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NONUTILITY POWER GENERATION IN COSTA RICA: POTENTIAL, IMPEDIMENTS, AND POLICY ISSUES

Final Report

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CURRENCY EQUIVALENTS
(November 1987)

Currency unit = Colon
U.S. $ = 66.75 Colones

ACRONYMS

AID	U.S. Agency for International Development
CNFL	Compania Nacional de Fuerza y Luz
COOPEGUANACASTE	Cooperativa de Electrificacion Rural de Guanacaste, R.L.
COOPELESCA	Cooperativa de Electrificacion Rural de San Carlos
COOPESANTOS	Cooperativa de Electrificacion Rural Los Santos, R.L.
DSE	Direccion Subsectorial de Energia
EEM	Empresa Electricidad de Matamoros
EFAP	Economic and Financial Analysis Program
ESPH	Empresa de Servicios Publicos de Heredia
FODEIN	Funds for Industrial Development
GOCR	Government of Costa Rica
ICE	Instituto Costarricense de Electricidad
IDB	Interamerican Development Bank
JASEC	Junta Administrativa de Servicios Electricos de Cartago
kW	Kilowatt
MRNEM	Ministerio de Recursos Naturales, Energia y Minas
MW	Megawatt
O&M	Operation and maintenance
PURPA	Public Utility Regulatory Policies Act
RECOPE	Refineria Costarricense de Petroleo, S.A.
SNE	Servicio Nacional de Electricidad

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EXECUTIVE SUMMARY

Until recently, Costa Rica appeared able to meet projected growth in the demand for electricity in both the short and the medium term primarily with planned additions of hydro and geothermal power plants. Its installed generating capacity of roughly 900 MW (nameplate), together with its planned additions of generation facilities, was expected to provide the necessary margin of capacity beyond the turn of the century. However, because of an unforeseen combination of drought and a surge in demand in 1987, the country's dependable capacity dropped to 650-700 MW as compared with a peak load of 612 MW. The peak load is likely to reach 650 MW in 1988 as compared to the same level of dependable capacity as in 1987.

Although Costa Rica's well-managed utility, Instituto Costarricense de Electricidad (ICE), has a history of providing reliable, low-cost service, its options for boosting capacity economically are limited in the short run. ICE has ordered gas turbines to meet the short-term shortage, but the first turbine will not be on-line before 1989. In the meantime, ICE's hydrosystem is suffering from severe drought conditions, and the utility cannot import more electricity from Honduras because the transmission line is used at full capacity (about 50 MW). Although ICE owns 140 MW of thermal units, these units are generally believed to be unreliable and expensive to run, with a maximum of 70 MW effective at any given time.

Costa Rica could, however, attempt to use cheaper options, primarily by exploiting energy resources and technologies that are not being fully used and are appropriate for development by the private sector: industrial cogeneration, minihydro plants, and energy produced from biomass process waste.

Another approach -- improved load management -- could also relieve the possible shortage by significantly reducing daily peak demand. This option is being addressed in a separate study.

To the extent that private-sector resources can be applied to power generation -- for use in generating power and selling it -- they will shift the financial burden of investment in new generating capacity from the government to the private sector, thus reducing public

spending and the national debt. While there are no known recent precedents for the sale of power to the Costa Rican grid, a start is being made in this direction. Two private companies (Matamoros and Industria Nacional de Cementos) are planning hydropower projects of 10-15 MW each. Several sugar mills have approached ICE and the Interamerican Development Bank (IDB) to obtain financing for projects aimed at producing an additional 30 MW of power generated from bagasse combustion for sale to ICE.

Significant progress in private power development, however, will require the active support of the government, and in this connection, U.S. experience with the Public Utility Regulatory Policies Act (PURPA) may be a useful guide. This legislative measure promoted the development of over 24,000 MW of nonutility power generation in the United States between 1980 and mid-1987. Basically, the U.S. law mandates electric utilities to purchase power from cogenerators and systems using renewable resources at a cost directly related to their own generation and transmission marginal cost.

Given the growing private-sector interest in power generation, the Ministry of Natural Resources, Energy and Mines (MNREM) has assigned priority to identifying the prerequisites for formulating appropriate private power policies for Costa Rica.

Energy-sector policymaking involves several government entities. MNREM has overall coordination responsibility for the energy sector. The key organizations that constitute the energy sector include: ICE, the principal electric utility; Servicio Nacional de Electricidad (SNE), a regulatory body; and Refineria Costarricense de Petroleo S.A., the national oil company.

Of ICE's installed generating capacity of approximately 850 MW, more than 80 percent is large hydropower. Local power companies have additional generating capacity of some 58 MW, most of which is small or mini hydropower. With a peak demand of 612 MW in November 1987 (10 percent above 1986 peak) and a lack of water in the nation's reservoirs, ICE's reserve margin became less than 10 percent.

In 1986, growth of electricity consumption was strongest among residential consumers and small industrial users which together accounted for 66.5 percent of all the power

consumed. Much of the country has electrical power; approximately 82 percent of households have service.

In drawing up a capacity expansion plan, MRNEM and ICE used several scenarios. The plan based on the medium scenario would double generating capacity by the year 2005 at a cost of U.S. $1.67 billion. But the utility reported a loss of 770 million colones in 1986, and has not been able to raise tariffs sufficiently to meet a growing debt service. The situation improved in 1987 and ICE's finances are expected to show a surplus.

STUDY OBJECTIVES

To identify the possible role of private-sector power generation, MRNEM and ICE requested a study of the potential for and impediments to such generation. The study objectives were:

1. Identify the market and economic potential for cogeneration and private-sector small power production from renewable and indigenous resources, particularly mini hydro power and indigenous wastes

2. Identify the policy, regulatory, institutional, and other impediments to off-system, private-sector generation of electricity from cogeneration or renewable/indigenous resources for sale to the grid

3. Develop recommendations and an action plan for addressing the impediments to off-system generation.

The analysis was carried out in Costa Rica by an RCG/Hagler, Bailly team during the period November 6-27, 1987. The team was assisted by the staff of ICE and by local energy consultants, Sol 2000. Discussions and revisions of the draft report were carried out between December 1987 and April 1988 when the report was finalized.

Six options were explored in evaluating the potential for independent power generation:

- Industrial cogeneration

- Sugar mill power generation
- Dendrothermal power generation (i.e., power from wood combustion)
- Agricultural and biomass waste-fired power generation
- Small and mini hydropower
- Geothermal generation.

Other options such as large thermal power units running on imported oil or coal were not explored in detail after a cursory analysis showed that their production cost would be significantly higher than ICE's long-run marginal cost. Power plants running on domestic coal were not analyzed since they were the topic of a recent USAID study, which found them to be a promising alternative for power in the long term.[1] Solar and wind options were not part of the scope of work as international experience and a cursory analysis have suggested that such resources cannot compete with ICE's marginal costs.

STUDY FINDINGS

The study findings are divided into two categories: power generation potential and major impediments.

Power Generation Potential

For each of the six options, the technical, economic, and financial potential was evaluated. Although each option has some potential, only two would have a significant impact on the country's energy situation in the short to medium term: 1) sugar mill power generation (short term); and 2) small and mini hydropower (medium term).

Efforts can be made to involve the private sector in financing such systems. However, Costa Rican investors generally seek a high return on investment (well over 30 percent in local currency) because of the 15 percent inflation rate and the declining value of the

[1] Pre-feasibility Study of Coal Use in Costa Rica, by Bechtel National, Inc., under contract to USAID, June 1987

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colon. Consequently, private capital in Costa Rica is strongly attracted to export-producing activities that earn foreign exchange; this capital may not be easily mobilized for power generation projects. According to the interviews conducted with potential investors during the in-country visit, however, the private sector will invest in power generation if the proper conditions are created.

The private sector could help meet future power demand by generating electricity from resources that are not being fully used. Between 20 MW and 30 MW could be provided by mid-1989 in this way, and 30-50 MW by 1990.

The technical, economic, and financial potential of the six options for independent power generation in Costa Rica is summarized in Exhibit 1, together with the generation costs of each option. The bulk of the technical potential of 5,500-5,800 MW lies in dendrothermal and biomass energy sources. However, they cannot be exploited economically because of their physical dispersion and the lack of an organized market and reliable supply. Use of these energy sources would also raise major environmental issues (land erosion). Owing to the small scale of manufacturing, and its reliance on fuel oil for energy generation, there is little potential for cogeneration in industry. But sugar mills and palm oil companies, which have a large, available supply of biomass waste, offer substantial potential. Most of the large hydropower and geothermal resources are not appropriate to private-sector exploitation because the projects would be too large for private financing at this time and ICE is much better suited for this role.

Thus, the greatest potential for private power lies in hydropower systems between 500 kW and 5,000 kW, which offer 100-300 MW of economic and financial potential. Unfortunately, the potential for small and mini hydropower is neither well documented nor understood because a nationwide survey of these resources is lacking. Also, capital investment cost and precise economic performance are difficult to estimate without knowing specific site conditions.

The sugar industry could bring some 20 MW to 30 MW on line in the short term simply by renovating boilers and turbines and arriving at a purchasing arrangement with ICE on excess power. However, to realize this potential, policy action must be taken rapidly by the government, and the sugar industry must respond quickly to the new

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Exhibit 1

**Electricity Generation Costs and Potential for Nonutility Power Options*
(1987-1995)**

Resource	Technical Potential (MW	Economic Potential (MW)	Economic Cost*** ($/kWh)	Financial** Potential (MW)	Financial** Cost**** ($/kWh)
Cogeneration	17	3	.025-.057	3	.032-.086
Sugar Cane Power	100	90	.035-.058	90	.020-.056
Dendrothermal	2,100	0	0.066	0	0.095
Biomass	2,200	0	0.06	0	0.069
Hydropower*****	350	350	.017-0.035	200	.034-.068
Geothermal	400-700	******	.027-.034	0	.06-.07
TOTAL	**5,500-5,800**	**443**		**293**	

* For the near term; coal may have some potential in the long term.

** Assuming a debt to equity ratio of 2.3.

*** Systems with electricity costs of under $0.05/kWh are considered economically attractive. This figure reflects the avoided cost to ICE from power supplied by nonutility generators and is estimated based on the long-run marginal cost of electricity generation (see Appendix D).

**** Systems with electricity costs of under $0.0455/kWh are considered financially attractive. This figure reflects the current average price to industry in Costa Rica.

***** For system sizes between 500 kW and 5,000 kW.

****** The economic potential for geothermal is sizeable but the projects are felt to be too large for private financing at this time.

Source: RCG/Hagler, Bailly, Inc.

opportunities presented. With an aggressive, capital-intensive policy, it could even be possible to produce 90 MW of power from the mills.

Major Impediments

Several barriers must be overcome before private power development can take place on a significant scale. The principal barriers identified by the study are:

- Lack of clear or well-articulated government policies on the provision of essential public services such as electricity and water by the private sector
- Scarcity of medium- and long-term financing for major private power projects, as well as a general liquidity shortage
- Preference of the private sector to invest in export-oriented businesses rather than public service enterprises
- Inadequate technical and economic information on opportunities for cogeneration and power generation
- Economic advantages granted exclusively to ICE, and widespread satisfaction with electric power service.

RECOMMENDATIONS

A number of actions are required to overcome the obstacles to private power and to promote its development. They fall into two categories: (1) actions within the authority of the government of Costa Rica, and (2) those appropriate to USAID (which financed this study).

Government of Costa Rica

- Clarify and publicize private power policy and the licensing process to correct misconceptions that hinder development of independent generation, to facilitate licensing of projects, to reduce uncertainty and risk to project

sponsors, and to improve return to investors. Key elements of this action are:

(i) Provide a legal framework for the generation, transmission, and sale of private power

(ii) Define contractual terms between ICE and independent generators. The terms should cover technical and financial issues

(iii) Simplify the licensing procedure

(iv) Specify electricity purchase price calculation guidelines and procedures (see Exhibit 2 for an example)

(v) Draft a prototypical contract incorporating the results of the above actions; it should set forth technical requirements of power generation and links with the grid as well as the terms for purchase of power by the electric utility.

Establish a high-level Private Power Committee[2] to plan and coordinate actions to promote the development of private power and to monitor progress toward its realization. The committee membership should include all entities that could contribute to its objectives, with a mix of the public and private sectors. Specifically, the committee should:

(i) Be chaired by the Minister of Natural Resources, Energy and Mines and include representatives of ICE, SNE, DSE, the Central Bank, the General Directorate of Forests, the

2 The existing "small power group" recently established at MRNEM could have its role expanded to act as the recommended committee.

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Exhibit 2

Example of Possible Power Purchase Arrangements

- Purchase price could be established through one of the following two possibilities:

  A. Average Economic Value

    - 2.6 - 2.96 colones/kWh year-round
    - Same for all independent generators, year-round

  B. Avoided Cost

    - Dry Season

      -- Peak hours: 5 colones/kWh (1,825 hours)
      -- Off-peak hours: 2.4 colones/kWh (2,555 hours)

    - Wet Season

      -- All hours: 2.1 colones/kWh (4,380 hours)

Under such cost structure, the public and ICE would share the benefits approximately equally.

Source: RCG/Hagler, Bailly, Inc.

Ministry of Planning, the Chamber of Commerce and Industry, the Association of Engineers, and other appropriate parties; it should meet monthly

(ii) Report to the President of the Republic

(iii) Have an advisory role to the regulatory and implementing agencies to allow them to expedite the review process.

- Provide tax exemptions to private power projects to increase their attractiveness to investors, developers, and the banking system, and to place them on an equal footing with ICE in terms of cost advantages. Specifically, measures should be taken to:

  (i) Reduce project capital requirements by waiving import duties and taxes on equipment

  (ii) Increase project profitability by waiving income tax on project revenue.

  These provisions would attract capital from private sources and avoid the problem of competition with ICE and the GOCR for the same financial resources (e.g. supplier credit, international organizations).

- Conduct an information and awareness program aimed at engineers, bankers, potential private generation developers, and industry associations. ICE might play a major role in this effort.

- Determine the training needs of personnel to be involved in the practical aspects of private power development and sponsor training on the design, planning, implementation, and operation of independent power projects. ICE and local consultants might assist in this effort, which might train:

  (i) Industrial managers in securing project approval and financing

(ii) Engineers in project design, equipment selection, procurement and installation, connecting the independent generation system to the grid, and system operation

(iii) Equipment operators in operating routines.

USAID

- Carry forward the analysis of private power potential in hydropower and the sugar cane industry,[3] where more accurate data are needed as a basis for planning further actions.
- Consider a line of credit dedicated to private power development. Funding, credit terms, and fund regulations should be based on a detailed analysis of potential borrowers' needs and the availability of other credit for this purpose.
- Provide assistance for training and information services.

3 Study underway as of March 1988, under funding by AID's Bioenergy Systems and Technology (BST) Project

CHAPTER 1: THE POWER SITUATION IN COSTA RICA

The objective of this chapter is to review the current power-sector structure in Costa Rica and identify the factors likely to necessitate the development of nonutility power. The chapter begins with a review of the decision making process, identifying key energy policy organizations and their roles. Next, the power sector is described, with the current capacity and energy production data provided, then future demand and nonutility power activities are discussed, and finally, ICE's financial situation is reviewed.

POWER SECTOR POLICY ENVIRONMENT

Several government units are involved in power-sector policymaking. The Ministerio de Recursos Naturales, Energia y Minas (MRNEM) has principal overall responsibility for the energy sector. The major organizations that constitute the sector include: the Instituto Costarricense de Electricidad (ICE) and the Refineria Costarricense de Petroleo, S.A. (RECOPE). Within MRNEM, there is a planning unit, the Direccion Sectorial de Energia (DSE). In addition, the Servicio Nacional de Electricidad (SNE), which reports directly to the Cabinet, plays the key role of authorizing tariff changes for electricity, water and fuels. The roles of these organizations are described below.

Instituto Costarricense de Electricidad

ICE, the nation's principal utility, is responsible for power generation, transmission, and distribution. It was created in 1949 and today provides over 90 percent of the country's power. It is also responsible for telecommunications. It cannot formulate plans for tariff increases without formal approval by its principal government regulatory agency, the SNE.

Direccion Sectorial de Energia

The DSE was created in 1984 to meet the need for a comprehensive energy planning capability in Costa Rica as well as to coordinate all energy activities in the country. It

tracks all projects, issuing regular reports on the status of all energy supplies, disposition, and demand.

Refineria Costarricense de Petroleo S.A.

RECOPE, the national oil company, operates Costa Rica's only refinery. It also distributes petroleum products, along with two private distributors. Until recently, it has done little long-term planning and has been at the mercy of the supply market, primarily Mexico and Venezuela. It depends on the SNE for permission to adjust product prices.

Servicio Nacional de Electricidad

The SNE is primarily a regulatory body that establishes priorities for the power sector and other necessary services. It was created in 1941 as a watchdog to assure that the public was being well served. Tariff increases must be approved by SNE. Private power projects must also have the approval of the national assembly.

There is some attempt at policy coordination, but it is clear that each organization has its own area of responsibility. DSE is supposed to play the key role but, in reality, organizations such as ICE and RECOPE have much larger resources and have institutional ties to development banks and other government units. Currently, MRNEM is coordinating policy at top level with regard to electric power.

POWER-SECTOR STRUCTURE

The formal creation of ICE took place in April of 1949, with the mandate to develop national energy resources and to transmit and distribute electrical power to Costa Rica's population.[1] Today, ICE is responsible for coordinating all electrical energy generation, transmission, and distribution in the country. ICE generates roughly 90 percent of Costa Rica's public power, while cooperatives, municipalities, and private companies generate the rest. It is the ICE grid that ties the various generation and

[1] Since then, ICE has also been put in charge of the national telephone and telecommunications system.

distribution entities together. Installed capacity, energy production, and sales prices for the various power entities in Costa Rica and shown in Exhibits 1.1 and 1.2.

Current ICE installed capacity is approximately 845 MW (see Exhibit 1.3), of which 80 percent consists of hydropower and thermal plants larger than 30 MW. Plants operated by other entities total approximately 60 MW, most of which is small or minihydro power (see Exhibit 1.4). Much of this capacity was installed many years ago, when local power companies had to operate independently because ICE did not exist.

The last plant built by ICE was the Ventanas-Garita project (96 MW), which has been operating since October 1987 with a single 45 MW turbine. The Arenal-Corobici project went on line in 1982, essentially doubling the country's hydropower capacity. This project also addressed the problem of storage during dry periods. ICE's petroleum consumption is rather low (3.5 percent of the country's consumption in 1983) compared with other sectors of the economy. The cost of hydropower generation in Costa Rica is approximately $0.03/kWh and thermal generation, approximately $0.09/kWh.

Currently, ICE capacity may be short to meet the country's electrical energy needs in 1988 because of a severe drought and because of a very high growth in demand (10 percent against 5 percent planned). The 1987 peak electrical energy demand was approximately 612 MW (4.5 percent higher than planned -- see Exhibit 1.5). Although ICE's installed capacity of approximately 850 MW will be theoretically sufficient until 1990, the problem is lack of water in the nation's reservoirs. The peak of 612 MW is almost 10 percent above the 1986 peak of 565 MW and must be compared to a firm capacity of about 700 MW. Gas turbines will not be installed until 1989. In 1988, the peak is likely to exceed 650 MW, as compared to the same level of firm capacity, i.e. a reserve margin of less than 10 percent.

Exhibit 1.1

Power Capacity and Generation by Producer (1985)*
(nameplate, not effective)

	MW
ICE	845.0
Cooperative and Municipals	43.0
Private Power Companies	16.5
Total	**904.5**

Does not include industrial captive power.

Source: ICE

Exhibit 1.2

Sales of Power in Costa Rica

	Power Sales, GWh			Average Price, Colones/kWh		
	1984	1985	1986	1984	1985	1986
ICE[1]	2,176	2,351	2,560	2.01	2.21	2.28
CNFL[2]	1,251	1,305	1,400	2.25	2.59	2.75
ESPH[3]	72	75	83	1.95	2.22	2.43
JASEC[4]	103	110	123	1.92	2.33	2.57
COOPEGUANA-CASTE[5]	40	42	46	2.13	2.25	2.27
COOPELESCA[6]	47	52	60	1.54	1.61	1.63
COOPESANTOS[7]	20	22	24	1.84	1.93	2.06
COOPEALFARO[8]	5	5	6	2.01	2.15	2.27

1 Instituto Costarricense de Electricidad.
2 Compania Nacional de Fuerza y Luz.
3 Empresa de Servicios Publicos de Heredia.
4 Junta Administrativa de Servicios Electricos de Cartago.
5 Cooperativa de Electrificacion Rural de Guanacaste, R.L.
6 Cooperativa de Electrificacion Rural de San Carlos, R.L.
7 Cooperativa de Electrificacion Rural Los Santos, R.L.
8 Cooperativa de Electrificacion Rural de Alfaro Ruiz, R.L.

Source: ICE

Exhibit 1.3

ICE Installed Power Capacity
(as of December 31, 1987)

Plant Name	Type	Capacity (nameplate)	(MW) effective	Year of Installation	Province
Corobici	Hydro	174.0	174.0	1982	Guanacaste
Arenal	Hydro	157.4	156.0	1979	Guanacaste
Rio Macho	Hydro	120.0	120.0	1963	Cartago
Cachi	Hydro	100.8	100.0	1966	Cartago
Ventanas-Garita	Hydro	96.0	96.0	1987	San Jose
La Garita	Hydro	30.0	30.0	1958	Alajuela
Barranca	Gas T/Th	41.6	18.0	1974	Puntarenas
San Antonio	Gas T	48.1	18.0	1973	Heredia
Colima	Dies.	19.5	14.0	1956	San Jose
Moin	Dies.	32.0	18.0	1977	San Jose
Ciudad Neily	Dies.	7.0	15.5	1975	Puntarenas
Palmar Norte	Dies.	3.3	15.5	1976	Limon
Mini Hydro	--	1.5	15.5	--	--
Diesels less than 1.0 MW	--	3.7	15.5	--	--
Total Installed Capacity		**834.9**	**759.5**		

Source: ICE

Exhibit 1.4

Installed Power Capacity of Cooperatives, Municipals and Private Generators*

PLANT NAME	OPERATOR	CAPACITY (MW)	YEAR OF INSTALLATION	LOCATION	TYPE
Ventanas	CNFL	10.0**	1944	Alajuela	H
Nuestro Amo	CNFL	7.5	1949	Alajuela	H
Brasil	CNFL	2.8	1912	San Jose	H
Belen	CNFL	5.0	1914	San Jose	H
Electriona	CNFL	2.7	1930	San Jose	H
Birris No.1	JASEC	1.7	1952	Cartago	H
Birris No.2	JASEC	2.4	1957	Cartago	H
Birris No.3	JASEC	4.3	1968	Cartago	H
Carrillos	ESPH	2.0	1952	Alajuela	H
Cebadilla	FECOSA***	6.0	1930	Alajuela	H
Damas	CB de CR***	1.5	1951	Puntarenas	D
Quepos	CB de CR***	1.4	1939	Puntarenas	D
Coto	CB de CR***	3.0	1938	Puntarenas	D
Golfito	CB de CR***	3.1	1938	Puntarenas	D
Osa	CB de CR***	1.5	1938	Puntarenas	D
Matamoros	MATAMOROS	3.3	1967	Alajuela	H
Other Mini Hydro	--	1.2			H
TOTAL		**59.4**			

Source: SNE

---

* Excludes industrial captive generation

** not operating

*** CB de CR - Compania Bananera de Costa Rica

FECOSA - Ferrocarriles de Costa Rica

H - Hydro

D - Diesel

Exhibit 1.5

ICE Demand Past, Present and Forecast*

Year	Peak (MW)	Load Factor	Generation (GWh)
1980	410	0.60	2,144
1981	424	0.62	2,295
1982	446	0.59	2,292
1983	430	0.59	2,372
1984	483	0.61	2,568
1985	513	0.60	2,708
1986	565	0.60	2,968
1987	588**	0.60	3,105
1988	616	0.61	3,276
1989	643	0.61	3,437
1990	669	0.61	3,599
1991	685	0.62	3,704
1992	705	0.62	3,827
1993	727	0.62	3,960
1994	751	0.63	4,111
1995	781	0.63	4,292
2000	980	0.64	5,477

* There are three levels of forcasts, only the high is given.

** Actual 1987 peak was 612 MW.

Source: ICE

DEMAND AND SUPPLY PATTERNS

Demand Growth

Demand has grown steadily, with the peak increasing at approximately 6 percent annually since 1980 (see Exhibit 1.5). Most of this increase has occurred over the last 4 years, as both the light industrial and residential sectors grew.

The largest user of power is the residential sector (46 percent of total consumption), followed by the commercial sector (22.6 percent), and small industry (20.5 percent) (see Exhibit 1.6). Surprisingly, large industry is a minor user of ICE-supplied power (7.9 percent). High demand growth in all five sectors -- residential, commercial, large industrial, small industrial, and public lighting -- has occurred over the past 2 years, indicating a relatively healthy economy, particularly in small industry. However, this growth is around 10 percent/year as compared to planned average growth of 5.5 percent/year and this unexpected situation must be viewed in light of the existing capacity expansion plan.

Expansion Plan as of October 1987

ICE's capacity expansion plan had been formulated through the year 2005 using three scenarios: low, medium, and high. By the year 2005, an investment of $2.2 billion was to be needed under the high scenario, $1.67 billion under the medium scenario, and $1.2 billion under the low scenario. If the medium scenario was to be followed, ICE capacity needed to double over the next 13 years to reach 1,591 MW by the year 2000. The high scenario was to require an additional 1,086 MW -- an increase of 132 percent over current capacity -- by 2000 (see Exhibit 1.7a). Clearly the magnitude of the contemplated investments were posing a major problem to the country (debt situation) as they represented about 25 percent of the total National Investment Plan for the period.

The average installed cost for the medium and high scenarios was $1,440/kW and $1,313/kW, respectively (see Exhibit 1.8). The projected hydro energy cost was

Exhibit 1.6

Historical Growth In Consumption

Year	General		Residential		Small Industry		Large industry[1]		Public Light		Total		Generation[2]		
	GWh	% Growth	GWh	% Growth	GWh	% Growth	GWh	% Growth	GWh	% Growth	GWh	% Growth	GWh	Load Factor	MW
1980	355	10.9	843	12.9	457	11.2	182	13.7	57	14.0	2,144	12.2	2,144	0.596	405
1981	437	23.1	901	6.9	417	-8.8	223	22.5	69	21.1	2,047	8.1	2,291	0.618	417
1982	508	16.2	946	5.0	383	-8.2	168	-24.7	74	7.2	2,079	1.6	2,292	0.618	438
1983	512	0.8	977	3.3	414	8.1	172	2.4	76	2.7	2,151	3.5	2,372	0.589	451
1984	532	3.9	1,046	7.1	472	14.0	208	20.9	79	6.8	2,337	0.7	2,568	0.606	482
1985	576	8.3	1,123	7.4	475	0.6	217	4.3	81	2.5	2,472	5.8	2,708	0.603	511
1986	609	5.7	1,242	10.6	526	10.7	238	9.7	82	1.2	2,697	9.1	2,968	0.600	565

1 Includes projects being constructed.
2 National systems.

Source: ICE

Exhibit 1.7a

Planned ICE Generation Expansion, 1988-2000
as of October 1987

Plant Types	Medium Scenario		High Scenario	
	MW	Cost, $\$10^6$	MW	Cost, $\$10^6$
• Hydropower	453	640	453	640
• Geothermal	220	407	220	407
• Thermal				
Gas T	96	60	288	181
Coal	-	—	125	198
Total	**769**	**1,107**	**1,086**	**1,426**

Source: ICE, 1987

Exhibit 1.8

ICE Future Power Capacity Expansion Plan: High Scenario

Year	Project	Capacity MW	Type	Energy (GWh) Firm	Energy (GWh) Average	Investment Cost ($/kW)
1987	Ventanas Garita	96	Hydro	373	1,500	-
1988						
1989	Gas Turbine	36	Gas T.	224	224	627
1990	Gas Turbine	72	Gas T.	448	448	627
1991	Miravalles I	55	Geo	389	389	2,179
	Gas Turbine	36	Gas T.	224	224	627
1992	Gas Turbine	32	Gas T.	224	224	627
1993	Sandillal	32	Hydro	140	140	1,421
	Miravalles II	55	Geo	389	389	1,743
1994	Toro I	24	Hydro	721	18	947
	Toro II	66	Hydro	189	315	529
1995	Gas Turbine	64	Gas T.	448	448	627
1996	Angostura	177	Hydro	664	996	1,500
1997	Miravalles III	55	Geo	389	389	1,743
1998	Siquirres	154	Hydro	630	760	1,765
1999	Miravalles IV	55	Geo	389	389	1,743
2000	Carbon	125	Therm	723	723	1,587

Source: ICE, 1987

approximately $0.030/kWh, roughly equal to current cost, and the projected cost of thermal power was approximately $0.070/kWh, compared with a current cost of approximately $0.090/kWh.

Revised Expansion Plan (February 1988)

Because of an unexpected surge in demand and worse - than - expected rainfall, ICE had to modify its expansion plan. The new plan under the medium scenario, calls for 889 MW of new installed capacity for the period 1990 - 2000 (see Exhibit 1.7b), a 30 percent increase over the previous plan. According to this new plan, ICE would have to invest on average in excess of $100 million each year between 1990 and 2000.

ICE FINANCES

ICE remains financially troubled, and is unable to raise tariffs without a major review by SNE to meet a growing debt service. In 1985 and 1986, debt service accounted for 43 percent and 40 percent, respectively, of total income. The situation has improved slightly over what it was in 1984, perhaps the utility's most difficult financial year. SNE approved tariff increases for ICE of roughly 17 and 15 percent, respectively, for the years 1985 and 1986. In October of 1987, ICE was allowed another tariff increase of 22 percent. This increase was quickly followed by increases at the other power companies; CNFL, for example, raised its tariff by approximately 17 percent, ESPH by 12 percent, and the Cooperatives by between 12 percent and 14 percent. An income statement for 1984, 1985, and 1986 is shown in Exhibit 1.9. The current tariff structure is shown in Exhibit 1.10.

Clearly, the combination of (1) the unexpectedly high demand growth, (2) the severe drought, (3) the national debt situation, and (4) ICE's financial situation requires finding innovative solutions to the problem. Allowing independent producers to either generate their own power or generate power for sale to the grid, especially at peak hours and during the dry season, is an attractive way to resolve the problem in the short term.

Although there is only little practical experience in Costa Rica, discussions with potential investors and developers have indicated a real interest and potential in such

Exhibit 1.7b

Revised National Generation Expansion Plan
(as of February 1988)

Year	Plant Name	Capacity	Type
1990	Thermal	3x 36 MW	Gas turbines
1991	Thermal	36 MW	Gas turbines
1992	Miravalles-I	55 MW	Geothermal
1993	Sandillal	32 MW	Hydro
	Thermal	36 MW	Gas Turbine
1994	Miravalles - II	55 MW	Geothermal
	Toro I & II	24 + 66 MW	Hydro
1995	Thermal	36 MW	Gas Turbine
1996	Angostura	177 MW	Hydro
1997	Miravalles - III	55 MW	Geothermal
1998	-	-	-
1999	Siquirres	154 MW	Hydro
2000	Miravalles - IV	55 MW	Geothermal
Total 10 years		**889 MW**	

Source: ICE

Exhibit 1.9

Income Statement for ICE, 1984-1986
(1,000 Colones)

	1984	1985	1986
Energy Sales (MWh)	2,176,418	2,351,332	2,560,471
Average Sale Price, Colones/kWh	2.20	2.23	2.21*
Income			
Sale of Energy	4,796,001	5,278,270	5,664,467
Other income	12,523	14,454	14,265
Total Income	**4,808,524**	**5,292,724**	**5,578,732**
Expenses			
Direct			
Purchase of energy	12,971	1,469	126,833
Hydrogeneration	111,270	170,360	165,391
Thermal generation	77,466	82,099	101,089
Transmission	82,559	113,449	152,022
Distribution	223,713	296,917	403,425
Administrative Cost	136,144	162,737	215,910
Subtotal Direct Cost	**644,123**	**827,031**	**1,164,670**
Indirect			
Depreciation	768,607	897,811	1,078,229
Institutional Costs	181,680	223,528	304,971
Financial Costs	3,118,231	3,314,803	3,884,185
Insurance	4,180	5,298	7,398
SNE taxes	4,199	4,199	8,993
Subtotal Indirect Costs	**4,076,897**	**4,445,639**	**5,283,776**
Total Cost	**4,721,020**	**5,272,670**	**6,448,446**
Income Net of Operations	87,504	20,054	(769,714)

* - HBC computed this number to be 2.52

Source: ICE

Exhibit 1.10

ICE Tariff Structure
(¢ = Colon)

T-1 **Residential**

Energy Charge	
First 30 kWh or less	¢55.50/kWh
Following 20 kWh	¢1.85/kWh
Following 50 kWh	¢2.20/kWh
Following 150 kWh	¢2.25/kWh
Following 400 kWh	¢3.00/kWh
Excess of 450 kWh	¢6.50/kWh

T-2 **General (Commercial)**

- less than or equal to 3,000 kWh per month

Energy Charge:	
First 30 kWh	¢184.80
Each additional kWh	¢6.16

- 3,001 - 20,000 kWh per month

Demand Charge:	
First 13 kW	¢7,346.70
Each additional kW	¢565.13
Energy Charge:	
First 3,000 kWh	¢10,980.00
Each additional kWh	¢3.66

- greater than 20,000 kWh per month

Demand Charge:	
First 27 kW	¢15,250.25
Following 60 kW (each kW)	¢566.13
Each additional kW	¢859.80
Energy Charge:	
First 20,000 kWh	¢73,620.10
Each additional kWh	¢2.68

Exhibit 1.10
(continued)

T-3 **Industrial**

- 3,000 kWh per month

Energy Charge:	
First 30 kWh	¢159.90
Each additional kWh	¢5.33

- 3,001 - 20,000 kWh per month

Demand Charge:	
First 13 kW	¢6,296.40
Each additional kW	¢484.34
Energy Charge:	
First 3,000 kWh	¢9,450.00
Each additional kWh	¢3.15

- Greater than 20,000 kWh per month

Demand Charge:	
First 27 kW	¢13,077.20
Following 60 kW (each kW)	¢484.34
Each additional kW	¢736.17
Energy Charge:	
First 20,000 kWh	¢63,109.30
Each additional kWh	¢2.28

T-6 **Small Industry (1,500 kWh per month)**

Energy Charge:	
First 30 kWh	¢114.60
Each additional kWh	¢3.82

Source: ICE

ventures. In this regard, it may be useful to look at two examples of existing or potential projects to provide some background for the study.

Two systems provide examples of power generated by parties other than ICE, Compania Bananera and Matamoros.

EXISTING NON-UTILITY POWER GENERATION

Compania Bananera de Costa Rica - Palm Oil Plants

This is the only known case of cogeneration in the Costa Rican manufacturing sector. Compania Bananera de Costa Rica operates three palm oil plants in the vicinity of Quepos (Pacific coast), which extract oil from African Palm nuts produced on nearby plantations. A considerable amount of combustible process waste is produced, part of which is burned to produce electricity and process steam in cogeneration installations. The remaining waste is sold for boiler fuel (palm nut shells), animal feed (nut kernels), or discarded (fibers). The stalks are burned without heat recovery and the ashes (high in potassium content) are used as fertilizer in the palm nut plantations.

Key energy data are presented in Exhibit 1.11. The Naranjos plant currently purchases about 25 percent of its electricity, but a project to make it self-sufficient in electricity is planned within two years. Energy characteristics of the African Palm nut waste products are:

Type of Waste	Heat Value	Moisture Content
Shells (cascarilla)	5,200 Kcal/Kg.	12%
Fiber (fibra)	5,000 Kcal/Kg.	15%
Stalks (pinzote)	4,500 Kcal/Kg.	30%

The process yields a 6 percent excess of palm nut shells, all of which is sold to a cement company in the Central Valley for 600 colones per ton. The transport· ·on cost to the cement plant exceeds the price paid to Compania Bananera.

Exhibit 1.11

Compania Bananera De Costa Rica
Palm Oil Plants
Key Energy Data

	Plant		
	Palo Seco	**Naranjos**	**Coto 47 Nueva**
Operations			
Production capacity, tonnes/hr (Palm Nuts)	30	20	50
Month of peak production	May		
Month of lowest production	November		
Hours of operation per year	~ 3,600	~ 3,600	~ 3,600
Steam System			
Number of boilers	3	2	1
Boiler rated capacity, tonnes/hr	15	2 x 5	15
Boiler rated pressure	350	350	350
Steam generated - tonnes/hr average	15		
Steam generated - pressure, psi	250	250	200
Projected increase - year 1992	50%		
Process steam pressure, psi	40	40	40
Boiler fuels	Palm nut shells and fibers		
Number of steam turbines	1	0	1
Number of reciprocating steam engines	1 (idle)	1	--
Electrical Power System			
Installed generating capacity, kVA	500	110	500
Purchased electricity, kWh	0	1,152,000	Not in operation yet
Cogenerated electric[illegible] kWh/year	1,080,000	396,000	---
Turbine type	1 stage	--	1 stage
Principal Energy Uses			
Steam	- Cooking palm nuts (direct injection) -		
Electricity	motors		

Source: Compania Bananera

There is excess generating capacity at two of the plants; consequently, if favorable terms of sale could be arranged, 400 kW of capacity could be harnessed for sale to the electrical utility (ICE). With additional investment the plants could generate 1,475 kW for sale to the grid. This additional generation potential is divided among the plants as follows:

	Without New Investment		With New Investment	
Plant	kW	kWh	kW	kWh
Palo Seco	200	720,000	500	1,800,000
Naranjos	0	0	350	1,350,000(planned)
Coto 47	200	720,000	625	2,250,000
Total	**400**	**1,440,000**	**1,475**	**5,400,000**

Empresa Electricidad de Matamoros (EEM)

EEM is a small, private power company operating three minihydro plants in Alajuela, near Ciudad Quesada, that provide power to the Cooperativa De Electrificacion Rural De San Carlos (COOPELESCA). The area is in a rich agricultural zone with ample hydropower resources. The plants were built some 35 years ago on the Rio Platanar, which drops from the mountains behind Quesada to the lowlands of Alajuela. They were installed by the sugar industry to provide electrical power for processing and to sell the rest to the city of Quesada, which today has a population of approximately 15,000.

EEM has 3.3 MW of capacity provided by three plants -- Cedral, Carmen, and Hospital. EEM purchased them at low cost and therefore has little debt. The power is sold directly to COOPELESCA at a levelized cost of 0.92 colones/kWh (demand charge, 207.87 colones/kW and energy charge, 0.6113 colones/kWh). COOPELESCA, which has some 18,000 members, in turn sells the power at a nominal cost of 2.05 colones/kWh. The cooperative buys most of its power from ICE at similar rates to meet a peak demand of 12,000 to 13,000 kW. EEM supplies only a fourth of COOPELESCA's power needs.

EEM seeks to increase its installed capacity by building a 10-15 MW (6 MW firm), high head hydropower plant (250 M) with reservoir. A feasibility study is currently under way (by Bel Ingenieria S.A.) and preliminary costs are estimated at $1,000/kW. This plant was originally envisioned as providing round-the-clock power for COOPELESCA, but it is more likely to be used for peaking until local demand develops. A financial analysis of this plant produced by the EPAP model is shown in Exhibit 1.12. The results suggest that it would be a worthwhile venture for the private sector. Financing has not been arranged yet, but discussions are under way with a German equipment manufacturer about an attractive loan that would require government guarantees. There have also been discussions by some private investors on financing the civil works, but this initiative is not moving ahead because investors believe that ICE's tariff structure will limit their return.

In the next chapter, the national potential for such independent power generation projects is analyzed in detail.

Exhibit 1.12

PRIVATE POWER PROJECT APPRAISAL
****

PROJECT NAME:	Matamoros	
TECHNOLOGY:	Hydroelectricity	
TECHNICAL CHARACTERISTICS		
SYSTEM SIZE:	15,000	kW
CAPACITY FACTOR:	0.60	
ANNUAL POWER PRODUCTION:	78,840,000	kWh/year
FINANCIAL PERFORMANCE		
CAPITAL COST:	$15,000,000	
ANNUAL O&M COST:	$300,000	
ANNUAL FUEL COST:	$0	
MARGINAL TAX RATE:	50	Percent
EQUITY ONLY:		
CAPITAL RECOVERY FACTOR:	0.270	
NPV:	($2,056,392)	
IRR:	12.083	Percent
NET POWER COST:	0.055	$/kWh
DEBT AND EQUITY:		
DEBT TO EQUITY RATIO:	2.300	
INTEREST RATE:	11	Percent
CAPITAL RECOVERY FACTOR:	0.105	
NPV:	$2,563,641	
IRR:	26.890	Percent
NET POWER COST:	0.034	$/kWh
ECONOMIC PERFORMANCE		
CAPITAL COST:		
FOREIGN EXCHANGE:	$4,500,000	
LOCAL CURRENCY:	$5,250,000	
NPV:	$16,032,733	
IRR:	51.190	Percent
NET LEVELIZED COST OF POWER:	0.017	$/kWh

Source: RCG/Hagler, Bailly, Inc.

CHAPTER 2: POTENTIAL FOR NONUTILITY POWER GENERATION

This chapter evaluates the potential for nonutility power generation in Costa Rica. Six options are explored:

- Industrial cogeneration
- Sugar mill generation
- Dendrothermal generation
- Agricultural and biomass waste-fired systems
- Small and minihydro systems
- Geothermal generation.

For each option, the technical, economic, and financial potential is evaluated and discussed. Although each option has some potential, only two would have a significant impact on the Costa Rican energy situation. In order of importance, they are: in the short-run, sugar industry generation and in the long-run, small and minihydropower. Another AID-Funded study examined the potential for coal-fired power plants in the long-run.[1] Solar and wind power generation were not included in the scope of work as both options cannot compete with ICE's long run marginal cost. (Indeed the lowest busbar cost of power from these options is U.S. 7 cents/kWh under the best world circumstances.)

ASSUMPTIONS FOR ECONOMIC AND FINANCIAL ANALYSES

To determine the relative attractiveness of the various nonutility power generation options, three sets of numbers were developed: the technical potential, the economic potential, and the financial potential. For each power generation option, the technical potential is that amount of generation that can be developed given the current and

1 Prefeasibility Study of Coal Use in Costa Rica, by Bechtel National, Inc., June 1987

expected state of the technology and the availability of the natural resources. This potential is largely a resource-limited number. The economic potential is that portion of the technical potential that can be developed with resulting electricity costs lower than the marginal production cost of electricity. This analysis uses only the true economic costs and benefits and factors out "transfer payments" such as taxes, duties, and profits that do not represent actual costs but rather shifts of resources from one sector to another.

Similarly, the financial potential is the generation capacity that can be developed with costs below the price of power provided by utilities. The financial analysis looks at the project from the viewpoint of the investor. It determines the actual cashflows of a project using market values for capital costs, labor, and materials. It incorporates taxes, duties, profits, and other transfer payments explicitly, and determines actual returns to the investor.

The key economic and financial costs and assumptions used in these analyses are summarized in Exhibit 2.1 and are further explained in Appendix C.

In the economic analysis, the economic cost of electricity is assumed to equal the average short-term and long-run marginal generation cost of electricity to ICE. This assumption is based on the avoided cost concept, the electricity generated from a nonutility power plant can in effect reduce the need for electricity generation by the utility, resulting in reduced generation costs to the grid. This cost saving or "avoided cost" is a fair value for pricing the nonutility electricity supply. The estimate of this value is based on ICE's power plant mix and power generation costs as well as the characteristics of electricity supply from other generators such as CNFL. For example, if a nonutility power plant can reliably supply firm capacity, the utility will not have to install additional peak generators and will thus realize large avoided costs. On the other hand, if the nonutility generators only provide interruptible energy (kWh) to the grid and no firm capacity, the utility's avoided cost will be limited to its variable generation costs. For a detailed discussion of avoided cost, see Appendix D.

In the economic analysis, the average value of nonutility electricity to the grid is assumed to be $0.050/kWh. This figure represents the average marginal generation cost of electricity to ICE, but it is only a first approximation of the avoided cost.

Exhibit 2.1

Key Assumptions for Financial and Economic Analysis

Economic

- Value of Electricity: $0.050/kWh
- Marginal Return on Capital: 10%
- Standard Conversion Factors:

O&M costs	0.75
Capital costs	0.70
Power costs	0.75
Fuel costs	0.95
Noncogeneration fuel costs	0.95

- Period of Analysis: 20 Years

Financial

- Value of Electricity: $0.0455/kWh
- Required Return on Equity: 15%
- Cost of Debt: 11%
- Debt/Equity Ratio: 2.3%
- Marginal Tax Rate: 50%
- Depreciation Period: 20 Years

Note: All assumptions are for U.S. dollar equivalent, in constant terms. For example, a 35 percent rate current colones translates, based on interviews with financial institutions and private investors into a 15% required return on equity in current dollars.

Source: RCG/Hagler, Bailly, Inc.

Estimating a more accurate value of avoided cost requires an integrated production costing analysis of each utility, taking into account the quantity, quality, and location of nonutility power sources. The capacity and energy components of this avoided cost value are discussed at length in Appendix D.

In addition, no attempt has been made in the economic analysis to estimate the full economic value of electricity to the economy. The economic losses resulting from power shortages are believed to be far greater than the cost of electricity supply. Several analyses carried out in Costa Rica indicate that the cost of load shedding, which is equal to the cost to the economy of interrupting power, is around U.S. $1.20/kWh. The economic value of electricity to the economy should be considered in developing national nonutility power generation policies.

In the financial analysis, the current price of electricity to the nation is assumed to be the financial value of electricity. The average price of electricity in Costa Rica is about $0.0515/kWh. This figure includes a demand charge, energy charge, and fuel adjustment charge, and other supply expenses and applicable taxes for industry, which is the most concerned sector with this study, an average price of $.0455/kWh has been retained.

To allow comparison of systems having major differences in their cash flows, a capital recovery factor (CRF) approach was used. This approach, which is equivalent to a net present value calculation, gives an estimate of power cost in $/kWh.

It was not the purpose of this study, however, to recommend or evaluate the non-economic or "soft" economic factors used to justify investments in power systems. Rather, the study focused on how the Government of Costa Rica could stimulate investment by the private sector in power systems as a substitute for public-sector investment in electric power generating projects. Consequently, projects requiring significant government assistance in the form of subsidies or soft loans (because of significant nonmonetary benefits) have not been recommended for private investment. In general, such projects would not significantly reduce the need for government financing, but merely change its form (for example, from a single large loan guarantee to many small ones).

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INDUSTRIAL COGENERATION

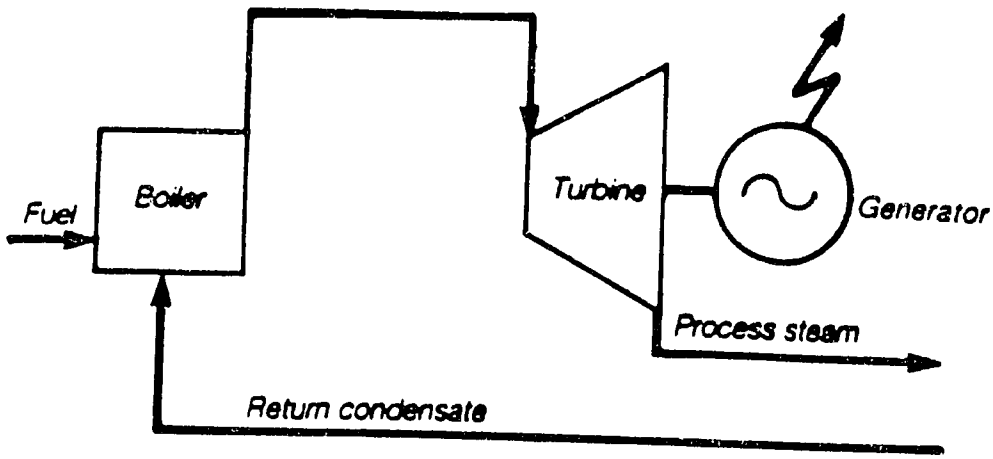
Cogeneration potential depends on several factors, including the size and number of individual companies, the nature and quality of their present and projected energy needs, and all of the cost factors that enter into the financial analysis of a project. This section examines these factors, and evaluates cogeneration potential based on data gathered mainly at plant level and on experience gained worldwide in similar endeavors.

Cogeneration systems fall into two categories: topping systems and bottoming systems. In a topping system, thermal energy exhausted in the production of electrical or mechanical energy is used in industrial processes (see Exhibit 2.2). This thermal energy is usually in the form of low-grade (i.e., low-pressure, low-temperature) steam. Typical applications of this low-grade heat steam include heating, drying, distillation, and concentration. At any site using low-grade steam and electricity, a topping system is usually an efficient alternative to purchasing power from the grid and generating the heat separately by a dedicated system, usually a low-pressure boiler or a heater. The incremental investment needed for the cogeneration alternative consists of the cost of the power unit (generally a gas or steam turbine or a diesel engine) and the difference in the cost of purchasing and operating a higher pressure boiler than would otherwise be used. The main advantage of a topping cogeneration system is the amount of fuel that it saves. In addition, cogeneration systems located at industrial sites may also improve power reliability and quality for that site.

Bottoming cogeneration systems differ from more conventional topping systems in that they use waste heat from industrial processes as the heat source for electricity generation, rather than the heat released from the combustion of commercial fuels. Basically, a bottoming cycle system consists of a waste heat boiler used to vaporize water or organic fluids and a turbine generator with condenser, unless low-pressure exhaust steam extracted from the turbine is used directly in the process. Such systems are used in processes generating large waste heat streams at temperatures of 300°C and higher. Cement, steel, glass, and some chemical and petroleum refining industries are possible candidates for bottoming systems.

Exhibit 2.2

Fuel Oil Fired Boiler/Steam Turbine Cogeneration Plant



Source: Power, McGraw-Hill.

Industry Profile

As would be expected in a country of 2.5 million inhabitants, with manufacturing oriented toward the domestic market, manufacturing operations tend to be small-scale when judged by international standards. Thus, plants found in Costa Rica generally represent those industries where the minimum economic scale of manufacturing matches the relatively small domestic demand. Exceptions are plants geared to the export market, such as tire and glass container manufacturers (large scale) and textiles (medium to small scale, but numerous). The energy-intensive basic metal and basic chemical industries are absent in Costa Rica; only metal and chemical converters, with relatively low energy consumption, are found there.

RECOPE, the state enterprise for petroleum refining and distribution, is the largest enterprise and energy user in the manufacturing sector; however, manufacturing activity lies mainly in the private sector and (apart from certain major state enterprises) there is a trend toward further privatization, actively supported by government policy. The largest concentrations of companies are found in the food, beverage, and tobacco subsectors, and typically one or two companies dominate each type of manufacturing activity. This industry structure and scale permitted the collection of representative plant level data by means of relatively few plant visits, this information was supplemented by existing audit reports and surveys.

Industry Growth Projection

Most industrial managers interviewed shared an outlook characterized by uncertainty, and by low growth expectations over the next 5 years. This view reflects the current situation of tight credit and an inflation rate of 15 percent. The Chamber of Commerce has announced that the shortage of credit is severely depressing industrial activity at this time, obliging some companies to lay off employees.

Energy Profile

The industrial sector (excluding RECOPE and the sugar industry) consumes approximately 931,000 barrels of fuel oil and 1,100,000 MWh of electricity. From an

energy standpoint, the sector is dominated by the cement, fertilizer, and glass subsectors, all of which use mainly direct-fired thermal energy in their processes. They have only small steam systems, which offer no potential for cogeneration.

Thirty-one companies purchased 650,300 barrels of fuel oil, or 77 percent of total sales to manufacturing companies, in 1987 (see Exhibit 2.3). Of these companies, only four were major steam users. By industry category, the nonmetallic mineral products group accounted for 50.5 percent of fuel oil sales, followed by food, beverages, and tobacco (23 percent) (see Exhibit 2.4). Similarly, electricity consumption is concentrated in only a few companies; the major users are the cement, fertilizer, and glass industries (direct-fired processes), followed by two large textile firms and a tire manufacturer (steam systems) (see Exhibit 2.5).

Only four plants in Costa Rica have steam generation rates in excess of 10 tonnes/hour -- the minimum rate for cogeneration feasibility (see Exhibit 2.6). Steam users are concentrated in the food, beverages, and tobacco group, followed by the textile, clothing, and leather group.

Costa Rican manufacturing plants generate steam almost exclusively with fuel oil. Only three companies using waste fuels were identified:

Industrial Users of Waste Fuel - Costa Rica

Company	Products	Fuel
Compania Bananera de Costa Rica	Palm Oil	African palm nut shells and fibers
Industria Nacional de Cemento	Cement	African palm nut shells
Portico	Mahogany doors	Lumber cuttings

All three of Compania Bananera's palm oil plants (near Quepos) are cogenerating electricity and steam, and Portico is currently exploring this option. These are the only

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Exhibit 2.3

Fuel Oil Sales to Major Industrial Customers
1986 (Thousands of Barrels)

Company	Products	Sales
Industria Nacional de Cemento	Cement	163.9
Cementos del Pacifico	Cement	106.7
Vidriera Centroamericana S.A.	Glass containers	47.8
Fertica S.A.	Fertilizer	42.5
Compania Numar S.A.	Vegetable oil, margarine	35.3
Coop. Prod. de Leche R.L.	Dairy products	32.0
Scott Paper de Costa Rica S.a.	Paper & paper products	31.9
Industrias AKRON S.A.	Tires	21.0
Cerveceria Costa Rica	Beer	17.7
Matadero Montecillo	Meat Products	16.5
Laminadora Costarricense	Steel Shapes	14.4
Fabrica Nacional de Licores	Liquor	13.8
Textiles Ind. Centro-americanos S.A.	Textiles	10.7
Productos Gerber de Costa Rica S.A.	Baby food	9.5
Punto Rojo S.A.	Toilet soap	8.5
Plywood Costarricense S.A.	Plywood	7.4
Pieles Costarricenses S.A.	Leather	6.2
Envases Ind. de CR S.A.	Packaging	6.1
El Gallito Industrial S.A.	Chocolate candies	6.0
Central American Meat S.A.	Meat	5.5
Productos de Concreto S.A.	Concrete Products	5.3
Ricalit	Concrete Products	5.1
Alunasa	Aluminum Shapes	5.0
Tubotico S.A.	Pipe	4.9
Henderson Cia. S.A.	Meat	4.0
Cost Rica Cocoa S.A.	Cocoa Products	4.0
Galvatica S.A.	Galvanized Steel	3.9
Cerveceria Tropical	Beer	3.9
Textiles Tres Rios	Textiles	3.8
Metales Cia. S.A.	Metals	3.3
Ganaderia Industrial	Meat	3.3
Total		**650.3**

Source: RECOPE

Exhibit 2.4

Petroleum Sales to Major Customers

by Industry Group

1986

Industry Code	Industry Group	Sales (Thousands of Barrels)	%
31	Food, Beverages & Tobacco	151.5	23.3
32	Textiles, Clothing & Leather	20.7	3.2
33	Wood & Wood Products	0.0	0.0
34	Paper & Paper Products	45.4	7.0
35	Chemicals & Chemical Products	72.0	11.1
36	Nonmetallic Mineral Products	328.8	50.5
37	Basic Metals	31.9	4.9
38	Metal Products, Mach. & Equip.	0.0	0.0
39	Other Manufacturing	0.0	0.0
	Total	**650.3**	**100.0**

Source: RCG/Hagler, Bailly, Inc., based on RECOPE sales statistics.

Exhibit 2.5

ICE Electricity Sales to Major Private Customers
1986

Company	Products	Electric Power Purchased (MWh)
Industria Nacional de Cemento	Cement	41,493
Cementos del Pacifico	Cement	33,293
FERTICA	Fertilizer	32,578
VICESA	Glass container	18,118
Olympic Fibers	Textiles	17,557
TICASA	Textiles	13,390
Industria Akron	Tires	11,293
ALUNASA	Aluminum	5,216
Total		**211,803**
Total ICE Sales (bulk, no sales)		**1,884,088**

Source: ICE

Exhibit 2.6

Estimated Potential for Cogeneration by Company

Company	Annual Steam Consumption		Technical Potential
	T/hr.	%	MW
Largest Steam Users[1]			
Scott Paper de Costa Rica	23.5	10.0	1.67
Fabrica Nacional de Licores	18.0	7.6	1.28
Matadero Montecillos	12.4	5.3	0.88
Coop. Productores de Leche (Dos Pinos)	11.8	5.0	0.83
Total Largest Steam Users	85.7	27.9	4.66
Other Steam Users Identified	170.1	72.1	12.01
Total	**235.8**	**100.0**	**16.67**

[1] 10 tonnes/hour minimum

Source: RCG/Hagler, Bailly, Inc.

two companies known to be operating a cogeneration unit or planning one, and waste fuel is involved in both cases. The palm oil plants are not connected to the utility grid; however, they -- and Portico -- would consider selling power to their electricity companies if it were to prove feasible and financially attractive.

Methodology

Owing to the small number of companies involved, their concentration in the Central Valley, and the large amount of useful data available from earlier surveys, it was possible to employ a bottom-up approach to data gathering and analysis, which yields greater accuracy than using data of a broader character. In addition, the availability of considerable data from previous studies and audits facilitated data gathering. The collection and the analysis of data entailed three steps:

Data Collection

1. Developed a list of major energy users (oil and electricity) and tabulated their steam capacity and use, as well as their electricity consumption. Data sources consisted of prior surveys (DSE and Meta Systems); RECOPE and ICE sales data; DSE, ICAITI and SOL 2000 personnel; and energy audit reports.

2. Visited seven plants of companies representing the principal industrial subsectors for which data were not already available. Also used plant visits to gather information on industrial managers' attitudes toward cogeneration potential and perception of barriers to its development.

3. Visited UNDP, IDB, and AID to gather information on financial and economic issues and barriers to cogeneration development.

Analysis

1. Selected major steam users, rejecting those with steam requirements below 10 tonnes/hour.

2. Selected a "best case" for analysis, using the Hagler, Bailly EFAP computer model (see Appendices C and G for details). Confirmed this finding by computer analysis of other potentially good cases.

3. Calculated theoretical cogeneration potential by assuming an electricity-to-thermal-energy ratio (E/T) of 0.1 based on a back-pressure steam turbine system, which has the broadest application in Costa Rican industry. Assuming that the cogeneration system would be sized to meet steam needs, the electricity capacity was estimated by applying the E/T factor to thermal energy output. The factor was first applied to all steam users (theoretical technical potential), and then only to users with 10 tonnes/hour or more (practical technical potential).

Technical Potential

The theoretical technical potential for cogeneration in Costa Rica industry (assuming that all process steam is cogenerated and extracted from back pressure turbines) is estimated at 16.67 MW. This potential is primarily in the food, beverages, and tobacco subsector, as shown in Exhibit 2.7. Elimination of companies generating less than 10 tonnes/hour of steam reduces the potential to 4.66 MW (practical technical potential), which is distributed among the four large steam users, shown in Exhibit 2.6.

Economic and Financial Potential

1. Best Case Study

Scott Paper de Costa Rica is the sole paper producer in Costa Rica and has the highest steam consumption in the industrial sector (excluding RECOPE and the sugar industry). Data from the company energy profile shown in Exhibit 2.8 were used to

Exhibit 2.7

Technical Potential for Cogeneration by Industrial Category[1]

Industry Code	Industry Group	Steam Consumption tonnes/hour	Technical Potential (MW)
31	Food, Beverages & Tobacco	114.8	8.12
32	Textiles, Clothing & Leather	48.5	3.43
33	Wood & Wood Products	5.0	0.35
34	Paper & Paper Products	23.5	1.66
35	Chemicals & Chemical Products	27.6	1.95
36	Nonmetallic Mineral Products	6.7	0.47
37	Basic Metals	0.0	0.0
38	Metal Products, Machinery & Equipment	9.7	0.69
39	Other Manufacturing	0.0	0.0
	Total	**235.76**	**16.67**

1 Basis: Back pressure steam turbine systems, assuming E/T = 0.1.

Source: RCG/Hagler, Bailly, Inc.

Exhibit 2.8

Energy Profile of Scott Paper de Costa Rica

Steam system size:	31.36 T/hr.
Annual capacity factor:	0.75
Noncogeneration efficiency:	0.236
Electric-to-thermal-energy ratio (E/T):	0.46
Bunker fuel consumption	4,789.05 T/yr.
Steam consumption:	23.5 T/hr
Electricity-Peak demand:	4,760.0 kW
-Average demand:	4,725.0 kW
-Consumption:	2,998,000.0 kWh/month

Source: RCG/Hagler, Bailly, Inc.

determine the company's cogeneration potential. The results indicated a negative internal rate of return; therefore, cogeneration would be uneconomical in this case. (Exhibit 2.9).

2. Other Case Studies

Further analysis of the most promising candidates verified the absence of an economic cogeneration potential among major Costa Rican steam users, virtually all of which operate fuel oil-fired steam systems (these are not competitive with ICE's hydro base for power generation). A notable exception is the three palm oil plants of Compania Bananera, which fire their boilers with African Palm nut waste and already cogenerate.

3. Fluor Canada Ltd. Study of the Cogeneration Potential of RECOPE

A cogeneration option at the RECOPE refinery in Puerto Limon on the Atlantic coast was examined by Fluor Canada Ltd., and found to be uneconomical.

RECOPE heads the list of Costa Rican steam users, generating 24.7 tonnes/hour at 250 psi, of which 10.4 tonnes/hour are extracted from turbines to be used at 20 psi for its own process requirements as shown in Exhibit 2.10. The balance of the steam (14.4 tonnes/hour) is condensed. Existing captive generating capacity is 455 kW (diesel generators), which is supplemented by purchased power; however, the service provided by the utility is unreliable because the plant is located at the end of the distribution line. The study examined the feasibility of additional power generation by means of cogeneration. The proposed system would add steam generating capacity of 15.9 tonnes/hour at 600 psi to generate an additional 388 kW. The system, which would cost U.S.$2,815,000, was found to have a payback period of 14 years, which Fluor deemed to be unsatisfactory. A further negative factor was the lack of an adequate supply of boiler feedwater. Thus, a diesel-electric plant costing U.S.$1,000 per kW of generating capacity was judged by Fluor to be a cheaper and thus better option.

4. Special Cases

Good potential for cogeneration probably exists in only two of the companies examined: Numar S.A. (vegetable oils, margarine) and Portico S.A. (mahogany doors).

Exhibit 2.9

COGENERATION PROJECT APPRAISAL
****

PROJECT NAME:	Scott Paper	
PLANT TYPE:	Paper plant	
TECHNICAL CHARACTERISTICS		
SYSTEM SIZE:	65	mmBtu/hr
E/T RATIO:	0.10	
CAPACITY FACTOR:	0.70	
ANNUAL POWER PRODUCTION:	11,681,712	kWh/year
FINANCIAL PERFORMANCE		
CAPITAL COST:	$4,680,000	
ANNUAL O&M COST:	$234,000	
ANNUAL FUEL COST:	$1,764,840	
MARGINAL TAX RATE:	50	Percent
EQUITY ONLY:		
CAPITAL CHARGE RATE:	0.270	
NPV:	($2,679,494)	
IRR:	0.848	Percent
NET POWER COST:	0.130	$/kWh
DEBT AND EQUITY:		
DEBT TO EQUITY RATIO:	2.300	
INTEREST RATE:	11	Percent
CAPITAL RECOVERY FACTOR:	0.105	
NPV:	($1,238,043)	
IRR:	ERR	Percent
NET POWER COST:	0.086	$/kWh
ECONOMIC PERFORMANCE		
CAPITAL COST:		
FOREIGN EXCHANGE:	$2,808,000	
LOCAL CURRENCY:	$936,000	
NPV:	($1,236,060)	
IRR:	ERR	Percent
NET LEVELIZED COST OF POWER:	0.057	$/kWh

Source: RCG/Hagler, Bailly, Inc.

Exhibit 2.10

Sugar and Bagasse Production in Costa Rica (1982)

Mill	Cane Milled Tonnes/Year	Sugar Production Tonnes/Year	Bagasse Produced Tonnes/Year
Viejo	152,079	13,064	53,228
Catsa	233,840	16,561	81,861
Palmar	282,397	20,510	98,800
Taboga	278,568	22,976	97,498
Quebrada Azul	218,520*	18,574**	72,116**
Victoria	189,118	19,000	43,500
Atirro	109,173	10,292	36,163
Juan Vinas	103,671	9,600	32,670
Argentina			

* 1987 Data

** Estimated, 1987

Source: Meta Systems

Numar S.A., with a steam consumption of 9.41 tonnes/hour at 130 psi, has a medium pressure steam plant (250 psi) that could probably be retrofitted to generate steam of a quality suitable for driving a turbine. This would reduce the capital cost of a cogeneration plant to an estimated U.S.$500,000, including a turbo-generator. The EFAP computer analysis indicates a good financial potential for generating 1 MW. Based on a U.S. dollar equivalent, the financial IRR is estimated at 42 percent (assuming a debt to equity ratio of 2.3) and economic IRR at 111 percent. (Exhibit 2.11).

Portico S.A., which generates an estimated 5 tonnes/hour of steam using mahogany wood waste from its process, has excess waste that could be used to fuel a cogeneration system. The plant's two boilers date from 1940 and would require replacement. Based on a marginal investment of U.S.$1,700,000 the EFAP analysis is favorable for a 550 kW cogeneration system. Using a U.S. dollar equivalent, the financial IRR is 16 percent and the economic IRR is 44 percent. (Exhibit 2.12).

The technical potential for cogeneration among Costa Rican manufacturers identified as steam users is approximately 16.7 MW (see Exhibits 2.6 and 2.7); however, the economic and financial potential is probably only about 3 MW as follows:

Numar	1.00 MW
Portico	.55
Compania Bananera	1.48
TOTAL	3.03 MW

This gap is due mainly to the fact that oil-fired generation of electricity cannot compete with the cost of electricity generated by ICE from the country's abundant hydropower resources. Therefore, as a rule, cogeneration or captive power generation is feasible only if it is based on fuels other than oil, although in cases where a medium- or high-pressure boiler already exists, (significantly reducing capital investment for cogeneration), a cogeneration project may prove to be financially attractive.

A further negative factor is the relatively small scale of Costa Rican plants, which increases the capital cost per kW of new generating capacity. Only four plants were

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Exhibit 2.11

COGENERATION PROJECT APPRAISAL
****

PROJECT NAME:	Numar	
PLANT TYPE:	Vegetable oil plant	
TECHNICAL CHARACTERISTICS		
SYSTEM SIZE:	37	mmBtu/hr
E/T RATIO:	0.10	
CAPACITY FACTOR:	0.56	
ANNUAL POWER PRODUCTION:	5,319,672	kWh/year
FINANCIAL PERFORMANCE		
CAPITAL COST:	$499,500	
ANNUAL O&M COST:	$24,975	
ANNUAL FUEL COST:	$803,681	
MARGINAL TAX RATE:	50	Percent
EQUITY ONLY:		
CAPITAL CHARGE RATE:	0.270	
NPV:	$47,517	
IRR:	16.950	Percent
NET POWER COST:	0.042	$/kWh
DEBT AND EQUITY:		
DEBT TO EQUITY RATIO:	2.300	
INTEREST RATE:	11	Percent
CAPITAL RECOVERY FACTOR:	0.105	
NPV:	$201,364	
IRR:	41.589	Percent
NET POWER COST:	0.032	$/kWh
ECONOMIC PERFORMANCE		
CAPITAL COST:		
FOREIGN EXCHANGE:	$299,700	
LOCAL CURRENCY:	$99,900	
NPV:	$768,913	
IRR:	111.193	Percent
NET LEVELIZED COST OF POW	0.025	$/kWh

Source: RCG/Hagler, Bailly, Inc.

Exhibit 2.12

COGENERATION PROJECT APPRAISAL
****

PROJECT NAME:	Portico	
PLANT TYPE:	Door manufacturer	

TECHNICAL CHARACTERISTICS

SYSTEM SIZE:	30	mmBtu/hr
E/T RATIO:	0.15	
CAPACITY FACTOR:	0.30	
ANNUAL POWER PRODUCTION:	3,466,002	kWh/year

FINANCIAL PERFORMANCE

CAPITAL COST:	$1,290,000	
ANNUAL O&M COST:	$64,500	
ANNUAL FUEL COST:	$0	
MARGINAL TAX RATE:	50	Percent
EQUITY ONLY:		
CAPITAL CHARGE RATE:	0.270	
NPV:	($203,477)	
IRR:	8.488	Percent
NET POWER COST:	0.067	$/kWh
DEBT AND EQUITY:		
DEBT TO EQUITY RATIO:	2.300	
INTEREST RATE:	11	Percent
CAPITAL RECOVERY FACTOR:	0.105	
NPV:	$9,045	
IRR:	15.994	Percent
NET POWER COST:	0.045	$/kWh

ECONOMIC PERFORMANCE

CAPITAL COST:		
FOREIGN EXCHANGE:	$774,000	
LOCAL CURRENCY:	$258,000	
NPV:	$347,894	
IRR:	44.289	Percent
NET LEVELIZED COST OF POWER:	0.031	$/kWh

Source: RCG/Hagler, Bailly, Inc.

found to have a steam consumption in excess of 10 tonnes/hour, which is roughly the lower limit for economic cogeneration.

SUGAR MILL POWER GENERATION

The sugar industry is one of the major industries in Costa Rica and has by far the largest steam generating capacity of all. With an estimated installed steam capacity of over 2 million pounds/hour, the industry can theoretically generate anywhere between 60 MW and 200 MW, depending on the type of power system used, e.g., straight back pressure turbines, condensing steam turbines. Currently, the sugar industry has a total installed power (i.e., electrical and mechanical turbines) capacity of approximately 42 MW and generates approximately 25 MW on average during the crushing season. Therefore, an additional 45 MW to 175 MW could theoretically be made available. In the next sections the structure and characteristics of this industry are described and then the economics of additional power generation for sale to the grid is examined to determine whether such an option is economically and financially justifiable.

The Industry

There are 24 operating sugar mills in Costa Rica that produced a total of 240,000 tons of sugar equivalent (including alcohol) during the 1985-1986 season. The production of a mill varies from 20,000 tons to 420,000 tons of cane crushed per season, or roughly 200 to 4,200 tons per day. The crushing season typically lasts 4 months, from January to late April, for an average of 100 days or 2,400 hour/year. The total amount of cane crushed in the 1985-1986 season was 2,484,000 tonnes (see Exhibit 2.13).

From an energy standpoint, the mills burn bagasse -- the fibrous residue of the cane left after crushing -- in boilers that generate medium pressure steam to run mechanical drive turbines (back pressure-type) and power turbines that generate the electricity needed to run the mill during the season. The low-pressure steam extracted from the turbines is then used in the process for heating purposes.

EXHIBIT 2.13

SUGAR STATISTICS

TONNES OF CANE PROCESSED BY SEASON

	1981-82 TONS	1982-83 TONS	1983-84 TONS	1984-85 TONS	1985-86 TONS
Aragon	33,743.440	44,928.516	33,663.514		
Atirro	109,172.581	124,468.900	160,280.807	190,383.270	159,102.860
Florencia	48,728.357	45,045.684	57,213.611	69,829.270	66,783.550
Juan Vilas	103,670.575	132,593.240	145,693.255	146,279.460	141,233.550
SUBTOTAL	295,314.953	347,036.340	396,851.187	406,492.000	367,119.960
Argentina	77,567.256	72,809.185	98,562.015	96,360.870	83,111.360
Costa Rica	88,091.012	95,062.681	96,508.113	93,225.620	85,489.270
El General	50,580.007	55,215.538	72,978.765	76,999.690	61,434.240
Esmeralda	30,259.896	21,870.970	24,089.342	19,411.130	16,782.050
La Hilda	22,513.920	24,002.910	23,445.390	22,187.000	16,826.240
La Luisa	22,886.024	22,945.173	22,396.785	23,713.980	19,789.989
Ojo de Agua	39,295.600	40,793.700	41,748.450	46,836.930	35,424.570
orvenir	64,595.710	53,764.630	64,371.510	62,074.960	50,610.270
Providencia	55,243.540	54,808.370	53,185.090	52,130.160	48,975.820
San Ramon	25,603.370	22,646.900	32,302.720	29,747.790	29,131.060
Victoria	189,117.720	192,399.310	230,131.010	208,043.880	200,991.860
SUBTOTAL	665,754.055	656,319.367	759,719.190	730,732.010	648,566.729
Curtis	32,345.134	38,819.558	48,904.479	50,900.400	51,528.420
Quebr. Azul	94,865.843	104,678.149	152,297.837	157,198.200	139,595.320
Santa Clara	4,690.805				
Sante Fe	49,974.118	44,309.605	48,057.449	57,065.320	61,825.510
SUBTOTAL	181,875.900	187,807.312	249,259.765	265,163.920	252,949.250
CATSA	233,890.069	192,292.806	270,423.975	249,561.170	326,870.050
El Palmar	282,397.588	292,495.630	277,199.872	243,269.790	295,666.970
El Viejo	152,079.478	175,240.229	214,830.775	193,293.020	248,239.780
Azuc. Guan.	18,958.595	18,225.860	17,848.520		
San Gerardo	19,907.690	20,510.400	19,173.080	19,420.020	18,643.690
Taboga	278,567.993	336,100.470	413,042.120	341,277.740	326,147.910
SUBTOTAL	985,801.413	1,034,865.395	1,212,518.342	1,046,821.740	1,215,568.400
T O T A L	2,128,746.321	2,226,028.414	2,618,348.484	2,449,209.670	2,484,204.339
VARIATION (percent)		4.57	17.62	(6.46)	1

SOURCE: LIGA AGRICOLA INDUSTRIAL DE LA CANA DE AZUCAR

Energy Profile

Some sugar mills have a connection with an electric utility, generally ICE or CNFL, and a peak demand of 200-1,200 kW (see Exhibit 2.14). Most mills, however, are not connected.

Equipment

The Direccion Sectorial De Energia (DSE) just commissioned, with OLADE's assistance, a comprehensive and detailed survey of the country's 13 major sugar mills. (see Appendix H for a copy of the questionnaire). Those 13 mills account for about 88 percent of total national production. As of November 20, 11 questionnaires had been completed and the information is summarized in Exhibit 2.15. The survey covered production data, energy consumption, and details about equipment, including boilers, mechanical drive turbines, and electricity turbogenerators. The survey shows that a mill crushing 200,000-300,000 tonnes of cane per season typically has three to four boilers rated at 50,000-120,000 pounds/hour each operating at about 80 percent capacity and at 50-60 percent efficiency. Typical steam pressures are 250-300 psig. Each mill has four to seven turbines (both mechanical and electrical) for a total of 5-6 MW.

While most sugar mills are almost totally self sufficient in energy during the crushing season, they generally rely on the electric utility to operate off season. In the next sections, the potential for generating additional power for sale to the grid is analyzed.

Technical Potential for Sale of Electricity

In estimating how much additional energy could be generated by sugar mills, three options were considered.

Option 1. Burn excess bagasse using existing equipment, with a minimum investment in additional equipment. By improving the efficiency of the existing equipment and modifying the power system, the amount of bagasse needed to meet on site energy needs could be reduced by at least 10 percent and the amount of excess bagasse could be increased from a current est. ated 118,000 tonnes to 180,000 tonnes per year. Even

Exhibit 2.14

Peak Electric Demand (1987)

Customers on tariff T-8 only

Sugar Mill	Peak Demand (kW)
La Luisa	415
Taboga	1,200
Atirro	200
Coopevictoria	780
Coopeagri	205

Source: ICE.

Exhibit 2.15

Summary of DSE Survey on 11 Sugar Mills

NAME/ LOCATION (T/CANE CRUSHED)	ENERGY: DAYS OPERATING PER YEAR	ELECTRICITY PURCHASED: KVA	ELECTRICITY PURCHASED: TARIFF	FUEL USED: BAGASSE (T)	FUEL USED: BUNKER (GAL)	FUEL USED: OTHER (T)	EQUIPMENT: BOILERS: No.	BRAND	FUEL BURNED	'000 LBS/HR NOMINAL	'000 LBS/HR PRODUCED	PRES. (PSI)	EFF. (%)	TURBINES: No.	HP	TEMP. IN (F)	TEMP. OUT (F)	ELECTRICITY GENERATORS: KW	USE
1) CATSA/GUARDIA/GUAN. (225-327 KT) 1986 Also produces alcohol (2-24 million liters)	80-100 Purch. for Distillery Only	165	T.8	55,360 (77,436?) .36x.65 (35% excess)	15,000	Lena 1000	1	Alfa	Bg	120	120	300	63	1	700 HP	500	369	3,000	Principal
							2	B&W	Bg	100	100	300	63	2	500 HP	500	369	2,000	Reserve
							3	Riley	Bg	70	35	200	60	3	643 HP	500	369	500	Reserve
							4	Serrey	Bg	150	NA	250	63	4	286 HP	500	400		
														5	265 HP	500	400		
														6	3,000 kW	500	400		
														7	2,000 kW Reserve	419 (15psi)			
2) ELVIETO/GUANACASTE (248K) 1986	100	3,401 (1152 ICE)		74,800	147,000	Lena 200	1	B&W	Bg	100	85	200	60	1	1,500 KW	180C	99C	650	
							2	B&W	Bg	100	NA	200	65	2	500 KW	180C	99C	1,500	
							3	B&W	Bg	200	NA	550	65	9	Mechan.Turbines Total: 3,500 KW			500	
							4	B&W	Bg	60	NA	550						500	
3) TABUGA/GUANACASTE (326K) 1986	90-120	1,500	T-9	97,000 (10%excess)	0	600M3Lena	1	Sanine	Bg	143	143	250	65	1	2x2500 HP	414		2x(1875KV	Principal
							2	Erie City	Bg	50	50	250	65	2	1,200 HP	414		875	Reserve
							3	B&W	Bg	22	0	200	65						
							4	Erie City	Bg	20	0	183							
4) ELPALMAR/PUNTA RENAS (295K)	100	2,000		84,974 (10%excess)	7,122	NA	1	Heine	Bg,Le,Bu	30	19.5	280	60max	1	1,000 KW	400	220	1,000	Principal
							2	B&W	Bg,Le,Bu	50	50	280	60max	2	1,500 KW	400	220	1,500	Principal
							3	B&W	Bg,Le,Bu	30	80	80	60max	3	3,000 KW	400	220	3,000	Principal
														4	2,000 KW	400	220	2,000	Reserve
5) CENTRAL AZUCARENA TURRIALBA S.A./TURRIALBA (159K)	130	1,000	T-8	27,000	0	100-150m3 Lena	1	4xB&W	Bg	25	20	160	85		12x1000HP	480	130	750	Principal
							2	NA		10	10							500	Reserve
																		440	Reserve
																		750	Reserve
6) JUAN VINAS S.A. JUAN VINAS/CARTAGO (147K)	170	Self-Sufficient		25,650	14937-734	0	1	Erie City	Bg,Bu	68	59	270	53	1	2,000 KW	456	259	2,000	Principal
							2	Zurn	Bg,Bu			270	55	2	750 KW	406	259	750	Principal
														3	660 KW	406	259	600	Reserve

Exhibit 2.15 (continued)

Summary of DSE Survey on 11 Sugar Mills

NAME/ LOCATION (T/CANE CRUSHED)	DAYS OPERATING PER YEAR	ENERGY: ELECTRICITY PURCHASED KVA	ELECTRICITY PURCHASED TARIFF	FUEL USED BAGASSE (T)	FUEL USED BUNKER (GAL)	FUEL USED OTHER (T)	EQUIPMENT: BOILERS No.	BRAND	FUEL BURNED	'000 LBS/HR NOMINAL	'000 LBS/HR PRODUCED	PRES. (PSI)	EFF. (%)	TURBINES No.	HP	TEMP. IN (F)	TEMP. OUT (F)	ELECTRICITY GENERATORS KW	USE
7) FLORENCIA/TURRIALBA (67K)	230	0	5colx10^6 Zafra	13,521	0	0	1	NS	Bg	27	30	200	NA	1	250 HP	NA	NA	None-want to install e boiler with turbogen. 200psi	
8) COOPEVICTORIA/GRECIA (201K)	100	990 +990 Reserve	T-8	64,320	0	500m3 Lena	1 2 3	Erie City Bigelow Sperlis	Bg Bg Bu	20 35 60	0 25 60	250 250 250	NA 63 63	1 2 3 4	2,500 KW 1,000 KW 500 KW 1,000 KW	450 450 450 (2000psi)	259 259 240 (20psi)	1,000 500 2,500	
9) COSTA RICA/PUAS CANILLUS (85K)	150-180	Nearly self sufficient		30,000 35,000	0	0	1	4xB&W	Bg	50 Total?	50	250-300	NA	1 2 3 4	700 HP 500 HP 800 HP 202 HP	366 366 388 NA	366(15ps 366(15ps 266 NA	500 700 800 202HP	Reserve Hydro
10)QUELRODA AZUL/SAN CARLOS (140K)	120			46,415	0	Lena 100	1 2	Comb.Eng 2xNS	Bg,Lena Bg	80 40 Total?	80 0	220 220	NA NA	1	2x400 HP	235	130	1,500HP 2x1000HP have hydro plant	Principal Reserve
11)SANTA FE/SAN CARLOS, PRIMERO (63K)	120	350	Normal	20,790	0	500m3 Lena	1 2	B&W B&W	Bg,Lena Bg,Lena	38.5 21	32 20	225 225	80 90	1 2 3 4	500 KW 600 KW 2x250 KW 2x275 KW	350 350 350 350	NA NA NA NA	500 600	

KEY: Bg = Bagasse
Le = Lena (wood)
Bu = Bunker

Source: DSE

at a 10 percent efficiency, this amount of bagasse could represent a possible supply of almost 10MW of power, which is considered as the low end of the technical market.

Option 2. Modify equipment to achieve higher efficiencies. Under this option, the overall power system -- boilers and steam systems -- could be replaced by new, efficient systems able to generate power at 20 percent efficiency. Up to 116 MW of power could be produced, leaving an excess of 91 MW for possible sale to the grid, after taking into account on-site needs (estimated at 25 MW). This is considered as the high end of the technical market (see Exhibit 2.16).

Option 3. Year-round operation using cane residues; Recent experiments in Jamaica, the Dominican Republic, and Thailand have shown that cane residues -- the tops and leaves that are traditionally burned on the field in Costa Rica and represent the largest energy waste in the country or about 250,000 tonnes of oil equivalent -- can be collected and dried on the fields, baled, and burned in bagasse boilers during the off season. International experience suggests that for each ton of cane stalk harvested, 0.67 tonne of residue is left in the field (at 50 percent moisture, which falls to 30 percent after 4-6 days of sun drying). In Costa Rica, about 50 percent -- or 832, 800 tonnes -- of residues could be made available for power production, after taking into account other needs.

At 50 percent moisture, this option represents enough energy to produce 100-170MW of electricity for sale to the grid during the off season. This power would be of greater value to ICE in May, June, and July, when the hydro system is not yet at its full capacity.

The three options entail different levels of investment and complexity.

Economic and Financial Potential

The investment needed for option 1 is probably within the reach of the sugar industry as it does not exceed $1.5 million and provides a higher return than any other alternative. The investment needed for option 2 would be $25 million to $45 million, for a return that, although attractive, might not be sufficient to attract the needed capital. Finally, option 3 would require a total investment (power system and residue collection) of $50 million, probably more than the industry could mobilize (see Exhibit 2.17).

Exhibit 2.16

Technical Potential

Number of Mills		Cane crushed (thousand tonnes,)	Use of Bagasse[3] (thousand tonnes, 86-87)			Steam generated (thousand lb/hr)	Power Production (MW)		
			Burnt	Left	Total		Possible[6]	Needed[7] on site	Available[8]
11	from survey	2,052[1]	514	50[1]	564[1]	1,204	--	--	--
24	total, extrapolated	2,484[2]	627[5]	118[5]	745[4]	1,458	116	25	91

Sources

(1) From DSE survey

(2) LAICA-1985-86 statistics

(3) At 50-52% moisture, 2,900 Btu/lb heat value

(4) Estimated at 30% of total amount of cane crushed

(5) Number estimated by (1) extrapolation of survey results and (2) interviews with DSE and sugar mills- on the average there is a 15% excess of bagasse.

(6) Total enthalpy of bagasse is 745,000 tonnes x 2,200 lb/tonne x 2,900 Btu/tonne.
Using 2400 hours of operation and 20% efficiency, the total amount of power which can be generated is 116 MW.

(7) Extrapolated from survey results

(8) = (6)-(7)

Source: RCG/Hagler, Bailly, Inc.

Exhibit 2.17

Comparison of the 3 Options

	Option 1 Minor Investment	Option 2 (Major investment-season operation only)	Option 3 (Major investment and off-season operation)
- Excess Power Available (MW)	15[1]	91	91
- Months of Availability	4	4	8
- Specific Invt. Cost ($/kW)	150	480	600
- Total investment ($, million)	1.5	43.6	55 (est.)
- Financial IRR (%)	57.7	22.4	68.9
- Economic IRR (%)	158.6	49.4	191.2
- Financial cost of power (¢/kWh)	2.0	3.8	1.7
- Economic cost of power (¢/kWh)	1.3	2.4-3.0	1.1-1.5

(1) 5 MW already available without any investment

Source: RCG/Hagler, Bailly, Inc.

Option 1. Minor Investment

Even with no investment at all, it is estimated that up to 5 MW of power could easily be sold to the grid during the dry season. The economic cost of this power, at mill gate, consists of the bagasse costs and additional O&M costs. If the opportunity cost of bagasse is zero, because there is excess, power can be produced at roughly U.S. $0.012/kWh or 0.8 colon/kWh (Exhibit 2.18).

Assuming an opportunity cost for bagasse of U.S.$5/tonne (average value in other countries), the additional fuel cost would be $0.015/kWh (at 20,000 Btu/kWh) for a total of $0.0275 or 1.8 colon/kWh.

To produce more than 5 MW of power, investment would be required to (1) increase the efficiency of the boiler/turbogenerator systems, and (2) increase the condensing capacity. Based on similar cases in other countries and studies recently performed by the World Bank, the cost of such modifications is estimated at roughly $150/kW, which would correspond to an average capital charge of $0.0125 or 018 colon/kWh. Therefore, the total cost of this power would be between $0.025 and $0.04 (1.7 to 2.7 colones)/kWh, which is half ICE's short-term marginal cost.

Option 2. Major Investment

To produce more power from the available bagasse under thus option, the boilers would have to be replaced with more efficient ones operating at 650-900 psig and the turbines replaced with new, efficient double-stage extraction condensing turbines. The average capital cost of these major system modifications would range from $300 to $900/kW, depending on the mill size and other characteristics. Assuming a heat rate of 14,500[2] Btu/kWh, power could be produced at an economic cost of from $0.024 - .03/kWh, or 1.6 to 2.0 colones.

2 Electric Power from Cane Residues in Thailand, USAID, pp.56.

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Exhibit 2.18

PRIVATE POWER PROJECT APPRAISAL
****

PROJECT NAME:	Sugar Mill 1	
TECHNOLOGY:	Thermal	
TECHNICAL CHARACTERISTICS		
SYSTEM SIZE:	10000	kW
CAPACITY FACTOR:	0.27	
ANNUAL POWER PRODUCTION:	23,652,000	kWh/year
FINANCIAL PERFORMANCE		
CAPITAL COST:	$1,500,000	
ANNUAL O&M COST:	$45,000	
ANNUAL FUEL COST:	$0	
MARGINAL TAX RATE:	50	Percent
EQUITY ONLY:		
CAPITAL RECOVERY FACTOR:	0.270	
NPV:	$1,706,026	
IRR:	36.802	Percent
NET POWER COST:	0.019	$/kWh
DEBT AND EQUITY:		
DEBT TO EQUITY RATIO:	2.300	
INTEREST RATE:	11	Percent
CAPITAL RECOVERY FACTOR:	0.105	
NPV:	$2,168,029	
IRR:	105.237	Percent
NET POWER COST:	0.012	$/kWh
ECONOMIC PERFORMANCE		
CAPITAL COST:		
FOREIGN EXCHANGE:	$900,000	
LOCAL CURRENCY:	$300,000	
NPV:	$6,613,092	
IRR:	296.562	Percent
NET LEVELIZED COST OF POWER:	0.008	$/kWh

Source: RCG/Hagler, Bailly, Inc.

Option 3. Use of Cane Residues

Using investment and O&M costs developed by AID for application in other countries, e.g., Thailand, and using the local value of bagasse and residues, the financial cost of power generation under this option is estimated at $.017/kWh and the economic cost at $.011 - .015/kWh, which is lower than ICE's short-term marginal cost (Exhibit 2.19).

DENDROTHERMAL SYSTEMS

Dendrothermal systems burn wood in a boiler to generate power using a conventional steam turbine. The wood is grown on nearby "plantations," which are managed and selectively harvested to provide a continually renewing fuel supply. Even though dendrothermal plantations have been under study for some time in Costa Rica, there is limited experience to draw on. As a result, the following estimates are somewhat rough.

Technical Potential

A study by the Direccion General Forestal and the Ministerio De Agricultura y Ganaderia[3] reports that two thirds of Costa Rica's total land area of 51,100 square kilometers is suitable for forests -- or 3,280,000 of 5,110,000 hectares -- approximately 50 percent of this area is covered by protected forests, leaving 1,785,910 hectares suitable for commercial forestry. A study by DSE[4] estimated that 30 cubic meters/hectare/year of wood could be produced from industrial dendrothermal plantations of 50 hectares. Trees from such an estate would have a specific gravity of 0.35, so production would equal 10.5 tonnes/hectare/year. At this rate, commercial forests could produce 18,752,055 tonnes of wood per year. Current usage amounts to approximately 6 million cubic meters per year, or 2.1 million tonnes per year at 0.35 specific gravity. Thus there are approximately 16,652,055 tonnes of potential excess

3 Jose G. Flores Rodas, Diagnostico del Sector Industrial Forestal, 1985, pp.16.

4 Meta Systems Inc., Utilizacion De Recursos Bioenergeticos para la Sustitucion De Combustibles Fosiles en el Sector Industrial De Costa Rica, Direccion Sectorial De Energia, Ministerio De Industria Energia y Minas, funded by the U.S. Agency for International Development (USAID), 1984.

Exhibit 2.19

PRIVATE POWER PROJECT APPRAISAL
****

PROJECT NAME:	Sugar Mill 2	
TECHNOLOGY:	Thermal	
TECHNICAL CHARACTERISTICS		
SYSTEM SIZE:	10000	kW
CAPACITY FACTOR:	0.75	
ANNUAL POWER PRODUCTION:	65,700,000	kWh/year
FINANCIAL PERFORMANCE		
CAPITAL COST:	$6,000,000	
ANNUAL O&M COST:	$180,000	
ANNUAL FUEL COST:	$0	
MARGINAL TAX RATE:	50	Percent
EQUITY ONLY:		
CAPITAL RECOVERY FACTOR:	0.270	
NPV:	$3,244,544	
IRR:	25.642	Percent
NET POWER COST:	0.027	$/kWh
DEBT AND EQUITY:		
DEBT TO EQUITY RATIO:	2.300	
INTEREST RATE:	11	Percent
CAPITAL RECOVERY FACTOR:	0.105	
NPV:	$5,092,558	
IRR:	68.933	Percent
NET POWER COST:	0.017	$/kWh
ECONOMIC PERFORMANCE		
CAPITAL COST:		
FOREIGN EXCHANGE:	$3,600,000	
LOCAL CURRENCY:	$1,200,000	
NPV:	$16,663,899	
IRR:	191.168	Percent
NET LEVELIZED COST OF POWER:	0.011	$/kWh

Source: RCG/Hagler, Bailly, Inc.

capacity. Assuming a heat rate of 670 kWh/tonne, 11,156.84 GWh per year could be generated from this wood. Assuming a load factor of 60 percent, or 5,256 hours of operation per year, dendrothermal systems would have a technical potential of 2,123 MW of capacity, if all available commercial forest resources were used.

By way of comparison, current generating capacity in Costa Rica is approximately 830 MW.

Financial Potential

To determine the financial potential of dendrothermal plantations, the DSE study analyzed four cases: (1) a 50 hectare industrial dendrothermal plantation in the area of Guanacaste and the Central Valley; (2) a 50 hectare industrial dendrothermal plantation in the Atlantic coastal area; (3) a microplantation in the Atlantic area; (4) a small estate in the Guanacaste region. The DSE study took into account costs for land preparation, including agricultural chemicals, saplings, and leveling. The study also took into account drying the wood and 4 months of inventory for the kiln dryer to produce wood with 20 percent moisture content ready for transport. DSE assumed that the land used for a dendrothermal plantation would be largely pasture and did not assign a value to land rents.

To the land preparation costs must be added labor costs. Depending on the type of plantation, the topography of the land, and the agricultural practices, this cost can vary significantly. The DSE study chose a mid-range estimate of labor of 52 man-days for the first year, 12 for the second, and 30 for the third year for a 50 hectare plantation. It estimated labor rates at 158 colones a day plus 46 percent fringe benefits for a total of 231 colones per day. The DSE study assumed that the costs of manpower for small plantations would be approximately 30 percent smaller than the costs for industrial-sized plantations, and used a figure of 1,050 colones/tonne of kiln-dried material. Over the total productive life of the plantation, total labor costs would be approximately 70 percent of the total cost of fuelwood output.

The DSE study concluded that the total financial costs of production of fuelwood from dendrothermal plantations are between 1,050 and 1,350 colones per tonne of dry material ($15.75 to $20.25/tonne) (Exhibit 2.20). The DSE study used 3 scenarios to

estimate these costs: (1) High -- a large plantation (50 hectares) in the Guanacaste region where the cost of manpower (approximately 46 percent of the total cost) is not far from estimates from other sources. (2) Medium -- a somewhat optimistic estimate based on an industrial-scale plantation in the Atlantic region with manpower costs at approximately 70 percent of the total cost. (3) Low -- based on a small plantation of 1-10 hectares.

EXHIBIT 2.20

Financial Costs of Fuelwood Production from Plantations (1984 colones)*

Scenario	Scale of Operation	Cost per Tonne of Dry Material Including 4 months Inventory	
		Colones	U.S. $
High	Industrial (50 ha)	1,350	20.25
Medium	Industrial (50 ha)	1,200	18.00
Low	Small Estate (1-10 ha)	1,050	15.75

* Meta Systems Inc., pp.43.

This cost is comparable to the costs encountered in other developing countries. Therefore, an annual cost of 1,200 colones/collected tonne was used as the variable cost of wood from an energy plantation.

Transportation costs from dendrothermal plantations can have a large impact on the final cost of fuel for power production. Estimating transportation costs for power plants some distance from their source of fuel is difficult, as many variables must be accounted

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for, including quality of roads, directness of route, size and efficiency of vehicle, and the different taxes on freight transport in various parts of the country. DSE assembled a number of cost estimates, which varied from 3.5 to 7.5 colones/tonne-kilometer, with most costs falling between 3.7 and 5.5 colones/tonne-kilometer ($0.056 to $0.083/tonne-kilometer). DSE assumed, in its analysis, a cost of 6 colones/tonne-km for trips of 80 to 125 kilometers. Assuming some economies can be gained from a steady demand for the transportation of a large volume, transport costs are likely to fall in the 4-5 colones/tonne-kilometer range.

An independent study in Costa Rica found that the cost of cutting, transporting, and unloading per cubic meter of wood is much higher in natural forests than in dendrothermal plantations. The DSE study, however, estimated that such costs are approximately equal to the costs from small dendrothermal plantations.

Siting a power plant close to its source of fuel supply would be the first choice, essentially eliminating transport costs. Assuming a plant is sited 35 kilometers (20 miles) from the dendrothermal plantation, delivered fuel prices would increase by 175 colones to between 1,225 and 1,525 colones per tonne of dry material.

One final cost that a private investor might face is a land rent. Generally, these rents would be low for the marginal land that the plantations would be expected to use. In other developing countries, they have been on the order of $10 to $15/hectare/year. If such a charge were levied, it would increase the cost of fuel by between 62.9 and 94.7 colones/tonne ($0.95 to $1.43/tonne).[5]

Estimates of the calorific value (or heat content) of wood depend on the wood species, and the moisture content. Representative characteristics of a mixture of recently cut wood from natural forests in Costa Rica are as follows: 50 percent water content; 434 kilograms/cubic meters apparent density; 1,575 kilocalories/kilogram energy content.[6] For this study, careful cultivation was assumed to produce wood with a heat rate of 670 kWh/tonne.

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5 ($10/ha)/($10.5 tonnes/ha) = $0.95/tonne
($15/ha)/($10.5 tonnes/ha) = $1.43/tonne

6 Meta Systems, pp.81. Other sources indicate that the recoverable heat value of Costa Rica wood is 17.6 GJ/tonne of kiln dried material, or 4,200 kcal/kg.

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The capital investment costs for a dendrothermal plant, including building, boiler, steam turbine, and auxiliaries, are estimated to be 84,800 colones/kW ($1,280/kW).[7] These costs are comparable to those estimated in other developing countries for plants of 10 MW or more. The efficiency of these plants, after accounting for the power requirements of the plant itself, is assumed to be 20 percent. Annual O&M expenses are about 2-5 percent of the initial capital investment. Typical annual capacity factors are 40-60 percent. For this study, O&M costs were assumed to be 3 percent of capital investment and the annual capacity factor was assumed to be 60 percent (an optimistic case).

For the private investor who is, financing a power plant with a combination of debt (70 percent) and equity, the financial cost of power from a dendrothermal plant (that is, the price the investor would need to be paid for the power to realize his required return on investment) would be 5.94 colones/kWh ($0.089/kWh) if fuel costs $15.75/tonne (the low scenario); 6.34 colones/kWh ($0.095/kWh) if fuel costs $18.00/tonne (the medium scenario); and 6.74 colones/kWh ($0.101/kWh) if fuel costs $20.25/tonne (the high scenario) (see Exhibit 2.21 for basic assumptions and costs for the medium scenario and Exhibit 2.22 for a summary of costs from all scenarios). These cost estimates are based on a least-cost scenario with no transport costs and no land rent.

7 Estimates derived from technical and costs characteristic of Dendrothermal power system by the World Bank for systems of 3 MW ($1,388/kW) and 10 MW ($1,114/kW).

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Exhibit 2.21

PRIVATE POWER PROJECT APPRAISAL
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PROJECT NAME:	Dendrothermal	
TECHNOLOGY:	Thermal	
TECHNICAL CHARACTERISTICS		
SYSTEM SIZE:	5000	kW
CAPACITY FACTOR:	0.60	
ANNUAL POWER PRODUCTION:	26,280,000	kWh/year
FINANCIAL PERFORMANCE		
CAPITAL COST:	$6,400,000	
ANNUAL O&M COST:	$192,000	
ANNUAL FUEL COST:	$1,291,210	
MARGINAL TAX RATE:	50	Percent
EQUITY ONLY:		
CAPITAL RECOVERY FACTOR:	0.270	
NPV:	($5,476,689)	
IRR:	-19.576	Percent
NET POWER COST:	0.122	$/kWh
DEBT AND EQUITY:		
DEBT TO EQUITY RATIO:	2.300	
INTEREST RATE:	11	Percent
CAPITAL RECOVERY FACTOR:	0.105	
NPV:	($3,505,475)	
IRR:	ERR	Percent
NET POWER COST:	0.095	$/kWh
ECONOMIC PERFORMANCE		
CAPITAL COST:		
FOREIGN EXCHANGE:	$3,840,000	
LOCAL CURRENCY:	$1,280,000	
NPV:	($4,532,542)	
IRR:	ERR	Percent
NET LEVELIZED COST OF POWER:	0.066	$/kWh

Source: RCG/Hagler, Bailly, Inc.

Exhibit 2.22

Financial Cost of Power From A Dendrothermal Plant ($/kWh)

	Cost of Fuel in 3 Scenarios		
	High	Medium	Low
	$20.25/tonne	$18.00/tonne	$15.75/tonne
Debt Only	0.128	0.122	0.116
Debt & Equity	0.101	0.095	0.089

Source: RCG/Hagler, Bailly, Inc.

The financial costs under all three scenarios are substantially higher than current utility tariffs (3 colones/kWh or $0.045/kWh). Thus, dendrothermal systems will not be financially attractive to private investors without significant government subsidies. Fuel would have to cost as little as $0.0625 per tonne for a dendrothermal system to produce financially attractive power.

Economic Potential

No precise figures could be found for the economic cost of fuel from dendrothermal plantations. According to the DSE study, approximately 25 percent of the total cost of fuel from a dendrothermal plantation is from social charges, which would indicate that fuel costs are between 788 colones and 1,013 colones/tonne ($11.82 - $15.20/tonne) (see Exhibit 2.23). In 1983, the World Bank stated that the economic costs of fuel range from 1,020 colones to 2,041 colones per tonne ($15.40 to $30.80 per tonne), but its report did not provide any details on how it arrived at this figure.

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Exhibit 2.23

Economic Costs of Fuelwood Production from Plantations (1984 Colones)*

Scenario	Scale of Operation	Cost per Tonne of Dry Material Including 4 months Inventory	
		1984 Colones	U.S. $**
High	Industrial (50 ha)	1,013	15.20
Medium	Industrial (50 ha)	900	13.50
Low	Small Estate (1-10 ha)	788	11.82

* Estimated by reducing the financial costs in Exhibit 2.17 by 25 percent.

** U.S.$1 = 66.75 colones in November 1987.

At the lowest cost of fuel ($11.82 per tonne), the calculated cost of power from a dendrothermal plant is 4.07 colones/kWh ($0.061/kWh). This cost is higher than the utility's marginal cost of 3.3 colones/kWh ($0.05/kWh), so the economic potential is zero. The economic cost of fuel would have to be as low as $5.30/tonne for the economic value of electricity to be equal to ICE's marginal cost of power.

Such ancillary benefits as rural employment and reclamation of land have not been accounted for in calculating the economic value of power from dendrothermal systems. Including such benefits could increase the economic attractiveness of these projects. On the other hand, even if the land is not suitable for crops and can be used for wood cultivation, it may make more sense to use the wood for cooking than power generation. Costa Rica, as many other developing countries, is facing a severe shortage of fuelwood for cooking in rural areas and a severe deforestation problem as forests are cleared for agricultural land. Costa Rica is relatively unique in that its peak electricity demand is defined by power used for cooking in the residential sector. A strategy of reducing peak

power demand by improving the use of wood for cooking may be more productive and economically attractive than using wood for power production. Such a strategy could include improved production of charcoal for residential use. Evaluating this kind of approach, however, is beyond the scope of this study.

POTENTIAL FOR AGRICULTURAL AND BIOMASS WASTE-FIRED SYSTEMS (EXCLUDING SUGAR AND DENDROTHERMAL PLANTATIONS)

In addition to the cane sugar industry, a number of other agroindustries produce residues that could be used to generate power. The major agricultural wastes available include coffee husks, rice husks, corn residues, cotton residues, cocoa residues, African Palm nut shells, and African Palm seed stalks. In addition to potential dendrothermal production, waste wood is available from such sources as forest product industries and coffee plantation shade trees for use in generating power.

In most cases, the amount of wastes available is too small to be worth considering for power production. Approximately 22,000 tonnes of coffee husks are produced each year, but they are consumed totally in the production of heat for drying coffee (Exhibit 2.24). Over 29,000 tonnes of rice husks are produced each year, but these too are consumed in processing rice. Over 24,000 tonnes of corn residues are produced each year, but they are dispersed over a large area and transport costs for collecting them are prohibitive. The residues of cotton and cocoa are too small, at 186 tonnes, to be worth considering for power production.

There is some potential for power from African Palm oil operations. The three plants in Costa Rica use most of their nut shells for process heat, but they dispose of 21,900 tonnes of nut stalks as waste each year. Assuming a heat rate of 18 TJ/tonne, a moisture content of 30 percent, and a 20 percent efficient system, this amount of waste could produce 4.4 MW.

There is also some potential from wastes from forest product industries and natural and planted trees. The total waste wood not used for other purposes from all such sources is over 11,200,000 tonnes, which could produce over 200,000 mmBtu per year. Assuming a capacity factor of 0.6, a system efficiency of 20 percent, and a heat rate of 18 TJ/tonne, this amount of waste could produce 2,200 MW.

Exhibit 2.24 (in Dollars)

Biomass Energy Market and Additional Potential (Sugar Mills Excluded) (1986-1987)

Type Biomass	Source	Supply: Net Supply (Tonnes)	Supply: Unit Heat Value (10^9Btu/T)	Supply: Total Heat Value (10^9Btu)	Supply: Unit Price ($/10^9Btu)	Supply: Unit Transport Cost* ($/10^9Btu)	Supply: De-livered Unit Cost** ($/10^9Btu)	Demand: Net Demand (Tonnes)	Demand: Total Heat Value (10^9Btu)	Demand: Potential Substitution (10^9Btu)
Wood	Trees in Rangelands	2,435,000	17	41,551	0.99	0.33	1.31	292,200	4,986	36,565
	Coffee Shade Trees	974,000	17	16,620	0.99	0.33	1.31	292,200	4,986	11,634
	Trees in the Mountains	7,305,000	17	124,653	0.99	0.33	1.31	146,100	2,493	122,159
	Wind Break Trees	974,000	17	16,620	0.99	0.33	1.31	97,400	1,662	14,958
	Industrial Wood Waste	1,461,000	17	24,931	0.99	0.33	1.31	48,700	831	24,099
	Madero	340,900	17	5,817	0.99	0.33	1.31	47,400	809	5,008
	SUBTOTAL	13,489,900	17.1	230,192	0.99	0.33	1.31	924,000	15,767	214,425
Vegetable Residues	Coffee hulls	22,000	17	371	0.00	0.00	0.00	37,749	637	(266)
	Rice Hulls	29,148	13	380	0.31	0.00	0.31	29,184	380	(0)
	Corn Stalks	24,699	12	288	0.00	0.00	0.76	0	0	288
	Cotton Residues	186	0	0	0.00	0.00	0.00	0	0	0
	Cacao Residues	0	20	0	ERR	0.00	ERR	462	9	(9)
	African Palm Nut Hulls	660	20	13	0.41	0.00	0.41	10,340	204	(191)
	African Palm Stalks	21,900	17	374	0.00	0.00	0.00	0	0	374
	SUBTOTAL	98,593	14.0	1,426	ERR	0.00	ERR	77,735	1,230	195
	GRAND TOTAL	13,588,493		231,618				1,001,735	16,998	214,620

* Net of Internal use. Assuming 20 percent water and a density of 487 kg/m3 for wood.
** Transport costs in the Central Valley.

Source: RCG/Hagler, Bailly, Inc., derived from various sources.

Financial and Economic Potential

Since only a small amount of residues would be available within a reasonable distance, power systems for agricultural and forest product wastes will be small -- in the 1 MW to 5 MW range -- and thus capital costs will tend to be high. The initial financial and economic analyses assumed a capital cost of $1,600 per kilowatt, a capacity factor of 0.5, and an efficiency of 20 percent. Largely because of the high capital costs, power from such systems is neither economically nor financially attractive. Even if both the financial and economic fuel costs were zero, systems for using agricultural and forest wastes to produce electricity would produce a negative net present value and unattractive internal rates of return (Exhibit 2.25). Only if capital costs were brought down to between $1,000 and $1,100 per kW would the power produced from such systems be either financially or economically competitive and produce a positive net present value (Exhibit 2.26). Since this capital cost is well below likely actual costs, the financial and economic potential for power production from agriculture and wood wastes is zero.

SMALL AND MINIHYDROPOWER SYSTEMS

Hydropower is Costa Rica's principal energy resource base because of favorable topography, high precipitation, and significant river gradients over short reaches. As far back as 1963, the government carried out a major hydrographic study on the country's 34 river basins. A total power capacity of 25,000 MW and some 223,000 GWh per year of energy were identified. However, only some 17 percent -- or 8,600 MW -- of this potential was determined to be economically developable, which, with a capacity factor of 0.5, results in 4,300 MW. More recently, in 1984, a study was conducted of sites with a potential greater than 20 MW. A total potential of 8,800 MW and 36,824 GWh per year of energy were identified, of which some 716 MW had been developed by 1987, producing some 3,657 GWh annually.

There has been little investigation of micro or minihydropower systems. For this report, microhydro systems are defined as those of less than 100 kW capacity, minihydro systems as those between 100 kW and 1,000 kW, and small hydro systems as plants larger than 1,000 kW but less than approximately 20 MW. Although there are

Exhibit 2.25

PRIVATE POWER PROJECT APPRAISAL
****

PROJECT NAME:	Biomass Wastes	
TECHNOLOGY:	Thermal	

TECHNICAL CHARACTERISTICS

SYSTEM SIZE:	5000	kW
CAPACITY FACTOR:	0.50	
ANNUAL POWER PRODUCTION:	21,900,000	kWh/year

FINANCIAL PERFORMANCE

CAPITAL COST:	$8,000,000	
ANNUAL O&M COST:	$240,000	
ANNUAL FUEL COST:	$0	
MARGINAL TAX RATE:	50	Percent
EQUITY ONLY:		
CAPITAL RECOVERY FACTOR:	0.270	
NPV:	($3,809,303)	
IRR:	3.799	Percent
NET POWER COST:	0.109	$/kWh
DEBT AND EQUITY:		
DEBT TO EQUITY RATIO:	2.300	
INTEREST RATE:	11	Percent
CAPITAL RECOVERY FACTOR:	0.105	
NPV:	($1,345,285)	
IRR:	-5.716	Percent
NET POWER COST:	0.069	$/kWh

ECONOMIC PERFORMANCE

CAPITAL COST:		
FOREIGN EXCHANGE:	$4,800,000	
LOCAL CURRENCY:	$1,600,000	
NPV:	($27,991)	
IRR:	9.717	Percent
NET LEVELIZED COST OF POWER:	0.044	$/kWh

Source: RCG/Hagler, Bailly, Inc.

Exhibit 2.26

Agricultural and Wood Wastes
Economic and Financial Sensitivity Analysis

	Capital Cost of Power Equipment (US$/kW)			
	1,600	1,400	1,200	1,000
Financial				
(Equity Only)				
NPV*	(3,809)	(2,994)	(2,179)	(1,363)
IRR**	3.799	5.137	6.815	9.013
PC***	0.109	0.096	0.082	0.068
Financial				
(Equity & Debt)				
NPV*	(1,345)	(838)	(331)	176
IRR**	(5.716)	3.883	10.499	17.625
PC***	0.069	0.061	0.0652	0.043
Economic				
NPV*	(2,775)	1,845)	(195)	16,278
IRR**	****	****	(7.842)	10.261
PC***	0.060	0.055	0.049	0.044

Assumption: Financial and economic costs of fuel equal zero.

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* Net present value (U.S $'000)

** Internal rate of return

*** Net levelized power cost

**** Cannot be computed, negative.

Source: RCG/Hagler, Bailly, Inc.

many minihydro plants in Costa Rica, mostly on private land, they do not represent a major energy resource at this time.

In 1981, a preliminary evaluation of the country's minihydro potential was carried out by ICE. The study focused on plants of less than 5,000 kW, with special emphasis on plants in the range of 500 kW. The purpose of this investigation was to address the needs of non-electrified rural areas which had a population of approximately 250,000 at that time. The study team found that of a total of 476 sites, 76 percent did not have appropriate conditions for minihydro, 21 percent required further in-depth study, and only 2 percent had clearly favorable conditions. Assuming that the 2 percent of sites with favorable minihydro conditions (11 communities) and a fourth of those requiring further study -- some 21 percent (103 communities) -- can be economically developed, using a 500 kW unit, a potential of 20 MW results. By extension, the countrywide minihydro potential should be on the order of 80 MW. This estimate is thought to be conservative, given the large resource base in Costa Rica, because it is demand-driven rather than supply-driven.

The study did not give a firm estimate of the power potential or energy production available from such small plants on a countrywide basis.

During 1972 and 1973, more than 100 micro and minihydro plants were operating in Costa Rica. That number had fallen to 36 by 1977 as the ICE grid began to reach more people in rural areas. Most of these plants had capacities of less than 20 kW, clearly in the micro range, and were used on private farms. In addition, some 70 percent of the larger minihydro capacity by 1977 was in the hands of Ferrocarriles de Costa Rica, with the rest belonging to CNFL. By 1984, the number of plants of less than 10 MW capacity had fallen to 18 (see Exhibit 2.27).

Recently the Faculty of Engineering at the University of Costa Rica has been testing microhydro sets in rural areas as well as carrying out research on micro turbines, mostly Bank types. It is not known how many "private" microhydro (less than 10 kW) sets there are in the country today. Estimates range as high as a hundred, mostly in areas where the grid has not reached. Current projects being implemented by the University of Costa Rica are listed in Exhibit 2.28.

Exhibit 2.27

Size Distribution of Small and Minihydro Plants (1984)

Plant Capacity (kW)	Number of Plants	Total Capacity (kW)
50-199	2	259
200-499	5	1,605
500-999	2	1,272
1,000-4,999	7	18,023
5,000-9,999	2	12,500

Source: SNE.

Exhibit 2.28

University of Costa Rica Micro Hydro Projects

- Currently under study or being designed:

  -- 22 microhydro plants ranging size from 1 kW to 500 kW

- Currently seeking construction financing:

  -- 2 plants of 90 kW and 60 kW

- Completed and operating:

Rincon de la Vieja	7 kW
Santa Tere	30 kW
Monte Ramo	15 kW
Los Angeles	60 kW
Private Farm	5 kW
Total	**117 kW**

Source: University of Costa Rica.

Although there is significant mini and small hydropower potential in Costa Rica, current ICE efforts are focused on larger hydropower plants because of the widespread perception that such plants are more cost effective. Smaller power companies such as CNFL, EEM, and the cooperatives have significant installed minihydro capacity, most of which was built many years ago. However, several factors dictate the initiation of an aggressive minihydro program: Future peak demand is expected to be met with expensive gas turbines in the early 1990s, a sufficient minihydro resource base exists and a relatively short construction period is required. Some work in this field is currently under discussion at ICE.

The technical potential cannot be precisely determined, but there are at least 350 MW in the watersheds that have been investigated for large hydropower. The economic potential is equivalent to the technical potential, and the financial potential is roughly 200 MW, depending on the number of plants built and their size. Clearly, larger plants will be more cost effective and can be located further from load centers. To determine the contribution that minihydro can make, a regional study approach is recommended. Using this approach, one large hydro plant could be compared with several small or minihydro plants in one watershed. The methodology could then serve as a model for analysis and development in all 34 of the country's watersheds.

Small and Minihydro Technical Potential

The 1984 survey of plants larger than 20 MW identified a technical potential of 8,800 MW at 110 sites. There is significant minihydro potential in these watersheds as well. To determine Costa Rica's small and minihydro technical potential, the results of this 1984 survey were reviewed. The capacity size distribution of these sites shown in Exhibit 2.29 is clearly skewed toward smaller plants, indicating that there may be a great deal of potential below the 20 MW limit that has not been identified. Through a combination of minihydro (less than 1 MW) and small hydro (1 MW-20 MW) plants, up to 350 MW of potential is possible (see Exhibit 2.30). By using a large number of similar sized plants, certain economies of scale can be achieved. There are other approaches to determining the national minihydro potential, but these would require in-depth analysis using maps and yet yield only approximate results. In any case, the

Exhibit 2.29

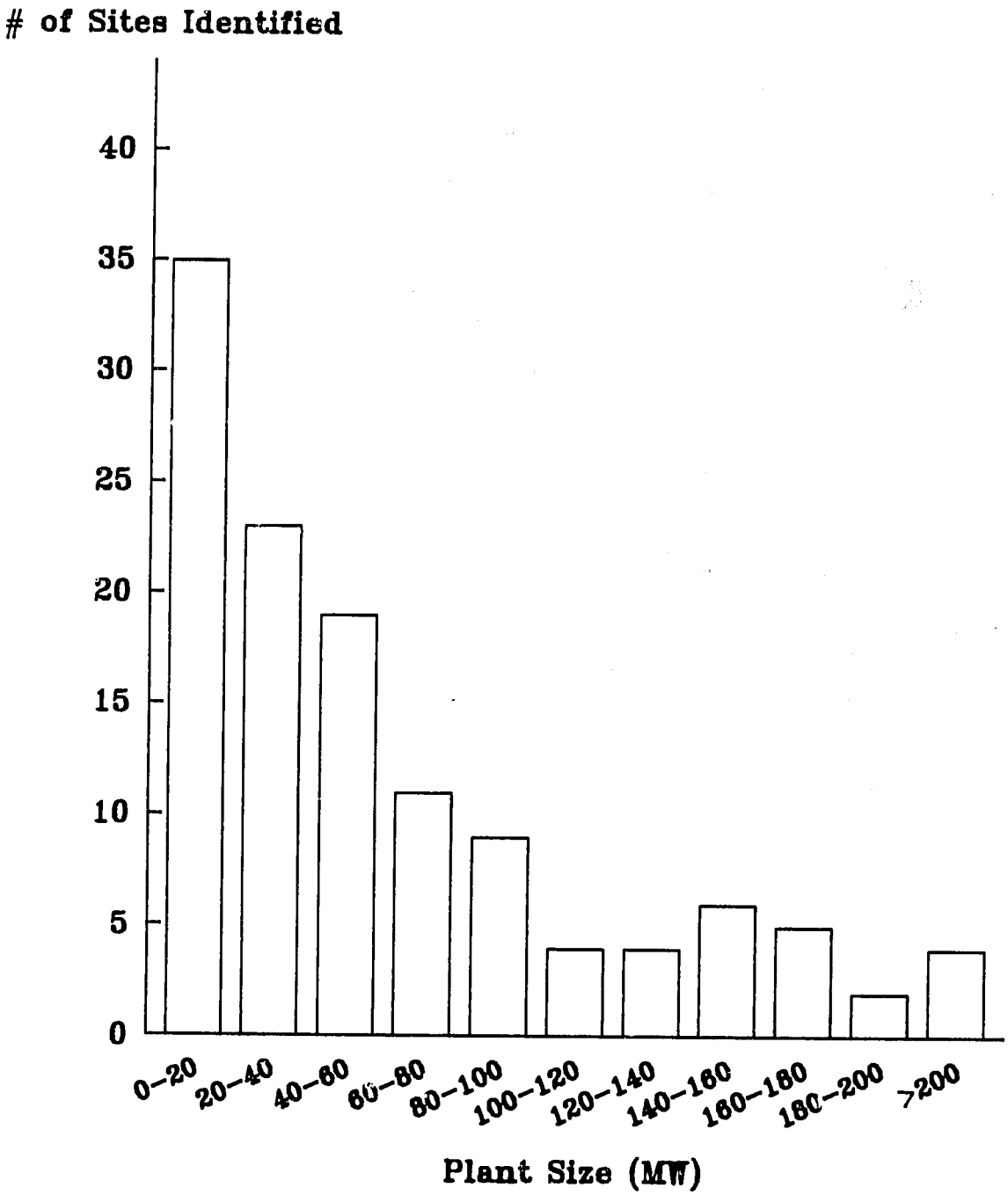
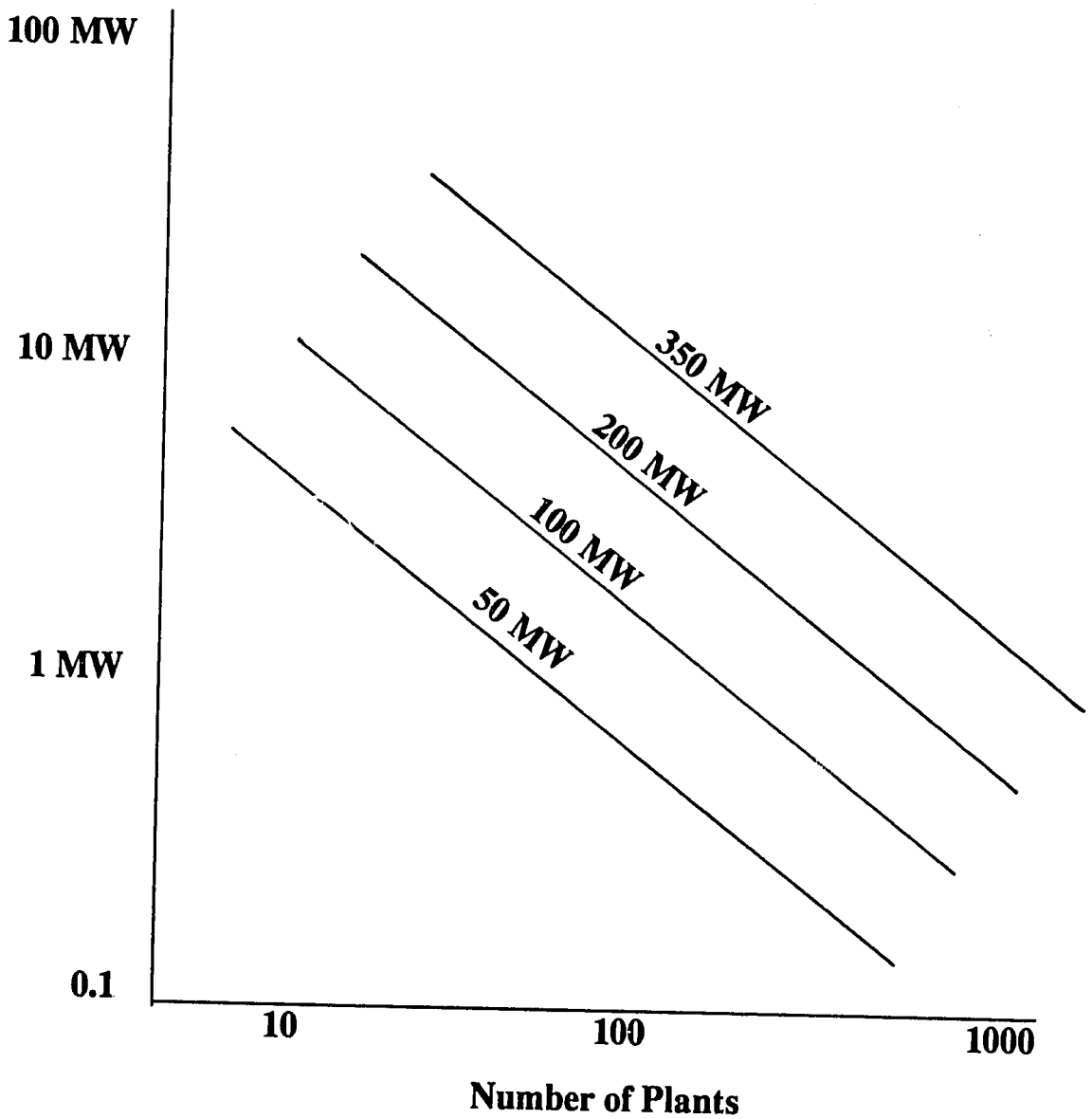

# of Sites Identified
40
35
30
25
20
15
10
5
0
0–20
20–40
40–60
60–80
80–100
100–120
120–140
140–160
160–180
180–200
>200
Plant Size (MW)

Exhibit 2.30


100 MW
10 MW
1 MW
0.1
350 MW
200 MW
100 MW
50 MW
10
100
1000
Number of Plants

technical potential is believed to be far greater than the country's financial and economic ability to exploit it in the near future.

Economic and Financial Potential

Most of the operating minihydro plants in Costa Rica were built more than 30 years ago, and there is little recent cost data available. However, based on current experience in Thailand, where the costs for a dozen plants ranged between $1,500 and $2,000 per kilowatt installed, with significant local equipment content, costs are likely to be similar in Costa Rica. In fact, the topography and hydrology are more favorable in Costa Rica. It is clear, however, that economies of scale are necessary to bring costs well below $1,500 kW, which would make minihydro competitive with ICE's large-scale hydro expansion plans. To achieve these economies, a major program of several dozen minihydro plants is needed, which would make it cost effective for design firms, fabricators, and construction firms in Costa Rica to respond to the market. Such a program is under way in Thailand, where the government has given minihydro a high priority for rural development.

A complete analysis of four typical small and minihydro plants is shown in Exhibit 2.31-2.34. Plant sizes from 500 kW to 5,000 kW were selected as being appropriate for Costa Rica in terms of local engineering, equipment manufacture, and construction. The most costly will be the 500 kW plant at approximately $2,000/kW. These costs, which include taxes, import duties on equipment, engineering design, and construction supervision, are representative of Costa Rica. For example, a preliminary analysis of a 10-15 MW, high head plant, currently in the feasibility study phase, yields a capital cost of $1,000/kW.

The economic analysis shows the energy cost is below the ICE marginal cost of $0.050/kWh. However, the difference between the financial and economic analysis indicates that there are significant distortions introduced by the high return required on equity financing -- some 15 percent above the inflation rate of approximately 16 percent for an overall rate of return of at least 30 percent.

Exhibit 2.31

PRIVATE POWER PROJECT APPRAISAL
****

PROJECT NAME:	Minihydro1	
TECHNOLOGY:	Hydroelectricity	
TECHNICAL CHARACTERISTICS		
SYSTEM SIZE:	500	kW
CAPACITY FACTOR:	0.60	
ANNUAL POWER PRODUCTION:	2,628,000	kWh/year
FINANCIAL PERFORMANCE		
CAPITAL COST:	$1,000,000	
ANNUAL O&M COST:	$20,000	
ANNUAL FUEL COST:	$0	
MARGINAL TAX RATE:	50	Percent
EQUITY ONLY:		
CAPITAL RECOVERY FACTOR:	0.270	
NPV:	($462,507)	
IRR:	4.184	Percent
NET POWER COST:	0.110	$/kWh
DEBT AND EQUITY:		
DEBT TO EQUITY RATIO:	2.300	
INTEREST RATE:	11	Percent
CAPITAL RECOVERY FACTOR:	0.105	
NPV:	($154,505)	
IRR:	-1.663	Percent
NET POWER COST:	0.068	$/kWh
ECONOMIC PERFORMANCE		
CAPITAL COST:		
FOREIGN EXCHANGE:	$300,000	
LOCAL CURRENCY:	$350,000	
NPV:	$178,988	
IRR:	17.641	Percent
NET LEVELIZED COST OF POWER:	0.035	$/kWh

Source: RCG/Hagler, Bailly, Inc.

Exhibit 2.32

PRIVATE POWER PROJECT APPRAISAL
****

PROJECT NAME:	Minihydro2	
TECHNOLOGY:	Hydroelectricity	

TECHNICAL CHARACTERISTICS

SYSTEM SIZE:	1,000	kW
CAPACITY FACTOR:	0.60	
ANNUAL POWER PRODUCTION:	5,256,000	kWh/year

FINANCIAL PERFORMANCE

CAPITAL COST:	$1,500,000	
ANNUAL O&M COST:	$30,000	
ANNUAL FUEL COST:	$0	
MARGINAL TAX RATE:	50	Percent
EQUITY ONLY:		
CAPITAL RECOVERY FACTOR:	0.270	
NPV:	($531,054)	
IRR:	7.044	Percent
NET POWER COST:	0.083	$/kWh
DEBT AND EQUITY:		
DEBT TO EQUITY RATIO:	2.300	
INTEREST RATE:	11	Percent
CAPITAL RECOVERY FACTOR:	0.105	
NPV:	($69,050)	
IRR:	11.290	Percent
NET POWER COST:	0.051	$/kWh

ECONOMIC PERFORMANCE

CAPITAL COST:		
FOREIGN EXCHANGE:	$450,000	
LOCAL CURRENCY:	$525,000	
NPV:	$713,412	
IRR:	29.127	Percent
NET LEVELIZED COST OF POWER:	0.026	$/kWh

Source: RCG/Hagler, Bailly, Inc.

Exhibit 2.33

PRIVATE POWER PROJECT APPRAISAL
****

PROJECT NAME:	Minihydro3	
TECHNOLOGY:	Hydroelectricity	
TECHNICAL CHARACTERISTICS		
SYSTEM SIZE:	1,500	kW
CAPACITY FACTOR:	0.60	
ANNUAL POWER PRODUCTION:	7,884,000	kWh/year
FINANCIAL PERFORMANCE		
CAPITAL COST:	$1,950,000	
ANNUAL O&M COST:	$39,000	
ANNUAL FUEL COST:	$0	
MARGINAL TAX RATE:	50	Percent
EQUITY ONLY:		
CAPITAL RECOVERY FACTOR:	0.270	
NPV:	($560,204)	
IRR:	8.670	Percent
NET POWER COST:	0.072	$/kWh
DEBT AND EQUITY:		
DEBT TO EQUITY RATIO:	2.300	
INTEREST RATE:	11	Percent
CAPITAL RECOVERY FACTOR:	0.105	
NPV:	$40,400	
IRR:	16.561	Percent
NET POWER COST:	0.044	$/kWh
ECONOMIC PERFORMANCE		
CAPITAL COST:		
FOREIGN EXCHANGE:	$585,000	
LOCAL CURRENCY:	$682,500	
NPV:	$1,283,380	
IRR:	35.965	Percent
NET LEVELIZED COST OF POWER:	0.023	$/kWh

Source: RCG/Hagler, Bailly, Inc.

Exhibit 2.34

PRIVATE POWER PROJECT APPRAISAL
****

PROJECT NAME:	Minihydro4	
TECHNOLOGY:	Hydroelectricity	
TECHNICAL CHARACTERISTICS		
SYSTEM SIZE:	5,000	kW
CAPACITY FACTOR:	0.60	
ANNUAL POWER PRODUCTION:	26,280,000	kWh/year
FINANCIAL PERFORMANCE		
CAPITAL COST:	$6,000,000	
ANNUAL O&M COST:	$120,000	
ANNUAL FUEL COST:	$0	
MARGINAL TAX RATE:	50	Percent
EQUITY ONLY:		
CAPITAL RECOVERY FACTOR:	0.270	
NPV:	($1,473,386)	
IRR:	9.647	Percent
NET POWER COST:	0.066	$/kWh
DEBT AND EQUITY:		
DEBT TO EQUITY RATIO:	2.300	
INTEREST RATE:	11	Percent
CAPITAL RECOVERY FACTOR:	0.105	
NPV:	$374,627	
IRR:	19.570	Percent
NET POWER COST:	0.041	$/kWh
ECONOMIC PERFORMANCE		
CAPITAL COST:		
FOREIGN EXCHANGE:	$1,800,000	
LOCAL CURRENCY:	$2,100,000	
NPV:	$4,633,371	
IRR:	40.207	Percent
NET LEVELIZED COST OF POWER:	0.021	$/kWh

Source: RCG/Hagler, Bailly, Inc.

The results of the economic and financial analysis indicate that:

- The economic potential is equivalent to the technical potential for plant sizes down to 500 kW; it is 350 MW.
- The financial potential is equivalent to the technical potential for plant sizes equal to or above 1,000 kW, for plant sizes around 500 kW, the financial potential is 150-200 MW.

Clearly, these conclusions depend heavily on the capacity factor. A conservative capacity factor of 0.60 is used based on ICE's experience at existing large hydropower plants. Costa Rica's minihydro plants have a higher capacity factor: CNFL has 0.90 and Empressa Electricidad de Matamoros has 0.90. These factors are unusually high and it is not clear what the factor would be for a non-grid connected plant. In many developing countries, it can be as low as 0.25 because of a lack of water or demand.

GEOTHERMAL GENERATION

It is not readily apparent that there is some potential for involving the private sector in the development of geothermal energy. However, this section was included as an exercise to see if a role for the private sector could be identified and to briefly examine the potential economics of private geothermal energy activities.

ICE plans to develop Costa Rica's geothermal resources both in the near term and over the long run. It has estimated the potential at between 400 MW and 800 MW of capacity from roughly 54 geothermal areas. Another estimate put the resource at 720 MW. ICE has estimated the energy production at between 10 GWh and 20 GWh per year. Current activities center around the Miravalles field, where technical assistance is being provided by ElectroConsult of Italy. The first plant, Miravalles I, is scheduled for start-up by 1992, with 55 MW of capacity producing 389 GWh of energy at a capacity factor of 0.85. The cost of the first plant is put at $2,179/kW installed, producing energy at $0.045/kWh, which is equivalent to the current marginal cost of power in Costa Rica. Four subsequent plants -- II, III, IV, V -- will cost $1,743/kW installed, with energy production costs of $0.038/kWh.

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ICE is optimistic about this resource for three reasons: (1) the cost of energy will be competitive with hydro and approximately half that of thermal generation, (2) power production will be constant throughout the year, with no need for reservoirs as with hydropower, and (3) the investment can be scaled because each unit is between 30 MW and 50 MW. The feasibility study for Miravalles I was completed in 1985, and ICE has reached loan agreements with Japan and the IDB. The agreement was ratified by the Asamblea Legislativa in March 1987. The first stage of construction is under way, with the drilling of 11 production wells, the construction of the plant foundation, the purchase of necessary land, and the publication of tenders for the equipment. ICE also plans to finalize the feasibility study for Miravalles II soon.

The private sector could play a role in operating Miravalles I once it is built. However, because of plant size and the lack of immediate capital, it is highly unlikely that private-sector funding could be secured for the construction of plants for Costa Rica's geothermal program. The private sector could be involved, however, in maintaining, servicing, and retrofitting equipment as well as other long-term plant servicing activities. Another short-term option which could be considered for private sector participation is the use of "well-head"turbines that could be installed within 6 months and help ICE pass the difficult months ahead.

SUMMARY

The technical, economic, and financial potential of six options for independent power generation in Costa Rica, is summarized in Exhibit 2.35 together with the generation costs of each option. The bulk of the technical theoretical potential of 5,500-5,800 MW lies in dendrothermal and biomass energy sources; however, they cannot be exploited economically because of the physical dispersion and the lack of an organized market and reliable supply. Owing to the small scale of manufacturing, and its reliance on fuel oil for energy generation, there is little potential for cogeneration in industry except in sugar mills and palm oil companies. Large hydropower and geothermal resources exist, but they are not appropriate to private sector exploitation because the projects are too large for private financing, at this time, and ICE is much better suited for this role. Thus, the greatest potential for private power lies in hydropower systems between 500 kW and 5,000 kW, which offer 100-300 MW of economic and financial potential.

Exhibit 2.35

**Electricity Generation Costs and Potential for Nonutility Power Options*
(1987-1995)**

Resource	Technical Potential (MW	Economic Potential (MW)	Economic Cost*** ($/kWh)	Financial** Potential (MW)	Financial** Cost**** ($/kWh)
Cogeneration	17	3	.025-.057	3	.032-.086
Sugar	100	90	.035-.058	90	.020-.056
Dendrothermal	2,100	0	0.066	0	0.095
Biomass	2,200	0	0.06	0	0.069
Hydropower*****	350	350	.017-0.035	200	.034-.068
Geothermal	400-700	******	.027-.034	0	.06-.07
TOTAL	**5,500-5,800**	**443**		**293**	

* For the near term, coal may have some potential in the long-term.

** Assuming a debt to equity ratio of 2.3.

*** Systems with electricity costs of under $0.05/kWh are considered economically attractive. This figure reflects the avoided cost to ICE from power supplied by non-utility generators and is estimated based on the long-run marginal cost of electricity generation (see Appendix D).

**** Systems with electricity costs of under $0.0455/kWh are considered financially attractive. This figure reflects the current average price to industry in Costa Rica.

***** For system sizes between 500 kW and 5,000 kW.

****** The economic potential for geothermal is sizeable but the projects are felt to be too large for private financing at this time.

Source: RCG/Hagler, Bailly, Inc.

Unfortunately, the potential for small hydropower is neither well documented nor understood because a nationwide mini hydro power survey is lacking. Also, capital investment cost and precise economic performance are difficult to estimate without knowing specific site conditions.

The sugar industry could bring some 20 MW to 30 MW on line in the short-term simply by renovating boilers and turbines and arriving at a purchasing arrangement with ICE on excess power. However, to realize this potential, policy action must be taken rapidly by the government, and the sugar industry must respond quickly to the new opportunities presented. With an aggressive, capital intensive policy, it could even be possible to produce 90 MW of power from the existing mills.

CHAPTER 3: IMPEDIMENTS TO NONUTILITY POWER GENERATION

Under current conditions, only a small fraction of the nonutility power generation potential is likely to be realized because of a number of real or perceived impediments. The major barriers to nonutility power generation were identified during in-depth discussions with representatives of government, the private sector, and international donor agencies. As a result of these discussions, it became clear that major shifts in attitudes and policies would be necessary to encourage private power initiatives. Five issues of prime concern were identified:

- Lack of clear or well-articulated government policies regarding the provision of public services such as electricity and water supply by the private sector.
- Scarcity of long-term financing for major private projects, as well as a liquidity shortage.
- Preference by the private sector for investment in export-oriented businesses rather than investment in public service enterprises.
- Inadequate technical and economic information on opportunities for cogeneration and power generation.
- Widespread satisfactory service provided by ICE and its institutionalized economic advantages.

LACK OF CLEAR POLICY

The government in Costa Rica controls every aspect of power generation: the supply and price of domestic power equipment and spare parts, capital and foreign exchange availability and costs, fuel availability and prices, tariffs for sale of power to public and private entities, and dispatching. The recently prepared energy plan for the 1986-2005 period stresses the need for the government to play the key role in energy matters.

Therefore, government policy on nonutility power generation is among the most important issues concerning potential developers of such power options.

Currently there is no single, clear policy document covering all aspects of private power generation. Although the existing laws and regulations do not prohibit such generation, the procedure that must be followed to get a project started appears complex, time-consuming, and bureaucratic. The lack of clear policy takes three major forms:

1. Relevant laws and regulations are old and not well-known or understood by the public

2. Following the "strict sense" of the laws and regulations is a cumbersome process

3. Current laws and regulations do not cover the key technical and financial aspects of the purchase of independently produced power by electric companies. The laws provide specific financial incentives to ICE, but not to private power developers.

Law and Regulations are Old and Not Well Understood

Two laws are particularly relevant to private power generation: The Ley Constitutiva of ICE (Decree No. 449 of April 1949) and the law establishing SNE (Law 250 of 1941).

The law establishing ICE is broad and liberal, offering great flexibility in all matters related to electricity generation, transmission, and use. In Article 2, the law gives to ICE: access to all technical, legal, and financial means to develop and execute such activities; a mandate to promote the greatest use of electricity (especially from hydroelectric origins) for power and heat production; and a mandate to ensure the most rational use of all national natural resources. However, in Article 3, the law states that ICE will carry out a national policy of "progressive nationalization of all electrical services." Despite this provision, there is nothing in the law that prohibits (or encourages) the generation and distribution of electric power by institutions or parties other than ICE. The law does, however, provide substantial financial incentives, with exemption from all duties on imported equipment and income taxes for ICE alone.

A Cumbersome Process

The law establishing SNE gives it national responsibility to regulate, among other, all matters related to water and electricity. SNE issues all licenses (concessions) for the generation and transmission of electric power and the use of water for any commercial purpose by installations of any size. If a power system uses water as input and is greater than 50 HP or 37.5 kW, the application must also be submitted to the National Assembly. SNE is also the established authority for setting the tariffs for all commercial transactions of water and power (considered as public utility matters).

In addition, for any power project of more than 500 HP (375 kW) National Assembly Approval is required. The whole process also can take from 6 to 12 months, and consists of the following steps:

Step 1: Proposal is prepared and submitted, using a specific format and including the following information:

- Detailed identification of requestor
- Certificates of land ownership
- Detailed identification of the water
- Flow, head, and other characteristics of the water stream
- Theoretical power available
- Proposed schedule of project development
- Blueprints
- Supporting computations
- Detailed summary reports to be prepared by a certified engineer

Step 2: Proposal is published in the Gazet (three times)

If objections to the project are raised and cannot be resolved by the proposer and the objector, SNE will act as the referee.

Step 3: SNE reviews and analyzes proposed project from a technical and socioeconomic standpoint

Step 4: SNE submits results of review and its recommendation to SNE managing committee (Junta Directiva) and, eventually, to parties potentially affected by project

Step 5: Project file, complete with required legal and technical information, is passed to SNE managing committee (Junta Directiva) for final decision.

The whole process from project identification to start-up can take from 1 to 3 years and includes many decision points (see Exhibit 3.1). In addition to its complexity, duration, and inherent uncertainty, the process is also little known or understood by potential independent developers. Interviews revealed that most of them had limited familiarity with the procedure.

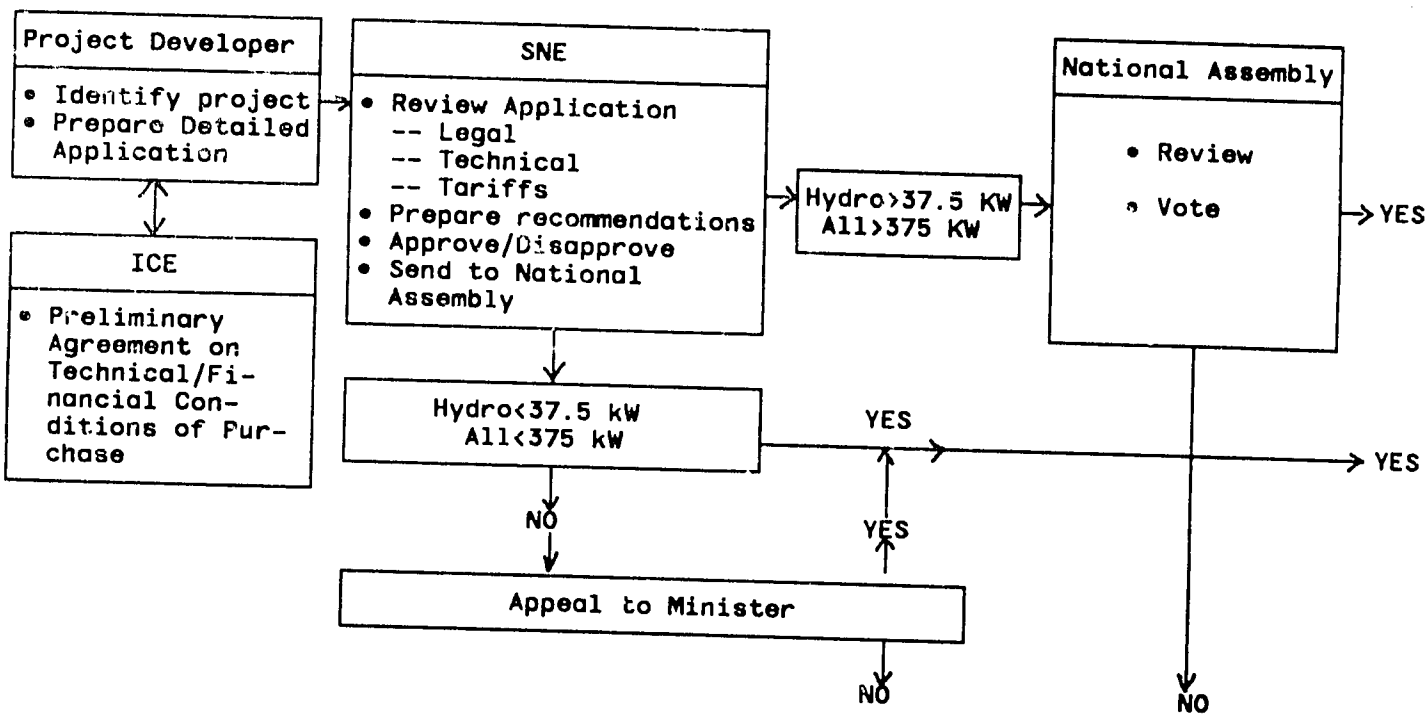
Limitations of Existing Legal Framework

The laws and decrees pertaining to ICE and SNE, their roles, and responsibilities do not have specific provisions, requirements, or guidance for two important aspects of the private generation of power for sale to the grid or the public:

- Technical requirements for parallel operation, synchronization and protection
- Base for establishing tariffs for sale and "wheeling" of power. As the entity in charge of "public utilities," SNE may or may not be the one to decide on the price and contractual conditions of such transactions.

Ehibit 3.1

Licensing Process for a Commercial Power Project
Summary Flowsheet



Source: RCG/Hagler, Bailly, Inc. based on interviews and reviews of the existing laws and decrees.

SCARCITY OF INVESTMENT FUNDS

Private-sector companies that require financing for attractive energy generation projects or large industrial projects face a formidable -- but not insurmountable -- problem in Costa Rica. None of the potential sources of funds available to them is able to provide adequate financial services. The processing of loans -- from application to disbursement -- is a lengthy process, and virtually no long-term credit is available in the amount required for most power generation projects.

It is difficult to channel private capital into energy generation projects because of their size and their typically long payback periods. Private capital seeks a safe haven abroad owing to the 15 percent inflation rate and uncertainty about the future course of the economy. To attract such capital, a project would have to provide a return on investment well above the bank rate of 30 percent, and would have to pay back the investment in 1 or 2 years. Tight currency controls further complicate and lengthen loan procedures involving foreign exchange, and the current international payments crisis has restricted credit from foreign banks.

In the interest of supplementing ICE's power generation investments, it would be desirable for private-sector projects to tap sources of funds not available to the electric utility. In general, however, private-sector credit from Costa Rican sources is limited, and most other sources entail guarantees by the government that, in the end, reduce the credit available to ICE. In the case of funds that have been earmarked for private-sector projects (for example, AID and FODEIN), this objection does not arise; however, these funds are generally intended for smaller projects.

Recognizing the need to assist the manufacturing sector, the government has taken measures to channel funds into industrial development, but most of the funds and systems created for this purpose are aimed at increasing exports. Funds for Industrial Development (FODEIN), the one fund that appears to provide for independent power projects, has a limit of $2 million that excludes many good power generation projects.

Potential sources of credit in Costa Rica are the banking system, FODEIN, leasing companies, the securities markets, and private investors. However, close examination reveals that none of them meets the financing needs of typical power generation

projects Most current commercial loans are limited to 3 years or less at interest rates of 28-30 percent. Most banks do not appear to be interested in offering long-term loans to companies providing public services such as electricity or water, since competing opportunities for financing linked to the dollar and export products bring higher returns. There is also a shortage of capital -- both colones and dollars -- with most wealth tied up in plantations and small businesses.

The commercial banking system consists of four state banks and a number of private banks, which lend their own funds and serve as intermediaries for various donors or funds. The state banks are much larger, and although they accept applications for long-term industrial loans, in practice such credit is not thought to be obtainable. Private banks tend to limit use of their own funds to short-term loans. The equity-to-debt requirement applying to their loans varies with the circumstances, and can be zero. Large loans require collateral in the form of real estate or bank deposits.

FODEIN is an industrial development fund created by the Central Bank to provide medium- and long-term credit to manufacturing industries. The funds are channeled to the private sector by the four state banks. FODEIN offers project financing of between $250,000 and $2,000,000. The funding is $30 million, divided between the World Bank and the Central Bank of Costa Rica.

Loan terms include a grace period of up to 3 years and an interest rate of 14 percent (excluding inflation). The actual interest rate at present is 26 percent. In addition, 30-percent equity is required. In view of the these conditions, the largest project that could be financed would be approximately $22,860,000, which would be sufficient for a 5 MW cogeneration package ($600/kW) or a 15 MW small hydropower plant ($1,500/KW).

The leasing industry in Costa Rica is in a very early phase of development, and does not offer funds for major capital equipment at this time.

The Costa Rican stock market is small, with a daily volume of about $7.5 million. Given the current investment climate, it seems unlikely that companies could attract capital for power generation projects through this channel. The same is true of the bond market. Moreover, the possibility of raising funds through these channels is limited to listed companies, and would require underwriting of the securities by banks.

Private Costa Rican investors, concerned about protecting their capital, commonly transfer it to the United States Only very attractive investment opportunities, with high returns and short payback periods, could bring repatriation of this capital.

Normally there are a number of foreign sources for funding of energy generation projects in Costa Rica. They include foreign banks, international banks, suppliers, and donors. Unfortunately, Costa Rica has failed to reach an agreement on payment of interest due to foreign creditor banks, and this situation currently casts a shadow on some sources of funds.

Credits from international banks and foreign equipment suppliers are generally country-to-country arrangements requiring guarantees by the government of Costa Rica. Thus, such loans are subject to national investment priorities as established by the Ministry of Planning. Indeed, the IDB, which currently offers financing up to 20 years at 8.75 percent interest, will not accept loan applications for projects without this priority.

Sales of power generation equipment in Costa Rica are dominated by German, Italian, and Japanese firms that offer early technical assistance and (government-subsidized) low-cost financing. American equipment suppliers cannot offer competitive financing and their selling efforts are deficient.

Two prominent donor organizations active in Costa Rica are AID and the European Community. AID has been providing some $7.5 million three times a year, channeled through a number of intermediary banks. These funds are intended for private-sector projects that will expand exports, and have terms of 2 to 7 years at 26.5 percent interest. These loan conditions would probably exclude most power generation projects from eligibility. EEC funds have not yet reached the intermediary banks, and little could be learned about this source. These funds are expected to become available in early 1988.

The time period for obtaining funding for independent power projects is estimated at 6 to 12 months, although there is little experience on which to base this estimate.

Generally, the rate of return required by industrial managers for capital projects is five points above the interest rate, or about 35 percent. This appears to be the case for power generation projects as well, although the need to provide reliable electricity to

their plants and avoid the costs of power interruptions may sometimes override managers' financial considerations.

Neither the Costa Rican banking community nor the international banks are furnishing the financial services needed to develop the potential for independent power generation in Cost Rica. In addition, the financial returns of such projects are not sufficiently attractive to compete with alternative opportunities for the limited amount of private capital in the country.

Thus, in practice, independent power generation developers must look to industrial development funds backed by the government and donor organizations, where competition with export development projects is keen.

PRIVATE SECTOR ATTITUDES

Most private-sector investors prefer to invest in well-known commodity exports or in light manufacturing currently being encouraged by the government. The office of the Private Sector of AID, for example, has a nontraditional export program that favors the establishment of maquilladoras by U.S. companies in duty-free zones. This $2 million program has been under way for 18 months, and assembly operations are in textiles, electronics, plastics and light metal products.

There are a number of promising export opportunities for investors in Costa Rica, but it will be difficult to channel capital into private power investments without government support. Much of the capital for the export-oriented programs is coming from equity sources, which require a high rate of return. It is clear that a major promotional effort will be needed to encourage the private sector to participate.

LACK OF INFORMATION

One of the principal barriers to the development of private power is the lack of institutional, economic, and technical information on investment opportunities by for

private-sector developers. Traditionally, the private entrepreneur has avoided public service-type investments in favor of export-oriented opportunities. For example:

- The permitting and licensing process for a private developer is confusing and not formally laid out
- The industrial sector has little understanding of cogeneration, its economics, or technical benefits
- The sugar industry has little knowledge about the possibility of selling surplus power to ICE, the terms of the buyback, or technical details regarding the interconnection
- There has never been an in-depth survey of minihydro potential
- It is not clear where financing for private power development can be obtained at reasonable rates.

This is a sampling of the kind of information that needs to be developed and disseminated to Costa Rica's private sector. Most representatives of private organizations indicated they had not been previously approached with a proposal to generate power on a private basis. It is clear that further promotional efforts will have to be organized to fully mobilize the private sector.

INSTITUTIONAL ADVANTAGES ENJOYED BY ICE

ICE has clear advantages over a private developer seeking to begin a power venture. These advantages are the result of the laws governing the institution and of many years of operational experience as the major provider of power in Costa Rica. Although some advantages were conferred at the time of ICE's creation, many have evolved over the years as it became clear that ICE would tie the country together through the provision of power, which was important for national development. Moreover, with each new expansion -- transmission or generation -- ICE has enhanced its political power.

In addition to its predominant role in the country's economic life, ICE is able to deliver electricity to its customers at reasonable cost (about $0.0515/kWh) with a high degree of reliability. Over 90 percent of generation is from large hydropower plants with high capital costs but low variable costs, both of which are predictable from year-to-year. About half the installed hydropower was constructed during the 1960s, with low-cost loans, so ICE is able to price its electricity at attractive rates. The generally held view is that only ICE should be in the power business and that the state should provide Costa Rica's electricity.

ICE also has the authority to negotiate with international donor organizations such as the IDB or World Bank for low-cost loans. Repayment of these loans is usually guaranteed by the Costa Rican government. Typical IDB rates are 8-9 percent over 20 years, with 3 years grace period. These rates are far more attractive than those being offered by local banks in Costa Rica. The private sector does not have access to capital on such a basis.

ICE is also exempted from taxes on its profits; such taxes are approximately 50 percent for private enterprises. SNE limits ICE's rate of return to 10 percent, putting a cap on what it might be able to achieve otherwise. On this basis, SNE hopes to keep tariffs at a minimum while encouraging efficient service. A private power operator would not be limited by such a cap and would therefore have a very strong incentive for profit maximization under the constraint of fixed purchased price which should ensure a very high level of managerial and technical efficiency.

ICE is also exempted from import duties on power generation equipment. For the private sector, such imported equipment is usually taxed at about 30 percent.

ICE also has a broad base of customers and a ready power market which favors rural residential clients over urban industrial users through its tariff structure. It can therefore compensate for a few non-paying users by spreading the costs over the entire system. A private generator may be faced with non-paying customers or a tariff structure that will not support its costs.

These ICE advantages do not preclude the development of private power, as the private developer will not compete with ICE power but supplement it. Future generation

expansion by ICE will mean high capital and fuel costs, so its long-run marginal cost of power (as well as its short-run cost of power) will not be as low as in the past (in constant dollars). Future generation using gas turbines, geothermal, and large hydro will be capital expensive and therefore continue to be a drain of foreign exchange (although a recent USAID study found that, in the long-term, coal power plants may be developed economically).[1]

Private power, particularly from resources that are essentially in place -- sugar mills and minihydro -- would be cost competitive if reasonable financing could be arranged.

In the following chapter, recommendations are made to overcome these barriers and accelerate the role of the private sector in power generation.

1 Prefeasibility study of coal use in Coast Rica, by Bechtel National, Inc., June 1987.

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CHAPTER 4: CONCLUSIONS AND RECOMMENDATIONS

In this chapter, the major conclusions of this study are presented and recommendations for encouraging the development of nonutility power generation are given.

CONCLUSIONS

With a peak demand of 612 MW in 1987, which is likely to increase to 650 MW in 1988, and a firm capacity of about 700 MW, 50-100 MW of new capacity needs to be added by 1989. The government of Costa Rica is currently discussing the addition of three to four 36-MW gas turbines. This report shows that the private sector could provide some relief, as 30-50 MW of power generation from private sources could be developed before 1990. This would reduce the requirement for new thermal units and thus save precious foreign exchange.

Private Sector Interest in Power Generation

In-depth discussions were held with various private-sector representatives, bankers, private investors and AID private-sector program managers. There is clearly an interest by the private sector in new types of investments. Traditionally these investments have gone into export-oriented activities that bring U.S. dollars into Costa Rica. If the proper conditions can be created, the private sector will invest in power generation. Investors in Costa Rica generally seek a high return on their investment, above 30 percent because of inflation and the fluctuating value of the colon. Entrepreneurs in Costa Rica, as anywhere else, act in their own best interest.

However, before investors will act, a number of specific policy initiatives must be taken. These include reduction of real and apparent institutional barriers, reducing or eliminating certain types of taxes, providing project financing at rates competitive with those of international development banks, developing technical and economic approaches for the sale of power to ICE, and providing the private sector with information on private power opportunities.

Private Power Potential

The private sector could assist ICE in meeting future demand for additional capacity and energy production. It would do this by generating power using indigenous resources that are currently not being fully used. These resources include small hydropower, excess bagasse from the sugar industry, and excess power through industrial cogeneration.

ICE's current capacity of approximately 845 MW could be augmented by 30-50 MW by 1990. The first gas turbine is not scheduled for installation until 1989, making 1988 the critical year.

The technical, economic, and financial potential of private power generation is summarized in Exhibit 4.1.

As shown in the exhibit, the economic potential is about 450 MW, and the financial potential about 300 MW, most of this is in small hydropower. Unfortunately, the potential for small hydropower is the least understood, because no nationwide minihydro survey exists. In addition, plant capital costs are difficult to determine without knowing specific site conditions.

The short-term potential-- some 30 MW to 50 MW--could be brought on line from the sugar industry simply by replacing or renovating boilers and turbines and working out buyback details with ICE. However, for this to happen, rapid government policy action must be taken and the sugar industry must respond quickly to this action.

Barriers

The identification of the major barriers to nonutility power generation resulted from in-depth discussions with representatives of government, the private sector and donor agencies. The five barriers of prime concern are:

- Lack of clear or well-articulated government policies regarding the provision of public services such as electricity and water supply by the private sector

Exhibit 4.1

**Electricity Generation Costs and Potential for Nonutility Power Options*
(1987-1995)**

Resource	Technical Potential (MW	Economic Potential (MW)	Economic Cost*** ($/kWh)	Financial** Potential (MW)	Financial** Cost**** ($/kWh)
Cogeneration	17	3	.025-.057	3	.032-.086
Sugar	100	90	.035-.058	90	.020-.056
Dendrothermal	2,100	0	0.066	0	0.095
Biomass	2,200	0	0.06	0	0.069
Hydropower*****	350	350	.017-0.035	200	.034-.068
Geothermal	400-700	******	.027-.034	0	.06-.07
TOTAL	**5,500-5,800**	**443**		**293**	

* For the near term, coal may have some potential in the long-term.

** Assuming a debt to equity ratio of 2.3.

*** Systems with electricity costs of under $0.05/kWh are considered economically attractive. This figure reflects the avoided cost to ICE from power supplied by non-utility generators and is estimated based on the long-run marginal cost of electricity generation (see Appendix D).

**** Systems with electricity costs of under $0.0455/kWh are considered financially attractive. This figure reflects the current average price to industry in Costa Rica.

***** For system sizes between 500 kW and 5,000 kW.

****** The economic potential for geothermal is sizeable but the projects are felt to be too large for private financing at this time.

Source: RCG/Hagler, Bailly, Inc.

- Scarcity of long-term financing for major private projects, as well as a liquidity shortage
- Preference by the private sector for investment in export-oriented businesses rather than investment in public service enterprises
- Inadequate technical and economic information on opportunities for cogeneration and power generation
- Widespread satisfactory service provided by ICE and its institutionalized economic advantages.

RECOMMENDATIONS

The findings of this study indicate that measures must be taken to remove the impediments that were revealed, and that further measures must then be taken to inform and motivate potentially interested parties. Implementation of an effective development program will require joint action by the government institutions in the initial phase, followed by continuing guidance of the program by a committee representing all involved entities and parties. In both phases, AID could provide support to the various institutions and parties involved.

The recommendations addressed to the Government are listed below, followed by those appropriate to AID.

Government of Costa Rica

1. There is a widespread belief in the industrial sector that public policy and existing laws and regulations oppose and prevent any form of private power generation, and that, in any case, ICE would block licensing of such projects. Should such a license be granted, it is not known if the utility would purchase power, and under what terms. Therefore, it is necessary to clarify and publicize private power policy and the licensing process to correct prevailing misconceptions that block development of independent generation, to facilitate licensing of projects, to reduce uncertainty and risk

to project sponsors and to improve return to investors. Key elements of this action are:

A. Provide a legal framework for the generation,transmission and sale of private power. In this connection an examination of the United States' experience with PURPA might be helpful.

B. Define contractual terms between ICE and independent generators. The terms should cover technical and financial issues.

C. Simplify the licensing procedure to shorten the time required.

D. Specify electricity purchase price calculation guidelines and procedures. Again, a review of the PURPA provisions that apply in the United States might provide useful information (see Exhibit 4.2).

E. Draft a prototypal contract incorporating the results of the above actions. It should set forth technical requirements of power generations and links with the grid, as well as the terms for purchase of power by the electric utility.

2. An effort of this magnitude, requiring the support and involvement of diverse public and private entities and organizations requires an appropriate institutional structure to provide authority, cooperation, and coordination. Consequently, it is necessary to establish a high-level Private Power Committee to plan and coordinate actions to promote the development of the private power potential and to monitor progress in its realization. The committee membership should include all parties that could contribute to its objectives, with a mix of the public and private sectors. Specifically, the committee should:

A. Be chaired by the Minister of Natural Resources, Energy and Mines and include representatives of ICE, SNE, DSE, the Central Bank, the Directorate General of Forests, the Ministry of Planning, the Chamber of Commerce of Industry, the Association of Engineers and other appropriate parties.

Exhibit 4.2

Example of Possible Power Purchase Arrangements

- Purchase price could be established through one of the following two possibilities:

  A. Average Economic Value

    - 2.6 - 2.96 colones/kWh year around
    - Same for all independent generators, year around

  B. Avoided Cost

    - Dry Season

      -- Peak hours: 5 colones/kWh (1,825 hours)
      -- Off-Peak hours: 2.4 colones/kWh (2,555 hours)

    - Wet Season

      -- All hours: 2.1 colones/kWh (4,380 hours)

Under such cost structure, the public and ICE would share approximately equally the benefits.

Source: RCG/Hagler, Bailly, Inc.

B. Report to the President of the Republic.

C. Meet monthly and exercise its authority through an advisory role.

3. The modest financial returns characteristically provided by private power generation projects are not likely to attract interest on the part of industrial managers, investors and bankers. Therefore, to attract sufficient capital to private power projects it will be necessary to provide tax exemptions in order to increase their attractiveness to decision-makers, and to place them on an equal footing with ICE in terms of cost advantages. Specifically, measures should be taken to:

   A. Reduce project capital requirements by waiving import duties and taxes on equipment.

   B. Increase project profitability by waiving income tax on project revenue.

4. The fundamentals and benefits of independent power generation are not widely known. To gain the interest and support of groups that might have a role in its development, it is necessary to conduct an information and awareness program aimed at engineers, bankers, potential private generation developers and industry associations. Upon successful completion of projects, case studies should be prepared and distributed to interested parties. ICE might play a major role in this program.

5. Costa Rica is fortunate in having a large pool of highly qualified and experienced engineers and technicians; however, the development of private power generation requires certain skills and knowledge that are likely to be scarce outside of the power sector. Therefore, it is necessary to determine the training needs of personnel to be involved in the practical aspects of private power development and sponsor training on the design, planning, implementation, and operation of independent power projects. ICE and local consultants could assist in this effort, which might, for example, train:

   A. Industrial managers in securing project approval and financing.

B. Engineers in project design, equipment selection, procurement and installation, connecting the independent generation system to the grid, and system operation.

C. Equipment operators in operating routines.

AID

1. Although there are strong indications that the bulk of the potential for independent power generation lies in hydropower and the sugar industry, much more information is required (particularly in regard to hydraulic resources) before a reasonably accurate estimate of potential can be obtained. Therefore, it is necessary to carry forward the analysis of these two areas and obtain sufficient data to provide a firm basis for planning further actions. AID has broad experience in these two areas and could assist the GOCR in carrying out these activities.

2. In practice, capital for funding private power projects of significant size is not available. Since access to funding is critical to private power development, AID may want to consider establishing or make available a line of credit solely dedicated to this purpose. Funding, credit terms and fund regulations should be based on a detailed analysis of potential borrowers' needs and the availability of other credit for private power generation projects.

3. AID is also very well positioned to provide training to ICE, SNE, and private power developers both in Costa Rica and in the United States (PURPA experience, "sister utility concept"). AID can also assist these institutions in the information promotion activities described above.

APPENDIX A: SCOPE OF WORK

ARTICLE III - STATEMENT OF WORK

A. PROMOTION OF INDEPENDENT POWER GENERATION STUDY

The study will be carried out in three tasks.

Task 1: Identify Market and Economic Potential

In carrying out this task, Contractor will successively analyze the background, the situation of the current off-system generation and its costs and benefits, and describe the utility system and the existing power sector policies.

Background

1. Country energy situation: Describe briefly, using existing data, the current energy situation and the factors influencing the introduction of private sector off-system electrical generation. Such factors may be power sector constraints (e.g., capital availability, skilled manpower, inadequate generation capacity, system reliability) and the size and type of industrial base and its capacity for cogeneration.

2. U.S. experience: Briefly describe the Public Utility Regulatory Policies Act (PURPA) and the U.S. experience in fostering private sector non-utility electrical generation.

Current Off-System Generation

Identify any current purchase arrangements between public utilities and non-utility generators. Identify any projects under discussion or in the planning stage. Determine the extent of a trend toward private (captive) diesel or fuel oil-based generation.

Potential for Off-System Generation

Estimate the potential for non-utility renewable or indigenous energy based generation and cogeneration and assess the character of the generation, e.g., intermittent, seasonal, daily peaks.

Make preliminary estimates of industrial cogeneration potential. Use existing industrial data and growth projections and identify the market for cogeneration by industry type, size of current and projected electricity/steam demands, applicable cogeneration technologies, and energy supply (coal, biomass, and/or oil). Indicate what the utility would pay for surplus electricity that would make the system financially attractive. Provide an estimate (a range, if appropriate) of electricity that could be available for sale to the grid and an estimate of the capital investment needed.

Identify other decentralized private sector generation options and, based on existing information, estimate the potential electricity that could be provided to the grid. Identify the energy resources, the energy conversion technology options, and the institutional arrangements for generating the electricity. For example:

- bagasse or rice hulls; steam boilers; mill owners

- hydro; small scale turbines; industrialists

For the major generation options, indicate the financial viability of the systems and what the utility would pay for surplus electricity that would make the system financially viable.

Costs and Benefits of Off-System Generation

Identify the costs and benefits of indigenous/renewable-based off-system electrical generation from the utility, user, and national perspective.

Utility System Description

Briefly describe the utility system, ownership, fuel use, marginal cost of generation, load projections, system expansion projects, and tariffs.

Determine the utility technical concerns about off-system generation such as system protection, metering, and reliability, and any related concerns about the purchase of off-system generation.

Identify the factors affecting the utility's marginal costs. Derive estimated "avoided costs" and the price and utility might reasonably be expected to pay for intermittent power during peak and off-peak.

Discuss the basis for the calculation, whether any fuel cost should be used in establishing the price to be paid by the utility for intermittent power, or whether some capacity cost should also be included in the price.

Power Sector Policies

Analyze the policy, legal, and regulatory framework governing the power sector, including:

- government policy on non-utility generation of electricity for sale to the grid;
- legal and regulatory authority for generation of electricity; and
- rate setting mechanisms and source of authority.

In carrying out this task, local consultants will be hired to gather basis market data, e.g., energy resource assessment, site specific project information, energy prices, taxes, and electricity utility costs.

Task 2: Identify Impediments to Off-System Generation

In this task, Contractor will analyze the policy, legal, regulatory, institutional, or other problems and impediments to off-system generation and determine the views of key institutions, industries, and individuals on the impediments to and potential for private sector off-system generation; these groups will include, but not be limited to, utilities, government ministries, banks, and other financial institutions, commissions responsible for energy and utilities, key industrial and private sector entities, and policymakers and lawmakers.

Task 3: Develop Recommendations and an Action Plan for the GOCR

In this task, the Contractor will provide policy, legal, regulatory, and other recommendations that will foster the introduction of private indigenous/renewable energy-based generation and cogeneration of electricity for sale to the grid, including the drafting of legislation and prototypical purchase contracts between private generators and ICE.

Counterpart. The counterpart for this project will be ICE which should make one senior person available to the project on a full time basis during the three calendar months required for the study. Other key agencies to be involved on an ad hoc basis in the project include DSE and SNE (tariffs).

APPENDIX B: LIST OF CONTACTS[1]

Monday, November 9, 1987

Organization	U.S. Agency for International Development
Main Topic	Kick Off Meeting
Attendees	Ing. Heriberto Rodriguez, Energy Officer JF, RK[2] Tel.: 33-11-55
Organization	U.S. Agency for International Development Office of the Private Sector
Main Topic	Private Sector Activities
Attendees	Neil Billig, Deputy, JF, RK Tel.: 33-11-55
Organization	Institute Costarricense de Electricidad Direccion Planificacion Electrica
Main Topic	Kick Off Meeting
Attendees	Ing. Agustin Rodriguez, Jefe JF, RK Tel.: 20-72-26

1 Meeting held in San Jose, unless otherwise indicated.

2 Hagler, Bailly, and Sol 2000 staff members:
JE: Jeff Erickson
AS: Alain Streicher
RK: Robert Kowalski
JF: Jack Fritz
JR: Juan Rojas
IMG: Ismael Mazon Gonzalez

Tuesday, November 10, 1987

Organization	Interamerican Development Band
Main Topic	IDB Loan Energy Activities
Attendees	Eduardo Marquez, Sector Specialist JF, RK Tel.: 33-22-44

Organization	Instituto Centro Americano de Investigacion y Tecnologia Industrial
Main Topic	Financing
Attendees	Felix del Barco, RK

Organization	United Nations Development Program
Main Topic	Energy Sector Activities
Attendees	Soren Aarslev, Program Officer JF, RK Tel.: 25-03-66

Wednesday, November 11, 1987

2:00 pm

Organization	DSE Documentation Center
Main Topic	Literature Search
Attendees	Juan Salazar, Librarian RK

Organization	Empresa de Electricidad de Matamoros
Main Topic	Small Hydro Activities
Attendees	Ing. Carlos Chaves, Gerente, JF, JR Tel.: 46-05-97

Organization	Quebrada Azul
Main Topic	Power Generation in the Sugar Industry
Attendees	Ing. Arnaldo Chavaria, Gerente
	JF, RK
	Tel.: 47-50-54

Thursday, November 12, 1987

9:00 am

Organization	El Gallito Industrial
Main Topic	Cogeneration Potential
Attendees	Ing. Alejandro Odio
	RK, JR

11:00 am

Organization	El Portico S.A.
Main Topic	Plant Inspection
Attendees	RK, JR

Alajuela

2:00 pm

Organization	Tica Tex
Main Topic	Cogeneration Potential
Attendees	Tako Watanabe, Plant Engineer
	Jos Manuel Retana, Head of Research Section
	Ing. Luis Alfonso Hernandez, Assistant of Head of Research Section
	RK, JR

3:30 pm

Organization	Punto Rojo, S.A.
Main Topic	Cogeneration Potential
Attendees	Bernal Soto Ch., Manager
	Ing. Arnaldo Garca, Head of Maintenance
	RK, JR.

Organization	Direccion Sectarial Energia
Main Topic	DSE Energy Activities
Attendees	Lic. Ana Lorena Leon, Coordinator
	JF, RK
	Tel.: 33-19-55

Organization	Direccion General Forestal
Main Topic	Biomass Energy Activities
Attendees	Jose Luis Fallas,
	JF, RK
	Tel.: 21-95-33

Organization	Compania Nacional de Fuerza y Luz
Main Topic	Small Hydro Activities
Attendees	Ing. Fernando Chanto,
	JF
	Tel.: 33-02-11

Organization	Servicion Nacional de Electricidad
Main Topic	SNE Regulations regarding Private Power
Attendees	Lic. Magda Sanchez
	Tel.: 23-09-66

Organization	University of Costa Rica Ingeniera Mecanica
Main Topic	Micro Hydro Activities
Attendees	Glenn Dewey, Manuel Murillo, Professors JF Tel.: 25-78-38

Friday, November 13, 1987

8:45 am

Organization	Dos Pinos
Main Topic	Cogeneration Potential
Attendees	Ing. Gazel, Plant Engineer RK

10:00 am

Organization	Portico
Main Topic	Cogeneration Potential
Attendees	Arq. Edgardo Barrenechea, Director of Production RK

1:30 pm

Organization	Direccion Sectorial de Energia
Main Topic	Data
Attendees	Lic. Ana Lorena Leon Ing. Alexandra Hernandez Ing. Giovanni Castillo JF, RK

Saturday, November 14, 1987

Palo Seco (Near Quepos)

9:45 am

Organization	Compania Bananera, Planta de Aceite de Palo Seco
Main Topic	Cogeneration Potential
Attendees	Ing. Carlos Matamoros, Plant Superintendent
	RK, JE, JR, IMG,

Monday, November 16, 1987

8:30 am

Organization	Direccion Sectorial de Energia
	Centro de Documentacion
Main Topic	Cogeneration and Biomass Potential
Attendees	Ing. Giovanni Castillo
	RK, LM

9:00 am

Organization	Direccion Sectorial Forrestal
Main Topic	Dendrothermal and Biomass Resources
Attendees	Ing. Jose Luiz Salas
	JF, JE
	Tel: 21-19-55

Organization	ICE
	Oficina Proyectos Hidroelectricos
Main Topic	Hydroelectric Resources
Attendees	Ing. Mario Lopez Soto, Jefe
	Oficina de Proyectos Hidroelectricos
	Ing, Jorge Valverde, Jefe
	JF
	Tel.: 20-72-37

Wednesday, November 18, 1987

Cartago

2:00 pm

Organization	VICESA
Main Topic	Cogeneration and Biomass Potential
Attendees	Ing. Miguel Sotela Castro, Director of Production RK, JR

Thursday November 19

1:30 pm

Organization	ICE-Direccion Produccion y Transporte de Energia
Main Topic	Load Control and Marginal Costs
Attendees	Ing. Ricardo Chinchilla, Jefe Depto. Ing. Luis A. Barquero, AS Tel.: 32-88-05

3:00 pm

Organization	DSE
Main Topic	Survey of Sugar Mills
Attendees	Lic. Ana Lorena Leon AS Tel.: 33-19-55

Organization	CNFL
Main Topic	Private Sector Attitudes
Attendees	Ing. Guillermo Rohrmoser, Gerente General JF, AS, JR Tel.: 23-44-33

Organization	Banco Nacional de Costa Rica
Main Topic	Private Power Financing
Attendees	Ing. Joffre Zambrano JF, AS, JR Tel.: 23-21-66

Friday, November 20

9:00 am

Organization	RECOPE - Planning
Main Topic	Petroleum product pricing; cogeneration potential at the refinery
Attendees	Ing. Jose Ruben Naranjo, Jefe Departamento AS Tel.: 23-96-11

10:30 am

Organization	CNFL
Main Topic	Review Investment Climate
Attendees	Ing. Guillermo Rohrmoser, Gerente General AS, JF, JR

11:30 am

Organization	Banco Nacional de Costa Rica
Main Topic	Credit situation-overall economic and financing matters
Attendees	Ing. Joffre Zambrano AS, JF Tel.: 23-21-66 Ext. 2265

4:30pm

Organization	Scott Paper
Main Topic	Potential for Cogeneration and Load Management
Attendees	Ing. Joaquin Lizano, Vicepresidente de Desarrollo e Ingeniera AS

Monday, November 23, 1987

Organization	ICE - Thermal Department
Main Topic	Miravalles
Attendees	Alfredo Mainiere, Jefe JF Tel.: 20-75-33

Wednesday, November 25, 1987

10:00 am

Organization:	Banco Anglo Costarricense, Loan Department
Main Topic:	Financing of Private Sector Power Generation Projects
Attendees:	Edwin Brenes, Credit Analysis R.K.

2.00 pm

Organization:	Banco de Comercio, Loan Department
Main Topic:	Financing of Private Sector Power Generation Projects
Attendees:	Carlos Sota, Loan Officer R.K.

Thursday, November 26, 1987

4:00 pm

Organization:	Representaciones Mario Cantillo
Main Topic:	Financing of Private Sector Power Generation Projects
Attendees:	Ing. Mario Cantillo, President R.K.

Saturday, November 28, 1987

10:30 am

Organization:	Chambers of Commerce of Industry of Costa Rica
Main Topic:	Financing of Private Sector Power Generation Projects
Attendees:	Max Koberg, Chairman of Energy Committee R.K. (By Telephone)

APPENDIX C: TECHNICAL, ECONOMIC, AND FINANCIAL ANALYSIS

INTRODUCTION

The ECSP team used a computer model to aid in performing the technical, economic, and financial analysis. The Economic and Financial Analysis Program (EFAP), developed by RCG/Hagler, Bailly, Inc.. analyzes potential energy investments. EFAP performs a variety of standard financial analysis computations to identify the economic and financial costs and returns from prospective cogeneration and power generation investments. It provides all the basic information needed to evaluate the attractiveness of projects from the point of view of investors (the financial analysis) and, using inputs adjusted for taxes and subsidies, from the point of view of the economy (the economic analysis). Among other things, EFAP calculates the net present value and internal rate of return for investments. It also calculates capital inflows and outflows over the life of a project and calculates the cost of power from cogeneration and power projects.

EFAP prepares financial and economic evaluations based on a series of inputs from the user. Basic technical, financial, and economic information must be entered to form the basis for the analysis. These inputs include, among other things, system size and cost, capacity factor, cost of equity and debt, fuel prices, inflation rates, and power purchase rates. From these inputs, the model calculates the components of the cash flows over the life of the project, including expenses, revenues, profits, depreciation, taxes, internal rates of return, net present values, and net power costs, among other things. Sensitivity analyses can be quickly performed by varying one of the inputs while observing the effects on the various results.

The following paragraphs explain the various assumptions and inputs prepared by the ECSP team to run the technical, economic, and financial analysis. Following that, guidelines for interpreting the results are given.

POWER ASSUMPTIONS

The data to be entered in the POWER EFAP model (which estimates the financial and economic performance of power-only systems) is organized into three categories (Exhibit 1): (1) Technology Description; (2) Financial Assumptions; (3) Economic Assumptions. Most of the data needs are self-explanatory, however, some specific points need to be clarified. Each will be dealt with in the following paragraphs.

Exhibit 1

TECHNOLOGY ASSUMPTIONS: POWER ONLY SYSTEM

TECHNOLOGY DESCRIPTION Assumptions	:Basic
SYSTEM SIZE (KW)	: 10,000
ANNUAL CAPACITY FACTOR (Fraction)	: 0.6
HEAT RATE (Fuel Units/kWh)	: 0.003412
CAPITAL COST (Local Currency / kW)	: 1280 US$
ANNUAL NON-FUEL O&M COST (Fraction of CAPITAL COST)	: 0.03
SYSTEM LIFE (Years)	: 20
ANNUAL POWER OUTPUT (kWh/YR)	: 52,560,000

FINANCIAL ASSUMPTIONS: POWER ONLY SYSTEM

MARKET EXCHANGE RATE (Local Currency/US$)	: 1 US$
AFTER-TAX COST OF EQUITY	: 15
COST OF DEBT (%)	: 11
DEBT-TO-EQUITY RATIO	: 2.3
INITIAL FUEL PRICE (Local Currency / Fuel Unit)	: 18 US$
ANNUAL FUEL PRICE INFLATION (% / yr)	: 0
INITIAL POWER PRICE (Local Currency / kWh)	: 0.0455
ANNUAL POWER PRICE INFLATION (% / yr)	: 0
ANNUAL O&M COST INFLATION (% / yr)	: 0
MARGINAL TAX RATE (%)	: 50

ECONOMIC ASSUMPTIONS: POWER ONLY SYSTEM

REAL EXCHANGE RATE (Local Currency / US$)	: 1 US$
MARGINAL RETURN TO CAPITAL (%)	: 10
FRACTION OF CAPITAL COST IN FOREIGN EXCHANGE	: 0.6

Exhibit 1 continued

INTEREST, FEES, ETC. ON FOREX CAPITAL COST (%/YR)	:	10
FRACTION OF O&M COST IN FOREIGN EXCHANGE	:	0.5
O&M COST ESCALATION RATE (%/YR)	:	0
ECONOMIC FUEL COST (Local Currency / Fuel Unit)	:	5 low US$
FRACTION OF FUEL COST IN FOREX	:	0.95
FUEL COST ESCALATION RATE (% / yr)	:	0
ECONOMIC POWER COST (Local Currency / kWh)	:	0.05 US$
FRACTION OF POWER COST IN FOREX	:	0.5
POWER COST ESCALATION RATE (% / yr)	:	0
SCF* FOR LOCAL CURRENCY O&M COSTS	:	0.75
SCF* FOR LOCAL CURRENCY CAPITAL COSTS	:	0.5
SCF* FOR LOCAL CURRENCY FUEL COSTS	:	0.95
SCF* FOR LOCAL CURRENCY POWER COSTS	:	0.75

* -"SCF = Specific Conversion Factor for converting the market price to the true economic cost

Technology Description

- **System Size**: The system size is the net power output of the system, expressed in kilowatts. This is the power available for use or for sale, and does not include power needed by the system for its own operation.

- **Annual Capacity Factor**: The capacity factor is the ratio of the average load on a generating resource to its capacity rating over the whole year. This is calculated by dividing the hours of operation per year by 8760 (8760 = 24 hours times 356 days). Alternatively it can be calculated by dividing the annual output by the product of the peak hourly output and 8760.

- **Heat Rate**: A measure of generating station thermal efficiency generally expressed in Btu per net kilowatt-hour. The heat rate is computed by dividing the total Btu content of the fuel burned by the resulting net kilowatt-hours generated.

- **Capital Cost**: The capital cost is entered as either local currency or U.S. dollars per kilowatt of capacity. Consistency must be maintained with other data that refer to costs.

- **Annual Non-fuel O&M Cost**: Operations and maintenance (O&M) costs are expressed as a fraction of the capital cost.

- **System Life**: The total system life is entered in years. At present the cash flow analysis assumes a 20 year system life.

Financial Assumptions

Financial assumptions are based on the actual market costs as seen by the investor. They include taxes, duties, profits, and other transfer payments and are used to calculate the cash flows and returns that an investor would actually realize.

- **Market Exchange Rate**: This should be either the official exchange rate or the actual "street" exchange rate. If all costs are being expressed in U.S. dollars, a 1 (one) is entered.

- **After-Tax Cost of Equity**: This is the return a company must offer to attract new equity, or the "hurdle rate" a company uses for new capital investment.

- **Cost of Debt**: This is the cost of long-term bank loans or bonds to the firm making the investment.

- **Debt-to-Equity Ratio**

- **Initial Fuel Price**: The initial fuel price is entered as the cost per unit of fuel.
- **Annual Fuel Price Inflation**: The expected fuel price inflation is entered as an annual percent (e.g., if it is 20 percent per year enter 20).
- **Initial Power Price**: The initial power price is entered in dollars (or local currency) per kilowatt-hour. This is the price actually paid by the industry for power from the utility, or if the power is to be sold, the price which will be paid to the industry for it.
- **Annual Power Price Inflation**: The expected power price inflation rate is entered as an annual percent.
- **Annual O&M Cost Inflation**: The expected operations and maintenance (O&M) cost inflation in entered as an annual percent.
- **Marginal Tax Rate**: The marginal tax rate is the tax rate that must be paid on any additional income received.

Economic Assumptions

Economic assumptions are used to calculate the true economic costs and benefits, factoring out the effects of taxes, duties and other transfer payments that do not represent actual costs but rather shifts of resources from one sector to another. Thus the economic data entered in the following items are the "real" costs or the "shadow prices", not the "market" costs. These numbers are used to calculate the actual costs and benefits to the economy of the projects.

- **Real Exchange Rate**: This is the actual cost to the economy of foreign exchange. It may be represented by the "black market" exchange rate.
- **Marginal Return to Capital**: The marginal return to capital is the return expected in the economy from investing one more unit of capital. In most developing countries this return is estimated to be between 10 percent and 15 percent.
- **Fraction of Capital Cost in Foreign Exchange**: This is the amount of the capital cost of the power system that must be paid for in foreign exchange.
- **Interest, Fees, Etc. on Foreign Exchange Capital Cost**:
- **Fraction of O&M Cost in Foreign Exchange**: This is the amount of the operations and maintenance (O&M) costs that must be paid for in foreign exchange.

- **O&M Cost Escalation Rate**: The expected operations and maintenance (O&M) cost escalation is entered as an annual percent.

- **Economic Fuel Cost**: The initial fuel price is the cost per unit of fuel. This cost represents the actual cost to the economy of the fuel, factoring out taxes, import duties, and other transfer payments.

- **Fraction of Fuel Cost in Foreign Exchange**: This is the amount of the fuel costs that must be paid for in foreign exchange.

- **Fuel Cost Escalation Rate**: The expected fuel cost escalation rate is entered as an annual percent.

- **Economic Power Cost**: The initial power price is entered in dollars (or local currency) per kilowatt-hour (e.g., 7 cents/kWh would be entered as 0.07). This is the long-term marginal cost of power to the utility, or the actual cost to the economy of the power.

- **Fraction of Power Cost in Foreign Exchange**: This is the amount of the power cost that can be attributed to foreign exchange costs.

- **Power Cost Escalation Rate**: The expected power cost escalation rate is entered as an annual percent.

When true economic costs are not known, the EFAP model can convert financial costs to economic costs using Specific Conversion Factors (SCF). They represent the ratio of the market values to the true or real costs and are expressed as a fraction. SCFs are used in the equations to calculate economic costs for the cash flow analysis, based on numbers from the Technology Description and Financial Assumptions. The POWER EFAP model uses four SCFs:

- **SCF for Local Currency O&M Costs**: The estimated ratio between the local currency portion of the Economic O&M Costs and their true cost to the economy.

- **SCF for Local Currency Capital Costs**: The estimated ratio between the local currency portion of the Economic Capital Costs and their true cost to the economy.

- **SCF for Local Currency Fuel Costs**: The estimated ratio between the local currency portion of the Economic Fuel Costs and their true cost to the economy.

- **SCF for Local Currency Power Costs**: The estimated ratio between the local currency portion of the Economic Power Costs and their true cost to the economy.

COGEN ASSUMPTIONS

The data entered in the COGEN EFAP model (which estimates the financial and economic performance of cogeneration systems), like that for the POWER EFAP model is organized into three categories (Exhibit 2): (1) Technology Description; (2) Financial Assumptions; (3) Economic Assumptions.

Many of the cogeneration assumptions are the same as those in the power-only model. The cogeneration model, however, also compares the costs and benefits of a cogeneration system with the costs of a non-cogeneration system. All data categories referring to the non-cogeneration system refer to a system that would produce the needed quantity of process heat but would not cogenerate electricity.

Most of the data needs are self-explanatory, although a few specific points need to be elaborated. Each will be dealt with in the following paragraphs.

Technology Description

- **System Size**: The system size is the net steam output of the system, expressed in steam units per hour.

- **Annual Capacity Factor**: The capacity factor is the ratio of the average load on a generating resource to its capacity rating over the whole year, expressed as a fraction (i.e., a 60 percent capacity factor should be entered as 0.6). This is calculated by dividing the hours of operation per year by 8760. (8760 = 24 hours times 356 days.) Alternatively it can be calculated by dividing the annual output by the product of the peak hourly output and 8760.

- **Cogeneration Efficiency**: A measure of the cogeneration system's efficiency expressed in fuel units per steam unit.1 Note that this is not the same as system efficiency, which is defined as fuel energy content divided by the sum of steam to process plus electric power.

- **Non-Cogen Efficiency**: The non-cogen system efficiency is also expressed in fuel units per steam unit. System efficiency is defined as fuel energy content divided by the energy content of the steam or heat output.

1This is the inverse of standard expressions of efficiency.

Exhibit 2

TECHNOLOGY ASSUMPTIONS: COGENERATION SYSTEM

TECHNOLOGY DESCRIPTION Assumptions	:Basic
SYSTEM SIZE (Steam Units/Hr)	: 65mmBtu
ANNUAL CAPACITY FACTOR (Fraction)	: 0.7
COGEN EFFICIENCY (Fuel Units / Steam Unit)	: 1.447mmBtu
1/(NON-COGEN EFFICIENCY) (Fuel Units / Steam Unit)	: 1.33
ELECTRIC-TO-THERMAL RATIO	: 0.1
THEORETICAL STEAM UNITS / kWh	:0.003412mmBtu/kW
COGEN SYSTEM CAPITAL COST (Local Currency / Steam Unit)	: 40000
ANNUAL COGEN NON-FUEL O&M COST (Fraction of CAPITAL COST)	: 0.05
COGEN SYSTEM LIFE (Years)	: 20
NON-COGEN SYSTEM CAPITAL COST (Local Currency / Steam Unit)	: 0
ANNUAL NON-COGEN NON-FUEL O&M COST (Fraction of CAPITAL COST)	: 0.05
NON-COGEN SYSTEM LIFE (Years)	: 20
COGEN SYSTEM POWER OUTPUT (kWh/YR) (Calculated)	: 11,681,712

FINANCIAL ASSUMPTIONS: COGENERATION SYSTEM

MARKET EXCHANGE RATE (Local Currency/US$)	: 1
AFTER-TAX COST OF EQUITY (%)	: 15
COST OF DEBT (%)	: 11
DEBT-TO-EQUITY RATIO	: 2.3
INITIAL COGEN SYSTEM FUEL PRICE (Local Currency / Fuel Unit)	: 3.06
ANNUAL COGEN FUEL PRICE INFLATION (% / yr)	: 0

Exhibit 2 continued

INITIAL NON-COGEN SYSTEM FUEL PRICE (Local Currency / Fuel Unit)	:	3.06
ANNUAL NON-COGEN SYSTEM FUEL PRICE INFLATION (% / yr)	:	0
INITIAL POWER PRICE (Local Currency / kWh)	:	0.0455
ANNUAL POWER PRICE INFLATION (% / yr)	:	0
ANNUAL COGEN O&M COST INFLATION (% / yr)	:	0
ANNUAL NON-COGEN O&M COST INFLATION (% / yr)	:	0
MARGINAL TAX RATE (%)	:	50

ECONOMIC ASSUMPTIONS: COGENERATION SYSTEM

REAL EXCHANGE RATE (Local Currency / US$)	:	1
MARGINAL RETURN TO CAPITAL (%)	:	10
COGEN SYSTEM FRACTION OF CAPITAL COST IN FOREIGN EXCHANGE	:	0.6
COGEN SYSTEM FRACTION OF O&M COST IN FOREIGN EXCHANGE	:	0.6
COGEN ECONOMIC FUEL COST (Local Currency / Fuel Unit)	:	3.02
COGEN FUEL COST ESCALATION RATE (% / yr)	:	0
COGEN SYSTEM FRACTION OF FUEL COST IN FOREIGN EXCHANGE	:	0.95
NON-COGEN SYSTEM FRACTION OF CAPITAL COST IN FOREIGN EXCHANGE	:	0.6
NON-COGEN SYSTEM FRACTION OF O&M COST IN FOREIGN EXCHANGE	:	0.6
NON-COGEN ECONOMIC FUEL COST (Local Currency / Fuel Unit)	:	3.02
NON-COGEN FUEL COST ESCALATION RATE (% / yr)	:	0
NON-COGEN SYSTEM FRACTION OF FUEL COST IN FOREIGN EXCHANGE	:	0.95
COGEN/NON-COGEN O&M ESCALATION RATE (%/YR)	:	0

Exhibit 2 continued

INTEREST, FEES, ETC. ON FOREX CAPITAL COST (%/YR)	:	10
ECONOMIC POWER COST (Local Currency / kWh)	:	0.05
POWER COST ESCALATION RATE (% / yr)	:	0
FRACTION OF POWER COST IN FOREX	:	0.5
SCF* FOR LOCAL CURRENCY O&M COSTS	:	0.75
SCF* FOR LOCAL CURRENCY CAPITAL COSTS	:	0.5
SCF* FOR LOCAL CURRENCY POWER COSTS	:	0.75
SCF* FOR LOCAL CURRENCY COGEN FUEL COSTS	:	0.95
SCF* FOR LOCAL CURRENCY NON-COGEN FUEL COSTS	:	0.95

* -"SCF = Specific Conversion Factor for converting the market price to the true economic cost

- **Electric-to-Thermal Ratio:** The electric-to-thermal (E/T) ratio is the net electric power output (the total electric power output less cogeneration system power requirements) divided by the net steam available for process. These values will generally fall in the following ranges:

Type of System	E/T Range
Boiler/Steam Turbine	0.1-0.15
Gas Turbine	0.3-0.5
Combined Cycle	0.5-0.9
Diesel	0.9-1.2

- **Theoretical Steam Units/kWh:** This is the theoretical number of steam units per kilowatt-hour, ignoring conversion losses. The number used will be determined by the choice of steam units made elsewhere. The values are as follows:

Steam Units	Theoretical Steam Units
Btu	3,412
Lbs of Steam	3.412
Tonnes of Steam	.00155
Kcal	860
Kilojoule	3,597
Kiloliter of oil equivalent	0.086

- **Cogen System Capital Cost:** The capital cost is entered as either local currency or U.S. dollars per unit of steam. This is determined by dividing the actual cost of the cogen system by its true steam output.

- **Annual Cogen Non-Fuel O&M Cost:** Operations and maintenance (O&M) costs are expressed as a fraction of the capital cost.

- **Cogen System Life:** The expected system life is entered in years. At present the cash flow analysis assumes a 20 year system life. The levelized cost calculations however use the system life entered here.

- **Non-Cogen System Capital Cost:** The capital cost of the non-cogeneration system is entered as either local currency or U.S. dollars per unit of steam. If the alternative to installing a cogeneration system is to install a new boiler or other heat-producing system, then the capital cost of the non-cogeneration system is entered here. If the alternative to installing a cogeneration system is to continue using existing equipment, then a zero (0) is entered.

- **Annual Non-Cogen Non-Fuel O&M Cost:** Operations and maintenance (O&M) costs are expressed as a fraction of the capital cost.

- **Non-Cogen System Life**: The total system life is entered in years. At present the cash flow analysis assumes a 20 year system life. The levelized cost calculations use the system life entered here.

Financial Assumptions

Financial assumptions are based on the actual market costs as seen by the investor. They include taxes, duties, profits, and other transfer payments and are used to calculate the cash flows and returns that an investor would actually realize.

- **Market Exchange Rate**: The exchange rate should be either the official exchange rate or the actual "street" exchange rate. If all costs are being expressed in U.S. dollars, a 1 (one) is entered.

- **After-Tax Cost of Equity**: The after-tax cost of equity is the return a company must offer to attract new equity, or the "hurdle rate" a company uses for new capital investment.

- **Cost of Debt**: The cost of debt is entered as a percent.

- **Debt-to-Equity Ratio**: The debt-to-equity ratio is entered as a fraction.

- **Initial Cogen System Fuel Price**: The initial fuel price is entered as the cost per unit of fuel.

- **Annual Cogen Fuel Price Inflation**: The expected fuel price inflation is entered as an annual percent.

- **Initial Non-Cogen System Fuel Price**: The initial fuel price is entered as the cost per unit of fuel.

- **Annual Non-Cogen Fuel Price Inflation**: The expected fuel price inflation is entered as an annual percent.

- **Initial Power Price**: The initial power price is the price actually paid by the industry for power from the utility, or if the power is to be sold, the price that will be paid to the industry for it.

- **Annual Power Price Inflation**: The expected power price inflation is entered as an annual percent.

- **Annual Cogen O&M Cost Inflation**: The expected operations and maintenance (O&M) cost inflation is entered as an annual percent.

- **Annual Non-Cogen O&M Cost Inflation:** The expected operations and maintenance (O&M) cost inflation is entered as an annual percent.

- **Marginal Tax Rate:** The marginal tax rate is the tax rate that must be paid on any additional income received.

Economic Assumptions

Economic assumptions are used to calculate the true economic costs and benefits, factoring out the effects of taxes, duties, and other transfer payments that do not represent actual costs but rather shifts of resources from one sector to another. Thus the economic data entered in the following items are the "real" costs or the "shadow prices", not the "market" costs. These numbers are used to calculate the actual costs and benefits to the economy of the projects.

- **Real Exchange Rate:** The exchange rate is the actual cost to the economy of foreign exchange. It may be represented by the "black market" exchange rate. If all costs are being expressed in U.S. dollars, a 1 (one) is entered.

- **Marginal Return to Capital:** The marginal return to capital is the return expected in the economy from investing one more unit of capital. In most developing countries this return is estimated to be between 10 and 15 percent.

- **Cogen System Fraction of Capital Cost in Foreign Exchange:** This is the fraction of the capital cost of the cogeneration system that must be paid for in foreign exchange.

- **Cogen System Fraction of O&M Cost in Foreign Exchange:** This is the amount of the operations and maintenance (O&M) costs that must be paid for in foreign exchange.

- **Cogen Economic Fuel Cost:** This cost represents the actual cost to the economy of the fuel, factoring out taxes, import duties, and other transfer payments.

- **Cogen Fuel Cost Escalation Rate:** The expected fuel cost escalation rate is entered as an annual percent.

- **Cogen System Fraction of Fuel Cost in Foreign Exchange:** This is the amount of the fuel costs that must be paid for in foreign exchange.

- **Non-Cogen System Fraction of Capital Cost in Foreign Exchange:** This is the amount of the capital cost of the non-cogeneration system that must be paid for in foreign exchange.

- **Non-Cogen System Fraction of O&M Cost in Foreign Exchange:** This is the amount of the operations and maintenance (O&M) costs that must be paid for in foreign exchange.

- **Non-Cogen Economic Fuel Cost:** This is the initial fuel price as the cost per unit of fuel.

- **Non-Cogen Fuel Cost Escalation Rate:** The expected fuel cost escalation rate is entered as an annual percent.

- **Non-Cogen System Fraction of Fuel Cost in Foreign Exchange:** This is the amount of the fuel costs that must be paid for in foreign exchange.

- **Cogen/Non-Cogen O&M Cost Escalation Rate:** The expected operations and maintenance (O&M) cost escalation rate is entered as an annual percent. EFAP assumes that the rate will be the same for both cogen and non-cogen systems.

- **Interest, Fees, Etc. on Foreign Exchange Capital Cost:** These represent license fees, royalties, etc. on foreign technologies.

- **Economic Power Cost:** This is the long-term marginal cost of power to the utility, or the actual cost to the economy of the power.

- **Power Cost Escalation Rate:** The expected power cost escalation rate is entered as an annual percent.

- **Fraction of Power Cost in Foreign Exchange:** This is the amount of the power cost that can be attributed to foreign exchange costs.

When true economic costs are not known, the EFAP model can convert financial costs to economic costs using Specific Conversion Factors (SCF). They represent the ratio of the market values to the true or real costs and are expressed as a fraction. SCFs are used in the equations to calculate economic costs for the cash flow analysis, based on numbers from the Technology Description and Financial Assumptions. The COGEN EFAP model uses four SCFs:

- **SCF for Local Currency O&M Costs:** The estimated ratio between the local currency portion of the Economic O&M Costs and their true cost to the economy.

- **SCF for Local Currency Capital Costs:** The estimated ratio between the local currency portion of the Economic Capital Costs and their true cost to the economy.

- **SCF for Local Currency Cogen System Fuel Costs:** The estimated ratio between the local currency portion of the Economic Fuel Costs for the cogenerating system and their true cost to the economy.

- **SCF for Local Currency Power Costs:** The estimated ratio between the local currency portion of the Economic Power Costs and their true cost to the economy.

- **SCF for Local Currency Non-Cogen System Fuel Costs:** The estimated ratio between the local currency portion of the Economic Fuel Costs for the non-cogenerating system and their true cost to the economy.

INTERPRETING THE RESULTS

Most of the results of the EFAP model are self-explanatory however some points should be noted to call attention to the most important information. Two things need some explanation: (1) The structure of the model results; and (2) The nature and meaning of the results.

Structure of EFAP and Definitions

Browsing through the EFAP printouts in Appendix G will quickly show that, like the assumptions, the results are divided into Financial and Economic sections. As stated before, the financial analysis evaluates the attractiveness of projects from the point of view of investors and the economic analysis uses inputs adjusted for taxes, subsidies, and other distortions to market values to evaluate projects from the point of view of the economy. A wide divergence between the relative attractiveness of projects in the financial and economic analysis indicates that there are significant distortions in the economy affecting power projects. These distortions can cause investors to make non-optimal energy system choices and may point to areas for restructuring government policies.

The financial analysis is further subdivided based on the proportion of equity and debt used to finance the project. The equity-only scenario assumes that the entire cost of the project is financed with equity and the cash flow analysis does not include interest on debt. The debt-plus-equity scenario uses the debt-to-equity ratio entered in the Financial Assumptions to calculate interest expenses in the cash flow analysis. The effect of debt will be to "leverage" the project's financial performance. That is, if the project's after-tax return-on-equity (ROE) in the equity-only scenario is greater than the after-tax cost of debt, the return-on-equity will increase if a portion of the project is financed with debt. The greater the debt financed portion is, the greater the increase. Conversely, if the equity-only scenario's after-tax ROE is less than the after-tax cost of debt, the ROE will be reduced by debt leveraging.

EFAP Results

To make EFAP results clear and easily understood, the models calculate simple cash flow figures and uses them to calculate three numbers, the net present value (NPV), the internal rate of return (IRR), and the net power cost. This system was chosen to provide a relatively simple means of estimating the impact on the apparent relative costs of various economic and financial options by providing single number measures based on a complicated set of varying cash flows over the project life.

Net Present Value

The Net Present Value (NPV) is the cumulated value of all project cash flows that have been discounted to the beginning of the development period at the after-tax cost of equity specified in the Financial Assumptions or the Marginal Return to Capital specified in the Economic Assumptions. This value is a measure of the increase in the equity investor's net worth that could be expected from undertaking the project. A power project becomes financially attractive to an investor when the NPV becomes positive.

Internal Rate of Return

The Internal Rate of Return (IRR) is a measure of the project's financial performance per currency unit of equity invested. When the IRR is equal to the After-Tax Cost of Equity specified in the Financial Assumptions or the Marginal Return to Capital specified in the Economic Assumptions, the NPV will be equal to zero indicating that an investor will be indifferent to the investment. The more the IRR is above these two rates, the more financially attractive a project will be to an investor and the economy.

Net Power Cost (Net Levelized Cost of Power)

The POWER and COGEN models use a "levelized cost" method whereby the capital, fuel, and O&M costs are "levelized" over the lifetime of the system. The capital costs are levelized by using a Capital Recovery Factor (sometimes called a Capital Charge Rate). This converts these costs to a set of equal levelized annual charges that have the same net present value as the payment stream that results from the way the project is actually financed. Similarly, fuel and O&M cost streams can be "levelized" to an equal annual value having the same NPV as the actual cost streams. The sum of these annualized capital, fuel, and O&M costs can be divided by the annual energy output to determine the net power cost. Comparing this cost with the cost of power from the utility will indicate whether the system can produce power that will be competitive with the utility's power.

APPENDIX D: ESTIMATES OF AVOIDED COST FOR INSTITUTO COSTARRICENSE DE ELECTRICIDAD

To estimate the avoided cost of ICE, we use the "proxy unit" approach. In this approach, first, the avoidable generation unit in the utility's existing plants or in its expansion plan will be identified. Next, the capital and operating costs of that specific unit will be computed. And then, the avoided costs payments to the independent generator for energy and capacity will be calculated.

The avoided costs are estimated for two periods of up to 1989 and 1989 to 1992. In the first period, the electricity from independent generators will replace that generated by existing thermal power plants. In the second period, the independent generator will replace either the future gas turbines or geothermal plants.

1. SHORT TERM AVOIDED COST

In the short term (up to 1989), the avoided cost to ICE from the purchase of electricity from independent generators consists only of the variable operation costs of the existing thermal power plants. These thermal power plants are very old, their efficiency is very low, and they have very high operation costs. There will be no capital costs savings associated with the purchase of power from independent generators.

Assuming a fuel use of 15,000 Btu per kWh for thermal power plants,[1] and variable non-fuel operation costs of 5 cents/kWh,[2] the avoided cost will be:

Fuel: 15,000 Btu/kWh * $2.35/mmBtu * 100 cents/$ * mm/1000,000 = 3.53 cents/kWh.

If thermal plants use diesel oil at $3.63 per mmBtu, the avoided fuel cost will be 5.45 cents/kWh.

---

1 This is the actual fuel consumption for Barranca and San Antonio gas plants. The fuel use for other thermal plants varies between 9,313 Btu/kWh (for Mion plant) to 16,556 Btu/kWh (for San Antonio Vapor) equivalent to 4.0 to 2.25 kWh per liter of fuel respectively.

2 An estimation. The plants are old and if operated they would require a lot of maintenance.

Total avoided cost therefore will be 8.53 cents to 10.54 cents/kWh during peak hours when these plants are operating.

During off-peak hours, the avoided cost would be equal to the price of electricity purchased from Honduras or about 3 cents/kWh.

2. MEDIUM TERM AVOIDED COSTS

For the medium term (1989 and after) we will take a gas turbine or a geothermal plant as the proxy unit.

Geothermal Plant

The next geothermal unit in ICE's expansion plan is the Miravalles unit 1, to be brought on line in the early 1990s. The estimated cost of Miravalles unit 1 is $1,842 per kilowatt with a generation capacity of 55 MW. Part of this cost is to add capacity, and part must be attributed to energy. We have assigned the capacity value to be equal to the construction cost of a hypothetical equivalent gas turbine, and the energy value the balance. ICE's estimate of construction cost of its future gas turbines (Sandillal unit) is $558 per kW. This implies that the construction cost associated to energy is $1,842 minus $588 or $1,284. These figures must now be converted to annual rates. Using a capital recovery factor (CRF) equal to 0.13 yields a capacity cost of $75.54/kw-yr, and a capital component of the energy cost of $166.9/kW-yr.

At this point fixed operation and maintenance costs must be added in. This represents $3.14 per kW per month or $37.68/kW-yr. Of this $1.56 can be attributed to capacity (based on ICE's estimated fixed O&M costs of Sandillal unit). The balance $36.12 per kW per year is attributable to energy production, for a total capacity cost of $77.10 per kW per year and an energy cost due to fixed charges of $203.02 per kW per year.

To convert the annual value of capacity to a value per kWh, we must now spread the annual cost across the on-peak hours. ICE on-peak hours are 7 A.M. to 8 P.M. Assuming this load shape remains during the entire year (including weekends and holidays), there will be 4,745 peak hours and 4,015 off-peak hours.

Allowing for ICE's expected on-peak capacity factor of 85 percent for the Miravalles geothermal plant, based on a forced outage rate of 15 percent with no scheduled maintenance during the peak period, the geothermal plant is expected to operate the equivalent of 4,033.25 hours per year on-peak at full capacity. This results in a fixed capacity value of 1.90 cents per kWh.

For energy, the annual cost must be spread across all the hours in the year, and adjusted to the annual capacity factor expected for the proxy unit, 80 percent. This results in a fixed cost component of the energy rate equal to 2.90 cents per kWh, applicable to all kWhs.

The final step in developing an avoided cost rate for ICE is to account for the variable part of energy costs and for avoided line and transformer losses. There is no fuel costs for the geothermal plant, and the variable operation and maintenance cost is zero (according to ICE). Finally all of these costs should be increased by 5 percent to allow for the avoided line and transformer losses from high tension to medium tension.[3]

The resulting avoided costs, assuming ICE would have no excess capacity, would be:

For energy delivered on-peak: 5.05 cents per kWh
For energy delivered off-peak: 3.05 cents per kWh

Gas Turbines

Using the same approach for estimating the avoided costs when the proxy unit is a gas turbine will result in the following cost figures:

For energy delivered on-peak: 7.32 cents per kWh
For energy delivered off-peak: 0

3 5 percent is the average figure for U.S. utilities. We assume that ICE has similar transformer and line losses.

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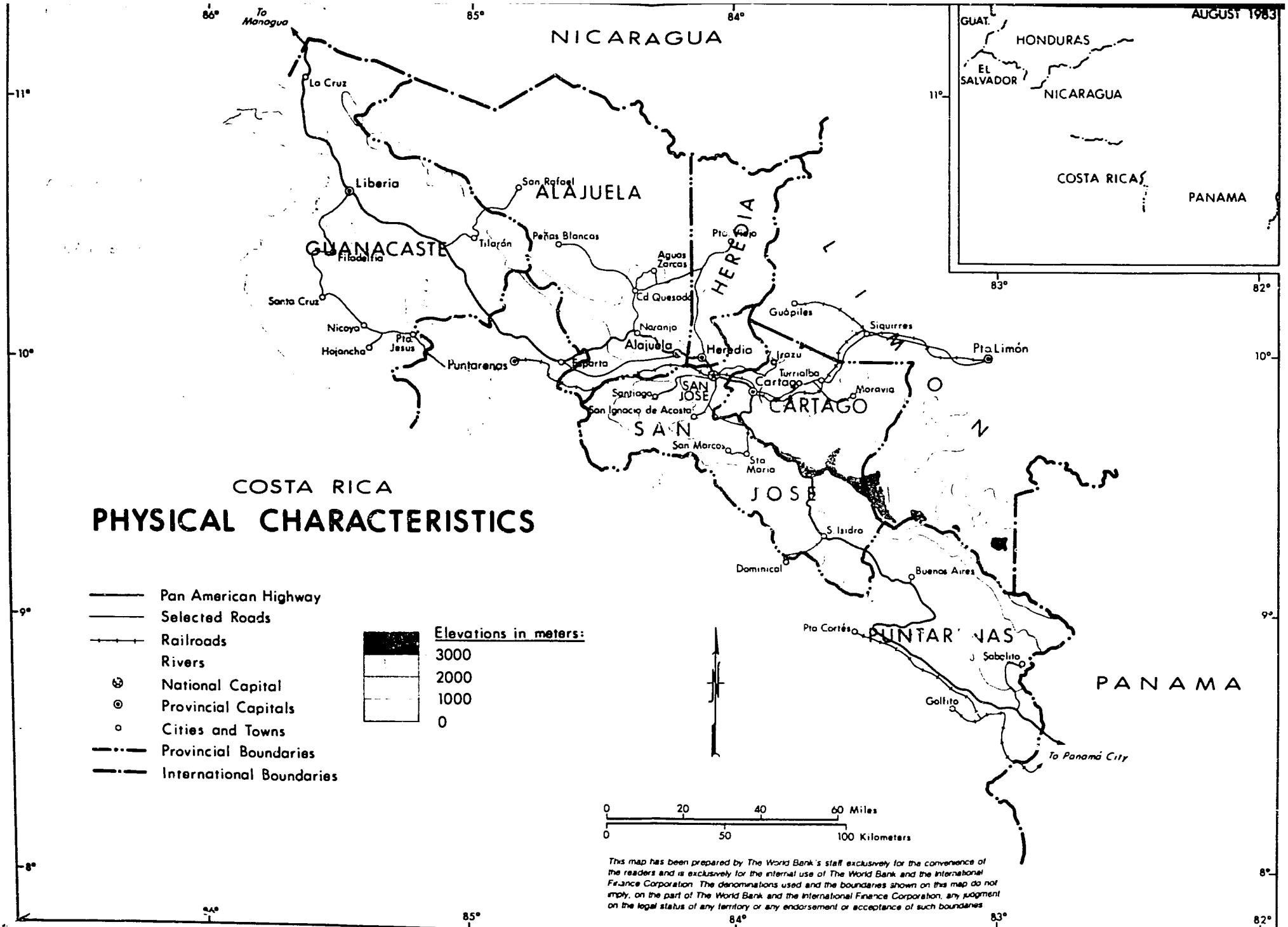
The following exhibit summarizes ICE's avoided costs during peak and off-peak periods for near and medium term.

Exhibit 1. ICE's Avoided Costs (cents per kWh)

Period	Avoided Cost Proxy Unit	Peak	Off-Peak
Up to 1989	Existing Thermal Units	8.5-10.5	*
After 1989			
	Geothermal	5.05	3.05
	Gas Turbine	7.32	*

* Cost of electricity from Honduras

APPENDIX E: MAP OF COSTA RICA


AUGUST 1983
NICARAGUA
To Managua
La Cruz
Liberia
GUANACASTE
Filadelfia
Santa Cruz
Nicoya
Hojancha
Pta. Jesus
Puntarenas
Tilarán
San Rafael
ALAJUELA
Peñas Blancas
Aguas Zarcas
Cd Quesada
Naranjo
Alajuela
Esparta
Pto. Viejo
HEREDIA
Heredia
Guápiles
Siquirres
Pta Limón
Irazu
Turrialba
Cartago
CARTAGO
Moravia
SAN JOSE
Santiago
San Ignacio de Acosta
SAN JOSE
San Marcos
Sta Maria
S. Isidro
Dominical
Buenos Aires
Pta Cortés
PUNTARENAS
Sabalito
Golfito
To Panamá City
PANAMA
COSTA RICA
GUAT.
HONDURAS
EL SALVADOR
NICARAGUA
COSTA RICA
PANAMA
COSTA RICA
PHYSICAL CHARACTERISTICS
Pan American Highway
Selected Roads
Railroads
Rivers
National Capital
Provincial Capitals
Cities and Towns
Provincial Boundaries
International Boundaries
Elevations in meters:
3000
2000
1000
0
0 20 40 60 Miles
0 50 100 Kilometers
This map has been prepared by The World Bank's staff exclusively for the convenience of the readers and is exclusively for the internal use of The World Bank and the International Finance Corporation. The denominations used and the boundaries shown on this map do not imply, on the part of The World Bank and the International Finance Corporation, any judgment on the legal status of any territory or any endorsement or acceptance of such boundaries.

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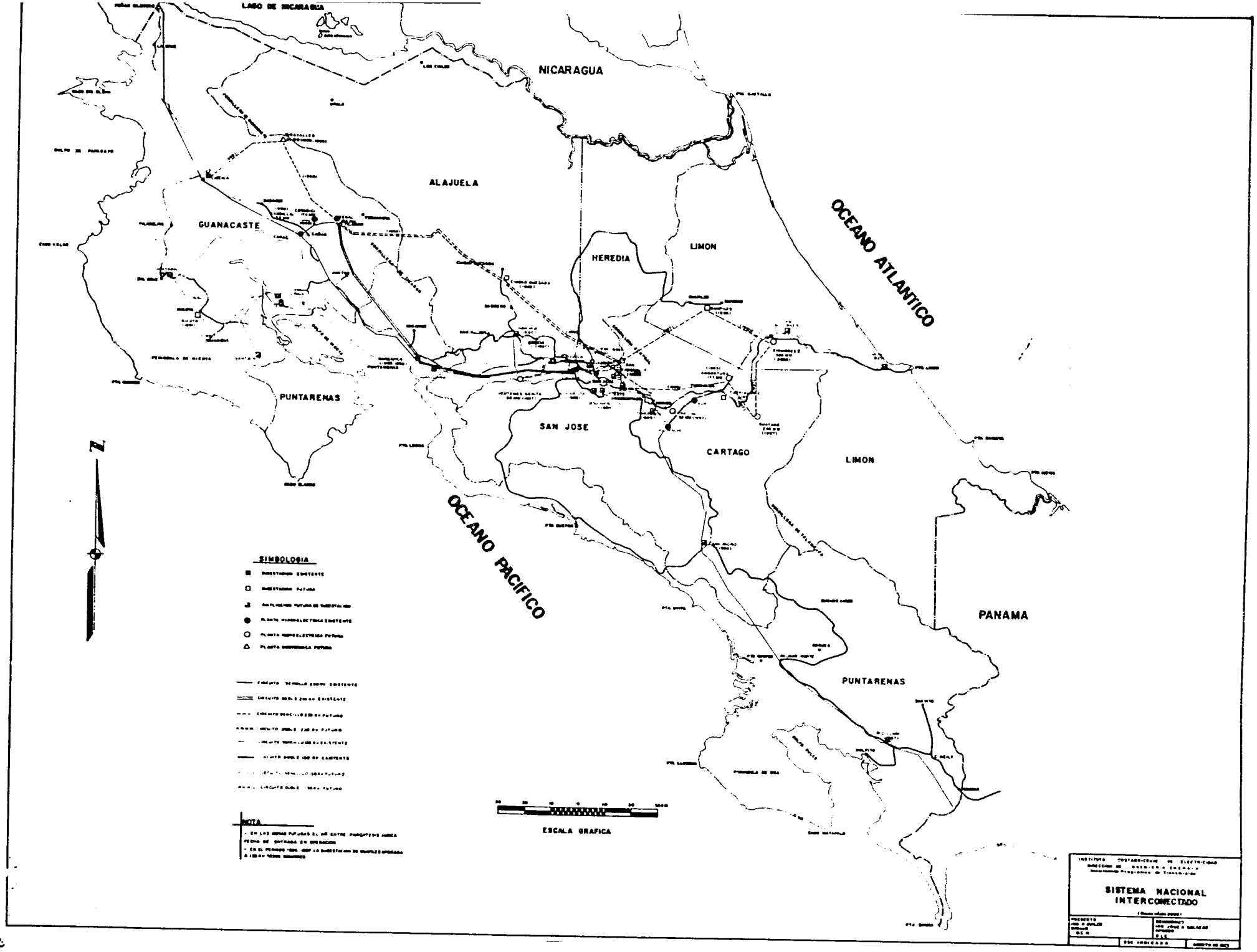
APPENDIX F: POWER/GRID MAP OF COSTA RICA


LAGO DE NICARAGUA
NICARAGUA
ALAJUELA
GUANACASTE
HEREDIA
LIMON
OCEANO ATLANTICO
PUNTARENAS
SAN JOSE
CARTAGO
LIMON
OCEANO PACIFICO
PANAMA
PUNTARENAS
N
SIMBOLOGIA
NOTA
ESCALA GRAFICA
SISTEMA NACIONAL
INTERCONECTADO

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APPENDIX G: SAMPLE COMPLETE FINANCIAL AND ECONOMIC ANALYSES

The EFAP model analyzes power and cogeneration projects in a number of ways, as indicated in Appendix C. For most purposes, the summary printout from the model given in the text of this report contains enough information to evaluate a proposed project. To analyze a project in greater depth, the complete printout from the EFAP model can be used. On the following pages the complete printout of the following examples is given:

Power Only:

- Sugar Mill base case (#1)
- Sugar Mill with major modifications (#2)
- Matamoros hydroelectric
- Dendrothermal

Cogeneration:

- Portico
- Scott Paper

TECHNOLOGY ASSUMPTIONS: POWER ONLY SYSTEM

TECHNOLOGY DESCRIPTION	:	Sugar Mill 1
SYSTEM SIZE (kW)	:	10,000
ANNUAL CAPACITY FACTOR (Fraction)	:	0.27
HEAT RATE (Fuel Units*/kWh)	:	0.01706
CAPITAL COST (Local Currency / kW)	:	250 US$
ANNUAL NON-FUEL O&M COST (Fraction of CAPITAL COST)	:	0.03
SYSTEM LIFE (years)	:	20
ANNUAL POWER OUTPUT (kWh/YR) (Calculated)	:	23,652,000

* - "Fuel Units" must be the same as those used for "Fuel Prices" in the Financial and Economic Assumption inputs.

FINANCIAL ASSUMPTIONS: POWER ONLY SYSTEM

MARKET EXCHANGE RATE (Local Currency/US$)	:	1 US$
AFTER-TAX COST OF EQUITY	:	15
COST OF DEBT (%)	:	11
DEBT-TO-EQUITY RATIO	:	2.3
INITIAL FUEL PRICE (Local Currency / Fuel Unit*)	:	0 US$
ANNUAL FUEL PRICE INFLATION (% / yr)	:	0
INITIAL POWER PRICE (Local Currency / kWh)	:	0.0455
ANNUAL POWER PRICE INFLATION (% / yr)	:	0
ANNUAL O&M COST INFLATION (% / yr)	:	0
MARGINAL TAX RATE (%)	:	50

* - "Fuel Units" must be the same as those used for "Fuel Prices" in the Financial and Economic Assumption inputs.

ECONOMIC ASSUMPTIONS: POWER ONLY SYSTEM

REAL EXCHANGE RATE (Local Currency / US$)	:	1 US$
MARGINAL RETURN TO CAPITAL (%)	:	10
FRACTION OF CAPITAL COST IN FOREIGN EXCHANGE	:	0.6
INTEREST, FEES, ETC. ON FOREX CAPITAL COST (%/YR)	:	10

FRACTION OF O&M COST IN FOREIGN EXCHANGE	:	0.5
O&M COST ESCALATION RATE (%/YR)	:	"
ECONOMIC FUEL COST	:	" low
(Local Currency / Fuel Unit*)		US$
FRACTION OF FUEL COST IN FOREX	:	0.95
FUEL COST ESCALATION RATE (% / yr)	:	"
ECONOMIC POWER COST	:	0.05 US$
(Local Currency / kWh)		
FRACTION OF POWER COST IN FOREX	:	0.5
POWER COST ESCALATION RATE (% / yr)	:	"
SCF** FOR LOCAL CURRENCY O&M COSTS	:	0.75
SCF** FOR LOCAL CURRENCY CAPITAL COSTS	:	0.5
SCF** FOR LOCAL CURRENCY FUEL COSTS	:	0.95
SCF** FOR LOCAL CURRENCY POWER COSTS	:	0.75

* - "Fuel Units" must be the same as those used for "Fuel Prices" in the Financial and Economic Assumption inputs.

** -"SCF = Specific Conversion Factor for converting the market price to the true economic cost

SUGAR MILL ANALYSIS 1

SUGAR MILL #1

SMALL POWER SYSTEM ASSESSMENT

Financial (Equity Only):	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	NPV	Levelize NPV
Capital Investment:	2500000																						
Expenses:																							
O&M:		75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	469449.	75000
Fuel:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Revenues:																							
Power:		1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	6736079	1076166
Profit Before Taxes and Depreciation:		1001166	1001166	1001166	1001166	1001166	1001166	1001166	1001166	1001166	1001166	1001166	1001166	1001166	1001166	1001166	1001166	1001166	1001166	1001166	1001166	6266629	1001166
Depreciation:		125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	782416.	125000
Profit Before Taxes:		876166	876166	876166	876166	876166	876166	876166	876166	876166	876166	876166	876166	876166	876166	876166	876166	876166	876166	876166	876166	5484213	876166
Taxes:		438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	2742106	438083
Profit After Taxes:		438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	438083	2742106	438083
Net Cash Flow:	-3E+06	563083	563083	563083	563083	563083	563083	563083	563083	563083	563083	563083	563083	563083	563083	563083	563083	563083	563083	563083	563083	3524523	563083

Net Present Value: 890889.

Internal Rate of Return: (%) 22.1086

Levelized Costs:

			PER KWH
Weighted Cost of Capital: (%)	15		
Capital Recovery Factor:	0.26952		
Levelized Capital Cost:		673807.	0.02848
Initial Fuel Price:	0		
Levelized Fuel Price:		0	0
Initial O&M Cost:	75000		
Levelized O&M Cost:		75000	0.00317
Total Levelized Cost:			0.03165

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SUGAR MILL ANALYSIS 1

Initial Purchased Power Cost:	0.0455
Levelized Purchased Power Cost:	0.0455

Financial (With Debt):	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	NPV	Levelize NPV
Equity Investment:	757575.																						
Expenses:																							
O&M:		75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	469449.	75000
Fuel:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest:		191666.	188681.	185367.	181689.	177606.	173074.	168044.	162460.	156262.	149382.	141745.	133269.	123860.	113416.	101823.	88955.3	74671.7	58816.9	41218.1	21683.4	1025323	163807.
Revenues:																							
Power:		1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	1076166	6736079	1076166
Profit Before Taxes and Depreciation:		809499.	812484.	815798.	819476.	823559.	828091.	833121.	838705.	844903.	851783.	859420.	867896.	877305.	887749.	899342.	912210.	926494.	942349.	959947.	979482.	5241306	837358.
Depreciation:		125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	125000	782416.	125000
Profit Before Taxes:		684499.	687484.	690798.	694476.	698559.	703091.	708121.	713705.	719903.	726783.	734420.	742896.	752305.	762749.	774342.	787210.	801494.	817349.	834947.	854482.	4458890	712358.
Taxes:		342249.	343742.	345399.	347238.	349279.	351545.	354060.	356852.	359951.	363391.	367210.	371448.	376152.	381374.	387171.	393605.	400747.	408674.	417473.	427241.	2229445	356179.
Profit After Taxes:		342249.	343742.	345399.	347238.	349279.	351545.	354060.	356852.	359951.	363391.	367210.	371448.	376152.	381374.	387171.	393605.	400747.	408674.	417473.	427241.	2229445	356179.
Net Cash Flow:	-757575	440110.	438617.	436960.	435121.	433080.	430814.	428299.	425507.	422408.	418968.	415149.	410911.	406207.	400985.	395188.	388754.	381612.	373685.	364886.	355118.	2667605	426180.
Net Present Value:	1660895																						
Internal Rate of Return: (%)	57.6676																						
Interest and Principal Annual Payment:	218806.																						
Initial Value:		1742424	1715284	1685160	1651721	1614605	1573405	1527674	1476912	1420566	1358023	1288599	1211539	1126002	1031056	925667.	808684.	678833.	534699.	374710.	197122.	9321118	1489155
Interest:		191666.	188681.	185367.	181689.	177606.	173074.	[illegible]	[illegible]	156262.	149382.	141745.	133269.	123860.	113416.	101823.	88955.3	74671.7	58816.9	41218.1	21683.4	1025323	163807.
Principle:		27139.3	30124.6	33438.4	37116.6	41199.4	45731.	[illegible]	[illegible]	62543.6	69423.5	77060.0	85536.6	94945.7	105389.	116982.	129850.	144134.	159989.	177587.	197122.	344256.	54998.9

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Levelized Costs:

Weighted Cost of Capital: (%)	8.37878	Capital Recovery Factor:	0.10473
Capital Charge Rate:	0.15947		
Levelized Capital Cost:		398699.	0.01685
Initial Fuel Price:	0		
Levelized Fuel Price:		0	0
Initial O&M Cost:	75000		
Levelized O&M Cost:		75000	0.00317
Total Levelized Cost:		473699.	0.02002
			========
Initial Purchased Power Cost:	0.0455		
Levelized Purchased Power Cost:			0.0455
			========

Economic:

Capital Investment:

Local Currency (LC):	500000
Foreign Exchange (FX):	1500000

Expenses:																					
LC O&M:		28125	28125	28125	28125	28125	28125	28125	28125	28125	28125	28125	28125	28125	28125	28125	28125	28125	28125	28125	28125
FX O&M:		37500	37500	37500	37500	37500	37500	37500	37500	37500	37500	37500	37500	37500	37500	37500	37500	37500	37500	37500	37500
LC Fuel:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FX Fuel:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FX Interest, etc.:		176189.	176189.	176189.	176189.	176189.	176189.	176189.	176189.	176189.	176189.	176189.	176189.	176189.	176189.	176189.	176189.	176189.	176189.	176189.	176189.
Revenues:																					
LC Power:		443475	443475	443475	443475	443475	443475	443475	443475	443475	443475	443475	443475	443475	443475	443475	443475	443475	443475	443475	443475
FX Power:		591300	591300	591300	591300	591300	591300	591300	591300	591300	591300	591300	591300	591300	591300	591300	591300	591300	591300	591300	591300
Net Economic Cash Flows:																					
Local Currency (LC):	-500000	415350	415350	415350	415350	415350	415350	415350	415350	415350	415350	415350	415350	415350	415350	415350	415350	415350	415350	415350	415350
Foreign Exchange (FX):		377610.	377610.	377610.	377610.	377610.	377610.	377610.	377610.	377610.	377610.	377610.	377610.	377610.	377610.	377610.	377610.	377610.	377610.	377610.	377610.
Total Economic Cash Flows:	-500000	792960.	792960.	792960.	792960.	792960.	792960.	792960.	792960.	792960.	792960.	792960.	792960.	792960.	792960.	792960.	792960.	792960.	792960.	792960.	792960.
	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========

Net Present Value: 5682654

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Internal Rate of Return: 158.592
========

Levelized Costs:

Marginal Return to Capital: (%/yr)	10		
LC Capital Recovery Factor:	0.11745		
Interest, Fees, etc. on FX : (%/yr)	10		
FX Capital Recovery Factor:	0.11745		
LC Levelized Capital Cost:		58729.8	0.00248
FX Levelized Capital Cost:		176189.	0.00744
Initial LC Fuel Price:	0		
Levelized LC Fuel Price:		0	0
Initial FX Fuel Price:	0		
Levelized FX Fuel Price:		0	0
Initial LC O&M Cost:	28125		
Levelized LC O&M Cost:		28125	0.00118
Initial FX O&M Cost:	37500		
Levelized FX O&M Cost:		37500	0.00158
Total LC Levelized Cost:			0.00367
Total FX Levelized Cost:			0.00903
Total Levelized Cost:			0.01270
			========

		Total	per kWh
Initial LC Power Cost:	443475	----------	
Levelized LC Power Cost:		443475	0.01875
Initial FX Power Cost:	591300		
Levelized FX Power Cost:		591300	0.025
Total Power Cost:			0.04375
			=========

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SUGAR MILL ANALYSIS 2

TECHNOLOGY ASSUMPTIONS: POWER ONLY SYSTEM

TECHNOLOGY DESCRIPTION	:	Sugar Mill 2: Major
SYSTEM SIZE (kW)	:	13,500
ANNUAL CAPACITY FACTOR (Fraction)	:	0.27
HEAT RATE (Fuel Units*/kWh)	:	0.01706
CAPITAL COST (Local Currency / kW)	:	480 US$
ANNUAL NON-FUEL O&M COST (Fraction of CAPITAL COST)	:	0.03
SYSTEM LIFE (Years)	:	20
ANNUAL POWER OUTPUT (kWh/YR) (Calculated)	:	31,930,200

* - "Fuel Units" must be the same as those used for "Fuel Prices" in the Financial and Economic Assumption inputs.

FINANCIAL ASSUMPTIONS: POWER ONLY SYSTEM

MARKET EXCHANGE RATE (Local Currency/US$)	:	1 US$
AFTER-TAX COST OF EQUITY	:	15
COST OF DEBT (%)	:	11
DEBT-TO-EQUITY RATIO	:	2.3
INITIAL FUEL PRICE (Local Currency / Fuel Unit*)	:	1 US$
ANNUAL FUEL PRICE INFLATION (% / yr)	:	0
INITIAL POWER PRICE (Local Currency / kWh)	:	0.0455
ANNUAL POWER PRICE INFLATION (% / yr)	:	0
ANNUAL O&M COST INFLATION (% / yr)	:	0
MARGINAL TAX RATE (%)	:	50

* - "Fuel Units" must be the same as those used for "Fuel Prices" in the Financial and Economic Assumption inputs.

ECONOMIC ASSUMPTIONS: POWER ONLY SYSTEM

SUGAR MILL ANALYSIS 2

REAL EXCHANGE RATE (Local Currency / US$)	:	1	US$
MARGINAL RETURN TO CAPITAL (%)	:	10	
FRACTION OF CAPITAL COST IN FOREIGN EXCHANGE	:	0.6	
INTEREST, FEES, ETC. ON FOREX CAPITAL COST (%/YR)	:	10	
FRACTION OF O&M COST IN FOREIGN EXCHANGE	:	0.5	
O&M COST ESCALATION RATE (%/YR)	:	0	
ECONOMIC FUEL COST (Local Currency / Fuel Unit*)	:	2	Tow US$
FRACTION OF FUEL COST IN FOREX	:	0.95	
FUEL COST ESCALATION RATE (% / yr)	:	0	
ECONOMIC POWER COST (Local Currency / kWh)	:	0.05	US$
FRACTION OF POWER COST IN FOREX	:	0.5	
POWER COST ESCALATION RATE (% / yr)	:	0	
SCF** FOR LOCAL CURRENCY O&M COSTS	:	0.75	
SCF** FOR LOCAL CURRENCY CAPITAL COSTS	:	0.5	
SCF** FOR LOCAL CURRENCY FUEL COSTS	:	0.95	
SCF** FOR LOCAL CURRENCY POWER COSTS	:	0.75	

* - "Fuel Units" must be the same as those used for "Fuel Prices" in the Financial and Economic Assumption inputs.

** -"SCF = Specific Conversion Factor for converting the market price to the true economic cost

SUGAR MILL ANALYSIS 2

SMALL POWER SYSTEM ASSESSMENT

Financial (Equity Only):	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	NPV	Levelize NPV
Capital Investment:	6480000																						
Expenses:																							
O&M:		194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	1216814	194400
Fuel:		544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	3409640	544729.
Revenues:																							
Power:		1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	9093707	1452824
Profit Before Taxes and Depreciation:		713694.	713694.	713694.	713694.	713694.	713694.	713694.	713694.	713694.	713694.	713694.	713694.	713694.	713694.	713694.	713694.	713694.	713694.	713694.	713694.	4467252	713694.
Depreciation:		324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	2028023	324000
Profit Before Taxes:		389694.	389694.	389694.	389694.	389694.	389694.	389694.	389694.	389694.	389694.	389694.	389694.	389694.	389694.	389694.	389694.	389694.	389694.	389694.	389694.	2439229	389694.
Taxes:		194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	1219614	194847.
Profit After Taxes:		194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	194847.	1219614	194847.
Net Cash Flow:	-6E+06	518847.	518847.	518847.	518847.	518847.	518847.	[illegible]	518847.	518847.	518847.	518847.	518847.	518847.	518847.	518847.	518847.	518847.	518847.	518847.	518847.	3247638	518847.
Net Present Value:	-3E+06																						
Internal Rate of Return: (%)	4.97448																						

Levelized Costs:

			PER KWH
Weighted Cost of Capital: (%)	15		
Capital Recovery Factor.	0.26952		
Levelized Capital Cost:		1746508	0.05469
Initial Fuel Price:	544729.		
Levelized Fuel Price:		544729.	0.01706
Initial O&M Cost:	194400		
Levelized O&M Cost:		194400	0.00608
Total Levelized Cost:			0.07784

Initial Purchased Power

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SUGAR MILL ANALYSIS 2

Cost:	0.0455
Levelized Purchased Power Cost:	0.0455

Financial (With Debt):	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	NPV	Levelize NPV
Equity Investment:	1963636																						
Expenses:																							
O&M:		194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	194400	1216814	194400
Fuel:		544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	544729.	3409640	544729.
Interest:		496800	489062.	480472.	470938.	460356.	448609.	435570.	421097.	405031.	387199.	367405.	345434.	321045.	293974.	263926.	230572.	193549.	152453.	106837.	56203.5	2657637	424588.
Revenues:																							
Power:		1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	1452824	9093707	1452824
Profit Before Taxes and Depreciation:		216894.	224632.	233222.	242755.	253338.	265085.	278124.	292597.	308662.	326495.	346289.	368200.	392648.	419719.	449768.	483122.	520145.	561241.	606857.	657491.	1809615	289106.
Depreciation:		324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	324000	2028023	324000
Profit Before Taxes:		-107105	-99367.	-90777.	-81244.	-70661.	-58914.	-45875.	-31402.	-15337.	2495.36	22289.3	44260.7	68648.3	95719.9	125768.	159122.	196145.	237241.	282857.	333491.	-218407	-34893.
Taxes:		-53552.	-49683.	-45388.	-40622.	-35330.	-29457.	-22937.	-15701.	-7668.5	1247.68	11144.6	22130.3	34324.4	47859.9	62884.3	79561.3	98072.8	118620.	141428.	166745.	-109203	-17446.
Profit After Taxes:		-53552.	-49683.	-45388.	-40622.	-35330.	-29457.	-22937.	-15701.	-7668.5	1247.68	11144.6	22130.3	34324.4	47859.9	62884.3	79561.3	98072.8	118620.	141428.	166745.	-109203	-17446.
Net Cash Flow:	-2E+06	200102.	196233.	191938.	187171.	181880.	176006.	169487.	162250.	154218.	145301.	135404.	124419.	112225.	98689.6	83665.3	66988.2	48476.7	27928.9	5120.92	-20196.	1026506	163996.
Net Present Value:	-814895																						
Internal Rate of Return:	3.10383																						
Interest and Principal Annual Payment:	567145.																						
Initial Value:		4516363	4446018	4367935	4281262	4185056	4078267	3959731	3828156	3682108	3519995	3340049	3140310	2918599	2672499	2399329	2096110	1759537	1385941	971249.	510941.	2E+07	3859891
Interest:		496800	489062.	480472.	470938.	460356.	448609.	435570.	421097.	405031.	387199.	367405.	345434.	321045.	293974.	263926.	230572.	193549.	152453.	106837.	56203.5	2657637	424588.
Principle:		70345.2	78083.2	86672.3	96206.3	106789.	118535.	131574.	146047.	162113.	179945.	199739.	221711.	246099.	273170.	303219.	336573.	373596.	414691.	460307.	510941.	892312.	142557.

Levelized Costs:

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Weighted Cost of Capital: (%)	8.37878	Capital Recovery Factor:	0.1047
Capital Charge Rate:	0.15947		
Levelized Capital Cost:		1033429	0.03236
Initial Fuel Price:	544729.		
Levelized Fuel Price:		544729.	0.01706
Initial O&M Cost:	194400		
Levelized O&M Cost:		194400	0.00608
Total Levelized Cost:		1772558	0.05551
			========
Initial Purchased Power Cost:	0.0455		
Levelized Purchased Power Cost:			0.0455
			========

Economic:

Capital Investment:

Local Currency (LC):	1296000
Foreign Exchange (FX):	3888000

Expenses:

LC O&M:	72900	72900	72900	72900	72900	72900	72900	72900	72900	72900	72900	72900	72900	72900	72900	72900	72900	72900	72900	72900
FX O&M:	97200	97200	97200	97200	97200	97200	97200	97200	97200	97200	97200	97200	97200	97200	97200	97200	97200	97200	97200	97200
LC Fuel:	51749.2	51749.2	51749.2	51749.2	51749.2	51749.2	51749.2	51749.2	51749.2	51749.2	51749.2	51749.2	51749.2	51749.2	51749.2	51749.2	51749.2	51749.2	51749.2	51749.2
FX Fuel:	1034985	1034985	1034985	1034985	1034985	1034985	1034985	1034985	1034985	1034985	1034985	1034985	1034985	1034985	1034985	1034985	1034985	1034985	1034985	1034985
FX Interest, etc.:	456683.	456683.	456683.	456683.	456683.	456683.	456683.	456683.	456683.	456683.	456683.	456683.	456683.	456683.	456683.	456683.	456683.	456683.	456683.	456683.

Revenues:

LC Power:	598691.	598691.	598691.	598691.	598691.	598691.	598691.	598691.	598691.	598691.	598691.	598691.	598691.	598691.	598691.	598691.	598691.	598691.	598691.	598691.
FX Power:	798255	798255	798255	798255	798255	798255	798255	798255	798255	798255	798255	798255	798255	798255	798255	798255	798255	798255	798255	798255

Net Economic Cash Flows:

Local Currency (LC):	-1E+06	474041.	474041.	474041.	474041.	474041.	474041.	474041.	474041.	474041.	474041.	474041.	474041.	474041.	474041.	474041.	474041.	474041.	474041.	474041.	474041.
Foreign Exchange (FX):	*	-790613	-790613	-790613	-790613	-790613	-790613	-790613	-790613	-790613	-790613	-790613	-790613	-790613	-790613	-790613	-790613	-790613	-790613	-790613	-790613
Total Economic Cash Flows:	-1E+06	-316571	-316571	-316571	-316571	-316571	-316571	-316571	-316571	-316571	-316571	-316571	-316571	-316571	-316571	-316571	-316571	-316571	-316571	-316571	-316571

Net Present Value:	-4E+06
	========
Internal Rate of Return:	ERR
	========

Levelized Costs:

Marginal Return to Capital: (%/yr)	10		
LC Capital Recovery Factor:	0.11745		
Interest, Fees, etc. on FX : (%/yr)	10		
FX Capital Recovery Factor:	0.11745		
LC Levelized Capital Cost:		152227.	0.00476
FX Levelized Capital Cost:		456683.	0.01430
Initial LC Fuel Price:	51749.2		
Levelized LC Fuel Price:		51749.2	0.00162
Initial FX Fuel Price:	1034985		
Levelized FX Fuel Price:		1034985	0.03241
Initial LC O&M Cost:	72900		
Levelized LC O&M Cost:		72900	0.00228
Initial FX O&M Cost:	97200		
Levelized FX O&M Cost:		97200	0.00304
Total LC Levelized Cost:			0.00867
Total FX Levelized Cost:			0.04976
Total Levelized Cost:			0.05843
			========

		Total	per kWh
Initial LC Power Cost:	598691.	----------	
Levelized LC Power Cost:		598691.	0.01875
Initial FX Power Cost:	798255		
Levelized FX Power Cost:		798255	0.025
Total Power Cost:			0.04375
			=========

```
 1 TECHNOLOGY ASSUMPTIONS: POWER ONLY SYSTEM
 2 ------------------------------------------
 3
 4 TECHNOLOGY DESCRIPTION                          :Matamoros
 5
 6 SYSTEM SIZE (kW)                                :      15,000
 7 ANNUAL CAPACITY FACTOR (Fraction)               :         0.6
 8 HEAT RATE (Fuel Units*/kWh)                     :           0
 9
10 CAPITAL COST (Local Currency / kW)              :        1000 US$
11 ANNUAL NON-FUEL O&M COST                        :        0.02
12       (Fraction of CAPITAL COST)
13 SYSTEM LIFE (Years)                             :          20
14 ANNUAL POWER OUTPUT (kWh/YR)                    : 78,840,000
15        (Calculated)
16 * - "Fuel Units" must be the same as those used
17     for "Fuel Prices" in the Financial and
18     Economic Assumption inputs.
19
20
21 FINANCIAL ASSUMPTIONS: POWER ONLY SYSTEM
22 ---------------------------------------
23
24 MARKET EXCHANGE RATE (Local Currency/US$)       :           1 US$
25 AFTER-TAX COST OF EQUITY                        :          15
26 COST OF DEBT (%)                                :          11
27 DEBT-TO-EQUITY RATIO                            :         2.3
28
29 INITIAL FUEL PRICE                              :           0 US$
30       (Local Currency / Fuel Unit*)
31 ANNUAL FUEL PRICE INFLATION (% / yr)            :           0
32 INITIAL POWER PRICE (Local Currency / kWh)      :      0.0455
33 ANNUAL POWER PRICE INFLATION (% / yr)           :           0
34
35 ANNUAL O&M COST INFLATION (% / yr)              :           0
36
37 MARGINAL TAX RATE (%)                           :          50
38
39
40
41
42 * - "Fuel Units" must be the same as those used
43     for "Fuel Prices" in the Financial and
44     Economic Assumption inputs.
45
46
47
48 ECONOMIC ASSUMPTIONS: POWER ONLY SYSTEM
49 -------------------------------------
50
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51 REAL EXCHANGE RATE (Local Currency / US$)      :          1 US$
52 MARGINAL RETURN TO CAPITAL (%)                 :         10
53
54 FRACTION OF CAPITAL COST IN FOREIGN EXCHANGE   :        0.3
55 INTEREST, FEES, ETC. ON FOREX                  :         10
56       CAPITAL COST (%/YR)
57 FRACTION OF O&M COST IN FOREIGN EXCHANGE       :        0.1
58 O&M COST ESCALATION RATE (%/YR)                :          0
59 ECONOMIC FUEL COST                             :          0 low
60       (Local Currency / Fuel Unit*)                         US$
61 FRACTION OF FUEL COST IN FOREX                 :          0
62 FUEL COST ESCALATION RATE (% / yr)             :          0
63 ECONOMIC POWER COST                            :       0.05 US$
64       (Local Currency / KWh)
65 FRACTION OF POWER COST IN FOREX                :        0.5
66 POWER COST ESCALATION RATE (% / yr)            :          0
67
68 SCF** FOR LOCAL CURRENCY O&M COSTS             :       0.75
69 SCF** FOR LOCAL CURRENCY CAPITAL COSTS         :        0.5
70 SCF** FOR LOCAL CURRENCY FUEL COSTS            :       0.95
71 SCF** FOR LOCAL CURRENCY POWER COSTS           :       0.75
72
73 * - "Fuel Units" must be the same as those used
74     for "Fuel Prices" in the Financial and
75     Economic Assumption inputs.
76
77 ** -"SCF = Specific Conversion Factor for converting
78      the market price to the true economic cost
```


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MATAMOROS ANALYSIS

SMALL POWER SYSTEM ASSESSMENT

Financial (Equity Only):	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	NPV	Levelize NPV
Capital Investment:	2E+07																						
Expenses:																							
O&M:		300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	1877799	300000
Fuel:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Revenues:																							
Power:		3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	2E+07	3587220
Profit Before Taxes and Depreciation:		3287220	3287220	3287220	3287220	3287220	3287220	3287220	3287220	3287220	3287220	3287220	3287220	3287220	3287220	3287220	3287220	3287220	3287220	3287220	3287220	2E+07	3287220
Depreciation:		750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	4694498	750000
Profit Before Taxes:		2537220	2537220	2537220	2537220	2537220	2537220	2537220	2537220	2537220	2537220	2537220	2537220	2537220	2537220	2537220	2537220	2537220	2537220	2537220	2537220	2E+07	2537220
Taxes:		1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	7940650	1268610
Profit After Taxes:		1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	1268610	7940650	1268610
Net Cash Flow:	-2E+07	2018610	2018610	2018610	2018610	2018610	2018610	2018610	2018610	2018610	2018610	2018610	2018610	2018610	2018610	2018610	2018610	2018610	2018610	2018610	2018610	1E+07	2018610
Net Present Value:	-2E+06																						
Internal Rate of Return: (%)	12.0827																						

Levelized Costs:

		PER KWH
Weighted Cost of Capital: (%)	15	
Capital Recovery Factor:	0.26952	
Levelized Capital Cost:	4042844	0.05127
Initial Fuel Price:	0	
Levelized Fuel Price:	0	0
Initial O&M Cost:	300000	
Levelized O&M Cost:	300000	0.00380
Total Levelized Cost:		0.05508

Initial Purchased Power

MATAMOROS ANALYSIS

Cost:	0.0455
Levelized Purchased Power Cost:	0.0455

Financial (With Debt):	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	NPV	Levelize NPV
Equity Investment:	4545454																						
Expenses:																							
O&M:		300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	300000	[illegible]	[illegible]
Fuel:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest:		1150000	1132038	1112205	1090136	1065639	1038447	1008264	974762.	937574.	896295.	850475.	799616.	743161.	680497.	610940.	533731.	448030.	352901.	247308.	130100.	6151938	982842.
Revenues:																							
Power:		3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	3587220	2E+07	3587220
Profit Before Taxes and Depreciation:		2137220	2155131	2175014	2197083	2221580	2248772	2278955	2312457	2349645	2390924	2436744	2487603	2544058	2606722	2676279	2753489	2839189	2934318	3039911	3157119	1E+07	2304377
Depreciation:		750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	750000	4694498	750000
Profit Before Taxes:		1387220	1405131	1425014	1447083	1471580	1498772	1528955	1562457	1599645	1640924	1686744	1737603	1794058	1856722	1926279	2003488	2089189	2184318	2289911	2407119	9729362	1554377
Taxes:		693610	702565.	712507.	723541.	735790.	749386.	764477.	781228.	799822.	820462.	843372.	868801.	897029.	928361.	963139.	1001744	1044594	1092159	1144955	1203559	4864681	777188.
Profit After Taxes:		693610	702565.	712507.	723541.	735790.	749386.	[illegible]477.	781228.	799822.	820462.	843372.	868801.	897029.	928361.	963139.	1001744	1044594	1092159	1144955	1203559	4864681	777188.
Net Cash Flow:	-5E+06	1280773	1271817	1261876	1250841	1238593	1224997	1209906	1193154	1174560	1153921	1131011	1105581	1077354	1046022	1011243	972639.	929768.	882224.	829428.	770824.	7493641	1197195
Net Present Value:	2563640																						
Internal Rate of Return: (%)	26.8898																						
Interest and Principal Annual Payment:	1312836																						
Initial Value:		1E+07	1E+07	1E+07	9910330	9687630	9440433	9166045	8861474	8523400	8148138	7731596	7269236	6756016	6186341	5554003	4852107	4073003	3208197	2248262	1182735	6E+07	8934933
Interest:		1150000	1132038	1112205	1090136	1065639	1038447	1008264	974762.	937574.	896295.	850475.	799616.	743161.	680497.	610940.	533731.	448030.	352901.	247308.	130100.	6151938	982842.
Principle:		162836.	180748.	200630.	222699.	247196.	274388.	304571.	338074.	375262.	416541.	462360.	513220.	569674.	632338.	701895.	779104.	864805.	959934.	1065527	1182735	2065538	329993.

Levelized Costs:

Weighted Cost of Capital: (%)	6.37878	Capital Recovery Factor:	0.10473
Capital Charge Rate:	0.15947		
Levelized Capital Cost:		2692197	0.03034
Initial Fuel Price:	0		
Levelized Fuel Price:		0	0
Initial O&M Cost:	300000		
Levelized O&M Cost:		300000	0.00380
Total Levelized Cost:		2692197	0.03414
			========
Initial Purchased Power Cost:	0.0455		
Levelized Purchased Power Cost:			0.0455
			========

Economic:

Capital Investment:

Local Currency (LC):	5250000
Foreign Exchange (FX):	4500000

Expenses:

LC O&M:	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500
FX O&M:	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000
LC Fuel:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FX Fuel:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FX Interest, etc.:	528568.	528568.	528568.	528568.	528568.	528568.	528568.	528568.	528568.	528568.	528568.	528568.	528568.	528568.	528568.	528568.	528568.	528568.	528568.	528568.

Revenues:

LC Power:	1478250	1478250	1478250	1478250	1478250	1478250	1478250	1478250	1478250	1478250	1478250	1478250	1478250	1478250	1478250	1478250	1478250	1478250	1478250	1478250
FX Power:	1971000	1971000	1971000	1971000	1971000	1971000	1971000	1971000	1971000	1971000	1971000	1971000	1971000	1971000	1971000	1971000	1971000	1971000	1971000	1971000

Net Economic Cash Flows:

Local Currency (LC):	-5E+06	1275750	1275750	1275750	1275750	1275750	1275750	1275750	1275750	1275750	1275750	1275750	1275750	1275750	1275750	1275750	1275750	1275750	1275750	1275750
Foreign Exchange (FX):		1412431	1412431	1412431	1412431	1412431	1412431	1412431	1412431	1412431	1412431	1412431	1412431	1412431	1412431	1412431	1412431	1412431	1412431	1412431
Total Economic Cash Flows:	-5E+06	2688181	2688181	2688181	2688181	2688181	2688181	2688181	2688181	2688181	2688181	2688181	2688181	2688181	2688181	2688181	2688181	2688181	2688181	2688181

Net Present Value:	2E+07
	========
Internal Rate of Return:	51.1903
	========

Levelized Costs:

Marginal Return to Capital: (%/yr)	10		
LC Capital Recovery Factor:	0.11745		
Interest, Fees, etc. on FX : (%/yr)	10		
FX Capital Recovery Factor:	0.11745		
LC Levelized Capital Cost:		616663.	0.00782
FX Levelized Capital Cost:		528568.	0.00670
Initial LC Fuel Price:	0		
Levelized LC Fuel Price:		0	0
Initial FX Fuel Price:	0		
Levelized FX Fuel Price:		0	0
Initial LC O&M Cost:	202500		
Levelized LC O&M Cost:		202500	0.00256
Initial FX O&M Cost:	30000		
Levelized FX O&M Cost:		30000	0.00038
Total LC Levelized Cost:			0.01039
Total FX Levelized Cost:			0.00708
Total Levelized Cost:			0.01747
			========

		Total	per kWh
Initial LC Power Cost:	1478250		----------
Levelized LC Power Cost:		1478250	0.01875
Initial FX Power Cost:	1971000		
Levelized FX Power Cost:		1971000	0.025
Total Power Cost:			0.04375
			=========

HENDROTHERMAL ANALYSIS

TECHNOLOGY ASSUMPTIONS: POWER ONLY SYSTEM

TECHNOLOGY DESCRIPTION	:	Hendrothermal
SYSTEM SIZE (KW)	:	5.000
ANNUAL CAPACITY FACTOR (Fraction)	:	0.6
HEAT RATE (Fuel Units*/kWh)	:	0.01706
CAPITAL COST (Local Currency / kW)	:	1280 US$
ANNUAL NON-FUEL O&M COST (Fraction of CAPITAL COST)	:	0.03
SYSTEM LIFE (Years)	:	20
ANNUAL POWER OUTPUT (kWh/YR) (Calculated)	:	26,280,000

* - "Fuel Units" must be the same as those used for "Fuel Prices" in the Financial and Economic Assumption inputs.

FINANCIAL ASSUMPTIONS: POWER ONLY SYSTEM

MARKET EXCHANGE RATE (Local Currency/US$)	:	1 US$
AFTER-TAX COST OF EQUITY	:	15
COST OF DEBT (%)	:	11
DEBT-TO-EQUITY RATIO	:	2.3
INITIAL FUEL PRICE (Local Currency / Fuel Unit*)	:	2.88 US$
ANNUAL FUEL PRICE INFLATION (% / yr)	:	0
INITIAL POWER PRICE (Local Currency / kWh)	:	0.0455
ANNUAL POWER PRICE INFLATION (% / yr)	:	0
ANNUAL O&M COST INFLATION (% / yr)	:	0
MARGINAL TAX RATE (%)	:	50

* - "Fuel Units" must be the same as those used for "Fuel Prices" in the Financial and Economic Assumption inputs.

ECONOMIC ASSUMPTIONS: POWER ONLY SYSTEM

DENDROTHERMAL ANALYSIS

REAL EXCHANGE RATE (Local Currency / US$)	:	1 US$
MARGINAL RETURN TO CAPITAL (%)	:	10
FRACTION OF CAPITAL COST IN FOREIGN EXCHANGE	:	0.6
INTEREST, FEES, ETC. ON FOREX CAPITAL COST (%/YR)	:	10
FRACTION OF O&M COST IN FOREIGN EXCHANGE	:	0.5
O&M COST ESCALATION RATE (%/YR)	:	0
ECONOMIC FUEL COST (Local Currency / Fuel Unit*)	:	2.16 low US$
FRACTION OF FUEL COST IN FOREX	:	0.95
FUEL COST ESCALATION RATE (% / yr)	:	0
ECONOMIC POWER COST (Local Currency / kWh)	:	0.05 US$
FRACTION OF POWER COST IN FOREX	:	0.5
POWER COST ESCALATION RATE (% / yr)	:	0
SCF** FOR LOCAL CURRENCY O&M COSTS	:	0.75
SCF** FOR LOCAL CURRENCY CAPITAL COSTS	:	0.5
SCF** FOR LOCAL CURRENCY FUEL COSTS	:	0.95
SCF** FOR LOCAL CURRENCY POWER COSTS	:	0.75

* - "Fuel Units" must be the same as those used for "Fuel Prices" in the Financial and Economic Assumption inputs.

** -"SCF = Specific Conversion Factor for converting the market price to the true economic cost

SMALL POWER SYSTEM ASSESSMENT

Financial (Equity Only):	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	NPV	Levelized NPV
Capital Investment:	6400000																						
Expenses:																							
O&M:		192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	1201791	192000
Fuel:		1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	8082111	1291209
Revenues:																							
Power:		1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	7484533	1195740
Profit Before Taxes and Depreciation:		-287469	-287469	-287469	-287469	-287469	-287469	-287469	-287469	-287469	-287469	-287469	-287469	-287469	-287469	-287469	-287469	-287469	-287469	-287469	-287469	-2E+06	-287469
Depreciation:		320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	2002966	320000
Profit Before Taxes:		-607469	-607469	-607469	-607469	-607469	-607469	-607469	-607469	-607469	-607469	-607469	-607469	-607469	-607469	-607469	-607469	-607469	-607469	-607469	-607469	-4E+06	-607469
Taxes:		-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-2E+06	-303734
Profit After Taxes:		-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-303734	-2E+06	-303734
Net Cash Flow:	-6E+06	16265.0	16265.0	16265.0	16265.0	16265.0	16265.0	16265.0	16265.0	16265.0	16265.0	16265.0	16265.0	16265.0	16265.0	16265.0	16265.0	16265.0	16265.0	16265.0	16265.0	101808.	16265.0

Net Present Value: -5E+06

Internal Rate of Return: -19.575 (%)

Levelized Costs:

		PER KWH
Weighted Cost of Capital: (%)	15	
Capital Recovery Factor:	0.26952	
Levelized Capital Cost:	1724946	0.06563
Initial Fuel Price:	1291209	
Levelized Fuel Price:	1291209	0.04913
Initial O&M Cost:	192000	
Levelized O&M Cost:	192000	0.00730
Total Levelized Cost:		0.12207

Initial Purchased Power

DENDROTHERMAL ANALYSIS

Cost:	0.0455
Levelized Purchased Power Cost:	0.0455

Financial (With Debt):	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	NPV	Levelize NPV
Equity Investment:	1939393																						
Expenses:																							
O&M:		192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	192000	1201791	192000
Fuel:		1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	1291209	8082111	1291209
Interest:		490666.	483024.	474541.	465124.	454672.	443071.	430193.	415898.	400031.	382419.	362869.	341169.	317082.	290345.	260667.	227725.	191159.	150571.	105518.	55509.7	2624827	419346.
Revenues:																							
Power:		1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	1195740	7484533	1195740
Profit Before Taxes and Depreciation:		-778136	-770494	-762011	-752594	-742142	-730541	-717663	-703368	-687501	-669889	-650339	-628639	-604552	-577815	-548137	-515195	-478629	-438041	-392988	-342979	-4E+06	-706816
Depreciation:		320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	320000	2002996	320000
Profit Before Taxes:		-1E+06	-1E+06	-1E+06	-1E+06	-1E+06	-1E+06	-1E+06	-1E+06	-1E+06	-989889	-970339	-948639	-924552	-897815	-868137	-835195	-798629	-758041	-712988	-662979	-6E+06	-1E+06
Taxes:		-549068	-545247	-541005	-536297	-531071	-525270	-518831	-511684	-503750	-494944	-485169	-474319	-462276	-448907	-434068	-417597	-399314	-379020	-356494	-331489	-3E+06	-513408
Profit After Taxes:		-549068	-545247	-541005	-536297	-531071	-525270	-518831	-511684	-503750	-494944	-485169	-474319	-462276	-448907	-434068	-417597	-399314	-379020	-356494	-331489	-3E+06	-513408
Net Cash Flow:	-2E+06	-298545	-302366	-306607	-311316	-316542	-322342	-328781	-335929	-343862	-352668	-362443	-373293	-385337	-398705	-413544	-430015	-448298	-468592	-491119	-516123	-2E+06	-334295
Net Present Value:	-4E+06																						
Internal Rate of Return: (%)	ERR																						
Interest and Principal Annual Payment:	560143.																						
Initial Value:		4460606	4391129	4314010	4228407	4133389	4027918	3910346	3780895	3636650	3476538	3298814	3101540	2882566	[illegible]	[illegible]	[illegible]	1737814	1368830	959258.	504633.	2E+07	3812238
Interest:		490666.	483024.	474541.	465124.	454672.	443071.	430193.	415898.	400031.	382419.	362869.	341169.	317082.	[illegible]	[illegible]	227725.	191159.	150571.	105518.	55509.7	2624827	419346.
Principle:		69476.7	77119.2	85602.3	95018.5	105470.	117072.	129950.	144244.	160111.	177724.	197273.	218973.	243061.	269797.	299475.	332417.	368983.	409572.	454624.	504633.	881296.	140797.

Levelized Costs:

Weighted Cost of Capital: (%)	8.37878		Capital Recovery Factor:0.10473
Capital Charge Rate:	0.15947		
Levelized Capital Cost:		1020671	0.03883
Initial Fuel Price:	1291209		
Levelized Fuel Price:		1291209	0.04913
Initial O&M Cost:	192000		
Levelized O&M Cost:		192000	0.00730
Total Levelized Cost:		2503881	0.09527
			========
Initial Purchased Power Cost:	0.0455		
Levelized Purchased Power Cost:			0.0455
			========

Economic:

Capital Investment:

Local Currency (LC):	1280000
Foreign Exchange (FX):	3840000

Expenses:

LC O&M:	72000	72000	72000	72000	72000	72000	72000	72000	72000	72000	72000	72000	72000	72000	72000	72000	72000	72000	72000	72000
FX O&M:	96000	96000	96000	96000	96000	96000	96000	96000	96000	96000	96000	96000	96000	96000	96000	96000	96000	96000	96000	96000
LC Fuel:	45999.3	45999.3	45999.3	45999.3	45999.3	45999.3	45999.3	45999.3	45999.3	45999.3	45999.3	45999.3	45999.3	45999.3	45999.3	45999.3	45999.3	45999.3	45999.3	45999.3
FX Fuel:	919987.	919987.	919987.	919987.	919987.	919987.	919987.	919987.	919987.	919987.	919987.	919987.	919987.	919987.	919987.	919987.	919987.	919987.	919987.	919987.
FX Interest, etc.:	451044.	451044.	451044.	451044.	451044.	451044.	451044.	451044.	451044.	451044.	451044.	451044.	451044.	451044.	451044.	451044.	451044.	451044.	451044.	451044.

Revenues:

LC Power:	492750	492750	492750	492750	492750	492750	492750	492750	492750	492750	492750	492750	492750	492750	492750	492750	492750	492750	492750	492750
FX Power:	657000	657000	657000	657000	657000	657000	657000	657000	657000	657000	657000	657000	657000	657000	657000	657000	657000	657000	657000	657000

Net Economic Cash Flows:

Local Currency (LC):	-1E+06	374750.	374750.	374750.	374750.	374750.	374750.	374750.	374750.	374750.	374750.	374750.	374750.	374750.	374750.	374750.	374750.	374750.	374750.	374750.
Foreign Exchange (FX):*		-810032	-810032	-810032	-810032	-810032	-810032	-810032	-810032	-810032	-810032	-810032	-810032	-810032	-810032	-810032	-810032	-810032	-810032	-810032
Total Economic Cash Flows:	-1E+06	-435281	-435281	-435281	-435281	-435281	-435281	-435281	-435281	-435281	-435281	-435281	-435281	-435281	-435281	-435281	-435281	-435281	-435281	-435281

==========

Net Present Value:	-5E+06
	========
Internal Rate of Return:	ERR
	========

Levelized Costs:

Marginal Return to Capital: (%/yr)	10		
LC Capital Recovery Factor:	0.11745		
Interest, Fees, etc. on FX : (%/yr)	10		
FX Capital Recovery Factor:	0.11745		
LC Levelized Capital Cost:		150348.	0.00572
FX Levelized Capital Cost:		451044.	0.01716
Initial LC Fuel Price:	45999.3		
Levelized LC Fuel Price:		45999.3	0.00175
Initial FX Fuel Price:	919987.		
Levelized FX Fuel Price:		919987.	0.03500
Initial LC O&M Cost:	72000		
Levelized LC O&M Cost:		72000	0.00273
Initial FX O&M Cost:	96000		
Levelized FX O&M Cost:		96000	0.00365
Total LC Levelized Cost:			0.01021
Total FX Levelized Cost:			0.05582
Total Levelized Cost:			0.06603
			========

		total	per kWh
Initial LC Power Cost:	492750		
Levelized LC Power Cost:		492750	0.01875
Initial FX Power Cost:	657000		
Levelized FX Power Cost:		657000	0.025
Total Power Cost:			0.04375
			=========

TECHNOLOGY ASSUMPTIONS: COGENERATION SYSTEM

TECHNOLOGY DESCRIPTION	:Number	
SYSTEM SIZE (Steam Units/Hr)	: 37	mmBtu
ANNUAL CAPACITY FACTOR (Fraction)	: 0.56	
COGEN EFFICIENCY (Fuel Units* / Steam Unit)	: 1.447	mmBtu
1/(NON-COGEN EFFICIENCY) (Fuel Units* / Steam Unit)	: 1.33	
ELECTRIC-TO-THERMAL RATIO	: 0.1	
THEORETICAL STEAM UNITS / kWh **	: 0.002412	mmBtu/kW
COGEN SYSTEM CAPITAL COST (Local Currency / Steam Unit)	: 13500	
ANNUAL COGEN NON-FUEL O&M COST (Fraction of CAPITAL COST)	: 0.05	reduced f zero non-
COGEN SYSTEM LIFE (Years)	: 20	
NON-COGEN SYSTEM CAPITAL COST (Local Currency / Steam Unit)	: 0	
ANNUAL NON-COGEN NON-FUEL O&M COST (Fraction of CAPITAL COST)	: 0.05	
NON-COGEN SYSTEM LIFE (Years)	: 20	
COGEN SYSTEM POWER OUTPUT (kWh/YR) (Calculated)	: 5,319,672	

* - "Fuel Units" must be the same as those used for "Fuel Prices" in the Financial and Economic Assumption inputs.

** - This is the theoretical number of steam units per kWh, ignoring conversion losses; e.g. if the steam units were in btu, the value would be 3412 (btu/kWh)

FINANCIAL ASSUMPTIONS: COGENERATION SYSTEM

MARKET EXCHANGE RATE (Local Currency/US$)	: 1
AFTER-TAX COST OF EQUITY (%)	: 15
COST OF DEBT (%)	: 11
DEBT-TO-EQUITY RATIO	: 2.3
INITIAL COGEN SYSTEM FUEL PRICE (Local Currency / Fuel Unit*)	: 3.06
ANNUAL COGEN FUEL PRICE INFLATION (% / yr)	: 0
INITIAL NON-COGEN SYSTEM FUEL PRICE (Local Currency / Fuel Unit*)	: 3.06
ANNUAL NON-COGEN SYSTEM FUEL PRICE INFLATION	: 0

(% / yr)		
INITIAL POWER PRICE (Local Currency / kWh)	:	0.0455
ANNUAL POWER PRICE INFLATION (% / yr)	:	0
ANNUAL COGEN O&M COST INFLATION (% / yr)	:	0
ANNUAL NON-COGEN O&M COST INFLATION (% / yr)	:	0
MARGINAL TAX RATE (%)	:	50

* - "Fuel Units" must be the same as those used for "Fuel Prices" in the Financial and Economic Assumption inputs.

ECONOMIC ASSUMPTIONS: COGENERATION SYSTEM

REAL EXCHANGE RATE (Local Currency / US$)	:	1
MARGINAL RETURN TO CAPITAL (%)	:	10
COGEN SYSTEM FRACTION OF CAPITAL COST IN FOREIGN EXCHANGE	:	0.6
COGEN SYSTEM FRACTION OF O&M COST IN FOREIGN EXCHANGE	:	0.6
COGEN ECONOMIC FUEL COST (Local Currency / Fuel Unit*)	:	3.02
COGEN FUEL COST ESCALATION RATE (% / yr)	:	0
COGEN SYSTEM FRACTION OF FUEL COST IN FOREIGN EXCHANGE	:	0.95
NON-COGEN SYSTEM FRACTION OF CAPITAL COST IN FOREIGN EXCHANGE	:	0.6
NON-COGEN SYSTEM FRACTION OF O&M COST IN FOREIGN EXCHANGE	:	0.6
NON-COGEN ECONOMIC FUEL COST (Local Currency / Fuel Unit*)	:	3.02
NON-COGEN FUEL COST ESCALATION RATE (% / yr)	:	0
NON-COGEN SYSTEM FRACTION OF FUEL COST IN FOREIGN EXCHANGE	:	0.95
COGEN/NON-COGEN O&M ESCALATION RATE (%/YR)	:	0
INTEREST, FEES, ETC. ON FOREX CAPITAL COST (%/YR)	:	10

PORTICO ASSESSMENT

ECONOMIC POWER COST (Local Currency / kWh)	:	0.05
POWER COST ESCALATION RATE (% / yr)	:	0
FRACTION OF POWER COST IN FOREX	:	0.5
SCF** FOR LOCAL CURRENCY O&M COSTS	:	0.75
SCF** FOR LOCAL CURRENCY CAPITAL COSTS	:	0.5
SCF** FOR LOCAL CURRENCY POWER COSTS	:	0.75
SCF** FOR LOCAL CURRENCY COGEN FUEL COSTS	:	0.95
SCF** FOR LOCAL CURRENCY NON-COGEN FUEL COSTS	:	0.95

* - "Fuel Units" must be the same as those used for "Fuel Prices" in the Financial and Economic Assumption inputs.

** -"SCF = Specific Conversion Factor for converting the market price to the true economic cost

COGENERATION SYSTEM ASSESSMENT

Financial (Equity Only):	0	1	2	3	4	5	6	7	8	9	10
Cogeneration:											
Capital Investment:	499500										
Expenses:											
O&M:		24975	24975	24975	24975	24975	24975	24975	24975	24975	24975
Fuel:		803681.2	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2
Revenues:											
Power:		242045.0	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0
Profit Before Taxes and Depreciation:		-586611.	-586611.	-586611.	-586611.	-586611.	-586611.	-586611.	-586611.	-586611.	-586611.
Depreciation:		24975	24975	24975	24975	24975	24975	24975	24975	24975	24975
Profit Before Taxes:		-611586.	-611586.	-611586.	-611586.	-611586.	-611586.	-611586.	-611586.	-611586.	-611586.
Taxes:		-305793.	-305793.	-305793.	-305793.	-305793.	-305793.	-305793.	-305793.	-305793.	-305793.
Profit After Taxes:		-305793.	-305793.	-305793.	-305793.	-305793.	-305793.	-305793.	-305793.	-305793.	-305793.
Net Cogen Cash Flow:	-499500	-280818.	-280818.	-280818.	-280818.	-280818.	-280818.	-280818.	-280818.	-280818.	-280818.
Non-Cogeneration:											
Capital Investment:	0										
Expenses:											
O&M:		0	0	0	0	0	0	0	0	0	0
Fuel:		738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0
Profit Before Taxes and Depreciation:		-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.
Depreciation:		0	0	0	0	0	0	0	0	0	0
Profit Before Taxes:		-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.
Taxes:		-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.
Profit After Taxes:		-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.
Net Non-Cogen Cash Flow:	0	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.

Financial (Equity Only):	11	12	13	14	15	16	17	18	19	20
Cogeneration:										
Capital Investment:										
Expenses:										
O&M:	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975
Fuel:	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2
Revenues:										
Power:	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0
Profit Before Taxes and Depreciation:	-586611.	-586611.	-586611.	-586611.	-586611.	-586611.	-586611.	-586611.	-586611.	-586611.
Depreciation:	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975
Profit Before Taxes:	-611586.	-611586.	-611586.	-611586.	-611586.	-611586.	-611586.	-611586.	-611586.	-611586.
Taxes:	-305793.	-305793.	-305793.	-305793.	-305793.	-305793.	-305793.	-305793.	-305793.	-305793.
Profit After Taxes:	-305793.	-305793.	-305793.	-305793.	-305793.	-305793.	-305793.	-305793.	-305793.	-305793.
Net Cogen Cash Flow:	-280818.	-280818.	-280818.	-280818.	-280818.	-280818.	-280818.	-280818.	-280818.	-280818.
Non-Cogeneration:										
Capital Investment:										
Expenses:										
O&M:	0	0	0	0	0	0	0	0	0	0
Fuel:	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0
Profit Before Taxes and Depreciation:	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.
Depreciation:	0	0	0	0	0	0	0	0	0	0
Profit Before Taxes:	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.
Taxes:	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.
Profit After Taxes:	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.
Net Non-Cogen Cash Flow:	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.

Cogen/Non-cogen Diff. Cash Flow: -499500 88530.92

Net Fresent Value: 47516.89

Internal Rate of Return: 16.95027
(%)

Levelized Incremental Power Cost:

Weighted Cost of Capital: 15
(%)

Capital Charge Rate: 0.269522

	Cogen	Non-Cogen	Diff.
Capital:	134626.7	0	134626.7
Levelized Fuel:	803681.2	738698.0	64983.20
Levelized O&M:	24975	0	24975
Total:			224584.9

Annual Power Production: 5319671.

NET POWER COST: 0.042217
=========

Financial (Equity & Debt):

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Cogeneration:																	
Capital Investment:	499500																
Equity	151363.6																
Debt	348136.3																
Expenses:																	
O&M:		24975	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975
Fuel:		803681.2	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2	803681.2
Interest:		38295	37698.53	37036.45	36301.54	35485.79	34580.30	33575.22	32459.58	31221.21	29846.62	28320.83	26627.21	24747.28	22660.57	20344.31	17773.26
Revenues:																	
Power:		242045.0	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0	242045.0
Profit Before Taxes and Depreciation:		-624906.	-624309.	-623647.	-622912.	-622096.	-621191.	-620186.	-619070.	-617832.	-616457.	-614931.	-613238.	-611358.	-609271.	-606955.	-604384.

	14	15	16
Power:	242045.0	242045.0	242045.0
Profit Before Taxes and Depreciation:	-601530.	-598362.	-594846.

	14	15	16
O&M:	24975	24975	24975
Fuel:	803681.2	803681.2	803681.2
Interest:	14919.41	11751.62	8235.386

	14	15	16
Power:	242045.0	242045.0	242045.0
Profit Before Taxes and Depreciation:	-590943.		

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PORTICO ASSESSMENT

Depreciation:		24975	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975	24975
Profit Before Taxes:		-649881.	-649284.	-648622.	-647887.	-647071.	-646166.	-645161.	-644045.	-642807.	-641432.	-639906.	-638213.	-636333.	-634246.	-631930.	-629359.	-626505.	-623337.	-619821.	-615918.	
Taxes:		-324940.	-324642.	-324311.	-323943.	-323535.	-323083.	-322580.	-322022.	-321403.	-320716.	-319953.	-319106.	-318166.	-317123.	-315965.	-314679.	-313252.	-311668.	-309910.	-307959.	
Profit After Taxes:		-324940.	-324642.	-324311.	-323943.	-323535.	-323083.	-322580.	-322022.	-321403.	-320716.	-319953.	-319106.	-318166.	-317123.	-315965.	-314679.	-313252.	-311668.	-309910.	-307959.	
Net Cogen Cash Flow:	-151363.	-305388.	-305686.	-306017.	-306384.	-306792.	-307245.	-307747.	-308305.	-308924.	-309612.	-310375.	-311221.	-312161.	-313205.	-314363.	-315648.	-317075.	-318659.	-320417.	-322369.	
Non-Cogeneration:																						
Capital Investment:	0																					
Equity	0																					
Debt	0																					
Expenses:																						
O&M:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel:		738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0	738698.0
Interest:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Profit Before Taxes and Depreciation:		-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.
Depreciation:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Profit Before Taxes:		-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	-738698.	
Taxes:		-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	
Profit After Taxes:		-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	
Net Non-Cogen Cash Flow:	0	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	-369349.	
Cogen/Non-cogen Diff. Cash Flow:	-151363.	63960.98	63662.74	63331.70	62964.25	62556.37	62103.63	61601.09	61043.27	60424.09	59736.79	58973.90	58127.08	57187.12	56143.76	54985.63	53700.11	52273.18	50689.29	48931.17	46979.66	

Net Present Value: 201363.9

Internal Rate of Return: (%) 41.58909

Levelized Incremental Power Cost:

Weighted Cost of Capital: (%) 8.378787 Capital Recovery Factor: 0.104739

Capital Charge Rate: 0.159479

	Cogen	Non-Cogen	Diff.
Capital:	79660.18	0	79660.18

Levelized Fuel:	803681.2	738698.0	64983.20
Levelized O&M:	24975	0	24975
Total:			169618.3

Annual Power Production: 5319671.

NET POWER COST: 0.031885
=========

Cogen Interest and Principal Payments:
Annual Payment: 42717.44

Loan Beginning Balance:	348136.3	342713.9	336695.0	330014.0	322598.1	314366.4	305229.3	295087.0	283829.2	271332.9	257462.1	242065.5	224975.3	206005.1	184948.3	161575.1	135631.0	106832.9	74867.14	39385.08				
Interest:	38295	37698.53	37036.45	36301.54	35485.79	34580.30	33575.22	32459.58	31221.21	29846.62	28320.83	26627.21	24747.28	22660.57	20344.31	17773.26	14919.41	11751.62	8235.386	4332.359				
Principle Payment:	5422.445	6018.914	6680.995	7415.904	8231.654	9137.136	10142.22	11257.86	12496.23	13870.81	15396.60	17090.23	18970.15	21056.87	23373.13	25944.17	28798.03	31965.81	35482.05	39385.08				

Non-Cogen Interest and Principal Payments:
Annual Payment: 0

Loan Beginning Balance:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Principle Payment:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

ECONOMIC:

Cogeneration System:

Capital Investment:
Local Currency (LC): 99900
Foreign Exchange (FX):* 299700

Expenses:

LC O&M:	7492.5	7492.5	7492.5	7492.5	7492.5	7492.5	7492.5	7492.5	7492.5	7492.5	7492.5	7492.5	7492.5	7492.5	7492.5	7492.5	7492.5	7492.5	7492.5	7492.5
FX O&M:	14985	14985	14985	14985	14985	14985	14985	14985	14985	14985	14985	14985	14985	14985	14985	14985	14985	14985	14985	14985
LC Fuel:	37675.83	37675.83	37675.83	37675.83	37675.83	37675.83	37675.83	37675.83	37675.83	37675.83	37675.83	37675.83	37675.83	37675.83	37675.83	37675.83	37675.83	37675.83	37675.83	37675.83
FX Fuel:	753516.7	753516.7	753516.7	753516.7	753516.7	753516.7	753516.7	753516.7	753516.7	753516.7	753516.7	753516.7	753516.7	753516.7	753516.7	753516.7	753516.7	753516.7	753516.7	753516.7
FX Interest, etc.:	35202.64	35202.64	35202.64	35202.64	35202.64	35202.64	35202.64	35202.64	35202.64	35202.64	35202.64	35202.64	35202.64	35202.64	35202.64	35202.64	35202.64	35202.64	35202.64	35202.64

Revenues:

LC Power:	99743.84	99743.84	99743.84	99743.84	99743.84	99743.84	99743.84	99743.84	99743.84	99743.84	99743.84	99743.84	99743.84	99743.84	99743.84	99743.84	99743.84	99743.84	99743.84	99743.84
FX Power:	132991.7	132991.7	132991.7	132991.7	132991.7	132991.7	132991.7	132991.7	132991.7	132991.7	132991.7	132991.7	132991.7	132991.7	132991.7	132991.7	132991.7	132991.7	132991.7	132991.7

Net Economic Cash Flows:

Local Currency (LC):	-99900	54575.50	54575.50	54575.50	54575.50	54575.50	54575.50	54575.50	54575.50	54575.50	54575.50	54575.50	54575.50	54575.50	54575.50	54575.50	54575.50	54575.50	54575.50	54575.50
Foreign Exchange (FX):*	-670712.	-670712.	-670712.	-670712.	-670712.	-670712.	-670712.	-670712.	-670712.	-670712.	-670712.	-670712.	-670712.	-670712.	-670712.	-670712.	-670712.	-670712.	-670712.	-670712.

Total Economic Cash Flows:	-99900	-616137.	-616137.	-616137.	-616137.	-616137.	-616137.	-616137.	-616137.	-616137.	-616137.	-616137.	-616137.	-616137.	-616137.	-616137.	-616137.	-616137.	-616137.	-616137.	-616137.	-616137.

Non-Cogen System:

Capital Investment:																						
Local Currency (LC):	0																					
Foreign Exchange (FX):*	0																					
Expenses:																						
LC O&M:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FX O&M:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LC Fuel:		34629.48	34629.48	34629.48	34629.48	34629.48	34629.48	34629.48	34629.48	34629.48	34629.48	34629.48	34629.48	34629.48	34629.48	34629.48	34629.48	34629.48	34629.48	34629.48	34629.48	34629.48
FX Fuel:		692589.7	692589.7	692589.7	692589.7	692589.7	692589.7	692589.7	692589.7	692589.7	692589.7	692589.7	692589.7	692589.7	692589.7	692589.7	692589.7	692589.7	692589.7	692589.7	692589.7	692589.7
FX Interest, etc.:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Economic Cash Flows:																						
Local Currency (LC):	0	-34629.4	-34629.4	-34629.4	-34629.4	-34629.4	-34629.4	-34629.4	-34629.4	-34629.4	-34629.4	-34629.4	-34629.4	-34629.4	-34629.4	-34629.4	-34629.4	-34629.4	-34629.4	-34629.4	-34629.4	-34629.4
Foreign Exchange (FX):*	0	-692589.	-692589.	-692589.	-692589.	-692589.	-692589.	-692589.	-692589.	-692589.	-692589.	-692589.	-692589.	-692589.	-692589.	-692589.	-692589.	-692589.	-692589.	-692589.	-692589.	-692589.
Total Economic Cash Flows:	0	-727219.	-727219.	-727219.	-727219.	-727219.	-727219.	-727219.	-727219.	-727219.	-727219.	-727219.	-727219.	-727219.	-727219.	-727219.	-727219.	-727219.	-727219.	-727219.	-727219.	-727219.

Incremental Cash Flow:

Local Currency (LC):	-99900	89204.99	89204.99	89204.99	89204.99	89204.99	89204.99	89204.99	89204.99	89204.99	89204.99	89204.99	89204.99	89204.99	89204.99	89204.99	89204.99	89204.99	89204.99	89204.99	89204.99	89204.99
Foreign Currency (FX):*		21877.07	21877.07	21877.07	21877.07	21877.07	21877.07	21877.07	21877.07	21877.07	21877.07	21877.07	21877.07	21877.07	21877.07	21877.07	21877.07	21877.07	21877.07	21877.07	21877.07	21877.07
Net Cash Flow:	-99900	111082.0	111082.0	111082.0	111082.0	111082.0	111082.0	111082.0	111082.0	111082.0	111082.0	111082.0	111082.0	111082.0	111082.0	111082.0	111082.0	111082.0	111082.0	111082.0	111082.0	111082.0

Net Present Value: 768912.9

Internal Rate of Return: 111.1932

* Note: This assumes that the fx requirements are met solely through borrowed FX funds

Levelized Costs:

Marginal Return to Capital: 10
(%/yr)
LC Capital Recovery Factor: 0.117459
Interest, Fees, etc. on FX : 10
(%/yr)
FX Capital Recovery Factor: 0.117459

	Cogen	Non-cog	Diff.
LC Levelized Capital Cost:	11734.21	0	11734.21

FX Levelized Capital Cost:	35202.64	0	35202.64
Initial LC Fuel Price:	37675.83	34629.48	
Levelized LC Fuel Price:	37675.83	34629.48	3046.353
Initial FX Fuel Price:	753516.7	692589.7	
Levelized FX Fuel Price:	753516.7	692589.7	60927.06
Initial LC O&M Cost:	7492.5	0	
Levelized LC O&M Cost:	7492.5	0	7492.5
Initial FX O&M Cost:	14985	0	
Levelized FX O&M Cost:	14985	0	14985

Total LC Levelized Cost:	22273.06
Total FX Levelized Cost:	111114.7
Net Total Levelized Cost:	133387.7
NET LEVELIZED COST:	0.025074

Initial LC Purchased Power Cost:	99743.84
Levelized LC Purchased Power Cost:	99743.84
Initial FX Purchas·· Power Cost:	132991.7
Levelized FX Purchased Power Cost:	132991.7
Total Purchased Power Cost:	232735.6
NET PURCHASED POWER COST:	0.04375

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SCOTT PAPER ANALYSIS

TECHNOLOGY ASSUMPTIONS: COGENERATION SYSTEM

TECHNOLOGY DESCRIPTION	:	Scott Paper	
SYSTEM SIZE (Steam Units/Hr)	:	65	mmBtu
ANNUAL CAPACITY FACTOR (Fraction)	:	0.7	
COGEN EFFICIENCY (Fuel Units* / Steam Unit)	:	1.447	mmBtu
1/(NON-COGEN EFFICIENCY) (Fuel Units* / Steam Unit)	:	1.43	
ELECTRIC-TO-THERMAL RATIO	:	0.1	
THEORETICAL STEAM UNITS / KWh **	:	0.003412	mmBtu/kW
COGEN SYSTEM CAPITAL COST (Local Currency / Steam Unit)	:	72000	
ANNUAL COGEN NON-FUEL O&M COST (Fraction of CAPITAL COST)	:	0.05	reduced f zero non-
COGEN SYSTEM LIFE (Years)	:	20	
NON-COGEN SYSTEM CAPITAL COST (Local Currency / Steam Unit)	:	0	
ANNUAL NON-COGEN NON-FUEL O&M COST (Fraction of CAPITAL COST)	:	0.05	
NON-COGEN SYSTEM LIFE (Years)	:	20	
COGEN SYSTEM POWER OUTPUT (KWh/YR) (Calculated)	:	11,681,712	

* - "Fuel Units" must be the same as those used for "Fuel Prices" in the Financial and Economic Assumption inputs.

** - This is the theoretical number of steam units per kWh, ignoring conversion losses: e.g. if the steam units were in btu, the value would be 3412 (btu/kWh)

FINANCIAL ASSUMPTIONS: COGENERATION SYSTEM

MARKET EXCHANGE RATE (Local Currency/US$)	:	1
AFTER-TAX COST OF EQUITY (%)	:	15
COST OF DEBT (%)	:	11
DEBT-TO-EQUITY RATIO	:	2.3
INITIAL COGEN SYSTEM FUEL PRICE (Local Currency / Fuel Unit*)	:	3.06
ANNUAL COGEN FUEL PRICE INFLATION (% / yr)	:	0
INITIAL NON-COGEN SYSTEM FUEL PRICE (Local Currency / Fuel Unit*)	:	3.06
ANNUAL NON-COGEN SYSTEM FUEL PRICE INFLATION	:	0

(% / yr)		
INITIAL POWER PRICE (Local Currency / kWh)	:	0.0455
ANNUAL POWER PRICE INFLATION (% / yr)	:	0
ANNUAL COGEN O&M COST INFLATION (% / yr)	:	0
ANNUAL NON-COGEN O&M COST INFLATION (% / yr)	:	0
MARGINAL TAX RATE (%)	:	50

* - "Fuel Units" must be the same as those used for "Fuel Prices" in the Financial and Economic Assumption inputs.

ECONOMIC ASSUMPTIONS: COGENERATION SYSTEM

REAL EXCHANGE RATE (Local Currency / US$)	:	1
MARGINAL RETURN TO CAPITAL (%)	:	10
COGEN SYSTEM FRACTION OF CAPITAL COST IN FOREIGN EXCHANGE	:	0.6
COGEN SYSTEM FRACTION OF O&M COST IN FOREIGN EXCHANGE	:	0.6
COGEN ECONOMIC FUEL COST (Local Currency / Fuel Unit*)	:	3.02
COGEN FUEL COST ESCALATION RATE (% / yr)	:	0
COGEN SYSTEM FRACTION OF FUEL COST IN FOREIGN EXCHANGE	:	0.95
NON-COGEN SYSTEM FRACTION OF CAPITAL COST IN FOREIGN EXCHANGE	:	0.6
NON-COGEN SYSTEM FRACTION OF O&M COST IN FOREIGN EXCHANGE	:	0.6
NON-COGEN ECONOMIC FUEL COST (Local Currency / Fuel Unit*)	:	3.02
NON-COGEN FUEL COST ESCALATION RATE (% / yr)	:	0
NON-COGEN SYSTEM FRACTION OF FUEL COST IN FOREIGN EXCHANGE	:	0.95
COGEN/NON-COGEN O&M ESCALATION RATE (%/YR)	:	0
INTEREST, FEES, ETC. ON FOREX CAPITAL COST (%/YR)	:	10

SCOTT PAPER ANALYSIS

ECONOMIC POWER COST (Local Currency / 1Wh)	:	0.05
POWER COST ESCALATION RATE (% / yr)	:	0
FRACTION OF POWER COST IN FOREX	:	0.5
SCF** FOR LOCAL CURRENCY O&M COSTS	:	0.75
SCF** FOR LOCAL CURRENCY CAPITAL COSTS	:	0.5
SCF** FOR LOCAL CURRENCY POWER COSTS	:	0.75
SCF** FOR LOCAL CURRENCY COGEN FUEL COSTS	:	0.95
SCF** FOR LOCAL CURRENCY NON-COGEN FUEL COSTS	:	0.95

* - "Fuel Units" must be the same as those used for "Fuel Prices" in the Financial and Economic Assumption inputs.

** -"SCF = Specific Conversion Factor for converting the market price to the true economic cost

COGENERATION SYSTEM ASSESSMENT

Financial (Equity Only):	0	1	2	3	4	5	6	7	8	9	10
Cogeneration:											
Capital Investment:	4680000										
Expenses:											
O&M:		234000	234000	234000	234000	234000	234000	234000	234000	234000	234000
Fuel:		1764840.	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.
Revenues:											
Power:		531517.8	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8
Profit Before Taxes and Depreciation:		-1467322	-1467322	-1467322	-1467322	-1467322	-1467322	-1467322	-1467322	-1467322	-1467322
Depreciation:		234000	234000	234000	234000	234000	234000	234000	234000	234000	234000
Profit Before Taxes:		-1701322	-1701322	-1701322	-1701322	-1701322	-1701322	-1701322	-1701322	-1701322	-1701322
Taxes:		-850661.	-850661.	-850661.	-850661.	-850661.	-850661.	-850661.	-850661.	-850661.	-850661.
Profit After Taxes:		-850661.	-850661.	-850661.	-850661.	-850661.	-850661.	-850661.	-850661.	-850661.	-850661.
Net Cogen Cash Flow:	-4680000	-616661.	-616661.	-616661.	-616661.	-616661.	-616661.	-616661.	-616661.	-616661.	-616661.
Non-Cogeneration:											
Capital Investment:	0										
Expenses:											
O&M:		0	0	0	0	0	0	0	0	0	0
Fuel:		1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.
Profit Before Taxes and Depreciation:		-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106
Depreciation:		0	0	0	0	0	0	0	0	0	0
Profit Before Taxes:		-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106
Taxes:		-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.
Profit After Taxes:		-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.
Net Non-Cogen Cash Flow:	0	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.

Financial (Equity Only):	11	12	13	14	15	16	17	18	19	20
Cogeneration:										
Capital Investment:										
Expenses:										
O&M:	234000	234000	234000	234000	234000	234000	234000	234000	234000	234000
Fuel:	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.
Revenues:										
Power:	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8
Profit Before Taxes and Depreciation:	-1467322	-1467322	-1467322	-1467322	-1467322	-1467322	-1467322	-1467322	-1467322	-1467322
Depreciation:	234000	234000	234000	234000	234000	234000	234000	234000	234000	234000
Profit Before Taxes:	-1701322	-1701322	-1701322	-1701322	-1701322	-1701322	-1701322	-1701322	-1701322	-1701322
Taxes:	-850661.	-850661.	-850661.	-850661.	-850661.	-850661.	-850661.	-850661.	-850661.	-850661.
Profit After Taxes:	-850661.	-850661.	-850661.	-850661.	-850661.	-850661.	-850661.	-850661.	-850661.	-850661.
Net Cogen Cash Flow:	-616661.	-616661.	-616661.	-616661.	-616661.	-616661.	-616661.	-616661.	-616661.	-616661.
Non-Cogeneration:										
Capital Investment:										
Expenses:										
O&M:	0	0	0	0	0	0	0	0	0	0
Fuel:	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.
Profit Before Taxes and Depreciation:	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106
Depreciation:	0	0	0	0	0	0	0	0	0	0
Profit Before Taxes:	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106
Taxes:	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.
Profit After Taxes:	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.
Net Non-Cogen Cash Flow:	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.

SCOTT PAPER ANALYSIS

Cogen/Non-cogen Diff. Cash Flow:	-4680000	255391.8	255391.8	255391.8	255391.8	255391.8	255391.8	255391.8	255391.8	255391.8	255391.8	255391.8	255391.8	255391.8	255391.8	255391.8	255391.8	255391.8	255391.8	255391.8	255391.8	255391.8	255391.8	255391.8

Net Present Value: -2679493

Internal Rate of Return: (%) 0.847986

Levelized Incremental Power Cost:

Weighted Cost of Capital: (%) 15

Capital Charge Rate: 0.269522

	Cogen	Non-Cogen	Diff.
Capital:	1261367.	0	1261367.
Levelized Fuel:	1764840.	1744106.	20734.13
Levelized O&M:	234000	0	234000
Total:			1516101.

Annual Power Production: 11681711

NET POWER COST: 0.129784

Financial (Equity & Debt):	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Cogeneration:																	
Capital Investment:	4680000																
Equity	1418181.																
Debt	3261818.																
Expenses:																	
O&M:		234000	234000	234000	234000	234000	234000	234000	234000	234000	234000	234000	234000	234000	234000	234000	234000
Fuel:		1764840.	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.	1764840.
Interest:		253800	353211.4	347008.1	340122.5	332479.4	323995.6	314578.6	304125.7	292523.0	279644.0	265348.4	249480.1	231866.4	212315.2	190613.3	166524.3
Revenues:																	
Power:		531517.8	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8	531517.8
Profit Before Taxes and Depreciation:		-1826122	-1820534	-1814330	-1807445	-1799802	-1791318	-1781901	-1771448	-1759845	-1746966	-1732671	-1716802	-1699189	-1679637	-1657936	-1633846

Financial (Equity & Debt):	17	18	19	20
Cogeneration:				
Capital Investment:				
Equity				
Debt				
Expenses:				
O&M:	234000	234000	234000	234000
Fuel:	1764840.	1764840.	1764840.	1764840.
Interest:	139785.4	110105.3	77160.37	40591.47
Revenues:				
Power:	531517.8	531517.8	531517.8	531517.8
Profit Before Taxes and Depreciation:	-1607109	-1577427	-1544482	-1507314

SCOTT PAPER ANALYSIS

Depreciation:		234000	234000	234000	234000	234000	234000	234000	234000	234000	234000	234000	234000	234000	234000	234000	234000	234000	234000	234000	234000
Profit Before Taxes:		-2060122	-2054534	-2048330	-2041445	-2033802	-2025318	-2015901	-2005448	-1993845	-1980966	-1966671	-1950802	-1933189	-1913637	-1891936	-1867846	-1841108	-1811427	-1778482	-1741914
Taxes:		-1030061	-1027267	-1024165	-1020722	-1016901	-1012659	-1007950	-1002724	-996922.	-990483.	-983335.	-975401.	-966594.	-956818.	-945968.	-933923.	-920554.	-905713.	-889241.	-870957.
Profit After Taxes:		-1030061	-1027267	-1024165	-1020722	-1016901	-1012659	-1007950	-1002724	-996922.	-990483.	-983335.	-975401.	-966594.	-956818.	-945968.	-933923.	-920554.	-905713.	-889241.	-870957.
Net Cogen Cash Flow:	-1418181	-846866.	-849660.	-852762.	-856204.	-860026.	-864268.	-868976.	-874203.	-880004.	-886444.	-893591.	-901526.	-910332.	-920108.	-930959.	-943004.	-956373.	-971213.	-987686.	-1005970
Non-Cogeneration:																					
Capital Investment:	0																				
Equity	0																				
Debt	0																				
Expenses:																					
O&M:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel:		1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.	1744106.
Interest:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Profit Before Taxes and Depreciation:		-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106
Depreciation:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Profit Before Taxes:		-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106	-1744106
Taxes:		-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.
Profit After Taxes:		-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.
Net Non-Cogen Cash Flow:	0	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.	-872053.
Cogen/Non-cogen Diff. Cash Flow:	-1418181	25186.97	22392.70	19291.06	15848.25	12026.72	7784.823	3076.317	-2150.12	-7951.47	-14390.9	-21538.6	-29472.9	-38279.7	-48055.3	-58906.3	-70950.8	-84320.2	-99160.3	-115632.	-133917.

Net Present Value: -1238043

Internal Rate of Return: (%) ERR

Levelized Incremental Power Cost:

Weighted Cost of Capital: (%) 8.378787 Capital Recovery Factor: 0.104739

Capital Charge Rate: 0.153479

	Cogen	Non-Cogen	Diff.
Capital:	746365.7	0	746365.7

SCOTT PAPER ANALYSIS

Levelized Fuel:	1764840.	1744106.	20734.13
Levelized O&M:	234000	0	234000
Total:			1001099.

Annual Power Production: 11681711

NET POWER COST: 0.085698
=========

Cogen Interest and Principal Payments:
Annual Payment: 409604.8

Loan Beginning Balance:	3261818.	3211013.	3154619.	3092023.	3022540.	2945415.	2859806.	2764779.	2659300.	2542219.	2412258.	2268001.	2107877.	1930138.	1732849.	1513857.	1270776.	1000957.	701457.9	369013.4
Interest:	358800	353211.4	347008.1	340122.5	332479.4	323995.6	314578.6	304125.7	292523.0	279644.0	265348.4	249480.1	[illegible]	[illegible]	190613.3	166524.3	139785.4	110105.3	77160.37	40591.47
Principle Payment:	50804.89	56393.43	62596.71	69482.35	77125.40	85609.20	95026.21	105479.0	117081.8	129960.7	144256.4	160124.7	177738.4	197289.6	218991.5	243080.5	269819.4	299499.5	332444.5	369013.4

Non-Cogen Interest and Principal Payments:
Annual Payment: 0

Loan Beginning Balance:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Principle Payment:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

ECONOMIC:

Cogeneration System:

Capital Investment:
Local Currency (LC): 936000
Foreign Exchange (FX):* 2808000

Expenses:

LC O&M:	70200	70200	70200	70200	70200	70200	70200	70200	70200	70200	70200	70200	70200	70200	70200	70200	70200	70200	70200	70200
FX O&M:	140400	140400	140400	140400	140400	140400	140400	140400	140400	140400	140400	140400	140400	140400	140400	140400	140400	140400	140400	140400
LC Fuel:	82734.10	82734.10	82734.10	82734.10	82734.10	82734.10	82734.10	82734.10	82734.10	82734.10	82734.10	82734.10	82734.10	82734.10	82734.10	82734.10	82734.10	82734.10	82734.10	82734.10
FX Fuel:	1654682.	1654682.	1654682.	1654682.	1654682.	1654682.	1654682.	1654682.	1654682.	1654682.	1654682.	1654682.	1654682.	1654682.	1654682.	1654682.	1654682.	1654682.	1654682.	1654682.
FX Interest, etc.:	329826.6	329826.6	329826.6	329826.6	329826.6	329826.6	329826.6	329826.6	329826.6	329826.6	329826.6	329826.6	329826.6	329826.6	329826.6	329826.6	329826.6	329826.6	329826.6	329826.6

Revenues:

LC Power:	219032.0	219032.0	219032.0	219032.0	219032.0	219032.0	219032.0	219032.0	219032.0	219032.0	219032.0	219032.0	219032.0	219032.0	219032.0	219032.0	219032.0	219032.0	219032.0	219032.0
FX Power:	292042.7	292042.7	292042.7	292042.7	292042.7	292042.7	292042.7	292042.7	292042.7	292042.7	292042.7	292042.7	292042.7	292042.7	292042.7	292042.7	292042.7	292042.7	292042.7	292042.7

Net Economic Cash Flows:

Local Currency (LC):	-936000	66097.98	66097.98	66097.98	66097.98	66097.98	66097.98	66097.98	66097.98	66097.98	66097.98	66097.98	66097.98	66097.98	66097.98	66097.98	66097.98	66097.98	66097.98	66097.98
Foreign Exchange (FX):*		-1832865	-1832865	-1832865	-1832865	-1832865	-1832865	-1832865	-1832865	-1832865	-1832865	-1832865	-1832865	-1832865	-1832865	-1832865	-1832865	-1832865	-1832865	-1832865

Total Economic Cash Flows:	-936000	-1766768	-1766768	-1766768	-1766768	-1766768	-1766768	-1766768	-1766768	-1766768	-1766768	-1766768	-1766768	-1766768	-1766768	-1766768	-1766768	-1766768	-1766768	-1766768	-1766768	-1766768

Non-Cogen System:

Capital Investment:																						
Local Currency (LC):	0																					
Foreign Exchange (FX):*	0																					
Expenses:																						
LC O&M:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FX O&M:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LC Fuel:		81762.11	81762.11	81762.11	81762.11	81762.11	81762.11	81762.11	81762.11	81762.11	81762.11	81762.11	81762.11	81762.11	81762.11	81762.11	81762.11	81762.11	81762.11	81762.11	81762.11	81762.11
FX Fuel:		1635242.	1635242.	1635242.	1635242.	1635242.	1635242.	1635242.	1635242.	1635242.	1635242.	1635242.	1635242.	1635242.	1635242.	1635242.	1635242.	1635242.	1635242.	1635242.	1635242.	1635242.
FX Interest, etc.:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Economic Cash Flows:																						
Local Currency (LC):	0	-81762.1	-81762.1	-81762.1	-81762.1	-81762.1	-81762.1	-81762.1	-81762.1	-81762.1	-81762.1	-81762.1	-81762.1	-81762.1	-81762.1	-81762.1	-81762.1	-81762.1	-81762.1	-81762.1	-81762.1	-81762.1
Foreign Exchange (FX):*	0	-1635242	-1635242	-1635242	-1635242	-1635242	-1635242	-1635242	-1635242	-1635242	-1635242	-1635242	-1635242	-1635242	-1635242	-1635242	-1635242	-1635242	-1635242	-1635242	-1635242	-1635242
Total Economic Cash Flows:	0	-1717004	-1717004	-1717004	-1717004	-1717004	-1717004	-1717004	-1717004	-1717004	-1717004	-1717004	-1717004	-1717004	-1717004	-1717004	-1717004	-1717004	-1717004	-1717004	-1717004	-1717004

Incremental Cash Flow:

Local Currency (LC):	-936000	147860.0	147860.0	147860.0	147860.0	147860.0	147860.0	147860.0	147860.0	147860.0	147860.0	147860.0	147860.0	147860.0	147860.0	147860.0	147860.0	147860.0	147860.0	147860.0	147860.0	147860.0
Foreign Currency (FX):*		-197623.	-197623.	-197623.	-197623.	-197623.	-197623.	-197623.	-197623.	-197623.	-197623.	-197623.	-197623.	-197623.	-197623.	-197623.	-197623.	-197623.	-197623.	-197623.	-197623.	-197623.
Net Cash Flow:	-936000	-49763.6	-49763.6	-49763.6	-49763.6	-49763.6	-49763.6	-49763.6	-49763.6	-49763.6	-49763.6	-49763.6	-49763.6	-49763.6	-49763.6	-49763.6	-49763.6	-49763.6	-49763.6	-49763.6	-49763.6	-49763.6

Net Present Value: -1238060

Internal Rate of Return: ERR

* Note: This assumes that the fx requirements are met solely through borrowed FX funds

Levelized Costs:

Marginal Return to Capital: 10
(%/yr)
LC Capital Recovery Factor: 0.117459
Interest, fees, etc. on FX : 10
(%/yr)
FX Capital Recovery Factor: 0.117459

	Cogen	Non-cog	Diff.
LC Levelized Capital Cost:	109942.2	0	109942.2

SCOTT PAPER ANALYSIS

FX Levelized Capital Cost:	329826.6	0	329826.6
Initial LC Fuel Price:	82734.10	81762.11	
Levelized LC Fuel Price:	82734.10	81762.11	971.9971
Initial FX Fuel Price:	1654682.	1635242.	
Levelized FX Fuel Price:	1654682.	1635242.	19439.94
Initial LC O&M Cost:	70200	0	
Levelized LC O&M Cost:	70200	0	70200
Initial FX O&M Cost:	140400	0	
Levelized FX O&M Cost:	140400	0	140400
Total LC Levelized Cost:			181114.2
Total FX Levelized Cost:			489666.5
Net Total Levelized Cost:			670780.7
NET LEVELIZED COST:			0.057421

Initial LC Purchased Power Cost:	219032.0
Levelized LC Purchased Power Cost:	219032.0
Initial FX Purchased Power Cost:	292042.7
Levelized FX Purchased Power Cost:	292042.7
Total Purchased Power Cost:	511074.8
NET PURCHASED POWER COST:	0.04375

APPENDIX H: DSE SUGAR QUESTIONNAIRE

IDENTIFICACION DEL CONSUMIDOR

Nombre del Ingenio: _____

_____

Codigo CIIU

Ubicación:

Provincia _____

Cantón _____

Distrito _____

Otra dirección: _____

_____

_____

Teléfono _____

Apartado Postal _____

Telex _____

Nombre de la persona entrevistada

B. INFORMACION SOBRE EL SUMINISTRO DE ELECTRICIDAD

Compañía distribuidora: _____

_____

Código del consumidor

No. total transformadores _____

Potencia Instalada Total KVA _____

Tensión de Suministro V _____

Tipo de tarifa

Observaciones: _____

_____

_____

_____

PRODUCCION Y CONSUMO ANUAL DE ENERGETICOS

Energético/ Producto	CONSUMO				Perfil utilización de los Energéticos.
	Unidad	84-85	85-86	86-87	Observaciones
Caña molida					
Bagazo prod.					
Alcohol prod.					
Azucar prod.					
Bagazo consum.					
Bunker					
Diesel					
E.E. Generada					
E.E. Comprada					

Observaciones: _____

_____

_____

D. CALDERAS

Tipo tubos Fuego ☐ Agua ☐

Marca _____

Producción Vapor — Unidad _____ Nominal _____ Media _____

Presión Vapor — Unidad _____ Máxima _____ Media _____

Tipo _____

Temperatura _____

Temperatura de Uso — Unidad _____ Máxima _____ Mínima _____

Cantidad de Quemadores _____

Régimen de Operación

Horas por día _____

Días por mes _____

Mes de inicio _____ _____

Mes de finalización _____ _____

Energéticos utilizados

Principal _____

Otro _____

Otro _____

Cantidad Calderas en Operación

Principal _____

Reserva _____

Edad(es)

Principal _____

Reserva _____

Rendimiento estimado _____ %

Observaciones _____

E. TURBINAS

Marca _____ ☐☐☐ Tipo _____ ☐ Cantidad

Edad _____ ☐☐☐ No. etapas _____ ☐☐☐ Principal ☐☐☐

Uso(s) _____ ☐☐☐ Potencia _____ ☐☐☐☐☐ Reserva ☐☐☐

Entrada		Extracción		Salida	
Presión	Temperatura	Presión	Temperatura	Presión	Temperatura
☐☐☐☐	☐☐☐	☐☐☐☐	☐☐☐	☐☐☐☐	☐☐☐

Régimen de Operación

Horas por día _____ ☐☐

Días por mes _____ ☐☐

Mes de inicio _____ _____ ☐☐ ☐☐

Mes de fin _____ _____ ☐☐ ☐☐

☐☐☐☐☐☐

Observaciones:

_____

_____

_____

_____

240

F. GENERADORES

Potencia (kW) _____ |_|_|_|_|_|

Tensión (V) _____ |_|_|_|_|_|

Factor de Potencia _____ |_|_|_|

Marca _____ |_|

Cantidad

Principal |_|_|

Reserva |_|_|

Régimen de Operación

Horas por día _____ |_|_|

Días por mes _____ |_|_|

Mes inicio _____ _____ |_|_|_| |_|_|_|

Mes fin _____ _____ |_|_|_| |_|_|_|

Total horas anuales _____ |_|_|_|_|_|

Observaciones _____

_____

_____

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G. ENERGIA ELECTRICA (RESUMEN)

Energía Eléctrica	Consumo (MWh)			Demanda Máxima (MW)		
	1984	1985	1986	1984	1985	1986
1. Energía comprada						
2. Energía Producida						
3. Suministro a terceros						

H. ENERGIA ELECTRICA COMPRADA Series Históricas

	MES	kW	kWh	FC
1 9 8	enero			
	febrero			
	marzo			
	abril			
	mayo			
	junio			
	julio			
	agosto			
	setiembre			
	octubre			
	noviembre			
	diciembre			

	Mes	kW	kWh	FC
1 9 8	enero			
	febrero			
	marzo			
	abril			
	mayo			
	junio			
	julio			
	agosto			
	setiembre			
	octubre			
	noviembre			
	diciembre			

Fecha de lectura del medidor.

ENERGIA ELECTRICA GENERACION TERMICA

Series Históricas

	198____			198____			198____		
Mes	kW	kWh	FC	kW	kWh	FC	kW	kWh	FC
enero									
febrero									
marzo									
abril									
mayo									
junio									
julio									
agosto									
setiembre									
octubre									
noviembre									
diciembre									

J. ENERGIA ELECTRICA GENERACION HIDROELECTRICA

Series Históricas

	1984			1985			1986		
Mes	kW	kWh	FC	kW	kWh	FC	kW	kWh	FC
enero									
febrero									
marzo									
abril									
mayo									
junio									
julio									
agosto									
setiembre									
octubre									
noviembre									
diciembre									

Potencia Instalada kW _____

Energía Potencial (h) _____

Q máximo m3/s _____

Posibilidades de ampliación _____ kW

K. OTROS EQUIPOS ELECTRICOS

Uso de motores

Tipo	Cantidad	Potencia	Unidad
Compresor			
Ventilador			
Bombas			
Bombas para riego			

L. OTROS EQUIPAMENTOS NO ELECTRICOS

Flota vehículos trabajo

	Tipo	No. unidades	Tipo combustible
Equipo agrícola:			
Camiones			

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