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INTERNATIONAL BANK FOR RECONSTRUCTION AND DEVELOPMENT

OPERATIONS EVALUATION REPORT: ELECTRIC POWER

(in three books)

BOOK II

Chapters 7 - 12

Programming and Budgeting Department
Operations Evaluation Division

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I - Introduction

1.01 The Comision Federal de Electricidad (CFE) was created in 1937 by the Mexican Government as a wholly Government owned agency for the main purpose of constructing and operating, on a non-profit basis, a national system of power facilities. In 1949, CFE was restructured as an autonomous government agency authorized to construct and operate power facilities throughout the country with preference over private interests in acquiring and developing water and other power resources. CFE's continuing sources of income are the sale of power and the proceeds of a 10% tax on all consumption of electricity in Mexico; those sources are supplemented by government appropriations and borrowing. The Government exempts CFE from most taxes and refunds any import duties CFE may pay. CFE's Director General is appointed by the President of the Republic and the Assistant Director General by a Board of Directors chaired by the Secretary of Industry and Commerce.

1.02 From 1939 through 1948, the Comision had constructed small plants aggregating about 100 MW with necessary transmission and distribution systems, largely in rural areas where power was urgently needed and private capital not available. The generating capacity of CFE grew by 19% p.a. on average between 1950 and 1970, mainly through its construction program, but also through the acquisition of other companies after the nationalization of the power sector in 1960. CFE's generating capacity reached in 1970 5,400 MW, made up of 2,915 MW of hydroelectric plants, 2,030 MW of steam plants and 455 MW of diesel plants. The Bank loans strongly supported CFE's development by partly financing the construction of about 4,500 MW (about 86% of CFE's generating capacity expansion over 1950-1970) and about 13,900 km of transmission lines. At present, CFE has some 18,500 employees and supplies directly more than 3,800,000 consumers, as compared with 40,000 consumers in 1950 (25.5% p.a. average increase).

1.03 The total installed generating capacity in Mexico at the end of 1970 was about 7,300 MW, of which 1,200 MW was "captive plants" owned and operated by industry for its own needs. The public power sector comprises two large entities owned by the Government - the Compania de Luz y Fuerza del Centro (Mexlight/Centro), with nearly 700 MW of generating capacity, and the Comision, with the above mentioned 5,400 NW. The Mexican power market consists of 6 major systems, 4 smaller systems and some isolated undertakings. All the power facilities of these systems are presently owned by CFE and operate at a 60-cycle frequency, except those of the 50-cycle Central system owned by Centro which supplies consumers in and around Mexico City and supplements generation from its own plants by purchasing large blocks of power from CFE. Since 1960, in accordance with Government policy, CFE has been the only organization to install new generating plants and has been responsible for coordinating all investment planning for the sector. The 10 power systems of the market have not been interconnected yet, except for the Oriental (Puebla - Veracruz) and the Occidental (Michoacan, Guanajuato) systems, the two largest after the Central system, which were linked in mid-1969 through a by-pass of Mexico City.

History of the Power Sector in Mexico.

1.04 As a result of the dominant role of foreign capital in the early development of the power supply industry in Mexico, ninety percent of generating capacity installed by the late 1940's was owned by numerous subsidiaries of foreign power companies, covering essentially the urban and industrialized areas where expected returns were highest; due to a lack of investments during the pre-war and war years, there were serious shortages of power in the central and northern parts of the country. CFE had started its activities by installing and operating small diesel units in rural areas, and, after 1945, by supplying bulk power from its first hydro plant to Mexlight, serving the Federal District where a considerable industrial growth had helped to support a rapidly increasing population. Additional generating capacity was urgently needed to relieve the shortage of power in areas where it was hampering industrial growth, and also in the rural areas to permit irrigation pumping and the development of local industries.

1.05 The first participation of the Bank (1949) in financing CFE power projects marked the beginning of the rapid growth of CFE during the 1950's based primarily on the development of hydro resources and the sale of its power mainly in bulk to other interconnected companies. With the assistance of three Bank loans CFE had built up by the end of the 1950's one third of the total capacity of the country and reached the size of the largest private company in Mexico, namely, the Mexican Light and Power Company - Mexlight - founded in 1902 as a Canadian corporation. In 1960 the Government, through Nacional Financiera S.A. (Nafinsa), acquired the largest two private companies, namely Mexlight and Impulsora (a subsidiary of American and Foreign Power) by buying up a majority of the former's shares and purchasing the latter's assets. Furthermore, CFE had purchased during the 1950's about 50 small distributing companies, and bought in 1962 the Cia de Luz y Fuerza de Monterrey (owned by the International Power Company of Canada) which was the last sizable private power company. Mexlight and Impulsora continued to operate as separate legal entities; in 1962 the rights and obligations acquired through the 1960 purchase of Impulsora were transferred by Nafinsa to Industrial Electrica Mexicana S.A. (IEMSA), a small affiliated company of CFE; in 1963 the physical assets of Mexlight in Mexico were transferred to its largest operating subsidiary, Compania de Luz y Fuerza del Centro (Centro). Early in 1965 CFE added some 50 companies to its system, thereby placing the Government in control of all but about 2% of the capacity available for public supply, and the nationalization of the Mexican power industry was practically complete; the power sector then consisted of three main groups (CFE, Centro, IEMSA) corresponding to the collective labor contracts held by three different labor unions. An agreement concluded in 1966 between CFE and two unions made possible in 1967 the merging with CFE of IEMSA and 18 other subsidiaries which had been operating previously with their own management and organization. The integration process continued in 1968 when CFE purchased from Nafinsa a majority of Mexlight/Centro shares. The full integration of the Power Sector into some form of a national organization, as recommended in 1962 by a "Technical Committee for the Study of the Integration of the Electric Power Services" and by Electricite de France, will be realized when Mexlight/Centro is absorbed by CFE; so far its dissolution has not been practicable because the funds needed to pay off its interest and its secured debt owed to the public (US $ 15 million) could be better employed in the development of the Sector. However, CFE has been in charge of investment planning for the whole sector since 1960, and responsible for full budgetary and financial control of the sector since 1969; moreover three members of CFE's Board have also been on Centro's Board and in 1970 CFE's Director General was appointed President of Centro.

II - The Association between the Bank and the Comision Federal de Electricidad

2.01 The Bank has made nine[1/] loans for power in Mexico for a total of US$579.8 million. Of this amount, US$80 million went to Mexlight/Centro directly (loans 24-ME and 186-ME) or through CFE. Since 1949 CFE has received seven loans totalling US$499.8 million equivalent as follows:

Loan No.	Date of Loan Agreement	Effective Date	Closing Date	Amounts ($ mln) Committed	Disbursed 2/	Interest %	Period (years) Grace	Term
12-ME	1/49	3/49	3/56	24.1	24.1	4-1/2	4	25
56-ME	1/52	6/52	7/59	29.7	29.7	4-1/2	3	25
194-ME	5/58	7/58	12/62	34.0	34.0	5-3/8	4	25
316-ME	6/62	7/62	4/65	130.0	130.0	5-3/4	2	23
436-ME	12/65	1/66	6/67	95.0 3/	95.0	5-1/2 - 6	4	20
544-ME	6/68	8/68	12/69	78.0 4/	72.1	6-1/4	4	20
659-ME	2/70	5/70	6/72	109.0 5/	32.4	7	4	20
Total				499.8	417.3			

The first three loans 12, 56 and 194-ME were made to finance the foreign exchange costs of selected power projects within the investment programs of the Comision. The fourth loan 316-ME was made to complete the financing

1/ A tenth loan, Loan 13-ME for US$10 million to Mexlight, was repaid from the proceeds of Loan 24-ME to Mexlight and cancelled.
2/ As of December 31, 1970.
3/ Loan 436-ME totalled US$110 million, with US$15 million to be relent by CFE to Mexlight.
4/ Loan 544-ME totalled US$90 million, with US$12 million to be relent by CFE to Mexlight.
5/ Loan 659-ME totalled US$125 million, with US$16 million to be relent by CFE to Mexlight.

of the Comision's overall investment program for 1962-65. The last three loans 436, 544 and 659-ME were designed to finance parts of the investment programs of the Power Sector as a whole; those three loans therefore included funds to be made available by CFE to Mexlight/Centro for the latter's expenditures.

2.02 Early in 1948 the Mexican Light and Power Company (Mexlight), serving the Federal District, applied to the Bank for a loan to finance new power plants and transmission lines. The Bank informed Mexlight that it could not consider its application until the Company undertook to reorganize its deficient capital structure.1/ Then Nacional Financiera, a corporation established and owned by the Government to finance industrial development and the sole agency entitled to negotiate external loans on behalf of the Government, applied for a loan of about US$109 million to finance part of CFE's 1947-1952 construction program. This program had been designed to eliminate the shortage of power prevailing in the northern and central regions of Mexico and to meet the future demand induced by the rapid population growth and industrialization. After giving careful consideration to CFE's program in view of a possible excess of capacity, the Bank, in consultation with the private companies serving the areas concerned, selected ten projects which were most urgently needed and which were complementary to the

1/ After Mexlight expressed its intention to carry out a reorganization of its capital structure, the Bank agreed to make an interim loan (13-ME of January 1949) of US$10 million to Nafinsa and CFE to be relent to Mexlight for the financing of its ongoing construction program up to July 1950. This short-term loan was refunded with the US$26 million loan 24-ME made by the Bank to Mexlight after its reorganization was completed in April 1950.

programs of the private companies.

2.03 The first loan (12-ME) made to CFE through Nafinsa in 1949 was to cover the foreign exchange cost, estimated at US$24.1 million, of these ten projects, with a total cost of US$56.7 million equivalent, to be completed by early 1954. The most important project was an increase of 155 MW in the capacity of the CFE's Miguel Aleman hydro-electric system, in order to supplement the power supplied by Mexlight to the Mexico City area where more than half of total sales originated from important industrial and commercial sectors. The second main project, scheduled to receive 14% of the Bank loan, consisted of a program of rural electrification in outlying areas, consisting of 28 generating stations totalling about 16.8 MW with appropriate transmission and distribution systems (para. 3.10). Other component projects were designed to increase the power supplied by CFE to foreign-owned companies servicing major agricultural or mining areas. Considering that the production of electrical goods in Mexico had consisted mainly in assembling components imported from the U.S., the Bank agreed that an amount not exceeding US$4 million of the Loan could be applied to purchases of electrical equipment within Mexico. The principal covenants of the Loan Agreement provided that: a) the Comision would not incur long-term debt unless its annual revenue was at least 1.5 times the maximum principal and interest payments in any fiscal year (see Table IV), and b) Nafinsa would provide CFE with local funds necessary to meet the estimated expenditures required for carrying out the projects.

2.04 After measures were taken by CFE and the Government under Bank recommendations to solve CFE's initial difficulties due to the lack of peso appropriations in 1949 and to CFE's lack of experience in carrying out a relatively large construction program (para. 3.02), the Bank made in 1952 a second loan (56-ME) of US$29.7 million to cover the foreign exchange cost of seven projects involving the installation of about 250 MW of new capacity, together with 1,450 km of transmission lines plus distribution facilities in the Monterrey area and the state of Sonora, to be completed by the end of 1955. Major covenants of the Loan Agreement were identical to those of the first Loan 12-ME. During negotiations of Loan 56-ME, Nafinsa agreed that a line of credit of US$150 million made by Eximbank to Nafinsa in 1951 would be reduced to US$120.3 million, i.e. by an amount equal to that of Loan 56-ME.

2.05 In September 1957 the Government of Mexico requested the Bank's assistance in financing the foreign exchange cost, estimated at US$78 million, of the major plants included in the 1955-62 investment program of CFE; this program had been based on the results of a power study recommended by the Bank after 1952 and undertaken by the Committee for the Study of the Mexican Electrical Industry (CEE-MEX). However, in view of the continuing low revenues of CFE and of the uneconomic lack of coordination between CFE's investment program and those of the private companies interconnected to CFE's network, the Bank was unwilling to consider the loan application until first steps had been taken by CFE and the Government to improve the situation (para. 5.02). Because many of the plants in CFE's investment program needed substantial further planning and engineering work before their economic feasibility could be established, CFE agreed that the Bank should finance in a first step only the most urgent projects already underway in areas where service was restricted and reserve generating capacity lacking. Therefore in May 1958 the Bank made Loan 194-ME to cover the foreign exchange cost, estimated at US$34 million, of four projects totalling 413 MW to be completed by the end of 1961, together with the installation of 1,600 km of transmission lines. Major covenants about the incurrence of long-term debt by CFE and about Government financing of local currency expenditures involved in the projects were identical to those of the previous loans to CFE. In addition, CFE and Nafinsa confirmed in six side letters that:

(a) it was desirable for CFE to earn a rate of return of at least 9% for the large systems of CFE;

(b) all steps would be taken to adjust power rates promptly to meet increases in the cost of labor and fuel, and CFE would study the advisability of changing existing procedures for adjustments of tariffs;

(c) careful consideration would be given to the possibility of consolidating the smaller systems of the Comision into zones with uniform tariffs;

(d) the Comision would hire consultants to supervise the construction of major hydro projects; CFE would also initiate at an early date reviews of its financial and budgetary procedures and of its procedures and manuals for the operation of its plants, and would retain consultants or senior officers to advise on these reviews;

(e) CFE would inform the Bank before making any major change in, or addition to, the 1958-62 construction program; and

(f) CFE would initiate consultations with interconnected companies with a view to achieving economies in future generation expansion through closer interconnection of networks and coordination of investments.

2.06 It had been assumed during the negotiations for Loan 194-ME that the Bank would make a fourth loan to cover the foreign exchange costs after January 1959 of eleven other projects in CFE's 1958-62 investment program. The first discussions with the Bank about a fourth loan took place in 1959 but at that time the financial position of CFE and the lack of progress by CFE and the Government on the issues covered by the 194-ME side letters caused the Bank to refuse further financing. In 1960 practically all the private foreign-owned companies which accounted for more than half of the power capacity of the country became Government-owned. All generation, transmission and distribution of electric power for public use became the exclusive domain of the Government. CFE was given responsibility for construction of all additions to the generating capacity of the electricity supply industry and for planning the industry's future growth. It set up an ambitious investment program for 1961/1965 in order to meet the rapidly growing demand in the whole country and the need for adequate capacity reserve. With Bank financing not forthcoming, the Comision obtained during 1960 and 1961 a number of large suppliers credits, incurred by Nafinsa on behalf of the Government, to finance most of the large items of equipment and a substantial part of the larger civil works in the investment program. After extensive further discussions between the Bank, the Government and CFE about the need to raise tariffs to levels which would enable CFE to finance its expansion program on a satisfactory basis, the Government put into effect in January 1962 new tariffs for the entire country which met the Bank's minimum objectives. The Bank considered a loan to complement the financing of the CFE investment program rather than to finance specific works in that program; this "program lending" was justified on the basis that CFE was sufficiently competent and experienced to borrow on lines normal in utility financing and that the larger items of the program were already financed, leaving only a multiplicity of small items to be covered.

2.07 In June 1962 the Bank approved Loan 316-ME of US$130 million to complement the financing of CFE's 1962-65 investment program, with a total cost of US$435 million and consisting of additional installed capacity of about 2,400 MW in the major systems, about 4,500 km of transmission lines, the expansion of CFE's own distribution systems and a rural electrification program involving 150 MW of small generating plants. Loan 316-ME was scheduled to finance the expenditures for: i) the purchase, through international bidding with up to 15% protection to local manufacturers, of the equipment not yet financed - US$85 million, ii) the foreign exchange component of all civil works not yet financed - US$39 million, iii) the foreign exchange costs for consultants and training - US$2 million, and iv) a part of the interest during construction on the Loan - US$4 million. Disbursements from the Loan were expected to be concentrated in 1962 and 1963 when financial requirements were projected to be greatest.

2.08 A number of covenants in the Loan and Guarantee Agreements were introduced by the Bank to ensure sound technical and financial development of CFE during the following years (Table IV). Debt limitation covenants were revised so that: a) CFE would not incur long-term debt in 1962 and 1963 without Bank approval, b) after 1963, CFE would not incur long-term debt unless its net receipts (before depreciation) plus the proceeds of the Power Consumption Tax covered the maximum debt service 1.5 times, and c) Nafinsa would not incur long-term debt on behalf of the Comision and all such debt outstanding would be transferred to CFE. The rate covenants stipulated that rates would be set and maintained to provide funds (including the proceeds of the Power Consumption Tax) sufficient to cover operating expenses and debt service and create a surplus adequate to meet a "reasonable" portion of the cost of CFE's expansion program; this portion was defined in a side letter as 33%. The Government guaranteed to grant rates enabling CFE to meet these stipulations; it guaranteed also to provide when necessary the additional funds needed to complete CFE projects. Other covenants relating to the investment program provided that no major addition would be made to CFE's investment program without Bank approval, and that CFE would during 1962-65 make annual agreements with the other two major Government-owned power companies (Mexlight and IEMSA) to coordinate the operation of their facilities and the planning of their investment programs for the subsequent five years. A covenant stipulated for the first time that CFE would have its financial statements audited annually by independent accountants or firms acceptable to the Bank. In a set of side letters, the Comision agreed to:

- award all contracts for equipment and materials and all contracts for civil works amounting to more than US$50,000 and Ps. 20 million, respectively, on the basis of international competitive bidding.

- employ a board of consultants to review the planning for major hydroelectric plants, and carry out formal acceptance tests for all plants entering into operation during 1962-65.
- prepare a plan to further improve its internal organization and administration, and promptly initiate an adequate training program for the operating staff of plants that would come into operation.
- make during 1962-65 annual revisions of its Financing Plan and of its expansion program for the five subsequent years; the revisions of the expansion program would be supported by studies about the economic justifications of the new plants and the advisability of interconnection between major systems and frequency unification, and would be reviewed by consultants acceptable to the Bank.

2.09 In 1965 the Government of Mexico requested assistance from the Bank in financing part of the investment program of the whole Power Sector. The heavy debt service obligations resulting from medium-term suppliers credits incurred by CFE before 1962 and by Mexlight together with the inadequate earnings of the sector had led to considerable short-term borrowing, and assistance was urgently needed to solve the short-term debt problem and to finance the ongoing investment program. During the negotiations, the Bank obtained from the Mexican authorities an undertaking that substantial loans from

Nafinsa and receipts from bond sales on external markets would be used to convert short- and medium-term debt into long-term debt, and that Mexico would obtain under a joint financing scheme US$35 million in credit commitments for the investment program from the probable suppliers of equipment. The Mexican authorities eventually agreed also to increase tariffs or the Power Consumption Tax so as to obtain a satisfactory rate of return on the Sector's assets. Loan 436-ME of US$110 million was made in December 1965 to cover the expenditures under the 1965-66 expansion program for foreign equipment and local equipment (purchased after international bidding with up to 15% protection), not financed from other sources, the foreign currency component (estimated at 15%) of civil works, and interest during construction. The two-year program included 1,835 MW of generating capacity under construction and to be completed over 1965-1968, but consisted mainly of transmission and distribution works totalling 2,900 km of lines and 2,700 MVA of substation capacity to be completed during 1965-1966. A significant feature of the power program was the start of the frequency changeover of the Central System from 50 cycles to 60 cycles; the frequency unification had been shown to be economically justified, and the Government confirmed, although reluctantly, that the first phase of the conversion would be completed in a three-year period starting July 1965.

2.10 A large number of covenants and side letters were introduced in the Loan Agreement 436-ME to insure a proper financial and technical development of the power Sector (see also Table IV):

(a) The rate covenant stipulated that rates would be adjusted and reviewed once a year so that the net revenues of the Power Sector (including the Power Consumption Tax) would produce a return of at least 8% on the net fixed assets in service; shortfalls in any one year would be compensated for in the following year over and above all other requirements.

(b) Withdrawals from the Loan Account were limited to US$40 million until action would have been taken to comply with the rate covenant, and the undisbursed loan amount would be cancelled if such action had not been taken prior to February 1966.

(c) Debt limitation covenants were revised so that the Sector would not incure long-term debt unless its net receipts before depreciation plus the proceeds of the consumption tax would cover the maximum service of the consolidated debt of the Sector at least 1.4 times. Nafinsa would assist the Power Sector in reducing its short-term debt. It was moreover confirmed in a side letter that the current position of the Power Sector would be balanced by the end of 1966 and afterwards if possible.

(d) CFE would be responsible for implementation of the program of frequency unification of the power systems and would retain consultants to provide technical assistance.

Several side letters confirmed the borrower's agreement to strengthen the coordination of the Power Sector with respect to budgetary control, investment planning and plant **operation** and by introduction of centralized dispatching for each system.

2.11 Though the frequency unification was subsequently eliminated from the 1965-66 investment program, against the Bank's recommendation (para. 4.08), progress toward full coordination and integration of the Power Sector was achieved during 1966-68 along several lines. CFE was given full control of the Sector's budgetary operations, Centro was reorganized satisfactorily and undertook to cooperate actively with CFE on the frequency changeover, and a load dispatch center was eventually set up in the Central System. In view of these efforts and Mexico's adherence to the rate covenant since 1966, the Bank agreed in 1968 to make a second loan, of US$90 million, to finance an investment program of the Power Sector including the construction of 3,220 MW of generating plants, about 5,400 km of transmission lines, about 7,300 MVA of substation capacity, and extensions to distribution network, all of which were under construction or expected to be started during the period April 1968-April 1969; initial work on the frequency changeover in the Central System was also included in the program. The Bank loan (544-ME) was to cover: (a) financial requirements of the Sector, estimated at US$71 million during the period April 1968-April 1969, for the foreign currency component of civil works and of equipment procured in Mexico, for the full cost of small equipment procured abroad and for two-thirds of the payments for larger equipment contracts (over $200,000) eligible for joint financing; and (b) specific contracts to the extent of US$19 million for major generating equipment with long manufacturing period on which payments would be made until late 1970. The size of the loan was based on the prospect that US$22.3 million of joint loans would be made available from supplying countries for the larger equipment contracts, and the specific contracts for major equipment, on a 2/3 - 1/3 sharing formula between the Bank and the joint lenders. Covenants and side letters agreed upon in the Loan Agreement were similar to those contained in the previous Agreement for Loan 436-ME (see above and Table IV) with additional assurances from the borrowers that:

(a) CFE and Centro would review the useful lives of major assets used in determining its depreciation charges.

(b) in view of the future high debt service requirements, the tariffs would not be reduced in 1968 and 1969,

(c) in order to avoid excessive debt service, indebtedness arising from acquisition of power utilities would be serviced only from funds set aside from earnings in excess of the minimum 8% rate of return.

2.12 The third sector program loan of US $ 125 million (Loan 659-ME) was made in 1970 to finance part of the 1970-1971 investment program of the Sector. An agreement on joint financing was worked out on the basis of a 50-50 participation of the Bank and joint lenders, the latter being expected to provide US $ 43 million. The 1970-1971 investment program consists of 2,980 MW of generating plants, about 8,800 km of transmission lines, and includes a new plan for the first phase of the frequency unification, to convert 300 MW of connected load by the end of 1972. A condition of effectiveness of the loan was the signing of a refunding agreement for the balance of the Sector's debt repayable to Nafinsa during 1970 through 1974. All covenants and side letters of the previous loan were repeated with changes in the covenant on debt service and on the Sector's cash position; the previous debt service covenant was replaced by a net income to interest test, an assets to total debt test and an assets to medium-term debt test; the Bank also agreed to reduce the minimum requirement on the current ratio from 1.0:1.0 to 0.95:1.00.

III. Projects Implementation and Costs

3.01 The first six Bank loans to CFE (1949-68) helped to finance a large number of projects, consisting of the construction or expansion of 24 hydroelectric plants totalling 2,527 MW, 19 steam electric plants and 5 gas turbines totalling 1,855 MW, small generating plants of various types aggregating 109 MW, transmission lines for a total of about 14,000 km of circuit-lines of which one-third of high-voltage (220 and 400 kv), and extension of various distribution systems including 15,800 new connections during the first two loans. All the major items are listed in Table III and its attachments at the end of this chapter.

3.02 Implementation of the projects financed by the first loan (1949) was difficult. The projects were originally expected to be completed by early 1954; the major part of the program was completed in 1955, except for the River diversions works of the Miguel Aleman system and some transmission lines, which were put in service in mid-1956. The main difficulties, which caused a delay of about two years in the completion of the program, arose soon after the loan was made. The Ps 50 million appropriation made by the Government to CFE in 1949 was insufficient to maintain the planned rate of construction, and so work on the projects was suspended or retarded. In view of the Bank's concern, the Government agreed to raise its appropriation to Ps 153 million in 1950 and Ps 161 million in 1951, amounts sufficient to finance the program. Also, because the preliminary plans and estimates put forward by CFE during the loan appraisal were very tentative, considerable revisions and changes had to be made in the various projects. In 1949/50 the Comision did not have the experience and staff necessary to handle a program that was far beyond anything it had previously attempted, and this led to technical errors, in addition to uncoordinated changes in the program; the Bank shared the blame by failing to examine the program more closely before granting the loan. In the original project, the needs of the Torreon-Chihuahua area were to be met by installing additional capacity at Chihuahua and Aldama. CFE afterwards decided, with Bank agreement, to install a single plant of three units at Chihuahua; the third unit was transferred in 1951 to Monterrey which was suffering shortage of power, and the Bank in 1953 financed from the undisbursed amounts of the loan another third unit for the Chihuahua plant. The River Diversions part of the Miguel Aleman system suffered large delays and local cost overruns because, as a result of deficient design and inadequate subsoil investigations, the canals were obstructed by slides and had to be replaced by tunnels, and leaking dams had to be emptied and sealed. The Comision had regarded the Rural Electrification project, considered by the Bank an important and justified part of CFE's program, as a safety margin to absorb changes and cost overruns in the rest of the program; the amount allotted to Rural Electrification was eventually reduced from US$3.26 million, as originally provided, to US$0.59 million, for the electrification of only 10 towns, as against 28 originally included. The List of Goods underwent numerous changes; as a result of these changes, the original underestimates of costs and delays in construction, the total cost of the projects amounted to US$85.3 million equivalent (compared to US$56.7 million forecast) with a foreign exchange cost of US$32.3 million (compared to US$24.1 million forecast) which was covered by the Bank loan plus other borrowings from foreign banks and suppliers. The major part of the total increase in local cost was attributable to the Miguel Aleman system and its River diversions, but substantial increases were incurred also in the Sonora and Puebla-Veracruz systems. Nevertheless, technical objectives were achieved; the expected 310 MW generating capacity were constructed, more than 1,400 km of transmission lines erected, and small distribution systems of CFE were expanded by 5,600 new connections.

3.03 The effect of the administrative and managerial measures (see paragraph 6.02) taken by CFE to improve the implementation of its construction programs did not materialize before 1958. Therefore, implementation of the projects covered by the second loan (56-ME of 1952) suffered from the same problems as encountered in the first -- except for the deficiency in Peso appropriations, which were satisfactory after 1950. Completion of the projects was originally expected by the end of 1955; some projects were completed with a few months' delay but the major part of the program was only accomplished by the end of 1957; some small hydro and thermal plants, which were added to the original list in 1953 and 1955 to use up the undisbursed amounts from the loan, were not completed until 1958-1960. Construction of projects was delayed mainly because of insufficient supervision and coordination within CFE; changes and additions to the loan projects had to be made in order to relieve power shortages that developed unexpectedly in some areas as a result of CFE's inadequate attention to overall planning (see paragraph 4.02). In view of the savings made on the foreign exchange cost of the two major hydroelectric projects (Tingambato and El Cobano plants, see Table III.1), the Comision asked and the Bank agreed to replace two small thermal plants in the List of Goods by seven plants and transmission facilities urgently needed in the corresponding areas. The US$29.7 million provided in loan 56-ME eventually financed the foreign exchange cost of the construction of 342 MW as against 252 MW originally planned, 2,200 km of transmission lines as against 1,450 km originally estimated, and the expansion of distribution systems by 10,200 connections. The total cost of the projects amounted to US$81.3 million equivalent as compared to US$52.1 million forecast, the difference arising from a local cost overrun of US$6.5 million on original projects (mainly the Tingambato plant) and from US$22.8 million due to the additional plants introduced into the project at a later stage.

3.04 Improvements in CFE's procedures and technical operations over the period 1950-1958 led to more satisfactory results in the implementation of the four projects covered by the third loan 194-ME (1958). Completion of the projects was expected by the end of 1961. Three projects were completed by mid-1962; the fourth one, the Mazatepec plant involving the construction of a thin arch dam, required longer time due to the careful geological investigations and supervisions made by an International Board of Consultants recommended by the Bank, and was completed in early 1963. Total capacity of projects amounted to 406 MW as compared to 414 MW forecast, with the expected 1,600 km of transmission lines. However, the total cost of the projects was almost double the forecast - US$130 million equivalent as against US$72 million - due to substantial increases in the local costs of the three hydroelectric plants and their associated transmission. A substantial part of the loan was used to finance equipment manufactured in Mexico, although the Bank had originally consented to this only in modest amounts; undisbursed amounts from the loan were used with Bank agreement to finance part of the foreign exchange cost of all the civil works undertaken since signature of the loan, without international competitive bidding (paragraph 3.08).

3.05 The first three loans had financed the installation of a total of 1,056 MW of new capacity in CFE over the period 1950-62. The fourth loan 316-ME encompassed CFE's total investment program for 1962-65.

CFE made annual construction program reviews, which were examined by its consultants and approved by the Bank, in order to take into account changes in load growth, construction and operating costs, etc.; in particular, the construction of the 720 MW Malpaso hydroelectric plant was substituted in December 1963 for that of three other plants totalling 145 MW. The program was on the whole implemented over the 1962-65 period except for the plants of Infiernillo, Delicias and Tijuana (Table III-3). The four units of the 600 MW Infiernillo hydroplant were planned for completion by June 1964; only two units were commissioned before 1966. The thermal plants of Tijuana and Delicias were planned for completion with four and three units respectively by the end of 1963; by the end of 1965 only three and two units had been installed respectively. For these reasons mainly, the 1962-65 construction program actually consisted of the installation in the large systems of 1,874 MW generating capacity as against 2,406 MW planned; in the smaller systems 104 MW were installed as compared to 114 MW originally forecast. As was the case with the first three loans, the total cost of the program turned out substantially higher than forecast; the 1,874 MW installed capacity had a total cost of US$441 million equivalent and required during 1962-65 investments totalling US$345 million, which is between 10 and 20% above the forecasts. Moreover, the efforts that CFE put into distribution and rural electrification (paragraph 3.11) led to investments of US$125 million equivalent during 1962-65, that is, 1.9 times the forecast amount, so that the expenditures in this period on facilities completed in the same period amounted to US$471 million as against US$353 million forecast. Due to substantial additional expenditures on other facilities to be completed after 1965, total investments of CFE during 1962-65 totalled US$620 million, more than 1.5 times the amount originally forecast.

3.06 The 1965-66 investment program partly financed by Loan 436-ME included CFE, Centro and IEMSA programs consisting of 1,115 MW generating capacity to be installed by CFE over 1965-66 (not including the 720 MW Malpaso plant expected to be completed by end of 1967), 2,900 km of high voltage transmission lines (220 kv and above), lower voltage transmission facilities, and distribution expansion to be undertaken by the three companies. This short-term program was not entirely completed, due to delays in construction of generating plants and to financial difficulties (paragraph 5.08) which led to reductions in the transmission and distribution investments. During the 1965-66 period, 984 MW of generating plants were installed (including 535 MW completed in 1965 and thus included also in Loan 316-ME program); the Topolobampo plant (41 MW) and extensions to the Merida and Tijuana plants (totalling 100 MW) were completed only after 1967 (para 3.07). About US$120 million equivalent were expected to be spent by the whole sector (of which one-third by CFE) on distribution and rural electrification, whereas only US$70 million was actually spent; investments on transmission amounted to US$70 million, about 55% of the forecast amount. Because of the elimination of the frequency changeover from the program, nothing was spent out of the original allocation for this purpose. Cost estimates for generating plants were again exceeded, US$200 million for 984 MW as against US$173 million for 1,115 MW planned. Because of the delays in the implementation of the investment program, US$16.6 million remained undisbursed from the loan by the end of 1967. The Bank agreed to amend the Loan Agreement and to allow CFE to use the undisbursed amount to finance the 1967 investment program; the interest rate on the undisbursed amount was raised from 5½% to 6%, in line with an interim change in the Bank's standard lending rate.

3.07 Under the 1968-69 investment program partly financed by Loan 544-ME, CFE and Centro were to install about 1,800 MW generating capacity (CFE) and about 3,700 km of high voltage transmission lines and to invest about US$175 million (of which 70% CFE) in distribution and rural electrification. With the final completion of the Malpaso plant in 1969, total generation capacity installed by CFE in 1968-70 amounted to 1,286 MW, complemented by more than 3,000 km of high voltage transmission lines and 3,900 MVA of high voltage transformer capacity. The Comision invested during 1968-69 about US$154 million in distribution and rural electrification and a total of US$435 million in fixed assets as against US$347 forecast, while Centro invested only US$64 million in transmission and distribution, i.e. US$20 million less than originally planned. Again the implementation of the first phase of the frequency changeover was postponed until the early 1970's, so that the 50 cycles generating capacity of CFE had to be increased by 150 MW in 1970 (second unit in the Valle de Mexico thermal plant).

Procurement

3.08 The three Loans 12, 56 and 194-ME to CFE during the 1950's were used to finance the foreign exchange components of the projects included. The policy of CFE had been to place equipment orders on the basis of international bidding and to award the construction contracts, financed entirely from CFE's own resources, on the basis of competitive bidding between, or negotiations with, Mexican contractors; in making the first three loans the Bank therefore confined itself to recommending purchase of equipment at reasonable prices. As a rule, proceeds from Bank loans were used to finance imported equipment, with exceptions in each case. The 12-ME Loan Agreement of 1949 stated that a maximum of US$4 million from the loan could be applied to equipment to be assembled with imported components in Mexico by the Industria Electrica Mexicana (a subsidiary of Westinghouse). After the 56-ME Loan Agreement was signed, the Bank reversed its negotiation position on local purchases and agreed to finance a maximum of US$2 million worth of imported equipment to be manufactured into finished products in Mexico. During disbursements of Loan 194-ME, the Bank, under increasing pressure from CFE, agreed again to finance local purchases of equipment in "moderate" amounts; disbursements for locally manufactured equipment purchased at competitive prices actually totalled US$9.2 million, of which US$3.8 million represented the value of imported components. The Bank also agreed at the end of 1961 to allow use of US$9.1 million undisbursed amounts from the loan to finance the foreign exchange component, estimated at 35%, of civil works undertaken for the project, on the basis that this imported component, consisting of construction equipment and spare parts, had been acquired through international "shopping".

3.09 The procurement procedures worked out for Loan 316-ME (1962) and adopted in the following loans represented a major change in the Bank's policy. As a matter of fact, with the development of the electrical equipment industry in Mexico, the Government and CFE had come under strong pressure from the Mexican manufacturers and therefore introduced in 1961 a procedure under which CFE has allowed electrical equipment produced locally (in part with imported components) a "Buy Mexican" differential. Because the bulk of the loan proceeds were to finance equipment and the foreign currency component of civil works of a very large investment program, the Bank and CFE agreed during negotiations that: (a) Mexican manufacturers would be granted a maximum 15% preference above the lowest foreign bid, and (b) CFE would award all civil works contracts above Ps 20 million on the basis of international competitive bidding, in order to obtain the lowest possible costs for the projects. Identical arrangements were made for procurement under the following Loan 436-ME of 1965; a similar procedure was set up for Loan 544-ME of 1968, with the exception that the Bank was to reimburse only the foreign currency component (estimated at 50%) of equipment orders placed with Mexican suppliers and would cover only 25% of the cost of civil works, instead of 100% and 30 - 35% respectively in the two previous loans. As a result of these extensions to the definition of goods eligible for Bank financing and of the availability of other funds for financing equipment, important parts of Bank loans have been used to finance civil works, as follows:

Loans	12-ME	56-ME	194-ME	316-ME	436-ME	544-ME
1. Amount of Loan (US$ mln)	24.1	29.7	34.0	130.0	110.0	83.2 1/
2. Disbursements for civil works (US$ mln)	-	-	9.1	57.3	13.2	9.9 1/
3. 2 as % of 1	-	-	27	44	12	12

1/ Amounts disbursed as of December 31, 1970.

3.10 Disbursements for local currency expenditures appear to have remained a rather constant proportion -- some 15-20% -- of total Bank disbursements, although they may well have been higher in the first half of the 1960s (mainly Loan 316-ME), for which period actual information is lacking. Some US$15 million out of the US$88 committed in the 1950s was devoted to purchase of locally produced equipment. Over the four-year period 1967-70, at least US$33 million, out of total disbursements of US$175 million, were devoted to local procurement, more than US$20 million for domestically produced electrical equipment. The share of total disbursements directed to local procurement does not seem to have fallen in recent years despite the above-mentioned reduction (from 100% to 50%) in the proportion of any individual equipment order that may be covered by loan proceeds.

Rural Electrification

3.11 When the first loan (12-ME of 1949) was made, the Bank considered rural electrification essential for the modernization of agriculture through irrigation pumping and the development of associated processing industries; although the justification based on the financial and economic returns of such undertakings had not been established, the rural electrification project was scheduled to receive 14% of the proceeds of Loan 12-ME; because of cost overruns on other projects rural electrification was eventually allotted a smaller amount despite the Bank's concern (paragraph 3.02). A small part of the second Loan 56-ME -- US$0.63 million -- was used to finance rural electrification projects. After program lending was initiated in 1962 with Loan 316-ME, the size of CFE's investment programs financed by the Bank loans has been such that the Bank could not devote much attention to the rural electrification part of these programs and gave CFE all responsibility and liberty about its important rural electrification programs which had been planned to cost US$29.3 million during 1962-1965, US$18.4 million during 1965-1966 and US$32.4 million during 1968-1969.

3.12 The increasingly important efforts made by CFE for rural electrification over the last two six-year periods can be summarized as follows:

Rural Electrification Investment of CFE 1/

	Period 1959-1964	1965-1970
- Investments (US$ mln)	46.6	120.5
- Number of villages and population centers newly connected in period	2,150	6,650
- Number of connections made	148,580	368,270
- Population of new service areas	2,660,600	5,752,600

In addition to its construction programs, CFE under the control of the Government has made financial efforts in favor of rural electrification by setting up for agricultural consumers low tariffs, subsidized by the

1/ Definition of rural electrification in this table is CFE's definition; it may overestimate the real investments made in "low density" areas. Figures used for 1970 relate to the program authorized for that year.

other classes of consumers (paragraph 5.13). Partly as a result of rural electrification effort, the share of households supplied with power (defined as residential and agricultural consumers) has increased from about 27% in 1960 to 53% in 1970 of the total number of households in Mexico. A small but significant part of this achievement has been funded by the Bank since disbursements from Loans 316 and 436-ME for rural electrification amounted to US$16.5 million.

IV. Load Forecasting, Investment Planning, and Interconnection[1/]

4.01 The Mexican power sector has traditionally comprised a substantial number of small and large isolated systems of plants and transmission networks; in the course of time small systems were progressively connected to larger ones, so that there are now six large systems -- Central, Occidental, Oriental, North, North West, North East -- and four smaller systems -- Acapulco, Tijuana, Yucatan, Ciudad Juarez. Tables II-A and the following analysis cover essentially the six larger systems.

4.02 During the 1950s, the Comision's methods and procedures in preparing and implementing its investment programs suffered from several weaknesses. The lack of flexible long-range planning was the cause of frequent program modifications to suit changes in the load growth, costs of investment and operation, etc.; these modifications often led to higher

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1/ Appraisal reports for the first two Loans 12-ME and 56-ME contained very little information and projections relating to the power market or to the demand and supply of power in the country and in CFE's systems. This chapter therefore covers only the subsequent Loans 194-ME up to 544-ME.

construction costs (paragraph 3.02 and 3.03). Moreover, CFE did not consistently investigate all alternative means of expanding system capacity before deciding on investments, due particularly to the lack of basic data about potential hydro sites; had this been done, the type, size and timing of some installations might have been somewhat different. Also, there was insufficient coordination of CFE's investments with those of the other interconnected companies, resulting in duplication in investments plans (especially in the Puebla - Veracruz system). After nationalization of the power sector in 1960 and concentration on CFE of responsibility for planning and providing all the new generating capacity in the country, projections of demand and generation for the whole sector have been made system by system by CFE on a long-term basis (8 to 10 years) and reviewed each year since 1961. For each system historic loads and sales for the past five years have been used for extrapolating "normal growth", and for systems with a rapid industrial growth CFE has made special surveys of the expected new industrial loads and added appropriate allowances to the projected "normal growth"; selection of investment alternatives has been on the basis of comparison of capital and operating costs discounted at a rate of 8%. The cost comparisons have used up-dated information and have been carried out since 1969 with a series of computer programs which take into account such factors as the probabilities of runoff, scheduled and unscheduled maintenance outages, etc. The planning of the investment programs was done on the whole with care and by competent staff, and was generally reviewed and approved by CFE's general consultants (SOFRELEC) engaged for this purpose since 1963 at the Bank's recommendation.

4.03 Projections in Loan 194-ME (1958) were made for the four systems -- Central, Oriental, Occidental, North West -- in which the four loan projects were to be built (see Table II-A.1). With the exception of the Occidental system, demand forecasts for the three other systems overestimated by about 15% on average the future demand over the 1958-1962 period; for the Central system, the load factor had been estimated correctly (0.59) but sales had been overestimated, while in the North West system sales had been correctly estimated on the average, but the load factor underestimated (forecast was increasing from 0.48 to 0.55 while the actual load factor averaged 0.57). Total sales of CFE, projected on the basis of past trends, were overestimated over 1958-1963 and underestimated for 1964 and 1965. The largest discrepancy occurred for the 1961 forecast, due to the drop in CFE's sales from 1960 to 1961 originating from a substantial decrease in CFE's sales in the Central System; this resulted from low rainfall in 1961 in the area of the Miguel Aleman hydroplants; and also from the storage of water in several large reservoirs in order to prevent a temporary shortage foreseen for 1963.

4.04 Planning of the expansion programs partially financed by Loan 316-ME of 1962 and later loans was done for each system by estimating the peak loads, capability and generation for the subsequent ten years, with more detail for the first five years than the second. The projections for generation and energy sales in each system covered all the suppliers and distributors of the system. In general, the sizes of the new units were determined so that each installation could carry the increase in demand for a two to three-year period and so that the maximum demand would be met by the firm capacity, defined as the installed capacity less the largest unit. In the 1962 plan the rate of installation of new capacity was scheduled to be higher during the first quinquenium than during the second, due mainly to the termination of power imports from the U.S.A. and the necessity for more reserve capacity. There was a marked tendency to overestimate future demand during the first quinquenium and to underestimate it afterwards, except in the case of the Central system, for which forecasts were fairly accurate, and the North East system for which future demand was strongly overestimated over the whole ten-year period. Because the load factors were in general slightly underestimated for all systems, discrepancies between forecast and actual developments were smaller for energy sales than for peak loads or even reversed; energy sales forecasts were fairly accurate or slightly underestimated for the Central, Occidental, North and North West systems but markedly overestimated for the Oriental and North East systems. As a consequence of the high load forecasts and the ample allowances made for reserves, it appears that there may have been some overinvestment in four of the major systems during the period 1963-1967 and in the Oriental and Occidental systems during the period 1962-1965 (see paragraph 4.07).

4.05 The general electrification plan for Mexico drawn up in 1962 by CFE's general consultants (Electricite de France and SOFRELEC) served as a general guide and was reviewed in 1963 and 1964; the Bank and the consultants approved all changes. Moreover, the sector program reviewed annually by CFE determined the new generating capacity required and the advisability of further extensions or interconnections of transmission systems. The 1965 program, which formed the basis for Loan 436-ME, planned for starting in 1966 the frequency changeover of the Central System from 50 cycles to 60 cycles, foreseeing a decrease of the 50 cycles peak load from 1,217 MW in 1965 to 640 MW in 1970 with a gradual conversion of the relevant installed capacity, and the 60 cycles peak load catering for the remaining demand in the Central System. It was also planned to connect the Occidental System with the Oriental System in 1967. Forecasts for load and energy requirements had been adjusted in light of past experience. The 1965 forecasts still show a tendency to underestimate the demand after the first five-year period of the projection; demand for the first period was somewhat overestimated in three systems and underestimated in the other three, seriously only in one. Because the frequency conversion in the Central System did not take place during 1965-1970, its actual peak demand was compared in Table II-A.3 to the forecast sum of 50 cycles and 60 cycles peak demands. Differences between projections and actual figures were, in several instances, greater in the case of energy sales, due to reinforcing errors on load factors. Interconnection between the Oriental and Occidental Systems was actually realized on a provisional basis in 1967 because of the urgent need to supply power to the Occidental System, and through permanent facilities in 1969. It appears again that over-investment which may have taken place after 1962 was absorbed by demand only in the late 1960s (paragraph 4.07).

Investment Planning

4.06 The 1962 appraisal report (Loan 316-ME) discussed the need to improve CFE's approach and methods of planning and, in particular, to overcome the previous lack of consistent investigation of all alternative means of expanding systems capacity. It was recognized by CFE and the Bank that some of the large thermal plants previously installed could have been delayed a year or two or started with smaller units. As a matter of fact, prior to 1962, there had been some duplication of investments in the Central, Oriental and Northern Systems; as suggested by the following table which shows for each system the effective capacity (different in many instances from the installed capacity because of the lack of acceptance testing of new units before 1962), the firm capacity (effective capacity less the largest unit), the actual peak load and the resulting "firm" reserve (firm capacity less peak load).

In MW	1957	1958	1959	1960	1961
Central System					
Effective Capacity	858	940	940	1023	1023
Firm Capacity	809	858	858	941	941
Peak Load	636	712	774	812	886
Firm Reserve 1/	173	146	84	129	57
Oriental System					
Effective Capacity	109	140	255	294	294
Firm Capacity	94	121	216	255	255
Peak Load	99	118	162	185	192
Firm Reserve 1/	-5	3	54	70	63
North System					
Effective Capacity	144	177	213	213	213
Firm Capacity	127	144	177	177	177
Peak Load	123	127	119	128	137
Firm Reserve 1/	4	17	58	49	40
Occidental System: Firm Reserve	19	36	42	16	0
North West System: Firm Reserve	-14	-9	-1	19	3
North East System: Firm Reserve	-6	-13	-28	-27	-3

1/ Underlined figures for firm reserve indicate when firm reserve exceeded the largest unit in service.

The high levels of firm reserve in Central, Oriental and North Systems suggest that the installation made in 1958 and 1960 of two 82 MW units in the Lecheria thermal plant of Mexlight financed by Loan 186-ME (1958) could have been postponed up to 1960 and 1961 respectively; that in the Temaxcal hydroplant of the Oriental System financed by the Loan 194-ME (1958) the third 39 MW unit might have been installed one year later (in 1961) and the fourth unit after 1961; and that better investment coordination between power entities would have resulted in installation of the fourth unit (33 MW) of the Francke thermal plant of IEMSA in 1961 instead of 1959.

4.07 CFE's 1962 investment plans recognized the need for increased reserve capacity in the Occidental and North West Systems, made somewhat reduced reserve allowances for the Oriental and Northern Systems, but apparently allowed for large reserves in the Central System, after 1964 and in the North East System during 1963-1965, as follows:

LOAN 316-ME (1962): FIRM RESERVE FORECASTS[1/] (MW)

	1962	1963	1964	1965	1966	1967	1968
Central System	81	150	55	525	425	315	195
Oriental System	96	53	15	20	39	62	37
Occidental System	28	2	41	13	21	66	32
North System	32	24	14	39	63	54	45
North West System	19	44	77	63	47	30	16
North East System	62	128	122	95	65	33	72

1/ Underlined figures indicate that the firm reserve exceeded the largest unit in service foreseen.

However, mainly because forecasts had overestimated the peak loads during the period 1962-1966 (paragraph 4.04), substantial firm reserves developed in four systems (Central, Oriental, North, and North East) as shown in the following table:

ACTUAL FIRM RESERVES IN THE LARGE SYSTEMS 1962-70

in MW	1962	1963	1964	1965	1966	1967	1968	1969	1970
Central									
Effective Capacity	1133	1353	1408	1763	2099	2044	1946	2099	2099
Firm Capacity	1051	1188	1243	1595	1931	1876	1778	1931	1931
Peak Load	952	1038	1159	1270	1356	1459	1584	1738	1935
Firm Reserve 1/	99	150	84	325	575	417	194	193	-4
Oriental (Interconnected as of 1967)									
Effective Capacity	331	403	405	459	459	941	1197	1764	1914
Firm Capacity	292	364	366	420	420	886	1142	1584	1734
Peak Load	211	280	308	349	427	938	1073	1286	1593
Firm Reserve 1/	81	84	58	71	-7	-52	69	298	141
North									
Effective Capacity	213	213	273	273	306	347	347	347	347
Firm Capacity	177	177	237	237	270	306	306	306	306
Peak Load	149	143	169	185	202	223	232	257	290
Firm Reserve 1/	28	34	68	52	68	83	74	49	16
North East									
Effective Capacity	142	292	349	431	431	431	461	461	503
Firm Capacity	104	217	274	356	356	356	386	386	428
Peak Load	132	145	189	221	248	293	334	399	458
Firm Reserve 1/	-28	72	85	135	108	63	52	-13	-30
Occidental									
Firm Reserves	50	31	51	26	-8	Interconnected with Oriental			
North West									
Net Reserves	4	6	87	48	35	26	50	7	28

1/ Figures for firm reserves were underlined when they exceeded the largest unit in service.

As CFE indicated to the Bank during the negotiations for Loan 436-ME, most systems had by the end of 1965 significant excess capacity which was slowly absorbed with the growth of demand in following years. Several units in the Central System were devoted to serving the needs of the Occidental and later the Interconnected Market (Occidental plus Oriental) to prevent shortages there - particularly one 55 MW unit of the Mazatepec plant in 1967 and 1968 and two 50 MW units of the Tingambato plant in 1968. Excess capacity in the Central System during 1965-69 resulted from the commissioning in 1965 and 1966 of the 670 MW Infiernillo hydroplant financed under Loan 316-ME; the last three out of the four 168 MW units in the plant could have been installed in 1967-68, that is, with two years delay. The previous table indicates also that in the Oriental System the installation in 1962/63 of 3 x 39 MW units in the Poza Rica thermal plant financed under Loan 316-ME could have been postponed by one year; in the North System the installation in 1964/66 of the second and third units (33 MW each) in the Delicias thermal plant financed under Loans 316 and 436-ME could have been postponed by two years, and the extension in 1967 of the Laguna thermal plant by one 41 MW unit could have been delayed up to 1970. In the North East System, where 30 MW excess generating capacity were shut down in 1965 as stand-by, it could have been possible to postpone the installation of the 3 x 37.5 MW units in the Rio Bravo and Nava thermal plants by one year and that of the third 75 MW unit in the Monterrey plant by three years; all these units were financed under Loans 316 and 436-ME. Fairly ample capacity reserve allowances were made in the plans underlying Loan 436-ME, especially for the North and North East systems, and spare capacity in the Central System has been in most years well above the 15% (of peak load) reserve margin used at that time for planning purposes. Recently, most excess capacity has been absorbed, partly due to higher than expected load growth. But it would seem that some of the units mentioned above might well have been postponed as indicated, and that this would have helped to lighten CFE's 1965-68 financial burden (paragraph 5.07).

Interconnection

4.08 The Bank first broached the question of interconnection among the major regional systems in Mexico in negotiations related to the 1962 loan. The EdF-SOFRELEC "National Electrification Plan", submitted in that year, had recommended frequency unification as a critical step toward interconnection. The Central System had been supplying Mexico City and the surrounding area at 50 cycles while all other systems were operating at 60 cycles. Frequency unification, and the interconnection that it would make possible, would have a number of advantages: minimization of resources required for production and transmission of electricity, use of larger and more economical generating units, a higher degree of reliability and flexibility in operations, and better utilization of the hydro-electric energy potential of the Mexican river basins, which have non-coincident regimes. Reports and reviews by CFE consultants in 1963 and following years confirmed the economic justification of the conversion of the Central System to 60 cycles and recommended that the conversion be started in 1965 because of the expected availability of sufficient capacity at Infiernillo and Malpaso to provide flexibility. The 1965 Sector Program financed with the assistance of Loan 436-ME included provisions for the frequency changeover to be carried out in 2 phases over eight years at a cost of about $ 120 million; the first phase was to be completed in three years according to a side letter to the Loan Agreement. During the following years several master plans were prepared, each of which in turn became obsolete because the Government and CFE, fearing consumer complaints and political opposition, did not take the necessary steps to implement them, and due also to the lack of cooperation from Centro and its labor union. Elimination of the frequency unification from the 1965-66 program destroyed the justification given in 1963 to the addition to Loan 316-ME of the Malpaso plant, which was expected to bring a surplus of capacity allowing for flexibility in the frequency changeover. Although the Bank mentioned the possibility of stopping disbursements from Loan 436-ME, and although the Guarantee and Loan Agreements for Loans 544-ME and 659 ME included covenants providing for the timely initiation and completion of the first phase, no actual conversion of any of the connected load has been accomplished to date. The last Loan and Guarantee Agreements (1970) have included covenants to assure that conversion will be carried out according to a new timetable, which provides for conversion of 300 MW of connected load by September 1972, as a first phase. Some measures have been taken to prepare the changeover; since 1968 decrees have provided that frequency sensitive equipment either imported or locally manufactured must be capable of operating at 60 cycles or both frequencies; a recent Presidential decree has committed the Government to prompt frequency unification. This is desirable since, according to the 1969 master plan, any further delay in frequency changeover would reduce by 2 to 2.5 percentage points per year the expected return on the investment, estimated at 14 to 20 per cent.

4.09 Other advantages similar to those of frequency unification could be obtained from the interconnection of the major southern and northern systems of Mexico. Moreover, because the peak power demand occurs during December in the southern systems (Central, Oriental and Occidental), while in the three northern systems the irrigation and air conditioning loads put the annual peak in August-September, linking of the two groups of systems would reduce the requirements for additional generating capacity. To date only the Occidental and Oriental Systems have been connected; this was implemented in 1969 through a permanent link which has enabled the Occidental System to be supplied indirectly from the Malpaso plant. One study that is contributing to long-term transmission planning is a joint effort between CFE and the Bank's Development Research Center. This study, based on computerized decision models, suggests that the relative costs of transmission and generating capacity are such that it is optimal to connect each system with at least one other as soon as possible and to permit the northern and southern systems to interchange power during the peak periods on each.

V - Financial Developments and Projections, Joint Financing and Tariffs

5.01 CFE's expansion was originally financed largely from Federal Government appropriations, the whole proceeds of the 10% Power Consumption Tax and to a small extent from loans; of the consolidated fund of the Comision in the mid 1950s 70% came from Government appropriations, 21% from the electricity tax, and the rest mainly from the Comision's profits. The long-term debt which amounted then to one quarter of total capitalization consisted principally of an Exim Bank loan of US$ 20 million incurred in 1945 and the first two IBRD loans. Even though inadequate provisions had been made for depreciation, the net operating revenues and profits of the Comision had been very low up to that time, due to the malfunctioning of the Tariff Commission. The structure and basis of all public utility tariffs in Mexico, including those of the Comision, were established by the Tariff Commission separately for each independent distribution system and for each particular installation; on the rate base defined as the historical cost of investment plus an allowance for working capital, the public utilities were allowed by law to earn a rate of return supposed to be not less than the highest rate for Government bonds. However, this return was seldom earned because CFE's accounting organization had not evaluated correctly the asset rate base, because sales were overestimated and costs underestimated and, above all, because of the complicated and time-consuming procedures of the Tariff Commission, which delayed adjustments of rates for increases in the cost of labor and fuel. As a result, the financial rate of return of CFE as a whole ranged from 1.3 to 3.3% of the net fixed assets in operation prior to 1957; the rate of return varied considerably among the various systems of CFE, from 0 in the Northern System to about 7% in the Central and Oriental Systems, reaching 10% in the smaller North West and North East Systems.

5.02 In 1957 CFE started to reorganize its financial and accounting procedures, following Bank suggestions; also a tariff increase of about

38% was granted in January 1957 which allowed CFE to earn a return of more than 5% in 1957-59. Early in 1958 CFE reached agreements with the private companies connected to its network about the use and the price of bulk supply from its future power plants, and the Bank then agreed to finance these power plants with Loan 194-ME. Covenants and side letters to the Loan Agreement expressed for the first time the Bank's concern about CFE's tariffs and earnings (para 2.05); it was agreed by CFE and Nafinsa that CFE's smaller systems should be consolidated into zones with uniform tariffs, that procedures for adjustment of tariffs be improved to permit adjustments, that a 9% return be earned on CFE's large systems, and that the financial and budgetary procedures of CFE be reviewed with the advice of consultants. Tariffs were not raised in 1959 to produce the 9% return, and, as a consequence, the Bank refused to pursue talks initiated by CFE and the Mexican Government about further lending. In late 1960 and early 1961 the Government approved certain increases in CFE's tariffs which were still not sufficient to rectify CFE's financial position; CFE's rate of return increased only slightly. Furthermore these increases were mostly in CFE's wholesale tariffs to Mexlight, worsening the latter's already difficult financial situation, because adequate adjustment of its retail tariffs was not permitted.

5.03 With the nationalization of the power sector in 1960, the previous tariff regulations lost their former justification of controlling the profits of a private monopoly; a study made in 1961 by a Governmental committee to determine the rate level necessary to finance adequately the expansion program of the power sector resulted in the establishment in January 1962 of new tariffs which met the minimum conditions put by the Bank for further lending. These new tariffs were set to achieve a 20% increase in revenues from sales and at the same time they established a schedule of eleven classes of consumers to be gradually introduced on a nationwide basis with full effect by 1964; this tariff revision benefitted the distributing companies as well. The new electric power legislation also instructed the power entities to charge annual depreciation at a flat 2% rate which, though on the low side, represented a clear improvement over previous practices, which had resulted, in the case of CFE in an accumulated depreciation reserve equivalent at the end of 1961 to only 4% of the fixed assets in operation.

5.04 As a result of the tariff revision and the large construction program to be undertaken by CFE over 1962-65, revenues of the Comision were projected to triple from 1961 to 1965 and net operating income was supposed to increase 3.5 times (Table II-A.2). Because CFE performance under the rate covenants of loans prior to 316-ME had been poor, a rate covenant was introduced in Loan 316-ME which called for a minimum contribution of 33% of construction expenditures, on a running four-year average basis, from net internal cash generation plus the proceeds of the power tax on all electricity sales in Mexico (whether or not sales of CFE). The earnings picture deteriorated after 1962, due to the fact that sales were lower than had been forecast in the tariff study of 1961 and that operating costs increased substantially mainly as a result of much larger depreciation allowances made in accordance with the new legislation. (Depreciation allowance in CFE increased from Ps 24.7 million in 1961 to Ps 78.4 million in 1962 and Ps 198 million in 1965). The financial return of CFE excluding the proceeds of the Power Consumption Tax, dropped from 6.2% in 1961 to 3.8% in 1964 and 1965. When the rate covenant calling for a minimum contribution of 33% of construction expenditures became operative at the end of 1964 CFE did not meet the requirements; over the four-year period 1961-1964, CFE's net internal cash generation plus the total proceeds of the power tax contributed 20.8% to the total construction expenditures of CFE. The Mexican authorities took no corrective steps, on the grounds that it was difficult to increase rates in view of the prevailing overinvestment in the power sector. However, because disbursements from Loan 436-ME were made conditional upon an increase of gross tariffs (including the Power Consumption Tax) sufficient to assure a return of 8% for the Sector, the Government did raise the Power Consumption Tax on Industrial and Commercial Consumers from 10 to 15 percent early in 1966. Since CFE has received the proceeds of the tax, including the part levied on other companies' sales, its financial position started to improve as soon as the increase became effective; its overall rate of return (including the proceeds of the tax) rose from 6.4% in 1965 to 8% in 1966 and to more than 9% since (Table II-A.2). Correspondingly, the Sector's overall rate of return increased from 6.6% in 1965 to 8% in 1966, and to more than 9% in 1968-69 (Table II-A.3), meeting the 8% rate covenant set up in the 436-ME Loan Agreement.

Financing of the Investment Programs - and the Debt Service Problem

5.05 The year 1958 marked the beginning of a difficult period for the Mexican Power Sector in connection with the service of its short- and medium-term debt. Loan 194-ME was made in 1958 to finance a first group of projects being the most urgent and already underway, with the remaining projects of CFE's 1958-62 investment program left for financing by another Bank loan at a later date. The US$ 240 million total cost of the 1958-62 investment program was expected to be covered by CFE's own resources to the extent of 20%, domestic public contribution 50%, and Bank loans 30%. Due to the traditional underestimation of construction costs and the great expansion of CFE's construction program caused by its nationwide responsibility for new generation, total cost of the 1962-1965 investment program doubled, amounting to US$ 470 million. With the planned second loan from the Bank not forthcoming because of the unsatisfactory tariff situation (para 5.02), CFE obtained in 1959-61 some large medium-term suppliers' credits, totalling US$ 187.2 million, partly for equipment and partly for civil works. Since CFE's net revenues did not provide the debt service coverage required under the Bank's 1958 loan agreement, these credits were incurred by Nafinsa on behalf of the Government. As a result, domestic sources, including

US$ 123 million from the suppliers' credits recorded as loans from Nafinsa, contributed 69% of fixed investment under the 1958-62 program while net internal cash generation contributed only 8% and Bank loans 11%; moreover the Comision had to resort during 1961 and 1962 to substantial short-term financing, mostly through bank loans and notes to contractors maturing in a year or less, so that US$ 39 million (8% of total cost) were financed at the expense of working capital. (Table II-B).

5.06 The plan made in connection with Loan 316-ME for financing the completion of the 1962-65 Investment program established that the estimated US$ 435 million total cost of the program would be financed 30% from the Bank, and 70% from domestic resources; internal cash generation and the Power Consumption Tax would cover 22% of total requirements of funds, the outstanding part of the suppliers' credits incurred by Nafinsa providing for US$ 132 million (29%), and local short-term borrowing and notes expected to provide US$ 21 million. Due to design changes and additions made to CFE's program (introduction of the Malpaso plant and additional distribution and rural electrification) and to cost overruns on the projects, total requirements of funds during 1962-65 amounted to US$ 657 million, 1.5 times forecast. In addition to the US$ 132 million of suppliers' credits made available to CFE through Nafinsa, CFE obtained in 1962-64 additional suppliers' credits totalling US$ 23 million and loans from foreign private banks totalling US$ 40 million; this borrowing was mostly on medium-range terms and was made in a few instances with Bank approval. Proceeds of a Mexican Government bond issue in Europe which were transferred to CFE contributed US$ 26 million in 1965, and Bank loans US$ 136 million as expected; as a result foreign borrowing (excluding Nafinsa suppliers' credits) financed one third of total requirements.

5.07 By the end of 1964, CFE's total long and medium term debt outstanding, excluding short-term debt due within one year, amounted to 42% of total capitalization, but of this debt 58% was medium term, involving large immediate obligations for amortization and interest. Moreover, the current ratio of CFE (current assets divided by current liabilities) was 0.7 as of December 1964, resulting from the short-term borrowing made partly to finance capital expenditures. As a consequence, total debt service in 1965 amounted to US$ 168 million, as compared to US$ 23 million in 1964 and US$ 18 million in 1962-1963, while gross internal cash generation of CFE in 1965 was only US$ 56 million. Confronted with this problem, CFE and the Mexican Government decided on concerted efforts to improve the Comision's debt structure. In 1965 Nafinsa agreed to the funding of US$ 112 million of the current portion of what it was owed by CFE. As a result of the 1965 debt servicing arrangements, the actual domestic contribution to the financing of the 1962-65 investment program accounted for two-thirds of total requirements of funds, CFE's own resources and the Power Consumption Tax exceeding total debt service slightly (by US$ 15.5 million 1/), Nafinsa loans (including the 1959-61 suppliers' credits) and Government appropriations providing the rest of the domestic contribution, with the exception of $ 73 million equivalent from local banks and consumers.

5.08 The high debt service requirements had also represented a formidable problem for the other entities of the Power Sector. Mexlight/Centro had to resort in the early 60's to medium-term suppliers' credits and to medium and short-term debt refinancing by foreign banks; and moreover in 1964 its gross internal cash generation amounted to only 28% of its total debt service. The current ratio for the Sector was 0.62 by the end of 1964. Loan 436-ME of 1965 was made by the Bank as part of a "salvage operation" of the financial problem which faced the whole Power Sector during 1965-66. First, construction expenditures and other investments were expected to amount still to US$ 308 million; second, total debt service requirements were to amount to US$404 million 2/ during those 2 years (excluding US$ 47 million debt incurred in 1965 and to be repaid in 1966). Gross internal cash generation of the Sector and the increased power tax were to provide US$ 247 million. Bank loans, and various joint loans to be obtained for a total of US$ 35 million from probable foreign suppliers of the Sector under the joint

1/ Table II-B shows net internal cash generation of $ 51.2 million and Power Consumption Tax receipt of $ 76.1 million; however the $111.8 million of debt refinanced by Nafinsa has to be deducted, leaving $ 15.5 million.

2/ Table II-B shows debt service requirements of only $200.1 million, the portion expected to be covered from CFE's internal cash generation; the remainder was to be refinanced as follows: $ 152 million by Nafinsa, $ 47.5 million by foreign bond issues and $4.2 million by loans from foreign private banks.

financing scheme, were expected to provide US$ 146 million; two suppliers' credits incurred by CFE with the Bank's permission in 1964 were to provide US$ 21 million. Domestic contributions from private and public sectors were expected to contribute US$ 72 million. In addition to the financing of its expansion, various measures were planned by the Power Sector for refinancing of its debt: Nafinsa was to refinance US$ 152 million, receipts from bond issues by the Government in the U.S. and by CFE in Europe were expected to contribute US$ 47.5 million, and CFE and Centro had obtained medium-term loans from foreign banks totalling US$ 26 million, of which $4.2 for debt service and $ 21.8 million for new investment. As in the previous cases, total costs of investments made during 1965-66 were higher than forecast, amounting to US$ 346 million; gross internal cash generation and the power tax totalling US$ 252 million were insuficient to meet the US$ 377 total debt service, which was therefore further covered, as expected by US$ 143 million refinancing from Nafinsa and by part of the proceeds of foreign bonds issued in 1965-66 for a total of US$ 60 million. Other domestic contributions from the private and public sectors amounted to US$ 86 million, representing one fourth of total investments. About 15 loans made by foreign banks in 1965-66 on a medium-term basis amounted to US$ 100 million, and suppliers' credits to about US$ 24 million. Due to the difficulties encountered in the complicated disbursement procedures set up under the joint financing scheme and to the delays in arranging the joint loans (para 5.12), the

436-ME Bank loan contributed only US$ 57 million during 1965-66 and disbursements from joint loans, beginning only in 1967, contributed nothing.

5.09 At the end of 1967, the long-term debt of the Power Sector, of which 77% was owed to Nafinsa and IBRD, represented 45% of total capitalization. The current position of the Sector had improved substantially since the 1965 crisis, mainly due to the funding on a long-term basis by Nafinsa and by proceeds of foreign bond issues in 1966 and 1967, of some of the short-term credits and to the transformation of most of the balance of the short-term credits into five-year commercial bank credits. The Sector owed more than US$ 100 million to 16 commercial banks at the end of 1967; because of the high requirements for servicing these debts during 1968-69, arrangements were sought to have all maturities rolled over by foreign banks as they would become due. The 1968-69 investment program of the Power Sector, expected to cost about US$ 500 million, was planned to be financed by net internal cash generation and Power Consumption Tax to the extent of 42%; other domestic contributions were expected to contribute 15%. Total foreign borrowing was supposed to provide US$ 214 million (excluding US$ 67 million of commercial bank maturities to be rolled over), of which US$ 170 million from IBRD, and US$ 15 million from foreign bond issues; although CFE, up to the end of 1967, had been able to avail itself of only US$ 7 million of joint loans arranged in conjunction with the previous Loan 436-ME, it was planned, on the basis of a second meeting on joint financing held in 1967, to have US$ 22 million of joint loans available during 1968-69. Total actual investments of the power sector during the two-year period amounted to US$ 606 million 1/; due mainly to the incurrence by Centro of large short and medium-term debt without Bank approval, the sector in 1969 had to face up to the fact that it was over-dependent on five-year credits from commercial banks, and part of the debt service during 1969-70 had to be refinanced by Nafinsa on a long-term basis. As a result of higher debt service and the substantial increase in investment, net internal cash generation and the power tax covered only 13% of total requirements of funds; and other domestic sources, primarily loans from the Government and others, contributed 19 percent. Foreign borrowing again covered two-thirds of the financial requirements; foreign bonds issued by the Government and CFE provided US$ 79 million and foreign private loans mainly on a medium-term basis provided about US$ 217 million. Bank loans supplied only US$ 93 million, due to the slow rate of disbursements caused by the joint financing procedures; joint loans under 436-ME provided US$ 1.1 million in 1968 and those under the 544-ME Agreement provided US$ 11.4 million during 1968-69, most of it in 1969.

Financing of the Development of the Power Sector: Conclusion.

5.10 The formidable expansion of CFE and the Power Sector during the 1960's has imposed huge financial requirements. During the period

1/ Including financial investments

1960-65 the lack of cash generation within the sector resulting from the Government policy of having low power rates, the delays in obtaining Bank loans because of the failure to respect rate covenants, the systematic cost overruns incurred on investment programs because of changes in design and addition of facilities, and the possible overinvestments made on generating facilities led the Power Sector to incur, without the Bank's consent and control, important amounts of short and medium-term debts from suppliers of equipment and commercial banks in Mexico and abroad. After 1965, revenues from the power tax were substantially increased as a result of pressure from the Bank, so that gross cash generation reached satisfactory levels; however the service of the debt incurred previously became the major issue, wiping out most of the cash generation and requiring large assistance from the National Development Bank (Nafinsa)and from commercial banks to refinance part of the debt; in the meanwhile, assistance from Bank loans became less efficient due to the complex and time consuming disbursement procedures of the joint financing schemes, which did not bring the expected amounts of funds. The salvage operation set up in 1965 to resolve the short-term debt service problem brought only a temporary relief in the financial difficulties of the Sector, and the conversion of short-term debt into medium-term debt has placed the Sector in the late 60's and early 70's in similar, but less critical, financial difficulties, which are expected to be solved by raising or maintaining tariffs above the levels sufficient to meet the 8% rate covenant and/or by Nafinsa refinancing of the medium-term debt, the latter probably to the detriment of other sectors.

Joint Financing.

5.11 Early in 1965, the initiative to set up a joint financing scheme for the Mexican Power Sector was taken by the Bank in view of favorable attitudes of various countries regarding Mexico's economic prospects and creditworthiness. The Mexican authorities had been reluctant initially, fearing less favorable conditions than obtainable on suppliers' credits and a gradual withdrawal of the Bank from Mexico. The Bank's main reply and objective was that the joint financing arrangement would permit it to lend larger amounts to other sectors which were in need of financial support, that joint financing would increase the inflow of foreign capital into Mexico, and that joint financing, by developing other sources of funds, would increase Mexico's independence of the Bank. After a great deal of time had been spent in working out the complicated arrangements, it was finally agreed in 1966 that -

a) the equipment to be financed by the Bank and joint loans would be procured as usual after international competitive bidding open to all member countries, with local manufacturers granted a preference margin not exceeding 15%

b) the Bank and the Governments of lending countries would determine the contracts eligible for financing by themselves

c) the joint loans would be made by financing institutions directly to the borrowers, and

d) orders won by a country offering joint financing would be financed two-thirds by the Bank and one-third by the supplying country.

The Bank moreover agreed to adjust the amortization schedule on its loan so that the annual amounts required from the borrower to service the Bank loan and the joint loans would not exceed those which would have been required had the entire amount been provided by the Bank loan. Arrangements made under the joint financing schemes of Loans 544-ME (1968) and 659-ME (1970) were on the whole similar to those above, with the exceptions that (a) in both loans, the sharing formula would only apply to individual orders for imported goods of at least US$ 200,000 aggregating at least US$ 1 million in any one supplying country, and (b) in Loan 659-ME, a 50-50 sharing formula was adopted in order to produce sufficient financing from the supplying countries.

5.12 Results of these arrangements met the expectations to a certain extent. Jointly with Loan 436-ME, four countries had offered by the end of 1967 loans totalling US$ 35 million, as expected, with reasonable terms (5 3/4 to 6% interest, 10 to 14 years amortization periods); delays in the signing of these loans resulted from discussion over the desire of some participating countries to have bidding restricted to those providing financing (which the Bank refused), from legal difficulties and from uncertainty about the type of equipment to be ordered. Also, there were delays in procurement, and the procurement pattern by countries did not match the credits available; for these reasons, and due to some countries winning insufficient contracts, disbursements from the joint loans amounted only to US$ 7 million in 1967 and US$ 1.1 million in 1968. The undisbursed amounts from these loans and four other loans from other countries were made available by early 1969 for the 1968-1969 investment program financed by Loan 544-ME; terms were 5½ to 7% interest with 9 to 12 years for amortization periods. Most of the joint loans were expected in 1968 to be disbursed during 1968 and 1969; for reasons similar to those under the previous financing scheme, disbursements from joint loans were delayed, as indicated in the following table:

Performance of the Joint Financing Schemes

	Date of Agreement	Original Amount US$ mln.	1966	Disbursements (US$ mln) 1967	1968	1969	1970
Loan 436-ME:							
Forecast	Early 1966	35	35	-	-	-	-
Actual	1966 thru 1967	35	-	7.0	1.1	-	-
Loan 544-ME:							
Forecast	Mid 1968	22.3	-	-	15	5.4	1.9
Actual	1968 thru 1969	30-50	-	-	0.8	10.6	10.4

Performance improved substantially with the second scheme, at least with regard to the amounts made available to Mexico. Simpler procedures, if feasible, might have reduced the delays in disbursements and helped the Power Sector to reduce its incurrence of medium-term debt, the service of which may be difficult and require further Bank assistance in the coming years; as a matter of fact CFE hopes that Bank loans of US$ 150 million each will be available every two years after 1972. Moreover, the share of power in the Bank lending program for Mexico has not decreased since 1966; through FY 1965, this share had been 54%, and during the last five fiscal years (1966-1970) it increased to 64%. On the other hand, access of Mexico to the foreign capital market has widened, since foreign bond issues in the U.S. and Europe for power have averaged about US$ 15 million annually over 1966-1970 and loans from commercial banks have represented an increasingly substantial part of the foreign borrowing by the Sector.

National Power Tariffs

5.13 Before 1962, power tariffs used to be established separately for each independent distribution system on the basis of the historical costs of investments, so that tariffs and returns varied substantially between different parts of the country. The present 11 schedules for the various consumer classes, introduced in 1962, have provided uniform rates for each consumer category throughout the country since 1964, regardless of the actual cost of supplying energy in the still separate power systems. When all systems are interconnected, the present uniformity of tariffs will be justified. Since 1962, revenue per kwh from the various consumer categories and the national distribution of sales by categories have both been rather stable. The most important change in the structure of tariffs in recent years was the 1966 increase in industrial rates as a result of raising the Power Consumption Tax for industrial consumers from 10% to 15%. The following table shows the national breakdown of sales and average prices to final consumers for the whole power sector.

Power Sector: Distribution of Sales, and Revenue/kwh Sold
(including Power Consumption Tax; in US$ equivalent)

	1962		1966			
	Sales (%)	Revenue (US¢)	Sales (%)	Revenue (US¢)	Sales (%)	Revenue (US¢)
Residential	16	3.6	17	3.8	17	3.8
Commercial	17	3.6	16	3.8	14	3.8
Industrial	49	1.6	51	1.7	54	1.6
Agriculture	7	1.3	7	1.3	6	1.4
Others	11	1.1	9	1.2	9	1.2
Total	100	2.2	100	2.3	100	2.2

A rough analysis by the Bank of the national rate structure has shown that the tariffs for the main categories (residential, commercial, and industrial) have been in reasonable balance with one another, but that some incentive might be given for commercial consumers to use more electricity off peak and that agriculture and "others" carry a large subsidy from other rate classes and industry a small one, as indicated in the following table:

Class	Daily Load Factor	Overall Marginal Cost Ratio	1970 Ratio of Average Revenue/kwh
Residential	30	Base	Base
Commercial	40	0.84	1.0
Industry	60	0.57	0.42
Agriculture) Others)	30	1.00	0.34

5.14 The above pattern and the low average level of tariffs are indicative of the Government's continuing policy to favor industrial development, and agriculture and rural electrification to a lesser extent (para 3.11). CFE has been an important tool in the implementation of this policy, by providing directly or through its bulk supplies to distributors large amounts of power at low prices; the average revenue per kwh sold by CFE (including the power consumption tax) levelled at about US¢ 0.9 in the late 1950's and increased afterwards from US¢ 1.3 in 1961 to US¢1.8 in 1970. This relatively low pricing was possible mainly because of low costs. CFE's average cost per kwh sold (excluding direct taxation) averaged only US¢ 0.6 during the 1950's and increased slightly from US¢ 0.7 to US¢ 1.1 over the 1961-70 period. The particularly low unit cost during the 1950's was partly the result of the very small provisions made by CFE for depreciation (para 5.03); in accordance with the new electricity legislation of 1962 CFE began to charge 2 percent straight line depreciation annually and this, along with the increased distribution responsibilities of CFE as of 1967, explains the increase in the unit costs after 1961, as follows:

CFE: Structure of Average Unit Costs
(Mexican centavos per Kwh sold)

	1953	1957	1961	1962	1964	1967	1969	1970
Administration and Salaries			5.4	5.6	5.6	8.0	7.8	7.9
Others (fuel, purchases of energy)	___	___	3.1	2.8	3.1	3.0	3.1	3.0
Operating Cost/kwh	4.6	7.2	8.5	8.4	8.7	11.0	10.9	10.9
Depreciation	0.3	0.6	0.6	1.6	2.3	2.5	2.7	2.7
Total Cost/kwh (Mex ¢)	4.9	7.8	9.1	10.0	11.0	13.5	13.6	13.6
Total Cost/kwh (US ¢)	0.6	0.6	0.7	0.8	0.9	1.1	1.1	1.1

CFE, which was supposed in accordance with the recommendations of Loans 436-ME and 544-ME to base its depreciation charge on the useful lives of its assets, adjusted its accumulated depreciation reserves in 1965-68 by a retroactive application of the 2% rate against an equal reduction in equity, with the consent of the Government, which owned most of the equity. The 2% depreciation rate, though acceptable, is still somewhat low; had a 3% depreciation rate been applied since 1950, the resulting costs would have led to much smaller net revenues and rates of return (Table I), and to the necessity to charge higher tariffs. Moreover with current tariffs, and a 3% depreciation rate, the rate of return would remain in the region of 8-9%.

VI. Management and Institutional Development.

6.01 With its increasing responsibilities for the supply of power in Mexico and in financial and investment planning for the whole Power Sector, CFE had over the course of time to convert and expand its administration and management from that of an ordinary public utility to that of a nationwide authority. In the early 1950s the staff of CFE had a comparatively short experience in the design, execution and operation of power projects. Important reforms were needed in the accounting and budgetary procedures of CFE and were suggested by the Bank; in particular there was a need for better coordination between the Department of Operations and the Financial Department in investment planning, for standardization of inventory control and recording methods, for adequate depreciation provisions, and for improved accounting and better procedures for costing of assets (para. 5.01).

6.02 In the mid 1950s eight regional divisions of CFE were created to operate as autonomous bodies. Regional operations were handled efficiently with adequate staff, but overlapping responsibilities for construction works between the divisions and the Head Office led to delays in the implementation of projects and there was some lack of coordination between long-term planning of the Head Office and the short-term operations of the divisions. When appraising the 1958 Loan 194-ME, the Bank recognized that the organizational structure of CFE, while not perfect, had been soundly conceived, especially with the decentralization of its operational functions, and that its top staff had been on the whole competent. CFE's engineering staff, however, appeared short of intermediate level personnel for both engineering and supervision, and there was a lack of long-range scheduling of staff assignments; some steps were taken by CFE to correct this shortcoming, especially through the employment of Mexican consultants to overcome the staff shortage. Moreover, because the number of outages in some of CFE's recent plants had been rather high, CFE initiated, at the Bank's recommendation (Table IV), a review of its operations and maintenance manuals and procedures and established a permanent program for the training of plant operators, especially for diesel plants. Accounting and financial methods and procedures had suffered from certain inconsistencies and many duplications as well as from deficient organization and supervision, and the long range forecasting of revenues and expenditures was inadequate; at the Bank's recommendation, CFE management introduced satisfactory budget control, check of regional divisions transactions and auditing of the divisions by outside auditors; finally CFE, in consultation with the Bank, selected and retained in 1959 a consulting firm to review its more important financial and budgetary procedures and to recommend changes in its decentralized organization, administrative procedures, internal financial controls, and preparation of annual and long-range budgets.

6.03 The recommendations of the management consultant's report issued in 1961 were agreed upon by the Bank and CFE, and in 1962 the latter retained the same firm for assistance in the implementation of its recommendations. In addition, under a covenant in the 1962 Loan

Agreement, CFE's accounts began in 1963 to be audited by independent outside auditors from the Secretaria del Patrimonio Nacional. On the other hand, CFE's planning methods still needed improvement in 1962, as well as the engineering and designs of projects, which had so far been prepared by CFE's own staff. The Bank also realized that the covenants of the past Bank loans to CFE had been largely confined to the financial aspects of tariff levels and debt limitation and had in a sense neglected other important and lasting factors affecting CFE's results, such as the economy of its investments and the efficiency of its operations; it became clear that in addition to financial covenants the Bank should attach to its new loans a series of specific conditions aimed directly at improving CFE's investment planning and operational efficiency. A large number of covenants and side letters were included in the agreements reached for Loan 316-ME of 1962, covering the improvements to be introduced in planning methods (para 2.07 and Table IV), the engagement by CFE of consultants for review of the investment program and of the designs of all important plants and for supervision of acceptance testing of all major equipment, and the establishment of an adequate training program for the operating staff of all new plants.

6.04 A start on the reorganization of CFE was made during 1962-65 by making the controller, the heads of the construction department and of a new supply department (to coordinate all purchasing and warehousing) Department Directors. However, it became apparent in 1965 that CFE as the leader of the industry had been operating with an organizational structure inadequate for existing needs, let alone for the future when other enterprises would merge with CFE; the rapid growth of the previous years had not permitted enough effort to be given to making the organizational modification necessary to obtain greater operating efficiency. Because too much direct responsibility for daily operations had been placed on the Director General, the latter did not have sufficient time to devote to policy-making for the Sector, and CFE's organization needed strengthening, particularly by delegation of authority at the upper levels. At the technical levels, much improvement was needed in coordination of operations among the major interconnected entities of the Sector; centralized load dispatch had been set up in four systems only and it appeared necessary to establish such dispatch controls in each system in order to minimize spillage of water from the hydro-plants and to operate the systems in the most economical manner by integrated scheduling of all plants. Operating costs were to be reduced by eliminating duplication of jobs, particularly between IEMSA and CFE in the divisions and systems where they had overlapped; during negotiations for Loan 436-ME, CFE submitted a memorandum on administrative policy to achieve cost reductions in the Sector so that return covenants would be met with minimum tariff increases; cost reduction was to be achieved through the elimination or retraining of surplus staff, the merging of smaller companies into CFE, the introduction of automation in the generating plants, and improvement of preventive maintenance.

6.05 The sector's arrangements for engineering and design of plants improved substantially after 1965 and have now led to a satisfactory situation. CFE's and Centro's engineering staff is carrying out the design of the small generating plants and transmission facilities and the distribution expansion, For the major new steam plants and transmission lines, CFE has engaged several consulting engineering firms to perform the design and supervise the construction. An International Board of Consultants which had been appointed in the early 1960's by the Bank to review Bank-financed thin arch dams has been retained by CFE and has continued to review the design and construction of major hydro projects. CFE has initiated since 1963 a program of acceptance testing of new generating units. The procedure established since 1963 of annual revisions of CFE's investment programs by its general consultants (SOFRELEC), followed by Bank reviews, has been satisfactory to the Bank, and CFE has recognized the need to continue the annual revisions; this procedure however may need changes since it did not prevent CFE from apparent overinvestment in several systems (para. 4.07). Some improvements have been made in the control of construction costs, which have invariably overrun the estimates. The progressive introduction from 1965 of computerized methods for inventory control, procurement planning and construction cost control, together with the use of more sophisticated methods in establishing the sector's development program, are expected to improve the accuracy of future investment forecasts; improvements in the data collecting system, which had apparently been neglected, are being achieved and will contribute to the successful use of the computerized methods.

6.06 The top management problems have been progressively solved through the increasing integration of the Power Sector and of its operations. The successful absorption of IEMSA and 17 affiliates within CFE in 1967 through agreements reached with the labor unions, and the unity of direction of the remaining two power entities through the common members of CFE's and Centro's Boards have simplified and facilitated the policy-making for power; in 1969 CFE was given responsibility for management of all the debt and funds of the sector. On the negative side, however, cooperation of the two entities was very disappointing during 1965-69 with regard to the vital issue of the frequency unification, to which Centro's former president and certain political leaders had been opposed. The installation in 1967 of a load dispatch center in the Central system linked to the Southern interconnected system (Oriental - Occidental) and the appointment in 1970 of CFE's Director General to the direction of Centro have reinforced CFE's control on Centro's operations and opened the way to a successful implementation of the frequency changeover in the coming years.

6.07 Partial and temporary improvements which were achieved in CFE's past financial performance, generally at the recommendation of the Bank, are reflected by the records. The financial rate of return of CFE on its average net fixed assets in service, after declining during the mid 1950s, recovered during the period 1958-62 and after 1966, with the tariff increases granted by the Government authorities at the Bank's insistence;

after 8 years of Bank action the rate of return for CFE and the power sector as whole (including revenue from the Power Consumption Taxes) has eventually met the rate covenants required by the Bank for the earnings of the Power Sector. CFE's Debt/Equity ratio has always been kept beneath the 55/45 level, due mainly to the large appropriations made by the Government towards the entity's equity. The financial indicators have reflected the continuous lack of cash generation within CFE and the related debt service problems; the self-financing rate and the debt service coverage (excluding the proceeds from the Power Consumption Tax) never exceeded 13% and 1.9 respectively, and indicated in 1965 and 1970 an insufficient amount of cash generation to service the debt. The low level of the current ratio after 1960 has resulted from an exceedingly large recourse to working capital and short-term debt to finance construction expenditure. These indicators would not favor CFE when comparing it to other entities run on a strictly commercial basis, but CFE's financial situation has never been really critical since it has always been supported financially by the Government, which was in turn committed to such support by its policy on power supply.

6.07 On the technical side, performance has been adequate; distribution losses never exceeded 4% of generation sent out when CFE was primarily a bulk supplier, and have risen to about 10% since 1967 when CFE became also a distributor by absorbing its 18 distributing affiliates. The productivity of CFE's labor, measured by the average annual energy sales per employee, increased at an average rate of 4.8% p.a. over the period 1955-66, and after a decline in 1967 resulting from the increased distribution responsibilities has risen to 1,086 MWH per employee, which is a satisfactory level. Finally, CFE has been successful in its conversion from an average size public utility to a national authority, responsible for the whole Power Sector of a large semi-industrialized country.

VII. Conclusion

7.01 In 1950, agriculture and industry each accounted for about one-fifth of the GDP of Mexico where population growth was averaging 3% per annum. The Mexican Government based part of its strategy for economic development on a sustained growth of industry to support the rapidly increasing population and increase its welfare. A pre-requisite to the development of industry was felt to be ample and reliable supply of electricity at low cost by an entity capable of contributing fully to the Government's objective and of making the most efficient use of the natural resources of the country. The early 1950's marked the beginning of a rapid growth of the Comision Federal de Electricidad which was an appropriate tool for achieving the targets set for the power sector and which therefore received increasing attention and investments from the Government and the Bank. The electricity industry which was contributing 0.5% to GDP in 1950 received during the 1950's between 2% and 4% of the total gross fixed capital formation in the country; while the GDP was increasing by 5.6% p.a. on average, the power contribution to it grew by 12.5% p.a. during 1950-60, so that its share by 1960 had doubled. As a matter of fact, more than half of electricity sales had been supplied to the industrial sector, which grew by 6.3% p.a. on average during that decade, and accelerated its growth afterwards to 9.2% p.a. on average during 1960-70. The importance of utility power supply for industrial development is reflected by the fact that the elasticity of industrial sales of electricity to value added in manufacturing industry has been very high - about 1.45 - since 1962.

7.02 Two distinct periods emerge in the past history of CFE and its relations with the Bank. Before 1960, CFE grew very rapidly, mainly on the basis of hydroelectric development and it operated primarily as a supplier of bulk power to the other distributing companies in Mexico; the Bank's action consisted mainly in financing a large number of selected projects without interfering substantially with the internal management of CFE or with Government power policy. The period 1960-70 has seen the progressive building and consolidation of CFE into the leading power supplier and distributor and the responsible authority in the power sector nationally. This followed from nationalization of the whole sector and the Government's decision to give CFE full responsibility for planning and construction of all new generating capacity, and for the financial management of the sector, through the absorption of other companies and control of Mexlight/Centro. Recognition by the Bank of this structural change has materialized with the introduction of "program" lending, in a first phase to CFE and in a second phase to the whole sector, through CFE. In view of CFE's large financial requirements, the Bank began to devote more attention to the financial and management aspects of the entity, primarily through a large set of covenants and side letters attached to the Loan Agreements. Covenants and side letters dealing with non-financial aspects, such as the use of consultants and improvement of planning, budgeting and training, were generally respected, sometimes with delays; delays on frequency unification and interconnection, which have been actively pursued since 1962 but are only now about to be accomplished, have been considerable. The financial covenants were respected only after 1965; the Mexican authorities, anxious to serve satisfactorily a rapidly increasing demand from all consumers, preferred to make a full use, even at a high beneficial cost, of all available sources of funds to build up a generating capacity as large as possible, and by-passed through a series of parallel channels under their control the Bank's financial covenants which seem to have been poorly fitted to an entity of CFE's constitutional position and policies.

7.03 With the absorption in the late 1960's of the excessive capacity which had developed previously, CFE is still engaged in a large construction program involving the installation and ongoing construction during 1970-71 of 3,910 MW generating capacity and of 8,850 km of transmission lines. Future investment programs of the power sector will probably be of a similar or larger size; in particular they will involve, as scheduled presently by CFE, the complete interconnection of all the major and smaller systems during the period 1971-74 and the installation of nuclear plants. Financing of future investment programs is expected by CFE to come from Government appropriations, Nafinsa loans, and foreign borrowing. The partial success of the previous joint financing schemes has helped somewhat to open the way for CFE to the foreign capital market, with encouraging prospects; because Mexico is close to exhausting its supply of low-cost hydro sites, supplier's credits are expected to contribute proportionately more than in the past to the foreign exchange costs of the predominantly thermal future investment programs and of the nuclear plants; reliance on the Bank is not expected by CFE to decrease since Bank loans of US$ 125 - 150 million accompanied by US$ 65 million of joint loans, are expected every two years after 1972.

7.04 Some important economic aspects of the Bank's contribution to the past development of the Mexican power sector and to the broad benefits derived from such a development could not be investigated within the limited scope of this review. A complete evaluation of this contribution and of its effects would require in particular, that the following points be further studied: social and economic benefits and costs of rural electrification (which has accounted for a significant share of CFE expenditures during the last 10 years), income distribution and efficiency aspects of power tariffs in Mexico, regional features of the development of the power industry, the impact of past Bank loans on the development of the Mexican electrical equipment industry through financing the local purchases of such equipment and the balance of public investment among the various economic sectors and their fiscal aspects. In connection with the last topic the question arises whether the heavy financing of power development through Government appropriations and Nafinsa loans has been to the detriment of other sectors and/or public services, in the sense that opportunities in the latter offering high social and economic return were left unfulfilled as a result of heavy expenditure on power. These questions would merit attention in further work.

TABLE I

MEXICO - COMISION FEDERAL DE ELECTRICIDAD

			1950	1951	1952	1953	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	Average Annual Increase Rate (%) 1950/60	1960/70	1950/70
	OPERATIONS																									
1.	Installed Capacity of CFE																									
	Hydro	MW	94	164	164	175	252	358	359	506	516	641	727	734	901	953	1,198	1,608	1,941	2,198	2,196	2,917	2,915	22.7	14.9	18.7
	Thermal	MW	53	80	115	156	183	196	211	224	255	251	297	340	424	953	1,109	1,186	1,184	1,540	1,610	1,715	2,030	18.8	21.2	20.0
	Diesel	MW	20	41	43	44	44	49	62	72	97	84	78	101	111	136	168	178	178	237	323	359	456	14.6	19.3	16.9
	Total	MW	167	285	322	375	479	603	632	802	868	976	1,102	1,175	1,436	2,042	2,475	2,972	3,303	3,975	4,129	4,991	5,400	20.8	17.2	19.0
	of which at 50 Hz	MW	78	123	123	123	173	217	217	352	352	352	352	352	456	710	710	1,070	1,410	1,410	1,410	1,410	1,560			
	Total as % in country a/	%	13.5	19.8	20.5	22.0	25.9	31.3	30.5	35.3	33.9	35.6	36.5	35.9	40.3	48.1	50.6	56.0	57.9	68.5	64.7	72.4	72.0			
2.	Installed Capacity in Country b/	MW									1,960	2,090	2,310	2,435	2,720	3,370	4,010	4,480	4,790	4,880	5,370	5,790	6,290		10.5	
3.	Peak Demand in Country c/	MW									1,550	1,680	1,840	2,010	2,170	2,400	2,700	2,950	3,230	3,530	3,870	4,450	5,010		10.5	
4.	Gross Reserves in Country (2-3)	MW									410	410	470	425	550	970	1,310	1,530	1,560	1,350	1,500	1,340	1,280		10.5	
5.	Gross Reserves as % of Peak Demand	%									26	24	26	21	25	40	49	52	48	38	39	30	26			
6.	Gross Generation of CFE		438	750	1,088	1,422	1,502	2,025	2,592	2,851	3,391	4,149	4,228	4,196	5,119	6,281	8,640	10,380	11,902	15,810	17,923	20,095	22,914	25.4	18.4	22.2
7.	Generation Sent-Out		417	724	1,048	1,369	1,435	1,951	2,507	2,762	3,283	4,046	4,123	4,075	4,965	6,128	8,430	10,126	11,612	15,324	17,395	19,943	22,647			
8.	Total Sales of CFE	Gwh	388	525	996	1,341	1,401	1,896	2,418	2,694	3,154	3,961	4,065	3,962	4,828	6,023	8,173	9,800	11,177	13,990	15,899	17,857	23,095	26.7	17.8	22.0
	of which: to direct consumers	%	6	11	11	13	16	17	18	22	21	21	25	30	28	34	31	30	30	63	62	67	67			
	to other utilities (bulk)	%	94	89	89	87	84	83	82	78	79	79	75	70	72	66	69	70	70	37	38	33	33			
9.	Customers of CFE	000's	42	82	99	115	118	177	232	278	331	386	455	527	669	810	930	1,019	1,100	2,557	2,808	3,363	3,822	26.9	23.7	25.3
10.	Number of Employees	no.	n.a.				n.a.	3,045	3,675	4,050	4,770	4,970	5,620	7,510	8,359	8,069	9,196	9,606	10,266	16,880	16,920	17,945	18,500	13.0 l/	12.6	12.8 l/
	FINANCES																									
11.	Sales Revenues d/	Ps. mln	28.7	37.3	65.5	79.9	105.7	158.4	208.5	319.4	389.8	420.6	552.2	665.9	852.4	1,109.5	1,413.0	1,665.3	1,979.3	3,273.5	3,516.0	4,017.4	4,486.4	32.2 k/	23.3	k/
12.	Operating Costs (non corrected) e/	Ps. mln	18.0	31.1	48.4	66.5	86.2	114.0	148.6	211.4	256.5	296.7	328.9	359.0	485.6	684.5	902.7	983.4	1,115.4	1,896.4	1,987.8	2,430.5	2,737.0	33.8	23.6	28.6 k/
13.	Average Revenue/Kwh Sold	Ps ¢	7.40	7.1	6.6	5.9	7.5	8.3	8.6	11.8	12.3	10.6	13.6	16.8	17.6	18.4	17.3	17.0	17.7	23.4	22.1	22.5	22.3	4.5 k/	5.1	k/
14.	Average Cost/Kwh Sold	Ps ¢	4.6	5.9	4.9	4.9	6.1	6.0	6.1	7.8	8.1	7.5	8.1	9.1	10.0	11.4	11.0	10.0	10.0	13.5	12.5	13.6	13.6	5.8	5.3	5.6
15.	Exchange Rate	US$ 1 = Mex. Ps.	8.65	8.65	8.65	8.65	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5			
16.	Average Revenue/Kwh Sold	US ¢	0.86	0.82	0.76	0.69	0.60	0.67	0.69	0.95	0.99	0.85	1.09	1.34	1.41	1.47	-1.38	1.36	1.42	1.87	1.77	1.80	1.79	0.7 k/	5.1	k/
17.	Average Cost/Kwh Sold	US ¢	0.54	0.68	0.56	0.57	0.49	0.48	0.49	0.63	0.65	0.60	0.65	0.72	0.80	0.91	0.88	0.80	0.80	1.08	1.0	1.10	1.09	1.9	5.3	3.6
18.	Net Revenues (11-12)	Ps. mln	10.7	6.2	17.1	13.4	19.5	44.4	59.9	108.0	133.3	123.9	223.3	306.9	366.8	425.0	510.3	681.9	863.9	1,377.1	1,528.2	1,586.9	1 749.4	29.4 k/	22.8	k/
19.	Gross Fixed Investments	Ps. mln	n.a.							n.a.	474.0	600.0	973.0	1,314.4	2,361.2	2,225.7	2,013.5	1,139.7	1,096.6	1,970.1	2,518.8	2,924.2	3,719.2		14.4	
20.	Av. Net Fixed Assets in Service	Ps. mln	235.5	286.5	460.0	710.5	964.8	1,348.2	1,643.8	1,860.0	2,159.8	2,600.0	3,084.4	3,561.0	4,483.6	6,256.2	9,335.6	11,199.0	11,578.1	13,531.2	15,050.9	16,776.2	19,579.6	29.3	20.3	24.8
21.	Operating Costs (corrected for depreciation) f/	Ps. mln	23.6	37.4	60.2	83.7	111.5	149.8	184.9	257.2	308.0	363.9	416.0	454.7	566.9	804.7	1,064.2	1,150.2	1,270.3	2,086.8	2,170.9	2,626.6	2,970.1	33.2	21.8	27.4
22.	Average Cost/Kwh Sold (Corrected) f/	US ¢	0.70	0.82	0.70	0.72	0.64	0.63	0.61	0.76	0.78	0.74	0.82	0.92	0.94	1.07	1.04	0.94	0.91	1.19	1.09	1.18	1.18	1.6	3.7	2.7
23.	Av. Net Fixed Assets (Corrected) f/	Ps. mln	189.1	217.3	356.6	566.9	792.1	1,117.3	1,373.8	1,633.1	1,945.4	2,326.2	2,830.6	3,225.5	3,959.8	5,636.4	8,559.0	10,242.2	10,478.0	12,258.5	13,591.5	15,179.1	17,798.5	31.1	20.2	25.5
24.	Net Revenues (Corrected) f/	Ps. mln	5.2	(-0.1)	5.3	(-3.8)	(-5.8)	8.6	23.6	62.2	81.6	56.6	136.2	211.2	285.5	304.8	348.8	515.1	709.0	1,186.8	1,345.1	1,390.8	1,516.4	26.5 k/	27.2	k/
	MANAGEMENT INDICATORS																									
25.	Rate of Return (Non corrected)	%	4.5	2.2	3.7	1.9	2.0	3.3	3.6	5.8	6.2	4.8	7.2	8.6	8.2	6.8	5.5	6.1	7.5	10.2	10.2	9.5	8.9			
26.	Rate of Return (After correction) f/	%	2.8	0	1.5	( )	( )	0.8	1.7	3.8	4.2	2.4	4.8	6.5	7.2	5.4	4.1	5.0	6.8	9.7	9.9	9.2	8.5			
27.	Financial Rate of Return g/	%	3.8	1.3	3.0	1.3	1.6	2.8	3.1	5.3	6.1	5.3	4.7	6.2	5.7	4.5	3.7	3.9	4.9	7.1	6.5	6.8	6.5			
28.	Self-financing Rate h/	%	n.a.	n.a.	n.a.	-	-	...	-	...	7.4	7.3	7.7	12.2	7.9	9.8	10.2	-	2.8	3.5	5.6	8.5	-			
29.	Debt-Service Coverage i/	Times	n.a.	n.a.	n.a.	0.32	0.40	1.04	0.76	1.03	1.32	1.42	1.53	1.86	1.44	1.81	1.86	0.30	1.02	1.09	1.11	1.19	0.99			
30.	Debt/Equity Ratio	./.	37/63	30/70	30/70	27/73	30/70	28/72	27/73	24/76	24/76	24/76	22/78	25/75	35/65	36/64	42/58	40/60	43/57	51/49	52/48	51/48	53/47			
31.	Energy Sales per Employee	MWH	n.a.	n.a.	n.a.	n.a.	n.a.	623	658	665	661	792	723	527	577	746	889	1,020	1,089	829	940	995	1,086	3.0 l/	4.1	3.8 l/
32.	Distribution Losses	%	7.0	27.5	5.0	2.0	2.4	2.8	3.6	2.5	3.9	2.1	1.4	2.8	2.7	1.7	3.0	3.2	3.7	8.7	8.6	10.4	11.2			
33.	CFE Investments in Distribution as % of Total Investments	%	n.a.									n.a.	15.0	5.4	20.6	9.9	26.6	10.2	1.5	8.7	33.7	19.7	29.8			
34.	Current Ratio j/	No.	n.a.	n.a.	n.a.	3.3	3.1	2.3	2.9	n.a.	n.a.	3.7	1.8	1.03	n.a.	0.78	0.66	0.86	2.4	1.7	1.29	n.a.	n.a.			
	POWER AND ECONOMIC DEVELOPMENTS																									
35.	Average Revenue of Power Sector/kwh Sold (incl. Power Tax)	US¢													2.21	2.25	2.31	2.31	2.36	2.37	2.30	2.31	2.24			
36.	Average Cost of Power Sector/kwh Sold	US¢													1.50	1.55	1.60	1.53	1.51	1.47	1.42	1.42				
37.	Self-financing Rate of Power Sector	%														( )	( )	( )	( )	6.6	17.9	5.0				
38.	Consumers of Power Sector	'000s													2450	2743	3032	3278	3541	3823	4163	4706	5370		10.2	
39.	Total G.D.P.	1960 Ps. mln	86,973	93,034	96,095	100,866	106,118	114,049	120,432	129,250	134,654	139,979	150,111	157,931	165,310	178,516	199,390	212,320	227,037	241,272	260,901	277,400	298 700	5.6	7.1	6.4
40.	G.D.P. from electricity	1960 Ps. mln	462	547	622	679	752	845	994	1,089	1,210	1,384	1,502	1,609	1,753	2,170	2,529	2,769	3,157	3,533	4,228	4,812	5,341	12.5	13.5	13.0
41.	Ind. G.D.P.	1960 Ps. mln	16,526	17,509	18,589	18,905	20,313	22,268	22,169	25,391	26,041	28,792	30,394	32,092	33,643	36,996	43,416	47,530	52,147	55,874	61,869	67,099	73,375	6.3	9.2	7.7
42.	G.D.P. from Electrical Manufacturing Equipment	1960 Ps. mln	362	394	396	409	434	545	627	754	736	853	896	1,057	1,068	1,262	1,745	1,954	2,313	2,248	n.a.	n.a.	n.a.	9.5	14.1 m/	
43.	G.D.P. Agriculture	1960 Ps. mln	15,442	15,768	15,814	16,819	18,861	20,163	20,222	21,546	22,806	22,501	23,970	24,416	25,339	26,663	28,669	30,222	30,740	31,583	32,558	32,912	34,730	4.5	3.8	4.1
44.	Total Gross Fixed Capital Formation	1960 Ps. mln	13,572	17,731	18,329	16,263	17,444	18,903	22,285	23,455	22,271	22,788	25,507	26,854	26,887	30,424	37,041	38,585	43,143	48,710	n.a.	n.a.	n.a.			
45.	G.F.C.F. in Electricity	1960 Ps. mln	1,305	712	320	580	630	575	344	324	506	729	1,343	2,342	1,906	1,557	1,598	1,296	2,336	2,333	n.a.	n.a.	n.a.			
46.	Ind. G.F.C.F.	1960 Ps. mln	3,852	5,651	5,652	5,364	4,956	6,619	7,559	7,336	7,133	7,329	6,370	7,622	8,912	9,389	12,444	14,702	15,838	15,795	n.a.	n.a.	n.a.			
47.	G.F.C.F. in Agriculture	1960 Ps. mln	1,420	1,787	1,842	1,811	1,817	2,150	1,475	2,532	2,119	2,286	2,454	2,911	2,279	2,786	2,881	2,483	2,559	2,998	n.a.	n.a.	n.a.			
48.	G.D.P. from Electricity as % of Total G.D.P.	%	0.53	0.59	0.65	0.67	0.71	0.74	0.83	0.84	0.90	0.99	1.00	1.02	1.06	1.22	1.22	1.30	1.39	1.46	1.52	1.74	1.79			
49.	G.D.P. from Agriculture as % of " "	%	17.76	16.95	16.46	16.68	17.77	17.68	16.79	16.67	16.94	16.08	15.97	15.46	15.33	14.94	14.38	14.23	13.54	13.09	12.48	11.86	11.63			
50.	G.F.C.F. in Electricity as % of Total G.F.C.F.	%	9.62	4.02	1.75	3.57	3.61	3.04	1.54	1.38	2.27	3.20	5.27	8.72	7.09	5.12	4.31	3.36	5.18	4.79	-	-	-			
51.	G.F.C.F. in Agriculture as % of " "	%	10.46	10.08	10.05	11.14	10.42	11.37	6.62	10.80	9.52	10.03	9.62	10.84	8.48	9.36	7.78	6.44	5.93	6.16	-	-	-			

a/ Including captive plants.
b/ Does not include captive plants.
c/ Non-coincident peak demand.
d/ Revenues from electric sales. Includes after 1960 estimates of the power consumption taxes generated by all CFE sales; data on power consumption taxes before 1960 were not available.
e/ Including depreciation, but excluding interest and direct taxation on CFE.
f/ Depreciation charges were taken as 3% of gross fixed assets; operating costs, net revenues, net fixed assets and average costs/Kwh sold were corrected correspondingly.
g/ Operating income after taxes (including miscellaneous revenues) as % of 20.
h/ Net internal cash generation excluding power consumption tax as % of total applications of funds.
i/ Times debt service was covered by internal cash generation.
j/ Current assets divided by current liabilities.
k/ The proceeds of the power consumption tax generated by CFE sales were included in the sales revenues only after 1960 - see footnote d/ - for this reason (making interannual comparisons difficult) average annual increase rates over 1950-1970 were not computed for items 11, 13, 16, 18 and 24.
l/ Average annual increase rates were computed over the periods 1955-1960, 1960-1970, and 1955-1970 respectively.
m/ Average annual increase rates over 1960-1967.

Table II-A.1

MEXICO: COMISION FEDERAL DE ELECTRICIDAD
LOAN 194-ME

	1957	1958	1959	1960	1961	1962	1963	1964	1965	AVERAGE ANNUAL INCREASE RATE (%) (1957/1962)
LOAD FORECASTS (MW)										
1. Central System: Effective Capacity		892	892	975	975	1120				
Annual Peak Demand		732	806	886	974	1072				11.0
2. Oriental System: Installed Capacity		185	293	293	293	293				
Annual Peak Demand		154	184	214	236	262				21.5
3. Occidental System: Installed Capacity		218	218	218	218	292				
Annual Peak Demand		169	174	182	192	202				8.8
4. North West System: Installed Capacity		69	88	88	106	106				
Annual Peak Demand		63	73	84	97	105				16.0
ACTUAL LOAD (MW)										
5. Central System: Effective Capacity	858	940	940	1023	1023	1133				
Peak Demand	636	712	774	812	884	952				8.0
6. Oriental System: Installed Capacity	116	149	264	303	303	342				
Peak Demand	99	118	162	185	192	211				16.4
7. Occidental System: Installed Capacity	218	251	254	254	254	321				
Peak Demand	166	185	181	207	223	237				7.4
8. North West System: Installed Capacity	49	59	69	109	109	142				
Peak Demand	50	55	57	70	86	105				16.0
LOAD FORECAST ACCURACY a/										
9. Peak Demand : Central System		103	104	109	110	113				
Oriental System		131	114	116	123	124				
Occidental System		91	96	88	86	85				
North West System		115	128	120	113	100				
SALES FORECAST (GWH)										
10. Total Sales of CFE		3721	3935	4249	5074	5673	6184	6740	7347	13.4
ACTUAL SALES (GWH)										
11. Sales : Residential	107	131	157	187	188	376	488	624	997	
Commercial	68	86	104	122	140	353	431	586	880	
Industrial	265	308	415	533	591	1012	1349	1873	2815	
Bulk Sales to other utilities	2111	2484	3133	3046	2785	2476	3152	4270	3936	
Others	123	145	152	177	258	611	603	820	1172	
Total	2694	3154	3961	4065	3962	4528	6023	8173	9800	17.5
SALES FORECAST ACCURACY a/										
12. Total Sales		118	99	104	128	118	103	82	75	
RETURN FORECAST (Ps million)										
13. Revenues b/		401.1	441.8	493.8	588.9	674.1	742.2	809.2	890.6	13.7
14. Less: Operating Costs c/		235.7	259.0	281.7	323.1	343.6	379.2	422.1	469.9	10.4
15. Operating Income		165.4	182.8	212.1	265.8	330.5	363.0	387.1	420.7	18.7
16. Financial Rate of Return (%) d/		5.8	5.3	5.2	5.5	6.1	6.1	5.9	5.8	
ACTUAL RETURN (Ps million)										
17. Revenues b/	319.7	389.5	435.1	480.0	584.5	758.1	992.5	1278.5	1456.4	20.9
18. Less: Operating Costs c/	213.0	257.6	297.6	334.7	364.4	503.5	708.9	935.8	1021.3	21.6
19. Operating Income	106.7	131.9	137.5	145.3	220.1	254.6	283.6	342.7	435.1	19.2
20. Financial Rate of Return (%) d/	5.7	6.1	5.3	4.7	6.2	5.7	4.5	3.7	3.9	

a/ Defined by the ratio Forecast/Actual, in %.
b/ Total revenues excluding indirect taxes on Power Consumption.
c/ Including depreciation and direct taxation on utility, but excluding interest.
d/ Operating income after taxes as per cent of average net fixed assets in operation.

MEXICO: COMISION FEDERAL DE ELECTRICIDAD
LOAN 316-ME

TABLE II-A.2

			1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	AVERAGE ANNUAL INCREASE RATE(%) (1961/1970)
	LOAD FORECAST (MW)												
1.	Central System:	Effective Capacity		1127	1351	1351	1915	1915	1915	1915	2065	2300	8.5
		Firm Capacity		1045	1201	1201	1765	1765	1765	1765	1915	2150	
		Peak Demand		964	1051	1146	1240	1340	1450	1570	1700	1840	
2.	Oriental System:	Installed Capacity		378	417	417	457	502	547	547	547	587	
		Firm Capacity		335	377	377	417	457	502	502	502	547	
		Peak Demand		239	324	362	397	418	440	465	494	523	11.8
3.	Occidental System:	Installed Capacity		325	325	385	385	460	535	535	535	735	
		Firm Capacity		288	288	348	348	385	460	460	460	660	
		Peak Demand		260	286	307	335	364	394	428	465	504	9.5
4.	North System :	Installed Capacity		169	235	235	268	301	301	301	334	334	
		Firm Capacity		125	179	179	212	245	245	245	278	278	
		Peak Demand		147	155	165	173	182	191	200	210	221	5.5
5.	North West System :	Installed Capacity		175	220	265	265	265	265	305	338	336	
		Firm Capacity		130	170	220	220	220	220	225	258	258	
		Peak Demand		111	126	143	157	173	190	209	230	253	12.8
6.	North East System :	Installed Capacity		251	356	469	469	469	469	544	544	519	
		Firm Capacity		190	281	394	394	394	394	469	469	544	
		Peak Demand		128	153	272	299	329	361	397	437	480	16.7
	ACTUAL LOAD (MW)												
7.	Central System:	Effective Capacity	1023	1133	1353	1408	1763	2099	2044	1946	2099	2099	
		Peak Demand	884	952	1038	1159	1270	1356	1459	1584	1738	1935	9.1
8.	Oriental System:	Installed Capacity	303	342	418	421	476	476	494	595	1270	1270	
		Peak Demand	192	211	280	308	349	427	488	568	695	860	15.1
9.	Occidental System:	Installed Capacity	254	321	326	391	407	407	459	606	509	659	
		Peak Demand	223	237	261	305	348	382	495	510	597	741	14.3
10.	North System:	Installed Capacity	201	201	201	267	267	300	341	341	341	341	
		Peak Demand	137	149	143	169	185	202	223	232	257	290	7.8
11.	North West System:	Installed Capacity	109	142	149	266	241	241	250	291	29[illegible]	332	
		Peak Demand	56	105	110	134	148	161	179	196	239	259	13.0
12.	North East System:	Installed Capacity	168	155	305	362	474	474	474	474	474	516	
		Peak Demand	120	132	145	189	221	248	293	334	399	458	16.0
	LOAD FORECAST ACCURACY a/												
13.	Peak Demand:	Central System		101	101	99	98	98	99	99	98	96	
		Oriental System		113	116	118	114	98	90	82	71	61	
		Occidental System		110	110	101	96	95	87	84	78	68	
		North System		99	108	198	194	90	86	86	82	76	
		North West System		106	115	107	106	107	106	107	96	98	
		North East System		97	106	144	135	133	123	119	110	105	
	SALES FORECAST (GWH)												
14.	Total Sales :	Central System		3860	4210	4590	4960	5360	5790	6250	6750	7220	
		Oriental System		939	1474	1717	1883	1971	2065	2166	2280	2403	
		Occidental System		930	1026	1104	1198	1300	1410	1530	1660	1800	
		North System		788	809	834	884	937	993	1052	1115	1181	
		North West System		406	486	586	645	709	780	858	944	1038	
		North East System		669	850	1205	1325	1458	1603	1764	1940	2135	
15.	Total Sales of CFE			4952	7346	10508	11719	13014	13949	14768	16380	18435	18.6
	ACTUAL SALES (GWH)												
16.	Total Sales :	Central System		3891	4164	4625	5085	5673	6218	6834	Not available		
		Oriental System		896	1157	1446	1679	1886	2306	2677			
		Occidental System		973	1052	1171	1379	1527	1746	2061			
		North System		756	778	847	911	952	1009	1063			
		North West System		443	496	587	642	704	771	843			
		North East System		603	608	760	934	1058	1282	1546			
17.	CFE Sales :	Residential	188	376	488	624	997	1101	1535	1719	1958	2253	
		Commercial	140	353	431	586	880	971	1263	1374	1531	1669	
		Industrial	591	1012	1349	1873	2815	3174	4407	5136	6329	7339	
		Bulk	2785	2476	3152	4270	3936	4701	5201	5990	5931	6541	
		Others	258	611	603	820	1172	1230	1584	1680	2108	2293	
			3962	4828	6023	8173	9800	11177	13990	15899	17857	20095	19.8
	SALES FORECAST ACCURACY a/												
18.	Total Sales:	Central System		99	101	99	98	94	93	91			
		Oriental System		105	127	119	112	105	90	81			
		Occidental System		96	98	94	87	85	81	74			
		North System		104	104	98	97	98	98	99			
		North West System		92	98	100	100	101	101	102			
		North East System		111	140	159	142	138	125	114			
19.	Total Sales of CFE			103	122	129	120	116	100	93	92	92	
	RETURN FORECASTS (Ps million)												
20.	Revenues b/			784.1	1130.6	1528.4	1779.4	1929.8	2077.2	2217.8	2447.7	2731.1	18.7
21.	Less: Operating Costs c/			511.1	707.5	908.0	1028.9	1144.7	1260.2	1363.0	1522.8	1623.8	
22.	Operating Income			273.0	423.1	620.4	750.5	785.1	817.0	854.8	924.9	1107.3	
23.	Financial rate of return (%) d/			6.1	6.4	7.0	7.3	6.9	6.9	7.0	7.3	8.4	
	ACTUAL RETURN (Ps million)												
24.	Revenues b/			758.1	992.5	1278.5	1456.4	1727.4	2920.3	3036.8	3643.1	4090.1	24.2
25.	Less: Operating Costs c/			503.5	708.9	935.8	1021.3	1159.0	1956.1	2952.2	2501.7	2818.1	
26.	Operating Income			254.6	283.6	342.7	435.1	568.4	964.2	984.6	1141.4	1272.0	
27.	Financial rate of return (%) d/			5.7	4.5	3.7	3.9	4.9	7.1	6.5	6.8	6.5	
28.	Rate of return including power tax (%)			10.1	8.1	6.3	6.4	8.0	10.2	9.6	9.8	9.8	

a/ Defined by ratio Forecast/Actual, in %.
b/ Total revenues excluding indirect taxes on power consumption.
c/ Including depreciation and direct taxation on utility, but excluding interest.
d/ Operating income after taxes as per cent of average net fixed assets in operation.

TABLE II-A.3

MEXICO: COMISION FEDERAL DE ELECTRICIDAD
LOAN 436-ME

		1965	1966	1967	1968	1969	1970	Average Annual Increase Rate (%) (1964/1970)
LOAD FORECAST (MW)								
1. Central System:	Installed Capacity	1,858	1,619	1,547	1,547	1,273	917	
(50 cycles)	Peak Demand	1,217	1,268	1,276	1,200	895	640	-25.8 after 1967
2. Interconnected System:								
Oriental:	Installed Capacity	551	834	1,656	2,016	2,290	2,926	
	Peak Demand	396	557	1,160	1,426	1,905	2,344	
Occidental:	Installed Capacity	385	393					
	Peak Demand	331	395					
3. Of Which Central System 60 Cycles Demand			45	141	330	757	1,146	
4. North System:	Installed Capacity	281	281	319	334	334	334	
	Firm Capacity	196	196	226	241	241	241	
	Peak Demand	162	167	181	197	206	212	3.8
5. North West System:	Installed Capacity	265	265	330	330	370	370	
	Firm Capacity	165	165	230	230	270	270	
	Peak Demand	152	197	206	222	239	261	11.8
6. North East System:	Installed Capacity	461	461	461	461	461	501	
	Firm Capacity	386	386	386	386	386	386	13.4
	Peak Demand	225	266	302	330	364	402	
ACTUAL LOAD (MW)								
7. Central System:	Installed Capacity	1,757	2,117	2,065	1,975	2,117	2,267	
(50 cycles)	Peak Demand	1,270	1,356	1,459	1,584	1,738	1,935	8.75
8. Interconnected System:	Installed							
Oriental:	Installed Capacity	476	476					
	Peak Demand	349	427	953	1,201	1,779	1,929	
Occidental	Installed Capacity	407	407	938	1,073	1,286	1,593	
	Peak Demand	348	382					
9. North System	Installed Capacity	267	300	341	341	341	341	
	Peak Demand	185	202	223	232	257	290	9.45
10. North West System:	Installed Capacity	241	241	250	291	291	332	
	Peak Demand	148	161	179	196	239	259	10.2
11. North East System:	Installed Capacity	474	474	474	474	474	516	
	Peak Demand	221	248	293	334	399	458	18.1
LOAD FORECAST ACCURACY a/								
12. Peak Demand:	Central System (50 & 60 Cycles)	96	97	97	97	95	92	
13. Interconnected:	Oriental System	113	120	109	103	92	79	
	Occidental System	95	103					
	North System	88	83	81	85	87	79	
	North West System	103	122	115	113	100	101	
	North East System	102	107	103	99	91	88	
SALES FORECAST (GWh)								
14. Total Sales	Central System	4,923	5,318	5,740	6,204	6,700	7.235	
15. Interconnected:	Oriental System	1,827	2,529	4,832	5,219	5,510	5,783	
	Occidental System	1,272	1,541					
	North System	883	910	990	1,076	1,122	1,155	
	North West System	667	761	921	985	1,045	1,125	
	North East System	964	1,239	1,389	1,543	1,699	1,879	
16. Total Sales of CFE and IEMSA b/		10,398	11,900	13,875	14,900	16,436	18,135	
17. Final Sales of Power Sector		12,054	13,796	15,417	16,653	17,840	19,120	
ACTUAL SALES (GWh)								
18. Total Sales:	Central System	5,085	5,673	6,218	6,834			
19. Interconnected:	Oriental System	1,679	1,886	4,052	4,738	Not Available		
	Occidental System	1,379	1,527					
	North System	911	952	1,009	1,063			
	North West System	642	704	771	843			
	North East System	934	1,058	1,282	1,546			
20. Total Sales of CFE		9,800	11,177	13,990	15,899	17,857	20,095	16.2
21. Final Sales of Power Sector		12,117	13,389	14,933	16,675	19,213	21,683	11.9
SALES FORECAST ACCURACY a/								
22. Total Sales:	Central System	97	94	92	91			
23. Interconnected:	Oriental System	109	134	119	110			
	Occidental System	92	101					
	North System	97	96	98	101			
	North West System	104	108	119	117			
	North East System	103	117	108	100			
24. Total Sales of CFE		106	106	99	94	92	90	
25. Final Sales of Power Sector		99	103	103	100	93	88	
POWER SECTOR RETURN FORECAST (Ps. million)								
26. Revenues (excl. Power Tax) c/		3,040.9	3,386.3	3,678.4	3,970.0	4,248.1	4,575.1	7.6
27. Less: Operating Costs d/		2,295.9	2,425.0	2,619.1	2,726.1	2,833.4	2,981.6	
28. Net Income		745.0	961.3	1,059.3	1,243.9	1,414.7	1,593.5	
29. Financial Rate of Return (%) e/		4.7	5.7	5.8	6.3	6.9	7.4	
30. Rate of Return Incl. Power Tax								
ACTUAL RETURN (Ps. million)								
31. Revenues (excl. Power Tax) c/		3,212.1	3,589.4	3,996.8	4,325.4	5,031.7	n.a.	11.2 until 1969
32. Less: Operating Costs d/		2,389.4	2,599.6	2,835.4	3,047.6	3,609.2	n.a.	
33. Net Income		822.7	989.8	1,161.4	1,277.8	1,422.5	n.a.	
34. Financial Rate of Return (%) e/		5.0	5.8	6.5	7.0	7.0	n.a.	
35. Rate of Return Incl. Power Tax (%)		6.7	7.9	8.9	9.6	9.5	n.a.	

a/ Defined by the ratio Forecast/Actual, in %.
b/ IEMSA Sales included after 1967 when it was absorbed by CFE.
c/ Total Revenues excluding indirect taxes on Power Consumption.
d/ Including depreciation and direct taxation on utility, but excluding interest.
e/ Operating income after taxes as percent of average net fixed assets in operation.

TABLE II-B

MEXICO - COMISION FEDERAL DE ELECTRICIDAD
INVESTMENT PROGRAMS PARTLY FINANCED BY IBRD (US$ million)

	COMISION FEDERAL DE ELECTRICIDAD								MEXICAN POWER SECTOR							
	LOAN 194-ME (1958) PERIOD 1958 - 1962				LOAN 316-ME (1962) PERIOD 1962 - 1965				LOAN 436-ME (1965) PERIOD 1965 - 1966				LOAN 544-ME (1968) PERIOD 1968 - 1969			
	FORECAST		ACTUAL		FORECAST		ACTUAL		FORECAST		ACTUAL		FORECAST		ACTUAL	
SOURCES OF FUNDS	Total	% of Total	Total	% of Total	Total	% of Total	Total	% of Total	Total	% of Total	Total	% of Total	Total	% of Total	Total	% of Total
Gross Internal Cash Generation	96.0		91.3		228.0		166.8		200.1		201.0		331.7		283.9	
Less: non-refinanced Debt Service	45.8		53.7		215.8		115.6 d/		200.1 e/		201.0 g/		200.2 h/		280.4 j/	
1. Net Internal Cash Generation	50.2	20	37.6	9	12.2	3	51.2 d/	8	- e/	-	- g/	-	131.5 h/	26	3.5 j/	.5
(Net Internal Cash Generation+Power Tax)	(111.9	45)	(98.9	23)	(95.8	21)	(127.3	20)	(-	-)	(18.2	5)	(213.6	43)	(81.6	13)
2. Domestic Contribution:																
from private sector:	5.2	2	54.4 a/	13	23.3	5	73.0	11	31.7	10	44.5	13	14.4 h/	3	34.3	6
from public sector:																
power consumption tax	61.7	25	61.3	14	83.6	19	76.1	12	46.5	15	51.4	15	82.1	16	78.1	13
NAFINSA loans and appropriations	53.2	22	205.8 b/	48	193.1 c/	43	220.1 c/ d/	34	40.1 e/	13	41.6 g/	12	59.5	12	80.9 j/	13
sub-total public	114.9	47	267.1	62	276.7	62	296.2	46	86.6	28	93.0	27	141.6	28	159.0	26
Total	120.1	49	321.5	75	300.0	67	369.2	57	118.3	38	137.5	40	156.0	31	193.3	32
3. Foreign Borrowing:																
Suppliers Credits	-						22.8	4	21.3	7	23.6	7	5.3	1	0.4	-
Foreign Bond Issues	-						26.3	4	- e/		27.2 g/	8	15.0 h/ i/	3	78.8	13
Foreign Private Loans	-		19.3	4			39.7	6	57.0 e/ f/	19	100.4 g/	29	23.4	5	236.9 k/	39
I.B.R.D.	76.8	31	51.6	12	135.7	30	135.7	21	111.2	36	57.0	16	169.9	34	93.4	15.5
Total	76.8	31	70.9	16	135.7	30	224.5	35	189.5	62	208.2	60	213.6	43	409.5	67.5
4. Total Sources	247.1	100	430.0	100	447.9	100	644.9	100	307.8	100	345.7	100	501.1	100	606.3	100
APPLICATION OF FUNDS																
5. Investments	236.7	96	468.7	109	434.8	97	656.8	102	292.0	95	331.0	96	477.0	95	586.7	97
6. Working Capital and cash	10.4	4	-38.7	-9	13.1	3	-11.9	-2	15.8	5	14.7	4	24.1	5	19.6	3
7. Total Applications	247.1	100	430.0	100	447.9	100	644.9	100	307.8	100	345.7	100	501.1	100	606.3	100
8. Total Debt Service	45.8		53.7		215.8		227.4		403.8		376.7		266.8		299.2	

a/ Mainly loans from local Banks made in 1960 and 1962.
b/ Includes US$ 123 million of suppliers' credits incurred for C.F.E. by NAFINSA on behalf of the Government.
c/ Includes US$ 132 million of which US$ 68 million for 1962 of suppliers' credits incurred for C.F.E. by NAFINSA on behalf of the Government.
d/ Does not take into account US$ 111.8 million debt service which was refinanced in 1965 by the National Development Bank (NAFINSA).
e/ The debt service does not include the expected refinancing by NAFINSA of US$ 152 million of short and medium term debt (15 years, 8%), it does not include either the reimbursement in 1966 of US $ 47 million of a short-term debt incurred in 1965. Also the debt service does not include the US$ 47.5 million receipts of 2 foreign bond issues expected to be used to pay off a part of the outstanding medium-term debt, nor US$ 4.2 million withdrawn for debt servicing from private foreign loans which are indicated here net of this withdrawal.
f/ Includes US$ 35 million of joint loans to be obtained from suppliers' countries.
g/ Does not take into account US$ 142.5 million which were refinanced in 1965/66 by NAFINSA, nor US$ 33.2 million which were refinanced from the proceeds of foreign bonds issued in 1965/66. The actual figure shown for foreign bonds is net of these US$ 33.2 million.
h/ Does not include US$ 66.6 million of local commercial bank credit maturities to be rolled over.
i/ Includes US$ 22.3 million of joint loans to be obtained from suppliers' countries.
j/ Does not include US$ 18.8 million which were refinanced by NAFINSA in 1968.
k/ Includes US$ 1.9 million in 1968 from 436-ME joint loans and US$ 10.6 million in 1969 from 544-ME joint loans.

Terms of Loans and Suppliers Credits:

	LOAN 194-ME		LOAN 316-ME		LOAN 436-ME		LOAN 544-ME	
	Interest (%)	Amortization (yrs)	Interest (%)	Amortization (yrs)	Interest (%)	Amortization (yrs)	Interest (%)	Amortization (yrs)
Suppliers Credits	-	-	5 3/4 - 7	5 - 15	6 - 7½	5 - 10	6½ - 7	4 - 5
Foreign Bond Issues	-	-	6½	14	6½ - 7	14 - 20	7.1 - 8.4	10 - 15
Foreign Private Loans			6½	3 - 8	6½ - 7¾	5 - 12	6 3/4 - 7.5	4 - 10
Joint Loans	-	-	-	-	5 3/4 - 6	10 - 15	5½ - 7	9 - 12
Nafinsa Loans	6 - 6½	5 - 16	6 3/4 - 8	5 - 15	7 2/3 - 9	15	8 - 9	5 - 25
Local Bank Loans	9	10	7	5	7 - 12	5 - 10	7 - 8	2 - 10

MEXICO - COMISION FEDERAL DE ELECTRICIDAD
PROJECTS IMPLEMENTATION

TABLE III.1

		Start Const.	Commiss. Date	Const. Period (months)	Project Scope a/		CONSTRUCTION COST (US$ million) L.C.	F.X.	TOTAL	COST/KW US$
LOAN 12-ME (US$ 24.1 million) (signed Jan. 1949)										
1. Miguel Aleman System	Forecast	1947	End 1953	About 78	155 MW	Hydro	13.06	6.84	19.90	128
Associated transmission	Forecast	-	-	-	n.a.	n.a.	3.59	1.88	5.47	
Miguel Aleman System:										
- Santa Barbara plant	Actual	Jan. 1947	Apr. 1951	51	67.6 MW	Hydro	5.56	2.05	7.61	112
Associated transmission	"	Jan. 1948	Feb. 1951	37	20 km	75 MVA	0.46	0.85	1.31	
- San Bartolo I plant	Actual	Jan. 1950	Sept. 1955	68	25.2 MW	Hydro	4.47	1.28	5.75	228
Associated transmission	"	May 1954	June 1955	13	20 km	28 MVA	0.07	0.17	0.24	
- El Durazno plant	Actual	May 1947	Nov. 1955	102	18 MW	Hydro	1.89	1.28	3.17	176
Associated transmission	"	Jan. 1951	May 1955	52	-	20 MVA	0.13	0.19	0.32	
- Ixtapantango plant	Actual	Jan. 1952	Oct. 1954	33	50 MW	Hydro 50 MVA	0.50	1.44	1.94	117 c/
Rivers diversions	"	Jan. 1948	Sept. 1956	104			21.02	0.47	21.49	
Transmission system	Actual	March 1950	Jan. 1956	70	236 km	140 MVA	1.15	2.74	3.89	
- Total system: generation					160.8 MW	Hydro	33.44	6.52	39.96	248
transmission	Actual				276 km	313 MVA	1.81	3.95	5.76	
2. Puebla-Veracruz System	Forecast	1947	End 1952	About 66	35.3 MW	Hydro	1.02	0.97	1.99	56
Associated transmission	Forecast				n.a.	n.a.	0.92	0.87	1.79	
Puebla-Veracruz System:										
- Tepazolco plant	Actual	Apr. 1949	March 1953	47	10.9 MW	Hydro	1.01	0.53	1.54	141
Associated transmission	"	Jan. 1952	Oct. 1952	9	-	15 MVA	0.08	0.16	0.24	
- El Encanto plant	Actual	Jan. 1947	Oct. 1951	57	10 MW	Hydro	1.26	0.44	1.70	170
Associated transmission	"	Jan. 1948	Aug. 1951	43	-	12 MVA	0.07	0.07	0.14	
- Minas I plant	Actual	June 1947	Dec. 1951	54	9.6 MW	Hydro	1.21	0.06	1.27	132
- Transmission system	"	Jan. 1950	Oct. 1953	45	456 km	47 MVA	0.77	1.70	2.47	
- Total system: generation	Actual				30.5 MW	Hydro	3.48	1.03	4.51	148
transmission	"				456 km	74 MVA	0.92	1.93	2.85	
3. Sonora System	Forecast	n.a.	n.a.	n.a.	40 MW	Thermal	2.88	2.66	5.54	139
Sonora System:										
- Ciudad Obregon plant	Actual	May 1949	Feb. 1951	21	3 X 5 MW	Thermal	0.96	1.98	2.94	196
- Guaymas plant I	Actual	Sept. 1949	March 1953	42	(2 X 12.5 MW	Thermal)	2.61	4.41	7.02	253 d/
Associated transmission	"	May 1950	July 1953	38	(125 km	30 MVA)				
- Total:	Actual				40 MW	Thermal	3.57	6.39	9.96	
4. Juarez power plant	Forecast	Sept. 1948	1953	About 57	1 X 5 MW	Thermal	0.61	0.76	1.37	274
	Actual	Sept. 1948	Sept. 1950	24	3 X 5 MW	Thermal	0.75	1.99	2.74	183
5. Bombana plant	Forecast	Jan. 1947	1953	About 78	(2.6 MW	Hydro)	0.43	0.10	0.53	204
and Associated transmission	Actual	Jan. 1947	March 1951	50	(45 km	3 MVA)	1.04	0.16	1.20	377
6. Chihuahua plant	Forecast	n.a.	1954	n.a.	2 X 25 MW	Thermal	2.00	3.57	5.57	111
Chihuahua plant	Actual	June 1950	Oct. 1953	40	3 X 15 MW	Thermal	3.67	3.72	7.39	164
Associated transmission	"	Oct. 1951	May 1953	19	40 km	51 MVA	0.84	0.54	1.38	
7. Aldama plant	Forecast	n.a.	1954	n.a.	6 MW	Thermal	0.35	1.07	1.42	237
replaced by Ciudad Victoria	Actual	Apr. 1951	Jan. 1954	33	2 X 1 MW	Thermal	0.37	0.26	0.63	315
8. Small diesel plants	Forecast	n.a.	1954	n.a.	16.9 MW	Diesel	7.25	3.88	11.13	
(incl. rural electrification)	Actual	Feb. 1949	July 1954	65	12.6 MW Diesel	25 MVA	1.53	2.99	4.52	
9. Various transmission extensions	Actual	Feb. 1950	July 1956	77	465 km	15 MVA	1.08	1.96	3.04	
10. Distribution expansion	Actual				5,575 connections		0.49	0.55	1.04	
LOAN 56-ME (US$ 29.7 million) (signed Jan. 1952)										
1. Tingambato plant	Forecast	Jan. 1952	Oct. 1955	45	150 MW	Hydro	9.21	7.63	16.84	112
	Actual	July 1952	Dec. 1957	65	135 MW	Hydro	19.28	5.93	25.21	187
Tingambato transmission	Forecast	-	-	n.a.	300 km	336 MVA	1.21	6.11	7.32	
	Actual	Oct. 1955	Dec. 1957	26	300 km	306 MVA	1.23	2.76	3.99	
2. El Cobano plant b/	Forecast	Dec. 1950	Dec. 1953	36	55 MW	Hydro	6.66	1.69	8.35	152
	Actual	Dec. 1950	Nov. 1955	59	52 MW	Hydro	8.04	1.74	9.78	188 b/
El Cobano transmission	Forecast				450 km	118 MVA	1.48	5.11	6.59	
	Actual	Apr. 1953	Dec. 1955	32	314 km	113 MVA	1.75	2.44	4.19	
3. Monterrey I plant	Forecast	Apr. 1951	Feb. 1953	22	2 X 15 MW	Thermal	0.78	2.84	3.62	121
	Actual	June 1951	Nov. 1953	29	2 X 15 MW	Thermal	2.11	2.82	4.93	164
Monterrey transmission	Forecast				218 km	45 MVA	0.67	0.99	1.66	
	Actual	Jan. 1952	Jan. 1954	24	187 km	25 MVA	0.65	0.86	1.51	
4. Veracruz plant	Forecast	Apr. 1952	March 1954	23	1 X 10 MW	Thermal	0.46	1.37	1.83	183
	Actual	May 1952	July 1954	26	1 X 10 MW	Thermal	1.50	1.43	2.93	293
Veracruz transmission	Forecast				57 km	19 MVA	0.19	0.40	0.59	
	Actual	July 1953	July 1954	12	42 km	13 MVA	0.18	0.27	0.45	
5. Sonora transmission	Forecast	Jan. 1952	Dec. 1953	23	430 km	37 MVA	0.81	1.87	2.68	
and distribution	Actual	Jan. 1952	July 1955	42	490 km	32 MVA	0.54	1.87	2.41	
6. Motul and La Paz plants	Forecast	Apr. 1952	Mar-Dec. 1953	11-20	2 X 2 MW, 1 X 2.5 MW	Thermal	1.00	1.62	2.62	403
replaced by:										
- Oviachic plant b/	Actual	Feb. 1955	Jan. 1958	35	19.2 MW	Hydro	2.00	0.74	2.74	143 b/
Associated transmission	"	1953	July 1957	48	40 km	20 MVA	0.36	0.38	0.74	
- Mocuzari plant b/	Actual	Feb. 1956	March 1959	37	9.6 MW	Hydro	1.35	0.36	1.71	178 b/
Associated transmission	"	Feb. 1956	Oct. 1957	20	40 km	12 MVA	0.23	0.37	0.60	
- El Fuerte plant b/ (2 first units, 40 MW)	Actual	July 1956	Nov. 1960	52	40 MW	Hydro	4.56	1.42	5.98	150 b/
Associated transmission	"	Nov. 1956	Dec. 1960	49	450 km	76 MVA	2.18	1.92	4.10	
- Merida plant	Actual	May 1953	Sept. 1955	28	1 X 6.25 MW	Thermal	0.61	0.67	1.28	205 d/
Associated transmission	"	1957	n.a.	n.a.	116 km	7 MVA	0.72	0.19	0.91	
- Villahermosa plant	Actual	Dec. 1957	Nov. 1959	23	2 X 2.25 MW	Thermal	0.73	0.43	1.16	258
Associated transmission	"	n.a.	1957	n.a.	223 km	7.7 MVA	0.70	0.04	0.74	
- La Laguna plant (1 unit, 33 MW)	Actual	June 1956	June 1958	24	1 X 33 MW	60 MVA	2.43	2.40	4.83	146 d/
- Ciudad Victoria plant (extension)	Actual	Jan. 1953	Aug. 1954	19	1 X 2.5 MW	Thermal	0.19	0.42	0.61	244
Total system: generation	Actual				82 MW Hydro and Thermal		11.80	6.24	18.04	
transmission	"				869 km	100 MVA	4.19	2.90	7.09	
7. Distribution expansion	Actual	-	-		10,210 connections		1.78	1.18	2.96	

LOAN DISBURSEMENT PATTERN

			1949	1950	1951	1952	1953	1954	1955	1956	1957	1958	1959
LOAN 12-ME:	Forecast:	Amount (US$ mln)	7.80	10.99	5.31								
		% of total	32.4	45.6	22.0								
		Cumulative %	32.4	78.0	100								
	Actual :	Amount (US$ mln)	2.21	7.24	3.70	4.83	2.99	1.41	1.23	0.49			
		% of total	9.2	30.0	15.4	20.0	12.4	5.9	5.1	2.0			
		Cumulative %	9.2	39.2	54.6	74.6	87.0	92.9	98.0	100			
LOAN 56-ME:	Forecast:	Amount (US$ mln)				14.95	10.35	4.40					
		% of total				50.3	34.9	14.8					
		Cumulative %				50.3	85.2	100					
	Actual :	Amount (US$ mln)				6.17	6.21	3.57	3.85	4.36	2.28	2.59	0.67
		% of total				20.8	20.9	12.0	13.0	14.7	7.7	8.7	2.2
		Cumulative %				20.8	41.7	53.7	66.7	81.4	89.1	97.8	100

a/ Project Scope for generation is megawatts of installed capacity and source of energy; for transmission components, kilometers of line erected; for distribution components, number of connections made.
b/ Plants built in connection with irrigation dams previously constructed by the Department of Hydraulic Resources. Costs refer to power additions only.
c/ Extension to plant.
d/ These unit costs cannot be used for comparison purposes because they correspond to plants partially completed.

TABLE III.2

MEXICO - COMISION FEDERAL DE ELECTRICIDAD
PROJECTS IMPLEMENTATION

			Start Const.	Commiss. Date	Const. Period (months)	Project Scope a/		CONSTRUCTION COST (US$ million) L.C.	F.X.	TOTAL	COST/KW US$
	LOAN 194-ME (US$ 34 million) (signed May 1958)										
1.	Mazatepec plant	Forecast	Jan. 1957	End of 1961	59	156 MW	Hydro	17.95	5.41	23.36	150
		Actual	Jan. 1957	March 1963	74	156 MW	Hydro	45.82	11.89	57.71	370
	Associated transmission	Forecast		1964	n.a.	400 km (220 kv)		1.29	7.58	8.87	
		Actual	April 1958	June 1962	50	460 km (250 kv)	334 MVA	4.78	5.87	10.65	
2.	Temaxcal plant b/	Forecast	Oct. 1954	Oct. 1958	48	154 MW	Hydro	7.76	5.42	13.18	85
		Actual	Oct. 1954	March 1960	65	154 MW	Hydro	17.07	3.41	20.48	133
	Associated transmission	Forecast	Jan. 1958	Dec. 1958	11	430 km (115 kv)	56 MVA	0.63	3.18	3.81	
		Actual	Jan. 1958	Sept. 1959	20	260 km (115 kv)	235 MVA	3.65	2.64	6.29	
3.	Cupatitzio plant	Forecast	April 1957	Nov. 1961	55	73.6 MW	Hydro	5.77	3.53	9.30	126
		Actual	April 1957	Sept. 1962	65	63 MW	Hydro	18.16	4.72	22.88	363
	Associated transmission	Forecast	n.a.	n.a.	n.a.	370 km (161 kv)	81 MVA	1.38	5.11	6.49	
		Actual	April 1961	Sept. 1962	17	370 km (161 kv)	188 MVA	3.77	2.02	5.79	
4.	Guaymas plant extension	Forecast	n.a.	Dec. 1960	n.a.	1 X 30 MW	Thermal	1.50	2.93	4.43	148
		Actual	Feb. 1959	June 1962	40	1 X 33 MW	Thermal	2.14	2.27	4.41	134
	Associated transmission	Forecast	n.a.	n.a.	n.a.	400 km (14, 115 kv)		0.56	2.11	2.67	
		Actual	Feb. 1959	June 1961	28	465 km (115 kv)	16 MVA	0.55	1.18	1.73	

LOAN DISBURSEMENT PATTERN

			1958	1959	1960	1961	1962	1963
LOAN 194-ME:	Forecast:	Amount (US$ mln)	5.44	10.19	9.81	8.56		
		% of total	16	30	28.8	25.2		
		Cumulative %	16	46	74.8	100		
	Actual :	Amount (US$ mln)	5.41	4.19	7.21	11.53	5.65	0.01
		% of total	15.9	12.3	21.2	34.0	16.6	-
		Cumulative %	15.9	28.2	49.4	83.4	100	

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a/ Project Scope for generation is megawatts of installed capacity and source of energy; for transmission components, kilometers of line erected; for distribution components, number of connections made.

b/ Plant built in connection with a flood protection dam previously constructed.

MEXICO - COMISION FEDERAL DE ELECTRICIDAD - PROJECTS/PROGRAMS IMPLEMENTATION — TABLE III.3

LOAN 316-ME (US$130 million) (signed June 1962)		Scope of the Program (Facilities scheduled or completed over 1962-1965)	Total Cost of Program (US$ million) Generation	Transmission & Distribution	Total Investments Made in 1962/65 (US$ Million) On facilities of program	On others	Total
Investment program 1962-1965 in:							
- Central system	Forecast	978 MW (828H + 1 x 150T)	160.69	-	78.62	4.16	82.78
	Actual	739 MW (565H + 1 x 150T)	183.35	21.78	132.51	n.a.	n.a.
- Oriental system	Forecast	157 MW (3 x 39 + 1 x 40T)	19.63	6.50	8.94	19.78	28.72
	Actual	117 MW (3 x 39) Thermal	22.17	3.42	13.18	n.a.	
- Occidental system	Forecast	134 MW Hydro	30.45	8.23	21.76	3.92	25.68
	Actual	123 MW Hydro	42.71	6.95	32.74	n.a.	
- North system	Forecast	99 MW (3 x 33 T)	13.51	2.63	13.84	1.2	15.04
	Actual	99 MW (3 x 33) Thermal	18.78	0.46	16.94	n.a.	
- North West system	Forecast	157 MW (124H + 1 x 33T)	38.57	5.82	31.40	-	31.40
	Actual	157 MW (124H + 1 x 33T)	47.99	3.49	38.48	n.a.	
- North East system	Forecast	337 MW (3 x 75 + 3 x 37T)	43.33	24.61	51.66	-	51.66
	Actual	337 MW (3 x 75 + 3 x 37T)	55.24	4.56	47.38	n.a.	
- Other systems (Incl. small systems)	Forecast	544 MW (84H+4x75+3x40+1x15+4x6.25 T) a/	80.65	15.63	80.02	22.42	102.44
	Actual	326 MW (48H+3x75+2x14+4x6.25 T)	71.24	5.21	64.22	n.a.	
- Sub-total: all systems	Forecast	2,406 MW b/ (1,170H + 1,236 T)	386.83	63.42	286.24	51.48	337.72
	Actual	1,874 MW b/ (860H + 1,014 T)	441.48	45.87	345.45	148.23	493.68
- Expansion of distribution and rural electrification	Forecast c/			67.20	67.20	-	67.20
	Actual			125.53	125.53		125.53
- Total Program	Forecast		386.83	130.62	353.44	51.48	404.92 d/
	Actual	1978MW + 3,400 km.	441.48	171.40	470.98	148.23	619.21 e/

LOAN 436-ME (US$110 million) (signed December 1965)		Scope of the Program f/ (Facilities scheduled or completed over 1965-1966)			Total Investments Made in 1965/66 (US$ million) CFE	Others
Investment program 1965-1966 of CFE in:						
- Central system	Forecast	644MW H + 660 km + 1,260 MVA	87.44	35.58	5.00	4.27
	Actual	336MW H + 355MW g/ + 660 km + 1210MVA	115.79	53.76	n.a.	n.a.
- Oriental system	Forecast	46MW (18H + 2 x 14 T) + Low volt. tran.	6.01	39.49	60.75	3.70
	Actual	46MW f/	8.50	1.14		
- Occidental system	Forecast	Lower voltage transmission	-	26.03	11.84	9.49
	Actual	- n.a. -	-	n.a.	n.a.	n.a.
- North system	Forecast	3 x 30 MW + 1 x 38 MW T	20.76	4.94	7.50	2.32
	Actual	74 MW T + 66 MW g/ + 40 MVA	27.45	1.04	n.a.	n.a.
- North West system	Forecast	1 x 40 MW T	6.52	7.30	12.51	0.24
	Actual	(1 x 41 MW h/)	(10.51) h/	n.a.	n.a.	n.a.
- North East system	Forecast	1 x 38 MW T + 370 km + 110 MVA	8.42	8.09	3.88	-
	Actual	1 x 38 MW g/ + 360 km + 110 MVA	13.34	9.50	n.a.	n.a.
- Other systems	Forecast	169 MW (69H + 1 x 82 + 2 x 9 T) i/	43.95	6.71	31.08	2.59
	Actual	39 MW H + 30 MW g/ (+ 100 MW h/)+250MVA	34.90(+17.05 h/)	4.72	n.a.	n.a.
- Expansion of distribution and rural electrification	Forecast			120.40	41.36 j/	79.04 m/
	Actual			69.19	20.88	48.31
Total	Forecast	1115 MW + 2900 km	173.10	248.54	173.92 k/	100.59 n/
	Actual	449 MW + 535 MW f/ (+141MW g/)+ + 1,020 km + 1610 MVA	199.98	139.35	178.90 l/	65.66 n/

LOAN 544-ME (US$90 million) (signed June 1968)		Scope of the Program f/ (Facilities scheduled or completed over 1968-1970)	Actual Cost of Programmed Works Completed during 1968-1970 (US$ million) Generation	Transmission & Distribution	Total Investments Made in 1968/70 (US$ million) CFE	Centro
Investment program 1968/1969 of CFE in:						
- Central system	Forecast	2 x 150 MW T + 290 km + 700 MVA	n.a.			35.30
	Actual	1 x 150 MW T + 230 km + 200 MVA	n.a.	11.69		23.65
- Oriental system	Forecast	720MW H +1x14MW T +1780km+1925MVA	n.a.	n.a.		
	Actual	720MW H +1x14MW T +1830km+2590MVA	82.29	134.94		
- Occidental system	Forecast	2x150MW+4x14MW T +1,020km+1,031MVA	n.a.	n.a.		
	Actual	1x150MW+3x14MW T +840km+770MVA	22.42	18.76		
- North system	Forecast	-	-		222.62	
	Actual	-	-		281.03	
- North West system	Forecast	2 x 41 MW T + 70 km	n.a.	n.a.		
	Actual	2 x 41 MW T + 40 MW	23.66	0.89		
- North East system	Forecast	1 x 75 MW T + 365 km + 354 MVA	n.a.	n.a.		
	Actual	OMW	-			
- Other systems	Forecast o/	1x82MW+2x22MW+3X14MW T +18MWD +2x30MWGT+150km+140MVA	n.a.	n.a.		
	Actual	1x82MW+2x14MW T +18MW D +170km+300MVA	20.87	6.58		
- Expansion of distribution and rural electrification	Forecast			174.34	124.84 p/	49.50
	Actual			194.82	154.41	40.41
Total	Forecast	1,793 MW + 3,680 km + 4,150 MVA	n.a.	n.a.	347.46 q/	84.80
	Actual	1,286 MW + 3,070 km + 3,900 MVA	148.64	357.68	435.44 r/	64.06 s/

LOAN DISBURSEMENT PATTERN

			1962	1963	1964	1965	1966	1967	1968	1969	1970	Undisbursed 12/31/70
LOAN 316-ME:	Forecast:	Amount (US$million)	69.36	60.64								
		% of Total	53.4	46.6								
		Cumulative %	53.4	100								
	Actual:	Amount (US$million)	14.31	60.35	54.03	1.31						
		% of Total	11.0	46.4	41.6	1.0						
		Cumulative %	11.0	57.4	99.0	100						
LOAN 436-ME:	Forecast:	Amount (US$million)				40.00	70.00					
		% of Total				36.4	63.6					
		Cumulative %				36.4	100					
	Actual:	Amount (US$million)				-	55.67	38.75	15.58			
		% of Total					50.6	35.2	14.2			
		Cumulative %					50.6	85.8	100			
LOAN 544-ME:	Forecast:	Amount (US$million)							60.00	22.00	8.00	
		% of Total							66.7	24.4	8.9	
		Cumulative %							66.7	91.1	100	
	Actual:	Amount (US$million)							19.91	54.36	8.91	6.82
		% of Total							22.1	60.4	9.9	7.6
		Cumulative %							22.1	82.5	92.4	

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a/ Does not include 114 MW and miscellaneous transmission facilities to be installed in the small systems over 1962-1970 with an estimated total cost of US$29.7 million, of which US$15.18 million would have been invested during 1962-1965 (included in the US$22.42 million investments planned for "others"). About 104 MW were installed in the small systems during 1962-1965.
b/ Includes 219 MW of hydro capacity and 33 MW of thermal capacity completed after January 1962 but recorded also in Table III.1 under Loan 194-ME (156 MW for the Guaymas plant of the North West system).
c/ Including US$29.28 million forecast for rural electrification.
d/ Does not include US$29.9 million of Central Office overhead and other investments.
e/ Does not include US$37.6 million of "other" investments, mainly relending.
f/ Generating stations, MVA capacity of substations in 400 or 230 kv only, transmission lines of 400 or 230 kv only.
g/ Completed before 1966 and thus included in Loan 316-ME.
h/ Completed after 1966 and thus included in Loan 544-ME.
i/ This does not include 50 MW programmed to be installed before 1967 in the small systems. About 5 MW were actually installed in these systems.
j/ Includes US$2.48 million special equipment, US$0.72 million for frequency change and US$18.40 million for rural electrification.
k/ Does not include US$16.48 million of Central Office overhead chargeable to construction.
l/ Does not include US$25.73 million of "other" investments.
m/ Includes US$1.04 million for frequency change.
n/ Does not include US$60.69 million of "other" investments.
o/ Does not include 30 MW diesel to be installed in small systems.
p/ Includes US$32.4 million for rural electrification.
q/ Does not include US$44.74 million for consultants, buildings, office overheads, etc.
r/ Does not include US$30.48 million for other investments, mainly financial.
s/ Does not include US$56.74 million for other investments.

MEXICO: COMISION FEDERAL DE ELECTRICIDAD

ANNEX TO TABLE III.3

IMPLEMENTATION OF PROJECTS IN CFE PROGRAMS

	End of Construction		Actual		Construction Cost Total (US$ million)		Cost/KW US$	
	Forecast	Actual	Project	Scope	Forecast	Actual	Forecast	Actual
LOAN 316-ME (US$ 130 million) a/ (signed June 1962)								
1. Mazatepec 4th Unit	March 1962	Sept. 1964	52 MW	Hydro	6.58	8.53	127	164 d/
2. San Bartolo II Associated transmission	Aug. 1963	March 1965	19 MW 132 kv trans	Hydro 25 MVA	2.90	4.61 0.61	145	243 -
3. Infiernillo 2 Units Associated transmission	June 1964 (4 units)	June 1965	336 MW -	Hydro 450 MVA		95.42 9.02		318 d/
4. Valle de Mexico (1st Unit) Associated transmission	Jan. 1963	March 1963	1 x 150 MW -	Thermal 200 MVA	13.62	17.91 0.68	91	119
5. Poza Rica Associated transmission	Nov. 1962	April 1963	3 x 39 MW ? km	Thermal 160 MVA	15.07	22.17 3.42	129	189
6. Santa Rosa Associated transmission	Jan. 1964	Sept. 1964	60 MW ? km	Hydro 80 MVA	14.67	19.83 1.16	245	331
7. Delicias (2 Units) Associated transmission	Nov. 1963 (3 units)	Dec. 1964	2 x 33 MW -	Thermal 72 MVA		18.32 0.45		278 d/
8. Sanalona Associated transmission	June 1962	Oct. 1964	14 MW 34 km (115 kv)	Hydro 21 MVA	1.96	2.26 0.62	140	161
9. El Fuerte (3rd Unit) Associated transmission	Nov. 1962	Aug. 1964	20 MW -	Hydro 25 MVA	1.02	1.10 0.21	51	55 d/
10. El Novillo Associated transmission	Dec. 1963	Oct. 1964	90 MW Distribution	Hydro 120 MVA	30.41	40.22 0.93	338	447 d/
11. Monterrey II Associated transmission	Nov. 1962	July 1965	3 x 75 MW -	Thermal 252 MVA	27.13	31.18 2.56	121	139
12. Rio Bravo Associated transmission	Dec. 1963	Aug. 1964	2 x 37.5 MW -	Thermal 84 MVA	9.20	10.72 1.00	123	143
13. Nava Associated transmission	Dec. 1963	Dec. 1965	1 x 37.5 MW -	Thermal 42 MVA	7.00	13.34 1.00	187	356
14. La Venta Associated transmission	April 1963	May 1965	30 MW -	Hydro 37.5 MVA	10.54	17.76 0.60	351	592
15. Tijuana Associated transmission	June 1963 (4 units)	Jan. 1964	3 x 75 MW -	Thermal 250 MVA	28.65	36.82 3.18	127	164 d/
16. Chilapan Associated transmission	June 1963	Dec. 1965	18 MW -	Hydro 22 MVA	1.89	3.91 0.33	105	217 d/
17. Juchitan Associated transmission	June 1962 (3 units)	End 1965	2 x 6.25 MW -	Thermal 12.5 MVA	3.79	4.16 0.29	303	333
18. Pajaritos (Minatitlan) Associated transmission	Jan. 1964	Dec. 1965	2 x 14 MW -	Gas turbine 33 MVA	3.34	4.59 0.81	119	164
19. Merida (2 Units)	June 1962	Nov. 1962	2 x 6.25 MW	Thermal	3.02	4.00	242	320 d/
LOAN 436-ME (US$ 110 million) b/ (signed December 1965)								
20. Infiernillo (2 Units) Associated transmission	Dec. 1965	March 1966	336 MW 100 km (132 kv)	Hydro 450 MVA		15.76 1.50		47 d/
21. La Laguna 4th Unit Associated transmission	Jan. 1966	Dec. 1967	1 x 41 MW -	Thermal 45 MVA	5.76	8.67 0.58	144	211 d/
22. Delicias 3rd Unit	May 1965	March 1966	1 x 33 MW	Thermal		0.46		14 d/
23. El Retiro Associated transmission	Jan. 1964	1966	21 MW 12 km (69 kv)	Hydro 30 MVA	4.90	11.60 0.90	348	552
24. El Salto Associated transmission	Dec. 1963	1966	18 MW -	Hydro 20 MVA	3.14	5.54 0.62	174	308
LOAN 544-ME (US$ 90 million) c/ (signed June 1968)								
25. Malpaso Associated transmission	1967, 1968	June 1969	720 MW -	Hydro 975 MVA	31.02	80.22 13.43	43	115 d/
26. Tampico	1968	Aug. 1968	1 x 14 MW	Gas turbine		2.07		148
27. Guadalajara extension	1968	Nov. 1968	2 x 14 MW	Gas turbine		2.85		102 d/
28. Salamanca I Associated transmission	1968	Sept. 1968	1 x 14 MW -	Gas turbine 15 MVA		1.48 0.06		106
29. Salamanca II	1969	Aug. 1970	1 x 150 MW	Thermal		18.10		121
30. Topolobampo Associated transmission	1968	Oct. 1968	1 x 41 MW -	Thermal 42 MVA	6.52	10.51 0.89	163	256
31. Guaymas 4th Unit	1968	March 1970	1 x 41 MW	Thermal	6.52	13.15	163	321 d/
32. Tijuana 4th Unit Associated transmission	1968	March 1969	1 x 82 MW -	Thermal 90 MVA	10.4	10.57 0.37	127	129 d/
33. Merida 4th Unit Associated transmission	1968	Jan. 1969	1 x 14 MW -	Gas turbine 15 MVA		1.65 0.05		118 d/
34. Merida Diesel Station	1968	Dec. 1968	2 x 9 MW	Diesel		6.48		360
35. Acapulco (Las Cruces)	1968	May 1970	1 x 14 MW	Gas turbine		1.57		112 d/

PLANTS BUILT OR EXPANDED OVER SEVERAL LOANS

- Guaymas I (12, 194,544 - ME) Associated transmission			2 x 12.5, 1 x 33, 1 x 41 MW 590 km	Thermal 46 MVA		24.58 1.73		248
- Ciudad Victoria (12, 56 - ME)			2 x 1 MW + 1 x 2.5 MW	Thermal		1.24		276
- La Laguna (56,436 - ME) Associated transmission			1 x 33 + 1 x 41 MW	Thermal 45 MVA		14.50 0.58		196
- Merida (56,316,544 - ME) Associated transmission			3 x 6.25 + 1 x 14 MW 116 km	Thermal 36 MVA		6.93 0.96		212
- Delicias (316-436 - ME) Associated transmission			3 x 33 MW	Thermal 108 MVA	13.51	18.78 0.46	136	190
- Tijuana (316-544 - ME) Associated transmission			3 x 75 + 1 x 82 MW	Thermal 340 MVA		47.39 3.55		154
- El Fuerte (56,316 - ME) Associated transmission			60 MW 450 km	Hydro 101 MVA		7.08 4.34		118
- Mazatepec (194,316 - ME) Associated transmission			208 MW 460 km	Hydro 334 MVA		65.41 11.48		314
- Infiernillo (316,436 - ME) Associated transmission			672 MW 100 km	Hydro 900 MVA	82.42	111.18 10.52	137	165

- El Novillo, Monterrey II and Salamanca II will be expanded under Loan 659-ME

a/- Does not include: Dos Bocas extension never made, Cupatitzio put under 194-ME, La Laguna extension put under 436-ME, Guaymas put under 194-ME, Progreso never made, El Salto and El Retiro put under 436-ME.

b/- Does include following plants completed during 1965 but put under 316-ME: San Bartolo II, Chilopan, Pajaritos, Nava, La Venta, Infiernillo 2 first units, Delicias 2 first units. Does not include Tijuana 4th unit, Merida extension, Malpaso and Topolobampo initiated under 436-ME but put and completed under 544-ME.

c/- Does not include Valle de Mexico 2nd unit - cost not available, Salamanca II 2nd unit under 659-ME, Acapulco gas turbine put under 659-ME.

d/- These unit costs cannot be used for comparison purposes because they correspond to plants partially completed or to the power part of hydro schemes which had been previously built for irrigation or flood control purposes.

MEXICO: COVENANTS AND SIDE LETTERS OF LOAN AND GUARANTEE AGREEMENTS BETWEEN BANK AND CFE - NAFINSA.

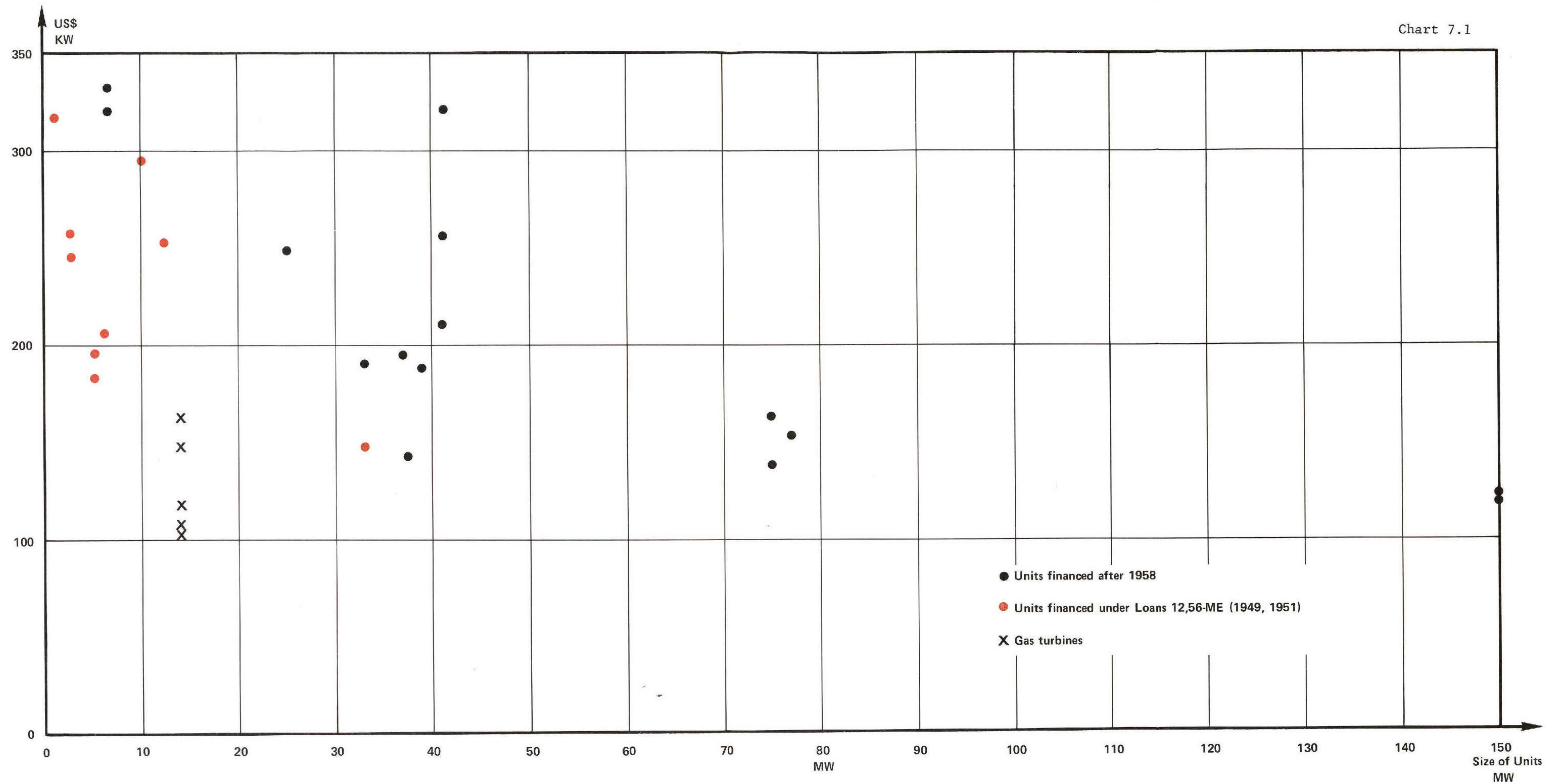
Appendix Table 7.1

	LOAN 12-ME (Jan. 1949)	LOAN 56-ME (Jan. 1952)	LOAN 194-ME (May 1958)	LOAN 316-ME (June 1962)	LOAN 436-ME[c/] (Dec. 1965)	LOAN 544-ME[c/] (June 1968)
- Rates adjustments to provide a return[a/] of			9%	Self financing[b/] 33%	8% Loan cancelled if rates not adjusted before Feb. 1966.	8%
- Incurrence of long-term debt = Int. cash generation[a/]/debt service ⩾	1.5	1.5	1.5	1.5	1.4 Current ratio = 1 end 1966.	1.4 Current ratio = 1
- No incurrence of debt by Nafinsa.				X	X	X
- Guarantee for local funds	X	X	X	X	X Refinance short-term debt.	X
- Local procurement with international bidding	X		X	X	X	X
- Retroactive financing			As from Aug. 1957	As from Jan. 1962	As from Jan. 1965	As from April 1968
- External Financing Auditing				X	X	X
- CFE's internal organization and management			- Review financial and budgetary procedures. - Review operations, procedures and manuals.	- Acceptance tests. - Review internal organization and administration. - Training program for new plants operating staff. - Annual revisions of Financing Plan and Expansion Program.	- Acceptance tests.	- Review of depreciation rates. - Acceptance tests for new equipment. - Annual Revision of CFE Expansion Program. - Review of budgetary procedures.
- Power Sector Policies.			- Review Government policy on adjustment of rates. - Consolidate small systems into uniform tariff zones. - Coordination with connected Companies on operations and investment programs.	- Coordination with connected Companies on operations and investment programs.	- Establish one dispatch control in each system. - Initiate frequency unification programs. - Sector coordination on operations, investment planning and budgetary control.	- Initiate Frequency unification.
- Consultants			- Construction and design of major hydro plants. - Advise on CFE review of operating procedures. - Advise on CFE review of financial procedures.	- Organization of training program for operating staff. - Review the revisions of the Expansion Program. - Board of Consultants on hydro plants. - Consultants for thermal plants and all equipment.	- Assistance on frequency unification. - Review annual Sector investment programs. - Review of Mexlight Investment Program. - Board of Consultants on hydro plants. - Consultants for thermal plants and all equipment.	- Board of international consultants on hydro projects. - Design and Supervision of construction of major new steam plants. - Assistance on frequency unification.
- Obtention of joint financing					US$ 35 million	US$ 22 million

a/ For the last three Loans 316, 436 and 544-ME, in the computation of the return and of the internal cash generation, the earnings of CFE were to include the proceeds of the Power Consumption Tax.
b/ Expressed in a Side Letter.
c/ Covenants and Side Letters of Loans 436 and 544-ME apply to the Power Sector.

Chart 7.1

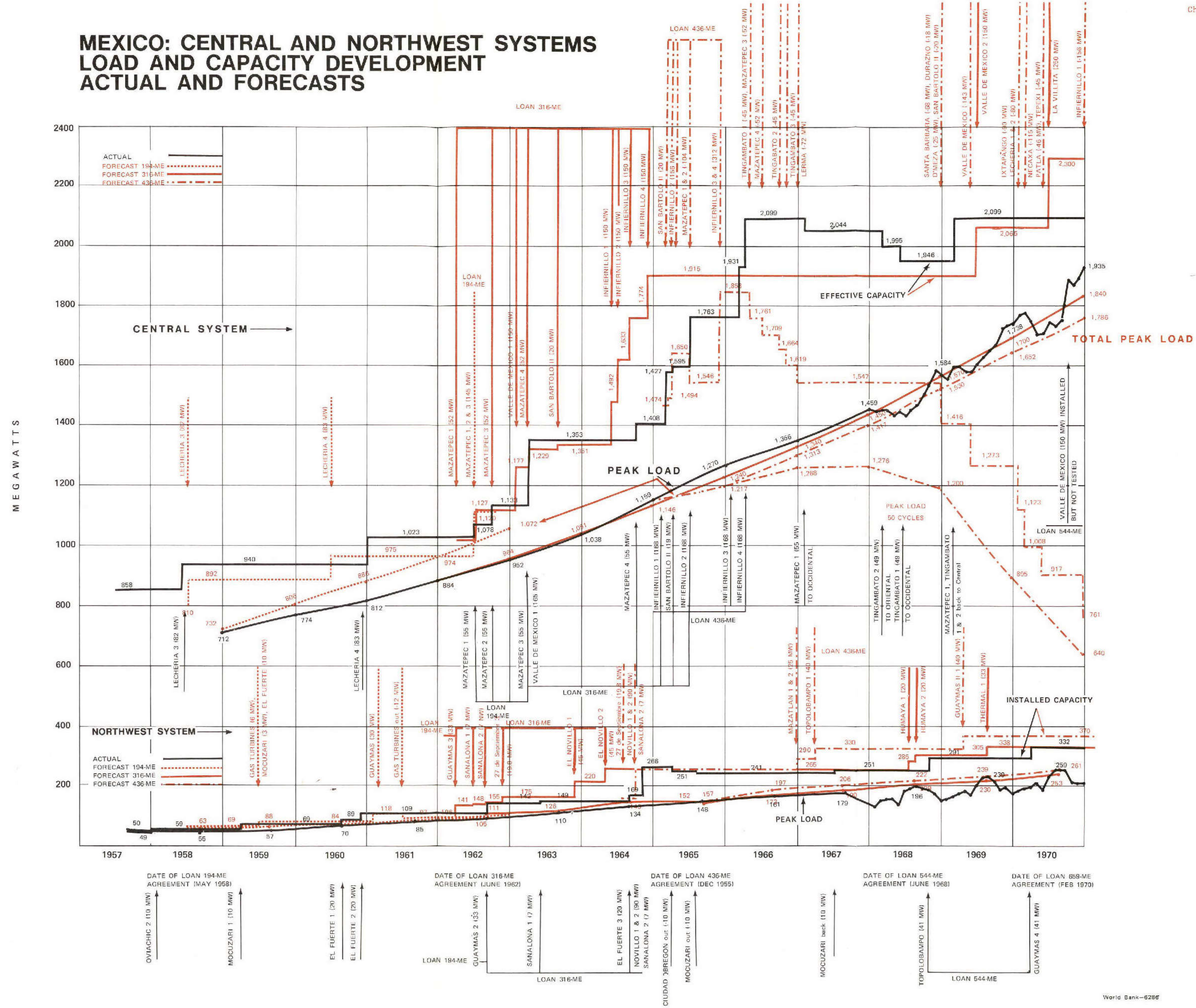
COSTS PER KW INSTALLED OF THERMAL GENERATING UNITS IN MEXICO



World Bank—6300

Chart 7.2

MEXICO: CENTRAL AND NORTHWEST SYSTEMS LOAD AND CAPACITY DEVELOPMENT ACTUAL AND FORECASTS



World Bank—6286

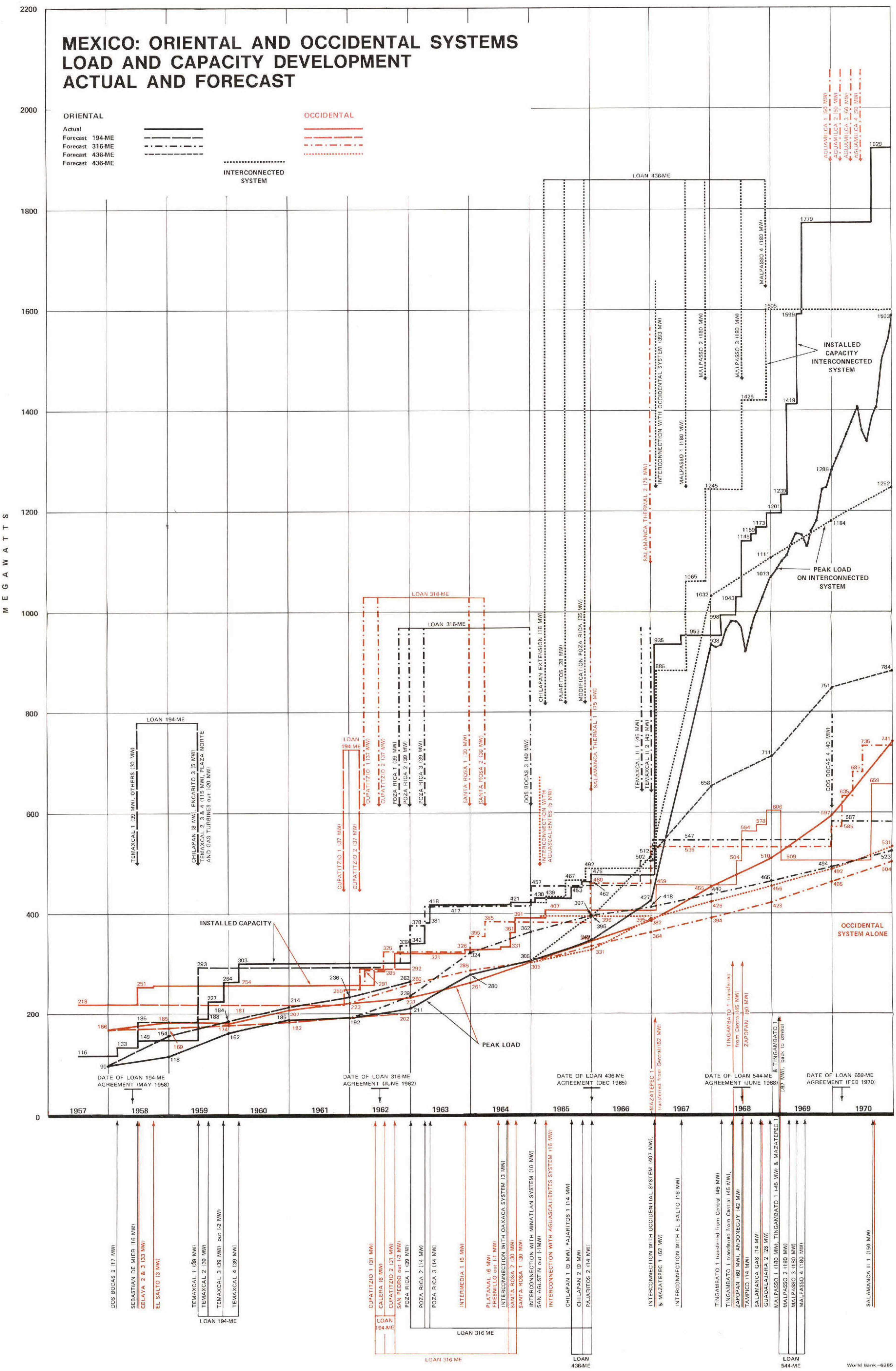
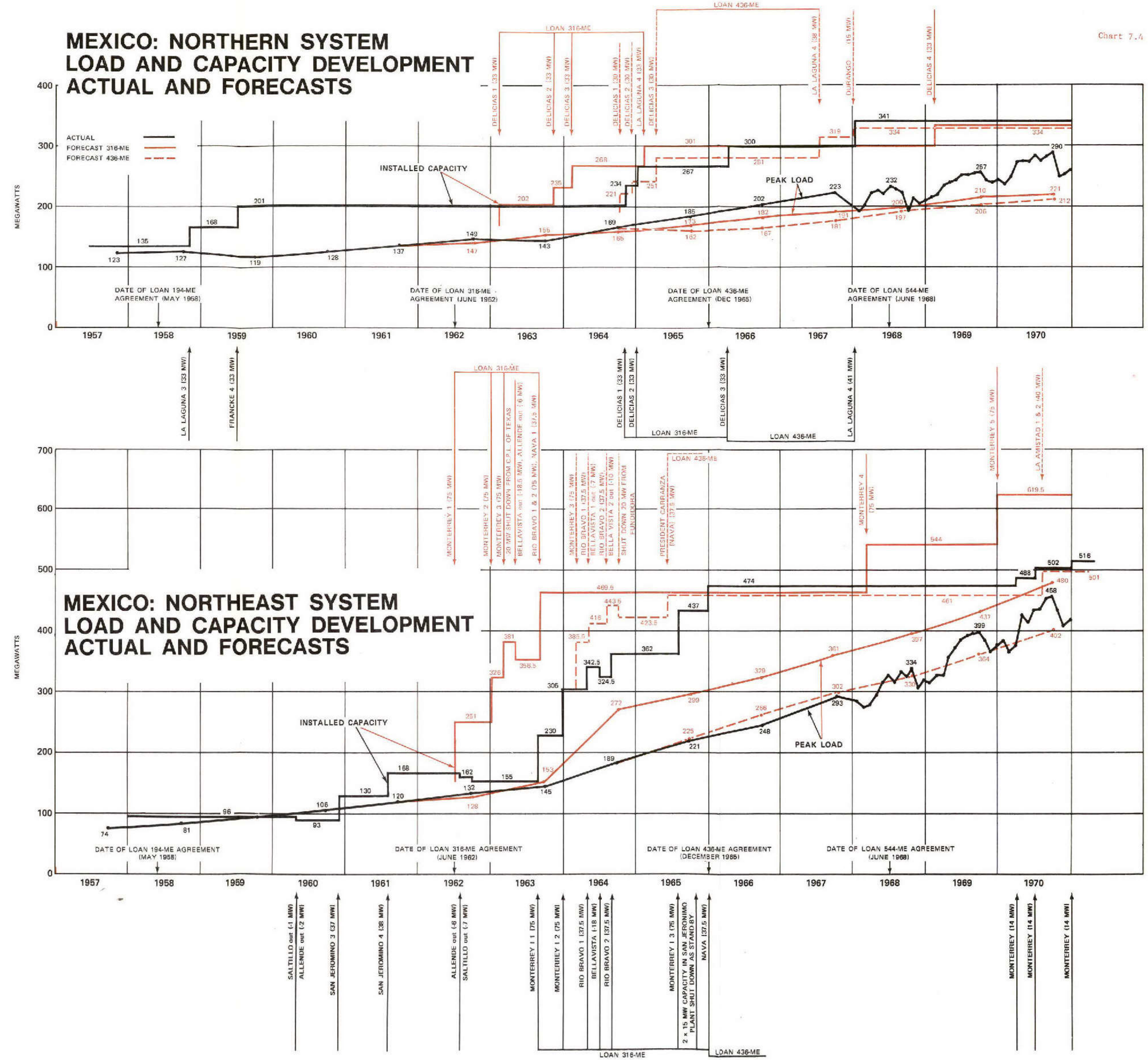

MEXICO: ORIENTAL AND OCCIDENTAL SYSTEMS
LOAD AND CAPACITY DEVELOPMENT
ACTUAL AND FORECAST
ORIENTAL
Actual
Forecast 194-ME
Forecast 316-ME
Forecast 436-ME
Forecast 436-ME
OCCIDENTAL
INTERCONNECTED SYSTEM
MEGAWATTS
INSTALLED CAPACITY
PEAK LOAD
INSTALLED CAPACITY INTERCONNECTED SYSTEM
PEAK LOAD ON INTERCONNECTED SYSTEM
OCCIDENTAL SYSTEM ALONE
LOAN 194-ME
LOAN 316-ME
LOAN 436-ME
LOAN 544-ME
DATE OF LOAN 194-ME AGREEMENT (MAY 1958)
DATE OF LOAN 316-ME AGREEMENT (JUNE 1962)
DATE OF LOAN 436-ME AGREEMENT (DEC 1965)
DATE OF LOAN 544-ME AGREEMENT (JUNE 1968)
DATE OF LOAN 659-ME AGREEMENT (FEB 1970)
1957
1958
1959
1960
1961
1962
1963
1964
1965
1966
1967
1968
1969
1970
World Bank—6285

Chart 7.4

MEXICO: NORTHERN SYSTEM LOAD AND CAPACITY DEVELOPMENT ACTUAL AND FORECASTS

MEXICO: NORTHEAST SYSTEM LOAD AND CAPACITY DEVELOPMENT ACTUAL AND FORECASTS



World Bank—6287

CHAPTER VIII - PUB - SINGAPORE

I. Introduction

1.01 The Public Utilities Board of Singapore is an autonomous public corporation solely responsible for the electricity, water and gas utilities of Singapore. It was established on May 1, 1963 by the Public Utilities Ordinance of 1963 as a body corporate with a perpetual concession. Although a single financial entity, it is required to keep three separate accounts for its Electricity, Water and Gas Departments.

1.02 The installed capacity of the Electricity Department increased more than four times from 150 MW in 1958 to 644 MW by the end of 1970, of which 240 MW were financed by IBRD; electricity generation has been entirely thermal from the three main stations called Pasir Panjang A, Pasir Panjang B and Jurong. There is no significant transmission system and power is distributed at 66 kv, 22 kv and 6.6 kv through mainly underground networks.

1.03 Singapore has long been, and still is, basically a trading community. A structural change in the economy is in progress; manufacturing for both home and export markets is presently the leading growth sector. Production in steel, textiles, metal fabricating and electronics has developed at an increasing rate during the last years; the electrical load growth in this sector is expected to compensate rapidly for the loss of demand resulting from the withdrawal of the British forces from the island during 1971 and 1972. The per capita gross national product reached an estimated US$ 700 per annum in 1968.

1.04 Singapore has no natural fossil fuel resources of its own, but it is located near an area (Indonesia) with large resources of oil and natural gas. Three oil refineries, two of them located on adjacent islets, are already established in Singapore. These refineries are presently the PUB's largest consumers of electricity.

II. The Association Between the Bank and the Board

2.01 The PUB received five loans from the Bank totalling US$ 75.3 million equivalent, of which US$ 60.5 million were for power.

Loan No.	Date of Loan Agreement	Effective Date	Closing Date	Amounts ($ mln) Committed	Disbursed a/	Interest	Period (years) Grace	Term
337 SI	5/63	12/63	5/67	15.00	14.40 b/	5.5%	3	20
405 MA (water)	2/65	2/65		6.80	6.80 b/	5.5%		
473 SI	11/66	11/66	6/68	10.00	9.54	6%	1	20
503 SI								
(power)	7/67	7/67	12/71	15.00	13.63	6%	3	20
(water)	7/67	7/67	12/72	8.00	5.36	6%	5	20
595 SI	4/69	6/69	9/72	20.50	11.46	6.5%	3-1/2	20
Total				75.3	61.77			

a/ As of December 31, 1970

b/ The difference between the amount shown in this column and the amount shown in the preceding commitments column was cancelled.

The first two loans 337 and 473 SI were made for the Pasir Panjang B thermal station (4 x 60 MW), the third loan 405 MA for water supply, and the last two loans 503 and 595 SI mainly for expansion of electricity distribution.

2.02 Prior to the establishment of the PUB, the electricity, water and gas undertakings supplying the island were owned and operated by the City Council. The Government decided in 1959 to disband the Council and transfer these departments to a Public Utilities Board, which was established in 1963 by the Public Utilities Ordinance; the various public utility undertakings, together with all related functions, services, assets, and liabilities, were transferred from the Singapore City Council to the PUB. The organizations, duties, responsibilities and powers of the PUB as prescribed in the Ordinance were established prior to the first power loan in consultation with the Bank. The Bank was concerned that the PUB would lack sufficient freedom in the appointment and control of its staff and in some aspects of its operations, requiring Government approval. The draft was amended with the Government's agreement and the provisions of the Ordinance have been generally satisfactory.

2.03 Loan 337 SI was made in May 1963, under the guaranty of the U. K., to the state of Singapore which in turn relent it to PUB. The project financed by the Bank was the first stage of the Pasir Panjang B thermal station (P.P.B.) with an initial installed capacity of 120 MW.

The station was designed for an ultimate capacity of 240 MW, many features being suitable for the ultimate capacity. It was expected to be completed by May 1965. At the Bank's request, the Government gave assurances that the Board would use its best efforts to:

a) recruit a competent and experienced General Manager;

b) retain the services of experienced staff then holding key positions in the departments transferred to it;

c) promptly fill any vacancies in such positions with qualified staff.

The Government also gave assurances to cause the accounts of the PUB to be regularly audited by independent auditors at least once a year and recognized the imperative need to organize the accounting system of the PUB in accordance with sound commercial accounting practices and to recruit additional qualified personnel required for this purpose. In addition, a side letter was obtained from the Government on a rate covenant requiring a minimum return of 8% on the Board's total net fixed assets in operation.

2.04 In August 1964 the PUB started the construction of the second stage of the Pasir Panjang B station and applied for a loan covering it. However, the position of General Manager was held by a civil servant and this temporary measure had proved unsatisfactory. The Bank delayed consideration of a second loan and expressed also its concern regarding both the number of senior posts then vacant in the Electricity Department and the delay in reorganizing the PUB's accounting system.

After discussions of the problem with PUB and the Government, the Bank proposed that PUB engage a firm of management consultants to make a comprehensive study of the organization and to prepare recommendations aimed at improving PUB's efficiency. The PUB and the Government agreed in early 1965 to the proposal and the foreign exchange cost of the consultants' services was included in the Water Supply loan 405 MA (1965). The consultants' report was submitted in October 1965, but consideration of its recommendations was deferred until a General Manager acceptable to the Bank was appointed in July 1966. The second stage of the P.P.B. station was financed in 1964-1966 by Government loans and temporary overdrafts on commercial banks.

2.05 The Bank made the second power loan, 473 SI, in November 1966, to cover the foreign exchange expenditures which had been incurred during the 120 MW expansion of the Pasir Panjang B station which was then almost completed. The loan was made to the PUB itself under the guaranty of the Government. Assurances were obtained from the Board that:

a) it would consult the Bank before replacing the Chief Finance Officer who was about to retire and before making subsequent appointments to this post and to the post of General Manager and Chief Electrical Engineer;

b) the reorganization of the accounting system would be completed "as soon as possible";

(c) it would consult the Bank regularly on the actions to be taken on the recommendations of the management consultants. The Government, prior to negotiations, had agreed with PUB to cancel partly the increase in fuel and property taxes imposed on PUB in 1965 and 1966, so that the Board would be able to achieve a minimum return of 8% for 1967 and onwards.

2.06 High voltage transmission has been up to now unnecessary in Singapore, and until 1963 power was transmitted at 22 kv from the generators to main step-down substations where it was connected for distribution over the 6.6 kv primary distribution system. With the increase in load density this arrangement grew inadequate and a 66 kv network to connect the main distribution centers with the generating stations was developed while the 22 kv network was largely converted to supplement the primary distribution. The Bank made in July 1967 a loan, 503 SI, to cover, in addition to a water supply project, the foreign exchange costs of a power project consisting of the expansion of the distribution system during the two-year period 1967-68, representing the first half of a program which the PUB had devised for the four years 1967-70 to meet the load growth forecast for that period. This expansion program was planned and designed by the PUB, seeking the advice of consultants with respect to particular problems. During negotiations for the loan, the Board agreed to continue the covenants adopted in the previous loans regarding maintaining tariffs sufficient to give an overall return of at least 8% per annum and consultations with the Bank before the appointment of senior officers. Moreover, following the Bank's recommendation, the Board agreed to engage consultants to review:

a) its tariff structure which had been inadequately spread over the whole range of consumers and needed rationalization and simplification; and

b) the basic distribution development program, given the fact that the load density would continue to increase markedly and that a system voltage higher than 66 kv might become necessary in the early 1970's.

2.07 Consulting firms were engaged to undertake the tariff structure review and the study of the basic distribution development program. The report on the tariff structure was submitted in May 1968, recommending the elimination of the two-meter system of the PUB and the replacement of the existing eight main tariffs with four tariffs; these recommendations were examined by the PUB with little action at that time. The other consultants' preliminary report on long-term system development was submitted in February 1969, and its recommendations were accepted by the PUB. The Bank made its fourth power loan, 595 SI, to the PUB in April 1969 to cover part of the foreign exchange cost of the expansion of the distribution system for the three-year period 1969-1971, excluding the carry-over from the 1967-1968 program which was partly financed from Bank loan 503 SI of 1967. This program had been revised to include the additional work recommended in the consultants' report. The covenants adopted in the previous loans regarding the appointment of senior officers and the rate of return were repeated; moreover, the Board gave assurances that:

a) immediate steps would be taken to appoint a Commercial Engineer (to supervise the introduction of the proposed new tariffs), a Planning and Development Engineer, and a Load Dispatch Engineer;

b) the PUB would consult with the Bank in regard to the actions it proposed to take on the consultants' recommendations on network development;

c) tariffs revised substantially in accordance with the recommendations contained in the consultants' report would be introduced within three years from the date of the loan agreement.

2.08 The General Manager did not apply for a renewal of his contract which expired in July 1969 and the Chief Electrical Engineer resumed as acting General Manager. The PUB then applied for a fifth Bank loan to cover part of the foreign exchange cost of the extension of the Jurong Power station with two units of 120 MW each; the first stage of this station had comprised four 60 MW sets financed by supplier credits. Appraisal of the project took place in December 1969, and negotiations in May 1970. During negotiations, the covenants of the previous loan were adopted and agreement was reached on the need to appoint as soon as possible a Load Dispatch Engineer, a Commercial Engineer and a Statistician; the Bank proposed three alternative solutions to the problem of top management, requiring that it be solved before December 31, 1970. In January 1971, the Bank decided to drop the loan because PUB did not find a solution along any of the three proposed alternative lines and because it considered it unreasonable to present the loan to the Executive Directors beyond the end of the calendar year 1970.

III. The Formal Management Problem of the PUB

3.01 The Ordinance establishing the Board in 1963 provided for the existing staff previously operating under the City Council to be transferred to PUB. This enabled the utilities to be operated without interruption, but with difficulty due to a shortage of experienced senior staff. When the first loan was made (1963), a person suitable for appointment as General Manager was not available locally and previous efforts by the Government to recruit such a person overseas had been unsuccessful.

3.02 With the appointment of a General Manager from Singapore in 1966, it was hoped that the Chairman and the Board, who had necessarily assumed the administrative responsibilities, would allow the General Manager to exercise his duties and responsibilities. This, however, did not take place due to the Chairman's inability to delegate and to the Board's lack of confidence in the General Manager. Additional maintenance and operating staff were still urgently required by the end of 1966 and arrangements were made to train PUB staff overseas. Moreover, the organizational changes recommended in the report submitted by the management consultants in 1965 were slow due to the poor staff relations and more particularly to the continuing shortage of experienced staff. But some progress was achieved. Training was put under the direct authority of the General Manager and designed to yield rapid results and improve gradually the staff situation, particularly in the Electricity Department where the replacement of expatriates by not fully experienced local personnel had led to a chronic shortage of competent senior staff. (In particular it was necessary to retain the services of engineers of the firms which manufactured the boilers of the Pasir Panjang B station to ensure proper supervision and maintenance). The Electricity Department was reorganized to include a planning division and a local dispatching section; a Budget Officer was appointed and management reporting greatly improved.

3.03 The Board's independent auditors, which were appointed as required by loan 337 SI (1963), reviewed PUB's accounting system and were assisting PUB's staff to implement the changes which they had recommended to reorganize the system along sound lines; the 1966 annual report presented the accounts for the first time on a commercial basis properly reflecting operating costs and depreciation charges.

3.04 The lack of clear and effective management resulted in a lack of coordination between the various departments and poor staff relations; due to the Board's lack of confidence, the General Manager indicated that he would not apply for a renewal of his contract which expired in July 1969. Notwithstanding some progress due to the training program, the staff shortage persisted, delaying further organizational changes, and was aggravated by the need to staff new sections such as the Planning and Load Dispatch Sections and the new Jurong Thermal station which was partially commissioned in 1969. The Board had also tried without success to replace the Chief Financial Officer who retired in 1967, but the former Chief Accountant who had been acting as Chief Financial Officer was then permanently appointed to the post. After the General Manager had decided to leave, the post was advertised world-wide; this action was unsuccesful due mainly to the low level of the salary offered for this important post. The former Chief Electrical Engineer of the PUB acted as General Manager but the Chairman and the Board were still undertaking the overall administrative responsibilities.

3.05 During the 1970 negotiations between the Bank and the Board for a further loan, no acceptable solution was found to the problem of top management. The Bank insisted on the creation of the post of Deputy General Manager to be groomed for the post of General Manager since the acting General Manager was expected to reach retirement age within about three years; the PUB rejected this idea on the ground that it would impair morale among the top executives of the PUB. In view of the ability of the part-time Chairman of the Board, the Bank suggested also to the Government that it recognize the existing situation in which the Chairman was in effect the Chief Executive of the PUB and appoint him as full-time Chairman with proper salary and remuneration. This suggestion was adopted by the Government, but failed because the Chairman made exorbitant salary demands in view of the Bank's expression of confidence in him. At the same time the acting General Manager left Singapore.

3.06 After the Bank decided early in 1971 not to go ahead with the new loan, the PUB indicated that a new Chairman had been appointed to its Board, that a Statistician was recruited and that two of its Engineers had been sent overseas for training as Commercial Engineer and Load Dispatch Engineer respectively with a view to filling these appointments by mid-1971. The post of General Manager with a relatively more attractive salary was again advertised world-wide and numerous applications received.

IV. Demand Forecasting and Investment Planning

4.01 It has been the practice of the PUB to do distribution planning and design itself (seeking the advice of consultants with respect to particular problems), and to employ consultants to plan, design, and supervise the construction of its thermal generating plants. The Bank has used in its reports the forecasts made by the PUB or its consultants without significant modifications; these forecasts generally cover six-year periods.

4.02 The annual peak-demand on the PUB electrical network had increased over the period 1958-1962 by 7.1% p.a. on the average, reaching 139 MW in 1962; the actual effective-peak[1/] spare capacity had been 13 MW in 1960 and 35 MW in 1962. The projections made for the first loan (1963) covered the period 1963-1968 and forecast an average increase of the annual peak-demand by 9.8% p.a. (Table II-A.1). Planning for addi-

1/ Effective-peak: critical time in the year when margin between demand and available capacity was least or load shedding greatest (excluding short-term outages).

tional capacity was based on the concept of firm capacity (installed capacity less the capacity of the largest unit in each plant in service). According to the forecast, the firm capacity reserve would have grown from 16 MW in 1963 to about 70 MW in 1968, with a minimum of 7 MW in 1964. The annual peak-demand actually grew by 13.4% p.a. on the average. However, more capacity was installed than forecast but also in higher amounts than required by the increase in the demand; as a result, the average spare capacity as well as the actual effective-peak spare capacity were always higher than forecast. The growth of total sales (Gwh) was also underestimated, in particular that of industrial sales which increased substantially after 1965 when large chemical and other industries were established in the Jurong industrial estate.

4.03 Although the forecasts for large industrial consumers, prepared by the Electricity Department, had been scaled down, the annual peak-demand was expected in the second appraisal report (1966) to grow on average by 19% p.a. over the period 1966-1970 (Table II-A.2); actually, the peak-demand grew along the past trends at 14% p.a. on average. The total sales forecasts, however, were in line with the actual sales, due to a higher load factor originating from the residential demand. The firm capacity reserve was expected to reach 140 MW in 1966 and 1968 and to decline to about 80 MW in 1969 and 1970. Because planning for additional capacity was based on a more conservative concept (firm capacity including a spinning reserve) and because the actual demand was lower than expected, the average spare capacity was again higher than had been forecast by very large amounts. The forecasts made in the third appraisal report (1967) are a slightly scaled down version of those in the second, and much the same conclusions as described above apply.

4.04 As the Singapore load has no seasonal variation, there is no period of the year when maintenance can be carried out without causing problems of availability and it therefore has to be spread uniformly throughout the year. In order to safeguard the continuity of supply in case of breakdown, the policy stated by the PUB's Electricity Department and its consultants has been since 1965 to provide a spinning reserve of 60 MW in addition to the allowance of two units (25 & 60 MW) made for maintenance and overhaul. This large provision for capacity out of service was justified by the maintenance problem mentioned above and the condition of the Pasir Panjang A station where some units were long overdue for major overhaul. As a matter of fact, a substantial portion of the installed capacity, averaging 115 MW in 1967 and 120 MW in 1969 and 1970, has been out of service since 1966 for maintenance and repairs as shown in the following table by the difference between installed capacity and average capacity actually available.

MW	1966	1967	1968	1969	1970
Installed Capacity	464	464	464	584	644
Average available capacity	413	349	392	463	523
Peak-demand	223	248	283	320	377
Reserve Capacity	190	101	109	143	146
Spinning Reserve	60	60	60	60	60
Net Spare Capacity	130	41	49	83	86

The amount of reserve capacity (before deducting spinning reserve) during the most critical times in each year after 1965 reached about 75 MW in 1966-1967 and more than 100 MW in 1968 and again in 1970.

4.05 The large amount of capacity out of service, outgrowing the 85 MW allowance planned for it, was due to worse than average conditions; as a result of the maintenance policy followed prior to 1966, substantial capacity was taken out of service for major overhaul in P.P.A. station and for breakdowns in the P.P.B. station which contributed about 70% in 1967-68 and 40% in 1969-70. to the total capacity out of service. Even under these conditions, the net spare capacity (after allowing for spinning reserve) has amounted to more than 60 MW in 1969-70. Though it is difficult to reach definitive conclusions in this matter without further investigation, it would appear that there may have been some over-investment since the Jurong station was commissioned. The ongoing installation of two 120 MW units (with possible addition of a third) to be commissioned by 1973-74 in this station and a possible reduction of maintenance requirements could reinforce this preliminary conclusion, unless future demand grows at a much faster rate than the 14% p.a. average increase of the past four years.

V. Project Construction and Cost

Generation

5.01 The most important project financed by the Bank in the PUB's Electrical Department has been the Pasir Panjang B Thermal station with a final capacity of 240 MW consisting of four generating units of 60 MW each. The first loan 337 SI (1963) covered the first phase of the plant erection, i.e., the major civil works and the installation of the first two units; the second power loan 473 SI (1968) provided for retroactive financing of the installation of the third and fourth units.

5.02 Construction for the first phase started in January 1963, and the first two units were commissioned in June and July 1965 respectively, two months behind schedule. The second phase was initiated in October 1964, more than two years before loan 473 SI was made, and the last two units went into operation in August and December 1966 respectively.

5.03 The cost of the first phase was slightly lower (6.5%) than expected (Table III) and the actual foreign exchange cost was US$ 13.6 million, leaving US$ 1.4 million savings from the loan, of which US$ 0.8 million were withdrawn with the Bank's consent for purchasing spare parts, supervisory control equipment, and transformers. As work on site for the second phase was nearing completion at the time of the second loan appraisal, the estimated costs had been very close to the actual cost of US$ 12.86 million (1% lower than forecast), with a foreign exchange cost of US$ 9.56 million leading to US$ 0.44 million savings from the loan. The total cost of the whole plant reached US$ 33 million which is equal to a unit cost of US$ 138 per kw installed, as compared to $144 forecast in the appraisal reports. This compares favorably with the Jurong Thermal station, financed without Bank help, which had a total cost of US$ 36 million, corresponding to a unit cost of US$ 150 per kw installed.

Distribution

5.04 The power part of loan 503 SI (1967) was made to cover the US$ 15 million foreign exchange cost of the 1967-68 expansion program of the PUB's distribution network. This program was expected to consist mainly in the installation of 232 km of cables and 430 MVA transformer capacity, with a total cost of US$ 25 million. Due, however, to the long delays in supply of equipment from the manufacturers the major part of the loan was actually used to finance the foreign exchange cost of the 1968-69 distribution investment program; this program consisted mainly in the installation of 315 km of cables and 432 MVA transformers capacity with a total cost of US$ 19.1 million, of which US$ 13.1 million for foreign exchange.

Procurement and Disbursement

5.05 The PUB has traditionally purchased equipment on the basis of international competitive tendering and bidding, and specifications for equipment required for all its projects have been prepared with this in view. Procurement actions which have been taken by the PUB are in accordance with the Bank's guidelines.

5.06 Disbursements were made against presentation of the usual documents evidencing expenditures of foreign exchange. In the case of retroactive financing (second power loan 473 SI for the second stage of the P.P.B. station) bids on an international competitive basis had been obtained for the works and all related contracts had been awarded with Bank approval.

VI. Forecasting the Financial Aspects

6.01 The financial projections made in the first appraisal report (1963) underestimated substantially the future investments to be made by the PUB during the period 1963-66. These investments were projected to be $43.3 million, half of it for the first stage of the Pasir Panjang B station (Table II-B); the PUB actually invested $68.4 million, half of it in both stages of Pasir Panjang B in order to meet the faster than expected load growth. Due to higher sales revenues, the rate of return on the net fixed assets in operation was higher than expected, except in 1965 and 1966 when a temporary rise in fuel and property taxes added to the operating costs (Table II-A.1).

6.02 Financing of the investments was different from the forecast for the 1963-66 period; about 65% of total funds were expected to come from net internal cash generation and the remainder from the Bank loan. Due mainly to the poor results of 1965 and 1966, net internal cash contributed only 35% to the total requirements, while foreign borrowing contributed 32% and domestic contribution was 33% (Table II-B). Because of the delay in Bank lending due to the absence of a General Manager, the expenditures incurred on the second stage of P.P.B. in 1964 and 1965 were partly financed by long-term loans from the Singapore Government and at the expense of working capital.

6.03 Total applications of funds as forecast in the second appraisal report (1966) for the period 1966-1970 were lower by 19% than the US$ 127 million applications actually made in the same period, of which US$ 104 million for fixed investments; the major discrepancy came from the working capital forecasts while fixed investments forecasts were off only by 4%. While net internal cash contributed about 40% to the total requirements as expected, total foreign borrowing was three times the forecast amount because of greater contributions from the suppliers and from the Bank itself; on the other hand, the Government stopped lending to PUB after 1968, reducing the domestic contribution from an expected 36% to 11% (Table II-B). Moreover, gross and net fixed assets in service, as well as the operating costs, were overestimated in the forecasts, while the sales revenues were underestimated due to the tariff increases introduced in November 1966; as a result, the rate of return on the net fixed assets was higher than expected. Forecasts made in the third appraisal report (1967) for the Electricity Department's cash flow for the period 1967-70 were similar to the previous ones; net internal cash was expected to contribute 37% to the total requirements, Government loans 31% and foreign borrowing 31%, most of it from the Bank.

6.04 There has been a strong complementarity between Government and Bank loans to PUB. During the period 1963-66, the necessity to invest more than expected and the delay in Bank lending obliged the Government to make loans which were not foreseen by the Bank. Conversely, during 1966-70, the Government withdrew its aid to PUB and the Bank took over with lending in 1966, 1967 and 1969 successively; as a result, the contribution from the Bank has been considerably higher than orginally foreseen.

VII. Institutional Development

The Consultants

7.01 After the installation of unsatisfactory free piston units recommended by the PUB's former consultants (Preece, Cardew and Rider, of London), Messrs. Merz and McLellan became the PUB's permanent consultants in 1963 and have since been working on the planning, design and construction supervision of the new thermal generating plants of the PUB. Management consultants, R. W. Beck and Associates of Seattle, who were selected with Bank approval, made in 1965 a comprehensive study of the PUB's organization and made a large number of recommendations. According to the requirements under the first Loan Agreement (1963), the PUB engaged external auditors, Messrs. Turquand, Youngs and Co., and appointed them to make recommendations for a proper system of accounts on a commercial basis; the PUB was also assisted by its auditors in carrying out the necessary reorganization. Under the covenants of the third power Loan Agreement (1967), the PUB engaged Electro-watt of Switzerland to review the tariff structure and to determine a rate suitable for domestic service which would eliminate the Singaporian two-meter system;

Electro-watt submitted its report and recommendations in April 1968. In 1968 the PUB engaged the Montreal Engineering Company Ltd. of Canada to undertake the study of the basic distribution development program suggested by the Bank and to submit recommendations for long-term system network development; the consultants' report was delivered in February 1969.

7.02 The PUB's experience with these consultants has taken various forms. The general technical consultants, Merz and McLellan of London, have not fulfilled any educational or expertise-building function within the PUB, and they have worked out their generation planning and design without close collaboration with PUB's staff; their terms of reference did not mention training. The quality of their planning and studies, relying on conservative methods based on a pragmatic approach, has not appeared, in the PUB's opinion, very satisfactory, because of the lack of long-range perspective and modern methodology. Ongoing discussions between the PUB and these consultants would allow the PUB to obtain adequate training and planning services in the future as well as lower fees than in the past. The management study made in 1965 did not bring very positive improvements in the PUB's situation, insofar as the formal management problem is still unsolved. Though the PUB agrees that outside views are in general helpful, its opinion on this matter is that recommendations of the consultants should have been adjusted to the local administrative and political conditions and environment, particularly with respect to the phasing in implementing these recommendations.

7.03 On the other hand, the reorganization of the PUB's accounting system yielded positive results, although the recommendations of the internal auditors were implemented slowly. Since 1966, accounts have been presented on a commercial basis and progressively refined; management reporting, which virtually did not exist before 1967, was geared to the new commercial system and has greatly improved, resulting in a meaningful budget control and a further improvement in the PUB's management. The PUB has been keeping separate accounts for the water, gas, electricity, and service departments. Water, gas and electricity meters are read once per month, and the bill prepared on the computer (introduced in 1964) is sent out for the three services; non-payment of a bill results in prompt cut-off of one or more of the services. This procedure works well and there is no problem concerning uncollected accounts.

7.04 Electro-watt's recommendations on electricity tariff structure were agreed upon by the PUB which is implementing them gradually and expects to complete their implementation by April 1972 as required by the last Loan Agreement (1969). Experience with the Montreal Engineering Company has been very fruitful, in the PUB's opinion. Long-range planning was introduced for the first time in the study of the generation and distribution development programs; though their terms of reference did not mention it, these consultants have fulfilled successfully the educational and expertise-building function, involving staff from PUB's different departments in their studies and having them work together on new methods and approaches, thus resulting in improved staff relations and coordination between the different departments.

Observance of Loan Agreements Covenants

7.05 The Bank's ordinary covenants on rate of return and long-term debt incurrence were easily observed by the PUB through the period 1963-1970 (except in 1965). These covenants actually have been less restrictive than the PUB's own Ordinance regulations drafted by the Government in 1963 with the Bank's assistance and revised after 1968. Other covenants were generally respected. Those covenants specifically designed to build up the internal management were implemented with delays, in particular the reorganization of the accounting system (337-SI) and the recruitment of specialized engineers (595-SI), but were eventually fulfilled (paragraphs 7.03 and 3.06).

VIII. Conclusion

8.01 The PUB's past performance has been reasonably satisfactory. After 1966, this was due, in the Bank's opinion, to the ability of the Board's Chairman rather than to the inherent strength of the PUB's management which suffered from the Chairman's apparent inability to delegate and to build up a responsible senior staff. However, the records suggest that performance was as good before 1966 as after (Table I).

8.02 On the technical side, distribution losses, averaging 7% over 1963-70, have been improving and are acceptable; the major concern has been the maintenance operations which were insufficient before 1967 and led afterwards to substantial amounts of capacity out of service (paragraph 4.04), although without causing failure to meet the demand. The financial rate of return of the whole PUB on its average net fixed assets in operation has been steadily over 9%, except in 1965 and 1966 (4.9% and 7.4%, respectively) when fuel and maintenance taxes were temporarily increased. The financial rate of return of the Electricity Department has been higher, growing from 11.8% in 1962 to 14.5% in 1970, with a drastic fall in 1965 and 1966 when it reached 6.1% and 7.2%, respectively; it recovered, however, in 1967, reaching 9.3% that year and growing afterwards. The average cost per kwh sold decreased steadily (except in 1965) from US¢ 1.74 in 1961 to US¢ 1.04 in 1970; part of the benefits of these economies was given to the customers. Average revenue per kwh sold decreased from US¢ 2.42 in 1961 to US¢ 2.19 in 1970, less percentagewise than the unit cost because of tariff increases in 1966. The productivity of labor in the Electricity Department has shown an average increase of 5.9% p.a. over the period 1960-1970, growing from 236 Mwh/per employee to 418 Mwh. The debt service coverage on an annual basis has always been higher than 2.0 (except in 1965: 1.8) with a maximum of 2.9 in 1963, and the debt/equity ratio reached a maximum of 57/43 in 1966.

8.03 The PUB's Electricity Department has been growing impressively during the last decade and operating satisfactorily on the whole. It has been gaining an increasing importance within Singapore's economy; its fixed investments have represented a significant part -- between 6% and 11% -- of the country's gross fixed capital formation, and the proportion of households supplied with electricity has grown from 32% in 1960 to 70% in 1970. The quality of its services has been satisfactory and no prolonged outage was recorded during this period; new connections are made presently without unreasonable delays (two weeks to one month) except in the small rural areas where important efforts are being made for rural electrification. Its internal management of financial and technical operations has been built up with considerable help and guidance from the Bank and some consultants, and in recent years the PUB has been studying and planning continuously its future operations: network development, design for civil works, feasibility studies for its future stations. It envisages the erection of a nuclear plant by about 1980 (the feasibility study is being financed by the UNDP) and feels able in future years to act itself as consultant to other utilities. The PUB expects to finance from its own resources half of its future investment, and, on the basis of its creditworthiness, to borrow the other half from the Asian Development Bank, equipment suppliers, the Bank, and the Government, if necessary. Suppliers credits would be used mainly for heavy equipment; the Bank, being cheaper than suppliers for financing of smaller equipment, would be asked to finance earmarked projects of the distribution type.

SINGAPORE PUBLIC UTILITY BOARD-ELECTRICTY DEPARTMENT

TABLE I

		UNIT	1958	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	Av. an. inc. rate(%) 1958-1963	Av. an. inc. rate(%) 1963-1970
	OPERATIONS																
1.	Installed Capacity (year-end)																
	Thermal	MW	150	150	150	150	175	197	197	317	437	437	437	557	617		
	Diesel	MW	--	--	27	27	27	27	27	27	27	27	27	27	27		
	Total	MW	150	150	177	177	202	224	224	344	464	464	464	584	644	8.3	16.3
	Total as % Total in Country a/	%	98.7	98.7	99.4	97.8	98.1	98.2	98.2	98.8	99.1	99.1	99.1	99.2	99.3		
2.	Peak Demand	MW	106	113	118	128	139	151	169	192	223	248	283	320	377	7.3	14.0
3.	Gross Reserves	MW	44	37	59	49	63	73	55	152	241	216	181	264	267	10.6	20.4
4.	Reserves as % of Peak Demand	%	41.5	32.7	50.0	38.3	45.3	48.3	32.5	79.2	108.1	87.1	64.0	82.5	70.8		
5.	Effective-Peak Spare Capacity	MW	9	14	40	33	35	20	39	44	78	72	101	80	109	17.3	27.4
6.	Gross Generation	GWh	571	616	659	720	794	823	914	1047	1236	1424	1639	1876	2206	7.6	15.1
7.	Generation Sent-out	GWh	536	576	624	684	749	784	870	993	1166	1346	1553	1774	2077	7.9	14.9
8.	Total Sales	GWh	492	525	578	637	691	730	828	912	1075	1238	1447	1653	1942	8.2	15.0
9.	Number of Customers	000's	86.6	93.1	98.2	106.5	118.7	133.1	146.5	169.3	186.0	202.3	218.8	244.4	267.6	9.0	10.5
10.	Number of Employees	No.	2220	2190	2450	2633	2721	2963	3119	3304	3648	3750	3855	4237	4650	5.9	6.6
	FINANCES																
11.	Sales Revenues b/	S$mln	37.06	39.45	42.17	47.19	50.29	53.74	59.84	64.69	75.16	88.82	101.30	122.72	141.50	7.7	14.8
12.	Operating Costs c/	S$mln	25.94	25.99	29.12	32.09	32.41	33.89	38.40	47.56	50.99	54.11	55.31	59.93	61.52	5.5	8.9
13.	Average Revenue/kwh Sold	S¢	7.53	7.51	7.31	7.41	7.29	7.36	7.23	7.09	6.99	7.17	7.00	6.87	6.71	-0.4	-1.3
14.	Average Cost/kwh Sold	S¢	5.27	4.95	5.04	5.04	4.69	4.64	4.64	5.21	4.74	4.37	3.82	3.62	3.17	-2.6	-5.6
15.	Average Revenue/kwh Sold g/	US¢	2.46	2.45	2.39	2.42	2.38	2.41	2.39	2.32	2.28	2.34	2.29	2.25	2.19		
16.	Average Cost/kwh Sold g/	US¢	1.76	1.65	1.68	1.68	1.56	1.52	1.52	1.70	1.55	1.43	1.25	1.21	1.04		
17.	Net Revenues (11 - 12)	S$mln	11.12	13.46	13.05	15.10	17.88	19.85	21.44	17.13	24.17	34.71	45.99	62.79	79.98	12.3	22.0
18.	Gross Fixed Investments	S$mln	16.71	20.83	9.38	15.27	18.98	35.87	67.11	53.22	49.09	40.88	80.56	56.40	84.29	11.5	13.0
19.	Av. Net Fixed Assets in Operation	S$	145.00	155.70	161.30	163.65	162.12	171.48	198.94	246.10	297.57	315.98	324.17	374.64	422.28	3.4	13.7
	MANAGEMENT INDICATORS																
20.	Rate of Return (17 as % of 19)	%	7.7	8.6	8.1	9.2	11.0	11.6	10.8	7.0	8.1	11.0	14.2	16.8	18.9		
21.	Financial Rate of Return d/	%	8.2	9.2	8.7	9.1	11.8	12.1	11.3	6.1	7.2	9.3	12.4	12.8	14.5		
22.	Financial Rate of Return of PUB	%				8.9	10.6	9.3	9.6	4.9	7.4	9.2	11.6	11.5			
23.	Self-financing Rate e/	%	30.6	67.6	83.2	87.3	67.7	92.4	32.7	28.8	23.5	45.7	35.5	57.9	38.0		
24.	Debt Service Coverage f/	times	1.6	1.7	1.8	2.0	2.3	2.9	2.8	1.8	2.1	2.0	2.1	2.3	2.1		
25.	Debt/Equity Ratio	./.	n.a.	n.a.	n.a.	63/37	56/44	48/52	52/48	55/45	57/43	56/44	56/44	52/48	53/47		
26.	Energy Sales per Employee	MWh	221.6	239.7	235.9	241.9	253.9	246.4	265.5	276.0	294.7	330.1	375.3	390.1	417.6	2.1	7.8
27.	**Residential Customers as % of Households**	%	28.8	30.6	31.8	34.1	37.6	41.6	45.2	51.6	56.0	58.9	61.6	66.5	70.4		
28.	Distribution Losses (7-8/7)	%	8.3	8.9	7.4	6.9	7.8	6.9	4.8	8.1	7.8	8.0	6.8	6.8	6.5		
29.	Average Capacity Out of Service as % of Installed Capacity	%	16.5	17.8	13.1	9.4	10.3	12.2	8.4	7.6	11.0	24.9	15.5	20.7	18.8		
30.	PUB's Investments in Distribution as % of Total	%	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	45.5	57.0	41.7	52.3	34.2	55.2	65.7 h/		
31.	PUB's Investment as % of Total Investments in Country	%	n.a.	n.a.	6.6	6.5	7.2	11.0	15.9	11.2	10.4	7.9	11.3	5.7	6.0		

a/ Includes captive plants.
b/ Revenues from sales of electric power only, including indirect taxes starting in 1969.
c/ Including depreciation, but excluding interest and direct taxation on utility.
d/ Net revenues after taxes as % of average net fixed assets in operation.
e/ Net internal cash generation as % of total applications of funds. See tables II-B.
f/ Times debt service was covered by operating income (including non-power revenues) and depreciation.
g/ Constant exchange rate US $ 1 = S $ 3.
h/ Provisional.

SINGAPORE PUBLIC UTILITY BOARD - ELECTRICITY DEPARTMENT TABLE II-A.1

LOAN 337-SI (May, 1963)

		1962	1963	1964	1965	1966	1967	1968	Av. an. inc. rate-% 1963-68
	LOAD FORECASTS (MW)								
1.	Installed Capacity		197	224	334	334	334	405	15.5
2.	Firm Capacity a/		172	172	257	257	257	317	13.0
3.	Annual Peak Demand		156	165	183	194	237	249	9.8
4.	Spare Capacity (2-3)		16	7	74	63	20	68	33.0
	ACTUAL LOAD (MW)								
5.	Installed Capacity	202	224	224	344	464	464	464	15.7
6.	Average available capacity	181	197	205	318	413	349	392	14.7
7.	Annual Peak Demand	139	151	169	192	223	248	283	13.4
8.	Average spare capacity (6-7)	42	46	36	126	190	101	109	21.0
9.	Effective-Peak Capacity b/	171	170	207	221	286	310	367	16.6
10.	Effective-Peak Demand b/	136	150	168	177	208	238	266	12.1
11.	Effective-Peak Spare Capacity (9-10)	35	20	39	44	78	72	101	38.0
	LOAD FORECAST ACCURACY								
12.	Firm Capacity		87	84	81	62	74	81	
13.	Annual Peak Demand		103	98	95	87	96	88	
14.	Spare Capacity		35	19	59	33	20	62	
	SALES FORECASTS (GWh)								
15.	Gross Generation		900	945	1038	1135	1438	1510	9.0
16.	Sales: Residential d/		366	391	417	443	469	496	5.2
	Public Lighting		14	15	15	16	17	18	4.3
	Industrial Use e/		402	416	470	528	765	798	12.1
	Total		782	822	902	987	1251	1312	10.9
	ACTUAL SALES (GWh)								
17.	Gross Generation	794	823	914	1047	1236	1424	1639	14.8
18.	Sales: Residential d/	345	382	436	424	471	496	518	6.3
	Public Lighting	13	14	15	18	21	23	26	13.2
	Industrial Use e/	n.a.	334	377	470	583	720	903	22.0
	Total	689	730	828	912	1075	1239	1447	14.7
	SALES FORECAST ACCURACY c/								
19.	Gross Generation		109	103	99	92	101	92	
20.	Sales: Residential		96	90	98	94	94	96	
	Industrial Use		120	110	100	91	106	88	
	Total		107	99	99	92	101	91	
	RETURN FORECAST (S $ mln)								
21.	Operating Revenues f/		58.3	60.7	65.5	70.4	80.8	85.1	7.8
22.	less: Operating Costs g/		36.9	40.0	42.5	45.7	50.9	51.9	7.1
23.	Operating Income		21.4	20.7	23.0	24.7	29.9	33.2	9.2
24.	Financial Rate of Return on Average Net Fixed Assets in Operation (%)		11.7	10.7	10.4	10.2	12.1	13.1	
	ACTUAL RETURN (S $ mln)								
25.	Operating Revenues f/	53.3	56.5	62.6	67.6	76.6	89.6	102.6	12.7
26.	less: Operating Costs g/	34.2	35.7	40.2	53.7	53.9	60.3	62.3	11.8
27.	Operating Income	19.1	20.8	22.4	13.9	22.7	29.3	40.3	14.1
28.	Financial Rate of Return on Average Net Fixed Assets in Operation (%)	11.8	12.1	11.3	6.1	7.2	9.3	12.4	
	RETURN FORECAST ACCURACY c/								
29.	Operating Revenues		103	97	97	92	90	83	
30.	Operating Costs		103	100	79	85	84	83	
31.	Operating Income		103	92	165	109	102	82	

a/ Installed capacity less 25, 52, 87 MW allowed as standby in 1963, 1964 and 1965 onwards respectively. Planning concept used in projections.

b/ Effective Peak: critical time in year when margin between demand and available capacity was least or load shedding greatest (excluding short-term outages).

c/ Defined by the ratio: Forecast/Actual.

d/ Lighting and Fans and Domestic Power.

e/ Commercial and Industrial and Large Industrial Power.

f/ Total Revenues of the Department, not including indirect taxes.

g/ Including depreciation and direct taxation on utility, but excluding interest.

TABLE II-A.2

SINGAPORE PUBLIC UTILITY BOARD - ELECTRICITY DEPARTMENT

LOAN 473-SI (Nov. 1966)

		1965	1966	1967	1968	1969	1970	Av.An.Inc. Rate (%) 1966-1970
	LOAD FORECASTS(MW)							
1.	Installed Capacity		464	464	584	584	644	8.5
2.	Firm Capacity a/		379	379	499	499	559	10.2
3.	Annual Peak Demand		240	287	359	418	481	19.0
4.	Spare Capacity (2-3)		139	92	140	81	78	-15.5
	ACTUAL LOAD (MW)							
5.	Installed Capacity	344	464	464	464	584	644	8.5
6.	Average available capacity	318	413	349	392	463	523	6.1
7.	Annual Peak Demand	192	223	248	283	320	377	14.0
8.	Average spare capacity (6-7)	126	190	101	109	143	146	-6.8
9.	Effective-Peak Capacity b/	221	286	310	367	379	455	12.3
10.	Effective-Peak Demand b/	177	208	238	266	299	346	13.6
11.	Effective-Peak Spare Capacity (9-10)	44	78	72	101	80	109	8.7
	LOAD FORECAST ACCURACY c/							
12.	Firm Capacity		92	108	127	108	107	
13.	Annual Peak Demand		108	116	127	131	128	
14.	Spare Capacity		73	91	128	57	53	
	SALES FORECASTS (Gwh)							
15.	Gross Generation		1207	1374	1642	1911	2123	15.1
16.	Sales: Residential d/		451	478	505	534	565	5.8
17	Public Lighting		20	22	23	25	26	6.8
	Industrial Use e/		586	702	909	1113	1267	21.3
	Total		1057	1202	1437	1672	1858	15.1
	ACTUAL SALES (Gwh)							
17.	Gross Generation	1047	1236	1424	1639	1876	2206	15.6
18.	Sales: Residential d/	424	471	496	518	567	638	7.9
	Public Lighting	18	21	23	26	28	31	10.2
	Industrial Use e/	470	583	720	903	1058	1273	21.6
	Total	912	1075	1239	1447	1653	1942	15.9
	SALES FORECAST ACCURACY c/							
19.	Gross Generation		98	96	100	102	96	
20.	Sales: Residential		96	96	97	94	89	
	Industrial Use		101	97	101	105	100	
	Total		98	97	99	101	96	
	RETURN FORECAST (S $ mln)							
21.	Operating Revenues f/		75.8	88.6	100.7	113.1	123.0	12.9
22.	less: Operating Costs g/		56.9	59.2	66.0	74.8	81.8	9.5
23.	Operating Income		18.9	29.4	34.7	38.3	41.2	21.0
24.	Financial Rate of Return on Average Net Fixed Assets in Operation (%)		6.1	8.4	8.8	8.6	8.8	
	ACTUAL RETURN (S $ mln)							
25.	Operating Revenues f/	67.6	76.6	89.6	102.6	115.1	131.9	14.6
26.	less: Operating Costs g/	53.7	53.9	60.3	62.3	67.3	70.5	6.9
27.	Operating Income	13.9	22.7	29.3	40.3	47.8	61.4	28.0
28.	Financial Rate of Return on Average Net Fixed Assets in Operation (%)	6.1	7.2	9.3	12.4	12.8	14.5	
	RETURN FORECAST ACCURACY c/							
29.	Operating Revenues		99	99	98	98	93	
30.	Operating Costs		105	98	106	111	116	
31.	Operating Income		83	100	86	80	67	

a/ Installed capacity less 1-60 MW and 1-25 MW units out of commission for inspection and overhaul.
b/ Effective Peak: critical time in year when margin between demand and available capacity was least or load shedding greatest (excluding short-term outages).
c/ Defined by the ratio: Forecast/Actual.
d/ Lighting and fans, and domestic power.
e/ Commercial and Industrial, and Large Industrial power.
f/ Total Revenues of the Department, not including indirect taxes.
g/ Including depreciation and direct taxation on utility, but excluding interest.

SINGAPORE PUBLIC UTILITY BOARD - ELECTRICITY DEPARTMENT TABLE II-A.3

LOAN 503-SI (July, 1967)

		1965	1966	1967	1968	1969	1970	1966-1970
	LOAD FORECASTS (MW)							
1.	Installed Capacity		464	464	584	557	617	7.4
2.	Firm Capacity a/		379	379	499	472	532	8.8
3.	Annual Peak Demand		223	281	331	383	440	18.4
4.	Spare Capacity (2-3)		156	98	168	89	92	-14.1
	ACTUAL LOAD (MW)							
5.	Installed Capacity	344	464	464	464	584	644	8.5
6.	Average available capacity	318	413	349	392	463	523	6.1
7.	Annual Peak Demand	192	223	248	283	320	377	14.1
8.	Average spare Capacity (6-7)	126	190	101	109	143	146	-6.8
9.	Effective-Peak Capacity b/	221	286	310	367	379	455	12.3
10.	Effective-Peak Demand b/	177	208	238	266	299	346	13.6
11.	Effective-Peak Spare Capacity (9-10)	44	78	72	101	80	109	8.7
	LOAD FORECAST ACCURACY c/							
12.	Firm Capacity		92	108	127	102	102	
13.	Annual Peak Demand		100	113	117	120	117	
14.	Spare Capacity		82	97	154	62	63	
	SALES FORECASTS (GWh)							
15.	Gross Generation		1223	1394	1668	1919	2153	15.2
16.	Sales: Residential d/		470	501	534	570	608	6.7
	Public Lighting		21	23	25	26	28	7.5
	Industrial Use e/		580	702	909	1093	1259	21.0
	Total		1071	1227	1468	1689	1895	15.3
	ACTUAL SALES (GWh)							
17.	Gross Generation	1047	1236	1424	1639	1876	2206	15.6
18.	Sales: Residential d/	424	471	496	518	567	638	7.9
	Public Lighting	18	21	23	26	28	31	10.2
	Industrial Use e/	470	583	720	903	1058	1273	21.6
	Total	912	1075	1239	1447	1653	1942	15.9
	SALES FORECAST ACCURACY c/							
19.	Gross Generation		99	98	102	102	98	
20.	Sales: Residential		100	101	103	100	95	
	Industrial Use		99	97	101	103	99	
	Total		100	99	101	102	98	
	RETURN FORECAST (S $ mln)							
21.	Operating Revenues f/		77.7	91.4	104.7	117.3	129.1	13.5
22.	less: Operating Costs g/		52.4	59.5	67.9	75.6	85.6	13.1
23.	Operating Income		25.3	31.9	36.8	41.7	43.5	14.5
24.	Financial Rate of Return on Average Net Fixed Assets in Operation (%)		8.2	9.0	9.8	9.7	8.9	
	ACTUAL RETURN (S $ mln)							
25.	Operating Revenues f/	67.6	76.6	89.6	102.6	115.1	131.9	14.6
26.	less: Operating Costs g/	53.7	53.9	60.3	62.3	67.3	70.5	6.9
27.	Operating Income	13.9	22.7	29.3	40.3	47.8	61.4	28.0
28.	Financial Rate of Return on Average Net Fixed Assets in Operation (%)	6.1	7.2	9.3	12.4	12.8	14.5	
	RETURN FORECAST ACCURACY c/							
29.	Operating Revenues		101	102	102	102	98	
30.	Operating Costs		97	99	109	112	121	
31.	Operating Income		111	109	91	87	71	

a/ Installed Capacity less 1-60 MW and 1-25 MW units out of commission for inspection and overhaul.

b/ Effective Peak: the critical time in year when margin between demand and available capacity was least or load shedding greatest (excluding short-term outages).

c/ Defined by the ratio: Forecast/Actual.

d/ Lighting and fans, and domestic power.

e/ Commercial and Industrial, and Large Industrial Power.

f/ Total Revenues of the Department, excluding indirect taxes.

g/ Including depreciation and direct taxation on utility, but excluding interest.

SINGAPORE PUBLIC UTILITY BOARD - ELECTRICITY DEPARTMENT

UTILITY INVESTMENT PROGRAMS PARTLY FINANCED BY IBRD (U.S. $ Million)

TABLE II-B

	LOAN 337-SI (1963) PERIOD 1963-1966				LOAN 473-SI (1966) PERIOD 1966-1970				LOAN 503-SI (1967) PERIOD 1967-1970			
	FORECAST		ACTUAL		FORECAST		ACTUAL		FORECAST		ACTUAL	
	Total	% of total	Total	% of total	Total	% of total	Total	% of total	Total	% of total	Total	% of total
SOURCES OF FUNDS												
1. Net Internal Cash Generation	28.50	64	23.20	35	45.17	43	50.18	39	35.49	37	45.36	43
2. Domestic Contribution:												
from public sector a/	-		19.63	31	35.30	34	10.66	8	29.33	31	5.66	5
from private sector	.80	2	1.61	2	2.02	2	3.23	3	1.23	1	2.71	3
Total	.80	2	21.24	33	37.32	36	13.89	11	30.56	32	8.37	8
3. Foreign Borrowing:												
Suppliers Credits b/	-		.03	-	7.83	8	22.33	18	10.10	11	22.30	21
IBRD	15.01	34	20.70	32	13.49	13	40.79	32	18.78	20	30.67	28
Total	15.01	34	20.73	32	21.32	21	63.12	50	28.88	31	52.97	49
4. Total Sources	44.31	100	65.17	100	103.81	100	127.19	100	94.93		106.70	
APPLICATIONS OF FUNDS												
5. Total Fixed Investments	43.30	98	68.43	105	98.99	95	103.74	82	89.45	94	87.38	82
6. Changes in Working Capital and Net Cash Accrual	1.01	2	-3.26	5	4.82	5	23.45	18	5.48	6	19.32	18
7. Total Applications	44.31	100	65.17	100	103.81	100	127.19	100	94.93	100	106.70	100
8. Debt Service	16.57		18.06		41.62		48.85		43.09		42.61	

Terms of Loans:	Interest (%)	Amortization (yrs)
a/ Government loans	5 3/4	20
b/ Suppliers credits	6	3 - 15

TABLE III

SINGAPORE PUBLIC UTILITY BOARD-ELECTRICITY DEPARTMENT

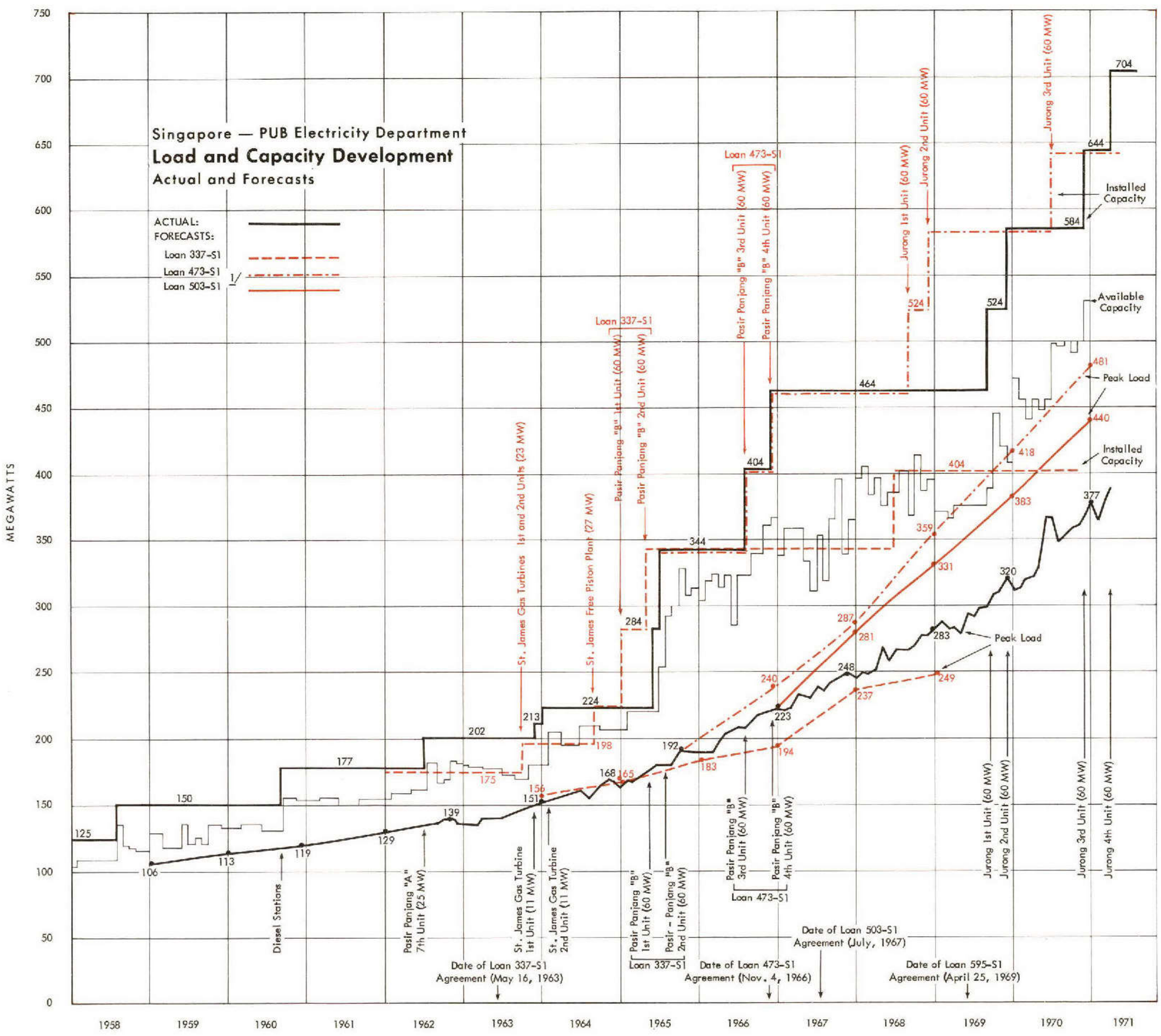
I.B.R.D. PROJECTS IMPLEMENTATION

		Start Construct.	Commis-sioning Date	Construct. Period (months)	Project Scope 1/		CONSTRUCTION COST (US$ million) L.C.	F.X.	Total	COST/KW US$
LOAN 337-SI (US$ 15 million) (Signed May 1963)										
Pasir Panjang "B" Station 1st Stage	Forecast	Jan. 1963	May 1965	29	2x60 MW	Thermal	6.48	15.08	21.56	179.7
	Actual	Jan. 1963	Jul. 1965	31	2x60 MW		6.57	13.59	20.16	168.0
LOAN 473-SI (US$ 10 million) (Signed Nov. 1966)										
Pasir Panjang "B" Station 2nd Stage	Forecast	Oct. 1964	Oct. 1966	24	2x60 MW	Thermal	3.00	10.00	13.00	108.3
	Actual	Oct. 1964	Dec. 1966	26	2x60 MW		3.30	9.56	12.86	107.2
LOANS 337-SI & 473-SI (US$ 15 mln and US$ 10 mln)										
Total Pasir Panjang "B" Station	Forecast	Jan. 1963	Oct. 1966	46	4x60 MW	Thermal	9.48	25.08	34.56	144.0
	Actual	Jan. 1963	Dec. 1966	48	4x60 MW		9.47	23.55	33.02	137.5
LOAN 503-SI (US$ 23 million) (Signed July 1967)										
Distribution System Expansion	Forecast	1967-1968	program	24	232 km & 430MVA		10.0	14.30	24.30	
	Actual	1968-1969	program	24	315 km & 432MVA		6.06	13.08	19.14	
PROJECTS NOT COVERED BY IBRD LOANS 2/										
Jurong Thermal Station	Actual	Sept. 1967	Apr. 1971	40	4x60 MW	Thermal	11.92	24.09	36.01	150.0

LOAN DISBURSEMENT PATTERN

			1963	1964	1965	1966	1967	1968	1969	1970	Undisbursed 12/31/70
LOAN 337-SI	Forecast:	Amount (US$ mln)	2.13	10.31	2.15	.41					
		% of Total	14.2	68.8	14.3	2.7					
		Cumulative %	14.2	83.0	97.3	100.0					
	Actual:	Amount (US$ mln)	.24	7.91	2.19	2.68	1.38				.6 3/
		% of Total	1.7	54.9	15.2	18.6	9.6				
		Cumulative %	1.7	56.6	71.8	90.4	100.0				
LOAN 473-SI	Forecast:	Amount (US$ mln)				9.39	.61				.5 3/
		% of Total				93.9	6.1				
		Cumulative %				93.9	100.0				
	Actual:	Amount (US$ mln)				7.57	1.59	.84			
		% of Total				75.7	15.9	8.4			
		Cumulative %				75.7	91.6	100.0			
LOAN 503-SI	Forecast:	Amount (US$ mln)					5.94	7.37	1.70		
		% of Total					39.6	49.1	11.3		
		Cumulative %					39.6	88.7	100.0		
	Actual:	Amount (US$ mln)						4.87	4.34	4.42	1.37
		% of Total						32.5	28.9	29.5	9.1
		Cumulative %						32.5	61.4	90.9	

1/ Project scope is Megawatts (MW) of installed capacity and source of energy in the case of Generation projects, and kilometers of lines erected (6.6 kv, 22 kv, 66 kv) and MVA capacity of substantions in the case of distribution items.
2/ For comparative purposes only.
3/ Canceled.



1/ The Loan 503-SI forecast for installed capacity is virtually identical to that of the Loan 473-SI forecast and therefore has not been separately indicated.

100% BLACK

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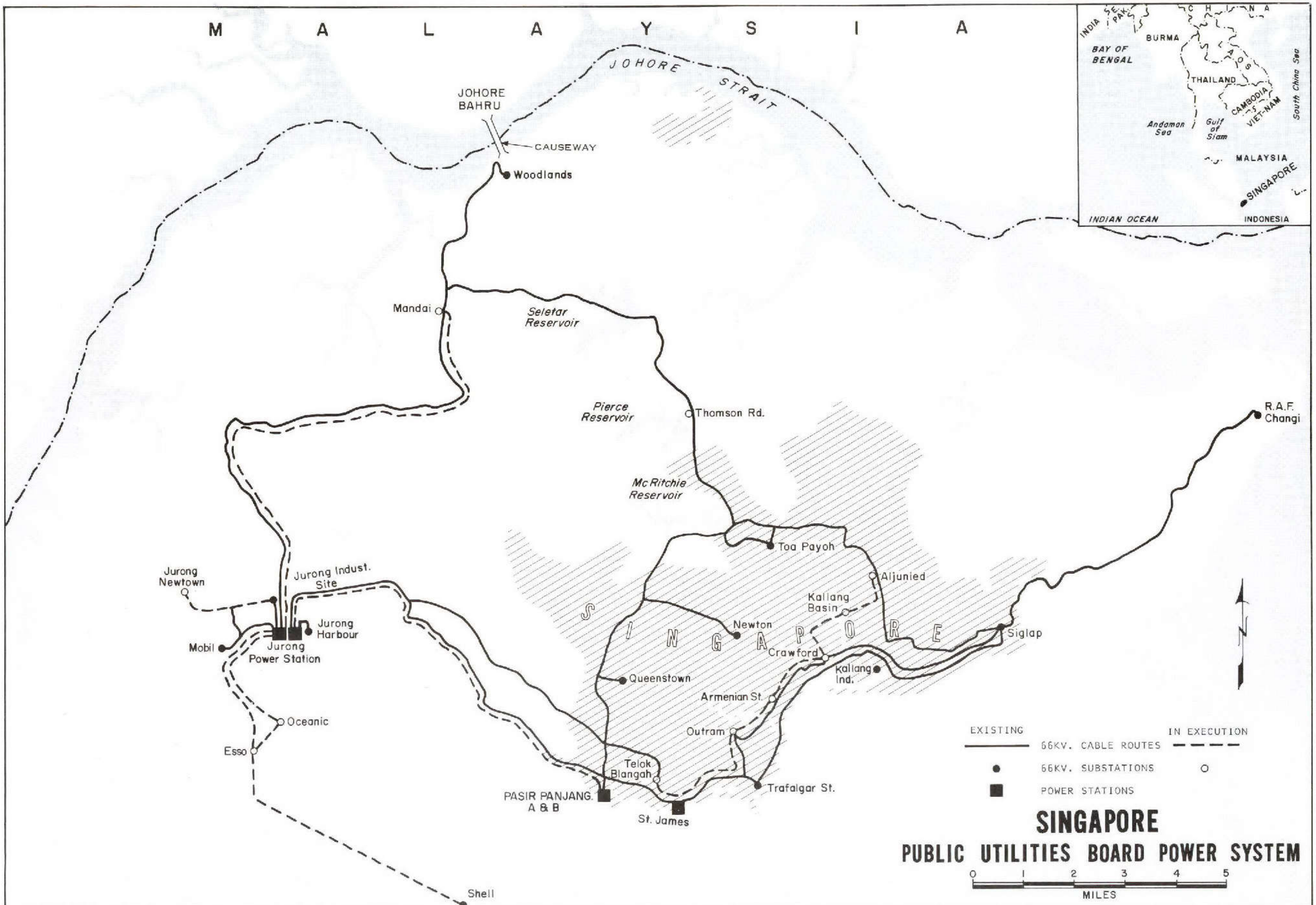
Chart 8.1



AUGUST 1971

IBRD 2875R

PART II

POWER IN COLOMBIA AND THE IBRD

CHAPTER IX - THE POWER SECTOR IN COLOMBIA

I. Overall Power Development 1950-70

1.01 The power sector of Colombia expanded at a fast rate between 1950 and 1970: total installed generating capacity increased almost tenfold, from 270 MW in 1950 to 2330 MW in 1970, while population nearly doubled from 12.2 million to 22.5 million and national income more than doubled from $ 2.1 billion to nearly $ 5.4 billion. Growth in electric power was especially high during the last decade when the average increase in capacity was about 140 MW annually. On a list of 11 Latin American countries,[1/] Colombia raised itself from sixth place in 1950 in terms of installed generating capacity to fifth place in 1968. With respect to installed capacity per capita Colombia has risen from ninth place, at 22 watts in 1950, to eighth place, at 96 watts, in 1968. The average growth rate for both total generating capacity and generating capacity per capita was probably the highest in all Latin America over the period. Current per capita capacity in Colombia, estimated at 103 watts, is close to the level of 120 watts which prevailed in the United States 50 years ago.

1.02 Economically, Colombia has diversified and strengthened over the last twenty years. It has become much less heavily dependent on coffee, which accounted for about 40% of total export earnings in 1970 but more than 70% in 1950. Agriculture, which still accounts for about 30% of national income, has grown about in line with population, at

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1/ Brazil, Argentina, Mexico, Venezuela, Chile, Colombia, Peru, Uruguay, Bolivia, Ecuador, Paraguay (countries are listed in decreasing order of total installed capacity in 1960).

somewhat over 3% per annum on average. Manufacturing, though still accounting for only about 18% of national income and significantly less of total employment, has been the most dynamic major sector, attaining an average annual growth of nearly 6.5%. The 1960s have seen an important growth of exports of manufactured goods, though still on quite a small scale. The slow growth in agriculture, despite the country's considerable natural potentials in this field, has been reflected in a very rapid pace of urbanization. The proportion of the population living in towns has increased by about one percentage point a year, reaching by 1970, nearly 60% in total and about 45% in towns over 50,000 inhabitants. Improvements in welfare have been heavily concentrated in the cities and, even there, principally among people with property or with jobs in the modern parts of manufacturing and commerce. Income is exceptionally ill-distributed in Colombia, with only about 13.5% of total personal income going to the bottom 50% of income receivers; most of the latter live in the countryside where the problem of extreme poverty is no less and in some respects greater than it was in 1950. The public sector of the Colombian economy has traditionally been small and weak. Not until the last few years did total tax revenues break out of the traditional range of some 10 - 12% of GDP, but even now they are only about 13.5%. Relative to personal incomes, the total tax burden ranges between 12 - 14% for the lowest ten percent of income receivers and only about 20 - 22% for the top ten percent.

1.03 Table 9.1 gives some comparative data about income and growth of income and electricity production in the eleven Latin American countries referred to above. The countries are ranked in order of the GNP growth rate attained over the period 1950-68. Colombia lies in the middle in terms of GNP growth but higher for growth of electricity production.

Table 9.1

11 Latin American Countries: 1968 Income and Income per Capita and Growth of Income and Electricity Production 1950-68

	Rate of Growth of GNP at factor cost 1950-68 (% p.a.)	Rate of Growth of Electricity Production (1950-1968) Total	Public Supply	1968 GNP per capita (1964 $)	Total GNP in 1968 (billion 1964 $)	1968 Population (million)
Venezuela	6.8	-	13.4	842	8,156	9.7
Mexico	6.3	9.5	9.9	464	21,920	47.3
Brazil	5.5	8.9	8.8	218	19,236	88.2
Peru	5.2	10.0	10.3	301	3,841	12.8
Ecuador	4.8	10.9	24.5	200	1,137	5.7
Colombia	4.7	10.3	11.1	238	4,775	20.0
Chile	3.6	5.0	6.0	430	3,990	9.4
Paraguay	3.1	8.1	8.2	200	447	2.2
Argentina	3.0	7.0	6.4	770	18,190	23.6
Bolivia	2.5	-	5.7	138	644	4.7
Uruguay	1.1	6.5	6.8	460	1,294	2.8

Sources: IBRD World Tables, and Appendix Tables to Chapter I.

In most Latin American countries other than Argentina, public utility supply of electricity has grown more rapidly over the last two decades than total electricity production, and this is true of Colombia. The relationship between growth of GNP and growth of electricity production shows no systematic pattern.

1.04 The power sector in Colombia has benefitted from the existence of a considerable and often relatively inexpensive hydroelectric potential, estimated at about 60,000 MW in aggregate at known sites. Of the 2,000 MW total installed capacity in the public sector at the end of 1970, about 1,460 MW were of hydroelectric origin, concentrated exclusively in the Andean region. The current installed hydro capacity represents less than 5% of the 30,000 MW hydroelectric potential of this area, demonstrating that the overall potential of the country has barely been tapped. The great majority of the exploited hydro potential of the Andean zone is concentrated within the so-called Bogota-Medellin-Cali industrial triangle (or Central region) which also includes the system of Manizales (see maps at end of chapter); these four centers accounted for 1,320 MW of the public sector hydroelectric installed capacity in 1970, and represented almost 90% of the total installed hydroelectric capacity in the country. Most of the hydroelectric plants now in operation are of limited capacity, having been established on easily exploitable low cost hydro sites to satisfy the limited needs of immediate markets. However, a new era in the power development of Colombia is now beginning which will see the realization of large scale hydroplants whose potentials will be sufficient to assure an adequate power supply for enlarged interconnected markets.

1.05 Colombia also enjoys a high thermoelectric potential. Its coal reserves, estimated at about 18 billion tons, are the largest in South America. Oil deposits, with possible reserves of 3 billion barrels, place the country in second place in South America, following Venezuela.

Most oil fields have a low gas-oil ratio and the exploitation of natural gas has not been of major significance; the extent of actual reserves is still unknown. The share of thermal generation in total generation has remained virtually the same since 1950, at about 24%. The largest proportion of such generation is found in areas having a low or nonexistent hydro potential, such as the whole Northern region. The predominant trend in thermal production has been the increasing share of gas generation since 1954 and the decreasing share held by diesel, which fell regularly from 8.9% in 1954 to 3.8% in 1970. This is easily explainable in view of the low cost of natural gas as compared to the constantly rising costs of fuel oil. Actual fuel consumption in thermoelectric plants has always accounted for only a minor portion of total fuel production in the country: 29% for coal and 4% for fuel oil. Comparable figures are not available for gas generation, which takes place exclusively in the four northern Departments of Atlantico, Bolivar, Cordoba and Norte de Santander, contributing about 46% of the almost exclusively thermal energy production in these Departments. Apart from electricity production in the North, the main demand for gas is related to the manufacture of chemicals. It can be asserted that, given the important reserves of fossil fuels and the relatively low share of thermal generation in Colombia, electricity production has not adversely affected the potential utilization of such resources in other sectors of the economy.

1.06 The high mountain ranges which cover the entire central portion of the country have isolated various regions, causing them to develop separately their own customs, regional institutions, and natural resources. The Andean region, with a population estimated at about 65% of the total population of Colombia, has a major advantage in terms of overall power availability, due to its high hydropotential and also to the existence of substantial mineral deposits. The development of such resources is well under way, mainly the hydroelectric resources. The Northern region, with about 22% of the total population, has to rely almost exclusively on more expensive thermal generation. The rest of the country has a relatively small population and potential power resources available there have remained virtually unexploited. The failure to give priority to transmission projects until recent years has induced the development of independent regional electric systems, leading to major regional discrepancies characterized by the relatively spectacular expansion of the Bogota, Medellin, Cali and Manizales electric systems which now form the Central Interconnected System.

1.07 Total installed capacity in the four main central systems represented 46% of total installed capacity of 111 MW in the public sector in 1950. This proportion has increased regularly over the last twenty years, reaching 71% in 1970, as shown in Table 9.2. The four main central systems had an installed capacity in 1970 of 1,466 MW. Installed capacity of these systems has grown at average rate of 13.6% per annum over the whole period, as compared with 8% in the rest of the public sector. Installed capacity per capita in the service area of the four systems, which now directly serve a population of about 6 million (27% of

Table 9.2

Growth of Installed Generating Capacity in the Public Sector 1950-70
(as of December 31)

	1950		1960		1970	
	MW	% of Total	MW	% of Total	MW	% of Total
Four Main Central Systems						
Bogota	46.0	19.1	128.0	19.1	587.5	28.3
Medellin	51.5	21.5	137.0	20.4	443.0	21.3
Cali	11.1	4.6	95.1	14.2	248.1	12.0
Manizales	2.8	1.2	22.8	3.4	187.8	9.0
Sub-Total	111.4	46.4	382.9	57.1	1466.4	70.6
Rest of Country	129.6	53.6	287.1	42.9	611.6	29.4
TOTAL	241.0	100.0	670.0	100.0	2078.0	100.0

total population), was about 242 watts in 1970, while the national average for the public sector came to only 92 watts. In other words, the gap which already existed in 1950 between the four central systems and other systems in the country has been progressively widening over the last twenty years. This gap is a reflection of the generally disproportionate rate of economic development in the country, which has traditionally favored the Departments of Cundinamarca, Antioquia, Valle del Cauca and Caldas. In other areas of the country, only the Department of Atlantico with the seaport of Barranquilla can be compared to these four Departments in terms of economic development and electric service. In 1970, the five aforementioned Departments accounted for about 50% of the country's population and generated 82% of total value added in the manufacturing sector.

1.08 In most areas of the country, the sub-transmission and distribution systems have remained insufficiently developed or poorly adapted. Although some progress has been made in the electrification of new areas, as much as 55% of the total population had no electric service at all in 1970. This proportion was about 74% in 1951. Statistics on this matter are very scarce and often inconsistent when available; an attempt to make interregional comparisons in the progress of electrification would be highly hazardous. A somewhat speculative extrapolation from the latest census (1964) suggests, however, that on the average about 70% of the population residing in the main centers [1/] is currently connected to the public network. As regards the remaining municipalities, which can be classified as "rural municipalities", the proportion is probably less than 7%. This tends to show that rural electrification has, on the whole, remained almost completely neglected until now.

II. Organization of the Sector and Major Institutional Developments

2.01 Public electricity is at present almost entirely supplied by four entities: the Empresa de Energia Electrica de Bogota (EEEB), the Empresas Publicas de Medellin (EPM), the Corporacion Autonoma Regional del Cauca (CVC), and the Instituto Colombiano de Energia Electrica (ICEL). [2/]

1/ Those 46 Centers which had a population of more than 10,000 in 1964.
2/ Formerly Electraguas, which ICEL replaced in 1968.

While EEEB and EPM are autonomous, municipally-owned companies, operating almost exclusively at the municipal level, CVC and ICEL are under the direct control of the Central Government. CVC, a multipurpose, autonomous, nationally-chartered, regional entity set up along the lines of the T.V.A., was established in 1954 and assigned the task of developing the resources of the Cauca Valley, mainly in the fields of electric power and agricultural development. To carry on its power development function, CVC became the majority shareholder in CHIDRAL (Central Hidroelectrica del Rio Anchicaya, Ltda.), the power company in charge of supplying electricity to the city of Cali. ICEL, the only nation-wide power entity, is a holding company rather than an operating entity, controlling 15 departmental subsidiaries which provide electric service to 20 of the 29 Departments of the country outside the service areas of EEEB, EPM or CVC. The remaining 9 Departments, with the exception of the Department of Valle which is supplied entirely by CVC, are located in the southeastern plain of the Llanos and have very limited public power facilities and a scattered population representing less than 5% of the country's total population. Central Hidroelectrica de Caldas (CHEC) is ICEL's major subsidiary, serving the Departments of Caldas, Quindio and Risaralda around Manizales in central Colombia. ICEL's main functions have been to promote the development of electric power in the country, formulate comprehensive national electrification plans and coordinate the construction programs of its subsidiaries.

2.02 One of the major institutional achievements of the 1960-70 period was the establishment in 1967 of two new companies, Interconexion Electrica S. A. (ISA) and Corporacion Electrica de la Costa Atlantica (CORELCA), created for the purpose of interconnecting major parts of the national electric network. ISA was founded as a joint-stock company under the sponsorship of the four major power entities of the Central region, i.e. EEEB, EPM, CVC/CHIDRAL and CHEC, which each contributed 25% of the paid-in share capital. ISA's statutory purposes are the interconnection of the sponsors' electric systems and the planning, construction, ownership and operation of new power generating plants serving the whole interconnected system. CORELCA, a decentralized public entity with regional jurisdiction, is responsible for the interconnection of the major markets in the Atlantic Coast region (including Barranquilla, Cartagena and Santa Marta), as well as for the planning, construction and operation of the generating plants supplying its system. The Central Interconnected System will be in operation at the end of 1971, while completion of the Northern Interconnected System is now slated for the beginning of 1972.

2.03 The last major innovation introduced in the institutional setup of the power sector has been the establishment, late in 1968, of a tariff regulatory agency (Junta Nacional de Tarifas de Servicios Publicos) as a part of Planeacion Nacional, the National Government Planning Department. The purpose of the agency was to restructure and adjust the traditionally inadequate public utility tariffs in Colombia in such a way that utilities could gradually become financially more self-sufficient, thereby permitting orderly financing of their system expansion programs.

2.04 Planeacion Nacional is basically responsible for drawing up national power development plans and for the preparation of the National Investment Budget. After having collected the necessary technical and financial data from the various power companies, the Department reviews the projects proposed by each in light of the recommendations appearing in the national development plan and attempts to establish an order of priority for projects based upon appropriate social and economic criteria, as well as the availability of foreign credit and budgetary resources.

III. Major Problems of the Power Sector

3.01 As indicated earlier, the development of the power sector has been far from uniform throughout the country and severe regional discrepancies have resulted; while cities like Bogota, Medellin, Cali and Manizales have enjoyed efficient electricity service, most other centers have continually suffered from major shortages and were forced to adopt short-term emergency solutions to cope with the growth of demand. This was the case, for instance, for Barranquilla, Santa Marta, Popayan, and to a lesser extent, for Cartagena and Bucaramanga, which were generally unsuccessful in carrying out long term economic planning for their respective electric systems.

3.02 The isolation and overly-emphasized independence of the various systems, coupled with inadequate delineation between the jurisdictions of the power companies, has led to a proliferation of small entities serving areas of uneconomic size, and to overall misallocations and inefficient uses of resources. The larger companies, which serve privileged urban markets and supply only limited zones outside their respective service areas, have seen their relative positions greatly strengthened over time, thus exacerbating regional discrepancies and widening the gap between urban and rural areas. In an effort to integrate the national electric service, ICEL attempted to regroup regional electric systems according to a more appropriate pattern which would take account of the specific geographic, economic and social characteristics of each region. The country was thus divided into six electric zones, but this measure has not yet resulted in a visible improvement in the organization of the sector.

3.03 The most positive reform introduced in recent years to promote national integration of the sector has probably been the creation of the two inter-Departmental interconnection companies, ISA (Central region) and CORELCA (Northern region). As pointed out earlier, ISA's system will begin operation shortly, while the Northern Interconnection is planned for completion by the beginning of 1972. The interconnection of the North-eastern region (Barrancabermeja, Bucaramanga) with the Central Interconnected System will probably also have been completed by 1972 and serious consideration is currently being given to the subsequent connection of the expanded Central System with CORELCA's network. This national network will provide for efficient and flexible transmission of large amounts of energy from large hydroelectric plants to all the major power markets of the country, thereby permitting important economies of scale. The completion of this national electric backbone will also ultimately allow a more economical connection of the as yet isolated rural areas.

3.04 Colombia has traditionally suffered from a lack of coordination between the various power planning agencies. The major problem which has arisen in this connection and still remains acute today is the difficulty encountered by ICEL, the official national power entity, in carrying out planning activities. The main reasons for this are the poor organization of the entity, the insufficient qualifications of its technical staff, the isolated and dispersed nature of the systems it controls, and its constant subjection to political pressures. Also, the influence of ICEL over the country's three major power companies (EEEB, EPM and CVC/CHIDRAL), which currently control more than 60% of the country's total generating capacity, has been negligible in the past; the service areas of these three companies, especially in the case of EEEB and EPM, have traditionally been looked upon as private domains. Over the last six years, which have witnessed the reorganization of ICEL, Planeacion Nacional has played a leading role in power planning on the national level. As indicated earlier, Planeacion was responsible for drawing up the budget and therefore held considerable leverage over ICEL's operations, which to a large extent, were financed through central budget allocations. The influence of Planeacion over the investment programs of EEEB, EPM and CVC/CHIDRAL was mainly applied in connection with their securing of foreign loans, because any project financed through such loans had to receive Planeacion's prior approval.

3.05 Planeacion has also greatly contributed to the planning of the Central Interconnected System and to the establishment of ISA which should become, within the next decade, the largest energy-generating authority in the country. The creation of ISA was the first tie ever established between ICEL, EEEB, EPM and CVC/CHIDRAL. It should be noted, however, that ICEL, through the participation of CHEC, became involved in Interconexion only a year after the three other companies had agreed (in 1963) upon the principle of interconnecting their systems, suggesting that the national power entity contributed only marginally to the overall planning of the integrated network. It is now high time to redefine the respective role of ICEL, ISA and Planeacion in the elaboration of national power expansion plans and to coordinate the activities of the three organizations.

3.06 The lack of statistics on hydrology, precipitation, availability and cost of fuel and manpower, etc., has made it difficult for the planning authorities to assess the economic viability of specific projects and has hindered attempts to carry out comparative studies on the attractiveness of prospective alternatives. The failure to collect adequate information on actual demand patterns, trends in public investments, self-financing ability of power companies, availability of local funds, and actual costs of past projects have made it difficult to benefit from past experience and, therefore, to carry out meaningful long term planning in the power sector.

3.07 As a result of this, project evaluations have often been carried out haphazardly, with some exceptions in cases when the contributing financial agent (whether an external financing agency or the Government) requested the use of sound technical and economic criteria in decision making. It is only recently that Planeacion, ICEL and the National Department of Statistics have undertaken the task of standardizing the collection, classification and dissemination of relevant statistics. Also, the financial assistance provided by the Fondo Nacional de Desarollo (FONADE) in recent years for the execution of feasibility studies has enabled Planeacion to standardize and improve the terms of reference of the studies.

3.08 The lack of planning at the national level, coupled with the absence of well-defined service areas for the various power utilities, has often led to the adoption of ill-advised investments involving duplication of equipment or insufficient installations. In some cases, investment decisions have been dictated by private or political interests incompatible with the national interest as a whole.

3.09 The choice of equipment, construction methods, maintenance and operation policies were generally not bound to suitable pre-established specifications. For instance, actual specifications for transmission and especially distribution equipment have often not been appropriate for the prevailing type of demand, causing significant system losses. Also, inadequate reservoir operation policies have resulted in major water wastages and unnecessary use of expensive thermal generation. Over the last five years, the development of the Central Interconnected System has included the systematic use of optimizing techniques in system planning and operation. The software, however, had been abandoned upon completion of the Interconnection Study and about four months of extensive research were required to revive and calibrate the program for the purpose of the evaluation study. Planeacion is currently working on a set of instructions for the use of the model, which will probably aid Planeacion, ICEL and ISA in contending with the increasingly complicated problems of system expansion planning.

3.10 As suggested earlier, the development of unbalanced power markets has made it difficult for the several smaller power entities to carry out their duties efficiently. Also, large centers such as Bogota and Medellin tend to attract the more capable and talented people, often leaving the smaller centers with managerial and technical staff of lower quality. Poorly organized operation and maintenance programs in such centers have led to a rapid deterioration of certain types of equipment, resulting in major deficiencies in electric service and high recurrent expenditures. As yet, ICEL has not made any major effort to improve the quality of its subsidiaries' management. The fact that ICEL is entirely responsible for the construction of major projects further limits the participation of the individual entities and therefore diminishes chances for improving local professional ability. In addition, ICEL rarely takes the opportunity presented by projects it finances to request reforms in the subsidiary's organization. There is an obvious need to improve coordination and standardization of system operations and control as well as accounting procedures. ICEL and Planeacion seem willing to exert pressure in this direction by setting up a rotating panel of engineers and financial analysts which would visit and assist each power entity for a limited period of time with a view to achieving these goals.

3.11 Past investments in the sector have concentrated mainly on the expansion of generation and, to a lesser extent, transmission facilities, leaving insufficient resources for the improvement and expansion of subtransmission and distribution networks. Between 1965 and 1970, investments in such networks represented only about 39% of total public fixed investment in the power sector. The poor physical condition of the networks has, in most cases, resulted in important system losses. Such losses,[1/] which vary greatly from one center to another, generally comprise between about 15%, and 25% of generation sent out, but in some cases reach up to 35%. Bogota is the only case in which such losses have remained below 12%, a limit which can be considered a reasonable operating level. The share of stolen energy in total system losses, although difficult to assess in general, has probably been quite significant for many companies. In the case of Medellin, for instance, the connection of marginal zones has been neglected until recently and stolen energy there accounts for 15% of total energy sent out or more than half of total system losses. As pointed out earlier, more than 55% of the country's population is still unconnected today. The Government, becoming more and more aware of the need to extend

1/ Difference between energy sent out and sales, expressed as a proportion of energy sent out.

electrification to more people, has recently launched a nation-wide distribution rehabilitation program for which a $ 25 million loan has been secured from the IDB. In this connection, ICEL and Planeacion have commissioned a study for the preparation of designs and construction norms, with the objective of standardizing distribution equipment and installation. Finally, the creation of ISA as a major generating entity will probably both enable and force the individual power companies to devote more attention to distribution problems.

3.12 The great majority of power companies in Colombia have always had major difficulties in generating sufficient resources to finance their own expansion programs. Returns on investments, even when positive, have generally been grossly inadequate to cover capital costs and debt service: in 1969, only 6 power companies had positive financial rates of return on non-revalued assets and, of these, only two had returns on revalued assets greater than 5%. The lack of self-financing ability, combined with the difficulties of raising local funds in other ways, has hampered the companies' long term planning ability and has often forced them to adopt emergency solutions to provide electric service; this, in turn, led to inadequate system expansion and low efficiency in system operation, ultimately involving additional financial losses and further difficulties in controlling the worsening situation. Financial outlays for power by the Central Government have therefore been increasing at a high rate but seem to have been used with a declining level of productivity, probably because the growing reliance of the power companies on such funds has weakened their motivation to improve overall system efficiency. One of the main reasons for the companies' weak financial situation has been the generally low average level of tariffs which could barely keep up with internal inflation and the repeated devaluation of the peso. Tariff increases in Colombia were in fact always fiercely opposed by local political leaders and, in several instances, gave rise to violent social disorders. It was with a view to coping with this delicate issue that the Government created the previously mentioned tariff regulatory agency in December 1968.

IV. Financing of the Sector

4.01 In spite of the scarcity and inconsistency of statistics regarding public and private investment in the various sectors of the economy, the broad trends of fixed investment in the power sector can be isolated with a reasonable degree of reliability. Total public investment in the power sector, after increasing steadily from 1950 to 1963, appears to have remained fairly constant since then at around $ 60 million equivalent per year. As a proportion of all public investment, it seems to have risen to about 15% in 1963, after which it has probably declined, in view of the large increase in total public investment. These figures reflect the high degree of importance attached to power by the Government, especially after 1958 when it decided to give it highest priority in the development program, in order to catch up with the backlog which had accumulated over previous years and to support industrial growth.

4.02 The aggregate share of EEEB, EPM, and CVC/CHIDRAL in the overall investment program has remained very high over the years, covering between

53% and 59% of total public investment in power. ICEL's fixed investment has experienced major fluctuations but its share in the overall national power investment program has remained more or less the same since 1960 at about 25%. This reflects the difficulties encountered by ICEL in financing the expansion of the numerous systems it controls. The fact that CHEC accounted for about one-fifth of the gross fixed investment realized by ICEL between 1956 and 1969 emphasizes the mediocre picture presented by the other subsidiaries.

4.03 The very scarce information available on investments of private companies in the expansion of their power facilities suggests that fixed investment in such enterprises has remained more or less stationary, at about $ 6 million equivalent annually. This tends to demonstrate that manufacturing industries, as they expanded, relied more and more upon public electricity service.

4.04 In the past, only EEEB and EPM were able to finance their operation and investment expenditures from self-generated funds and local and foreign borrowing without having to resort to national budget appropriations to a significant extent. This has also been the case for ISA which obtains part of its funds through the contributions of its sponsors. CVC/CHIDRAL, ICEL and more recently CORELCA have, over the years, received substantial budgetary allocations and credits from the Central Government to cover some of their current expenditures and investments, as well as to service credits and loans. The subsidiaries of ICEL seem to have become progressively less self-sufficient as they expanded, thereby increasingly straining national resources: budgetary allocations to ICEL rose regularly between 1965 and 1970, from $ 8 million equivalent to $ 22 million equivalent.

4.05 Local investment funds, in addition to Government subsidies, were obtained either from the companies' profits or from local banks and credit institutions. Appropriations for electric projects from Departmental Government resources declined substantially after the abolition in 1968 of the liquor tax which had originally been imposed for the purpose. Such contributions, as well as contributions from the municipal budgets, are now quite small except in a few exceptional cases. Local currency financing has been one of the major (if not the major) problems encountered consistently throughout the years in the development of the power sector. Average tariff levels were always insufficient to permit orderly financing of system expansion. Tariff increases, although frequent and considerable, were generally offset by inflation, which rapidly escalated local costs, and by repeated peso devaluations, which expanded the foreign debt. The self-financing rates of most power companies have remained quite low, even in the case of the two most efficient companies in the country, EEEB and EPM, which between 1961 and 1970, covered only 27% and 32%, respectively, of their investment expenditures from self-generated funds. Borrowing from local financing institutions has proved especially difficult because of the country's deficient capital market, and such funds never represented more than 5% of total investments in the power sector. The actual role of private banks, including development finance companies, appears quite limited when one realizes that the major supplier of local currency loans to the sector has been the Instituto de Fomento Industrial (IFI), a governmental credit institution. The extensive complications involved in securing local funds have probably enticed the various power companies into relying more heavily than necessary upon relatively easily secured foreign credits to finance their expansion programs. The recent decision of EPM to float a Ps. 100 million debenture is an important step which deserves special mention, for this is the first time that a power company in Colombia has attempted to tap the credit market directly, thus becoming a mobilizer of domestic savings itself.

4.06 The power sector has been a major user of foreign credits; between 1955 and 1970, 52% of total fixed investment in power was in foreign currency. Over the same period, the annual share of foreign credits in public power investments was from two to five times larger than the share of such credits in total public investment, making power the second most intensive user of foreign loans, after telecommunications and before industry. This tends to underline, aside from the difficulty of raising local funds discussed earlier, the limited development of the national electric equipment manufacturing industry in Colombia. Colombia has been successful in raising long term credits from international and bilateral organizations, such as the IBRD, the IDB and the Eximbank. The IBRD has been Colombia's main source of foreign exchange for the power sector in the past, supplying about 73% of total foreign financing for the sector between 1951 and 1970. This proportion has, however, experienced major fluctuations over the years: between 1960 and 1965, the IBRD was virtually the only source of foreign currency financing for power, while, since 1965, the relative share of other foreign financing institutions, mainly the IDB, has increased sharply, leaving the IBRD with a share of 53% in 1969.

4.07 The terms of IBRD, IDB and Eximbank loans to the power sector of Colombia have been especially attractive in comparison to other sources of credit. The remainder, representing about 9% of total foreign financing, consisted mainly of suppliers' credits with relatively high interest rates and short repayment periods. It appears that, in general, IBRD loans have been sought in preference over other sources of funds. When the IDB was created in 1959, the IBRD had already been involved in the power sector of Colombia for about nine years and had already made 7 loans to that sector. The fact that the terms, conditions and administrative procedures of IBRD loans were well known explains to a large extent why, in the late 1960s, the IBRD was usually approached first for the financing of power projects. By the time the IDB was in a position to undertake extensive lending to Colombia, i.e. around 1964, the IBRD was already deeply involved in financing the power development programs of EEEB, EPM, CHEC and CVC/CHIDRAL: this most probably explains why the initial loan requests for the San Francisco (CHEC) and Alto Anchicaya (CVC/CHIDRAL) plants were addressed to the IBRD, although both were ultimately financed by the IDB. After 1964, the IBRD made interconnection the keystone of its lending program to Colombian power, while the IDB concentrated its lending on Electraguas, the national power entity which was responsible for the rest of the country and which never received any really significant support from the IBRD.

V. IBRD Financial Participation

5.01 Several of the first projects for which Colombia requested the assistance of the Bank in 1948 and which were reviewed by the Bank's first economic mission of that year were in electric power. Ever since then the Bank has been involved in the development of the Colombian power sector, particularly heavily in the late 1950s and throughout the 1960s. Through the end of 1970 the Bank made 17 power loans totalling $ 294.1 million, or nearly 40% of total commitments to Colombia, substantially more than for any other sector. Disbursements on power loans amounted to $ 220.5 million by the end of 1970, accounting for just over 40% of all Bank disbursements to Colombia. This included $ 160.8 million in the form of 13 fully disbursed loans Table 9.3 lists the various loans.

5.02 Lending to Colombia for power started with three relatively small loans in 1950-51 to three companies subsidiary to Electraguas, the national power holding entity, and responsible for power supply in three of the larger cities: CHIDRAL (Cali), CHEC (Manizales) and Lebrija (Bucaramanga). Further loans were made in the middle 1950s to CHIDRAL, but the Bank's principal lending for power started after 1958. Then it was mainly concentrated on the three largest urban centers (Bogota, Medellin and Cali) first independently and later on in the context of the central interconnected system, for creation of which a loan was made in 1968. CHEC in Manizales, the seventh city in the country in terms of size and the smallest to have

Table 9.3

COLOMBIA - Electric Energy - IBRD Loans to the Power Sector

Company	Date of Agreement	Loan Number	Name of Project	Generating capacity provided (MW)	Amount of Loan (US$ mln)
Cauca Valley					
CHIDRAL	Nov. 1950	38 CO	Anchicaya	24	3.53
CHIDRAL	March 1955	113 CO	Anchicaya & Yumbo	30	4.50
CHIDRAL	Dec. 1958	215 CO	Yumbo	10	2.80
CVC/CHIDRAL	May 1960	255 CO	Yumbo & Calima I	93	25.00
CVC/CHIDRAL	June 1963	339 CO	Calima I	60	8.80
			Sub-Total	217	44.63
Manizales					
CHEC	Dec. 1950	39 CO	La Insula	20	2.60
CHEC	Jan. 1959	217 CO	La Esmeralda	30	4.60
			Sub-Total	50	7.20
Bogota					
EEEB	Jan. 1960	246 CO	Laguneta, Salto II & Zipaquira I	117	17.60
EEEB	May 1962	313 CO	El Colegio & Zipaquira II	188	50.00
EEEB	June 1968	537 CO	El Colegio & Canoas	200	18.00 a/
			Sub-Total	505	85.60
Medellin					
EPM	May 1959	225 CO	Guadalupe III & Troneras	108	12.00
EPM	May 1961	282 CO	Guadalupe III & Troneras	198	22.00
EPM	Feb. 1964	369 CO	Guatape I	264	45.00 a/
			Sub-Total	570	79.00
Interconnection					
ISA	Dec. 1968	575 CO	230 KV Interconnection network	-	18.00 a/
ISA	June 1970	681 CO	Chivor	500	52.30 a/
			Sub-Total	500	70.30
Bucaramanga					
Rio Lebrija	Nov. 1951	54 CO	Lebrija	9	2.40
Cartagena					
Electribol	July 1963	347 CO	Cospique	25	5.00
			TOTAL	1,876	294.13

Sources: IBRD; additional details are given in Annex Table 1.8

a/ Not yet fully disbursed.

been direct recipient of a Bank loan, received a second Bank loan in 1959 and is also involved in the central interconnected system. Cartagena, the sixth-ranking city of Colombia, benefitted from a small loan for power in the early 1960s.

5.03 By the end of 1970, Bank-financed installed capacity in operation amounted to 1,066 MW or about 51% of total installed capacity in the public sector. This ratio will probably have reached about 55% by the end of 1971 when the two hydroelectric plants at Canoas (50 MW) and Guatape I (264 MW) are completed, thus bringing total Bank-financed installed capacity to 1,380 MW. This does not include the 500 MW Chivor hydroelectric plant currently under construction and planned for completion by 1976. In 1970, total electricity generation in Bank-financed power plants amounted to some 4,200 Gwh (an average load factor of 45%), representing 53% of total generation in the country. It is estimated that, at the end of 1970, approximately 6 million people in Colombia, i.e. about 27% of the total population (22.5 million) and 60% of the population having electricity service (10 million), were supplied with electricity generated in power plants financed through Bank loans. Of the 1,066 MW Bank-financed capacity in service at the end of 1970, as much as 918 MW (86%) was hydro, representing 63% of total hydroelectric capacity installed in the country. The Bank has played a fundamental role in the power development programs of EEEB, EPM and CVC/CHIDRAL, by helping to finance 77% of the aggregate installed capacity in these three centers; this proportion will be raised to approximately 81% by the end of 1971.

5.04 It is estimated that fixed investment from Bank funds accounted for some 31% of total fixed investment in power in Colombia between 1960 and 1971. As mentioned, Bank lending, especially in this period, has been heavily concentrated on the four companies which together make the central interconnected system: as of December 31, 1970 total disbursements for projects in the four systems amounted to \$ 197.8 million or 89.7% of total power loan disbursements; loan commitments on such projects represented 74% of total commitments for power, or 97% if one includes the two loans to ISA.

5.05 The Bank was virtually the sole source of foreign currency for CVC/CHIDRAL between 1950 and 1968, the year in which the IDB extended a \$ 60 million loan for the Alto Anchicaya hydroelectric project. This was also the case for EEEB and EPM over the 1960-71 period when the installed generating capacity of the two companies was multiplied five- and four-fold, respectively. EEEB has recently secured foreign loans from the U. S. Exim-bank, an American commercial bank, and Japanese suppliers, in an aggregate amount of \$ 7 million, which will cover the foreign currency expenditures on the third unit at Zipaquira currently under construction. In the case of CHEC, the Bank remained the exclusive source of foreign currency financing between 1950 and 1965, when the IDB provided a \$ 8 million loan for the construction of the San Francisco hydroplant.

VI. IBRD Policy Advice and Project Selection

6.01 The main Bank involvement in power in Colombia started with the review of the sector that was undertaken in 1949 as part of a comprehensive survey of Colombia's development problems and prospects. This survey was sponsored by the Bank and carried out by a team headed by Dr. Lauchlin Currie, a former New Deal economist. Most of the principal recommendations made in the mission's report have eventually been followed, after lengthy delays and with varying degrees of success. The report emphasized the need to: (a) give priority to power development projects in some selected main centers;[1/] (b) create regional and, later, national interconnecting networks; (c) promote financial self-sufficiency of power companies; (d) establish an independent tariff regulating agency; and (e) make Electraguas the national power planning agency with the responsibility for collecting relevant statistics, developing national electrification plans and implementing such plans. Electrification has expanded substantially in the centers regarded by the mission as deserving primary attention, but some of them, namely Barranquilla, Cartagena and Popayan still have inadequate electric service today. It was not until twenty years after the initial recommendation had been made that the first regional interconnection network was implemented and the national tariff agency established. Electraguas (and later on ICEL) have actually played only a minor role in power planning; the 1954 National Electrification Plan prepared under the sponsorship of Electraguas as well as the 1964 improved version of the plan, have hardly affected the actual development of the sector. Furthermore, it is only very recently that ICEL has undertaken the systematic collection of statistics relevant to power planning and even today the national entity still appears insufficiently equipped to efficiently carry out its assigned functions.

1/ Bogota, Medellin, Cali, Barranquilla, Manizales, Cartagena, Cucuta and Popayan.

6.02 No Bank report since 1949 has attempted to take as broad and deep a view of the power sector in Colombia. Moreover, there was little or no follow-up to the 1949 mission's broader recommendations cited above; the issues were taken up anew, and probably without reference to that report, in the 1960s. Typically, even in the 1960s, the Bank's economic reports have contented themselves with a vague description of the sector and a more precise historical sketch of previous Bank projects. The only issues tackled in several cases were the necessity for tariff increases and for promoting the central interconnected system. A few reports, as in 1956 and 1962, have attempted to take a more comprehensive outlook in connection with the overall public investment program, but they have not gone much beyond a fairly superficial review of bulk supply projects in preparation and their financial requirements. Basic issues such as appropriate reliability standards, analysis of load forecasts, energy policies, regional allocation of investment, domestic production of electrical equipment, power distribution problems and policies, and tariff structures have never been touched. It can even be asserted that none of the Bank's economic reports has ever made any major recommendations other than with regard to raising tariffs, which have influenced Colombia's policy in power development matters. These facts appear especially striking considering what a large proportion of total Bank lending to Colombia has been for electric power.

6.03 Bank lending to the power sector has, broadly speaking, been on a project basis. Actual project identification has been very limited and loan consideration has always followed an initial request by the ultimate borrower. In virtually all cases, project evaluation has been made on the basis of engineering and financial criteria alone, with only very limited assessments of the actual long term economic implications of the projects, and of the comparable benefits investments in alternative projects might have brought.

6.04 It should not be concluded from the above that the Bank has taken a shortsighted view of power development in Colombia. On the contrary, Bank lending has been characterized by consistency, singularity of purpose in pursuing objectives, and ingenuity in the implementation of policies toward these objectives. The Bank has been an indefatigable advocate of the Central Interconnected System (see Chapter XIII) and, on several occasions, has risked imperiling its rapport with the three main borrowers, EEEB, EPM, and CVC/CHIDRAL, in order to emphasize the importance of this goal. Neither did the Bank hesitate to confront the open hostility of the central Government and local communities toward its constant insistence on tariff increases and, in the later 1960s, the necessity of establishing a national tariff regulatory agency. In retrospect, both of these objectives appear to have been well founded and important.

6.05 As stated before, Bank loans to the power sector have concentrated mainly on the three largest cities, i.e. Bogota, Medellin and Cali, which accounted, in 1970, for 38% of the country's urban population 1/

1/ Centers having population greater than 1,500.

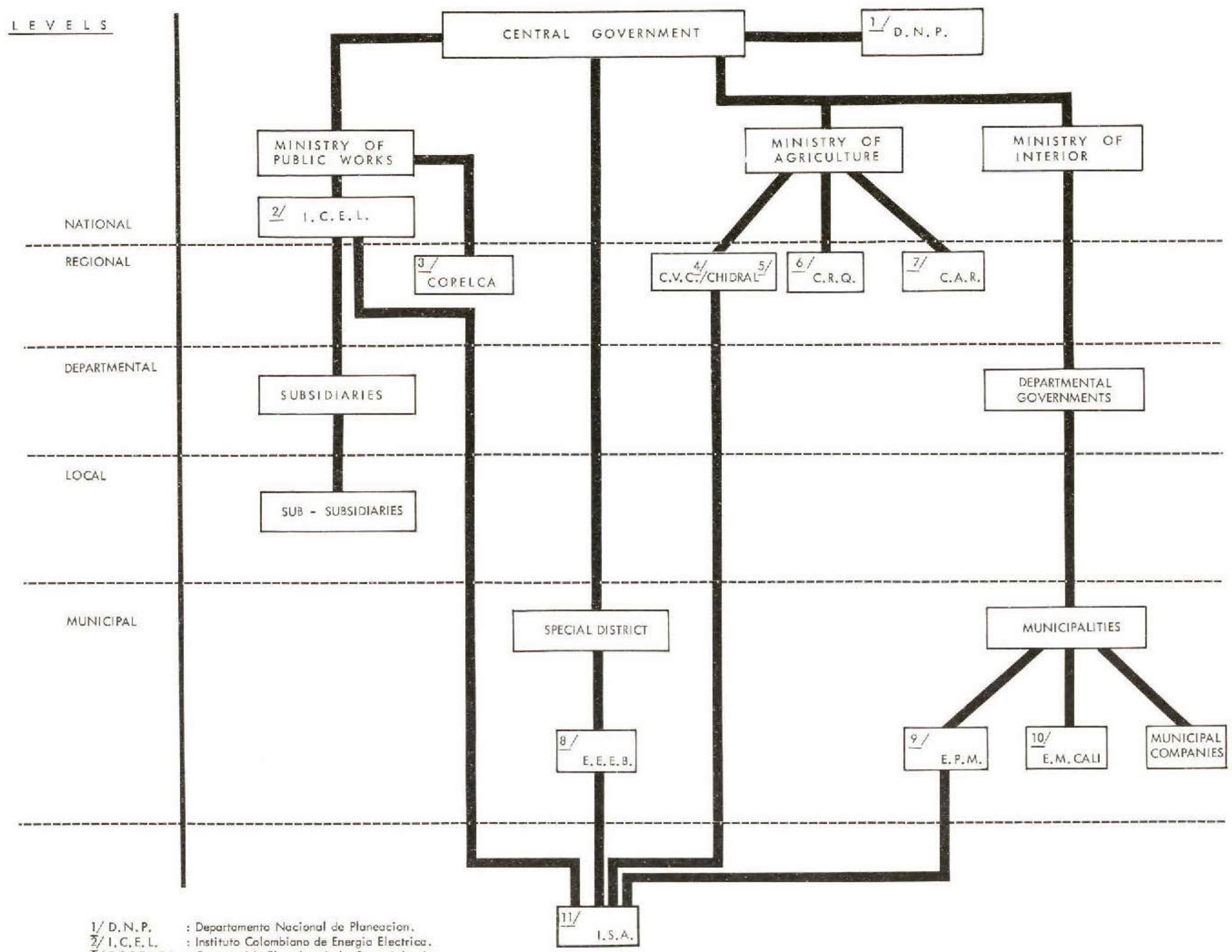
and 22% of the total population. The growth of these centers, traditionally Colombia's main industrial centers, necessitated major power investments, in face of the large influx of population from the smaller towns and the countryside. This was especially true after the deferral of investment in 1957-58 as a result of the financial crisis stemming from poor financial policies and the sharp deterioration in the world coffee market. At that time the IBRD, and to a much lesser extent the U.S. Eximbank, were probably the only lending institutions able to provide the large amounts of long-term foreign currency financing, on good terms, that were required. It would be unwise to cast doubt upon the high priority in the overall economy attached to development of the public utilities in Bogota, Medellin and Cali.

6.06 As mentioned earlier, however, the choice of projects by the Bank has not been based upon detailed evaluations of economic priorities at the overall national level, and financial criteria have, on the other hand, played a significant (if not exclusive) role in the Bank's decision-making process. Actually, the Bogota and Medellin power companies, even before the Bank's involvement, had always been the most viable power companies in the country. The power company serving Cali, although notably less efficient than these two, has, over the years, remained ahead of other utilities in the country, in terms of both financial performance and quality of service. The Bank, through its concentrated lending to EEEB, EPM and CVC/CHIDRAL, has probably conducted the most financially rewarding investment program public utilities in Colombia could provide. It can be argued that, in the long run, financial and economic efficiency may converge and that financial criteria may be an adequate tool for appraising economic benefits. This would probably be true if the actual pattern of demand within the economy had the opportunity of expressing itself freely. Institutional setups, however, always tend to distort the genuine image presented by spontaneous demand and it is not until the extent of such distortions are known, that meaningful conclusions can be drawn regarding the degree to which financial performance reflects economic welfare. Two areas where such distortions may be particularly relevant in Colombia are the electrification of marginal zones in the main cities, and power development in other parts of the country, mainly the responsibility of the weak ICEL subsidiaries. In the early 1960s, some concern developed in the Bank particularly with respect to the latter, and an effort was made to develop relations, either through Electraguas or directly, with some of the smaller power companies in Colombia. But it was soon determined that this would require more intensive work on institutional improvement than the Bank was in a position to provide, and so the effort was abandoned. This has probably had some small effect on the overall pattern of urban development in Colombia, but it is very hard to say how much. The largest centers have been growing steadily at rates close to 7% -- with more than half of the increase being due to immigration -- while the medium-sized towns have been growing at significantly lower rates, in the neighborhood of 5%, and the smaller towns still less.

6.07 Besides being the three largest cities of Colombia, Bogota, Medellin and Cali are located within the best endowed area of the country in terms of hydroelectric resources. Exploitation of such resources obviously has important implications at the national level. By investing heavily in the heart of Colombia's power resources, the Bank placed itself in a favorable position to influence the country's overall power development policy and it is probable that several of the major achievements in the sector over the last twenty years would not have taken place had the Bank not participated in this manner -- particularly the creation of Interconexion.

COLOMBIA

STRUCTURAL ORGANIZATION OF THE POWER SECTOR (1971)



1/ D.N.P. : Departamento Nacional de Planeacion.
2/ I.C.E.L. : Instituto Colombiano de Energia Electrica.
3/ CORELCA : Corporación Electrica de la Costa Atlantica.
4/ C.V.C. : Corporación Autónoma Regional del Cauca.
5/ CHIDRAL : Central Hidroelectrica del Rio Anchicaya.
6/ C.R.Q. : Corporación Autónoma Regional del Quindió.
7/ C.A.R. : Corporación Autónoma Regional de la Sabana.
8/ E.E.E.B. : Empresa de Energia Electrica de Bogota.
9/ E.P.M. : Empresas Publicas de Medellin.
10/ E.M. Cali : Empresas Municipales de Cali.
11/ I.S.A. : Interconexion Electrica S.A.

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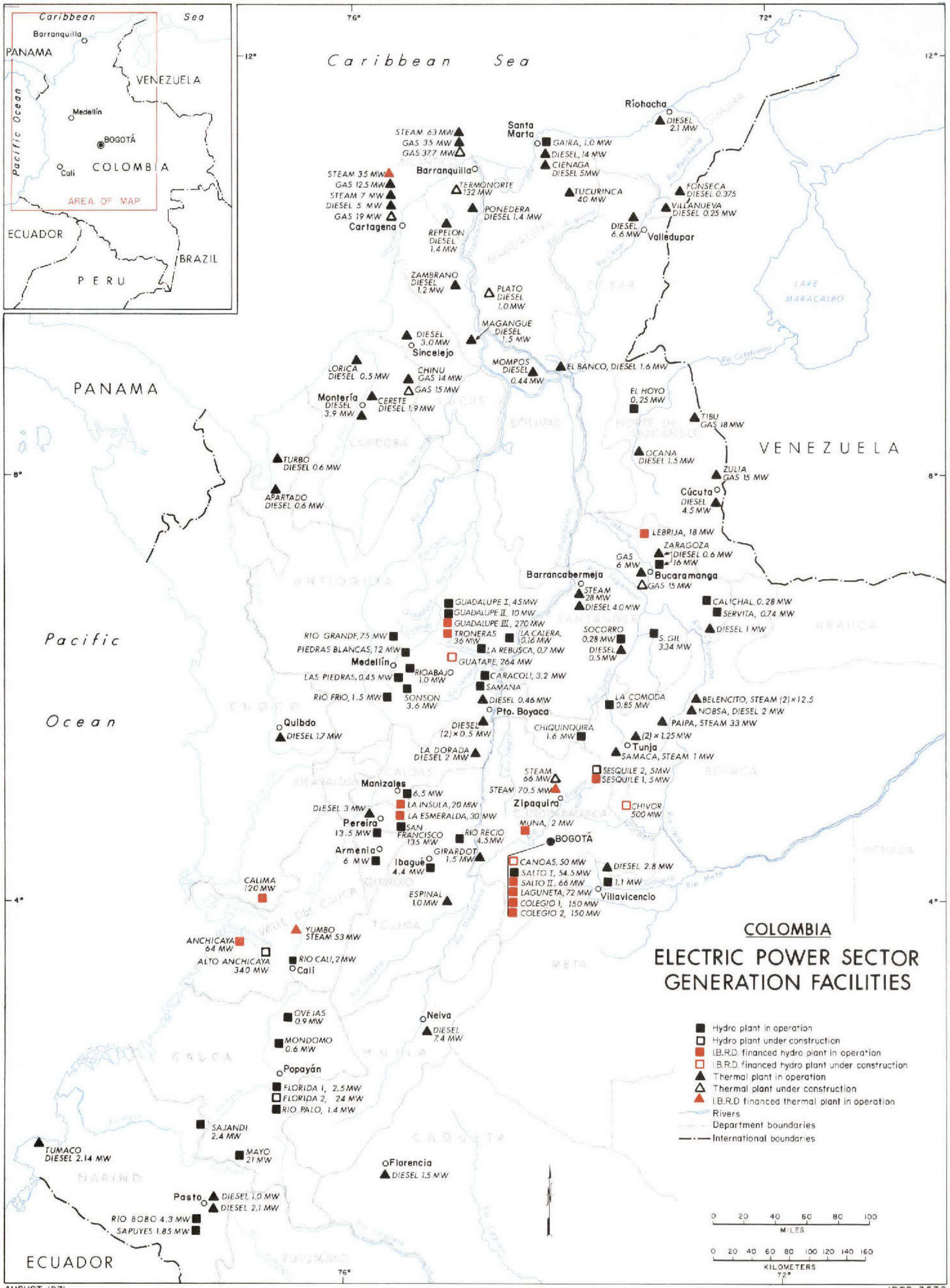

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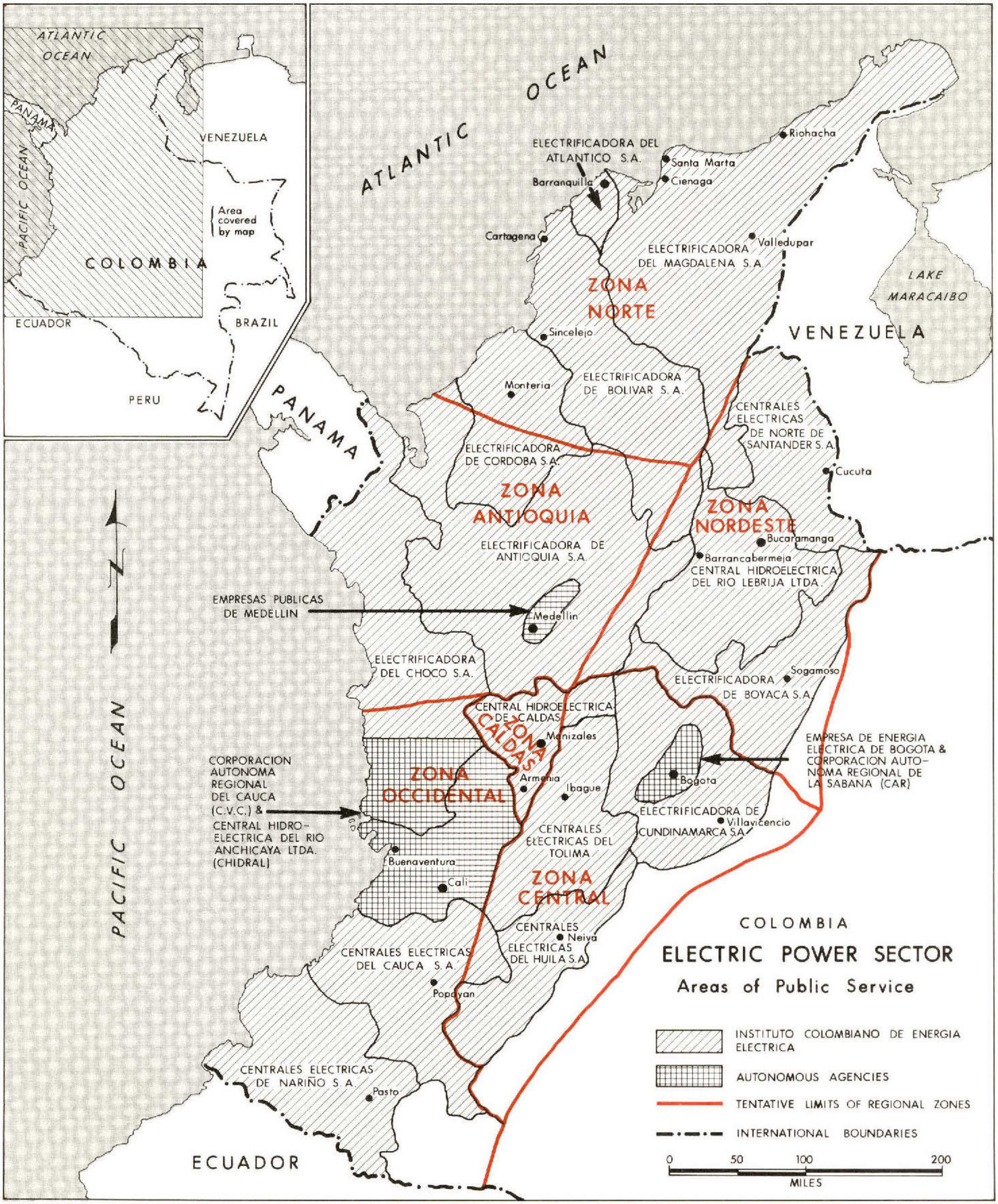

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Chapter X - BOGOTA POWER COMPANY (EEEB) - COLOMBIA

I. Introduction

1.01 The Bogota Power Company, the Empresa de Energia Electrica de Bogota (EEEB), was established in 1951 under trust agreement when a consortium of four local banks financed its acquisition by the municipality through the purchase of the outstanding stock of the former power company, Empresas Unidas de Energia de Bogota, S.A., a private corporation. Although the municipality thereby became the owner of all electric utility facilities in Bogota, the agreement stipulated that the banks were entitled to elect a majority of three out of five, later increased to four out of seven members of the Board of Directors of EEEB. The autonomy of the company and the private nature of its management were thus maintained. Despite the Municipal Council's repeatedly expressed desire to create a metropolitan district public service corporation which would group all public utility services including electricity, EEEB remained separate from the entities responsible for other services. The company supplies electricity to the Bogota area and also bulk energy to several subsidiaries of ICEL, the national agency for the development of electric power, in the departments of Tolima, Cundinamarca and Boyaca, as well as to CAR, a government agency responsible for the distribution of electricity to rural areas adjacent to Bogota.

1.02 EEEB's installed capacity rose from 74 MW in 1956 to 587.5 MW in 1970, corresponding to an average annual growth rate of 16%. The expansion of the generation system was especially impressive in the period 1960-70 when installed capacity increased about five fold. Demand growth corresponded very closely to the evolution of installed capacity until 1963, when reserve capacity began to appear in the system. Between 1961 and 1970, energy sales and peak demand have grown at average rates of 14% each with a 16.2% annual growth in installed capacity. During the same period, the excess of installed capacity over maximum peak demand ranged from 20.7 MW in 1966, when the largest generating unit in the system was 37.5 MW, to 132.9 MW in 1967 after the introduction of the first three 50 MW units at El Colegio and 108.5 MW in 1970 after completion of the last three units. EEEB's distribution network did not, however, keep pace with growth of demand or of installed capacity although for lack of reliable data it is not possible to calculate by how much it has lagged behind. All the hydroplants are located 20 kms west of the city on a 1,800 meter vertical drop on the Bogota river over a distance of only 24 kms. EEEB's system has now been linked with that of Medellin and Cali in an interconnected network which is due to become operative shortly. (The interconnection aspect is treated in fuller detail in Chapter XIII).

1.03 Besides being the capital, Bogota is a major industrial center; in 1968, it contributed 23% of total industrial value added of the country. In 1970, EEEB's installed capacity represented 28.3% of the national total, serving a population of approximately 2.5 million (in Bogota alone) or 10.6% of the total population of Colombia. EEEB's share in the overall public investment program in the power sector was 26.7% for the 1956-60 period, 28.9% between 1961 and 1965, declining to 17% for 1966-1969.

II. The Bank and EEEB's Power Expansion Program

2.01 EEEB received over the 1960-68 period three loans from the Bank as follows:

Loan No.	Date of Loan Agreement	Effective Date	Closing Date	Amounts ($ mln.) Committed	Disbursed[a/]	Interest	Periods (years) Grace	Term
246 CO	1/60	8/60	10/63	17.60	17.60	6%	3	25
313 CO	5/62	8/62	12/68	50.00	50.00	5-3/4%	4	25
537 CO	6/68	8/68	1/72	18.00	10.47	6-1/4%	4	20
				85.60	78.07			

a/ As of December 31, 1970.

2.02 The Bank had been approached as early as September 1954 for a loan to finance part of Bogota's electric system expansion program, but, because of legal problems mainly connected with the autonomy of the utility from the municipality, it was not until January 1960 that the First Loan Agreement was signed.[1/] In 1959, by resolution of the Municipal Council, the Bogota Power Company was made an autonomous entity, thereby meeting the main condition for IBRD financing. The Bank had also required from the company certain structural reorganizations necessary to cope with

1/ Between 1956 and 1958, the Bank temporarily suspended active consideration of new loans to Colombia because of the country's overall economic policies.

the proposed expansion program, especially with respect to financial management and planning. Finally, the Bank required a tariff rate increase sufficient to keep the Company solvent as a condition for loan effectiveness.

2.03 Although the expansion program for which Bank funds had initially been sought underwent major changes between 1954 and 1960, the Bank found that, subject to some modifications, EEEB's overall development program would be suitable for financing. The Bank helped to improve the program by persuading the Government to abandon the so-called Paipa thermal plant project in the Department of Boyaca. This project, for which two generating units had already been purchased by the Government, was motivated by political considerations and appeared dubious on economic and technical grounds. The solution proposed by the Bank of having EEEB purchase one of the two units, was accepted by the Government. The first loan, 246-CO of US$ 17.6 million, signed in January 1960, was intended to meet the substantial increase in demand which began to take place in 1957. Saturation of the system had already been reached by the end of 1959; installed capacity became insufficient to meet peak demand and restrictions had to be applied throughout the system. The loan provided for the addition of a fourth 18 MW unit to the existing Laguneta plant. Space had already been provided in the power house for this unit which was considered the cheapest solution to increase the installed capacity of the system. In addition, the loan provided for the installation of a thermal plant, Zipaquira I, having three major purposes: (a) provide reasonable hydrothermal balance to the system; (b) increase the peaking capability of the latter; (c) provide quick, reliable additional generating capacity in the then prevailing situation of severe restrictions. The thermal unit installed was the one originally assigned to the Paipa plant. Two other hydro units were provided under the loan at another site, called Salto II, offering a 419 m. drop in altitude over 2.4 km. This was considered the cheapest section of the Bogota River fall which could be harnessed at that time. The loan also included the first stage of construction of the Guatavita dam and reservoir to provide increased upstream storage on the Bogota River. Finally, allocations were made for the modernization and expansion of EEEB's transmission and distribution system.

2.04 Demand increased substantially over the period following the gradual commissioning of the various units provided for in the first loan. Delays in the financing and subsequent construction of the new plants resulted in major power shortages between 1960 and 1963. Saturation of the system seemed likely to occur again in early 1964. Therefore, a second expansion program, devised by EEEB's appointed consulting firm, OLAP, was submitted to the Bank for a further loan. Negotiations proceeded rapidly, EEEB having been granted in January 1962 a new 33% rate increase, and Loan 313-CO (US$ 50 million) was signed in May 1962 before the expiration of the first loan's drawn down period. The investment program initially proposed underwent some modifications as a result of exchanges between the Bank, EEEB and OLAP. The Bank recommended deferral of a hydroelectric project at Canoas because of the anticipated high local currency component and the difficulty of borrowing locally. This project was substituted with a second 33 MW thermal unit at Zipaquira. In addition the Bank persuaded EEEB and CAR (Corporacion Autonoma Regional de la Sabana, mentioned earlier), to agree on an arrangement whereby EEEB would expand its service into the rural area controlled by CAR instead of having CAR build its own distribution and transmission facilities, a project which CAR submitted to the Bank in November 1961 for financing.

2.05 There were tight negotiations between the Bank, EEEB, the Government and local financing institutions, to secure the additional funds needed to cover the local cost of the expansion program; such funds were eventually obtained from local banks. The loan finally made was for US$ 50 million. It provided for the construction of the first stage of a major 300 MW hydroelectric plant at El Colegio designed to meet the expected rapid growth of demand in the Bogota system. The loan also included provision for the second thermal unit at Zipaquira, as noted above, the second stage of the Guatavita dam and reservoir, and the above mentioned provision for CAR's development program, as well as US$ 3.0 million equivalent for local engineering costs, an exceptional measure taken by the Bank and intended to ease the company's shortage of local currency in the early years of the loan and to avoid discrimination against local consultant firms. Some of the items covered in the first loan, mainly for transmission and distribution facilities which could not be financed as intended because some funds had been diverted to cover the cost overruns on the major construction works, were reallocated to this second loan.

2.06 In December 1965, EEEB requested a third IBRD loan to finance its third expansion program and also to cover the foreign exchange cost overruns on El Colegio and part of the past engineering expenditures. After extensive discussion on several important issues which will be related in the next section of this Chapter, the Bank took the lead in 1967 in arranging among major industrialized countries (U.S.A., Germany, Italy, Japan) for the joint financing of three Colombian public utility projects, including EEEB's third expansion program. Joint financing was based on a formula providingthat above a certain minimum to be fully covered by the Bank, financing would be provided on a 50/50 basis between the Bank and the country in which contract orders would be placed. The IBRD loan signed on June 3, 1968, to an amount of US$ 18 million, was to cover the foreign exchange costs of completing El Colegio by adding three units and of constructing the Canoas plant on the only portion of the 1,800 meter drop not yet exploited. Although it was expected to involve higher unit costs per kw than the other three hydroplants (El Colegio, Salto II and Laguneta), Canoas had the advantage of being situated on the top reach of the Bogota River drop and was therefore expected to contribute to further regulation of water flows and more efficient use of the downstream hydroelectric system. The loan also included provisions for the expansion of transmission, distribution and public lighting systems in Bogota.

III. Major Issues

3.01 Issues that had considerably delayed the beginning of Bank lending to EEEB, namely the legal status of the company and some of its organizational aspects, including those relating to project preparation, were mentioned earlier. Although these organizational problems arose again in later years, they did not affect the timing of subsequent loans. The first loan, intended principally to meet emergency needs, did not entail further serious issues.

3.02 The second loan involved important issues mainly of a financial nature: (1) the Bank expressed frequent concern over the quality of EEEB's financial management, a matter that remained pending for nearly a year until the end of 1964 when it appeared that EEEB was making adequate progress in the matter; (2) the company was faced with major cash shortages throughout the construction period of the second expansion program, due to high internal inflation and consequent increase of local currency costs, to delayed Government approval of a tariff rate increase and to the failure of local banks to fulfill their expected contribution to local cost financing (see Section V below); (3) EEEB's continued failure to commission new distribution networks on schedule was a matter of concern to the Bank, especially since as a result, energy sales were significantly less than expected. At the Bank's insistence, the company hired a distribution consultant.

3.03 A number of important issues surrounded EEEB's third expansion program. The first related to the question of whether the Bank should finance cost overruns associated with ongoing Bank financed projects, a request having been made by EEEB to this effect for foreign exchange cost overruns on the previous loan. A special Loan Committee meeting, held in April 1966, concluded that such practice would be acceptable provided that the overrun amounted to at least US$ 5 million and that the reasons for the cost overruns in question were beyond the borrower's control. Although the overruns were due to geological difficulties, obviously beyond EEEB's control, the amount was far below US$ 5 million. Second, the Bank indicated to EEEB that no further loan requests would be considered as long as agreement on interconnection had not been reached between the four power companies concerned (EEEB, EPM, CVC and CHEC). The Interconnection Agreement was signed by all parties concerned in November 1966. Third, the issue of timely tariff increases had come up for discussion on several occasions, and a new increase of 40.8% was finally granted in September 1966. Fourth, the gap in local currency financing was a major question, especially in regard to the ability of the Power Company to cover a sufficient part of its investment program through self-generated resources. It was estimated that the Company's internal resources had covered only 23% of the expansion program costs between 1963 and 1965, while the Loan Agreement (for Loan 313-CO) specified that this proportion should be no less than 40%. Fifth, the Municipality of Bogota had indicated its intention to increase EEEB's existing contribution of 10% of the Company's net profits for investment in the city's public services, especially street lighting. The Bank insisted that the status quo be maintained and showed reluctance to consider a special loan provision for street lighting.

3.04 Finally, some disagreements had occurred between the Bank, EEEB, and the Colombian Government over EEEB's request that a certain margin of preference be given to domestic suppliers of electrical goods. The Bank's position was that a 15% preference could be granted to local manufacturers at the request of the borrower but that local costs of such awarded contracts could not be financed from IBRD funds, since these were to cover only the foreign exchange component of projects. Later on the Bank did authorize the power company to use loan funds to finance imports of raw materials necessary to manufacture cables in Colombia. This appears, however, to have been an exceptional measure. The issue at stake here had more general relevance than EEEB only. It was whether the Bank's procurement policy through international competitive bidding did not potentially inhibit development of the country's industry for products that could be manufactured locally. EEEB and the other power companies in Colombia had no objection to this policy since they had little desire to purchase local equipment which they considered more expensive and less reliable. The Bank, whose priority concern had always been the technical efficiency of its projects, probably held the same view, but it seems that a thorough investigation of the quality and cost of locally manufactured equipment might possibly have justified different conclusions which could have led the Bank, perhaps in connection with its own lending, to assist the industry to expand somewhat faster and more efficiently.

IV. Load Forecasting and Investment Planning

4.01 The three sets of forecasts examined in this study are those contained in the Appraisal Reports for Loans 246-CO (1960), 313-CO (1962) and 537-CO (1968), covering periods of nine, six and two years[1] respectively. Tables II.A-1, II.A-2, II.A-3 and Chart 10.1 compare the forecast projections with actual development.

4.02 As mentioned earlier, a substantial increase in energy consumption began to take place in 1957, and by 1959 installed capacity became insufficient to meet peak demand. The situation improved slightly in the second half of 1960 when the fourth unit of Laguneta, financed through the first Bank loan, Loan 246-CO, was put into service, but deteriorated again between 1960 and 1962 due to the delays on the commissioning of the various generating plants (from 12 to 18 months); lack of capacity gave rise to serious shortages. As shown on Chart 10.1, it was not until 1963 when the two Bank-financed plants of Salto II and Zipaquira I were commissioned that demand could be met. Thus, because of delays in the commissioning of the plants and the resultant restrictions applied to free load growth, both installed capacity and peak demand grew slower than forecast. According to estimates based on requests to the company for service, deferred demand at the end of 1961 totalled about 112 MW, a little more than the combined capacity of Salto II and Zipaquira I.

4.03 Because the program financed through the first loan was of a short term emergency nature designed to cope with the critical conditions prevailing at that time, the forecasts made in 1962 for the second loan appear more relevant here. The 1962 forecast assumed a 15.3% average growth in power demand over the 1961-70 period, with a particularly rapid growth (averaging 23%) in the first four years through 1965, as the backlog in demand which had accumulated in the years of shortage was

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1/ Original forecast extended six years, but we deal only with the period through 1970.

overcome. Actual load growth turned out to be 14% on average for the whole period 1961-70 and was less in the early years than later (13.4% 1961-65 compared with 14.5% 1965-70). Chart 10.1 illustrates the projected and actual patterns of load growth. The shortfall in demand was greatest between 1965 and 1968, when it was about 100 MW. The loan provided for substantial gross reserves with the highest level, of about 100 MW, foreseen for the end of 1965, after the commissioning of the first three units of El Colegio. In practice, however, reserves through 1966 were substantially less than projected, despite the shortfall in demand, due to delays in commissioning the El Colegio units. Once this had been done in 1967, reserve capacity reached 132.9 MW. Tables II.A-1 and II.A-2 show actual reserve capacity from 1960 to 1968 and also effective peak spare capacity. The latter shows that actual usable excess capacity in EEEB's system has been limited over the years, even though reliability of the system has been satisfactory on the whole and load shedding was largely eliminated by 1963.

4.04 The third loan appraisal slightly underestimated growth of demand between 1968 and 1970, as shown in Table II.A-3. However, because the second stage of El Colegio was completed about one-and-a-half years earlier than forecast (during the first half of 1970), reserve capacity in 1970 was 108.5 MW.

4.05 To summarize the above discussion: The 1962 appraisal report adopted high load forecasts, apparently based on the estimate of 112 MW of unmet demand existing in 1961 referred to above. It was not in fact until 1966 that total demand reached the 1961 level of estimated total demand (including deferred demand). However, due to obstacles in the implementation of the various steps of the overall program which led to delays in the commissioning dates of the various plants, growth of installed capacity proceeded closely in line with load growth, yielding a generally reasonable reserve capacity. Thus installed capacity has not been an obstacle to the growth of expressed demand and the possible limitations in the expansion of the latter should be entirely attributed to shortcomings in the transmission and distribution systems.

Alternative Plans - Zipaquira 2 vs. Canoas

4.06 As pointed out earlier, Canoas was recognized in 1962, during discussions leading up to the second loan, as being a more economic alternative than Zipaquira 2, but it was rejected partly because of its high local currency cost component and partly for technical reasons. A simulation of system behavior was used in this study to find out whether the overall expansion program financed had been optimal in retrospect. A summary of the results which apply to this particular investment choice follows. If projected demand had materialized, Zipaquira 2 would probably have made an important contribution to system performance. As demand was much lower than expected, it seems that Zipaquira 2 actually only served the purpose of meeting extreme peak demand. The results of the simulation model of the system without Zipaquira 2 indicate that the marginal contribution of the 37.5 MW Zipaquira 2 unit toward meeting actual market demand was quite limited. If the 50 MW Canoas alternative had been chosen both peak demand and energy requirements would equally have been met, because, even though it would have taken longer to build, the lag in demand growth was such as to mean that no shortage would have occurred.

4.07 An economic analysis on the basis of the system simulation shows that the present worth (in 1968) of the lifetime savings from building Canoas instead of Zipaquira 2, taking into account the additional 12.5 MW capacity provided by Canoas, is US$ 9.2 million using a shadow foreign exchange rate of twice the official rate, or US$ 5.4 million using the official exchange rate, equivalent to between a quarter and a third of the cost of the investment.[1/] These numbers suggest that, in practice, there would have been considerable economic advantage in choosing Canoas -- advantages that could not be realized because of the weakness of the local capital market and its inability to generate the funds needed for the project and because of the Bank's unreadiness to finance local currency costs for such a project. What now appears in retrospect to have been a mistake is consequence of two factors referred to above: (1) difficulties over local currency financing; (2) the excessively high load forecast used, which resulted in more value being assigned to the superiority of Zipaquira in terms of construction time than was really warranted. The disappointing load growth resulted partly from poor progress by EEEB in expansion of the distribution system in the early 1960s and partly from disappointing growth of the economy in these years. But as mentioned earlier, it appears that too much weight was given to the alleged deferred demand of 112 MW in selecting the load forecast in 1961. This

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1/ The relative saving is higher when the shadow exchange rate is used because of the much higher foreign cost component of the Zipaquira unit.

is illustrative to some degree of the mistakes that can result from allowing shortages of capacity to become serious enough that nobody can tell what "true" demand is; it is probably more illustrative in this case of the problems that arise from deficient records.

V. Financial Performance

5.01 The Bank has had a close relationship with EEEB for some thirteen years and this period has seen some significant improvement in the company's financial situation -- both in regard to adequacy of staff and planning procedures and in regard to financial performance. However, there were considerable difficulties in the early part of the 1960s.

Loan Covenant Goals

5.02 At the time of the appraisal of Loan 246-CO in 1959, EEEB was in a difficult situation with regard to its debt. While the Ps. 40 million it owed represented well under half of its equity, about 90% of this amount was either short-term or scheduled to mature by the end of 1961. Also EEEB had had some difficulty, like the other power companies, in keeping its tariffs in line with rising costs due to inflationary trends. The Bank, therefore, besides arranging to have the local debt rescheduled and insisting upon a new tariff increase, included a covenant in the loan agreement which provided that the company would not incur new debt unless net revenues would cover total debt service each year at least 1.3 times. When this covenant was drafted and agreed upon in 1959, no problems were foreseen regarding the company's compliance with it. By the time of the second loan (313-CO) in 1962, however, it was clear that EEEB would have to undertake considerable local borrowing, partly to cover the heavy local cost overruns occurring on the first project and partly to contribute to the forthcoming larger expansion program which included El Colegio. It was feared that such borrowing might not be consistent with the covenant on debt-service coverage that had been negotiated, but it was nevertheless agreed in principle to maintain the 1.3 ratio. In fact, although debt service coverage fell from 2.4 times in 1962 to 1.3 times in 1966, it has never fallen below that level. The same ratio was maintained in the covenant on the last loan (537-CO of 1968) and the Empresa seems to have had no difficulty in adhering to it; in 1970 debt service coverage was 1.9.

5.03 The Bank's main emphasis was on internal generation of cash to cover local currency needs, so that significant local borrowing would not be required. A side letter was agreed in connection with the first loan under which the Empresa undertook that "rates should be set at a level which would permit at least 40% of new investment in power facilities to be financed from retained earnings." While this was adhered to in 1960 and 1961, it was foreseen at the time of the second loan that compliance with the covenant would not be possible for the next few years, mainly due to the large size of the investment program envisaged. Net internal cash generation was expected to cover about 33% of construction expenditures over the four years 1962-65. With a view to making the self-financing target operational, however, it was agreed that the Empresa would maintain rates at a level sufficient for the 40% self-financing target to be met over the four-year period 1963-66.

5.04 In these years, EEEB again faced severe cash shortages; the projected self-financing rates were far from attained, due to lengthy delays in submission and approval of the tariff increases needed to keep pace with inflation and large local cost overruns on construction projects. Actual self-financing, as defined in the agreements with EEEB, was 23% over the 1963-66 period. Using the standard definition applied in this study,1/ actual self-financing over the four years 1962-65 was about 14% of fixed investment (see Table IIB) and it was about the same over the four years 1963-66. The shortages in internal cash generation seem to have affected most severely investment in expansion of the distribution system, causing it to be deferred.

1/ The method which the Bank employed to calculate EEEB's self-financing rate differs from that used in this study in the treatment of interest during construction. The following shows the differences in definition:

IBRD Appraisal Report on EEEB:	Present Evaluation Report:
Gross Internal Cash Generation	Gross Internal Cash Generation
Less: Debt Service plus dividends to Municipality (Excluding interest during construction)	Less: Debt Service plus dividends to Municipality (Including interest during construction)
Plus: Reserve for Employee Benefit	Plus: Reserve for Employee Benefit
Equals: Net Internal Cash	Equals: Net Internal Cash
Self-financing Rate =	Self-financing Rate =
$\dfrac{\text{Net Internal Cash}}{\text{Total Construction Expenditures (Including interest during construction)}}$	$\dfrac{\text{Net Internal Cash}}{\text{Total Construction Expenditures (Excluding interest during construction)}}$

5.05 The failure of the self-financing agreement to achieve the expected results despite persistent efforts of the Bank in contacts with the Company and the Government, and especially the difficulty of determining at any given point whether the Empresa was living up to a performance condition defined for a four-year period caused the Bank to change its approach in the third loan (537-CO). In this loan, a covenant was included to gauge performance on a rate of return basis. It was agreed during negotiations that the Empresa would earn a rate of return of at least 9 percent, measured against assets "reasonably valued." This last qualification was made because of the fact that EEEB, as other Colombian power entities, had valued their investments in historic terms, which, because of the persistent inflation and frequent devaluation of the peso, greatly undervalued assets and consequently inflated rate of return figures. Since 1967, the Empresa has revalued its assets to correspond with changes in the exchange rate. A special technique of revaluation developed for the purposes of the present study to cover a longer period indicates that EEEB has conformed with this last covenant; the rate of return on revalued assets for 1968, 1969 and 1970 has been 8.9, 9.9 and 11.1 percent respectively. Net internal cash generation has also been substantially higher, averaging Ps. 92 million (in 1968 prices) for 1968-70 compared with Ps. 37 million (in 1968 prices) for the four years 1963-66. Since investment has been lower in real terms in recent years, the self-financing rate has shown an even more marked improvement and has exceeded 40% in most years since 1967 and over the 1967-70 period as a whole.

Accuracy of Financial Forecasts

5.06 Financial forecasts are difficult to evaluate because of the rapid inflation. Nevertheless general trends can be seen from Tables II.A-1, 2, 3, showing forecast and actual figures for sales and rates of return. Though adequate comparative data is available only for Loan 313-CO, the tables for the first two loans show a consistent overestimation of sales. Growth of energy sales was considerably overestimated, particularly for industrial sales, over the 1962-68 period covered by Loan 313-CO, corresponding to the mistakes in forecast of peak load discussed above. Consequently, EEEB's Operating Income was also substantially overestimated. Performance to date under the last loan (537-CO) has been much better. Total Energy sales have somewhat exceeded the forecast for 1970, as Table II.A-3 shows, and except for bulk sales and commercial sales, above forecast figures were achieved for 1968-70.

VI. Project Construction and Costs

6.01 Once the first loan had been signed, after preconditions for loan consideration had been met as noted above, the delays in the implementation of the Company's expansion program were caused mainly by technical problems arising during the construction of the various projects. Delays which would normally have resulted from disagreements over tariff increases and from local currency shortages seem to have been absorbed by the overwhelmingly larger construction delays.

6.02 In most cases, the construction period of the various generating plants expanded far beyond what had initially been planned. Delays in plant commissioning ranged between one and two years, with the notable exception of the last generating units at El Colegio which came into operation about one-and-a-half years earlier than forecast. Table III gives the forecast and actual commissioning dates for each of the units provided for in the various IBRD loans. The table shows that, excepting the first three units of El Colegio, delays in the construction of thermal plants were not significantly shorter than those connected with hydroplants. The major argument made in favor of introducing thermal units into the system at selected periods, that is the reliability of the commissioning dates, seems therefore to be unsupported by the facts. It should be pointed out, however, that delays on thermal and hydro plants have not occurred for the same reasons. Although information concerning the actual causes of the late commissioning of the first unit at Zipaquira is lacking, it seems that the delay can be generally attributed to the somewhat lengthy negotiations which led to the purchase from the Government of one of the units originally destined for Paipa. The late erection of the second unit at Zipaquira was entirely due to Colombia's cumbersome import licensing procedures.

6.03 In the case of the hydroplants, delays occurred as a result of technical difficulties in the construction of projects or as a consequence of problems which arose in connection with the contractor. These various difficulties encountered in project implementation have led to substantial cost overruns. In this connection, it is worth mentioning that, given the prevailing inflationary conditions of the country, the extension of construction periods has contributed to the rise in local costs. Following are details on delays and cost overruns on the projects financed through the various Bank loans. For each loan, a table shows these details for the various project items. Table III (at the end of the Chapter) shows delays and cost overruns for major components of all projects.

Loan 246-CO

6.04 Actual project costs for this loan are only available for the foreign currency component. Comments on local currency overruns are therefore based solely on information available in Bank files and on conversations held with the Technical Director of EEEB.

6.05 Table 10.1 gives the forecast foreign and local cost of the various items included in the loan as well as the actual foreign currency cost. The table shows that all the generation plants provided for in the loan, as well as the regulatory dam at Guatavita, have suffered cost overruns to varying degrees, at least in the foreign exchange component. Salto II, which was finally completed more than a year behind schedule, had a cost overrun of about 14% on the foreign cost component and an unknown, but probably considerable, overrun on the local component.

6.06 The construction of the Guatavita dam gave rise to some important technical difficulties, resulting in additional high costs 55% above the forecast amount for the foreign component and a probably comparable overrun in the local component. In addition, the construction of the reservoir made it necessary to flood an entire village.

Table 10.1: EEEB - Loan 246 CO - Forecast and Actual Cost of Project

Loan 246 CO	Foreign Exchange Component (US$ million) Forecast	Actual	Overrun	Local Currency Component (US$ million equiv.) Forecast	Actual	Total Cost of Project (US$ million equiv.) Forecast	Actual
Laguneta (unit 4)	0.62	0.68	0.06	0.25	n.a.	0.87	n.a.
Salto II	3.16	3.62	0.46	1.66	n.a.	4.82	n.a.
Zipaquira thermal plant	3.00						
(unit 1)	2.84	3.23	0.39	4.00	n.a.	6.84	n.a.
Guatavita (Tomine) dam	1.72	2.67	0.95	5.44	n.a.	7.16	n.a.
Transmission lines and substations	3.18	2.37	(0.81)	0.21	n.a.	3.39	n.a.
Distribution system	3.86	2.47	(1.39)	0.88	n.a.	4.74	n.a.
Engineering for future expansion	0.21	0.13	(0.08)	0.25	n.a.	0.46	n.a.
Consulting engineers	-	1.13	1.13	-	n.a.	-	n.a.
Interest and other charges during construction	2.11	1.30	(0.81)	-	n.a.	2.11	n.a.
Contingencies	a/	-	-	a/	-	a/	-
Less: Work in Progress	(0.10)	-	0.10			(0.10)	
Total	17.60	17.60		12.69	n.a.	30.29	n.a.

a/ Equipment estimates for Laguneta, Salto, and Zipaquira were based on firm bids and contain no contingencies, but a 16% allowance was made on the remaining items and is included in the project figures.

Source: EEEB
IBRD

EEEB agreed to finance part of the resettlement costs estimated at about Ps 17 million in 1965. The new village, which has been built by an imaginative architect, offers some touristic interest but has apparently failed to recapture the psychological attachment of its population. No contingency allowance for the equipment of the power plants was provided for by the loan because the cost estimates for these items had been based on firm bids. The cost overruns mentioned previously were covered in part by a reduction in the amounts originally allocated to transmission and distribution. These reductions represented about 30% of the loan provision for these items, that is, twice the contingency allowances for them. The remaining overrun was covered by a cut-back on expenditures for future system expansion engineering and by reduced requirements for interest during construction. The various delays encountered in commissioning the generating units provided for in the project resulted in major power shortages between 1960 and 1963.

Loan 313-CO

6.07 The program financed through this loan was probably the most daring ever undertaken by EEEB. The El Colegio section of the Bogota river fall, with a drop of about 1,000 meters (see map at end of this Chapter), was the most difficult to harness. Actual local cost expenditures under the second program are only available for the generating plants, that is the first stage of El Colegio and the second thermal unit at Zipaquira.

6.08 Table 10.2 gives the detail of forecast and actual costs for the various items included in the project. The table shows that the only substantial foreign exchange cost overruns affected the El Colegio hydroplant and the transmission and sub-station installations. These extra costs were covered mainly by the US$ 4.28 million contingency allowance provided for in the loan, by the savings realized on equipment for the second thermal unit and by a cut-back of nearly 20% on the amounts initially allocated to distribution. It should be noted that the provision for transmission and distribution in Loan 313-CO had been calculated in such a way as to include compensation for the cut-backs in these items which took place during the first expansion program. Distributionn was therefore the ultimate victim of cost overruns on the various generating plants and it seems that the company has been mainly concerned with generation and transmission in the past, often at the expense of distribution.

6.09 The cost overruns on El Colegio placed EEEB in a tight financial situation. As mentioned earlier the company had major difficulties in securing funds to cover local cost overruns. These had been badly aggravated by internal inflation which resulted in a 26% domestic price increase. The contribution of local banks to coverage of local costs did not reach the expected level and, in addition, tariff rates were raised much later than expected. At the end of 1965, EEEB requested a third IBRD loan to cover the foreign exchange cost overruns on the project. Eventually the Company arranged additional financing through the Chemical Bank New York Trust Company and the

Table 10.2: EEEB - Loan 313 CO - Forecast and Actual Cost of Project

Loan 313 CO	Foreign Exchange Component (US$ million)			Local Currency Component (US$ million equiv.)			Total Cost of Project (US$ million equiv.)		
	Forecast	Actual	Overrun	Forecast	Actual	Overrun	Forecast	Actual	Overrun
El Colegio I hydro plant	18.03	22.17	4.14	9.73	18.05	8.32	27.76	40.22	12.46
Zipaquira thermal plant (unit 2)	5.53	4.67	(0.86)	1.42	2.81	1.39	6.95	7.48	0.53
Second stage Guatavita dam	0.73	0.77	0.04	0.90	n.a.	n.a.	1.63	n.a.	n.a.
Muna II pumping station	0.73	0.53	(0.20)	0.50	n.a.	n.a.	1.23	n.a.	n.a.
Transmission lines and substations	3.93	5.59	1.66	1.92	n.a.	n.a.	5.85	n.a.	n.a.
Distribution system	4.54	3.69	(0.85)	1.57	n.a.	n.a.	6.11	n.a.	n.a.
Construction equipment	0.50	0.63	0.13	0.04	n.a.	n.a.	0.54	n.a.	n.a.
C.A.R. program	1.70	1.70	-	-	n.a.	n.a.	1.70	n.a.	n.a.
Miscellaneous	0.18	0.14	(0.04)	0.40	n.a.	n.a.	0.58	n.a.	n.a.
Engineering and supervision	4.18 a/	4.44	0.26	1.38	n.a.	n.a.	5.56	n.a.	n.a.
Interest and other charges during construction	5.67	5.67	-	2.30	n.a.	n.a.	7.97	n.a.	n.a.
Physical contingencies	4.28			2.63	-	-	6.91	-	-
Contingencies for price increases	-			1.32	-	-	1.32	-	-
Total	50.00	50.00		24.11	n.a.	n.a.	74.11	n.a.	n.a.

a/ Includes US$3.0 million for local cost of engineering services.

Source: EEEB
IBRD

Central Bank of Venezuela and also obtained rate increases.

6.10 Major delays occurred in the case of CAR rural electrification project. As explained in the first part of this Chapter, the Bank had been reluctant to include a provision in the loan for this item, first of all because it was not an accepted practice of the Bank to finance such projects and, secondly, because the Bank was not satisfied with the type of arrangements finally made between EEEB and CAR regarding their respective responsibilities in the construction and operation of the proposed network. As a result, disbursements for the CAR project were authorized only in mid-1964, that is about two years after Loan 313-CO had been signed. There seems to have been no Bank follow-up on this part of the program.

Loan 537 CO

6.11 EEEB's third expansion program was financed both through a straight Bank loan and joint financing arranged by the Bank, as described before. The only part of the project which has now been completed is the last three units of El Colegio which were commissioned in the first part of 1970, about one year earlier than originally planned. Only US$ 10 million of the US$ 18 million IBRD loan had been disbursed by December 31, 1970 and it is difficult, at this stage, to assess the possible cost overruns (or underruns) on the other elements of the program covered by the loan.

6.12 Complications arose as a result of the joint financing arrangement and this has probably delayed project implementation to a certain extent. The major difficulties encountered resulted from the lack of a clear program for the allocation of funds from the various sources to specific items of the project. Also, each loan included its own set of conditions, often difficult to comply with and involving complicated administrative and legal procedures. The contractual conditions attached to the various loans, especially in the case of the Japanese and German credits, created considerable difficulties when presented to the Congress, for these were sometimes viewed as an infringement upon Colombia's national sovereignty. The current Manager of EEEB has expressed the view that the conditions and terms of loans secured through joint financing tend to be less favorable to the borrower than those arranged through simple bilateral negotiations.

6.13 Table 10.3 gives in detail the forecast project cost and actual disbursement (as of December 31, 1970) of the Bank loan and joint financing. The table demonstrates that the foreign exchange cost of the second stage of El Colegio was slightly lower than expected. Actual local costs were about the same as forecast. Costs for Canoas, which is now more than six months behind schedule, are unlikely to show savings. Operations were slowed down as a result of adverse geological conditions encountered during the construction of the 2,740 meter long pressure tunnel.

VII. Institutional Development

7.01 As related earlier, the juridical autonomy of EEEB was a Bank precondition that was met only after considerable delay. The Board

Table 10.3: EEEB - Loan 537 CO - Forecast and Actual Cost of Project

Loan 537 CO	Foreign Exchange Component[a] (US$ million)			Local Currency Component (US$ million equiv.)			Total Cost of Project (US$ million equiv.)		
	Forecast	Actual[b]	Overrun	Forecast	Actual[b]	Overrun	Forecast	Actual[b]	Overrun
El Colegio II hydroplant	6.78	6.56	(0.22)	1.47	1.56	0.09[b]	8.24	8.12	
Canoas hydroplant	4.91	3.99		3.92	2.57		8.83	5.96	
Transmission lines and substations	5.99	1.41		2.15	1.84		8.14	3.25	
Distribution system and street lighting	5.24	4.61		1.58	1.39		6.82	6.00	
Engineering services	0.19	0.18		2.30	1.74		2.49	1.92	
Physical contingencies									
- for El Colegio II	0.61			0.14			0.75		
- for Canoas	0.83			0.79			1.62		
- for transmission	0.24			0.12			0.36		
- for distribution	0.21			0.09			0.30		
Contingencies for price increases									
- for El Colegio II	-			0.25			0.25		
- for Canoas	-			0.91			0.91		
- for transmission	-			0.32			0.32		
- for distribution	-			0.24			0.24		
Total	25.00	16.75[b]		14.28	9.10[b]		39.28	25.25[b]	

a/ Actual figures include disbursements from joint-financing.
b/ As of December 31, 1970

Source: EEEB
IBRD

of Directors was made up of seven members, four representing the local banks which financed the city's acquisition of the previous company, and three, including the Mayor, representing the City Council. As this arrangement was due to expire in 1968, and the Bank was concerned that the company might then fall entirely under the control of the City Council, a new agreement was reached. It provided for the election in the same year of a Board of Directors composed of the Mayor of Bogota, two members elected by the City Council, one appointed by the President and three selected from lists of nominees submitted to the City Council by the Manufacturers Association, the Merchants Association and the Bankers Association. The functions of the Board, defined in the Charter of EEEB, cover an important range of questions and the Board has considerable power on many important management decisions.

7.02 Although at the time of negotiating the first loan (246-CO) EEEB was considered a well managed organization, the Bank had some concern over its financial management, particularly its auditing and accounting system. This was improved after hiring the services of external auditors, in conformity with Loan Agreement 246-CO. Of greater concern to the Bank at that time was the low level of tariffs which, in spite of a 24.8% increase in 1959, was unlikely to keep the Company solvent. As mentioned earlier, loan effectiveness was made contingent on a further rate increase.

7.03 In negotiating the second loan, covering the major part of EEEB's expansion program, the Bank focused on the need for some financial reorganization and on problems of financial planning, particularly cash flow projections, which had been one of the causes of cash shortages. As a result, the Bank sought and obtained the creation of a Financial Department (1963) and, after much pressure, the strengthening of financial management through the hiring of a senior financial executive (1964); this was made a condition of the second loan (313-CO). Nevertheless, as related earlier, the company did suffer severe cash shortages during the 1962-65 period. The shortage, causing the expansion of EEEB's distribution system to be delayed, was due to large local cost overruns, failure to obtain tariff increases sufficient to meet the company's cash requirements, severe difficulties of local borrowing and inadequate foresight as to cash needs. Responsibility for failure to enact timely tariff increases reflects only partly on inadequate financial management, since there were considerable political and bureaucratic obstacles to bringing about tariff increases periodically as needed. Subsequent to discussions with the Government in 1965 and after, it was agreed in connection with the third loan (537-CO, 1968) that rate increases would be given when necessary to maintain a nine percent rate of return. So far, this agreement continues to be effective. One aspect of this agreement, important also in connection with other Bank lending to public utilities in Colombia, was introduction of the rate of return concept, based on revaluation of assets, as the guiding criteria for making and adjusting tariffs.

7.04 The Bank also recommended and obtained that a Commercial Department be created in order to enable the company to realistically calculate sales projections and to meet them. In 1968 the company established an Operations Department, and a Department of Planning was set up under the Technical Management. EEEB's administrative structure has evolved from one in which management was highly centralized and personalized to one which makes more use of committees and allows greater, although still limited, participation in management decisions. Management reporting is generally adequate, but weak in financial coverage of some areas where budgeting is still weak. The Engineering Department continues to be understaffed due to the company's heavy reliance on the consulting firm of Ingetec.

Efficiency of Operations

7.05 EEEB has shown positive trends in efficiency of operations and this is partially illustrated by the figures in Table 10.4 which follows. Energy sales per employee have nearly doubled between 1960 and 1970. Operating costs (in real terms) per unit generated have fluctuated considerably from year to year and shown no particular trend. As the table indicates, the initial effect of the introduction of the large new generating units in 1962-63 and 1967 was to drive up average costs -- mainly due to the large increase in depreciation provisions required when these units were transferred to assets in operation. It is somewhat surprising that unit costs in real terms have not shown any significant downward trend over the long run. System energy sales in 1970, at 2033 GWh, were more than six times the 1955 level, and the units and stations generating most of the energy are larger than those in use in 1955; yet, unit operating costs were about

Table 10.4

EEEB: Trends in Efficiency of Operations

	1951	1955	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970
Average Revenues per per kwh (1968 centavos)	22.6	19.7	18.3	17.6	21.2	17.9	15.4	17.8	16.8	19.8	18.0	17.1	15.7
Average Operating costs[a/] per kwh (1968 centavos)	12.1	8.2	7.5	8.9	9.3	10.9	9.9	10.5	10.2	12.0	9.8	9.3	8.3
Sales (GWh)	200	322	606	625	677	783	909	1027	1117	1247	1453	1690	2033
No. of Employees	n.a.	n.a.	864	929	1026	1133	1201	1307	1410	1442	1443	1511	1530
Sales per Employee (GWh)	n.a.	n.a.	0.70	0.67	0.66	0.70	0.76	0.79	0.79	0.86	1.01	1.12	1.33

a/ All production, maintenance, administration, fuel, purchased energy and revalued depreciation costs but excluding direct taxation and interest charges.

Sources: Calculations based upon information supplied by EEEB.

the same, at just over 8 centavos (of 1968 value) per kwh. Some of the potential scale-economies from the expansion may have been compensated by the fact that the later sites to be exploited (especially El Colegio) were more difficult. But available data is too inadequate to be clear as to how unit capital costs of generation expansion have changed over time; it is not clear that they have increased, and there is some indication they may have fallen. As regards operating costs and administration one would expect to find significant economies of scale resulting from such a large growth. But none are apparent, except in the form of rising sales per employee. It may well be that the advantages of the system's great increase in scale have been taken more in the form of improved quality of service -- quality of distribution and infrequency of outage -- rather than in lower unit costs of supply. In other words, even though the cost of a kwh today is about the same as in 1955 (in real terms) it may be a more reliable kwh, with better voltage regulation, etc.

7.06 In sum, it may be said that EEEB's financial position has clearly strengthened over the last ten years, during which the company has accomplished a very large investment program, totalling nearly US$ 160 million equivalent. The company has also kept up relatively well with the growth of demand since 1962. Unit costs, if they have not fallen, at least have not increased.

VIII. Conclusion

8.01 The Bank has been a major contributor to EEEB's expansion program. Through three loans concluded between 1960 and 1970 and amounting to a total of US$ 85.60 million, the Bank has helped finance about 80% of EEEB's current generating capacity. 98% of residences in Bogota, the main service area of EEEB, are believed to be connected to EEEB's power system, and power supply is generally of good quality.

8.02 The Bank has played a relatively minor, though significant, role in helping to define the actual development program of EEEB. Due to the existence of a few especially attractive hydroelectric sites only 20 km west of the city, there were limited practical alternatives available for system expansion. The Bank brought two substantial modifications in EEEB's development programs: the first was persuading the Government to cut back on the so-called Paipa thermal project which was found economically unjustified; the second called for deferral of the Canoas hydroelectric plant in favor of early construction of the more flexible thermal unit (Zipaquira 2), mainly because Canoas was believed to have a high local cost component which the Bank could not finance (as opposed to the high foreign cost of Zipaquira 2 which the Bank could finance) and which it would be difficult to cover locally in view of the deficient Colombian capital market and EEEB's own cash shortage. Installation near Bogota of the unit originally designated for Paipa appears to have been a wise move. On the other hand a comparative analysis of Canoas and Zipaquira 2 suggests that the choice of a further thermal unit was not economically sound. Thus serious errors in load forecasting, a deficient local market, the Bank's inability to cover local costs and the Bank's emphasis on financial criteria led to selection of what appears in retrospect to have been the less attractive alternative.

8.03 The construction program has experienced substantial delays, ranging normally between one and two years, on the generating units, as well as cost overruns for both thermal and hydroelectric plants. In one case, Salto II, mediocre performance on the part of contractors hampered the progress of project implementation. Price increases on imported equipment and internal inflation of prices and wages aggravated construction problems. Expanded construction periods resulted in major cost overruns both in local currency and foreign exchange, as seen earlier, especially in connection with the generation plants. These overruns were partly covered by diverting some of the funds originally allocated to the modernization and expansion of sub-transmission and distribution networks. This has contributed to maintain a fairly high level of distribution losses for such a compact system, including losses from stolen energy, and has probably hindered the expansion of electrification into neighboring rural areas. As distribution works were allowed to become victim of cost overruns, it appears that the Bank had perhaps placed too much emphasis on merely satisfying itself that the plants it financed would be used at reasonable capacity factors and given too little attention to the consequences of inadequate distribution expansion.

8.04 The Bank has exerted sustained pressure for the financial viability of EEEB, during the thirteen years of close association with it, mainly by means of increased tariff rates. (The tariff structure did not receive any attention from the Bank -- a point taken up at some length in Chapter XVI). The Bank also helped arrange local financing for EEEB and it also secured foreign financing for the third loan. But the Bank's emphasis was on internal generation of cash to cover local currency needs. This was stipulated in tariff covenants providing that EEEB would maintain tariffs high enough to generate internally about 40% of total funds required for investment. Specific multi-year periods were established over which this 40% self-financing rate was to be accomplished. It was not reached, for a variety of reasons -- cost overruns, inflation, difficulty of obtaining Government approval for tariff increases, construction delays. In retrospect, in view of the very large investment programs being initiated and the mistakes made on cost estimates, the self-financing rates aimed at may have been too high, and problems might have been less if better preparation had been made for finding other sources of funds. Anyway the multi-year self-financing rate proved a rather ineffective test for operational purposes, as well as being of dubious economic validity, and it was abandoned in the late 1960s, to be replaced with a concept of rate of return on revalued assets. This covenant appears to have been adhered to by EEEB in the last two years. The Bank has also helped EEEB to improve financial planning and financial management in general. It is hoped that these improvements would enable EEEB to run its operation and future expansions more efficiently. EEEB's gains in this respect should also help to facilitate the effective functioning of the interconnected system which the Bank helped to create and for which it pressed EEEB to become a major participant, for the benefit of the power sector in Colombia.

COLOMBIA: EMPRESA DE ENERGIA ELECTIRCA DE BOGOTA (EEEB)

TABLE I

OPERATIONS	Unit	1950	1951	1952	1953	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	Average Annual Increase Rate(%) 1950/60	1960/65	1965/70
1. Installed capacity (year end) of which:	MW	46.0	46.0	66.0	66.0	74.0	74.0	74.0	128.0	128.0	128.0	128.0	146.0	146.0	245.0	282.5	285.5	287.5	437.5	437.5	437.5	587.5	10.8	17.4	15.5
Hydro a/	MW	39.6	39.6	59.6	59.6	59.6	59.6	59.6	113.6	113.6	113.6	113.6	131.6	131.6	197.6	197.6	200.6	202.6	352.6	352.6	352.6	502.6	11.1	12.0	20.0
Thermal	MW	6.4	6.4	6.4	6.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	47.4	84.9	84.9	84.9	84.9	84.9	84.9	84.9	8.4	43.0	0
Total as % of total in country b/	%	19.1	17.6	20.0	19.4	19.5	16.8	15.0	21.6	20.2	19.5	19.1	21.3	17.2	23.6	25.3	22.0	20.2	26.0	24.5	23.0	28.3			
2. Peak demand	MW	44.1	45.8	54.7	61.4	68.6	70.4	76.6	100.6	113.5	129.0	129.2	147.6	152.7	200.1	224.9	243.5	266.8	304.6	347.1	422.8	479.0	11.3	13.5	14.5
3. Gross reserves	MW	1.9	0.2	11.3	4.6	5.4	3.6	-2.6	27.4	14.5	-1.0	-1.2	-1.6	-6.7	57.6	47.6	42.0	20.7	132.9	90.4	14.7	108.5			
Gross reserves as % of peak demand	%	4.3	0.4	20.7	7.5	7.9	5.1	-3.4	27.2	12.8	-0.8	-0.9	-1.1	-4.4	22.4	25.6	17.2	7.8	43.6	26.0	3.5	22.7			
4. Effective peak spare capacity c/	MW	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	-9.8	-22.8	9.5	18.4	5.0	n.a.			
5. Generation sent out	GWh	215.50	230.30	249.80	290.50	328.80	366.7	400.60	441.10	526.20	593.10	689.50	706.70	761.70	873.10	982.20	1085.20	1218.70	1383.70	1629.70	1920.70	2270.60	12.4	9.5	15.9
6. Net purchases from (sales to) other systems d/	Gwh	n.a.	n.a.	n.a.	n.a.	nn.a.	n.a.	n.a.	n.a.	n.a.	n.a.	11.5	12.1	9.8	25.0	28.0	48.3	44.3	18.5	(65.6)	(132.9)	(261.3)			
7. Total sales to customers	GWh	182.04	200.08	210.44	249.30	287.15	321.70	353.30	394.10	467.00	516.90	605.80	625.30	676.90	783.10	909.10	1027.40	1117.40	1246.80	1452.70	1689.80	2032.80	12.8	11.1	14.7
8. Number of Customers	000's	70.77	75.22	79.79	83.86	89.03	95.93	101.30	107.41	115.85	125.84	130.82	149.65	160.11	173.21	191.01	206.74	220.06	234.84	246.68	263.55	284.72	6.3	9.6	6.6
9. Number of employees	No.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	804	864	929	1026	1133	1201	1307	1410	1422	1443	1511	1530	n.a.	8.6	3.3
FINANCE																									
10. Sales revenues (current prices)	Ps. mln	8.26	9.39	10.91	12.75	12.70	15.58	17.55	20.36	23.59	27.12	44.93	48.92	67.35	81.19	93.93	134.77	159.13	226.02	261.31	313.46	379.21	9.7	10.7	11.5 n/
11. Operating costs e/ (current prices)	Ps. mln	4.93	5.02	5.10	5.31	5.24	6.16	7.93	9.30	11.19	14.89	15.74	21.18	26.15	40.73	51.78	66.78	79.50	118.26e/	130.99e/	156.41e/	179.69i/	4.0	11.9	17.0 n/
12. Average revenue/kwh sold (current prices)	Ps.	0.05	0.05	0.05	0.05	0.04	0.05	0.05	0.05	0.05	0.05	0.07	0.08	0.10	0.10	0.10	0.13	0.14	0.18	0.18	0.19	0.19	5.1	10.6	7.3
13. Average revenue/kwh sold (constant 1968 prices)	Ps.	0.24	0.23	0.25	0.23	0.18	0.20	0.19	0.17	0.15	0.14	0.18	0.18	0.21	0.18	0.15	0.18	0.17	0.20	0.18	0.17	0.16	2.7	-0.5	-2.6
14. Average cost/kwh sold based on revalued assets (constant 1968 prices) f/	Ps.	n.a.	0.13	0.12	0.10	0.08	0.08	0.09	0.09	0.09	0.09	0.08	0.09	0.09	0.11	0.10	0.10	0.10	0.13	0.11	0.11	0.09	n.a.	6.7	-3.7
15. Average revenue/kwh sold	US¢ m/	1.51	1.42	1.54	1.45	1.13	1.23	1.17	1.04	0.92	0.87	1.14	1.11	1.33	1.12	0.96	1.12	0.05	1.24	1.13	1.07	0.98	-2.7	-0.5	-2.5
16. Average cost/kwh sold	USØ m/	n.a.	0.78	0.75	0.63	0.49	0.51	0.55	0.56	0.53	0.56	0.47	0.55	0.57	0.66	0.60	0.65	0.65	0.81	0.69	0.66	0.59	n.a.	7.0	-4.0
17. Net revenues from electricity sales in current prices (10-11)	Ps. mln	3.33	4.37	5.81	7.51	7.46	9.42	9.62	11.06	12.40	12.23	29.19	27.74	41.20	40.46	42.15	67.99	79.63	107.76	130.32	157.04	199.52	15.0	5.1	12.4 n/
18. Net revenues in current prices based on revalued assets	Ps. mln	3.33	4.20	5.61	7.20	7.15	9.09	9.25	9.42	9.85	9.63	26.40	24.48	37.80	31.65	33.45	55.65	62.37	88.26	118.22	141.98	178.76	13.9	3.1	14.4 n/
19. Gross fixed investments in current prices	Ps. mln	n.a.	3.09	6.84	4.83	16.85	20.59	23.88	24.95	18.72	14.93	44.13	102.54	163.34	227.34	200.43	154.44	128.20	66.54	178.26	222.39	197.53		28.0	5.1
20. Gross fixed investments in 1968 prices	Ps. mln	n.a.	14.89	32.49	21.88	68.58	83.80	89.13	80.34	53.16	39.86	108.56	232.77	347.91	393.30	298.64	210.04	151.28	72.53	260.26	261.64	245.73		14.1	3.2
21. Average net fixed assets in operation	Ps. mln	n.a.	26.07	29.83	33.19	33.65	35.18	36.24	40.69	77.24	113.32	120.36	136.67	154.59	238.30	320.64	434.17	541.73	749.59l/	969.83l/	994.84l/	1107.79i/			
MANAGEMENT INDICATORS																									
22. Rate of return on electricity sales (17 as % of 21)																									
1. Non-revalued net fixed assets	%	n.a.	16.8	19.5	22.4	22.2	26.8	26.5	27.2	16.0	10.8	24.3	20.3	26.7	17.0	13.2	15.7	14.7	15.6	15.0	17.5	19.9			
2. Revalued net fixed assets	%	n.a.	14.0	16.5	18.8	17.8	22.0	21.6	13.5	8.3	6.1	15.7	13.0	18.0	9.1	7.4	9.1	7.1	7.8	8.1	9.0	9.9			
23. Financial rate of return g/																									
1. Non-revalued net fixed assets	%	n.a.	16.3	25.0	28.0	27.4	37.3	37.8	41.2	24.1	16.0	29.3	27.8	32.1	21.9	17.3	18.2	16.6	16.7	15.8	18.9	21.9			
2. Revalued net fixed assets	%	n.a.	13.6	21.4	23.6	22.1	30.9	31.1	21.6	13.4	9.7	19.3	18.4	22.0	12.4	10.3	10.9	8.3	8.5	8.6	9.9	11.1			
24. Self-financing rate h/	%	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	34.4	19.8	11.4	14.7	15.1	17.7	119.6	33.5	52.3	66.1			
25. Debt service coverage i/	Times	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	5.1x	2.4x	1.7x	1.8x	1.4x	1.3x	2.0x	1.5x	2.0x	1.9x			
26. Debt/Equity ratio	/	n.a.	n.a.	n.a.	n.a.	n.a.	18/72	25/75	27/73	21/79	19/81	24/76	32/68	51/49	58/42	61/39	58/42	57/43	67/33	66/34	63/37	61/39			
27. Energy sales per employee	MWh	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	642.91	701.16	673.09	659.75	691.17	756.95	786.07	792.48	864.63	1006.72	1118.33	1320.00		2.3	11.0
28. Distribution and transmission losses j/	%	15.5	13.1	15.7	14.2	12.6	12.2	11.8	10.6	15.3	12.8	12.1	11.5	11.1	10.3	7.4	5.3	8.2	9.8	10.8	12.0	10.9			
29. Average capacity out of service as % of installed capacity k/	%	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	7.5	3.8	7.2	10.2	3.3	12.3			
30. EEEB's investment as % of gross fixed investment in country	%	n.a.	0.2	0.3	0.2	0.5	0.6	0.6	0.8	0.5	0.4	0.9	1.8	2.65	3.25	2.2	1.65	1.0	0.5	1.5	1.5	n.a.			
31. Accounts receivable as % of total sales	%	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	12.2	11.6	11.1	14.3	18.6	17.5			

* Financial calculation carried out in this table do not account for revaluation of assets except where specified.
a/ Includes generating capacity of pumping stations at Sesquile (3MW since 1965) and Muna II (2MW since 1966.)
b/ Does not include captive plants.
c/ Effective peak = Peak load at the critical time in the year when margin between demand and available capacity is minimum or load shedding maximum (excluding short-term outages).
d/ Energy EEEB purchased from (or sold to) Paipa, Sueva, Tolima, Girardot, and CVC/Chidral systems. excluding bulk sales to customers.
e/ Including depreciation but excluding interest and direct taxation.
f/ Revaluation of assets computation is treated in further detail in Annex I.
g/ Net revenues after taxes as % of average net fixed assets in operation.
h/ Net internal cash generation as % of Gross Fixed Investment.
i/ Times debt service was covered by operating income and depreciation.
j/ Generation sent out (net of sales to or purchases from other systems) less sales to EEEB's customers, as % of generation sent out (net of sales to or purchases from other systems.)
k/ Capacity out of service for maintenance and repairs.
l/ Excluding company's own revaluation for changes in exchange rate.
m/ Converted from 1968 pesos to dollars at the 1968 exchange rate of Ps. 15.9 = US $1.00.

SOURCE: EEEB

TABLE II-A.1

COLOMBIA: EMPRESA DE ENERGIA ELECTRICA DE BOGOTA (EEEB)
Loan 246-CO (Jan., 1960)

		1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	Average Annual Increase Rate (%) 1959-1968
	LOAD FORECASTS (MW) a/											
1.	Installed Capacity	128.0	146.0	212.0	245.0	285.0	310.0	372.0	372.0	434.0	539.0	17.4
2.	Annual Peak Demand	127.0	141.0	150.0	205.0	236.0	263.0	291.0	318.0	348.0	380.0	12.9
3.	Gross Reserve Capacity (1-2)	1.0	5.0	62.0	40.0	49.0	47.0	81.0	54.0	86.0	159.0	7.5
	ACTUAL LOAD (MW)											
4.	Installed Capacity	128.0	128.0	146.0	146.0	245.0	282.5	285.5	287.5	437.5	437.5	14.6
5.	Annual Peak Demand	129.0	129.2	147.6	152.7	200.1	224.9	243.5	266.8	304.6	347.1	11.7
6.	Gross Reserve Capacity (4-5)	-1.0	-1.2	-1.6	-6.7	44.9	57.6	42.0	20.7	132.9	90.4	15.0 j/
7.	Effective Peak Capacity b/	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	234.3	237.0	274.5	365.5	16.0 k/
8.	Effective Peak Demand b/	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	244.1	259.8	265.0	347.1	12.4 k/
9.	Effective Peak Spare Capacity (7-8)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	-9.8	-22.8	9.5	18.4	
	LOAD FORECAST ACCURACY c/											
10.	Installed Capacity	100	114	145	167	116	109	130	129	99	123	
11.	Annual Peak Demand	98	109	101	134	118	116	119	119	114	109	
12.	Gross Reserve Capacity	-	-	-	-	108	81	192	259	65	176	
	SALES FORECASTS (Gwh) a/											
13.	Residential Sales	154.3	178.9	206.0	248.0	295.0	n.a.	n.a.	n.a.	n.a.	n.a.	17.6 l/
14.	Industrial Sales	161.1	184.0	204.0	244.0	277.0	n.a.	n.a.	n.a.	n.a.	n.a.	14.5 l/
15.	Commercial Sales	134.0	147.5	166.5	196.0	232.0	n.a.	n.a.	n.a.	n.a.	n.a.	14.7 l/
16.	Others	63.6	66.6	72.5	77.0	83.0	n.a.	n.a.	n.a.	n.a.	n.a.	6.9 l/
17.	Total d/	513.0	577.0	649.0	765.0	887.0	1010.0	1140.0	1275.0	1425.0	1580.0	13.3 l/
	ACTUAL SALES (Gwh)											
18.	Residential Sales	144.2	164.3	175.1	191.1	228.0	262.4	307.1	336.9	385.8	437.6	13.2
19.	Industrial Sales	159.0	186.4	194.3	216.5	253.0	300.2	342.7	370.1	397.4	449.4	12.2
20.	Commercial Sales	129.8	148.1	148.0	157.5	175.9	200.3	217.5	229.3	237.4	256.6	7.8
21.	Official Sales	43.5	53.8	55.3	64.9	74.2	83.7	89.6	90.7	118.9	131.1	13.1
22.	Public Lighting Sales	19.3	25.4	28.6	31.8	35.2	40.0	42.0	43.9	45.8	56.0	12.6
23.	Bulk Sales	21.0	27.7	24.0	15.2	16.8	22.5	28.4	46.9	62.5	122.0	21.0
24.	Total Sales	516.8	605.7	625.3	677.0	783.1	909.1	1027.3	1117.8	1246.8	1452.7	12.2
	SALES FORECAST ACCURACY c/											
25.	Total Sales	99	95	103	112	113	111	111	114	114	108	
	RETURN FORECASTS (Col.Pesos mln.) a/											
26.	Operating Revenues e/	32.5	49.7	57.6	82.5	94.7	107.0	118.8	132.2	147.0	160.8	19.4
27.	Less: Operating Costs f/	16.7	19.6	22.5	30.3	34.3	41.0	47.0	53.0	56.2	62.4	15.8
28.	Operating Income	15.8	30.1	35.1	52.2	60.4	66.0	71.8	79.2	90.8	98.4	23.0
29.	Financial Rate of Return on Av. Net Fixed Assets in Operation g/ (Non-revalued Assets) (%)	13.8	24.7	19.8	17.0	13.8	12.6	10.5	9.6	10.5	11.1	
	ACTUAL RETURN (Col. Pesos Mln.) h/											
30.	Operating Revenues e/	34.4	50.1	53.5	62.1	62.0	61.1	76.8	77.4	97.4	103.0	13.0
31.	Less: Operating Costs f/	16.6	17.7	21.1	22.5	28.1	30.3	37.0	37.6	50.3	51.5	13.4
32.	Operating Income	17.8	32.4	32.4	39.6	33.9	30.8	39.8	39.8	47.1	51.5	12.5
33.	Financial Rate of Return on Av. Net Fixed Assets in Operation g/											
	(1) Non-revalued Assets (%)	15.8	29.3	27.8	32.1	21.9	17.3	18.2	16.6	16.7	18.8	
	(2) Revalued Assets (%) i/	9.7	19.3	18.4	22.0	12.4	10.3	10.9	8.3	8.5	8.6	
	FORECAST ACCURACY c/											
34.	Operating Revenue	94	99	107	133	152	175	154	171	151	156	
35.	Operating Costs	100	110	106	134	122	135	127	141	111	121	
36.	Operating Income	88	93	108	131	178	214	180	200	192	191	

a/ Source - IBRD Appraisal Reports.
b/ Effective Peak = peak load at the critical time in the year when the margin between demand and available capacity was minimum, or load shedding maximum (excluding short term outages).
c/ Defined by the ratio Forecast/Actual.
d/ Beyond 1963, total sales were forecast to increase at an average rate of approximately 12% per annum.
e/ Total Revenues, excluding indirect taxes.
f/ Including depreciation and direct taxation (provision of 10% of net income for public lighting in Bogota), but excluding interest payments.
g/ Net revenues after taxes as % of average net fixed assets in operation.
h/ All current pesos have been converted to 1959 constant Pesos for the purpose of comparison with the 1959 Loan 246-CO Appraisal Report Forecasts, using the national GDP deflator.
i/ Revaluation of assets computations as calculated by IBRD in Annex I.

j/ Average annual increase rate for 1963-1968.
k/ Average annual increase rate for 1965-1968.
l/ Average annual increase rate for 1959-1963.

Sources: EEEB
IBRD

COLOMBIA: EMPRESA DE ENERGIA ELECTRICA DE BOGOTA (EEEB)
Loan 313-CO (May 1962)

TABLE II-A.2

		1962	1963	1964	1965	1966	1967	1968	Average Annual Increase Rate (%) 1962-1968
	LOAD FORECASTS (MW) a/								
1.	Installed Capacity	245.0	278.0	278.0	428.0	428.0	428.0	428.0	9.8
2.	Annual Peak Demand	176.0	233.0	292.0	336.0	367.0	405.0	444.0	16.7
3.	Gross Reserve Capacity (1-2)	36.0	12.0	-14.0	42.0	61.0	23.0	-16.0	
	ACTUAL LOAD (MW)								
4.	Installed Capacity	146.0	245.0	282.5	285.5	287.5	437.5	437.5	20.0
5.	Annual Peak Demand	152.7	200.1	224.9	243.5	266.8	304.6	347.1	14.6
6.	Gross Reserve Capacity (4-5)	-6.7	44.9	57.6	42.0	20.7	132.9	90.4	15.0 i/
7.	Effective Peak Capacity b/	n.a.	n.a.	n.a.	234.3	237.0	274.5	365.5	16.3 j/
8.	Effective Peak Demand b/	n.a.	n.a.	n.a.	244.1	259.8	265.0	347.1	12.4 j/
9.	Effective Peak Spare Capacity (7-8)	n.a.	n.a.	n.a.	-9.8	-22.8	9.5	18.4	
	LOAD FORECAST ACCURACY c/								
10.	Installed Capacity	167	134	98	150	149	98	98	
11.	Annual Peak Demand	115	116	130	138	138	133	128	
12.	Reserve Capacity	-	27	-	100	295	17	-	
	SALES FORECAST (Gwh) a/								
13.	Residential Sales	187.0	225.0	300.0	365.0	416.0	469.0	525	18.8
14.	Industrial Sales	228.0	324.0	424.0	480.0	530.0	585.0	645	19.0
15.	Commercial Sales	157.0	188.0	213.0	230.0	250.0	272.0	293	10.9
16.	Official Sales	59.0	69.0	76.0	82.0	86.0	90.0	95	8.3
17.	Public Lighting	28.0	31.0	35.0	39.0	43.0	47.0	52	10.8
18.	Bulk Sales	24.0	38.0	52.0	68.0	73.0	83.0	83	23.0
19.	Total Sales	683.0	875.0	1100.0	1264.0	1398.0	1541.0	1693	16.3
	ACTUAL SALES (Gwh)								
20.	Residential Sales	191.1	228.0	262.4	307.1	336.9	385.8	437.6	14.8
21.	Industrial Sales	216.5	253.0	300.2	342.7	370.1	397.4	449.4	13.0
22.	Commercial Sales	157.5	175.9	200.3	217.5	229.3	237.4	256.6	8.5
23.	Official Sales	64.9	74.2	83.7	89.6	90.7	118.9	131.1	12.4
24.	Public Lighting Sales	31.8	35.2	40.0	42.0	43.9	45.8	56.0	9.9
25.	Bulk Sales	15.2	16.8	22.5	28.4	46.9	62.5	122.0	42.0
26.	Total Sales	677.0	783.1	909.1	1027.3	1117.8	1246.8	1452.7	13.6
	SALES FORECAST ACCURACY c/								
27.	Residential Sales	96	99	114	119	123	122	120	
28.	Industrial Sales	105	128	141	140	143	147	143	
29.	Commercial Sales	100	107	106	106	109	115	114	
30.	Official Sales	91	93	91	92	95	76	72	
31.	Public Lighting Sales	88	88	88	93	98	103	99	
32.	Bulk Sales	158	226	231	239	156	133	68	
33.	Total Sales	101	112	121	123	125	124	116	
	RETURN FORECAST (Col. Pesos mln) a/								
34.	Operating Revenues d/	76.0	99.0	122.5	139.6	144.0	159.0	174.0	14.8
35.	Less: Operating Costs e/	26.5	39.8	51.6	60.3	62.1	66.9	73.0	18.4
36.	Operating Income	49.5	59.2	70.9	79.3	81.9	92.1	101.0	12.7
37.	Financial Rate of Return on Av. Net Fixed Assets in Operation (Non-revalued Assets) f/	35.1	22.0	15.4	11.7	10.0	11.0	11.7	
	ACTUAL RETURN (Col. Pesos mln) g/								
38.	Operating Revenues d/	73.0	72.8	78.0	90.3	91.2	114.7	121.3	8.9
39.	Less: Operating Costs e/	26.5	33.1	35.7	43.5	44.2	59.2	60.6	14.8
40.	Operating Income	46.5	39.7	36.2	46.7	47.0	55.4	60.6	4.5
41.	Financial Rate of Return on Av. Net Fixed Assets in Operation f/								
	(1) Non-revalued Assets (%)	32.1	21.9	17.3	18.2	16.6	16.7	15.8	
	(2) Revalued Assets (%) h/	22.0	12.4	10.3	10.9	8.3	8.5	8.6	
	RETURN FORECAST ACCURACY								
42.	Operating Revenue	104	136	157	154	158	138	143	
43.	Operating Costs	100	120	144	138	140	113	120	
44.	Operating Income	106	149	196	170	174	166	166	

a/ Source - IBRD Appraisal Reports.
b/ Effective Peak = peak load at the critical time in the year when the margin between demand and available capacity was minimum, or load shedding maximum (excluding short term outages).
c/ Defined by the ratio Forecast/Actual.
d/ Total revenues excluding indirect taxes.
e/ Including depreciation and direct taxation (provision of 10% of net income for public lighting in Bogota), but excluding interest payments.
f/ Net revenues after taxes as % of average net fixed assets in operation.
g/ All current pesos have been converted to 1961 constant pesos for the purpose of comparison with the 1961 Loan 313-CO Appraisal Report forecast, using the national GDP deflator.
h/ Revaluation of assets computations as calculated by IBRD in Annex I.

i/ Average annual increase rate for 1963-1968.
j/ Average annual increase rate for 1965-1968.

TABLE II-A.3

COLOMBIA: EMPRESA DE ENERGIA ELECTRICA DE BOGOTA (EEEB)
Loan 537-CO (June, 1968)

	1968	1969	1970	Average Annual Increase Rate (%) 1968-1970	
LOAD FORECASTS (MW) a/					
1. Installed Capacity	456.0	456.0	456.0	0	
2. Annual Peak Demand	336.0	403.0	452.0	16.0	
3. Gross Reserve Capacity (1-2)	120.0	53.0	4.0		
ACTUAL LOAD (MW)					
4. Installed Capacity	437.5	437.5	587.5	16.0	
5. Annual Peak Demand	347.1	422.8	479.0	17.6	
6. Gross Reserve Capacity (4-5)	90.4	14.7	108.5	5.9	
7. Effective Peak Capacity b/	365.5	427.8	n.a.		
8. Effective Peak Demand b/	347.1	422.8	n.a.		
9. Effective Peak Spare Capacity (7-8)	18.4	5.0	n.a.		
LOAD FORECAST ACCURACY c/					
10. Installed Capacity	104	104	78		
11. Annual Peak Demand	97	95	94		
12. Reserve Capacity	133	361	4		
SALES FORECAST (Gwh)					
13. Residential Sales	422.0	475.0	533.0	12.4	
14. Industrial Sales	422.0	476.0	537.0	12.9	
15. Commercial Sales	260.0	288.0	319.0	10.8	
16. Official Sales	130.0	144.0	161.0	11.3	
17. Public Lighting Sales	52.0	60.0	67.0	13.5	
18. Bulk Sales	144.0	280.0	317.0	48.0	
19. Total Sales	1430.0	1723.0	1934.0	16.3	
ACTUAL SALES (Gwh)					
20. Residential Sales	437.6	493.0	566.5	13.8	
21. Industrial Sales	449.4	493.7	569.5	12.5	
22. Commercial Sales	256.6	286.2	292.9	6.8	
23. Official Sales	131.1	156.7	182.0	17.7	
24. Public Lighting Sales	56.0	70.7	78.0	18.0	
25. Bulk Sales	122.0	206.7	344.1	70.0	
26. Total Sales	1452.0	1839.8	2033.0	18.7	
SALES FORECAST ACCURACY c/					
27. Residential Sales	96	96	94		
28. Industrial Sales	94	96	94		
29. Commercial Sales	101	101	109		
30. Official Sales	99	92	88		
31. Public Lighting Sales	93	85	86		
32. Bulk Sales	118	135	92		
33. Total Sales	98	102	95		
RETURN FORECAST (Col. Pesos mln)					
34. Operating Revenues d/	260.7	303.5	337.9	13.9	
35. Less: Operating Costs e/	127.5	145.8	153.2	9.6	
36. Operating Income	133.2	157.7	184.7	17.7	
37. Financial Rate of Return on Av. Net Fixed Assets in Operation (Non-revalued Assets) f/	7.4	8.8	10.1		
ACTUAL RETURN (Col. Pesos mln) h/					
38. Operating Revenues d/	275.4	336.0	413.3	23 i/	11.5 j/
39. Less: Operating Costs e/	137.7	165.0	191.8	18 i/	7.6 j/
40. Operating Income	137.7	171.0	221.5	27 i/	15.4 j/
41. Financial Rate of Return on Av. Net Fixed Assets in Operation f/					
(1) Non-revalued Assets	15.8	18.9	21.9		
(2) Revalued Assets g/	8.6	9.9	11.0		
RETURN FORECAST ACCURACY c/					
42. Operating Revenues	94	90	82		
43. Operating Costs	92	88	80		
44. Operating Income	96	92	83		

a/ Source - IBRD Appraisal Reports.
b/ Effective Peak = peak load at the critical time in the year when the margin between demand and available capacity was minimum, or load shedding maximum (excluding short term outages).
c/ Defined by the ratio Forecast/Actual.
d/ Total revenues excluding indirect taxes.
e/ Including depreciation and direct taxation (provision of 10% of net income for public lighting in Bogota), but excluding interest payments.
f/ Net revenues after taxes as % of average net fixed assets in operation.
g/ Revaluation of assets computations as calculated by IBRD in Annex I.

h/ In current prices
i/ Average Annual Rate of increase over 1968-70 for non-deflated figures.
j/ Real growth rate over 1968-70, calculated by using national GDP deflator.

EMPRESA DE ENERGIA ELECTRICA DE BOGOTA (EEEB)
UTILITY INVESTMENT PROGRAMS PARTLY FINANCED BY IBRD
(US$ million)

TABLE II-B

	LOAN 246-CO (1960) Period 1960 a/-1962				LOAN 313-CO (1962) Period 1962-65				LOAN 537-CO (1968) Period 1968-1970			
	FORECAST		ACTUAL		FORECAST		ACTUAL		FORECAST		ACTUAL	
	Total	% of Total	Total	% of Total	Total	% of Total	Total	% of Total	Total	% of Total	Total	% of Total
SOURCES OF FUNDS												
1. Net Internal Cash Generation	12.02	31.2	15.23	24.2	25.48	26.2	13.31	13.5	14.60	36.9	17.83	40.7
2. Domestic Contribution:												
from private sector					10.46	10.7						
from public sector												
Total Domestic Contribution			15.98 b/	25.3	10.46	10.7	21.46	21.5			10.46	23.8
3. Foreign Borrowing: c/											5.14 d/	11.7
Suppliers credits												
Foreign Private Loans	8.85	23.0			1.50	1.6					10.46	23.8
IBRD	17.60	45.8	31.93	50.5	59.65	61.5	64.59	65.0	25.0	63.1	15.60	35.5
Total	26.45	68.8	31.93	50.5	61.15	63.1	64.59	65.0	25.0	63.1		
4. Total Sources	38.47	100.0	63.14	100.0	97.09	100.0	99.36	100.0	39.60	100.0	43.89	100.0
APPLICATION OF FUNDS												
5. Total Fixed Investments	37.32	97.0	40.24	74.6	94.23	97.0	80.73	85.0	41.30	104	29.73	66.7
6. Change in Working Capital & Cash	1.15	3.0	13.69	25.4	2.86	3.0	14.34	15.0	-1.60	-4	14.87	33.3
7. Total Applications	38.47	100.0	53.93	100.0	97.09	100.0	95.07	100.0	39.70	100	44.60	100.0

a/ For 1959, only forecast figures are available: Net Internal Cash Generation US $ 1.08 million.
Total Borrowing US $ 2.99 million of which .89 in suppliers credits and the rest in local sources.
Total Sources forecast for that year were $ 4.07 million.
Total fixed investment was $3.55 million and Working Capital $0.5 million.

b/ About $5.5 million from Reserve funds, operational surpluses, street lighting investments, liquid and other assets and the rest from local banks and local loans,

c/ In actual investments, IBRD is only foreign source.

d/ Consist of joint - Financing credits.

EMPRESA DE ENERGIA ELECTRICA DE BOGOTA
PROJECTS IMPLEMENTATION

TABLE III

		Start Construction	Commission Date	Construction Period (months)	Project Scope b/		Construction Cost c/ (US $ Million) Local Cost k/	Foreign Exchange	Total	Cost/ KW US $
LOAN 246-CO (US$ 17.6 Million) (Signed Jan. 20, 1960)										
Laguneta Unit 4 a/	Forecast	Mid 1959	Mid 1960	12	1 x 18 MW	Hydro	1.41	.99	2.40	133.7
	Actual	January 1960 d/	Mid 1961	18	1 x 18 MW	Hydro	n.a.	1.51	n.a.	n.a.
including transmission and generation	Forecast						1.44	1.48	2.92	162.7 --(includes 21.4% of Guatavita Dam, reservior & engineering cost)
	Actual						n.a.	2.27	n.a.	
Salto II (Units 1 and 2)	Forecast	Mid 1959	End 1961	30	2 x 33 MW	Hydro	5.93	4.51	10.44	158.2
	Actual	Feb. 1960 d/	June 1963	35	2 x 33 MW	Hydro	n.a.	6.70	n.a.	n.a.
including transmission and generation	Forecast						6.05	6.31	12.36	187.3 --(includes 78.6% of Guatavita Dam, reservior & engineering cost)
	Actual						n.a.	9.43	n.a.	n.a.
Zipaquira Unit 1	Forecast	Early 1961	Mid 1962	18	1 x 33 MW	Thermal	4.00	2.83	6.83	207.1
	Actual	End 1960	May 1963	32	1 x 33 MW	Thermal	n.a.	3.22	n.a.	n.a.
including transmission and generation	Forecast						4.05	3.73	7.79	236.1
	Actual						n.a.	4.58	n.a.	n.a.
LOAN 313-CO (US $50 million) Signed May 23, 1962										
El Colegio, Units 1,2,3	Forecast	May 1962 f/	End 1965 g/	43	3 x 50 MW	Hydro	14.76	24.19	38.95	259.7
	Actual	May 1962 f/	May 1967 g/	60	3 x 50 MW	Hydro	16.84	27.60	44.44	296.3
including transmission and generation	Forecast						16.66	27.90	44.56	297.1
	Actual						n.a.	35.20	n.a.	n.a.
Zipaquira, Unit 2	Forecast	May 1962 e/	December 1963	19	1 x 33 MW	Thermal	1.64	7.02	8.66	231.1
	Actual	May 1962 e/	December 1964	31	1 x 37.5 MW	Thermal	2.48	5.60	8.08	215
including transmission and generation	Forecast	August 1962	December 1965	40	176 km h/	115 kv	2.12	7.94	10.06	268.5
	Actual	n.a.	n.a.	n.a.	n.a.		n.a.	7.27	n.a.	n.a.
LOAN 537-CO (US $18.0Million) Signed June 3, 1968										
El Colegio, Units 4,5,6	Forecast	Mid 1968 j/	End 1971	42	3 x 50 MW	Hydro	.73	6.07	6.80	45.3
	Actual	Mid 1968 j/	July 1970	25	3 x 50 MW	Hydro	2.53	6.69	9.22	61.5
including transmission and generation	Forecast						3.10	10.77	13.87	92.5
	Actual						n.a.	11.20	n.a.	n.a.
Canoas Unit 1	Forecast	Mid 1968	End 1971	42	1 x 50 MW	Hydro	6.43	5.82	12.25	245.0
	Actual	Mid 1968	December 1971	42	1 x 50 MW	Hydro	n.a.	n.a.	n.a.	n.a
including transmission and generation	Forecast	Mid 1968	n.a.	n.a.	n.a.	n.a.	7.22	7.38	14.61	292.2
	Actual	Mid 1968	Mid 1972	48	180 km	115 kv	n.a.	n.a.	n.a.	n.a

LOAN DISBURSEMENT PATTERN

			1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	Undisbursed 12/31/70
LOAN 246-Co	Forecast:	Amount (US $ million)	8.00	7.31	2.26										
		% of Total	45.5	41.6	12.9										
		Cumulative %	45.5	87.1	100.0										
	Actual:	Amount (US $ million)	1.74	6.20	6.75	2.79	12								
		% of Total	9.9	35.2	38.4	15.8	.7								
		Cumulative %	9.9	45.1	83.5	99.3	100								
LOAN 313-CO	Forecast:	Amount (US $ million)			11.81	18.90	17.08	2.21							
		% of Total			23.6	37.8	34.1	4.5							
		Cumulative %			23.6	61.4	95.5	100							
	Actual:	Amount (US $ million)			3.54	14.40	13.51	8.77	7.46	2.30	.02				
		% of Total			7.0	28.7	27.0	17.5	14.8	4.6	.4				
		Cumulative %			7.0	35.7	62.7	80.2	95.0	99.6	100				
LOAN 537-CO	Forecast:	Amount (US $ million)									5.00	5.8	4.2	3.0	
		% of Total									27.8	32.3	23.3	16.6	
		Cumulative %									27.8	60.1	83.4	100	
	Actual:	Amount (US $ million)									5.07	2.58	2.81		7.54
		% of Total									28.2	14.3	15.6		
		Cumulative %									28.2	42.5	58.1		

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a/ Addition to Laguneta plant commissioned with three MW units in 1957.
b/ Project Scope for generation is Megowatts of installed capacity and source of energy, and for transmission components is kilometers of lines.
c/ Does not include interest during construction: inflationary contingencies were excluded from forecast projections for comparison purposes with the deflated actual costs.
d/ Bids had been received and awards recommended by consultants by January 1962.
e/ Bids were received and letters of intent issued by May 1962.
f/ Bids for sonstruction of the Colegio tunnel were opened on October 24 and work was underway by May 1962.
g/ Date last unit commissioned.
h/ of which 63 Kms were already under construction.
i/ Not completed as of 8/31/71; estimated commissioning date at that time was December 1971.
j/ Bidding concluded and results known as of May 7, 1968.
k/ Local costs of projects were computed by converting for each year the Col. Peso expenditure incurred during that year into constant 1968 pesos (GIP deflatos) and then converting into US Dollars at the 1968 average annual official exchange rate for imports of goods and services (Ps 15.90=US$ 1.00).

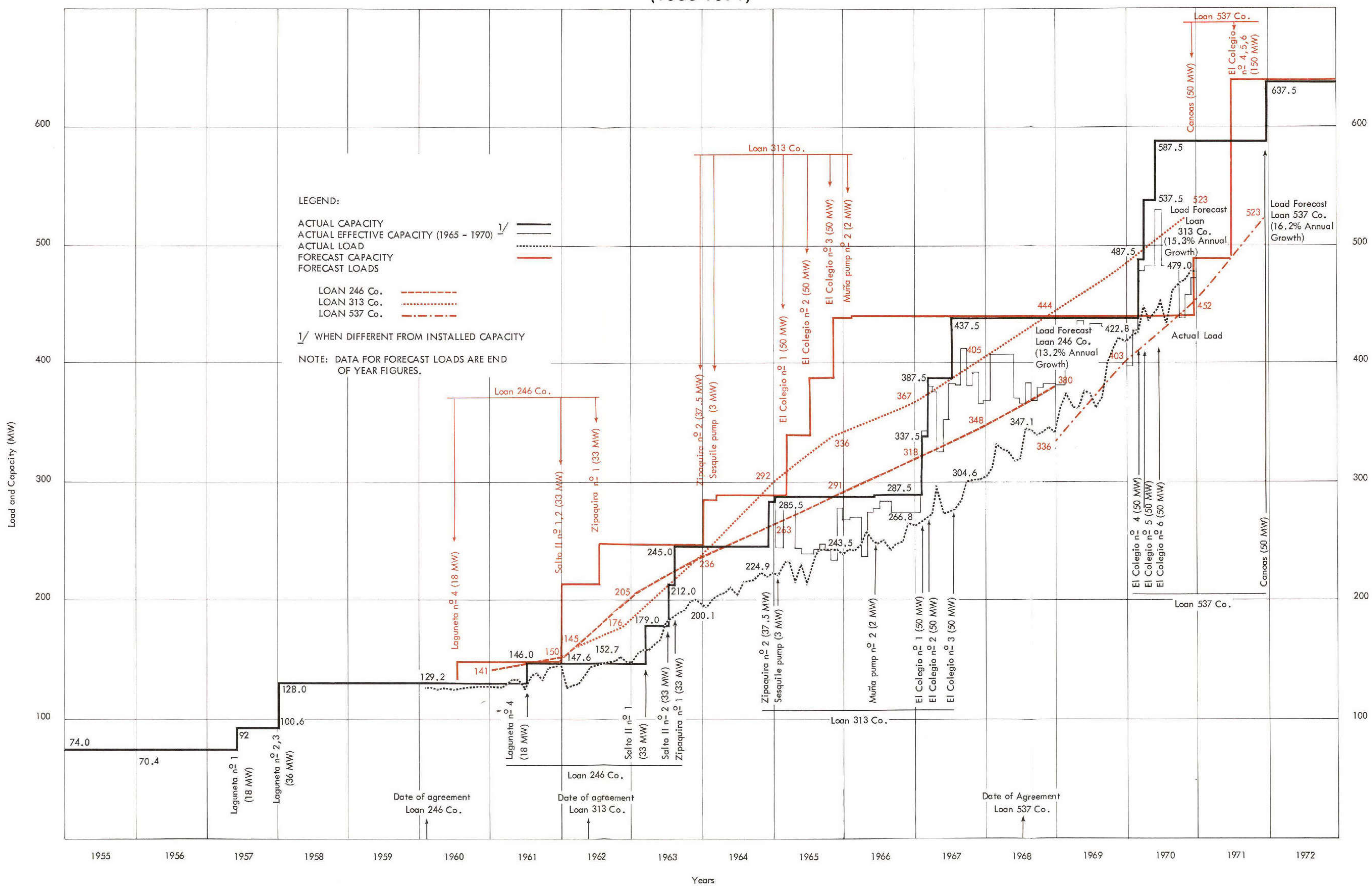
COLOMBIA

EMPRESA DE ENERGIA ELECTRICA DE BOGOTA

LOAD AND CAPACITY DEVELOPMENT

Actual and Forecast

(1955-1971)



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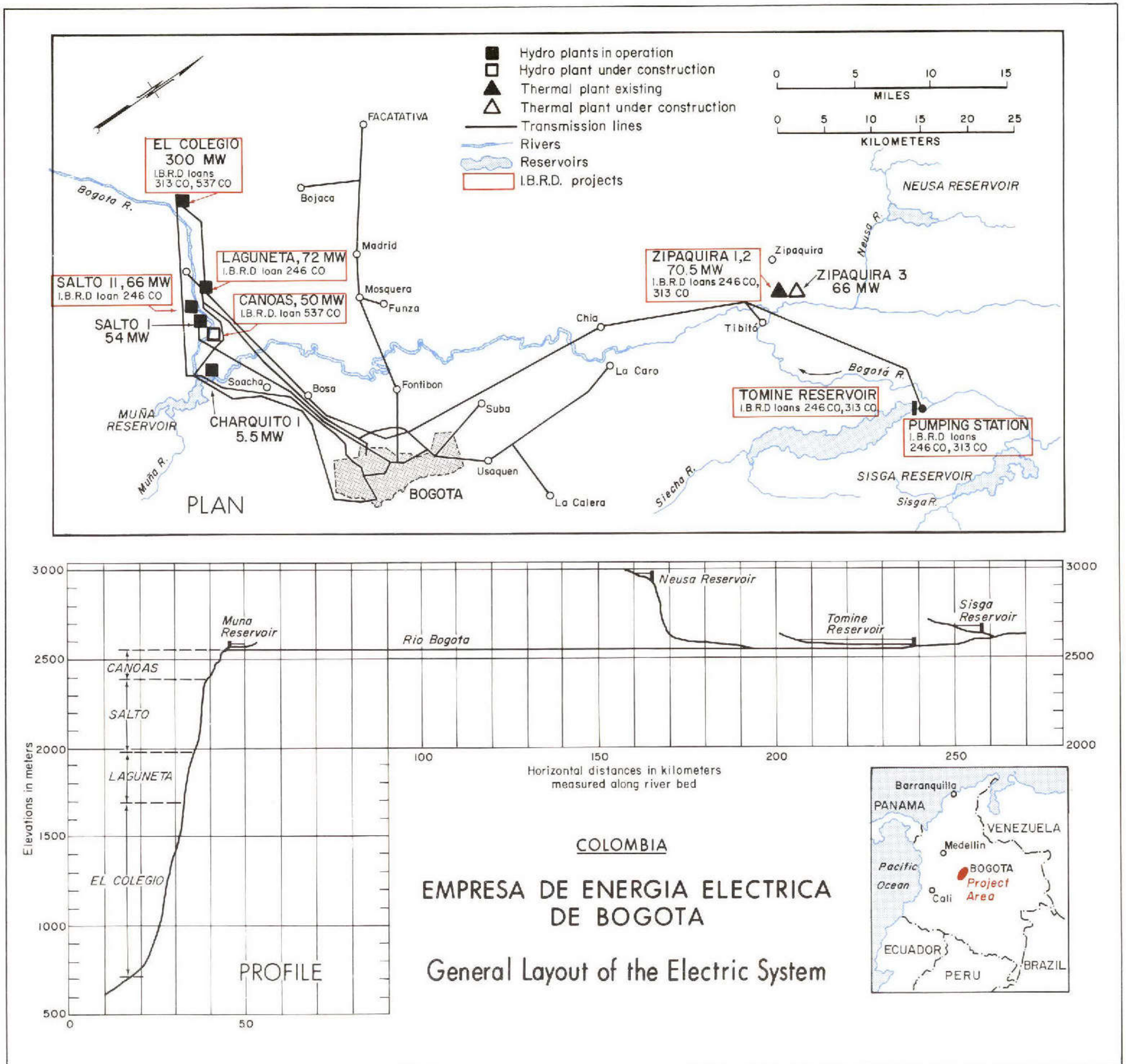

COLOMBIA

EMPRESA DE ENERGIA ELECTRICA DE BOGOTA

General Layout of the Electric System

AUGUST 1971

IBRD-914 R3

CHAPTER XI - MEDELLIN POWER COMPANY (EPM) - COLOMBIA

I - Introduction

1.01 Empresas Publicas de Medellin is an autonomous, municipally-owned entity which provides Medellin, Colombia's largest industrial center, with public services of electricity, domestic water supply, sewerage, and telephone. The four branches are operated as independent departments, except for administrative direction and use of common services. Accounts are kept separately for each department and energy revenues are utilized solely for power purposes. EPM currently supplies electricity directly to the city of Medellin and 13 smaller municipalities and also sells bulk energy to 9 other municipalities and to subsidiaries of the Electrificadora de Antioquia.

1.02 EPM was established by charter in 1955 through powers given to the city of Medellin by national law. Concurrently, the existing municipally operated utility was abolished and its assets and liabilities turned over to EPM. The company has a seven-member Board of Directors of which the Mayor of Medellin is ex-officio chairman. Two members are selected by and from the City Council. The other four are appointed by the Mayor from candidates proposed respectively by the Bank of the Republic, the National Banks of Medellin, the National Association of Industrialists and the Medellin Chamber of Commerce.

1.03 EPM is the second largest supplier of electricity in Colombia with an installed capacity in mid-1971 of 575 MW, of which 438 MW or 76% was partly financed with Bank loans. The abundant rainfall and large mountain ranges in the area have provided Medellin with rich sources of hydroelectric energy which have been partly utilized in all of its seven plants. EPM's installed capacity, which in 1970 represented 21% of the total public sector capacity in the country, has grown at an average annual rate of 13% during the period 1960-1970, while gross generation grew at a rate of 9%.

II - The Association Between the Bank and EPM

2.01 EPM received over the period 1959-1970 three loans from the Bank as follows:

Loan No.	Date of Loan Agreement	Effective Date	Closing Date	Amounts ($ mln) a/ Committed	Disbursed	Interest	Period (Years) Grace	Term
225 CO	5/59	7/59	7/63 b/	12.0	12.0	6%	4	25
282 CO	5/61	9/61	3/68 c/	22.0	22.0	5-3/4%	5	25
369 CO	2/64	8/64	- d/	45.0	33.9	6%	5	35
Total				79.0	67.9			

a/ As of December 31, 1970.
b/ Extended from December 1962.
c/ Extended from January 1966.
d/ Extended from December 1968.

2.02 Contact between the Bank and the City of Medellin first occurred about ten years before the first loan was made to Empresas Publicas de Medellin in May 1959. During that period, the Bank's main concern was the creation of an autonomous apolitical power company to which it could lend. The Empresas, consisting of four independent departments (electric energy, water supply, sewerage and telephone), each with its own manager and Advisory Board, had traditionally been owned and controlled by the City of Medellin. Although the management was generally considered competent, there was substantial duplication of the activities of the four departments. This duplication and the existence of political interference on the part of the City Council were considered by the Bank major obstacles to efficient administration of the Company. A study made in 1953 by Price-Waterhouse concluded that great advantages would be obtained from regrouping the four departments into a single organization with one general manager. Under the proposed arrangement, the four departments were to remain autonomous in their respective fields.

2.03 The Bank was officially approached in October 1954 for assistance in financing the Medellin electric power program. The Bank, however, set two preconditions for serious loan consideration. In the first place, it requested assurance that the expansion of the Medellin power system was part of the national electrification program. Secondly, the Bank requested that the power sector be organized as a separate entity with independent financial and administrative status.

2.04 In August 1955, the municipality established an independent municipally-owned agency known as the Empresas Publicas de Medellin to operate and manage the municipal power, telephone, water and sewerage systems. In December, the assets and liabilities of the existing municipal companies were transferred to this new entity. The new set-up conformed both with the Municipality's organizational wishes and the Bank's request for the financial autonomy of the power department.

2.05 Except for the tariff revision and increase recommended by the Bank in September 1955, all conditions for Bank lending appeared to have been met by 1956, when the Bank decided to suspend further consideration of projects in Colombia because of the country's deteriorating economic situation. Talks resumed in October 1958 when a Bank mission visited EPM to review the Guadalupe project. To the Bank's satisfaction, a tariff increase of 32% had been granted to the company on July 1, 1958. After some deliberation regarding the legal and financial status of EPM and an assessment by the Bank of the company's need for a strengthened technical staff and competent consulting services, the loan was signed on May 20, 1959.

2.06 The Bank accepted EPM's first power development program without fundamentally questioning the choice of the various components of the project. There had been a constant need for expansion of the Company's power facilities since the Company's first loan request had reached the Bank in 1955. Although the generating equipment was operated at its maximum overload capacity, the Company had to curtail consumption and to purchase energy from private industries equipped with generating plants. In 1960, sections of the city had to be cut off from service on a rotating basis for periods ranging from one half hour to four hours per day. The Company tried to confine the rationing to domestic consumers so as not to impinge upon the industrial growth of the community. In spite of this, several manufacturing industries had to install their own generating plants or to invest in stand-by diesel units. This resulted in a decline of EPM's industrial sales.

2.07 The first loan to EPM (Loan 225 CO) was for the amount of US$12 million (approximately 50% of the total project cost) to cover the foreign currency component of the following (see map at end of chapter):

(a) Construction of Guadalupe III hydroplant with an initial capacity of 80 MW.

(b) Construction of the Troneras reservoir and hydroplant with an initial capacity of 16 MW.

(c) Diversion of the Concepcion and Tenche Rivers to increase daily flow in the Guadalupe River.

(d) Erection of new transmission lines, enlargement of sub-stations and extension of primary and secondary distribution circuits.

(e) Studies of the Guatape scheme.

2.08 As early as February 1960, EPM requested a loan increase of US$3 million to cover the extra costs that the project was incurring due to internal inflation and higher than expected bids on civil works.

The original estimate of the cost of civil works had been based on the assumption that local contractors would be the successful bidders but the main construction contracts were finally won by foreign contractors who required substantially more foreign exchange than Colombian contractors. A Bank mission, which visited Colombia in March 1960, established that the foreign exchange cost overrun was in fact US$3.5 million and recommended an interim loan to cover this amount as well as the foreign exchange necessary to finance the second stage of the project. The mission also recommended a loan of US$22 million for the first stage of the Guatape hydroplant. Six months later, EPM reported to the Bank that a larger interim project and a temporary postponement of Guatape would be advantageous for system expansion. A Bank appraisal mission was sent to Colombia in November 1960 and a US$22 million loan was signed on May 12, 1961 to cover the cost overrun on the previously financed project, which was estimated at US$3.8 million and to cover the foreign exchange cost of the project described below:

(a) Addition of a second 18 MW unit in the Troneras hydroplant. 1/

(b) Installation of three additional 40 MW units at the Guadalupe III hydroplant.

(c) Construction of the Miraflores dam and reservoir on

1/ The first unit was finally 18 MW instead of the originally planned 16 MW.

the Tenche River to further increase daily flow in the Guadalupe River.

(d) Construction of additional transmission, distribution and sub-station capacity in Medellin.

2.09 In March 1963 EPM applied for a third loan for the amount of US$43 million to finance the foreign exchange component of the Guatape project. The Bank mission which left for Colombia shortly thereafter reported the project to be economically viable. EPM was anxious to go ahead with the project as soon as possible, but the decision of the Bank was slightly delayed when it appeared that the Colombian Government was nearing its guarantee limit. Colombia's creditworthiness was restored after supplemental legislation had been passed. Negotiations did not pose any major problems and a US$45 million loan was signed in August 1964 to cover the foreign exchange cost of the following items:

(a) Guatape I hydroelectric plant (including first two units of 66 MW each).

(b) 230 kv transmission line from Guatape to Medellin.

(c) Sub-transmission (110 kv), Medellin sub-stations and distribution.

2.10 All three loans contained covenants in the Loan Agreements and Side Letters which were designed to increase the institutional efficiency and financial viability of EPM. A detailed description and analysis of the covenants is to be found in the sections below on financial performance and institutional development. The most important of these provisions may be summarized as follows:

Main Provisions in Loans Agreements

(a) Separate Operation of Empresas' Departments

EPM shall operate each of its Departments separately and maintain separate accounts for each Department.

(b) Indebtedness to Equity Ratio

The long-term indebtedness to equity ratio for the Power Department shall not exceed a ratio of 60 to 40; and no other Department shall incur long-term indebtedness unless its revenues will be sufficient to cover operating expenses, including taxes, and all debt service payments.

(c) Debt Incurred

Where Departments other than the Power Department incur debts for more than one year the holder of the debts shall forego any rights he may have to the assets of the Power Department.

(d) Rate Adjustments for all Departments

EPM shall review its rates at least every two years to insure that sufficient money is provided to (i) cover operating expenses, including taxes, and contributions to the Municipality of Medellin, adequate maintenance and depreciation and interest; (ii) meet repayments on long-term indebtedness but only to the extent that such repayments shall exceed provision for depreciation; and (iii) leave a reasonable surplus to finance new investments.

Side Letters

(a) Letters which provide for the amount of cash to be internally generated by EPM for future capital expenditures (30 percent for Loan 225 CO, 40 percent for last two loans).

(b) Letters which provide that EPM consult the Bank before it changes any of its statutes and inform the Bank of any legislation, decrees or resolutions affecting its status.

III - Major Issues

Financial Performance

3.01 As explained earlier, EPM not only supplies electricity to Medellin but also has responsibility for the water, telephone and sewerage services of the city. Nevertheless, the four divisions are operated and managed separately and, at the insistence of the Bank, clear lines have been drawn between the electric department's operations and accounts and those of the rest. It is thus possible to examine the performance of the power division alone and the financial analysis which follows refers only to that division.

3.02 Basically, the performance of EPM has been similar to that of EEEB of Bogota (see previous chapter); before the IBRD entered the picture the company had a large potential market, but lacked the necessary capital to carry out the extensive expansion program it needed. The Bank was able to supply a large part of this capital by financing most of the foreign exchange portion of EPM's investments (over 97 percent in the 1959-70 period) but, as in the case of EEEB, the local currency portion had to be financed mainly from the Empresa's profits. The absence of adequate long term Peso credit facilities in Colombia made this essential to avoid lags in the expansion program. For this reason, as in all other loans to power entities in Colombia, the Bank insisted upon the Empresa's adoption of procedures designed to generate a substantial portion of its own local currency investment costs. From the evidence available it appears that EPM has been successful in improving and expanding its system over the past twelve years and its financial performance has generally lived up to expectations.

3.03 In financial covenants attached to the Loan Agreements, the Bank stipulated that 40 percent (originally 30 percent, but raised in the last two loans to 40 percent [1/]) of investments -- roughly corresponding to the total local currency portion -- should be financed through self-generated funds. Toward this end, it was agreed that the Empresa should review its tariff levels at least once every two years to ensure that revenues were high enough to meet all expenses (including taxes and depreciation), make debt service payments and cover the 40 percent self-financing provision. Performance in this last respect has generally been satisfactory. For the specific five-year period

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1/ Loan 369 CO specified that EPM should finance 40 percent of its construction expenses in each five-year period subsequent to December 31, 1963, through self-generated funds.

1964-68 covered by the Side Letter under Loan 369 CO, the self-financing rate was 40.6 percent (Loan 369 CO Appraisal Report forecast was 42.0 percent). 1/ This was an improvement over the 1961-65 period covered by the Side Letter of Loan 282 CO when the rate was 33.7 percent (Loan 282 CO Appraisal Report forecast was 39.1 percent), below the agreed 40 percent. During 1959-1963, when the Side Letter of Loan 225 CO specified a 30 percent self-financing rate, the rate was 36.4 percent. Performance during the last two years 1969-1970 has averaged 38.5 percent, with 1970 showing 44.9 percent. EPM's inability to contribute more to its investment program from self-generated resources during the 1961-1965 period resulted from a failure to adjust tariffs in a timely manner.

1/ The method which the Bank employed to calculate EPM's self-financing rate differs from that used elsewhere in this study in the treatment of interest during construction. The following shows the difference in definition:

IBRD Appraisal Report on EPM:	Present Evaluation Report:
Gross Internal Cash Generation	Gross Internal Cash Generation
Less: Debt Service plus dividends to Municipality (Excluding interest during construction)	Less: Debt Service plus dividends to Municipality (Including interest during construction)
Plus: Appropriation to Reserve for Employee Benefits	Plus: Appropriation to Reserve for Employee Benefits
Equals: Net Internal Cash	Equals: Net Internal Cash
Self-financing Rate = Net Internal Cash / Total Construction Expenditures (Including interest during construction)	Self-financing Rate = Net Internal Cash / Total Construction Expenditures (Excluding interest during construction)

3.04 EPM's rate increases have been largely neutralized by inflation, and tariffs expressed in real terms have only just managed to keep up with rising real costs; in the 1959-69 period, unit revenues in real terms grew at an average annual rate of 3.4 percent, close to the increase in real costs per unit of 3.1 percent yearly over the same period (see Table I). As in the case of EEEB, one of EPM's main difficulties has been to maintain a balanced relationship between the two. But EPM has managed to maintain a generally steadier balance, with real unit revenues rising from 12 centavos per kwh in 1959 to 17 in 1969 (both in 1968 prices). This is probably mainly due to the fact that tariff increases are easier to obtain in Medellin than in Bogota. Per capita incomes are somewhat higher in Medellin and the impact of a rate increase upon the average family budget is probably less noticeable. Also Bogota, being the capital city, is more likely to be influenced by political considerations in operations, than in the case of industrial Medellin.

3.05 Tariff rate increases were a major issue between the Bank and EPM during 1961-1963, when the tariff covenant of Loan 282 CO was in force, providing that internally generated cash should cover 40 percent of investment expenditures over the period 1961-1965. The Bank employed various means to encourage the Company to press for a rate increase. For instance, it indicated that reimbursement of the sum paid to a contractor from Loan 282 CO could be envisaged only after the presentation of concrete evidence supporting the timing and extent of a rate increase. EPM complained about the high tariff increase required, given the inflationary conditions in Colombia, for the company to comply with the Bank's condition regarding self-generated investment funds. The Company also argued that pressing for such an increase was likely to imperil its autonomy. An increase of about 60% was finally granted in March 1963.

3.06 In spite of the many revisions they have been subjected to, electricity tariffs in Medellin, as in Colombia in general, have been among the lowest in the world. It was only in 1968 that the Government created the Public Service Tariff Board with a view to encouraging the adoption of standard criteria on the national level for establishing tariff levels and structure. All utility tariff increases have to be approved by the Board. The latter has set as its major objective the restructuring and adjustment of tariffs so that they would cover expenditures and provide a reasonable return on revalued assets, thereby permitting orderly financing of system expansion. The impact of the recommendations made by the Board is only beginning to be felt and Colombia's utility tariff structure today is still far from conforming with the proposed policy. EPM is one of the very few companies which now has tariffs sufficient to yield a rate of return of more than 9% on net fixed assets, and this is a development of the last two years.

3.07 Due to rather disappointing internal cash generation in 1967 (28.1%) and 1969 (32.7%), and local cost overruns on Guatape, EPM had to rely to a greater extent than expected on other sources of funds, including an extraordinary government contribution of Ps 9.25 million in 1967 (covering 6 percent of total Application of Funds) and a special loan of Ps 20.0 million from the national budget through the Instituto de Fomento Industrial (IFI) in 1969.

3.08 It should be observed that factors other than finance are involved in determining the level of tariffs and it may be that the rates charged by EPM were the highest politically feasible. In addition, as mentioned before, EPM has been affected by very considerable distribution losses in the form of stolen energy, which have increased from 1.0 percent of total generation in 1960 to 15.7 percent in 1969 (see Section IV below). If all this energy had been sold to, rather than stolen by, the so-called "pirate" unconnected areas, EPM would have realized additional gross revenues (amounting to some 37 million pesos in 1969), which would have reduced the Empresa's need to seek outside investment financing.

Project Implementation: Delays and Cost Overruns

3.09 As in the case of the Bogota Power Company, preliminary negotiations between the Bank and EPM dragged on for years before a final agreement could be reached. The major point of friction again concerned the company's legal and financial status. The Bank insisted that the power section of EPM be organized as a separate entity with independent financial and administrative status. The new charter of the company, drawn up in 1955, conformed with the Bank's basic requirement of financial separation and insulation from political interference, even though not with the Bank's original proposal of total independence of power from all other services. The legal status of the Empresas has remained an issue, with the Municipality expressing on several occasions its desire to exercise stronger control over the company (see Section VI below), but it seems that, after the first loan was negotiated, the issue no longer contributed to slow down operations. The embargo imposed on lending to Colombia between 1956 and 1958 obviously extended the pre-negotiation period between the Bank and EPM. The tariff issue, although sometimes difficult, does not seem to have hindered the progress of project implementation in a significant way.

3.10 Project preparation was generally adequate and the Bank has not really intervened in the company's investment decisions. Initially, the Bank felt that the supervisory qualifications of EPM's staff were rather weak. During negotiations, it was agreed that EPM would hire special consultants who would have total responsibility for supervising and directing the contractors; the consultants' duties were to cover all technical matters in connection with the project, including items related to costs and schedules.

3.11 Delays in the commissioning of the various plants and units are given in the table below:

Table 11.1

EPM: Expected and Actual Commissioning Dates of Generating Plants

Generating Plants and Units	Expected Date of Commissioning	Actual Date of Commissioning	Delay
Loan 225 CO			
Troneras u_1 (H)	Mid 1962	Dec. 1964	2 years 6 mos.
Guadalupe III u_1 (H)	Early 1961	Aug. 1962	1 year 6 mos.
Guadalupe III u_2 (H)	Early 1961	Nov. 1962	1 year 10 mos.
Loan 282 CO			
Troneras u_2 (H)	Sept. 1963	Feb. 1965	1 year 5 mos.
Guadalupe III u_3 (H)	Oct. 1964	Oct. 1965	1 year
Guadalupe III u_4 (H)	Apr. 1965	March 1966	11 mos.
Guadalupe III u_5 (H)	Dec. 1965	May 1966	5 mos.
Guadalupe III u_6 (H)	a/	Sept. 1966	a/
Loan 369 CO			
Guatape I u_1 (H)	Dec. 1968	Sept. 1971 (exp.)	2 years 9 mos.
Guatape I u_2 (H)	Mid 1969	Sept. 1971 (exp.)	2 years 3 mos.
Guatape I u_3 (H)	a/	End 1971 (exp.)	a/
Guatape I u_4 (H)	a/	End 1971 (exp.)	a/

a/ Units not included in the original list of goods; attractive financial arrangements on the equipment resulted in savings which were used to purchase one additional unit for Guadalupe III and two additional units for Guatape.

The table shows that construction delays have generally been considerable. Delays and cost overruns on each of the projects are analyzed below in greater detail. Total project costs (as well as unit cost per kilowatt of installed capacity), forecast and actual, are compared in Table III.

Loans 225 and 282 are treated together since the latter merely financed completion of the expansion program initiated by the former. It should also be recalled that the second loan included the amount of $3.8 million to cover the foreign exchange cost overrun on the first loan.

Loans 225 CO and 282 CO

3.12 The construction delays which occurred in connection with these two loans were due mainly to the fact that the contractors were under-equipped, poorly directed, and had been handicapped by price increases in imported equipment occasioned by the Government's import restriction policy. This affected mainly progress on the Concepcion and Tenche diversion works, construction of the Troneras plant, and work on the Miraflores dam. Foreign and local cost overruns occurred on all major construction works and equipment covered by the loan, with the notable exception of the three units of the Guadalupe plant provided for in the second loans; the sixth unit of Guadalupe was purchased with the savings realized on units 3, 4 and 5, leaving a final foreign currency cost underrun of US$1.45 million on the Guadalupe plant. The table below gives in detail the forecast and actual expenditures.

3.13 The table shows that the foreign currency contingency allowance was almost entirely used to cover the excess cost of the Troneras dam and power station, and that the remaining overrun was partly covered through a reduction in the amount required to cover interest during construction. Local currency cost overruns, on the other hand, turned out to be drastically higher than forecast, amounting to nearly six times the contingency allowance. The only reduction was a 42% cut in expenditures on distribution. It is interesting to point out that extra expenditures on engineering and supervision amounted to more than 10% of total cost overruns. It is important to note, however, that in spite of these cost overruns, the final cost per KW installed was

Table 11.2

EPM - Loans 225 CO and 282 CO - Forecast and Actual Cost of Project

	Foreign Exchange Component ($ million)			Local Currency Component ($ million equiv.)			Total Cost of Project ($ million equiv.)		
Loans 225 CO and 282 CO	Forecast	Actual	Overrun	Forecast	Actual	Overrun	Forecast	Actual	Overrun
Roads and Construction Equipment	0.80	0.80	-	0.28	0.92	0.64	1.08	1.72	0.64
Diversion of Concepcion and Tenche Rivers	-	0.77	0.77	0.66	1.30	0.64	0.66	2.07	1.41
Troneras Dam and Power Station	1.97	4.74	2.77	2.54	6.11	3.57	4.51	10.85	6.34
Guadalupe III a/	11.77	10.32	(1.45)	3.12	7.66	4.54	14.89	17.98	3.09
Miraflores Dam	1.14	3.19	2.05	1.50	4.12	2.62	2.64	7.31	4.67
Transmission Lines	0.97	1.65	0.68	0.26	1.11	0.85	1.23	2.76	1.53
Substations and Distribution System	4.88	6.35	1.47	3.06	1.78	(1.28)	7.94	8.13	0.19
Engineering and Supervision	1.01	0.91	(0.10)	1.57	3.93	2.36	2.58	4.84	2.26
Engineering for Guatape	0.15	0.86	0.71	0.16	0.79	0.63	0.31	1.65	1.34
Interest and other charges during Construction	5.30	4.37	(0.93)	-	-	-	5.30	4.37	(0.93)
Contingencies b/	3.01			2.49			5.50		
Additional Foreign Exchange for Loan 225-CO	3.00			-			3.00		
Total	34.00	33.96		15.64	27.72		49.64	61.68	

a/ While forecast figure was for 3 units, actual figure also includes costs of a fourth unit bought with savings realized on the first three.
b/ Includes contingencies for price increases of Ps 0.83 million.

Source: EPM
IBRD

$ 162.8 for the completed 270 MW Guadalupe III plant, one of the lowest unit costs of all the projects examined in this study.

Loan 369-CO

3.14 The construction of the Guatape hydroplant is especially interesting, not only because of the spectacular nature of the project, but also because of the various technical problems encountered in its implementation. The plant, which is entirely underground, utilizes the flow of the Nare river and the head created by diverting its water to the adjacent Guatape valley, some 850 m below. The first stage of the Guatape project, as financed through Loan 369-CO, includes a small diversionary dam on the Nare river, an inlet pressure tunnel of about 4.7 km, an inclined penstock tunnel of approximately 1.2 km, a powerhouse cavern excavated for four 66 MW units 1/ and a free flow tailrace of about 4.7 km. The vehicular access tunnel to the power plant cavern has a total length of nearly 2,000 meters. The powerhouse cavern, which is located at a depth of about 680 meters below ground level, was, as of 1969, the deepest underground powerhouse in the world. The first stage of the project will utilize a net hydraulic head of about 780 meters which will be in-

1/ The second stage of Guatape (Guatape II) will provide for the expansion of the existing powerhouse and the installation of four additional 66 MW units.

creased to nearly 810 meters after the second stage dam is built.

3.15 The scope of the project has obviously brought with it several technical difficulties. These resulted in a total delay of almost three years. The main problems arose in connection with the excavation of the vehicular access tunnel, the tailrace tunnel, the penstock tunnel, and the powerhouse. Large quantities of water encountered while digging the access tunnel made it necessary to establish a complex pumping system, while, in the case of the tailrace tunnel, the excavation was slowed down due to the existence of a large rock fault. These two difficulties delayed the overall project by nearly 9 months. The rock on the walls of the powerhouse required a lengthy special lining treatment which delayed the initiation of work on the penstock tunnel. A major accident which occurred during the excavation of the latter resulted in the death of several workers requiring a change in building methods, which involved the construction and subsequent enlargement of a pilot tunnel. The construction of the pressure tunnel was carried out more efficiently than anticipated, in spite of minor problems which arose in connection with the concrete lining.

3.16 Other elements unrelated to specific technical difficulties encountered in the civil works also contributed toward retarding the progress of operations. These concerned mainly design revision suggested by the new foreign consultants appointed to the project. Furthermore, the original plans for the water intake structure underwent major alterations; the final scheme provided for the diversion of the Nare river by a tunnel rather than an open channel as initially planned. Finally, some complications arose as a result of a delay in the shipment of various pieces of equipment, and the Company complained about the difficulty of coordinating the orders made to the large number of suppliers. It is difficult, at this stage, to assess the exact cost overruns on the various parts of the project since it has not been fully completed yet; about $ 10 million still had to be disbursed from the Bank loan account as of December 31, 1970. Actual expenditures up to that date are shown in the table below.

Table 11.3

EPM - Loan 369 CO - Forecast and Actual Cost of Project a/

	Foreign Exchange Component ($ million)			Local Currency Component ($ million equiv.)			Total Cost of Project ($ million equiv.)		
Loan 369-CO	Forecast	Actual	Overrun b/	Forecast	Actual	Overrun b/	Forecast	Actual	Overrun b/
Land, access roads, etc.	-	-		2.24	3.64	1.40	2.24	3.64	1.40
Civil works	16.61	16.21	(0.40)	13.26	16.56	3.30	29.87	32.77	2.90
Power plant equipment c/	8.94	6.72	(2.22)	0.67	1.41	0.74	9.61	8.13	(1.48)
Transmission and Distribution System	4.77	4.56	(0.21)	3.91	0.95	(2.96)	8.68	5.51	(3.17)
Engineering	1.00	1.07	(0.07)	2.22	4.97	2.75	3.22	6.04	2.82
Interest and other charges during Construction	5.00	5.59	0.59	0.46	2.62	2.16	9.91	8.21	2.75
Physical contingencies	5.59			4.32					
Provisions for price increases	3.09			3.38			6.47		
Total	45.00 d/	34.15		30.46	30.15		75.46	64.30	

a/ Actual figures are as of 12/31/70
b/ Final overruns and/or underruns are not available as projects are not yet completed
c/ While forecast figure was for two units only, actual figure also includes cost of two additional units bought with savings realized on the first two.
d/ US $3.0 million were cancelled in August 1970.

Source: EPM
IBRD

3.17 Indications are that some savings are likely to appear on the foreign currency component of the project. As indicated earlier, the original loan provided for the installation of only two generating units at Guatape, but especially attractive offers from the suppliers induced the company to include four units in the contract. Local costs, on the other hand, will probably turn out to be much higher than originally anticipated. This will mainly be the case for civil works and engineering, for reasons previously cited. Once again, it appears more than likely that distribution will suffer in order to cover the overruns on the other items of the project. It should also be recalled that in 1969, EPM received a credit of Ps 20 million from the Central Budget through IFI to complement the local currency financing of Guatape. In addition, the company intends to float a Ps 100 million bond issue in the near future to cope with the constant threat of a peso shortage.

IV - Load Forecasting, Investment Planning and System Development

4.01 Installed capacity in the Medellin system grew at a very low rate between 1955 and 1962. There was no expansion of generation facilities at all between 1958 and 1962, and from 1959 on, although the system was operated at its maximum overload capacity, shortages began to appear, involving major rationing of the residential supply and forcing manufacturing industries to install their own generating facilities. The Company attempted to deal with this critical situation by purchasing energy from a large neighboring textile factory, but this remained insufficient to cope with prevailing demand.

4.02 The situation improved substantially when the first two units of Guadalupe III were put into operation at the end of 1962, yielding an increase in peak supplied of about 35 percent. Energy sales to the industrial sector, which had been subject to major fluctuations since

1954 (with a downward trend in 1956), experienced a continuous average growth of 10.5 percent per annum after 1961. However, it appears that the rate of growth of electricity sales to industry did not increase as much as would have been expected during the 1962-1968 period after the improvements in the public electricity supply were effected; this has probably been partly the result of the traditionally heavy reliance upon self-generation by the textile industry, Medellin's major industrial branch, as well as the slower than expected growth of the overall economy in the period. Also, Medellin, seems to have always attempted to give priority to industrial development and has caused the burden of electricity shortages to be borne by residential consumers. Finally, the price of coal in Medellin has always been low and the motivation of industries to switch to public electricity has probably not been as strong as in other places. On the other hand, there have been some instances of delays in industrial investment due to deficiencies of public power supply. For instance, the Futec foundry which had been planned since 1961-62, was only built in 1964 when improvement in public electricity supply was imminent. Residential consumption, which had been increasing regularly between 1951 and 1960, declined slightly in 1961 and caught up again in 1962.

4.03 The three expansion programs carried out by EPM between 1962 and 1971 have resulted in a large increase in system capacity, growing from 137 MW in mid-1962 to 575 MW by mid-1971 -- an average annual rate of 17.3 percent. Over the same period, peak demand increased by about

11.5 percent per year, leaving a relatively large gross reserve capacity margin. The expansion of the sub-transmission and distribution systems, although taking place at a slower relative rate than the expansion of generating facilities, generally kept pace with the growth of the city's economic activity and, seemingly, did not curtail load growth notably. It should be noted, however, that Medellin has suffered major electricity thefts in the past and that the official connection of the pirate areas to the network would probably have contributed to increasing system demand (see table below). The rapid growth of power theft by residents of marginal areas was mainly due to the refusal of the City Council to allow extesnion of Company services beyond the city limits and to incorporate the marginal areas within the city. In recent years, however, the company has undertaken a systematic electrification program in the "pirate" areas and significant reductions in losses are expected.

Table 11.4

EMPRESAS PUBLICAS DE MEDELLIN (EPM)
LOSSES IN THE ELECTRIC SYSTEM - BREAKDOWN BY ORIGIN

Year	Total Generation	Losses in Transmission and Transformation		Losses in Primary Distribution Networks		Losses in Distribution Transformers		Losses in Secondary Distribution Networks		Losses in Meters		Meter Reading Errors		Stolen Energy		Total Losses	
	(Mwh)	(Mwh)	%	(Mwh)	%	(Mwh)	%	(Mwh)	%	(Mwh)	%	(Mwh)	%	(Mwh)	%	(Mwh)	%
1960	824123	28801	3.49	33577	4.07	14753	1.79	10950	1.33	1779	0.22	13213	1.60	8257	1.00	111330	13.50
1961	851232	37953	4.46	31272	3.67	15455	1.82	9303	1.09	1873	0.22	13441	1.58	13183	1.55	122480	14.39
1962	936848	39078	4.17	32670	3.49	17508	1.87	10494	1.12	1972	0.21	14513	1.55	33001	3.52	149296	15.93
1963	1100442	33576	3.05	45232	4.11	20105	1.83	12211	1.11	2058	0.19	17055	1.55	66079	6.00	196316	17.84
1964	1236019	42389	3.43	57616	4.66	21592	1.75	13893	1.12	2161	0.18	18589	1.50	97275	7.87	253515	20.51
1965	1373309	53882	3.92	57948	4.22	23578	1.72	16618	1.21	2289	0.17	19932	1.45	148067	10.78	322314	23.47
1966	1478420	47132	3.19	69443	4.70	24881	1.68	18550	1.25	2383	0.16	21579	1.46	159630	10.80	343558	23.24
1967	1597009	53022	3.32	85196	5.33	26217	1.64	20901	1.31	2415	0.15	22578	1.41	199073	12.47	409402	25.63
1968	1698389	47369	2.79	70290	4.14	27351	1.61	23636	1.39	2506	0.15	23291	1.37	278999	16.43	473442	27.88
1969	1829074	55303	3.02	68960	3.77	26993	1.48	24466	1.34	2730	0.15	25517	1.40	287780	15.73	491749	26.89

Source: EPM

4.04 Installed capacity has been greatly in excess of actual peak demand since the end of 1966 when unit 6 of Guadalupe III was put into operation. Reserve capacity reached a maximum of about 150 MW at that time but declined to about 75 MW at the end of 1970; the capacity of the largest unit in service over the period being 45 MW. Forecast demand, as projected in the first two loan appraisal reports (see Tables II-A.1 and II-A.2) were for the most part substantially higher than actual demand, while projections for the third loan were much more accurate with only slight overestimations (see Table II-A.3). The variations observed between forecast and actual reserve capacity were the results of delays in commissioning the various generating units as well as the lower than expected load. The necessity of temporarily removing some units from operation for repair and maintenance purposes substantially lowered the actual spare capacity during the critical years 1963-66 (see Table II-A.2 and II-A.3, line 9, Effective Peak Spare Capacity).

4.05 While there has been very considerable excess capacity since 1966, computer simulation of the operation of the system shows that excess energy has been much more limited. A potential energy generation analysis was carried out, based on actual river flows and showing how much energy could have been generated by the different plants with these river flows. The table below shows the percentage that gross capacity reserves have represented of peak demand for each year since 1965 and equally the percentage that excess energy (i.e. corresponding to water-spill) has represented of actual system generation over the same period.

Table 11.5

EPM Reserve Supply Capacity 1965-70

	Generating Capacity		Energy Production	
	Gross Reserves (MW)	Gross Reserves as % of Peak Demand	Excess Available (Gwh)	Excess as % of Actual System Generation
1965	41.0	15.4	165.8	12.1
1966	154.0	53.3	170.5	11.5
1967	133.2	43.0	223.4	14.0
1968	116.0	35.5	162.3	9.5
1969	93.5	26.8	101.8	5.6
1970	72.2	19.5	260.9	13.3

The sharp rise in excess energy available in 1970 was due to exceptionally good stream flows in that year. The analyses undertaken indicate that additional energy generating capacity is required (as is being provided this year by completion of Guatape) but that the last two units of Guadalupe III have barely yet fulfilled an essential role -- although they will become useful as peaking units when loads are greater and there is more base load capacity in the form of Guatape. The fifth unit at Guadalupe might have been postponed two years and the sixth unit much longer, into the early 1970s, without adversely affecting energy supply; but these units were obtained at relatively low marginal cost (apparently some \$ 2.0 - 2.5 million equivalent in total) along with units 3 and 4 in 1963 so that it was probably preferable to install them simultaneously, in 1965-66, as was done.

4.06 Energy sales forecasts were overestimated in all three loan appraisal reports by approximately the same margins (see Tables II-A.1, II-A.2 and II-A.3) and this in turn resulted in an overestimation of net revenues (see Section V). Discrepancies between forecast and actual energy sales were greater for the residential sector than for the industrial, and they are partially accounted for by the rising energy thefts.

V - Forecasting the Financial Aspects

5.01 Comparison of forecasts and actual figures in Tables II-A.1, II-A.2, II-A.3 and II-B clearly show that forecasts of EPM's financial performance for all three loans have been optimistic. The most notable contrast between forecast and actual performance can be seen in the trend of operating income (which determines the extent to which the company can finance its investments itself, i.e., affect the self-financing rate) and the rate of return, particularly for the third appraisal report projections for 1964-68. While the fact that operating income fell behind projections (by about 40% for 1965-67) is in part related to the fact that (a) inflationary pressures (estimates of which, unlike in the first two loans, were explicitly included in the projections of Loan 369-CO) were stronger than expected, and (b) tariff increases did not occur as planned, it is also quite significant that energy sales were ovestimated and that sales have been more weighted toward low tariff consumers in actuality than in the forecasts.

5.02 Colombia experienced high rates of inflation in the period 1950-70, with the price level increasing about six fold. Although EPM partially revalued its assets between 1967 and 1970 (revalued the foreign component of its assets to allow for devaluations of the Colombian Peso since the loans had been contracted and plants built), further revaluation calculations have been made for this study in order to assess the actual financial performance of the company over the whole period in which the Bank has been associated with the company. Detailed explanation of how these revaluation calculations were made is found in Annex I. The financial rates of return for EPM based on revalued assets fall considerably below both forecasts and the partially re-valued EPM "actual" rates of return. For the years 1965-68 the rate was below 8 percent, the level that the Bank generally considers to be a minimum for utilities to maintain.

5.03 EPM is often considered to be the most efficient power entity in Colombia. It is true that it has among the lowest average production costs in the country, but this is partly due to its relatively large size and the existence of attractive hydroelectric sites in the area. EPM's sales per employee have risen significantly over the last seven years and are much higher than those for any other Colombian utility for which data are available. However, it is hard to say whether this reflects real superiority in performance -- resulting from greater efficiency and the advantages of the unified utility set-up -- or whether it reflects exclusion of some administrative personnel (classified in general management under the unified set-up), absence of thermal plants from the system and/or the more serious failure in Medellin to keep up with requirements for expansion of the distribution system in marginal areas.

5.04 It is surprising that real costs per unit sold should have shown such a sharp upward trend over the last ten years when the system has expanded so dramatically and it would consequently have been expected that significant economies of scale would have been attained with resultant lower average unit costs. Unit costs per kwh sold have grown in real terms at an average of some 3 percent per annum over the 1960s. An important part of the reason for this is the large quantity of energy stolen. Costs per kwh sold and stolen were 6.8 centavos in 1969 compared with 8.3 centavos per kwh sold. 6.8 centavos is only about 10 percent above the 1959 level. Analysis of the composition of EPM's operating costs suggests that the most important factors accounting for higher real costs today than ten years ago, after allowance for the stealing problem, are depreciation provisions -- due to the rapid growth of the system itself -- and administration expenses. Costs of the latter have increased in real terms at an average annual rate of 18 percent over the last ten years, whereas total operating costs (including depreciation) have increased at 11 percent. This large increase in administrative costs has been primarily due to the rather steep climb of total wages, salaries and social benefits (16 percent per annum) over the 1959-69 period. Although EPM has been since 1966 steadily reducing the absolute number of its employees and the rate of annual increase in personnel costs has declined to 4.2 percent over the last five years (with energy sales per employee rising faster than wages per employee) wages, salaries, and social benefits represented what appears to be a somewhat high 45 percent of 1970 total operating costs (47 percent in 1960 and 54 percent in 1965). This compares to 38 percent for EEEB. Average wages per employee for EPM in 1970 were 60 percent above those for EEEB, placing them in the top 5 percent of the national Colombian income scale.

VI - Institutional Development

6.01 EPM has passed through two phases and experienced a series of reorganizations since its founding. During its first seven years its priorities were technical -- the expansion of its power system. Beginning about 1962 it entered its second phase, characterized by more concern with operational and administrative improvement. This concern was manifest in the small reorganization of 1962 and the major reorganization of 1965. Since then the company has been concerned with the 1965 reorganization and has largely succeeded in implementing it. In essence, the organization has become more rationalized and specialized as the Company has consolidated its technical achievements.

6.02 With its first loan to EPM (225-CO of 1959) the Bank recommended the elevation of a small technical unit to the status of the technical department, and in side letters to the Loan Agreement it required the hiring of an engineering adviser to the director of the newly proposed technical department, and the hiring of an additional 11 engineers for the planning and engineering staff. Both recommendations were adopted by the borrower and, in addition, an engineering consultant was hired in early 1960 to help integrate the added engineers into the technical apparatus of the company. These measures supported the company's own priorities which were geared to improve its technical capabilities. The Bank also indicated that the general manager's term of office, which was one year, should be lengthened in order to insure greater continuity of management. Although this recommendation was not a loan condition, it was accepted.

6.03 The second stage, concerned with administrative improvement of the company, began in 1962. Examination of the administrative structure, personnel policies, and labor relations led to the major reorganization of 1965. Under the reorganization scheme two new departments, financial and administration, were created. The creation of the two departments, and their later staffing with competent professionals resulted in overall improved personnel policies and practices and a greater focus on the training needs of the entity. The financial department has computerized its work, developed a modern budgeting system, created a commercial division and increased its planning capabilities.

6.04 At the time the Bank made its first loan in 1959, the costs of common services were apportioned among the four main departments of EPM, the Power Department's share in 1959 being 55 percent. The Bank sought assurances that EPM would operate each of its departments separately and would not use the assets and revenues of the Power Department to help other departments, and second, that no other department would incur long-term debt unless its revenues covered both operating expenses and debt service and unless the lender waived any rights to obtain satisfaction of his debt from the revenues or assets of the Power Department. These assurances were included in the provisions of the Loan Agreement.

6.05 At the time of the second loan in 1961, these restrictions were again included in the terms of the loan, with an understanding that there might be one exception to the previous complete separation. It had been discovered that it was impractical for the several departments to borrow from local banks to meet temporary needs for cash when EPM had cash available in its general fund. It was therefore arranged that each department could draw on these funds, subject to limits as to time (three months) and amount (Water Department 1.5 million pesos, Sewerage Department 0.5 million pesos, Power Department 5.0 million pesos, Telephone Department 2.0 million pesos). At the time the third loan was being appraised in 1963, the Power Department had an interdepartmental overdraft of 3 million pesos.

6.06 To comply with a loan condition that the company retain the services of internationally recognized auditors to prepare annual audits, the company hired in 1960 the firm of Deloitte, Plender, Haskins and Sells as external auditors. In addition to preparing their annual report the auditors have made a number of suggestions concerning accounting procedures. An internal auditor, appointed by the City Council but independent of the organization, performs both pre- and post-audit functions. Also, at the Bank's recommendation, the company hired Price Waterhouse in 1957 as consultants on reorganization and inventory, and in 1967-69 the company retained the services of Arthur Andersen to assist in a modernization program which included data processing, installation of a new computer and training.

6.07 After the promulgation of EPM's charter, pressures continued to exist in the City Council for changes in the composition of the Board of Directors of EPM to bring it under greater control of the Council. The first attempt toward changing the Board took place late in 1960. The purpose of the change was to give the Council the authority to appoint a majority of the Board's members. The Bank stated unequivocally that it "continued to be of the opinion that if the present organizational structure is altered, ... the EPM would not be considered an acceptable borrower under the Bank's operating procedures. This would then preclude further Bank lending to the EPM." The attempted change, which was not supported by the Mayor, failed.

6.08 Another attempt, whose results are still being contested in the courts, was made in 1970 when the Municipal Council of Medellin, now controlled by the opposition party ANAPO, passed two decrees modifying the statutes of EPM. One of these decrees gives the head of the Municipal Planning Department a voice in the Board of Directors of the Corporation. The other would modify the composition and the powers of the Board as well as the procedures by which it is selected. One of the most disturbing changes, as far as the Bank is concerned, is an amendment which subjects the Board's resolutions on tariffs to the final approval of the Municipal Council.

6.09 There were two reasons for these changes. First, the company was organized by a group of entities such as the National Industrial Association and the local banks from which it had received loans. In 1968, when the loans granted by the local banks were amortized and the company became self-financing, the Municipal Council felt that these financial institutions lost any right they might have had to be represented on the Board. The second reason is political. Several groups in Medellin thought it would be necessary to have wider representation from professional associations and from the unions, which previously were unrepresented. The new members are to be chosen from lists drawn by these groups as well as the commercial, industrial and banking groups.

6.10 In 1971 the issue was in the courts. With the change of the statutes a new Board was immediately elected. The old Board questioned the legality of the new statutes and thus of the election of a new Board. Subsequently, two cases have been presented to the Tribunal of Administrative Contention, one on the legalityof the new statutes, the other on the issue of which Board is legally capable of acting. In the meantime the acting General Manager is working within the uncontested section of the statutes, consulting with the Mayor who is always the Chairman of the Board.

6.11 The changes have raised a number of interesting legal questions with regard to the status of the Bank vis-a-vis the company. According to the Bank's Legal Department the Bank acquired no right to determine the particular setup of the borrower's management and has no right to object to the proposed amendments of the borrower's charter. The Bank, in a supplemental letter, obtained the right to be promptly informed of any such proposal but not the right to object to it.

6.12 If the proposed changes, whenever they may be implemented, result in insufficient tariff levels the Bank would be entitled, pursuant to the quoted provisions and the supplemental letters, to demand that those levels be reached. The proposed change dealing directly with the tariff was, however, only an extra administrative step in the mechanism to determine tariffs. The Bank had no legal basis to object to it. With this legal advice at hand the Bank limited itself to an "exchange of views" with EPM.

VII - Conclusion

7.01 EPM has managed to improve the quality and capacity of its power supply to a considerable degree during the 1960s, keeping pace with the industrial growth of the city. The experience of the late 1950s and early 1960s suggests that, had the Bank not been able to provide the large amounts of capital required to exploit the attractive hydroelectric sites of the area, the company might have had to adopt less economic short-run solutions to its problems of shortage of power.

7.02 The main provisions of the Bank's three loans to EPM were designed to create and sustain an autonomous, efficiently operated and financially viable utility capable of meeting the load growth of Medellin. The organization has strengthened considerably over the years, and its financial performance, the best of the Colombian utilities which have borrowed from the Bank, has generally conformed to the covenants agreed with the Bank, though it was weak in the early and middle 1960s. EPM appears also to be a reasonably efficient entity. A question arises about the failure of unit costs to decline with such a large expansion of the system, the very rapid increase in the wage bill, and the apparently very high average salaries paid. The other particularly weak aspects of performance is in the expansion of the distribution system and connection of marginal barrios, with the latter being apparently more the result of deficiencies in municipal planning than of shortcomings on the part of EPM itself. It is surprising that the Bank appears never to have given serious attention to either of these points.

7.03 Although the major projects which the Bank helped finance experienced considerable delays and involved significant cost overruns, these do not seem to have resulted in serious failures to meet demand (after the backlog was overcome by 1963) -- mainly due to slower than expected load growth -- nor to have affected the overall economic justification of the projects. In the cases of both Guadalupe III and Troneras, the Bank complied with EPM's requests for assistance without seriously questioning the economic validity of the steps proposed, which was rather plain. The Medellin System shows prima facie evidence of considerable excess capacity over the last five years but system simulation indicates that the energy margin has sometimes been narrow, due to limited river flows. The last unit, and probably the last two units at Guadalupe III, could have been omitted from the investment program without curtailing EPM's ability to meet system load to date, but they were obtained at rather low marginal cost in connection with the contract for the preceding two units, and it appears that the decision to install them at that time (in 1966) was probably wise; they should come to play an important role when the system has additional base-load capacity.

7.04 The 264 MW hydro site at Guatape was considered the cheapest alternative means of expanding EPM's generating facilities, following Guadalupe III, to meet both the long-term needs of Medellin as an isolated market and of the Central Interconnected System as a whole; construction of the plant is now nearly completed and it appears that the cost per KW installed will probably be reasonably close to the forecast figure of $ 243. The plant will provide large amounts of firm capacity, a very fundamental and necessary feature for EPM, given the limited amount of energy available in its own system. The plant is also almost certainly the most appropriate major expansion in the context of the interconnected system, now nearing commissioning.

7.05 In overview, the fact that EPM has managed to expand and improve its services to meet the growing demands of Medellin reasonably well should be considered an achievement in view of the economic and political difficulties in the financing and management of such growth in Colombia.

TABLE I

COLOMBIA: EMPRESAS PUBLICAS DE MEDELLIN (EPM)
ELECTRICITY DEPARTMENT

		UNIT	1950	1951	1952	1953	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	Average Annual Increase Rate (%) m/ 1950/60	1960/65	1965/70
	OPERATIONS																									
1.	Installed Capacity (year end)																									
	Hydro (no thermal)	MW	51.5	51.5	100.0	100.0	100.0	100.0	125.5	125.5	137.0	137.0	137.0	137.0	227.0	227.0	248.0	308.0	443.0	443.0	443.0	443.0	443.0	10.3	17.6	7.5
	Total as % of total in country a/	%	na	na	na	na	na	23.0	25.0	21.0	22.0	21.0	20.0	20.0	27.0	22.0	22.0	24.0	28.0	26.0	26.0	23.0	21.0			
2.	Peak Demand	MW	53.8	52.4	77.9	83.7	96.8	101.2	117.1	125.4	137.1	147.5	149.9	148.3	199.6	215.8	231.5	267.0	289.0	309.8	327.0	349.5	370.8	10.8	12.2	6.6
3.	Gross Reserves	MW	-2.8	-0.9	22.1	16.3	3.2	-1.2	8.4	0.1	-0.1	-10.5	-12.9	-11.3	27.4	11.2	16.5	41.0	154.0	133.2	116.0	93.5	72.2			
	Reserves as % of Peak Demand	%	-5.0	-1.7	28.4	19.5	3.3	-1.2	7.2	0.1	-0.1	-7.1	-8.6	-7.6	13.7	5.2	7.1	15.4	53.3	43.0	35.5	26.8	19.5			
4.	Effective Peak Spare Capacity b/	MW	na	na	na	na	na	na	na	na	na	na	na	na	na	-15.2	-9.7	-1.1	41.4	123.0	116.0	80.5	72.2			
5.	Generation Sent Out	GWh	310.22	317.94	376.20	434.63	494.65	536.78	570.95	622.58	622.03	724.30	824.12	851.23	936.48	1100.44	1236.02	1373.31	1478.42	1597.01	1698.39	1829.07	1965.00	10.3	10.8	7.4
6.	Net Purchases from other systems c/	GWh	-	-	-	-	-	-	-	-	2.65	15.87	15.10	19.07	11.55	0.21	1.42	-	-	-	-	-	-			
7.	Total Sales to Customers	GWh	250.39	256.86	309.31	361.55	418.81	464.57	489.20	548.16	581.74	644.26	710.27	724.51	779.40	901.23	979.18	1048.27	1131.83	1182.78	1219.12	1331.00	1496.00	11.0	8.1	7.4
8.	Number of Customers	000's	48.46	51.30	54.34	68.08	73.44	78.43	82.58	85.39	89.09	95.09	99.91	105.34	110.73	114.80	122.07	127.80	133.29	137.74	143.59	153.40	174.54	7.5	5.0	6.4
9.	Number of Employees	No.	na	na	na	na	na	na	na	na	na	na	na	na	na	na	877	927	939	929	876	860	802			2.9
	FINANCE																									
10.	Sales Revenues (current prices)	Ps (mln)	na	na	na	na	na	16.20	16.92	18.81	22.98	29.24	37.76	44.27	46.61	73.33	95.01	103.46	130.77	157.32	197.20	244.67	279.34		8.6	10.5
11.	Operating Costs d/ (current Prices)	Ps(mln)	na	na	na	na	na	6.73	7.55	9.16	9.54	13.96	16.04	20.17	24.90	36.39	41.54	50.56	66.29	82.15	95.31	101.33	113.08		11.7	6.4
12.	Average revenue/kwh sold (current prices)	Ps	na	na	na	na	na	0.03	0.04	0.03	0.04	0.05	0.05	0.06	0.06	0.09	0.10	0.10	0.12	0.13	0.16	0.18	0.19			
13.	Average revenue/kwh sold (constant 1968 prices)	Ps	na	na	na	na	na	0.14	0.15	0.11	0.11	0.12	0.13	0.14	0.13	0.15	0.14	0.13	0.14	0.14	0.16	0.17	0.16		0.5	3.8
14.	Average costs/ kwh sold based on revalued assets (in constant 1968 prices)	Ps	na	na	na	na	na	na	na	na	0.05	0.06	0.06	0.07	0.07	0.08	0.07	0.08	0.09	0.10	0.10	0.8	na		5.9	2.2 n/
15.	Average revenue/kwh sold	US¢(1)	na	na	na	na	na	0.89	0.95	0.69	0.70	0.76	0.82	0.87	0.80	0.93	0.90	0.84	0.85	0.91	1.01	1.06	1.01		0.5	3.8
16.	Average costs/ kwh sold	US¢(1)	na	na	na	na	na	na	na	na	0.31	0.38	0.36	0.41	0.44	0.49	0.45	0.48	0.54	0.59	0.62	0.52	na		5.9	2.2 n/
17.	Net revenues in current prices (10 - 11)	Ps(mln)	na	na	na	na	na	9.47	9.37	9.65	13.44	15.28	21.72	24.10	21.71	40.94	53.47	52.88	64.48	75.17	101.89	143.34	166.26		6.2	16.3
18.	Net revenues in current prices based on revalued assets	Ps(mln)	na	na	na	na	na	na	na	9.65	12.85	14.54	20.82	22.99	20.79	36.27	47.66	44.75	47.64	58.71	87.30	124.91	na		3.5	17.1 n/
19.	Gross fixed investment (current prices)	Ps(mln)	na	na	na	na	na	na	9.60	18.89	34.91	28.31	21.97	60.42	106.91	61.18	144.55	149.72	174.21	166.31	180.19	343.02	267.16		47.0	12.3
20.	Gross Fixed investment (1968 prices)	Ps(mln)	na	na	na	na	na	na	36.29	60.83	99.14	75.59	54.05	137.15	227.72	105.84	215.38	203.62	205.57	181.28	180.19	315.58	224.41		30.0	2.0
21.	Average net fixed assets in operation	Ps(mln)	na	na	an	na	na	na	na	na	89.27	108.46	117.33	122.49	205.37	297.96	337.34	426.00	531.27	578.50 k/	585.14 k/	591.85k/	na			
	MANAGEMENT INDICATORS																									
22.	Rate of return on Electricity Sales (17 as % of 21)																									
	(1) non-revalued assets	%	na	na	na	na	na	na	na	na	15.1	14.1	18.5	19.7	10.6	13.7	15.8	12.4	12.1	13.8	19.1	25.9	na			
	(2) revalued assets e/	%	na	na	na	na	na	na	na	na	12.2	11.4	14.8	15.3	8.8	8.7	9.9	7.2	5.4	6.0	8.2	11.0	na			
23.	Financial rate of return f/																									
	(1) non-revalued assets	%	na	na	na	na	na	na	na	na	13.6	13.6	18.3	19.9	11.0	13.9	16.0	12.6	12.2	13.7	18.4	25.4	na			
	(2) revalued assets e/	%	na	na	na	na	na	na	na	na	10.9	11.0	14.6	15.5	9.2	8.8	10.0	7.3	5.5	5.9	7.9	10.7	na			
24.	Self-financing rate g/	%	na	na	na	na	na	na	na	na	na	25.8	92.3	35.0	13.8	59.2	30.7	35.8	29.7	28.1	45.2	20.8	33.3			
25.	Debt Service Coverage h/	Times	na	na	na	na	na	na	na	na	na	1.7x	4.8x	3.9x	2.3x	3.7x	3.2x	4.8x	2.6x	1.9x	2.3x	1.8x	1.9x			
26.	Debt/Equity ratio	./.	na	na	na	na	na	na	na	na	na	43/57	39/61	41/59	55/45	51/49	52/48	53/47	54/46	64/36	65/35	63/37	62/38			
27.	Energy Sales per Employee	Mwh	na	na	na	na	na	na	na	na	na	na	na	na	na	na	1116	1131	1206	1273	1392	1548	1865			
28.	Distribution and Transmission losses i/	%	19.3	19.2	17.8	16.8	15.3	13.5	14.3	12.0	6.9	13.0	15.4	16.8	17.8	18.1	20.9	23.7	23.4	25.9	28.2	27.2	23.9			
29.	Average capacity out of service as % of installed capacity j/	%	na	na	na	na	na	na	na	na	na	na	na	na	na	10.5	2.8	2.3	6.0	1.2	0.0	1.7	0.0			
30.	EPM's investment as % of fixed investment in country	%	na	na	na	na	na	na	0.3	0.6	1.0	0.7	0.5	1.1	1.7	0.8	1.6	1.6	1.5	1.2	1.1	1.8	na			
31.	Accounts receivable as % of Total Sales Revenue	%	na	na	na	na	na	na	na	8.3	na	9.0	12.0	11.5	12.2	13.2	12.5	12.3	15.1	15.6	16.7	15.0	16.1			

* Financial calculations carried out in this table do not account for revaluation of assets except where specified (revaluation of assets is treated in further detail in Annex I.
a/ Does not include captive plants
b/ Effective Peak: Peak load at the critical time in the year when the margin between demand and available capacity is minimum, or load shedding maximum (excluding short-term outages.)
c/ Bought from Coltejer - a private industrial concern with its own thermal generating plant.
d/ Including depreciation but excluding interest and direct taxation.
e/ Revaluation of assets computation as calculated by IBRD in Annex I.
f/ Net revenues after taxes as % average net fixed assets in operation.
g/ Net internal cash generation as % of Gross Fixed Investment.
h/ Times debt service was covered by operating income and depreciation.
i/ Generation sent out, including energy purchased from Coltejer (see footnote c) less sales to EPM's customers, as % of generation sent out (including energy purchased from Coltejer).
j/ Capacity out of service for maintenance and repairs.
k/ Excluding company's own revaluation for changes in exchange rate.
l/ Converted from 1968 pesos to dollars by 1968 exchange rate of Ps. 15.9 = US $ 1.00.
m/ Rates of increase for figures in current pesos have been calculated using national GDP deflator to obtain real growth rates bases on constant prices.
n/ Average annual increase rate for 1965-1969.

COLOMBIA: EMPRESAS PUBLICAS DE MEDELLIN - ELECTRICITY DEPARTMENT
LOAN 225-CO (May 12, 1959)

TABLE II-A.1

		1959	1960	1961	1962	1963	1964	Average Annual Increase Rate (%) 1959-1964
	LOAD FORECASTS (MW)							
1.	Installed Capacity	137	137	217	233	308	345	20.5
2.	Annual Peak Demand	137	137	217	233	233	285	15.8
3.	Gross Reserve Capacity (1-2)	0	0	0	0	75	60	
	ACTUAL LOAD (MW)							
4.	Installed Capacity	137	137	137	227	227	245	12.4
5.	Annual Peak Demand	148	150	148	200	216	232	9.4
6.	Gross Reserve Capacity (4-5)	-11	-13	-11	27	11	13	
7.	Effective Peak Capacity a/	n.a.	n.a.	n.a.	n.a.	177	221	
8.	Effective Peak Demand a/	n.a.	n.a.	n.a.	n.a.	192	231	
9.	Effective Peak Spare Capacity (7-8)	n.a.	n.a.	n.a.	n.a.	-15	-10	
	LOAD FORECAST ACCURACY b/							
10.	Installed Capacity	100	100	158	103	136	141	
11.	Annual Peak Demand	93	91	147	117	108	123	
12.	Gross Reserve Capacity	-	-	-	-	682	462	
	SALES FORECAST (Gwh)							
13.	Total Sales	655	675	790	950	1100	1240	13.6
	ACTUAL SALES (Gwh)							
14.	Sales: Residential	366	413	407	433	502	524	7.5
	Industrial	157	177	185	212	246	283	12.5
	Commercial	54	59	61	66	70	73	6.2
	Government	28	20	n.a.	n.a.	44	59	16.0
	Bulk	39	41	n.a.	n.a.	39	40	0.5
	Total	644	710	725	779	901	979	8.8
	SALES FORECAST ACCURACY b/							
15.	Total Sales	102	95	110	122	122	127	
	RETURN FORECAST (Col. Pesos mln.)							
16.	Operating Revenues c/	30.9	36.7	42.9	51.4	68.2	76.8	20.0
17.	Less: Operating Costs d/	15.2	17.8	21.9	26.3	32.9	40.1	21.5
18.	Operating Income	15.7	18.9	21.0	25.1	35.3	35.7	18.5
19.	Financial Rate of Return on Av. Net Fixed Assets in Operation (%) f/	11.2	10.6	8.6	7.9	9.1	8.3	
	ACTUAL RETURN (Col. Pesos mln.) e/							
20.	Operating Revenues c/	30.6	36.4	39.7	39.8	53.0	58.3	13.8
21.	Less: Operating Costs d/	15.9	16.7	19.0	21.8	26.0	22.1	6.8
22.	Operating Income	14.7	19.7	20.7	18.0	27.0	36.2	19.8
23.	Financial Rate of Return on Av. Net Fixed Assets in Operation f/							
	(1) non-revalued assets (%)	13.6	18.3	19.9	11.0	13.9	16.0	
	(2) revalued assets (%) g/	11.0	14.6	15.5	9.2	8.8	10.0	
	RETURN FORECAST ACCURACY b/							
24.	Operating Revenue	101	101	108	129	129	132	
25.	Operating Costs	96	107	115	121	127	181	
26.	Operating Income	107	96	101	140	131	101	

a/ Effective Peak: The critical time in the year when margin between demand and available capacity was least or load shedding greatest (excluding short-term outages).
b/ Defined by the ratio Forecast/Actual.
c/ Total Revenues, excluding indirect taxes.
d/ Including depreciation and direct taxation on utility, but excluding interest.
e/ All current or historic pesos have been converted to 1959 constant pesos for the purpose of comparison with the Loan 225-CO Appraisal Report Forecasts, using the national GDP deflator.
f/ Net Revenues after taxes as % of average net fixed assets in operation.
g/ Revaluation of assets computations as calculated by IBRD in Annex I.

TABLE II-A.2

COLOMBIA: EMPRESAS PUBLICAS DE MEDELLIN - ELECTRICITY DEPARTMENT
LOAN 282-CO (April 27, 1961)

		1961	1962	1963	1964	1965	1966	1967	1968	Average Annual Increase Rate (%) 1961-1968
	LOAD FORECASTS (MW)									
1.	Installed Capacity	136	216	252	292	332	372	422	472	19.5
2.	Annual Peak Demand	208	212	250	266	285	343	363	440	11.3
3.	Gross Reserve Capacity (1-2)	-72	4	2	26	47	29	59	32	41.5[h]
	ACTUAL LOAD (MW)									
4.	Installed Capacity	137	227	227	245	308	443	443	443	18.2
5.	Annual Peak Demand	148	200	216	232	267	289	310	327	11.9
6.	Gross Reserve Capacity (4-5)	-11	27	11	13	41	154	133	116	27.5[h]
7.	Effective Peak Capacity[a]	n.a.	n.a.	177	221	242	302	418	443	20.0[i]
8.	Effective Peak Demand[a]	n.a.	n.a.	192	231	243	260	295	327	11.2[i]
9.	Effective Peak Spare Capacity (7-8)	n.a.	n.a.	-15	-10	-1	42	123	116	
	LOAD FORECAST ACCURACY[b]									
10.	Installed Capacity	99	95	111	119	108	84	95	99	
11.	Annual Peak Demand	141	106	116	115	107	119	117	135	
12.	Gross Reserve Capacity	-	15	18	200	115	19	44	28	
	SALES FORECAST (Gwh)									
13.	Sales: Industrial	190	210	250	300	320	370	410	440	12.7
	Others	570	640	700	750	840	910	990	1110	10.0
	Total	760	850	950	1050	1160	1280	1400	1550	10.7
	ACTUAL SALES (Gwh)									
14.	Sales: Residential	407	433	503	524	562	592	609	620	6.2
	Industrial	185	212	246	283	300	320	340	358	9.9
	Commercial	61	66	70	73	79	86	90	95	6.7
	Government	n.a.	n.a.	44	59	66	92	101	104	18.8[i]
	Bulk	n.a.	n.a.	39	40	41	47	43	44	2.4[i]
	Total	725	779	901	979	1048	1137	1183	1222	7.7
	SALES FORECAST ACCURACY[b]									
15.	Sales: Industrial	103	99	102	106	107	116	121	123	
	Others	106	113	107	108	112	111	117	128	
	Total	105	109	105	107	111	113	118	127	
	RETURN FORECAST (Col. Pesos mln.)									
16.	Operating Revenues[c]	47.8	53.4	59.6	65.9	72.8	80.3	87.9	97.2	10.7
17.	Less: Operating Costs[d]	20.8	23.8	27.3	31.0	35.0	38.0	43.3	51.0	13.7
18.	Operating Income	27.0	29.6	32.3	34.9	37.8	42.3	44.6	46.2	8.0
19.	Financial Rate of Return on Av. Net Fixed Assets in Operation (%)[f]	17.5	12.5	11.0	10.0	9.3	10.0	8.4	7.2	
	ACTUAL RETURN (Col. Pesos mln.)[e]									
20.	Operating Revenues[c]	46.7	46.8	61.9	65.0	65.4	71.2	78.8	89.1	9.6
21.	Less: Operating Costs[d]	22.4	25.6	30.4	29.9	33.2	37.6	42.9	45.9	10.8
22.	Operating Income	24.3	21.2	31.5	35.1	32.2	33.6	35.9	43.2	8.6
23.	Financial Rate of Return on Av. Net Fixed Assets in Operation[f]									
	(1) non-revalued assets (%)	19.9	11.0	13.9	16.0	12.6	12.2	13.7	18.4	
	(2) revalued assets (%)[g]	15.5	9.2	8.8	10.0	7.3	5.5	5.9	7.9	
	RETURN FORECAST ACCURACY[b]									
24.	Operating Revenue	102	114	96	101	111	113	112	109	
25.	Operating Costs	93	93	90	104	105	101	101	111	
26.	Operating Income	111	140	103	99	117	126	124	107	

a/ Effective Peak: The critical time in the year when margin between demand and available capacity was least or load shedding greatest (excluding short-term outages).
b/ Defined by the ratio Forecast/Actual.
c/ Total Revenues, excluding indirect taxes.
d/ Including depreciation and direct taxation on utility, but excluding interest.
e/ All current or historic pesos have been converted to 1961 constant pesos for the purpose of comparison with the Loan 282-CO Appraisal Report Forecasts, using the national GDP deflator.
f/ Net Revenues after taxes as % of average net fixed assets in operation.
g/ Revaluation of assets computations as calculated by IBRD in Annex I.
h/ Average annual rate of increase over 1962-1968.
i/ Average annual rate of increase over 1963-1968.

TABLE II-A.3

COLOMBIA: EMPRESAS PUBLICAS DE MEDELLIN - ELECTRICITY DEPARTMENT
LOAN 369-CO (January 28, 1964)

No.	Item	1964	1965	1966	1967	1968	1969	1970	Average Annual Increase Rate (%) 1964-1970
	LOAD FORECASTS (MW)								
1.	Installed Capacity	216	252	342	387	450	450	582	17.9
2.	Annual Peak Demand	248	268	291	318	350	380	418	9.1
3.	Gross Reserve Capacity (1-2)	-32	-16	51	69	100	70	164	34.0 h/
	ACTUAL LOAD (MW)								
4.	Installed Capacity	245	308	443	443	443	443	443	10.4
5.	Annual Peak Demand	232	267	289	310	327	350	371	8.2
6.	Gross Reserve Capacity (4-5)	13	41	154	133	116	93	72	33.0
7.	Effective Peak Capacity a/	221	242	302	418	443	424	443	12.3
8.	Effective Peak Demand a/	231	243	260	295	327	343	371	8.2
9.	Effective Peak Spare Capacity (7-8)	-10	-1	42	123	116	81	72	14.4 h/
	LOAD FORECAST ACCURACY b/								
10.	Installed Capacity	88	82	77	87	102	102	131	
11.	Annual Peak Demand	107	100	101	103	107	109	113	
12.	Gross Reserve Capacity	-	-	33	52	86	75	227	
	SALES FORECAST (Gwh)								
13.	Sales: Residential	570	619	675	737	805	869	952	8.9
	Industrial	265	295	328	364	405	450	500	11.2
	Commercial	66	71	77	83	89	96	104	7.9
	Government	75	83	92	101	113	125	138	10.7
	Bulk	35	37	39	41	43	45	47	5.0
	Total	1011	1105	1211	1326	1455	1585	1741	9.5
	ACTUAL SALES (Gwh)								
14.	Sales: Residential	524	562	592	609	620	637	n.a.	4.0 i/
	Industrial	283	300	320	340	358	414	n.a.	7.9 i/
	Commercial	73	79	86	90	96	108	n.a.	8.1 i/
	Government	59	66	92	101	104	132	n.a.	17.5 i/
	Bulk	40	41	47	43	44	40	n.a.	0 i/
	Total	979	1048	1137	1183	1222	1331	1496	7.3
	SALES FORECAST ACCURACY b/								
15.	Sales: Residential	109	110	114	121	130	137	n.a.	
	Industrial	94	98	103	107	113	109	n.a.	
	Commercial	91	90	90	92	93	89	n.a.	
	Government	128	126	100	100	108	95	n.a.	
	Bulk	88	90	93	95	97	112	n.a.	
	Total	103	105	107	112	119	119	116	
	RETURN FORECAST (Col. Pesos mln.) k/								
16.	Operating Revenues c/	104.1	126.9	153.8	168.4	184.9	-	-	15.4
17.	Less: Operating Costs d/	39.5	44.8	53.7	57.9	70.1	-	-	15.4
18.	Operating Income	64.6	82.1	100.1	110.5	114.8	-	-	15.4
19.	Financial Rate of Return on Av. Net Fixed Assets in Operation (%) f/	21.3	20.1	20.0	21.9	14.3	-	-	
	ACTUAL RETURN (Col. Pesos mln.) e/								
20.	Operating Revenues c/	100.0	109.0	137.0	164.2	202.5	252.5	n.a.	19.3 i/ 8.1 j/
21.	Less: Operating Costs d/	41.5	50.6	66.3	82.2	95.3	101.3	n.a.	18.1 i/ 8.8 j/
22.	Operating Income	58.5	58.4	70.7	82.0	107.2	151.2	n.a.	16.4 i/ 4.2 j/
23.	Financial Rate of Return on Av. Net Fixed Assets in Operation f/								
	(1) non-revalued assets (%)	16.0	12.6	12.2	13.7	18.4	25.4	n.a.	
	(2) revalued assets (%) g/	10.0	7.3	5.5	5.9	7.9	10.7	n.a.	
	RETURN FORECAST ACCURACY b/								
24.	Operating Revenue	104	116	112	103	91			
25.	Operating Costs	95	89	81	70	74			
26.	Operating Income	110	140	142	135	107			

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a/ Effective Peak: The critical time in the year when margin between demand and available capacity was least or load shedding greatest (excluding short-term outages).
b/ Defined by the ratio Forecast/Actual.
c/ Total Revenues, excluding indirect taxes.
d/ Including depreciation and direct taxation on utility, but excluding interest.

e/ In current prices.

f/ Net Revenues after taxes as % of average net fixed assets in operation.
g/ Revaluation of assets computation as calculated by IBRD in Annex I.

h/ Average annual rate of increase over 1966-1970.
i/ Average annual rate of increase over 1964-1968 for non-deflated figures.
j/ Real growth rate over 1964-1968, calculated by using national GDP deflator.
k/ Includes estimated inflation factor

COLOMBIA: EMPRESAS PUBLICAS DE MEDELLIN (EPM) - ELECTRICITY DEPARTMENT
UTILITY INVESTMENT PROGRAMS PARTLY FINANCED BY IBRD (US$ million)

TABLE II-B

	LOAN 225-CO(1959) PERIOD 1959-62 FORECAST Total	FORECAST % of Total	ACTUAL Total	ACTUAL % of Total
SOURCES OF FUNDS				
1. Net Internal Cash Generation	4.14	12 b/	9.52	31
2. Domestic Contribution:				
from private sector	12.80 c/	38		
from public sector				
EPM Reserve Fund			6.12	20
Total Domestic Contribution	12.80	38	6.12	20
3. Foreign Borrowing:				
IBRD	12.00	35	14.31	48
Other	4.93 d/	15	.28	1
Total	16.93	50	14.59	49
4. Total Sources	33.87	100	30.23	100
APPLICATION OF FUNDS				
5. Total Fixed Investments	33.25	98	32.43	99
6. Change in Working Capital and Cash	.62	2	.49	1
7. Total Applications	33.87	100	32.92 a/	100

	LOAN 282-CO(1961) PERIOD 1960-66 FORECAST Total	FORECAST % of Total	ACTUAL Total	ACTUAL % of Total
SOURCES OF FUNDS				
1. Net Internal Cash Generation	24.58	33	26.79	36
2. Domestic Contribution:				
from private sector				
from public sector			4.16	6
EPM Reserve Fund			5.18	7
Total Domestic Contribution			9.34	13
3. Foreign Borrowing:				
IBRD	31.20	42	38.80	50
Other	19.18 e/	25	.52	1
Total	51.00	67	39.32	51
4. Total Sources	75.58	100	75.45	100
APPLICATION OF FUNDS				
5. Total Fixed Investments	75.64	100	79.52	100
6. Change in Working Capital and Cash	-.06	-	.06	-
7. Total Applications	75.58	100	79.58 a/	100

	LOAN 369-CO(1964) PERIOD 1963-68 FORECAST Total	FORECAST % of Total	ACTUAL Total	ACTUAL % of Total
SOURCES OF FUNDS				
1. Net Internal Cash Generation	37.99	34	26.79	37
2. Domestic Contribution:				
from private sector	3.89	3		
from public sector			4.31	6
EPM Reserve Fund			-1.66	-
Total Domestic Contribution	3.89	3	2.65	4
3. Foreign Borrowing:				
IBRD	64.20	58	41.39	56
Other	5.46	5	.73	1
Total	69.66	63	42.12	59
4. Total Sources	111.54	100	71.56	100
APPLICATION OF FUNDS				
5. Total Fixed Investments	104.52	94	74.42	100
6. Change in Working Capital and Cash	7.02	6	.16	-
7. Total Applications	111.54	100	74.59 a/	100

a/ The discrepancy between actual application of funds and actual sources of funds is primarily due to the unavailability of data on interest during construction which should have been deducted from total Fixed Investments.

b/ Revised Bank forecasts made one year after these original appraisal report forecasts show a revised estimate of net internal cash generation for 1959-62 of US$ 13.89 representing 41% of total sources, a figure more closely corresponding to the side letter provision calling for a self-financing rate of at least 30% over the 1959-64 period.

	Terms of Loans:	Interest (1%)	Amortization (yrs)
c/	Short-term Local Loans	7.0	n.a.
d/	Foreign Currency Loan	7.0	25
e/	Foreign Currency Loan	5.75	25

COLOMBIA: EMPRESAS PUBLICAS DE MEDELLIN (EPM) - ELECTRICITY DEPARTMENT
PROJECTS IMPLEMENTATION

TABLE III

		Start Construction	Commissioning Date	Construction Period (months)	Project	Scope a/	Construction Cost b/ (US$ million) L.C. c/	F.X.	Total	Cost/KW US $
LOAN 225-CO (US$ 12 million) (signed May, 1959)										
Troneras Unit 1 j/	Forecast	Mid 1959	Mid 1962	36	1 x 16 MW	Hydro	3.16	1.30	4.46	279.2
	Actual	Jan. 1960	Dec. 1964	59	1 x 18 MW	Hydro	4.37	1.47	5.84	324.7
Troneras Unit 1 (including associated transmission) j/	Forecast	Mid 1959	Mid 1962	36	1 x 16 MW	Hydro	3.23	1.50	4.73	295.3
	Actual	Jan. 1960	Dec. 1964	59	1 x 18 MW	Hydro	4.66	2.20	6.86	381.1
Guadalupe III Unit 1 & 2 l/	Forecast	Mid 1959	Early 1961	18	2 x 40 MW	Hydro	3.12	5.12	8.24	103.0
	Actual	Oct. 1959	Nov. 1962	37	2 x 45 MW	Hydro	4.32	5.78	10.10	112.2
Guadalupe III Unit 1 & 2 l/ (including associated transmission)	Forecast	Mid 1959	Early 1961	18	2 x 40 MW	Hydro	3.39	5.99	9.38	117.3
	Actual	Oct. 1959	Nov. 1962	37	2 x 45 MW	Hydro	5.57	9.21	14.78	164.2
LOAN 262-CO (US$ 22 million) (signed May 1961)										
Troneras Units 1 & 2 k/	Forecast	Mid 1961 d/	Sept. 1963	26	2 x 18 MW	Hydro	3.58	2.63	6.21	172.5
	Actual	Early 1962 d/	Feb. 1965	36	2 x 18 MW	Hydro	5.61	2.87	8.48	235.4
Troneras Units 1 & 2 k/ (including associated transmission)	Forecast	Mid 1961 d/	Sept. 1963	26	2 x 18 MW	Hydro	4.00	3.21	7.21	200.3
	Actual	Early 1962 d/	Feb. 1965	36	2 x 18 MW	Hydro	6.08	3.99	10.07	279.7
Guadalupe III Units 1-6 m/	Forecast	Early 1962 e/	Dec. 1965 f/	45	2 x 45 MW 3 x 40 MW	Hydro	7.08	15.96	23.04	109.7
	Actual	Jan. 1963 e/	Sept. 1966 f/	45	6 x 45 MW	Hydro	16.58	17.60	34.18	126.6
Guadalupe III Units 1-6 m/ (including associated transmission)	Forecast	Early 1962 e/	Dec. 1965 f/	45	2 x 45 MW 3 x 40 MW	Hydro	10.00	19.51	29.51	140.5
	Actual	Jan. 1963 e/	Sept. 1966 f/	45	6 x 45 MW	Hydro	19.33	24.62	43.95	162.8
LOAN 225-CO & 262-CO										
Distribution System	Forecast	n.a.	n.a.	n.a.	1100 km	13.2 kv	3.06	4.88	7.94	
	Actual	n.a.	n.a.	n.a.			1.78	6.35	8.13	
LOAN 369-CO (US$ 45 million) h/ (signed Feb., 1964)										
Guatape Units 1 & 2	Forecast	Mid 1965	Mid 1969	48	2 x 66 MW	Hydro	24.74	33.91	58.65	443.5
	Actual	End 1966	Sept. 1971	60	2 x 66 MW	Hydro	n.a.	n.a.	n.a.	n.a.
Guatape Units 1 & 2 (including associated transmission)	Forecast	Mid 1965	Mid 1969	48	2 x 66 MW	Hydro	25.33	35.20	60.53	458.6
	Actual	End 1966	Sept. 1971	60	2 x 66 MW	Hydro	n.a.	n.a.	n.a.	n.a.
Guatape Units 1-4	Forecast	g/	g/		4 x 66 MW	Hydro	26.24	35.96	62.20	235.6
	Actual	g/	End 1971 g/		4 x 66 MW	Hydro	n.a.	n.a.	n.a.	n.a.
Guatape Units 1-4 (including associated transmission)	Forecast	g/	g/		4 x 66 MW	Hydro	26.88	37.36	64.24	243.3
	Actual	g/	End 1971 g/		4 x 66 MW	Hydro	n.a.	n.a.	n.a.	n.a.

LOANS DISBURSEMENT PATTERN

			1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	Undisbursed 12/31/70
LOAN 225-CO	Forecast:	Amount (US$mln)	6.15	2.60	2.19	1.06									
		% of total	51.2	21.7	18.3	8.8									
		Cumulative %	51.2	72.9	91.2	100.0									
	Actual:	Amount (US$mln)	2.67	1.98	4.49	2.82	.04								
		% of total	22.3	16.5	37.4	23.5	0.3								
		Cumulative %	22.3	38.8	76.2	99.7	100.0								
LOAN 262-CO	Forecast:	Amount (US$mln)			2.03	4.52	6.21	6.50	2.74						
		% of total			9.2	20.5	28.3	29.5	12.5						
		Cumulative %			9.2	29.7	58.0	87.5	100.0						
	Actual:	Amount (US$mln)			.06	2.73	4.19	6.26	4.94	2.82	.81	.19			
		% of total			0.3	12.4	19.0	28.4	22.5	12.8	3.7	0.9			
		Cumulative %			0.3	12.7	31.7	60.1	82.6	95.4	99.1	100.0			
LOAN 369-CO	Forecast:	Amount (US$mln)						5.58	7.68	12.74	13.25	5.55			
		% of total						12.4	17.5	28.3	29.5	12.3			
		Cumulative %						12.4	29.9	58.2	87.7				
	Actual:	Amount (US$mln)						1.36	2.14	4.68	5.94	7.77	6.35	5.70	11.06 i/
		% of total						3.2	5.1	11.1	14.1	18.5	15.1	13.6	
		Cumulative %						3.2	8.3	19.4	33.5	52.0	67.1	80.7	

a/ Project Scope for Generation is Megawatts (MW) of installed capacity and source of energy, data was not available on kilometers of line or transformer capacity of Distribution components.
b/ Does not include interest during construction; inflationary contingencies were excluded from forecast projections for comparison purposes with deflated actual costs.
c/ Local costs of projects were computed by converting for each year the Col. Peso expenditure incurred during that year into constant 1968 pesos (GDP deflator) and then converting into US Dollars at the 1968 average annual official exchange rate for imports of goods and services (Ps 15.90=US$ 1.00).
d/ Starting date for Unit 2 only.
e/ Starting date for Unit 3 only.
f/ Unit 6 was not included in the original list of goods; attractive financial arrangements on the equipment resulted in savings which were used to purchase one additional unit for Guadalupe III.
g/ Although the original Appraisal Report forecasts projected an additional 2 units to be installed at a later date, Units 3 & 4 were not included in the original project costs or list of goods; however, the actual financial arrangements on the equipment resulted in savings which were used to purchase these 2 additional units.
h/ Actual final costs are not available due to the recent termination of the project.
i/ US$ 3.0 million were cancelled in August 1970.
j/ Includes 17% of costs of roads, construction equipment and diversion of the Conception and Tenche rivers.
k/ Includes 12% of cost of Miraflores dam and engineering.
l/ Includes 83% of costs of roads, construction equipment and diversion of the Conception and Tenche rivers.
m/ Includes 88% of cost of Miraflores dam and engineering.

Chart 11.1

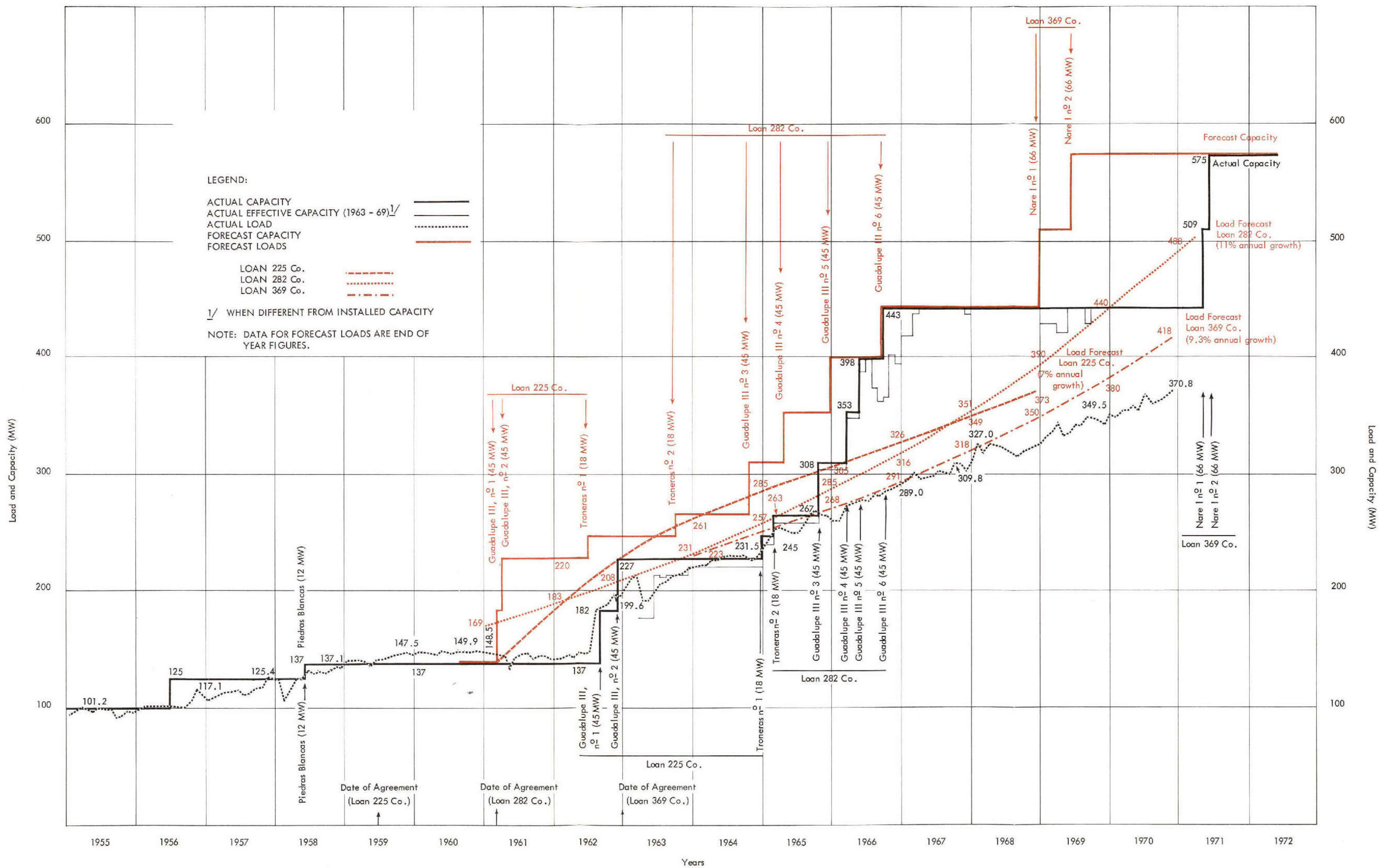
COLOMBIA

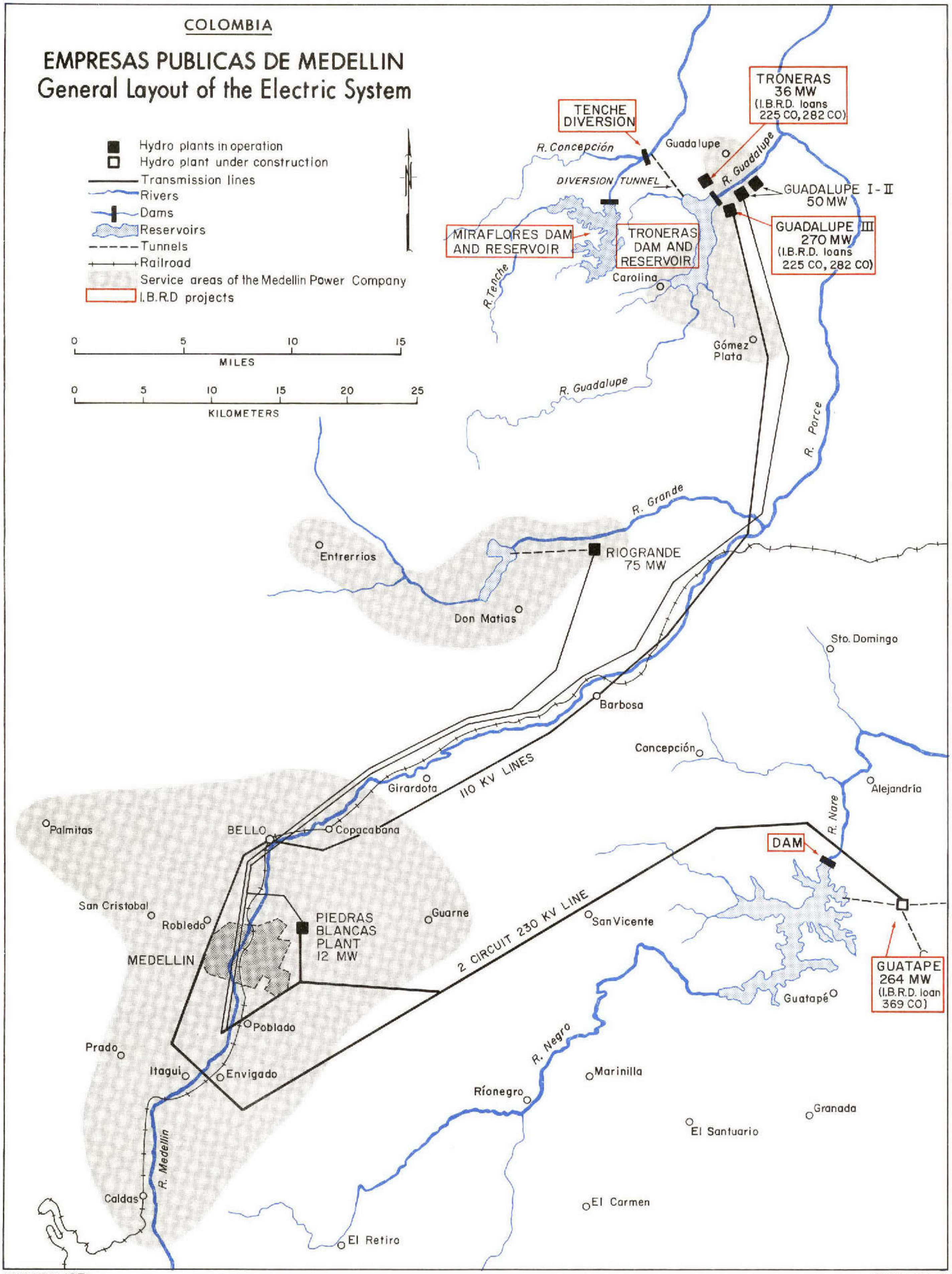
EMPRESAS PUBLICAS DE MEDELLIN - POWER

LOAD AND CAPACITY DEVELOPMENT

ACTUAL AND FORECAST

(1955-1971)




COLOMBIA
EMPRESAS PUBLICAS DE MEDELLIN
General Layout of the Electric System
Hydro plants in operation
Hydro plant under construction
Transmission lines
Rivers
Dams
Reservoirs
Tunnels
Railroad
Service areas of the Medellin Power Company
I.B.R.D projects
0 5 10 15
MILES
0 5 10 15 20 25
KILOMETERS
TENCHE DIVERSION
TRONERAS 36 MW (I.B.R.D. loans 225 CO, 282 CO)
R. Concepción
Guadalupe
R. Guadalupe
DIVERSION TUNNEL
GUADALUPE I-II 50 MW
MIRAFLORES DAM AND RESERVOIR
TRONERAS DAM AND RESERVOIR
GUADALUPE III 270 MW (I.B.R.D. loans 225 CO, 282 CO)
R. Tenche
Carolina
Gómez Plata
R. Guadalupe
R. Porce
R. Grande
Entrerrios
RIOGRANDE 75 MW
Don Matias
Sto. Domingo
Barbosa
Concepción
110 KV LINES
Girardota
Alejandría
Palmitas
BELLO
Copacabana
R. Nare
DAM
San Cristobal
Robledo
PIEDRAS BLANCAS PLANT 12 MW
Guarne
San Vicente
2 CIRCUIT 230 KV LINE
MEDELLIN
GUATAPE 264 MW (I.B.R.D. loan 369 CO)
Guatapé
Poblado
Prado
Itagui
Envigado
R. Negro
Marinilla
Rionegro
Granada
El Santuario
R. Medellin
Caldas
El Carmen
El Retiro
OCTOBER 1971
IBRD-3542R

CHAPTER XII - CVC/CHIDRAL - COLOMBIA

I. Introduction

1.01 The Central Hidroelectrica del Rio Anchicaya Ltda. (CHIDRAL) was organized under Colombian law in 1944[1/] and was given full rights to the power development of the Anchicaya River, near Cali. The power entity was established as a commercial company of limited liability with the national, departmental, and municipal governments as the only shareholders and holding, respectively, 51%, 23%, and 26% of the original share capital. In 1955, the Corporacion Autonoma Regional del Cauca (CVC) was established as a regional development agency, set up along the lines of the U.S. Tennessee Valley Authority, to coordinate the overall development of the natural resources of the Cauca Valley (including Cali). As this overall development naturally included development of power resources, it was logical that the efforts of the two entities, CVC and CHIDRAL, should be themselves as closely coordinated as possible. In practice, however, consolidation of the two entities has proved quite difficult. In 1958, the National Government transferred its majority shareholding in CHIDRAL to CVC, but the two affiliates still maintain their own boards of directors, general managers, and financial accounts. Under the present system CVC carries out the planning of new projects, enters into contracts for their construction, and upon completion turns them over to CHIDRAL for operation. The difficulty in differentiating between fixed assets under construction and in operation, and the recurrent inconsistencies between the financial statements prepared by

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1/ Reorganized on the same basis in 1950.

the two entities have made it hard to evaluate the performance of the CVC/CHIDRAL complex; for the purposes of this study the performance of CHIDRAL is defined to include all joint CVC-CHIDRAL power development programs, and exclude CVC's own (negligible) separate electric power operations.

1.02 Shortly after CHIDRAL was organized it began construction of the Anchicaya hydroplant with a planned ultimate capacity of 90 MW, but construction had to be halted in 1948 due to unsatisfactory foundation conditions which rendered the original design unsuitable. By the end of 1950, the dam had been redesigned and a loan application for financing by the Bank had been approved; the first two 12.0 MW units came into operation in July 1955. This was the first of five IBRD loans to CHIDRAL which, by 1970, had helped to finance 217 MW (or 87.5%) of CHIDRAL's total 248 MW of installed capacity.

1.03 All power generated by CHIDRAL is sold in bulk to retail distributors, by far the most significant of which is the Empresas Municipales de Cali (EMCALI), serving the city of Cali. CHIDRAL has also sold a smaller portion of its energy since 1961 to CVC, which, in addition to coordinating CHIDRAL's expansion program and executing major parts of it, has itself a small retail electric energy distribution operation covering smaller towns in the Cauca Valley. Since 1964, CVC's purchases have comprised about 20% of CHIDRAL's total sales. In addition, the Corporacion de Electricidad Colombiana (COEDEC) has purchased in recent years, through CVC, about 3% of CHIDRAL's bulk energy.

Loan No.	Date of Loan Agreement	Effective Date	Closing Date	Amounts ($ mln) Committed	Disbursed	Interest %	Period (years) Grace	Term
38-CO	11/50	2/51	3/55	3.53	3.53	4	4	20
113-CO	3/55	6/55	12/58	4.50	4.50	4 3/4	4	20
215-CO	12/58	1/60	4/63	2.80	2.80	5 3/4	2	20
255-CO	5/60	10/60	3/66	25.00	25.00	6	3	25
339-CO	6/63	10/63	12/65	8.80	8.80	5 1/2	3	20
TOTAL				44.63	44.63			

2.02 By the end of World War II the power supply situation in Cali was critical -- the Empresas Municipales de Cali owned a few small hydro and diesel units which by 1944 were already inadequate to meet the growing power demand of the city. For this reason, as mentioned previously, CHIDRAL was established to develop the electric power resources of the Anchicaya river and began to build the Anchicaya hydroplant. A preliminary loan request for aid in financing the project was presented to the Bank in 1948; due to difficult geological conditions, however, CHIDRAL was forced to redesign the dam and the project was not actually ready for Bank consideration until 1949. Late in 1949 the Bank's General Survey Mission to Colombia confirmed the priority of the project. In early 1950 the company was notified that, prior to any loan agreement, (a) adequate measures should be taken to raise the company's share capital by approximately Ps. 6 million to cover the local currency amount required to complete the project, and (b) satisfactory contracts should be agreed upon by CHIDRAL and the Municipality covering the terms and conditions under which electricity would be sold to the city. Under this agreement, CHIDRAL would acquire two old municipally-owned diesel plants so as to become the only supplier of electric energy to the city of Cali, while EMCALI would remain responsible for distribution. The loan for US$ 3.53 million was signed on November 2, 1950 although it did not become effective until the previous two conditions were met in February 1951.

2.03 The first two 12 MW units at Anchicaya, however, were not commissioned on schedule and the critical electricity shortage in Cali grew increasingly worse, particularly as Cali was by that time the fastest growing city in Colombia. By 1954 a rather considerable backlog of demand had built up due to the fact that CHIDRAL had been forced by the circumstances to refuse new residential and commercial connections and industrial enterprises had been forced to install their own generating plants. The interim report on the Colombian National Electrification Plan[1/] in 1954 recommended the immediate expansion of the generating facilities of CHIDRAL's system by at least 32.5 MW, in addition to the expeditious completion of the first (24 MW) stage of Anchicaya.

2.04 In April 1954, the Bank was requested to finance the foreign exchange costs of CHIDRAL's proposed expansion program which called for the installation of a third 20 MW[2/] unit at Anchicaya and the construction

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1/ Power survey made by Gai Pan American Corporation (GAIPAN), a subsidiary of Gilbert Associates of New York, and by the Colombian Technical Mission, a combination of Gibbs and Hill of New York and Electricite de France.

2/ Due to a favorable option from the supplier, EMCALI decided to purchase from its own funds a fourth unit (20 MW) which was also installed.

of a 12.5 MW thermal plant at Yumbo, an industrial suburb of Cali. After consultation with the National Planning Department on the immediate necessity of building the thermal plant, the Bank decided to go ahead with the project as presented. Negotiations were completed shortly thereafter and Loan 113-CO for US$4.5 million was signed on March 24, 1955, but a verbal agreement was reached that the company would negotiate for higher tariffs in the near future, and loan effectiveness was made conditional on two steps:

(a) CHIDRAL was to obtain from the Municipality of Cali assurances satisfactory to the Bank that the municipal electric distribution system would be expanded "to a capacity sufficient to distribute all energy generated by the borrower".

(b) Arrangements satisfactory to the Bank would have to be made to secure the local currency needed for expenditures in 1955 and 1956.

2.05 In October 1954, at the Bank's recommendation, the President of Colombia established CVC as a regional development agency for the Cauca Valley, and its charter was approved in June 1955. By the end of that year, CVC had made its first request for a Bank loan to cover the foreign exchange costs of the proposed Calima Hydroelectric Plant, while CHIDRAL had simultaneously requested Bank financing for a second unit (12.5 MW) to be added to the Yumbo plant already under construction under Loan 113-CO.

However, the Bank's two-year suspension of consideration of new loans to Colombia, due to the country's deteriorating economic and political situation, precluded further consideration of either project until 1958.

2.06 After the resumption of normal relations between the Bank and Colombia in that year, CVC had changed its position, in view of modification to its initial Calima scheme, and now supported early construction of Yumbo 2, but with the important qualification that --to establish its position in the power field firmly-- it be the loan recipient rather than CHIDRAL. The complexity of the negotiations between the Bank, CVC, and CHIDRAL in this regard is indicative of the generally difficult relations between the two companies, especially with regard to the transfer of assets and operating responsibility.

2.07 Since, however, CVC had as yet little experience in the power field, and since the transfer of the Government's share in CHIDRAL to CVC had been effected satisfactorily, indicating possibly improved coordination between the companies in the future, the loan for Yumbo 2 (215-CO) was ultimately extended to CHIDRAL. The project consisted of a second 10 MW addition to Yumbo, enlargement of substations in Cali and Yumbo, a dredge for the Anchicaya reservoir, studies on a possible third unit at Yumbo, and $550,000 to be re-lent to EMCALI for improvement of the distribution system. There were three conditions to effectiveness placed upon the US$2.8 million loan as follows:

(a) EMCALI was to agree to furnish all funds, local and foreign, in excess of the amount provided above to complete the distribution program. 1/

(b) Authorization of an "appropriate" increase in tariffs (not less than 30%) for both CHIDRAL and EMCALI by the Government.

(c) Debts of CHIDRAL to the Colombian Stabilization Fund and the Bank of the Republic were to be assumed by CVC. 2/

2.08 The last two IBRD loans for development of the power resources of Cali and the Cauca Valley (255-CO and 339-CO) were made to CVC and CHIDRAL jointly on the understanding that CVC would be the planning, design, and construction supervisor, while CHIDRAL would be the operating entity. Conditions were specified under which the facilities financed by the loans were to be transferred to CHIDRAL. Projects included in the first of the two joint loans (255-CO) consisted of:

(a) addition of a 33 MW unit to the existing Yumbo Thermal plant (Yumbo 3) to meet immediate demand requirements.

(b) construction of the 120 MW Calima I hydroplant with the initial installation of two 30 MW units.

1/ Construction of a distribution ring about Cali.

2/ This was accomplished by act of Law 25 of May 1959 in which CVC assumed these debts (some Ps. 7.7 million) in return for a like increase in its share of CHIDRAL's share capital.

(c) expansion of the distribution networks in Cali, and also in 9 smaller towns and 16 villages which were the responsibility of CVC.

(d) construction of a 154 kilometer 115 kv transmission line through the central part of the Cauca Valley between Yumbo and Cartago, which would connect the CVC-CHIDRAL system with that of CHEC. 1/

The amount of the loan was US$25.0 million of which Yumbo Unit 3 was to represent $4.4 million and Calima I (including Units 1 and 2) was to represent $14.5 million.

2.09 Conditions and covenants included in the loan, aside from that dealing with transfer of assets previously mentioned, were principally aimed at encouraging CHIDRAL to raise sufficient funds to finance the projects' local currency costs. The two financial covenants were that (1) CHIDRAL should seek to maintain its tariff rates at a level adequate to provide a reasonable operating surplus to finance new investments, and (2) that in the event CHIDRAL was unable to do so, CVC would provide the funds necessary to carry out the project. In addition, it was agreed that CHIDRAL would have its accounts audited annually by an outside source, and that whether or not a new loan was granted, the company would not incur new debt without the Bank's consent if at the time of considering such borrowing the company's actual revenues of the previous twelve months were less than 1.3 times the size of its current plus proposed debt service. This understanding replaced earlier agreements that the

1/ The Central Hidroelectrica de Caldas, serving Manizales.

company's debt/equity ratio should not exceed 50/50 because this previous arrangement had proved to be unrealistic.

2.10 While construction of the third unit at Yumbo was carried out efficiently 1/ and operation began as scheduled, many difficulties arose in connection with the construction of Calima which ultimately delayed the plant's commissioning by about two years and resulted in total cost overruns of some 46%. For this reason a new loan, 339-CO, for US$8.8 million, was negotiated between CVC/CHIDRAL and the Bank to finance the foreign exchange costs of completing Calima I (expanded to include Units 3 and 4 of 30 MW each), associated distribution expansion, and construction of a 115 kv transmission line between the Anchicaya power station and the seaport of Buenaventura. Covenants were essentially the same as under the previous loan except that they were more specific, providing that: (1) tariff rates should be raised as soon as possible and, in any case, not later than August 31, 1963; (2) CHIDRAL was expected to finance, from internally generated funds, a significant portion of its power expansion program, increasing from 10% in 1963-65 to 30% by 1968-70.

2.11 Since Loan 339-CO, the Bank has not participated actively in financing CVC/CHIDRAL's expansion program, although it was approached in 1964 to cover further overruns on Calima I and a fourth unit at Yumbo, in 1965 to participate in building the proposed Calima II hydro-plant, and in 1967 to finance the Alto Anchicaya project. Although the Bank refused to consider loans on the first two projects because it was dissatisfied with the National Government's policies toward necessary tariff increases and had some doubt about the feasibility of the projects,

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1/ Even involving savings of some US$0.7 million below the forecast cost.

it probably would have financed the Alto Anchicaya hydroplant now under construction had the IDB not expressed its desire to do so.

III. Major Issues

Coordination of Investment in the Sector

3.01 Public electricity in Colombia is almost entirely supplied by four entities: EEEB serving Bogota, EPM serving Medellin, CVC/CHIDRAL serving Cali and the Cauca Valley, and the Instituto Colombiano de Energia Electrica (ICEL), a government holding company which controls 15 subsidiary power companies serving 20 of the 29 Departments not served by the aforementioned three major companies. The isolated nature and overly-emphasized independence of the various systems, coupled with inadequate delineation between the jurisdiction of the power companies, have led to creation of a social and financial gap between the large companies serving privileged markets, on the one hand, and the numerous small entities serving areas of generally uneconomic size [1/] on the other. This gap has, in turn, led to misallocations and inefficient uses of resources.

3.02 In concentrating its lending on the four main population centers, the Bank has contributed to widening this gap -- of the 17 loans representing US$294.1 million to the sector, 13 loans representing US$216.4 million have gone to the companies serving these four areas. This may have been unavoidable given the power sector's set-up in Colombia at the time. One of the major reforms introduced in recent years, however, has been the creation of two new companies, Interconexion Electrica S. A. (ISA) and Corporacion

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1/ Basically, the subsidiaries of ICEL with the notable exception of CHEC (Central Hidroelectrica de Caldas) serving Manizales.

Electrica de la Costa Atlantica (CORELCA), for the purpose of interconnecting major parts of the national electric network. The role of the Bank was quite important on this issue, particularly with regard to ISA; by refusing to consider lending for new power projects in Colombia after 1963, except those planned within the framework of interconnection, the Bank was able to exert the necessary pressure to bring the major parties (EEEB, EPM, CVC/CHIDRAL, CHEC) to agreement. CHIDRAL is expected to be one of the major beneficiaries of the improved electric service and nationally coordinated expansion planning these organizations promise.

Tariffs

3.03 Rate adjustments in Colombia are authorized by the National Government which for political reasons has often been most reluctant to grant them. For this reason electricity tariffs in Colombia have traditionally been among the lowest in the world. The situation is further complicated in the case of CHIDRAL since EMCALI has control over CHIDRAL's Board of Directors in matters regarding tariff policies, and it has been exceedingly difficult for CHIDRAL even to submit applications to the National Government for tariff increases. 1/

3.04 The difficulties encountered by CHIDRAL in connection with tariff increases are partly responsible for the poor financial performance of the company, especially in 1955, 1958-59, 1963-64 and 1966. Over the last twenty years, the Bank has firmly insisted that adequate tariff increases be regularly implemented, but only on the occasion of the

1/ EMCALI, the city-owned distributor, has always been reluctant to increase its own tariffs because of feared local political repercussions such as the street riots of 1969.

third loan (Loan 215-CO) was such an increase made a condition of loan effectiveness. In the first loan (38-CO) no covenant at all[1/] regarding tariff increases was made and in the second loan (113-CO) simple verbal assurances by CHIDRAL that an appropriate tariff increase was to become effective shortly were accepted (in fact, however, no increase came about until a Bank staff member was sent to Cali to discuss the matter -- one year later). More than a year elapsed between signature and effectiveness of the third loan as a result of delay on tariff action. The last two loans (255-CO and 339-CO) did include conditions specifying that CHIDRAL should seek to maintain an adequate level of tariffs, but on the whole it seems that the Bank has taken a rather easier position on the tariff issue with CVC/CHIDRAL than with EEEB or EPM. Given the institutional set-up of electric power in Cali, the Bank should probably not have hesitated to deal directly with EMCALI on the tariff issue.

3.05 Although adequate financial statistics regarding the self-financing ability of CVC/CHIDRAL are not available and no definite conclusions on this matter can be drawn, it is possible to observe that, in view of the substantial National Government subsidies the complex has received, CVC/CHIDRAL's own contribution to its expansion program has been quite low and the company has not been able to achieve the self-sufficiency and independence of EPM and EEEB. This is largely due to the aforementioned difficulties the company has had in securing tariff increases. Some improvement in securing tariff increases and consequently

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1/ The contract between CHIDRAL and EMCALI included a provision for tariff adjustments to reflect the devaluation of the peso in relation to the dollar, and financial projections in the appraisal were based on this, but it was not a Bank covenant as such.

in the company's financial performance, has occurred in recent years; CHIDRAL's average revenue per kwh sold was only US¢0.7 equivalent in 1966 compared to US¢1.1 for EEEB and US¢0.9 for EPM, but rose to US¢1.1 by 1969 -- identical with the levels of EEEB and EPM. Furthermore, the recent creation of the governmental tariff regulatory agency, the Junta Nacional de Tarifas de Servicios Publicos, implies that more objective criteria may be used in determining the level of tariffs for CHIDRAL and other Colombian utilities by the Government in the future.

Project Financing

3.06 The financial difficulties of CHIDRAL and, later on CVC/CHIDRAL, stemmed partly from the high cost of power development in the Cauca Valley. Most hydrosites there proved difficult and expensive to harness. The two hydrosites developed to date, i.e. Anchicaya and Calima I, have yielded unit capital costs per KW installed of $387 equivalent[1/] and $378 equivalent[1/] respectively, as against a range of $160 to $250 for hydroplants in the case of EEEB and EPM. CHIDRAL had to include expensive thermal plants to complement its generating system. Such high investments have necessitated extensive borrowing. Between 1950 and 1968, when the IDB extended a loan to finance the Alto Anchicaya hydroelectric plant, the Bank remained CVC/CHIDRAL's sole source of foreign financing with a total disbursed amount of $44.63 million. Local currency financing was especially problematic, for there were long delays in securing additional

1/ Including transmission.

capital contributions from the stockholders and adequate tariff increases.

3.07 Local expenditures on CHIDRAL's expansion program were mainly financed through repeated increases in share capital subscribed by the three shareholders, namely CVC,[1/] the Department of Valle and the Municipality of Cali. CHIDRAL's original paid in share capital was Ps. 1.5 million in 1950, increasing to Ps. 64 million in 1960 and Ps. 105 million by 1969 (or Ps. 18 million in 1950 prices). Ever since its first loan to CHIDRAL in 1950, the Bank has taken a firm position on the necessity for the Company to regularly increase its share capital to cover local expenditures on its investment program: effectiveness of the first four loans was conditioned upon such an increase. In connection with the last two loans, it was agreed that CVC would provide CHIDRAL with the necessary funds to carry out the project if funds available to CHIDRAL became inadequate. Despite these measures, the Company found itself short of funds on many occasions during project implementation. In 1953, during the construction of Anchicaya, CHIDRAL had to borrow Ps. 4 million on a medium term basis from the Government Fondo de Estabilizacion; the first repayment on that loan had to be postponed by one year because of the Company's tight financial situation. At the end of 1953, the Bank turned down the Company's request for permission to accept a new loan from the same Fondo de Estabilizacion, for it considered that the resultant debt load would be more than could

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1/ In 1957, the shares held by Electraguas on behalf of the National Government had been transferred to CVC which now holds about 65% of CHIDRAL's share capital.

be considered prudent under the circumstances. The Bank kept insisting that actual expenditures be met from increased share capital and additional share subscriptions were obtained at the end of 1954 totalling Ps. 11.4 million, about Ps. 4.9 million above the most recent estimate of remaining expenditures to be made on Anchicaya.[1/]

3.08 In spite of a new Ps. 1.7 million increase in share capital and an additional amount of Ps. 15.0 million secured from local banking institutions, CHIDRAL found itself in a critical financial situation during the implementation period of its second expansion program (Loan 113-CO). The main reasons for this were: (a) the accumulation of expensive short term borrowing; (b) the construction and ordering of equipment for Yumbo 2 on a cash basis because financing could not be secured;[2/] (c) the devaluation of the peso in 1957, which nearly tripled the service of the foreign debt; and (d) the continued inflationary increase in operating costs.

3.09 Medium and short term debts reached a point where CHIDRAL could no longer carry them even with a substantial increase in tariffs and with the forthcoming Bank loan (Loan 215-CO). For this reason the Bank required that, as a condition of effectiveness to the new loan the debts then owed to the Fondo de Estabilizacion and the Banco de la Republica should be

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1/ In December of 1954, the Municipality of Cali had transferred to the ownership of CHIDRAL the last of its diesel plants in exchange for shares to the value of Ps. 1.5 million; the same procedure was followed later on when the Municipality decided to contribute US$510,000 for the purchase of the fourth unit at Anchicaya (which had not been provided for in Loan 113-CO).

2/ The unit was financed the following year through Loan 215-CO.

discharged or assumed by others. CVC agreed to take over some Ps. 7.7 million of CHIDRAL's debt[1/] in return for additional shares and also to extend a new Ps. 5.5 million medium term loan.

3.10 The financial situation of CHIDRAL, although it had improved substantially by 1960, remained somewhat fragile. As a condition to Loan 255-CO (May 1960), the Bank required once again that all debts currently owed by CHIDRAL to CVC be converted into equity. During negotiations, it was also agreed that local currency needs, other than those met from internal generation, would be met by equity contributions or non-interest bearing advances from CVC. CHIDRAL found itself once more in financial straits in 1964 and 1965 as a result of the large cost overrun on Calima; the debt/equity ratio which rose to 72/28 in 1964 has remained high ever since, reaching 78/22 in 1968. Also, the Colombian Government failed to live up to its agreement to permit rates to be raised and provide adequate local currency financing for the project. Finally, CVC found its revenues from land taxes to be less than had been expected at the time when Loan 255-CO was made, because the properties on which this tax was assessed were revalued more slowly than anticipated by the responsible agency of the Central Government. The Bank refused to provide additional funds to cover the cost overruns on Calima and the financing of new power developments proposed by CVC, in order to urge the Government to fulfill its obligations under the existing loans. The rigid attitude

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1/ The actual amount taken over by CVC was reduced to Ps. 7.0 million and was matched by a corresponding reduction in the amount of its equity share increase.

adopted by the Bank forced CVC to secure foreign currency funds necessary to complete Calima from other sources; credits secured from suppliers and contractors were especially expensive, however, and the corresponding debt was paid off only recently.

Financial Performance

3.11 For the many reasons discussed above, CHIDRAL's financial performance has been disappointing on the whole and no improvement seems to have taken place over the years. The table below presents a summary of some of the most relevant financial indicators:

Table 12.1

CVC/CHIDRAL - EVOLUTION OVER TIME OF SOME FINANCIAL INDICATORS

Year	Average Cost per kwh sold (1968 centavos) a/	Average Revenues per kwh sold (1968 centavos) a/	Average Profit per kwh sold (1968 centavos)	Rate of Return on non-revalued Assets %	Rate of Return on revalued Assets b/ %	Debt/ Equity Ratio
1955	9.2	17.1	7.9	n.a.	n.a.	34/66
1956	6.9	14.8	7.9	6.6	6.4	35/65
1957	9.0	13.3	4.3	7.8	3.4	55/45
1958	10.6	11.4	0.8	4.4	0.6	53/47
1959	9.7	10.2	0.5	3.4	0.4	48/52
1960	8.4	15.0	6.6	12.8	6.3	46/54
1961	8.4	13.8	5.4	10.5	5.6	48/52
1962	7.7	13.0	5.3	11.1	6.5	63/37
1963	9.3	10.7	1.4	6.3	2.0	68/32
1964	8.6	9.2	0.6	4.1	0.9	72/28
1965	9.3	12.2	2.9	9.6	3.7	70/30
1966	11.6	10.6	-1.0	6.5	neg.	69/31
1967	10.0	12.9	2.9	5.7	2.5	77/23
1968	9.6	14.3	4.7	7.6	3.7	78/22
1969	10.2	17.0	6.8	9.2	4.2	69/31

a/ Including revalued depreciation. See footnote b/.
b/ For Revaluation of Assets see Annex 1.

3.12 The table indicates that average revenues per kwh in real terms have experienced considerable fluctuations over the years, following the general inflationary trends in the economy and reflecting the several tariff increases implemented at various times. It is only after 1967 that a clear upward trend of such revenues began to appear. Fluctuations in the average unit costs were much less marked and the variations in the average rate of profit therefore mainly reflect the variations in revenues. Between 1960 and 1965, the increases in total costs were almost entirely due to rising expenditures on fuel: the share of such expenditures in total costs rose from 4.5% to 42% over the period. Fuel cost per kwh generated in thermal plants rose steadily from 5 centavos[1/] in 1960 to 8 centavos[1/] by 1965, a trend probably attributable entirely to the rising costs of coal and diesel fuel. Total expenditures on fuel dropped in 1966, following the commissioning of the first two units at Calima; in that year, the share in total costs held by depreciation reached 52%, as against 27% in the previous year.

3.13 Until 1965, the operating costs of CHIDRAL were directly related to fuel consumption, indicating the limited level of economies of scale in the system. Average cost per kwh rose after 1965, reflecting both the high depreciation provision for Calima, as well as the need to supplement local generation with purchases from elsewhere, and established itself at 10.2 centavos[1/] in 1969, a value comparable to that which had prevailed in 1958.

1/ In 1968 prices.

3.14 All the financial indicators appearing in Table 12.1 suggest that CHIDRAL has been operating at the limit of financial viability. The rate of return on revalued assets has remained very low, being generally less than 5% except for a brief period in the early 1960s, less than 1% in several years, and even negative in 1966. Between 1962 and 1967, financial performance bore the print of the high expenditures on Calima and it appears that the financial efficiency of the Company today is more or less comparable to that existing in 1955, not accounting for the heavy debt load which has built up since 1962. The debt/equity ratio rose from 34/66 in 1955 to 78/22 in 1968, despite major increases in share capital over the period. A slight recovery seems now to be taking place in this connection. Figures on debt service coverage are only available until 1962 and, from the figures shown (See Table I at end of chapter), it appears clearly that CHIDRAL has not been able to cope with the debt incurred to cover the high investments that have been necessary for the expansion of its system. Between 1950 and 1959, about 75% of local currency expenditures were met by contributions from the Company's shareholders and the balance by internal cash generation, yielding an average self-financing rate over the period of only about 14%.

Delays and Cost Overruns

3.15 Although delays in the commissioning of the three Yumbo thermal units have been negligible, considerable problems were encountered by CHIDRAL in commissioning its hydroplants, Anchicaya and Calima I.

3.16 The delay of nearly two years in commissioning the first two units of Anchicaya was mainly due to technical difficulties caused by a landslide at the site. This, in connection with difficulties encountered in importing equipment for the second stage of the Anchicaya program, contributed to substantial cost overruns for the project as a whole. A detailed breakdown of the forecast and actual project costs is presented below, but it was impossible to make a distinction between the foreign exchange and local currency components:

Table 12.2

CVC/CHIDRAL: LOANS 38-CO, 113-CO AND 215-CO - FORECAST AND ACTUAL COST OF PROJECTS (IN US$ EQUIVALENT)

Loan 38-CO[a/]	FORECAST	ACTUAL	OVERRUN[b/]
Anchicaya hydro plant	6.27	12.32	6.05
Cali Substation	0.19	0.20	0.01
Transmission Lines	0.61	0.25	(0.36)
Interest during Construction	0.27	0.80	0.53
Others	0.59		
Contingencies	0.17		
Total	8.10	13.57	

Loan 113-CO	FORECAST	ACTUAL	OVERRUN[c/]
Third Anchicaya hydro unit	2.10	5.16	3.06
Substation expansion	0.63	1.72	1.09
First Yumbo thermal unit	2.91	4.37	1.46 d/
Interest during Construction	0.56	0.63	0.07
Contingencies	0.63		
Total	6.83	11.88	

Loan 215-CO	FORECAST	ACTUAL	OVERRUN
Second Yumbo thermal unit	1.24	1.29	0.05
Enlargement of substations	0.23	0.25	0.02
Dredge and auxiliary equipment	0.40	0.39	(0.01)
Completion of distribution ring for Cali[e/]	0.55	0.55	-
Miscellaneous studies and services	0.54	0.24	(0.03)
Contingencies	0.17		
Total	3.13	2.72	

a/ Additions to projects already under construction.

b/ Overruns were financed by an increase of share capital of Ps. 6.0 million (3.5 million to Electraguas and 2.5 million to the Department of Valle), an Electraguas loan of Ps. 3.0 million and three short term loans from the Stabilization Fund amounting to Ps. 2.5 million.

c/ Local currency costs were about 300% over original estimates due to substantial increases in labor costs and prices of materials.

d/ Partly due to enlargement of Yumbo's coal facilities over original plan.

e/ Foreign exchange costs only -- local currency costs met by EMPRESAS MUNICIPALES DE CALI, the distributor.

Source: CVC/CHIDRAL, IBRD.

3.17 Major problems arose in connection with the last two loans, 255-CO and 339-CO, principally due to technical and financial difficulties encountered during the construction of the Calima hydroplant. In fact, Loan 339-CO was largely made for the purpose of covering part of the cost overruns on the project as well as to expand the plant to four units instead of the originally planned two.

3.18 There were four main reasons for delays on the Calima plant: (a) a two-month strike organized by the labor union against the project contractor in April-May 1962, (b) the contractor's poor organization and inadequate equipment at the start of construction, (c) technical problems in connection with the poor quality of the bedrock and the deficient supply of raw materials for the dam core, (d) time consuming negotiations with the National Government and various financing institutions (including the IBRD) in order to cover the cost overruns occasioned by the first three items. Overall delay in the construction of the plant amounted to about two years[1/] and the total cost overrun reached about US$16.5 million equivalent,[2/] i.e., 46% over the amount forecast by the two loans, including contingencies. A detailed breakdown of the forecast and actual cost of items covered by the last two loans to CVC/CHIDRAL is presented below:

1/ Resulting in power shortages in 1964 and 1965.

2/ Excluding Transmission.

Table 12.3

CVC/CHIDRAL -- Loans 255 CO and 339 CO -- Forecast and Actual Construction Costs

	Foreign Exchange Component ($ million)			Local Currency Component ($ million equiv.)			Total Project Cost ($ million equiv.)		
Loan 255 CO	Forecast	Actual	Overrun	Forecast	Actual	Overrun	Forecast	Actual	Overrun
Third Yumbo thermal unit	4.19	3.70	(0.49)	1.04	2.77	1.73	5.23	6.47	1.24
Calima I hydro plant	13.18	16.01	2.83	6.65	8.19 c/	1.54	19.83	24.20	4.37
Transmission and substations	4.36	4.71	0.35	2.47	9.39	6.92	6.83	14.10	7.27
Distribution	0.91	1.20	0.29	-	2.73	2.73	0.91	3.93	3.02
Unallocated	0.30			-			0.30		
Contingencies									
- for Yumbo	0.21			0.20			0.41		
- for Calima	1.32			1.33			2.65		
- for Transmission	0.44			0.50			0.94		
- for Distribution	0.09			-			0.09		
Total a/	25.00	25.62		12.19	23.08		37.19	48.70	

Loan 339 CO	Forecast	Actual	Overrun	Forecast	Actual	Overrun	Forecast	Actual	Overrun
Completion of Calima I with 4 units	4.00	5.64	1.64	1.82	12.35 d/	10.53	5.82	17.99	12.17
115 Kv Anchicaya -- Buenaventura Transmission line	0.35	0.28	(0.07)	0.16	0.11	(0.05)	0.51	0.39	(0.12)
Cali Distribution b/	1.00	0	(1.00)	0.20	n.a.	n.a.	1.20	n.a.	n.a.
Coal mine equipment	0.42	0.50	0.08	-	-	-	0.42	0.50	0.08
Engineering and power planning studies	1.85	2.10	0.25	-	1.61	1.61	1.85	3.71	1.86
Interest during construction	0.40	0.28	(0.12)	-	-	-	0.40	0.28	(0.12)
Contingencies									
- for Calima I	0.40			0.18			0.58		
- for Transmission line	0.05			0.04			0.09		
- for coal mine equipment	0.08			-			0.08		
- for engineering and power planning studies	0.25			-			0.25		
Total	7.80	8.80		2.20	14.07		10.00	22.87	

a/ Forecasts for interest during construction are not given not being provided for in the loan; the corresponding actual figures is US$2.72 million.

b/ The $1.00 million foreign currency amount was to be relevant to EMCali. It appears, however, that this amount was used to cover part of the cost overruns on Calima.

c/ 1958 - 63 only.

d/ 1964 - 69 only.

Source: CVC/CHIDRAL
IBRD

3.19 Foreign exchange cost overruns on Calima eventually totalled US$ 2.75 million (or US$ 4.47 million including the provisions for contigencies in the loans), raising the final foreign cost of the project to US$ 21.65 million. CVC had major difficulties in securing the necessary financial resources to cover these overruns and applied for additional assistance from the Bank. After the 1963 loan the Bank, however, made it clear that no additional financing would be made available in view of the Government's failure to provide its agreed upon contribution to local expenditures on the project and its failure to grant adequate rate increases. The attitude of the Bank was also geared toward exerting pressure on CVC to agree to Interconnection (see Chapter XIII). The Bank took it upon itself to convince U.S. AID, which was ready to make a loan to cover the foreign exchange overrun on Calima, to withdraw its proposal. It seems that transmission and distribution system expansion was the principal victim of the overruns on Calima; the funds originally allocated under the loans for this purpose being transferred to the hydroplant. The US$ 1 million included in Loan 339-CO for relending to EMCALI to finance the expansion of the Cali distribution ring actually was finally transferred to Calima.

3.20 Local currency cost overruns were even higher than those for the foreign exchange component, amounting in the end to some US$ 12.1 million equivalent, or 142% above the anticipated amount. CVC/CHIDRAL had to struggle to secure the necessary additional funds from local banks, contractors' credits, and through painful tariff increases, but mainly the overruns had to be covered by National Government subsidies. The finances of the company still bear today the "scars" inflicted by Calima.

3.21 Despite the good intentions which may have induced the Bank to adopt a rigid position on Calima, it seems that more support should have been given to CVC in these difficult circumstances, especially for a project which had been warmly recommended in the National Electrification Plan of 1955 and had received early support from the Bank. There are probably less harsh means which could have been used to push interconnection and convince the Government to live up to its obligations, i.e., providing the agreed upon financial support and granting the required tariff increases. Furthermore, it should be recalled that, in the case of Calima, the Bank had relied entirely on the cost estimates prepared by CVC's consultants, without really affirming their validity; this was partly due to the fact that the Bank had not anticipated major difficulties in the construction of the project.

IV. Load Forecasting, Investment Planning and System Development

4.01 CHIDRAL has always had extreme difficulty in meeting the demand requirements of its service area. Until 1955 when the first two units of the Anchicaya hydroplant began operation, actual system peak load and sales in Cali had been determined entirely by the limitations of the inadequate generating capacity available, and strict electricity rationing had to be imposed. That a backlog of demand had built up by then is evident when one realizes that peak demand during 1955 rose from 12.5 MW to 32 MW because of the additional 24 MW Anchicaya provided. The system attained adequate capacity in 1957 with the addition of the two 20 MW units at Anchicaya.

4.02 Thereafter, load growth followed a steady and considerably slower growth rate, increasing at an average rate of about 14% between 1958 and mid-1962. But the growth was more than had been foreseen at the time of the 1958 loan. Deficiency of capacity was temporarily avoided by the commissioning of Yumbo 3 (33 MW) in June 1962, but the load grew nearly 40% in 1963 and shortages began. They became severe in 1964 and especially 1965, with the two-year delay in commissioning of Calima. Purchases of peaking energy from the Central Hidroelectrica de Caldas (CHEC) which serves Manizales (Colombia's eighth largest city) helped to keep power deficits at a low level, but some shedding still occurred.

4.03 The 1964-65 shortage period caused unsatisfied demand to build up once more so that the eventual commissioning of Calima in 1966 and 1967 was closely followed by a rapid growth in demand. By December 1970, the nameplate reserve capacity of CVC/CHIDRAL was only 20 MW,[1/] the capacity of the largest unit being 33 MW. Moreover, actual effective capacity was considerably below the nameplate rating owing to the severe drought which crippled operation of Calima and an explosion in Yumbo 3 which resulted in recurrent forced outages. As a result, CHIDRAL has had to rely upon purchases of energy from CHEC and recently EEEB. Total purchases from these other sources represented in 1969 and 1970 12% and 21%, respectively, of CHIDRAL's actual sales.

4.04 In general CHIDRAL's system expansion has been characterized by lack of long-term planning, which has been reflected in Bank appraisal

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1/ Installed capacity in 1970 was 248.1 MW, peak demand was 228.0 MW, and the effective peak spare capacity was -16.5 MW.

load forecasts. The first loan to CHIDRAL (38-CO) was mainly designed to help complete the Anchicaya hydroplant, which had been started by CHIDRAL several years before. The Bank therefore was not involved in the planning of this unit, but the failure to foresee any necessity for installation of new plants over the succeeding ten years (see Table II-A.1) seems a deficiency on the part of the Bank. As a result of the Bank's lack of foresight,actual peak demand was, within five years, 37% above the forecast level; a trend which was progressively accentuated in subsequent years.

4.05 In the second loan (113-CO) demand forecasts were more optimistic and were fairly close to actual developments, but again the absence of any attempt at long-term planning is apparent; by 1960, five years after the forecast was made, a 2.5 MW deficit was predicted. While in actuality a 28.5 MW gross reserve occurred, this simply indicates that the appraisal of Loan 113-CO did not allow for the fourth (20 MW) unit at Anchicaya or the second emergency thermal unit which had to be installed at Yumbo. This is particularly surprising since Yumbo unit 1 financed under the loan was itself an emergency thermal plant which had to be built because of the lack of long-range planning in the system.

4.06 By 1958, as a result of the financial crisis of 1956/57 and consequent pessimism about Colombia's development prospects, peak demand forecasts for Loan 215-CO (see Table II-A.3) were rather underestimated, although system capacity forecasts were quite accurate. It should be noted, however, that the forecasts extended for only four years so that in effect no long-term plans were considered. It is probably significant to mention that inasmuch as the loan was made to finance a second Yumbo emergency thermal unit and preceded a loan (255-CO) to cover yet another, apparently neither CHIDRAL nor the Bank profited very much from previous experience.

4.07 The fourth loan (255-CO) to CVC/CHIDRAL, consisting of US$ 25.0 million to cover, among other things Yumbo 3 and Calima I units 1 and 2, was by far the largest and most important Bank loan to the company. One of the major features of the loan was the construction of the Yumbo-Cartago transmission line which connected CHIDRAL's system to that of CHEC which was favored by a large surplus of hydro-energy. This was a turning point in CHIDRAL's system expansion, because in allowing the utility to purchase cheap peaking energy when required, it eliminated the necessity of building expensive emergency thermal plants such as the Yumbo 4 plant later proposed by the company. The US$ 14.1 million equivalent[1/] line was also quite important in that it allowed several smaller municipalities (9 towns and 16 villages along the line's route) to become connected to the larger, more efficient CVC/CHIDRAL system. Hence the Yumbo-Cartago transmission line also constitutes one of the Bank's relatively rare contributions to rural electrification. Energy consumed by these rural areas accounts for the increasing portion of CHIDRAL's generation purchased by CVC and the growing influence of CVC as a power supplier in the Valle.

4.08 Table II-A.4, which shows the load forecast underlying the loan for Calima reflects the continued inadequacy of long-term planning, in the

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1/ Of which US$ 4.71 million was in foreign exchange. Total estimated cost was US$ 6.83 million equivalent.

capacity deficit foreseen for 1963, the failure to allow for any capacity addition after Calima and the inadequate levels of capacity (and doubtless, in this case, energy) reserve provided in later years. The load forecast turned out somewhat overoptimistic but, due to the delays in completion of Calima, capacity deficits occurred in 1964 and 1965, as pointed out; gross reserve capacity was more adequate than expected in later years, but this is somewhat misleading due to the difficulties encountered in filling Calima, acute energy shortages there and the outages at Yumbo 3 during much of 1969 and 1970. The capacity deficiencies have been met by purchases of energy from CHEC (and recently EEEB) which have risen from 7.3 Gwh in 1963 to 382.7 Gwh by 1970. Since this purchased energy was peaking energy, it is difficult to evaluate the actual extent to which CHIDRAL's system has had to be overloaded, but the fact that plant utilization factors have not increased appreciably over the years tends to indicate that peaking capacity deficits are the only limitation of the system.

4.09 The load forecast which underlay the last loan to CVC/CHIDRAL, Loan 339-CO of 1963, is depicted in Table II-A.5. It has proved excessive by a wide and increasing margin. This forecast did reflect for the first time adoption of a longer term view, allowing for construction of Calima II following completion of Calima I; provision was also made in this loan, for the first time, for financing studies of future system expansion. However, this load forecast was not of great operational significance, since the decision at the time was only to complete Calima I and install the last two units. It, and the related plans, were completely superseded subsequently by changed load prospects, interconnection discussions and the eventual decision to undertake Alto Anchicaya.

Economics of Calima

4.10 The heavy cost overruns on Calima and the lengthy delays in its completion raise a serious question as to whether it was in retrospect the most economic means to meet the growth of demand on the CHIDRAL system. Calima can be considered the most problematic project in the history of Bank involvement in Colombia's power sector. Apart from the two-year delay in completion and the 46% cost overrun (nearly 60% when allowance is made for the transmission link between the plant and the Cauca Valley transmission line) the plant has also suffered from hydrological difficulties. Calima was always envisaged as a peaking plant; the mean flows used in planning the project were considered sufficient to generate about 315 million kwh per year from the 120 MW installed capacity, equivalent to a capacity factor of only about 30%. Generation has not yet approached this level due to delays in filling the reservoir and poor hydrological years experienced, but it is still expected to do so -- and probably will this year or next, with the heavy rains of 1970 and 1971.

4.11 The feasibility study for the Calima project, on which the Bank based its decision to support it, indicated a rate of return of at least 15% on the extra investment required to build it, as opposed to a coal-fired thermal plant. We ran a comparison between Calima and a coal-fired plant of equivalent capacity, assuming a capital cost of US$ 200 per KW installed and a fuel cost equal to that currently experienced at the Yumbo station, or about US¢ 60 per million BTU. We found that if Calima's costs had been as originally forecast, then the return to the incremental investment would have been about 15%. With the cost overruns, on the other hand, the return to the actual incremental investment (of some US$ 20 million) was about 9%, using the official foreign exchange rate, and 6%, using a scarcity foreign exchange rate (including allowance for import tariffs, other premia and quantitative restrictions on imports) of twice the official rate. If the coal-fired alternative is assumed to have a capital cost of US$ 230 per kilowatt installed, the internal rate of return, using the official exchange rate, rises to 10%. None of these calculations makes allowance for the important fact that a coal-fired plant should have been built more quickly, hence avoiding at least part of the load shedding in 1964 and 1965 that resulted from the long delays in Calima. Considering that the opportunity cost of capital in Colombia is probably in the range of 10-12%, the figures seem clearly to indicate that Calima was a marginal investment.

4.12 These calculations depend in part on the assumption that there was sufficient coal available in the Cauca Valley to support a thermal plant of the type adopted as the alternative. There is some doubt about this and there may have been more doubt in 1959-60 when the Calima decision was made, although, as mentioned, CVC used a coal-fired plant as the alternative in its analysis. A survey in 1964 identified three potential new sources of coal capable of producing together some 350,000 tons a year and the hypothetical plant adopted as an alternative would have required only some 250,000 tons a year -- and possibly less in later years when advantage could be taken of cheaper hydroelectricity from the interconnected system. Moreover, another alternative would have been an oil-fired plant fed with oil brought up from Buenaventura -- perhaps from the neighboring Putumayo field -- and total costs for this alternative would probably not have been greatly different from those used in this analysis for the coal plant.

4.13 Calima appears to have been the only hydroelectric project ready for construction in 1960; it had been studied following the recommendations of the consulting group which had drawn up the 1954 National Electrification Plan and was especially favored by CVC. The Bank, in spite of its early contributions to CHIDRAL's development program, does not seem to have materially encouraged the initiation of planning studies before 1963; it was not until that year, as mentioned, that it participated in financing engineering and power planning studies, mainly in connection with the Calima II and Salvajina projects. This should be considered a shortcoming on the part of the Bank, especially in view of the fact that it had very actively promoted the initial establishment of CVC in 1955 as a multipurpose regional agency and that some of the alternative hydroprojects to Calima would, in adddition to providing electricity, have yielded other benefits in the form of flood control and irrigation.

Projects Turned Down

4.14 The role of the Bank in system planning was in some ways more important for Cali than for Bogota and certainly for Medellin. The actual contribution of the Bank was, in fact, largely a restraint upon CVC's enthusiasm to build additional plants. On several occasions, the Bank refused to consider various projects presented by CVC/CHIDRAL, including the Yumbo 4 thermal plant and the Calima II, Timba and Salvajina hydroplants. The Bank's reluctance to finance such projects was dictated by several factors, among which the fragile financial situation of CVC/CHIDRAL was one. The Bank had insisted that consideration of possible loans for such projects would be subject to the Government's actual contribution of its agreed upon share of financing the cost overruns of Calima, and to its approval of satisfactory tariff increases. Secondly, the Bank was far from convinced of the technical and economic soundness of some of these projects (mainly Salvajina and Timba). Finally, the Bank's strong position was intended to coax CVC toward agreement on Interconexion.

4.15 In 1965-66 CVC tried to persuade the Bank to finance the Yumbo 4 thermal unit. It appears, in retrospect, that the only useful effect of this additional unit would have been to bridge the six-month power gap which occurred as a result of the breakdown of the Yumbo 3 thermal unit late in 1969 and simultaneous lack of energy available from Calima. The Bank proposed an alternative scheme, consisting in the extension of the single-circuit 115 kv line then under construction between Bogota, Ibague and Armenia to the Buga-Cartago section of the CVC-CHEC line. This was the solution finally adopted, involving a cost in foreign exchange of only US$ 1.5 million; the line was commissioned in 1969. Energy purchases from EEEB's system amounted to 43 and 161 Gwh in 1969 and 1970, respectively, providing a useful complement to imports from the CHEC system.

V. Forecasting the Financial Aspects

5.01 Financial forecasts prepared by the Bank have been quite optimistic on the whole (as can be seen in Tables II-A.1-5), the most notable discrepancies being between the forecast and actual operating income and in the rates of return. Operating income, which determines the extent to which the company is able to finance its own expansion program as well as service its debt, has generally been overestimated because costs have always been underestimated. Even in the few cases when operating income was greater than forecast or grew at a faster annual rate than forecast (see Table II-A.3) this was a result of the fact that revenues grew at a faster rate than expected (in non-inflated terms) and overrode the increases in costs. Generally, however, revenues were overestimated as well, and the company's financial picture is comparatively even worse. As has been mentioned before, the fact that CHIDRAL's revenues were lower than expected has largely been due to the inadequate level of tariffs maintained over the years, but it is also significant that, in most loan forecasts, the company's annual kwh sales figures were themselves overestimated.

5.02 Despite the fact that the price level in Colombia has increased six-fold in the past twenty years, no real effort was made by the power utilities to accordingly revalue their assets, which were recorded in historic pesos. In the case of CHIDRAL, the only attempt made at revaluation seems to have been the inclusion of a "revaluation adjustment" of some Ps. 24.6 million in their balance sheets after 1957, which is hardly satisfactory in view of the true inflationary conditions in the country. For the purposes of this study a systematic revaluation of the company's assets was undertaken (see Annex 1) in order to determine the true rate of return.

5.03 This revaluation further emphasized the existing discrepancies between forecast and actual return figures, which in the last loan (339-CO) was expected to average 13 or 14% over the 1963-69 period but which in reality never exceeded 4.2% and were in one case even negative. It should also be observed that even in the absence of such an asset revaluation, performance was considerably below the forecast; the highest rate of return on non-revalued assets over the 1963-70 period was 9.6% in 1965 and the rate of return was generally much lower, for reasons discussed previously in this Chapter.

VI. Institutional Development

6.01 When CHIDRAL was incorporated as a company in October 1950, 51% of its shares were held by the Instituto de Aprovechamiento de Aguas y Fomento Electrico "Electraguas" (an agency of the National Government), 23% by the Department of Valle, and 26% by the municipality of Cali. After the creation of CVC, CHIDRAL's ownership was redistributed between CVC - 65%, the municipality of Cali - 18%, and the municipality's agency EMCALI - 17%. In short, CVC has almost two-thirds of equity participation in CHIDRAL and Cali the other third.

6.02 CHIDRAL's statutes provide that CVC appoint three of the five members of CHIDRAL's Board, the municipality of Cali appoint one and EMCALI appoint another. Since decisions, including those affecting tariffs, require affirmative votes by four directors, the municipality together with its agency EMCALI have a veto power over CHIDRAL's decisions. The Board also maintains tight financial control; it must approve contracts for amounts exceeding Ps. 60,000 which is a very small amount indeed (equivalent to some US$ 3,000). Cali also exercises another form of control over CHIDRAL through the city's Chief Engineer who participates in the planning commission of CHIDRAL.

6.03 EMCALI is CHIDRAL's major retail distributor, and is significant mainly because it is a major factor in setting the level of tariffs. The Bank has strongly recommended over the years that EMCALI administer and maintain separate accounts for its public water, sewerage, telephone, and electricity services with a view to making each division self-supporting. The agreement in 1950 that CHIDRAL should purchase the existing municipal power generating facilities in Cali and that it would sign a contract with the municipality whereby CHIDRAL would become the exclusive supplier of electric power (and EMCALI the sole distributor) was an important step toward rationalizing the power institutions in the Valley at the time. But in retrospect it might have been better had the Bank insisted that the generating company take over distribution as well (as it did in the two other loans made at the time) or else that EMCALI take over CHIDRAL.

6.04 In the middle 1950s, the Bank was a staunch proponent of the creation of a TVA-type regional development agency for the Cauca Valley, but the Bank's early enthusiasm for CVC and its exhortation for a regional approach later waned. When five years later the time for acting came, the Bank's approach was traditional -- one project at a time, and for power only. One explanation for that is that CVC had never submitted to the Bank a request for financing of a regional program. The Bank itself was hardly geared to finance such a program had it been submitted. In any case, the ultimate result of the establishment of two power generating agencies in the Cauca Valley was the agreement that CVC would plan, design, and build future plants while CHIDRAL would operate them. While this has resulted in some confusion over the ownership of assets and management responsibility, it was initially expected that by means of this arrangement, certain undesirable provisions of prior long-term contractual arrangements between CHIDRAL and EMCALI could be avoided. Specifically, EMCALI has a preferential right to power produced by CHIDRAL: such a preference was conceivable during a period of scarcity and considering that Cali was a shareholder of CHIDRAL, but it could not have been acceptable in the context of a regional system.

CVC, as the contractor, thought, or at least hoped, that the transfer of Calima, when completed, to CHIDRAL would give it enough leverage to have the preference removed from the EMCALI contract. CVC also had as a future objective the purchase of the Cali investment in CHIDRAL in order that CVC might become CHIDRAL's sole owner. CHIDRAL would have then become fully a branch of CVC for power generation and transmission. Both expectations failed to materialize.

6.05 Under the Loan Agreement (255-CO) CVC was committed to transfer to CHIDRAL the Calima project as soon as it was completed. CVC, in violation of the Agreement, continues to own Calima and appears reluctant to transfer it to CHIDRAL. It argues against the desirability of the transfer as long as EMCALI has a virtual veto over CHIDRAL. As to the matter of purchasing EMCALI's shares in CHIDRAL, at present, for political reasons, the municipality of Cali is not inclined to sell, and due to shortage of funds, CVC is not able to buy. Meanwhile, CVC has to live with a discriminatory agreement between the parties under which no matter how much CVC invests in CHIDRAL, its share in the equity, and hence voting power, is frozen. The Bank itself may have erred in not initiating a loan to EMCALI to improve its distribution system -- a tactic which would have established some sort of Bank-EMCALI dialogue. Over the years the Bank repeatedly complained about the anomalous organizational set-up instead of trying to build in-roads into the municipality of Cali in general and EMCALI in particular.

6.06 The Bank also missed a chance to clear up the CVC-CHIDRAL-EMCALI organizational monstrosity in the months immediately preceding negotiations on Loan 339-CO to cover the cost overruns on Calima. At this time CVC was in an extremely tight financial situation and the Bank might have been able to exert considerable leverage. But when the loan was negotiated, it was argued in the Bank that the disentangling could not be done in short order but that it should be a prerequisite for any further Bank loans for power in the Valley. This was an untenable argument because the Bank had already committed itself to working towards interconnection of the separate power systems in Colombia in order to considerably reduce, if not completely eliminate, the need for further loans to individual power systems. What is important is that the solution of important organizational problems was left for the future, and the opportunity to seize upon CVC's difficulties to rationalize the organizational structure was lost.

6.07 Seen purely from the institutional prism, the record and performance of the Bank were characterized by inconsistency and a lack of determination and foresight.

VII. Conclusion

7.01 The overall development of CHIDRAL over the 1950-70 period has not been spectacular nor even particularly satisfactory to the Bank. The company has managed to increase the public generating capacity serving the city of Cali and parts of the Cauca Valley from some 12.5 MW to about 250 MW, but there have been repeated shortages of electricity and the quality of supply has been relatively poor. The expansion path followed does not appear to have been particularly economic, with a series of emergency thermal plants and some relatively high cost hydroelectric plants, of which the largest, Calima, today appears in retrospect a dubious investment from the economic point of view. The company has suffered from a complex and quite inefficient institutional set up, has constantly been subjected to political pressures and as a result has had a particularly poor financial performance record.

7.02 The Bank has probably not been as helpful as it might have been to the CVC/CHIDRAL complex. Firstly, it did not materially encourage initiation of expansion planning studies until 1963, and even so seems to have confined its role to that of a "pragmatic sponsor" concerned with retarding the influence of excessive enthusiasm or backstage political pressures. Secondly, the IBRD has apparently not attempted to reform the financial set up of the two affiliates at all, and has been unsuccessful in reforming the organizational set up of the power supply for Cali -- which is particularly disappointing since the Bank was instrumental in the creation of CVC and in establishing CHIDRAL's relationship with CVC and EMCALI in the first place. Thirdly, by taking an inflexible position on Calima, for whatever good reasons, the Bank imposed a considerable financial hardship on CVC which eventually forced the company to obtain large-scale support from the National Government. Finally, no IBRD appraisal report has ever mentioned or questioned the quality of the financial management of CVC/CHIDRAL, while this was an important issue in the case of EEEB; there is no indication, however, that the former was more efficient than the latter.

7.03 There are, on the other hand, many ways in which the Bank has been quite helpful, the most important of which include its prevention of several uneconomic projects, support for the transmission developments in the Valle, the realization of Interconexion, and creation of the tariff regulatory agency. In recent years CHIDRAL's revenues have been at par with those of EEEB and EPM, and while the company may not as yet operate as efficiently as the former two, the general financial picture has improved somewhat. The commissioning of Interconexion, scheduled to take place shortly, promises to cope with CHIDRAL's peaking capacity deficiencies and allow the company to share the benefits of the more economic hydroplants in existence and under construction in other parts of the country. In addition, CVC/CHIDRAL has under construction the 340 MW Alto Anchicaya hydroplant, financed under favorable conditions by the IDB. The plant should be in operation by 1974.

7.04 From 1950 to 1968, when the IDB agreed to finance the US$ 60 million equivalent loan for Alto Anchicaya, the IBRD remained virtually the sole source of foreign currency for CVC/CHIDRAL. This is probably due to the fact that when the original Anchicaya loan (38-CO) was negotiated, the IBRD was the only multilateral lending agency CHIDRAL could apply to. By 1959 when the IDB was created the IBRD had nine years of experience with the company and had already made three loans to it; it was therefore logical for the company to continue to seek the Bank's help rather than involve the IDB. The request for financing the Alto Anchicaya project, in fact, was originally addressed to the IBRD, but in view of the IDB's interest in the project and the more favorable terms it could offer, it was decided that the latter agency should finance it. The IBRD has not actively participated in CVC/CHIDRAL's expansion program since the 1963 loan (339-CO), (except indirectly through encouraging the entity to join Interconexion) and any further financing role for the Bank would have to be in distribution or possibly, eventually, in any multi-purpose projects in the area that might prove worthwhile.

TABLE I

COLOMBIA: CENTRAL HIDROELECTRICA DEL RIO ANCHICAYA LTDA. (CHIDRAL)

																		Average Annual Increase Rate (%) j/		
		1955	1956	1957	1958	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1955/1960	1960/1965	1965/1970
OPERATIONS																				
1. Installed Capacity (yr.-end)																				
Hydro	MW	26.1	26.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	96.1	126.1	186.1	186.1	186.1	186.1	20.0	7.8	14.1
Thermal	MW	-	-	-	10.0	10.0	20.0	20.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	-	21.5	-
Diesel	MW	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	-	-	-
Total	MW	35.1	35.1	75.1	85.1	85.1	95.1	95.1	128.1	128.1	128.1	158.1	188.1	248.1	248.1	248.1	248.1	22.0	10.7	9.4
Total as % of country a/	%	8.0	7.1	12.6	13.4	13.0	14.2	13.9	15.1	12.3	11.5	12.2	13.2	14.8	13.9	12.9	12.0			
2. Peak Demand	MW	32.0 c/	35.0 c/	49.2	54.0	60.5	66.6	83.7	95.2	129.1	138.1	143.8	174.3	185.3	200.3	201.6	228.0	15.8	16.6	9.7
3. Gross Reserves (1 - 2)	MW	3.1	0.1	25.9	31.1	24.6	28.5	11.4	32.9	-1.0	-10.6	14.3	13.8	62.8	47.8	46.5	20.1			
Gross Reserves as % of Peak Demand	%	9.7	0.3	52.6	57.6	40.5	42.8	13.6	34.6	-0.8	-7.6	9.9	7.9	33.9	23.9	23.1	8.8			
4. Effective Peak Spare Capacity b/	MW	n.a.	n.a.	n.a.	26.6	24.5	25.3	11.4	4.4	(3.7)	(10.6)	(22.2)	(15.7)	7.2	42.8	13.5	(16.5)			
5. Gross Generation	Gwh	n.a.	n.a.	n.a.	n.a.	273.57	314.52	363.37	485.11	566.54	635.62	641.90	748.28	800.53	873.92	773.92	735.74		15.3	2.8
Total as % of country a/	%	n.a.	n.a.	n.a.	n.a.	10.5	10.7	11.6	13.8	13.9	13.9	12.8	13.6	13.5	13.2	10.9	9.4			
6. Energy Purchases from Other Systems d/	Gwh	-	-	-	-	-	-	-	-	7.34	27.19	43.86	53.59	60.08	51.14	182.51	382.7			55.0 i/
7. Total Sales	Gwh	59.61	156.71	195.45	223.36	264.85	301.38	348.19	463.04	563.00	649.82	671.51	788.75	846.06	907.94	942.36	1066.80	38.0	17.4	9.7
of which: EMCALI (%)	%	100	100	100	100	100	100	99	88	85	81	82	79	77	78	80	78			
CVC (%)	%	-	-	-	-	-	-	1	12	15	19	18	21	23	19	17	19			
COEDEC (%)	%	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3	3			
FINANCES																				
8. Sales Revenues e/	Ps.mln.	2.50	6.13	8.08	9.00	10.11	18.38	21.24	28.25	34.71	40.26	60.14	70.99	99.92	130.00	173.77	n.a.	35.0	12.6	18.2 i/
9. Operating Costs f/	Ps.mln.	1.35	2.88	4.32	6.25	7.56	8.08	10.68	14.71	25.17	32.80	40.07	49.33	64.28	75.75	104.42	n.a.	29.5	22.5	15.2 i/
10. Average revenue/kwh sold (current prices)	Pesos	0.04	0.04	0.04	0.04	0.04	0.06	0.06	0.06	0.06	0.06	0.09	0.09	0.12	0.14	0.18	n.a.			
11. Average revenue/kwh sold (constant 1968 prices)	Pesos	0.17	0.15	0.13	0.11	0.10	0.15	0.14	0.13	0.11	0.09	0.12	0.11	0.13	0.14	0.17	n.a.	-1.3	-4.6	9.1 i/
12. Average cost/kwh sold based on revalued assets h/ (constant 1968 prices)	Pesos	0.09	0.07	0.09	0.11	0.10	0.08	0.08	0.08	0.09	0.09	0.09	0.12	0.10	0.10	0.10	n.a.	-2.4	2.4	2.7 i/
13. Average Revenue/kwh sold	US¢ g/	1.07	0.94	0.82	0.69	0.63	0.94	0.88	0.82	0.69	0.57	0.75	0.69	0.82	0.88	1.07	n.a.	-1.3	-4.6	9.1 i/
14. Average Cost/kwh sold	US¢ g/	0.57	0.44	0.57	0.69	0.63	0.50	0.50	0.50	0.57	0.57	0.57	0.75	0.63	0.63	0.63	n.a.	-2.4	2.4	2.7 i/
15. Net Revenues (8 - 9)	Ps.mln.	1.15	3.25	3.76	2.75	2.55	10.30	10.56	13.54	9.54	7.46	20.07	21.66	35.64	54.25	69.35	n.a.	40.0	1.5	23.5 i/
16. Net Revenues based on Revalued assets h/	Ps.mln.	1.15	3.23	2.09	0.64	0.52	8.02	8.42	11.44	4.55	2.75	14.41	-6.94	22.40	42.24	50.00	n.a.	33.0	-0.1	23.5 i/
17. Gross Fixed Investment in Current prices	Ps.mln.	n.a.	12.47	37.95	11.82	6.29	13.54	16.67	55.76	125.19	69.31	122.12	118.15	151.80	37.19	81.24	n.a.			
18. Gross Fixed Investment in Constant 1968 prices	Ps.mln.	n.a.	47.14	122.20	33.57	16.79	33.31	37.84	118.78	216.58	103.27	166.08	139.42	165.46	37.19	74.7	n.a.		38.0	-25.0 i/
19. Average Revalued Net Fixed Assets in Operation h/	Ps.mln.	n.a.	49.35	48.19	62.07	75.38	80.72	100.55	121.47	152.34	181.54	196.52	356.84	604.07	714.85	729.22	n.a.		6.1	26.0 i/
MANAGEMENT INDICATORS																				
20. Rate of Return k/																				
(a) non-revalued assets	%	n.a.	4.3	7.8	3.2	2.5	10.1	8.3	11.1	6.7	4.5	9.9	4.5	5.7	7.0	9.2	n.a.			
(b) revalued assets h/	%	n.a.	6.4	3.4	0.6	0.4	6.3	5.6	6.5	2.0	0.9	3.7	neg.	2.5	3.7	4.2	n.a			
21. Self-Financing Rate	%	n.a.	24.8	15.2	neg.	3.8	neg.	28.6	10.6	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.			
22. Debt Service Coverage	times	n.a.	3.1x	0.9x	0.8x	1.0x	-	1.4x	1.4x	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.			
23. Debt/Equity Ratio	./.	34/66	35/65	55/45	53/47	48/52	46/54	48/52	63/37	68/32	72/28	70/30	69/31	77/23	78/22	69/31	n.a.			
24. Transmission Losses $(\frac{5+6-7}{5+6})$	%	n.a.	n.a.	n.a.	n.a.	3.2	4.2	4.2	4.5	1.9	2.0	2.1	1.6	1.7	1.9	1.5	n.a.			
25. Average Capacity Out of Service as % of Installed Capacity	%	-	-	-	-	-	-	-	0.7	2.0	-	1.6	3.9	2.7	2.0	7.0	5.2			
26. CHIDRAL's investments as % of Total Gross Fixed investments of country	%	n.a.	0.4	1.2	0.4	0.2	0.3	0.3	0.9	1.8	0.8	1.3	1.0	1.1	0.2	0.4	n.a.			
27. Accounts Receivable as % of Total Sales Revenues	%	16.4	15.4	12.6	10.3	10.1	20.2	18.3	18.8	14.3	12.6	12.9	7.6	14.3	22.9	15.6	n.a.			

a/ Excluding captive plants.
b/ Figures in brackets indicate negative reserves which were covered by purchases of energy from other systems (see line 6) and shedding.
c/ Source: IBRD
d/ Consists of purchases from Empresa de Energia Electrica de Bogota (EEEB) and Central Hidroelectrica de Caldas (CHEC).
e/ In historic pesos.
f/ Including depreciation but excluding interest and direct taxation, in historic pesos.
g/ Calculated by applying the National GDP deflator to bring figures in historic prices to constant 1968 prices, and then converting into US$ using the 1968 exchange rate of Ps. 15.90 = US$ 1.00.
h/ Revaluation of assets computations as calculated by IBRD in Annex I.

i/ Average Annual Increase Rate for 1965-69 only.
j/ Rates of Increase for figures in historic prices have been calculated using National GDP deflator to obtain real growth rates based on constant prices.
k/ Same as Financial Rate of Return, as company pays no taxes.

Source: CHIDRAL

Table II - A.1

COLOMBIA: CENTRAL HIDROELECTRICA DEL RIO ANCHICAYA LTDA (CHIDRAL)
Loan 38-CO (November 1950)

	1950	1951	1952	1953	1954	1955	1956	1957	1958	1959	1960	AVERAGE ANNUAL INCREASE RATE (%) (1955-60)
LOAD FORECASTS (MW)												
1. Installed Capacity	11.1	11.1	11.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	0.0
2. Annual Peak Demand	na	na	na	19.4	21.5	23.4	25.4	27.6	29.3	31.0	32.9	7.0
3. Gross Reserve Capacity (1-2)	na	na	na	15.7	13.6	11.7	9.7	7.5	5.8	4.1	2.2	
ACTUAL LOAD (MW)												
4. Installed Capacity	11.1	11.1	11.1	11.1	11.1	35.1	35.1	75.1	85.1	85.1	95.1	22.0
5. Annual Peak Demand	na	na	na	na	12.5	32.0	35.0	49.2	54.0	60.5	66.6	20.0
6. Gross Reserve Capacity (4-5)	na	na	na	na	-1.4	3.1	0.1	25.9	31.1	24.6	28.5	
7. Effective Peak Capacity a/	na	na	na	na	na	na	na	na	75.1	85.1	85.1	
8. Effective Peak Demand a/	na	na	na	na	na	na	na	na	48.5	60.5	59.8	
9. Effective Peak Spare Capacity (7-8)	na	na	na	na	na	na	na	na	26.6	24.6	25.3	
LOAD FORECAST ACCURACY b/												
10. Installed Capacity	100	100	100	316	316	100	100	47	41	41	37	
11. Annual Peak Demand	na	na	na	na	172	73	73	56	54	51	49	
12. Gross Reserve Capacity	na	na	na	na	*	377	*	29	19	17	8	
SALES FORECAST (GWh)												
13. Sales	na	68	na	77	81	86	91	97	103	109	115	6.0
ACTUAL SALES (GWh)												
14. Sales	na	na	na	na	na	60	157	196	223	265	301	38.0
SALES FORECAST ACCURACY b/												
15. Sales	na	na	na	na	na	143	58	49	46	41	38	
RETURN FORECAST (Col. Pesos mln) c/												
16. Operating Revenues	na	na	na	0.9	2.1	2.2	2.4	2.5	2.7	2.8	3.0	6.0
17. less: Operating Costs	na	na	na	0.4	0.8	0.8	0.9	0.9	0.9	1.0	1.0	3.8
18. Operating Income	na	na	na	0.5	1.3	1.4	1.5	1.6	1.8	1.8	2.0	7.3
ACTUAL RETURN (Col. Peso mln) e/												
19. Operating Revenues	na	na	na	na	na	1.9	4.3	4.9	4.8	5.3	8.6	34.5
20. less: Operating Costs d/	na	na	na	na	na	1.0	2.1	2.6	3.4	3.8	3.8	30.5
21. Operating Income	na	na	na	na	na	0.9	2.2	2.3	1.4	1.5	4.8	39.5
RETURN FORECAST ACCURACY b/												
22. Operating Revenues	na	na	na	na	na	116	56	51	56	53	35	
23. less: Operating Costs	na	na	na	na	na	80	43	35	26	26	26	
24. Operating Income	na	na	na	na	na	156	68	70	129	120	42	

a/ Effective Peak = peak load at the critical time in the year when margin between demand and available capacity was least or load shedding greatest (excluding short-term outages).
b/ Defined by the ratio Forecast/Accuracy.
c/ Converted from figures given in US $ by the 1950 official rate of Ps 1.96 = US $1.00.
d/ Including non-revalued depreciation but excluding interest.
e/ All current or historic pesos have been converted to 1950 constant pesos for the purpose of comparison with the loan 38-CO Appraisal Report forecasts, using the National GDP deflator.

TABLE II-A.2

COLOMBIA: CENTRAL HIDROELECTRICA DEL RIO ANCHICAYA LTDA. (CHIDRAL)
Loan 113-CO((March 1955)

		1955	1956	1957	1958	1959	1960	Average Annual Increase Rate (%) (1955-60)
	LOAD FORECASTS (MW)							
1.	Installed Capacity	35.0	55.0	55.0	67.5	67.5	67.5	14.0
2.	Annual Peak Demand	23.0	40.0	55.0	58.0	64.0	70.0	25.0
3.	Gross Reserve Capacity (1 - 2)	12.0	15.0	0	9.5	3.5	-2.5	
	ACTUAL LOAD (MW)							
4.	Installed Capacity	35.1	35.1	75.1	85.1	85.1	95.1	22.0
5.	Annual Peak Demand	32.0	35.0	49.2	54.0	60.5	66.6	15.8
6.	Gross Reserve Capacity (4 - 5)	3.1	0.1	25.9	31.1	24.6	28.5	
7.	Effective Peak Capacity a/	n.a.	n.a.	n.a.	75.1	85.1	85.1	
8.	Effective Peak Demand a/	n.a.	n.a.	n.a.	48.5	60.5	59.8	
9.	Effective Peak Spare Capacity (7 - 8)	n.a.	n.a.	n.a.	26.6	24.6	25.3	
	FORECAST ACCURACY b/							
10.	Installed Capacity	100	157	73	79	79	71	
11.	Annual Peak Demand	72	114	112	107	106	105	
12.	Gross Reserve Capacity	387	*	0	31	14	*	
	SALES FORECAST (Gwh)							
13.	Sales	63	202	304	329	354	383	43.5
	ACTUAL SALES (Gwh)							
14.	Sales	60	157	200	223	265	301	38.0
	FORECAST ACCURACY b/							
15.	Sales	105	129	152	148	134	127	
	RETURN FORECAST (Col. Pesos mln.)							
16.	Operating Revenues	2.2	5.7	7.8	8.4	9.1	9.8	35.0
17.	less: Operating Costs	1.4	3.0	3.2	3.6	4.5	4.8	28.0
18.	Operating Income	0.8	2.7	4.6	4.8	4.6	5.0	44.5
	ACTUAL RETURN (Col. Pesos mln.) c/							
19.	Operating Revenues	2.5	5.7	6.4	6.3	7.0	11.2	35.0
20.	less: Operating Costs d/	1.3	2.7	2.5	4.4	5.0	4.9	30.5
21.	Operating Income	1.2	3.0	3.9	1.9	2.0	6.3	39.5
	RETURN FORECAST ACCURACY b/							
22.	Operating Revenues	88	100	122	133	130	88	
23.	less: Operating Costs	108	111	128	82	95	98	
24.	Operating Income	67	90	118	253	230	79	

a/ Effective Peak = peak load at critical time in the year when margin between demand and available capacity, was least or load shedding greatest (excluding short-term outages).
b/ Defined by the ratio Forecast/Actual.
c/ All current or historic pesos have been converted to 1955 constant pesos for the purposes of comparison with the Loan 113-CO Appraisal Report forecasts, using the National GDP deflator.
d/ Including non-revalued depreciation but excluding interest.

COLOMBIA CENTRAL HIDROELECTRICA DEL RIO ANCHICAYA LTDA. (CHIDRAL)
Loan 215-CO (December 1958)

TABLE II -A.3

	1958	1959	1960	1961	1962	1963	AVERAGE ANNUAL INCREASE RATE (%) 1958-61	1958-63
LOAD FORECASTS (MW)								
1. Installed Capacity	86.5	96.5	96.5	96.5	n.a.	n.a.	3.7	
2. Annual Peak Demand	50.0	57.0	65.0	75.0	n.a.	n.a.	14.4	
3. Gross Reserve Capacity (1-2)	36.5	39.5	31.5	21.5	n.a.	n.a.	-19.5	
ACTUAL LOAD (MW)								
4. Installed Capacity	85.1	85.1	95.1	95.1	128.1	128.1	3.8	8.5
5. Annual Peak Demand	54.0	60.5	66.6	83.7	95.2	129.1	15.7	19.0
6. Gross Reserve Capacity (4-5)	31.1	24.6	28.5	11.4	32.9	-1.0	-39.5	
7. Effective Peak Capacity a/	75.1	85.1	85.1	95.1	85.1	118.1	8.2	9.5
8. Effective Peak Demand a/	48.5	60.5	59.8	83.7	80.7	121.8	19.9	20.5
9. Effective Peak Spare Capacity (7-8)	26.6	24.6	25.3	11.4	4.4	-3.7	-33.0	
LOAD FORECAST ACCURACY b/								
10. Installed Capacity	102	113	101	101	n.a.	n.a.		
11. Annual Peak Demand	93	94	98	90	n.a.	n.a.		
12. Gross Reserve Capacity	117	161	111	189	n.a.	n.a.		
SALES FORECAST (GWh)								
13. Sales	226	265	310	362	362	362	17.0	9.9
ACTUAL SALES (GWh)								
14. Sales	223	265	301	348	463	563	16.0	20.5
SALES FORECAST ACCURACY b/								
15. Sales	101	100	103	104	78	64		
RETURN FORECAST (Col. Pesos mln.)								
16. Operating Revenues	9.1	12.2	16.1	18.8	18.8	18.8	27.0	15.6
17. less: Operating Costs	5.9	8.4	9.6	11.0	11.5	12.0	23.0	15.3
18. Operating Income	3.2	3.8	6.5	7.8	7.3	6.8	34.5	16.3
ACTUAL RETURN (Col. Pesos mln.) c/								
19. Operating Revenues	9.0	9.9	17.2	16.9	21.2	21.1	23.0	18.6
20. less: Operating Costs d/	6.3	7.1	7.5	8.5	11.3	15.1	10.5	19.1
21. Operating Income	2.7	2.8	9.7	8.4	9.9	6.0	46.0	17.3
RETURN FORECAST ACCURACY b/								
22. Operating Revenues	101	123	94	111	89	89		
23. less: Operating Costs	94	118	128	129	102	79		
24. Operating Income	119	136	67	93	74	113		

a/ Effective Peak = peak load at the critical time in the year when margin between demand and available capacity was least or load shedding greatest (excluding short-term outages)
b/ Defined by the ratio Forecast/Actual
c/ All current or historic pesos have been converted to 1958 constant pesos for the purpose of comparison with the Loan 215-CO Appraisal Report forecasts, by using the National GDP deflator.
d/ Including non-revalued depreciation but excluding interest.

TABLE II-A.4

COLOMBIA: CENTRAL HIDROELECTRICA DEL RIO ANCHICAYA LTDA. (CHIDRAL)
LOAN 255-CO (May 1960)

		1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	Average Annual Increase Rate (%) (1960-69)
	LOAD FORECASTS (MW)											
1.	Installed Capacity a/	102.0	102.0	135.0	135.0	195.0	195.0	225.0	225.0	255.0	255.0	10.7
2.	Annual Peak Demand	84.0	102.0	131.0	147.0	162.0	179.0	197.0	219.0	242.0	277.0	14.2
3.	Gross Reserve Capacity (1 - 2)	18.0	0.0	4.0	-12.0	33.0	16.0	28.0	6.0	13.0	-22.0	
	ACTUAL LOAD (MW)											
4.	Installed Capacity	95.1	95.1	128.1	128.1	128.1	158.1	188.1	248.1	248.1	248.1	11.2
5.	Annual Peak Demand	66.6	83.7	95.2	129.1	138.7	148.8	174.3	185.3	200.3	201.6	13.1
6.	Gross Reserve Capacity (4 - 5)	28.5	11.4	32.9	-1.0	-10.6	14.3	13.8	62.8	47.8	46.5	
7.	Effective Peak Capacity b/	85.1	95.1	85.1	118.1	128.1	118.1	125.1	183.1	243.1	215.1	10.9
8.	Effective Peak Demand b/	59.8	83.7	80.7	121.8	138.7	140.3	140.8	175.9	200.3	201.6	14.5
9.	Effective Peak Spare Capacity (7 - 8)	25.3	11.4	4.4	-3.7	-10.6	-22.2	-15.7	7.2	42.8	13.5	
	LOAD FORECAST ACCURACY c/											
10.	Installed Capacity	107	107	105	105	152	123	120	91	103	103	
11.	Annual Peak Demand	126	122	138	114	117	124	113	118	121	137	
12.	Gross Reserve Capacity	63	0	12	-	*	112	203	10	27	*	
	SALES FORECAST (Gwh)											
13.	Sales	313	358	540	616	688	770	856	905	1015	1130	15.3
	ACTUAL SALES (Gwh)											
14.	Sales	301	348	463	563	650	672	789	846	908	943	13.5
	SALES FORECAST ACCURACY c/											
15.	Sales	104	103	117	109	106	115	108	107	112	120	
	RETURN FORECAST (Col. Pesos mln.)											
16.	Operating Revenues	19.1	21.8	32.9	37.6	42.0	47.0	52.2	55.2	61.9	68.9	15.3
17.	less: Operating Costs	10.7	12.3	17.6	19.9	20.3	23.3	24.9	24.0	24.3	26.1	10.4
18.	Operating Income	8.4	9.5	15.3	17.7	21.7	23.7	27.3	31.2	37.6	42.8	19.8
19.	Financial Rate of Return on Average Net Fixed Assets in Operation(%) g/	7.7	7.3	9.1	9.5	8.3	7.1	8.4	9.7	11.7	14.0	
	ACTUAL RETURN (Col. Pesos mln.) d/											
20.	Operating Revenues	18.5	19.6	24.4	24.4	24.4	33.2	34.1	44.3	52.9	65.0	15.0
21.	less: Operating Costs e/	8.1	9.9	13.0	17.4	19.5	21.5	25.9	28.7	30.8	39.0	19.1
22.	Operating Income	10.4	9.7	11.4	7.0	4.9	11.7	8.2	15.6	22.1	26.0	10.7
23.	Financial Rate of Return on Average Net Fixed Assets in Operation g/											
	a. Non-revalued assets (%)	12.8	10.5	11.1	6.3	4.1	9.6	6.1	5.7	7.6	9.2	
	b. Revalued Assets (%) f/	6.3	5.6	6.5	2.0	0.9	3.7	neg.	2.5	3.7	4.2	
	RETURN FORECAST ACCURACY c/											
24.	Operating Revenues	103	111	135	154	172	142	153	125	117	106	
25.	less: Operating Costs	132	124	135	114	104	108	96	84	79	67	
26.	Operating Income	81	98	134	253	443	203	233	200	170	165	

a/ In addition, 14 MW were available from the COMPANIA COLOMBIANA DE ELECTRICIDAD (CCE).
b/ Effective Peak = peak load at critical time in the year when margin between demand and available capacity was least or load shedding greatest (excluding short-term outages).
c/ Defined by the ratio Forecast/Actual.
d/ All current or historic pesos have been converted to 1960 constant pesos for the purposes of comparison with the Loan 255-CO Appraisal Report forecasts, using the National GDP deflator.
e/ Including non-revalued depreciation and direct taxation but excluding interest.
f/ Revaluation of assets computations as calculated by IBRD in Annex I.
g/ Net revenues as % of average net fixed assets in operation.

TABLE II - A.5

COLOMBIA: CENTRAL HIDROELECTRICA DEL RIO ANCHICAYA LTDA (CHIDRAL)
Loan 339-CO (June, 1963)

		1963	1964	1965	1966	1967	1968	1969	1970	AVERAGE ANNUAL INCREASE RATE (%) (1963-1970) g/	
	LOAD FORECASTS (MW)										
1.	Installed Capacity	135.0	165.0	255.0	255.0	310.0	370.0	490.0	490.0	20.5	
2.	Annual Peak Demand	141.0	166.0	191.0	215.0	258.0	289.0	319.0	356.0	14.1	
3.	Gross Reserve Capacity (1-2)	-6.0	-1.0	64.0	40.0	52.0	81.0	171.0	134.0		
	ACTUAL LOAD (MW)										
4.	Installed Capacity	128.1	128.1	158.1	188.1	248.1	248.1	248.1	248.1	9.9	
5.	Annual Peak Demand	129.1	138.7	143.8	174.3	185.3	200.3	201.6	228.0	8.5	
6.	Gross Reserve Capacity (4-5)	-1.0	-10.6	14.3	13.8	62.8	47.8	46.5	20.1		
7.	Effective Peak Capacity a/	118.1	128.1	118.1	125.1	183.1	243.1	215.1	205.1		
8.	Effective Peak Demand a/	121.8	138.7	140.3	140.8	175.9	200.3	201.6	221.6		
9.	Effective Peak Spare Capacity (7-8)	-3.7	-10.6	-22.2	-15.7	7.2	42.8	13.5	-16.5		
	LOAD FORECAST ACCURACY b/										
10.	Installed Capacity	105	129	161	136	125	149	198	198		
11.	Annual Peak Demand	109	120	133	123	139	144	158	156		
12.	Gross Reserve Capacity	-	*	448	290	83	169	368	667		
	SALES FORECAST (GWh)										
13.	Sales	670	791	918	1023	1199	1365	1586	1805	15.2	
	ACTUAL SALES (GWh)										
14.	Sales	563	650	672	789	846	908	943	1067	9.6	
	SALES FORECAST ACCURACY b/										
15.	Sales	119	122	137	130	142	150	168	169		
	RETURN FORECAST (Col. Pesos mln) c/										
16.	Operating Revenues	46.9	63.3	73.4	92.0	107.9	122.8	142.8	162.5	20.0	
17.	less: Operating Costs	19.0	22.6	28.7	37.1	34.5	31.4	35.9	44.1	11.2	
18.	Operating Income	27.9	40.7	44.7	54.9	73.4	91.4	106.9	118.4	25.0	
19.	Financial Rate of Return on Average Net Fixed Assets in Operation (%) d/	13.8	14.0	12.3	11.6	15.1	14.3	14.2	12.1		
	ACTUAL RETURN (Col. Pesos mln) e/										
20.	Operating Revenues	34.7	40.3	60.1	71.0	99.9	130.0	173.8	na	17.8 h/	30.5 i/
21.	less: Operating Costs f/	24.8	32.2	39.3	53.9	64.7	75.6	104.4	na	14.4 h/	27.0 i/
22.	Operating Income	9.9	8.1	20.8	17.1	35.2	54.4	69.4	na	24.5 h/	38.0 i/
23.	Financial Rate of Return on Average Net Fixed Assets in Operation d/										
	a. Non-Revalued Assets	6.3	4.1	9.6	6.1	5.7	7.6	9.2	na		
	b. Revalued Assets j/	2.0	0.9	3.7	neg.	2.5	3.7	4.2	na		
	RETURN FORECAST ACCURACY b/										
24.	Operating Revenues	135	157	122	130	108	94	82	na		
25.	less: Operating Costs	77	70	73	69	53	42	34	na		
26.	Operating Income	282	502	214	321	209	168	154	na		

a/ Effective Peak =peak load at critical time in the year when margin between demand and available capacity was least or load shedding greatest (excluding short term outages).
b/ Defined by the ratio Forecast/Actual.
c/ Includes an estimated inflation factor.
d/ Net revenues as % of average net fixed assets in operation.
e/ In current prices.
f/ Including non-revalued depreciation but excluding interest.
g/ Forecast and Actual Return growth rates are for 1963-69 only.
h/ Real growth rates have been deflated based upon the National GDP deflator.
i/ Non-deflated growth rate.
j/ Revaluation of Assets computations as calculated by IBRD in Annex I.

COLOMBIA: CENTRAL HIDROELECTRICA DEL RIO ANCHICAYA LTDA. (CHIDRAL)
PROJECTS IMPLEMENTATION

TABLE III

		Start Construction	Commission Date	Construction Period	Project Scope a/		Construction Cost b/ (US $ million) L.C.	F.X.	Total	Cost/ KW US $
LOAN 38-CO (US $ 3.53 million) (signed Nov., 1950)										
Anchicaya Units 1 and 2	Forecast	1951 c/	August 1953	30 c/	2 x 12 MW	Hydro	8.14 d/	3.89 d/	12.03 d/	501.3 d/
	Actual	1951 c/	Mid 1955	54 c/	2 x 12 MW	Hydro	n.a.	n.a.	n.a.	n.a.
Anchicaya Units 1 and 2 (including associated transmission)	Forecast	1951 c/	August 1953	30 c/	2 x 12 MW	Hydro	8.48 d/	4.32 d/	12.80 d/	533.3 d/
	Actual	1951 c/	Mid 1955	54 c/	2 x 12 MW	Hydro	n.a.	n.a.	15.33 d/	638.8 d/
LOAN 113-CO (US $4.50 million) (signed March, 1955)										
Anchicaya Units 1, 2, and 3	Forecast	Early 1955 f/	November 1956	20 f/	44 MW e/	Hydro	9.06 d/	5.30 d/	14.36 d/	326.2
	Actual	Early 1955 f/	June 1957	27 f/	44 MW e/	Hydro	n.a.	n.a.	n.a.	n.a.
Anchicaya Units 1,2, and 3 (including associated transmission)	Forecast	Early 1955 f/	November 1956	20 f/	44 MW e/	Hydro	9.38 d/	5.76 d/	15.14 d/	343.9
	Actual	Early 1955 f/	June 1957	27 f/	44 MW e/	Hydro	n.a.	n.a.	17.01 d/	386.7
Yumbo Unit 1	Forecast	Early 1955	End 1958	45	1 x 12.5 MW	Thermal	2.13	1.10	3.23	258.4
	Actual	Early 1955	May 1958	38	1 x 10.0 MW	Thermal	n.a.	n.a.	4.37	437.0
Yumbo Unit 1 (including associated transmission)	Forecast	Early 1955	End 1958	45	1 x 12.5 MW	Thermal	n.a.	n.a.	n.a.	n.a.
	Actual	Early 1955	May 1958	38	1 x 10.0 MW	Thermal	n.a.	n.a.	n.a.	n.a.
LOAN 215-CO (US $2.8 million) (signed December 1958)										
Yumbo Units 1 and 2	Forecast	Dec. 1958 h/	Feb. 1960	15 h/	22.5 MW i/	Thermal	3.41	1.42	4.83	214.6
	Actual	Dec. 1958 h/	Feb. 1960	15 h/	2 x 10 MW	Thermal	n.a.	n.a.	5.66	283.0
Yumbo Units 1 and 2 (including associated Transmission)	Forecast	Dec. 1958 h/	Feb. 1960	15 h/	22.5 MW i/	Thermal	n.a.	n.a.	n.a.	n.a.
	Actual	Dec. 1958 h/	Feb. 1960	15 h/	2 x 10 MW	Thermal	n.a.	n.a.	n.a.	n.a.
LOAN 255-CO (US $ 25.0 million) (signed May, 1960)										
Yumbo unit 3 (no transmission costs)	Forecast	Mid 1960 f/	Mid 1962	24 f/	1 x 33 MW	Thermal	1.24	4.40	5.64	170.9
	Actual	Mid 1960 f/	June 1962	24 f/	1 x 33 MW	Thermal	2.77	3.70	6.47	196.1
Calima Units 1 and 2	Forecast	Mid 1960	Early 1964	45	2 x 30 MW	Hydro	7.98	14.50	22.48	374.7
	Actual	Mid 1960	Jan. 1966	67	2 x 30 MW	Hydro	8.19	16.01	24.20	403.3
Calima Units 1 and 2 (including associated transmission) j/	Forecast	Mid 1960	Early 1964	45	2 x 30 MW	Hydro	8.44	16.28	24.72	412.0
	Actual	Mid 1960	Jan. 1966	67	2 x 30 MW	Hydro	10.70	17.27	27.97	466.1
LOAN 339-CO (US $8.8 million) (signed June, 1963)										
Calima Units 1,2,3, and 4	Forecast	June 1963 k/		18 k/	4 x 30 MW	Hydro	9.80	18.90	28.70	239.2
	Actual	June 1963 k/	Aug. 1967	50 k/	4 x 30 MW	Hydro	20.54	21.65	42.19	351.6
Calima Units 1,2,3, and 4 (including associated transmission) j/	Forecast	June 1963 k/	Dec. 1964	18 k/	4 x 30 MW	Hydro	10.60	19.79	30.39	253.3
	Actual	June 1963 k/	Aug. 1967	50 k/	4 x 30 MW	Hydro	22.42	22.91	45.33	377.8

LOAN DISBURSEMENT PATTERN

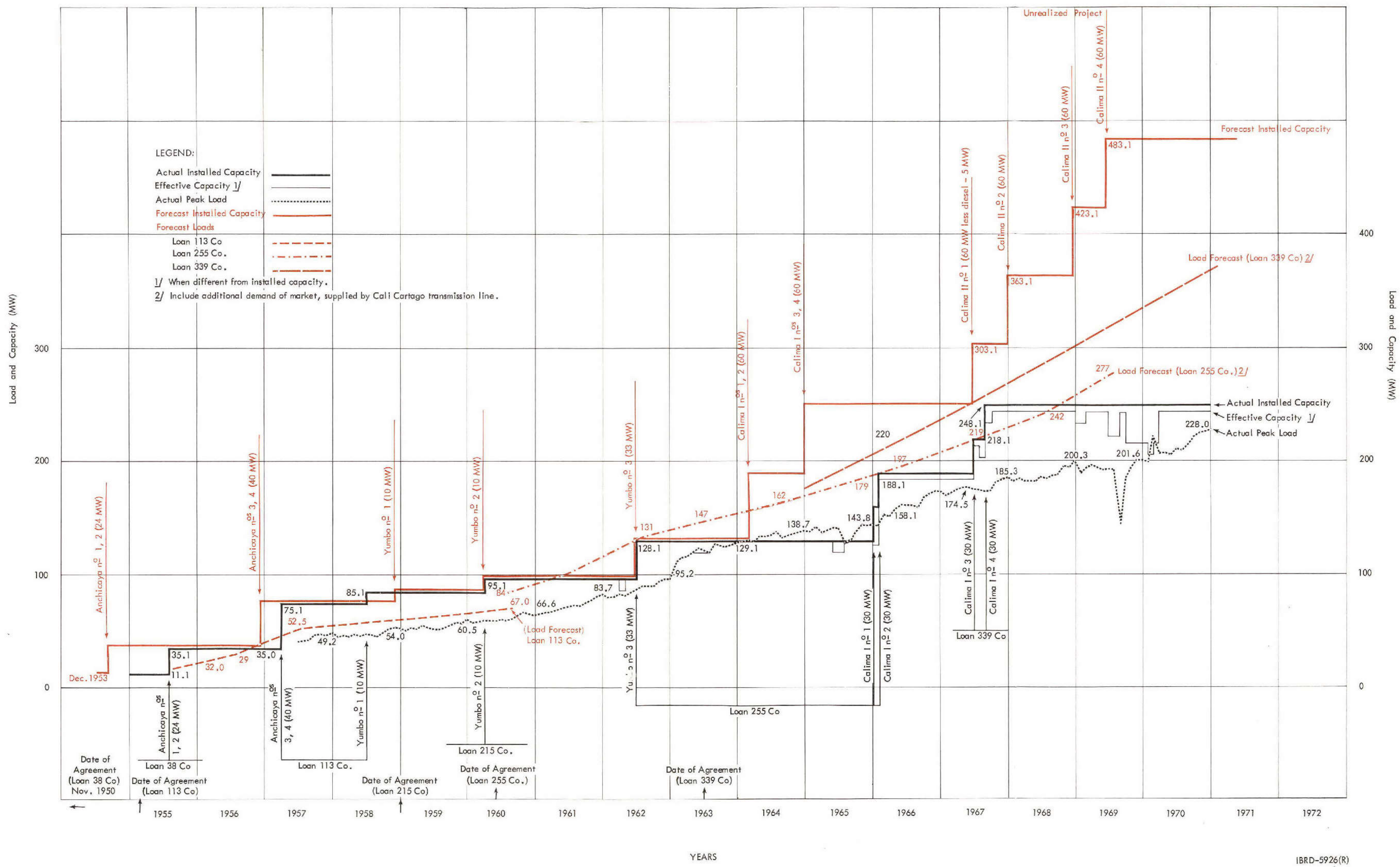
			1950	1951	1952	1953	1954	1955	1956	1957	1958
LOAN 38-CO	Forecast:	None l/									
	Actual:	Amount (US $mln)		0.72	1.56	0.74	0.50	0.01			
		% of Total		20.4	44.2	21.0	14.1	0.3			
		Cumulative %		20.4	64.6	85.6	99.7	100.0			
LOAN 113-CO	Forecast:	Amount (US $ mln)						1.21	1.90	0.88	0.51
		% of Total						27.0	42.3	19.5	11.2
		Cumulative %						27.0	69.3	88.8	100.0
	Actual:	Amount (US $ mln)						0.96	1.91	1.38	0.25
		% of Total						21.3	42.4	30.7	5.6
		Cumulative %						21.3	63.7	94.4	100.0
LOAN 215-CO	Forecast: m/	Amount (US $ mln)									
		% of Total									
		Cumulative %									
	Actual:	Amount (US $ mln)									
		% of Total									
		Cumulative %									
LOAN 255-CO	Forecast:	Amount (US $ mln)									
		% of Total									
		Cumulative %									
	Actual:	Amount (US $ mln)									
		% of Total									
		Cumulative %									
LOAN 339-CO	Forecast:	Amount (US $ mln)									
		% of Total									
		Cumulative %									
	Actual:	Amount (US $ mln)									
		% of Total									
		Cumulative %									

			1959	1960	1961	1962	1963	1964	1965	1966
LOAN 38-CO	Forecast:	None l/								
	Actual:	Amount (US $mln)								
		% of Total								
		Cumulative %								
LOAN 113-CO	Forecast:	Amount (US $ mln)								
		% of Total								
		Cumulative %								
	Actual:	Amount (US $ mln)								
		% of Total								
		Cumulative %								
LOAN 215-CO	Forecast: m/	Amount (US $ mln)	1.80	0.45						
		% of Total	80.0	20.0						
		Cumulative %	80.0	100.0						
	Actual:	Amount (US $ mln)	1.72	0.63	0.41	0.04				
		% of Total	61.4	22.5	14.6	1.5				
		Cumulative %	61.4	83.9	98.5	100.0				
LOAN 255-CO	Forecast:	Amount (US $ mln)		6.20	7.59	7.29	2.99	0.93		
		% of Total		24.8	30.3	29.1	12.0	3.8		
		Cumulative %		24.8	55.1	84.2	96.2	100.0		
	Actual:	Amount (US $ mln)		1.72	5.36	4.79	7.35	4.76	0.93	0.09
		% of Total		6.9	21.4	19.2	29.4	19.0	3.7	0.4
		Cumulative %		6.9	28.3	47.5	76.9	95.9	99.6	100.0
LOAN 339-CO	Forecast:	Amount (US $ mln)					3.47	4.53	0.80	
		% of Total					39.4	51.5	9.1	
		Cumulative %					39.4	90.9	100.0	
	Actual:	Amount (US $ mln)					0.59	6.12	2.09	
		% of Total					6.7	69.6	23.7	
		Cumulative %					6.7	76.3	100.0	

a/ Project scope for generation is Megawatts (MW) of installed capacity and source of energy. Data was not available for length in kilometers of transmission or distribution live expansion included in the projects (except the Buenaventina-Anchorage transmission live under loan 339-CO).
b/ Local costs of projects were calculated by changing for each year the Col. Peso expenditures or the projects into 1968 pesos by the National GDP deflator, and then converting the total amount into US Dollars at the 1968 average official exchange rate weighted by volume of imported goods and services (Ps. 15.9 = US $1.00).
c/ Construction period figures include only work done during involvement.
d/ Costs include expenses incurred before Bank participated.
e/ Of which units 1 and 2 each represented 12 MW and unit 3 represented 20 MW
f/ Construction period for third unit.
g/ For plants with more than one unit under construction, date for last unit.
h/ Construction period for second unit.
i/ Of which the first unit was to represent 12.5 MW, and the second 10 MW.
j/ The cost figures covering both generation and transmission include an allowance for the transmission live form Calina to Buga and an arbitrary small share of the line from Buga to Cali; 27% of 115 KV transmission under loan 255 was taken in total.
k/ Construction period for last two units.
l/ No disbursement forecast was made for this early loan.
m/ Exclusive of US $0.55 million originally shceduled to be re-lent to CHIDRAL'S distributor EMCALI.

Chart 12.1

COLOMBIA
CVC / CHIDRAL - Power
Load and Capacity Development
Actual and Forecast
(1953 - 1970)



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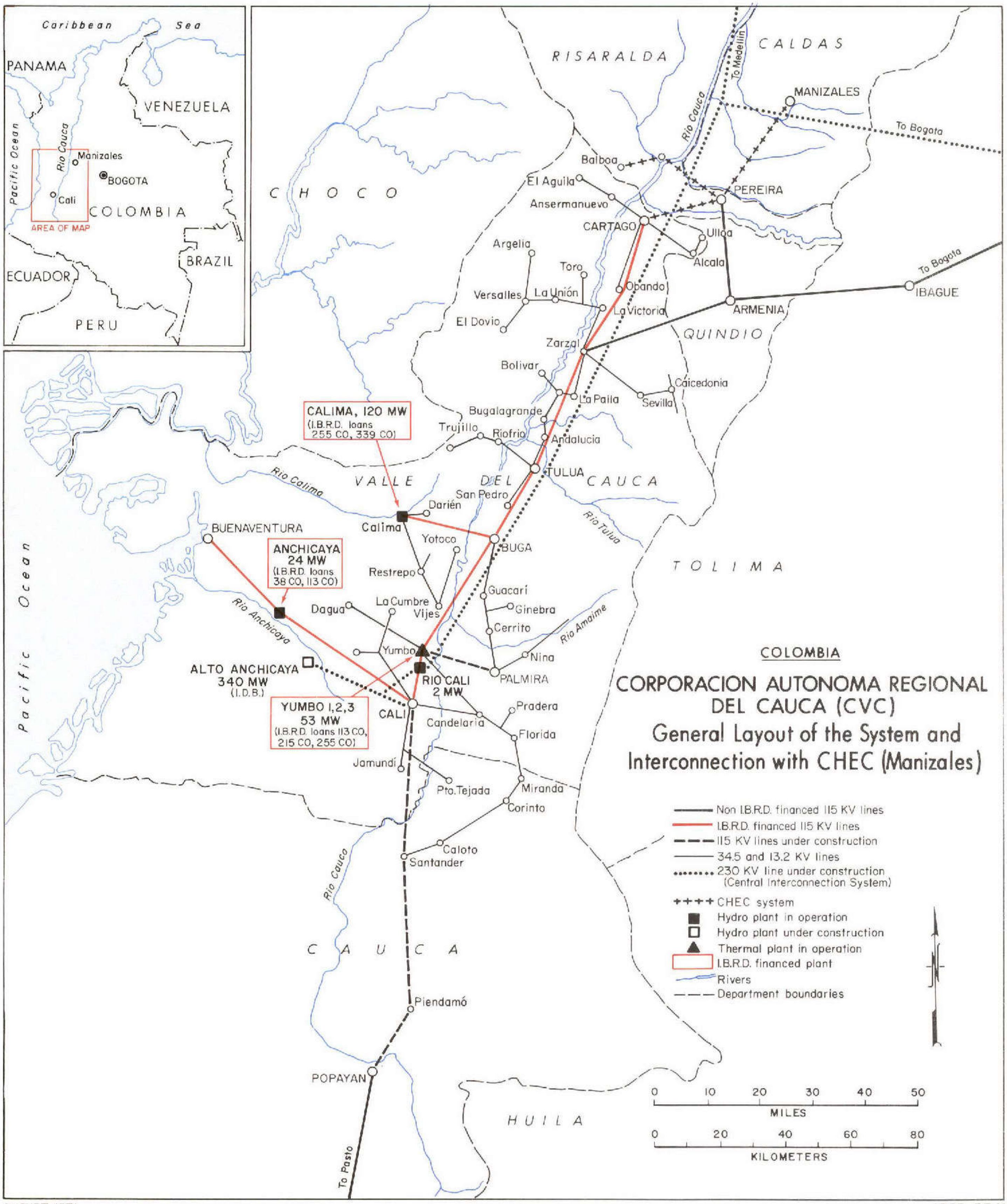

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