

Higher GDP growth will increase the demand for electricity and the per customer consumption of electricity which in turn will affect the economic benefits to the newly connected customers as well as the gain from reliability improvement. The results given in the following table show that changes in the growth rate of GDP, which translate into changes in demand for electricity, have a significant impact on the economic NPV.

Table 30 - Effect of GDP Growth On the growth of Electricity Demand and Project NPV (million pesos)

GDP Growth	**Economic** NPV real
2%	-652,575
3%	-380,055
4%	-72,169
4.9%	239,713
6%	655,911
7%	1,123,905
8%	1,639,007

5. Real Exchange Rate

An increase of the real exchange rate will also increase the cost, in pesos, of tradable investment items. This effect will reduce the economic NPV. However, since the fuel costs are linked to the exchange rate, such an increase of the real exchange rate will raise the fuel costs and hence the savings from the reduced power generation due to the loss reduction and curtailed pilfered consumption. Moreover, the electricity prices are allowed to adjust to the cost of fuel, the increase in real exchange rate will also raise the electricity tariffs, reducing the quantity of electricity demanded. The higher tariffs will increase the average economic value per unit of electricity consumed by the newly connected customers. Thus, the net impact of the real exchange is uncertain. In this study, a devaluation has a moderate negative impact on the economic NPV. Table 31 summarizes the results of changes in the real exchange rate on the economic NPV.

Table 31 - Effect Of A Once And Final Real Exchange Rate Change On NPV (million pesos)

Real Exchange Rate Change	**Economic NPV real**
-3%	351,386
-2%	314,122
-1%	276,898
-0%	239,713
1%	202,566
2%	165,457
3%	128,386

6. Alternative Power Supply Cost

The per kWh economic value of electricity supplied to newly connected customers depends on the estimate of the cost of alternative power supply which is defined as a multiple (n) of the benchmark electric tariff of 1990. For this study it is estimated that the cost of own-generation is 5.04 times the average gross-of-tax electric tariff in Mexico in 1990 or 904 pesos per kWh.[36] As Table 32 shows, the economic NPV is very sensitive to the alternative power supply cost factor.

Table 32 - The Effect Of Alternative Power Supply Cost Factor On Economic NPV (million pesos)

Alternative Supply Cost Factor	Economic NPV (real)
-25%	-662,847
-15%	-307,792
-10%	-126,895
-5%	55,704
0%	239,713
5%	424,901
10%	611,088
25%	1,174,307

VII. DISTRIBUTIVE ANALYSIS

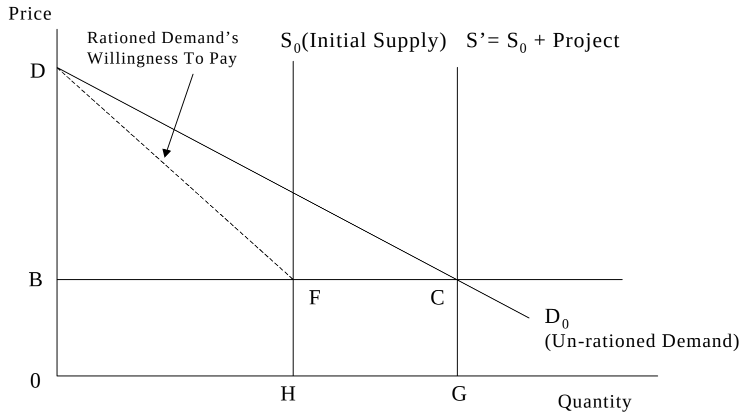
A. Measurement of Project Output's Impact on Stakeholders

In the case of a regulated electric utility, the increase in supply from one of its new projects does not cause the price to change. An utility typically increases its supply to meet a power shortage situation at a given price. With the additional output from the project, the utility's existing output and output price are not affected. In Figure 6, when the product price is 0B, the initial production is 0H. The potential demand is 0G. There is a supply (power) shortage of HG. The initial consumer surplus is BDF. When the project increases the total output by the amount HG, the consumer surplus gain (FDC) is equal to the economic value of the project output or shortage power (HFDCG) less the financial value of the output (HFCG). [37] This consumer surplus gain is computed in this study as the externality which is the difference between the economic value of the electricity and the gross of tax sales revenue of the same electricity.

[36] See Annex 15a, Economic Value of Electricity.

[37] Because CFE operates in a regulated environment, the distributional impact of electricity consumption is calculated somewhat differently than the standard procedure explained in the Jenkins-Harberger Manual. The basic concept remains the same.

Figure 6 - The Impact of a New Project in a Regulated Industry



B. Measurement of Project Cost's Impact on Stakeholders

The externality of generation cost savings due to transformer loss reduction and the curtailment of part of the pilfered demand is distributed between a government revenue gain and a labor loss for the following reasons. As we can see from Table 33 below for the calculation of the conversion factor for fuel cost, the main cause of the divergence between the economic value and the financial value of fuel is due to the premium on foreign exchange and the 25% government subsidy on the fuel price[38]. Since the utility no longer has to generate the lost power, the fuel for this power will no longer be purchased, so the government gains from not having to provide the fuel price subsidy and from the foreign exchange premium saved. This explains why we allocated the fuel cost externality mainly to the government.

[38] For details of computational procedure of the table, see Annex 16a Economic Analysis - Basic Conversion Factors.

Table 33 - Fuel Cost Conversion Factor

	Financial Value	Conversion Factor	Economic Value Unadjusted. for Foreign Exchange Premium	% Tradable	Foreign Exchange Premium	Financial Value * % Tradable * Foreign Exchange Premium	Economic Value adjusted
Fob Price	1,000	1	1000	100%	10.61%	106.12	1106.12
Port Charges, Transport And Insurance	100	0.933					93.3
Local Freight & Handling	90.00	0.933					83.93
Sales tax	134.88						
Subsidy	250						
Total	875						1096.75
Conversion Factor	1.253						

Another example is the allocation of the generation cost externality. As we can see in Table 34, the major divergences between economic costs and financial costs of the inputs occur in the fuel and skilled labor costs. For this reason, the externality of generation cost was allocated between government and labor.

Table 34 - Generation Cost Conversion Factor Calculation

	Share	Conversion Factor
Fuel	0.5	1.253
Material (tradable, equipment)	0.3	0.999
Material (non-tradable, civil work)	0.1	0.944
Skilled Labor	0.1	0.734
Conversion Factor		1.094

C. Allocation of Project Externalities - Overall Results

The overall results of the distribution of the project externalities are given in Table 35.

Table 35 - Distribution Of Project Externalities (Millions Pesos, 1990 Prices)

	(Millions Pesos)	(Millions US$)
Government	725,063	236
Consumers		
Newly Connected	2,489,321	811
Payment on Previously Pilfered Electricity*	-1,831,753	-596
Curtailed Pilfered Demand	-131,989	-43
Power Failures Affected	182,358	59
Labor	96,694	31
Society	-432	-0.1

D. Consumers

The consumers will have the most to gain from this project but the impacts on the different types of consumers are quite different.

Newly Connected Consumers

The connections to new customers contribute a major economic gain to the economy. Without new connections, this group of new customers would have to live either without electricity or to provide their own alternative power generation. The alternative power generation cost is typically two to three times the marginal power generation cost of the utility. This high alternative power generation cost also means high willingness to pay for power by those customers who would have to live without power supply if the new connections were not made. This has led to a very high consumer surplus gain 2,488 billion pesos in real NPV[39] to those newly connected consumers.

Previously Pilfering Consumers

While the newly connected customers are the biggest winners in economic benefits, the newly metered customers who have been hitherto unmetered are big losers financially. For the electricity they were able to consume for free before the new meters are installed, they now have to pay for it. In addition to these financial losses, this group of customers will also reduce their power consumption to the point where the willingness to pay is equal to the electric tariff[40]. For those customers who previously had pilfered electricity, they will continue to consume the major portion of their previous consumption

[39] Annex 19, Allocation of Externalities.
[40] For details on this discussion, see Appendix II, the Pilfered Electricity Demand section.

but will lose a small portion whose value is now less than the price of the electricity[41]. While these consumers will not gain nor lose in utility on the first portion of their consumption, they lose financially in having to pay for the power which they didn't have to pay before. This financial loss to the consumers amounts to 1,833 billion pesos. The curtailment of this part of the previously pilfered electricity represents a consumer surplus loss of 132 billion pesos to this group of consumers. The total loss suffered by this group of customers is 1,965 billion pesos.

Consumers Who Previously Suffered Losses During Power Failures

The improvement of power reliability is another source of economic gain. The cost of power failure to the consumers is very high, 12.5 times the 1990 electric tariff. It was estimated to be US$1 per kWh versus the long run marginal power cost of US$0.07 per kWh [42]. Electricity consumers' willingness to pay for the electricity during power failures is thus very high. Even though the reduction in power failure time is 136 minutes per year, it adds 182 billion pesos of consumer surplus to CFE's customers.

All consumers

Overall, the consumers as a whole will gain 705 billion pesos from this project.

E. Labor

The labor sector has a gain of 96 billion pesos mainly from their participation in the construction of the investment projects and employment in the production of power[43]. This gain is due partly to the protected sector wages being higher than the opportunity cost of labor. When the utility reduces power production because of the reduction in transformer loss, the labor sector will lose some financial benefits. When the utility increases power production, the labor will gain some financial benefits.

F. Government

The government makes a large gain from the sales tax it collected from the electricity sales to newly connected customers and the newly metered customers. This gain is somewhat offset by the increase in the government's oil price subsidies. The government will also gain from the import duties it will collect on the material, machinery and equipment that are to be imported[44]. Offsetting this revenue gain is the loss incurred by the government through the foreign exchange premium that is lost when tradable goods inputs are used by the project. Overall the government will gain 725 billion pesos from the project[45].

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[41] For a more complete discussion, see Appendix II, the section on Pilfered electricity.
[42] Luis Gutierrez, 1991, p. 8
[43] Annex 20a, Distribution of Project Externalities.
[44] For itemized gain or loss by the government, refer to Annex 19.
[45] Annex 20a, Distribution of Project Externalities.

G. Poverty Alleviation

Electricity Projects can have a direct and an indirect impact on poverty alleviation.

Direct Impact

The economic welfare of a group of people can be measured by the aggregate monetary income of the group or by the economic welfare the group enjoys. Governments often find it necessary to provide their poorer citizens with essential services such as transportation, water supply, electricity, health care and schools. These services are often labeled as necessities. In the framework of a cash flow analysis, they simply mean services that command very high willingness to pay (WTP) when they are not available. When roads and schools are provided free of charge by the government, the benefited citizens are receiving a very high consumer surplus that is equal to the WTP less monetary charges which are zero in this case. If this group of consumer-surplus recipients also belong to the low-income group, the gain of the consumer surplus by this group is a measurement of poverty alleviation even if the consumer surplus is not provided in any monetary form.[46] When a project that directly provides a product or service such as electricity in our case to the low income group, the poverty alleviation impact of the project can be measured by the consumer surplus gain by this group of electricity customers. This is what we shall call the direct poverty alleviation impact of a project. This impact can be calculated as follows[47].

$$\text{Direct impact} = (\text{quantity of electricity sales to new residential customers})^* \\ (\text{low income group share})^* \{(\text{Maximum WTP} + \text{Tariff})/2 - \text{Tariff}\} \qquad (14)$$

The direct poverty alleviation impact of this project is estimated at 294 billion pesos.[48]

[46] It is important to note that the WTP measurement is in fact a measurement of the monetary equivalent of the goods or services which the group receives.

[47] In this study, the share of low income group in total residential customers is 40% and it is assumed that on average the maximum willingness to pay of the group is 80% of the maximum willingness to pay of all customers.

[48] Annex 20c.

Indirect Impact

Other than the direct poverty alleviation impact provided through the direct consumption of the project's output by the lower income group, a project can also be beneficial to the economy that in turn will benefit the lower income group indirectly through higher employment and better wages caused by the project. We shall call this the indirect poverty alleviation impact of the project.[49]

Environmental Impact

There is a small negative environmental impact of 432 million pesos which is borne by the society at large. [50]

Reconciliation of Economic, Financial and Distribution Analysis

Using a common real economic discount rate of 12.3%, we find that the values in this case reconcile so that the economic NPV is equal to the financial NPV (evaluated using the economic discount rate) plus the sum of the distributional impacts brought about by the project (see Table 36).

Table 36 - Reconciliation Of Economic And Financial Values Of Inputs And Outputs (million Pesos real)[51]

Economic NPV at Econ. Discount Rate	=	Financial NPV at Econ. Discount Rate	+	PV Externalities at Econ. Discount Rate
239,713	=	-1,252,322	+	1,492,034

[49] The indirect impact is not calculated in this study. In principle, this indirect impact can be measured by an accounting of the employment and wage imacts on the lower income groups.

Wage content of output ={(electricity sales (pesos) to industrial customers) / (electricity input/output ratio) }*(labor input/output ratio)

Indirect Impact = *incremental* wage bill that is due to electricity provided by the project.

The same formula can be applied to the commercial customers.

[50] The environmental impact of distribution is small since it involves only small substations, transformers and low-voltage wires. Occasionally, unsightly wires may also have a negative impact.

[51] Annex 20b.

VIII. RISK ANALYSIS OF FINANCIAL AND ECONOMIC RETURNS

The base case analysis provides a single-value scenario with assumptions reflecting their most likely values; it does not provide a full picture of the project risk. To overcome this deficiency, we conducted a risk analysis that takes into account the variability of those variables identified in the sensitivity analysis. The probability distributions of the assumptions are shown in Table 37 below.

The risk variables in this project are the rate of inflation, the change in real fuel costs, the investment cost overrun factor, the growth of GDP that affects the growth in demand, and the average level of the real exchange rate, the quantity of transformer loss reduction, and the alternative power supply cost factor. It should be noted that although the electric tariff is an important factor in deciding the financial NPVs, it is not included in the risk analysis because it is a policy variable.

A. Risk Variables

Table 37 - Assumptions of Risk Variables

Risk Variable	Probability Distribution	Base Case Mean Value	Range Value	Probability Distribution
1. Inflation Rate	Step (Independent Yearly)	15%	0% to 5% 5% to 10% 10% to 15% 15% to 20% 20% to 25% 25% to 30% 30% to 35%	5% 15% 40% 20% 10% 5% 5%
2. Investment Cost Overrun Factor	Normal	0%	15% to 15%	Mean 0%, Standard Deviation 4%
3. Annual Percentage Change in Real Fuel Cost	Step (Independent, yearly)	0%	-40% to -30% -30% to -20% -20% to -10% -10% to 0%% 0% to10% 10% to 20% 20% to-30% 30% to 40%	4% 13% 25% 17% 8% 8% 13% 13%
4. GDP Growth	Normal	4.9%	1.9% to 7.9%	Mean 4.9%, Standard Deviation 1%
5. Percentage Change in Average Real Exchange Rate	Normal	0%	-23% to 23%	Mean 0, Standard Deviation 7.75%
6. Transformer Loss Reduction Factor	Normal	0	-15% to 15%	Mean 1.0 Standard Deviation 5%
7. Alternative Power Supply Cost Factor	Normal	0	-25% to 25%	Mean 0 Standard Deviation 5%

1. Inflation

Inflation in Mexico in the 1960’s until 1972 remained low - within the range of 1.5% to 5%. The OPEC oil price hike of 1973 had led to double-digit inflation in 1973 and the years thereafter as illustrated in Figure 7.

Figure 7 - Inflation in Mexico, 1949-1996

From 1973 to 1982, inflation fluctuated between 12% to 28% range, from 1984 to 1988, between 65% and 114%. Inflation in 1989 was 20%. It stayed at the double-digit range of 15% to 27% for the next three years and then dropped to 9.7% and 6.7% in 1993 and 1994. It climbed back up to 35% in 1995 and 38% in 1996. Inflation during the 1973-1996 period had a mean of 40.7% and a standard deviation of 35.1%.

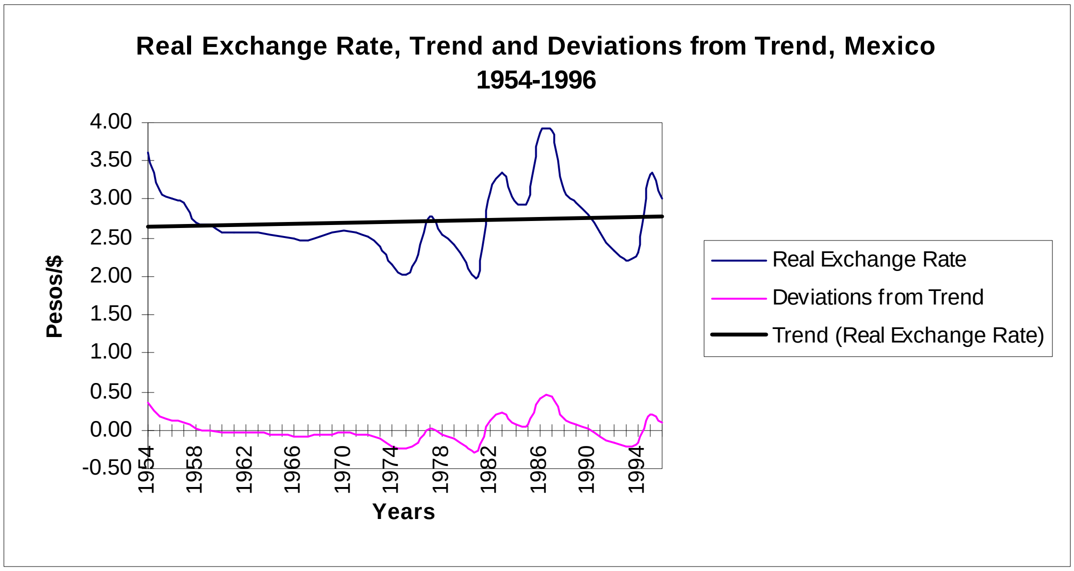
Fiscal discipline, monetary policy and trade balances are the main determinant factors of Mexican inflation and exchange rate adjustment. The general levels of inflation and exchange rate depend on the monetary, fiscal and trade policy of the government. The year to year changes of these two variables may be viewed as fluctuations around their general levels subjected to random influences. Of course, making long term inflation and exchange rate forecasts must be subject to both of these uncertainties. The country's political environment, government policy and international forces can not be predicted with precision. To the extent that we can in general assume that the government will learn from experience and that our present understanding of the economy is sufficient to control the economy within certain limits, future range of inflation and exchange rate fluctuations will be narrowed over time.

The inflation and exchange rate assumptions or forecasts used in project appraisal are subjected therefore to two risks: (1) the "average level risk over the duration of the project" which has a narrower range of fluctuation and is more stable and "predictable", and (2) the "annual variation risk" which has a wider range of fluctuation due to more random factors. With stricter monetary and fiscal discipline being adopted in Mexico, we can expect a gradual improvement in the management and control of inflation. In our cash flow model a long term inflation rate of 15% is used to approximate this prospect. A step distribution is used to represent the annual disturbances (see Table 37 above).

2. Foreign Exchange Rate

As mentioned above, inflation and exchange rate fluctuations in Mexico are closely related. Exchange rate fluctuation is itself determined by current account balance, international capital flows, and relative inflation rates in Mexico and the U.S. Prior to 1975, the Mexican exchange rate was pegged at 12.5 pesos per U.S. dollar. As shown in Figure 8, a huge devaluation of 267% in 1982 followed nearly a decade of double-digit inflation in Mexico.

Figure 8 - Real Exchange Rate, Trend, and Deviations from Trend, Mexico 1954-1996



In the following five years very large devaluations between 34% and 149% ensued. Another severe 71% devaluation in 1994 and 43% in 1995 followed. Over the 1975 to 1996 period, annual changes in the nominal exchange rates has a mean of 46.5% per year and a standard deviation of 67.6%. After the nominal exchange rates are adjusted by the relative inflation (nominal exchange rates deflated by Mexican CPI/U.S. CPI), the variation in the "real" exchange rates has a mean of 7.6% per year with a 40.4% standard deviation.

Table 38 - Nominal and Real Exchange Rates Variations in Mexico (1976-1996)

	Nominal Exchange Rate	Real Exchange Rate
Mean	46.5%	7.6%
Std. Deviation	67.6%	40.4%

With austere government budgets and a stringent monetary policy in place, it is most likely that the future real exchange rates will be stabilized with small annual nominal upward adjustments to reflection the higher inflation rate in Mexico. In Figure

8, a trend line is fitted to the real exchange rates of Mexico. The trend line indicates a small upward trend. The errors between the actual and calculated values have a mean of 0% and a standard deviation of 35.5%.

For the purposes of the risk analysis it is the level of the average real exchange rate that the project experiences over its life that has the most significant impact on the project outcome. Given the high volatility of the year to year change in the real exchange rate, most of these annual changes cancel each other out. If it is taken as given that the annual changes in the real exchange rate have a mean of zero and a standard deviation of 35.5%, then the movement of the mean real exchange rate averaged over the life (31 years)of the project will have a mean of zero and a standard deviation of 7.75%. It is this normal distribution that is used in the risk analysis of this project.

3. Fuel Cost

While the market power of OPEC cartel would seem to exert decisive influences on world oil prices at times, the true long-term forces that determine oil prices are really the demand and supply of oil. Figure 9 shows the US Imported Oil Price for period 1976-1996.

Figure 9 - Nominal Oil Price and Annual Changes 1973-1997

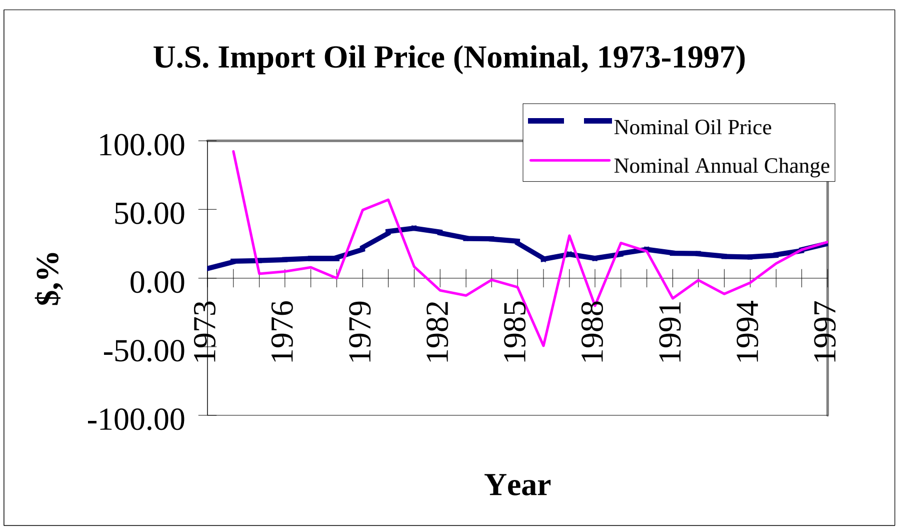
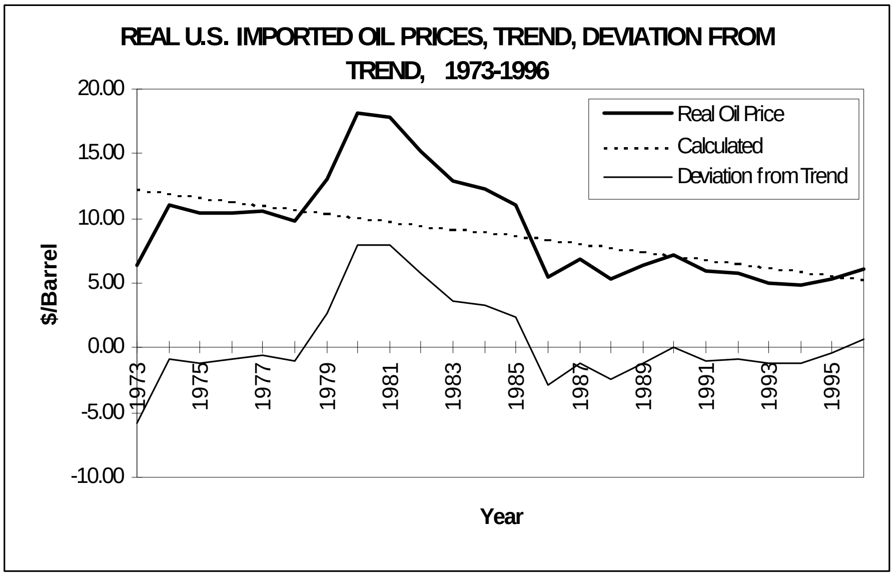


Figure 10 - Real U.S Imported Oil Price, Trend, and Deviation from Trend, 1976-1996



Following each price hike, the demand for oil adjusted and the oil price declined and stabilized. The long cycles of oil prices tend to reflect a recurrent pattern – " incident/price hike – demand adjustment – price decline – incident/price hike – demand adjustment …" . Basically, the long run oil price level is determined mainly by demand and the availability of oil and production costs. The yearly ups and downs in oil prices are heavily affected by unpredictable near-random incidents such as wars in the Middle-East, OPEC decisions and weather conditions.

Over the 1975 to 1997 period, the changes in average nominal U.S. import price of crude oil has a mean growth rate of 9.4% and a standard deviation of 28.7%. The average compound growth rate of oil prices from 1975 to 1997 is 3.2%. While the nominal oil prices exhibit a small upward trend around 3% per year, the real oil prices shows no long term trend - the average compound growth rate of real oil prices from 1975 to 1996 is –0.23%[52]. Based on this historical background, a long-term growth rate of 0% for real oil prices is assumed in this study. A trend line is also fitted to the real oil price data. The results are plotted in Figure 10. Based on the trend values and the actual values, the probability distribution of the errors used in the study is given in Table 39.

[52] The mean growth rate of real oil prices is 2.6% with a standard deviation of 24.9%.

Table 39 - Probability Distribution for Annual Disturbances of Real Oil Price Used in Study

% Error	Probability
-40% to -30%	4%
-30% to -20%	13%
-20% to -10%	25%
-10% to 0%%	17%
0% to10%	8%
10% to 20%	8%
20% to-30%	13%
30% to 40%	13%
Total	100%

4. Investment Cost Overrun

Typically, the investment cost estimates include a contingency provision. These contingency-included investment cost estimates are treated as the expected values of the investment costs. The actual investment costs are assumed to fluctuate around the expected values with a normal distribution which has a standard deviation of 4% of the investment costs.

5. Demand for Electricity

The demand for electricity is a function of GDP. We used a normal distribution with a mean of 4.9% and a standard deviation of 1% to represent the annual fluctuations around the expected growth of GDP.

6. Transformer Loss Reduction

The estimated value of the transformer loss it is uncertain. To deal with this uncertainty, a normal distribution with a mean of zero, a standard deviation of 5% is assumed.

7. Alternative Power Supply Cost Factor

The economic value of shortage power depends on the estimate of the alternative cost of power supply. To incorporate the possible variation in our estimate of the alternative supply cost, the alternative power supply cost factor is assumed to have a normal distribution with a mean of 0% and a standard deviation of 5%.

B. Results - Risk Analysis

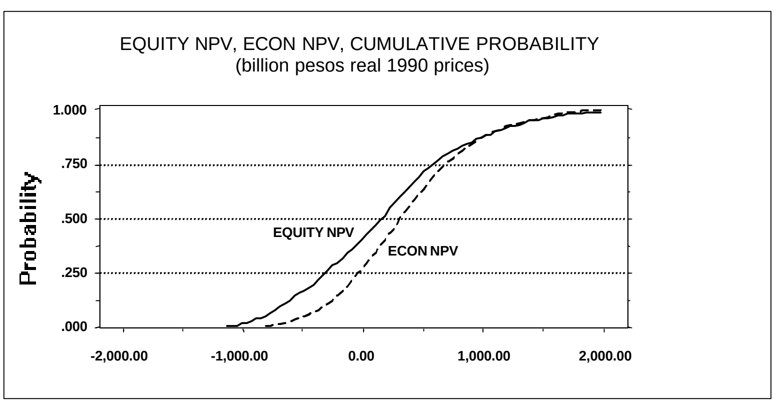
The results of the risk analysis summarized in Table 40 show that the expected value of the financial (equity) NPV is 190 billion pesos which is very close to its base case value of 191 billion pesos. The expected economic NPV is 362 billion pesos, which is higher than its base case value of 239 billion pesos. The difference, however, is small relative to the cost of the total investment.

Table 40 - Expected NPVs From Risk Analysis (Billion Pesos, Real)

	Financial NPV - Equity	Economic NPV
Base Case	193	239
Risk Analysis		
Expected Value	191	362
Minimum Value		
Maximum Value		
Probability Of Negative NPV	37%	25%

Figure 11 depicts the cumulative probability for the equity and economic NPVs of the project.

Figure 11 - Cumulative Provability Distribution, Economic And Financial NPV (Billion Pesos, Real)



While the project's final outcomes will remain uncertain, the risk analysis helps define the scope of these outcomes. There are a 25% chance for a negative economic NPV and a 37% chance for a negative financial NPV. The financial variability of the outcome could threaten the sustainability of such a project, if it were operated in the private sector. As this project is part of the activities of a state owned enterprise, perhaps the 37% probability of the project creating a negative financial NPV does not threaten the project to the same degree.

IX. CONCLUSION

The project is both economically and financially feasible in terms of their expected values. The project, however, is rather risky in terms of its financial and economic performance.

The distributive analysis shows that there will be a very large consumer surplus gain to the newly connected consumers, a large financial loss to the previously unmetered customers, and a large revenue gain to the government. The low-income group of the newly connected customers will receive a consumer surplus gain of about 294 billion pesos, while the labor sector will receive a modest gain of 96 billion pesos.

Overall the project is worthwhile to undertake but at the same time one needs to keep in mind that the control of investment costs, the willingness to pay, and the growth of GDP are all critical variables determining its economic feasibility.

APPENDIX I - THE DEMAND FOR ELECTRICITY

The estimation of the demand for electricity is important in power project appraisal because it often affects the benefits of the projects. For projects that involve a decision about the timing of investment – when to install new capacity to meet the demand – the precision of the electricity demand forecast can be critical. For others, when electric tariff policy is involved, it is essential to relate the demand for electricity with tariffs through the use of a electricity demand model or demand elasticities.

In this section, we shall discuss a commonly used demand for electricity model and demonstrate its use in our analysis.

1. Electricity Demand and Capital Stock

Electricity is not consumed directly; it is consumed through the use of equipment and electrical appliances. While it is possible to adjust the amount of electricity consumed through actions such as turning off the light, turning down the thermostat, taking shorter showers, going to bed earlier and so on, the amount of electricity consumption is nevertheless affected by the size and number of electrical appliances in the long run. The size of houses, the size and number of air-conditioners, television sets, refrigerators, hot-water heaters are the capital stock that will affect household and commercial consumption. The capacity and type of machinery and equipment being installed will affect the power consumption of the industry and some commercial customers. In short, electricity demand is strongly influenced by the existing capital stock of electrical appliances and machinery.

2. The Lag-Adjustment Model of the Demand for Electricity

The demand for electricity depends essentially on income or production level, prices and existing electrical capital stock[53]. It is also affected by other localized and transient secondary factors such as weather conditions, power failure rate, new customer connections. The demand model used here is based on models commonly used in the estimation and forecasting of electricity demand[54].

It is customary to use a lag-adjustment model to capture the lagged adjustment of electric capital stock to income and price changes. The lag-adjustment model or partial-adjustment model[55] postulates that the increase in capital stock in year t is a function of the desired level of capital stock (K_t*) and the actual level of capital stock (K_{t-1}) which can be written in the following form[56]:

$$K_t – K_{t-1} = f\ (K_t^* - K_{t-1}) \qquad \text{(A-1)}$$

[53] Lim (1979), Taylor (1975), Westley (1992).
[54] World Bank (1991).
[55] Westley (1992).
[56] Lim (1979), p.141; Westley (1992), p.241.

where $0 \le f \le 1$ is the adjustment factor. Equation (A-1) can be rewritten as

$$K_t = (1\text{-}f)K_{t-1} + K_t^* \qquad \text{(A-2)}$$

The desired level of capital (K_t*) is a function of income, price of electricity, price of appliance, alternative fuel cost and others. Under the assumption that the utilization factor (or load factor) of the capital stock is constant or at least stable, equation (A-2) can be rewritten as

$$Z_t = (1\text{-}f)Z_{t-1} + f(P_t, Y_t, C_t, O_t \ldots) \qquad \text{(A-3)}$$

where Z is the demand for electricity, f ( ) is a function, P is real price of electricity, Y is real income or output, C is cost of capital, O are alternative fuel cost and other variables. Equation (A-3) is the most common estimation form of the lag-adjustment model.

For the convenience of demand elasticity estimation, it is further postulated that the demand for electricity and the lag-adjustment assume a log-linear demand function which can be written as

$$Z_t^* = aY_t^b P_t^g \qquad \text{(A-4)}$$

where Z_t* is the demand based on the desired level of capital stock; a , b and g are parameters that can be estimated; and

$$\frac{\P Z^*}{ZY} \succ 0 \text{ and } \frac{\P Z^*}{\P P} \prec 0 .$$

The relationship between the desired and actual levels of demand in periods t and t-1 is assumed to have the following log-linear form:

$$\frac{Z_t}{Z_{t-1}} = \left[\frac{Z_t^*}{Z_{t-1}}\right]^{1-f} \qquad \text{(A-5)}$$

Substituting equation (A-4) in (A-5), we get

$$Z_t^* = aY_t^{b(1-f)} P_t^{g(1-f)} Z_{t-1}^f \qquad \text{(A-6)}$$

where b and g are the long run income and price elasticities of demand respectively. Short run income and price elasticities are given by *b(1-f)* and *g(1-f)*. In a log-linear form, equation (A-6) can be written as:

$$\ln Z_t^* = a + b(1-f)\ln Y_t + g(1-f)\ln P_t + f\ln Z_{t-1} \qquad (A-7)$$

When this equation is estimated, the coefficients of the equation will be the short run elasticities. The long run elasticities are equal to the short run elasticities divided by $(1-f)$.

3. Elasticity Estimates Used in Study

The income and price elasticities used in the electricity demand model are given in Table 41.[57] The growth rate in real GDP is assumed to be 4.9% in the base case

Table 41 - Short Run Elasticities and Adjustment Rates Used in Study

	Constant Term	Income Elasticity	Price Elasticity	Adjustment Rate
Residential	0.00	0.75	-0.11	0.300
Industrial	0.00	0.70	-0.11	0.400
Commercial	0.00	0.60	-0.02	0.400
Rural	0.00	0.80	-0.01	0.300
Services	0.01	0.70	-0.02	0.148

[57] Based on Lim (1979), p.141; Taylor (1975), Westley (1992), and the World Bank (1991) and modified by the authors.

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