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INDIA

Economic Issues in the Power Sector

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INDIA

Economic Issues in the Power Sector

This report is based on the findings of a mission to India consisting of the mission leader:

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and
C. White, consultant engineer
and M. Gellerson, consultant economist

in September/October 1978 and a follow-up visit by C. Taylor in February 1979. Ms. J. Voigt and N. Poduval at headquarters and Y. Satyanarayana in the New Delhi Office provided research assistance. V. Prakash, who is supervising the World Bank research project "Patterns of Industrial Development" kindly made his data tapes available to the mission.

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Preface

This review has grown out of the World Bank's increasing involvement in the power sector in India. As the Bank's operations grew in number and size it was felt that an overall strategy of assistance was needed and that the initial step required was to increase the Bank's knowledge of the operations and procedures within the power sector. Therefore, a review of issues at the national level was undertaken, with the main mission visiting India in September and October 1978 and a follow-up mission in February 1979. The present report contains the findings of those missions.

The range of subjects that could be covered at the national level is very large and the complexity of the Indian power sector means that much detailed work would be required for a definitive, comprehensive sector review. This was felt to be beyond the scope of two brief missions. This review has, therefore, concentrated on two major areas which are principally economic in character. These are (i) demand for electricity and (ii) investment in the power sector. It must be emphasized that the power sector is a sophisticated and complex part of India's basic infrastructure: the many Central organizations and the 18 State Electricity Boards between them employ over 600,000 regular staff. Thus, even on the subjects reviewed -- demand and investment -- the examination has been cursory and more work on them is highly desirable. In addition there are other major areas in which future work could be profitably taken up, including investment implementation, thermal plant operation and overall system management.

The Government of India is well aware that there are many problems with the operation and development of the power sector. To define these problems and to prescribe methods of dealing with them, a committee was recently established under the chairmanship of one of the members of the Planning Commission. The committee's terms of reference call for an examination of "all aspects of the functioning of State Electricity Boards and Central Organizations engaged in electricity generation, transmission and distribution and make recommendations for improving them". This committee should have far-reaching impact when it reports its conclusions early in 1980.

The main text of this review is organized in two major sections: Section I, entitled "Consumption", and Section II, entitled "Investment Planning and Resource Allocation". Before these two major sections, there is a summary followed by a background discussion of the relationship of the power sector with the economy at large and the institutional and legal framework of the sector, which should be particularly useful to readers who are not familiar with the power sector in India. At the very end of the report the main conclusions are drawn together in a separate section. The annexes to the main report are mostly statistical but also include two notes on terminology for the lay reader, graphs and an organization chart for the sector.

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Acting Vice President
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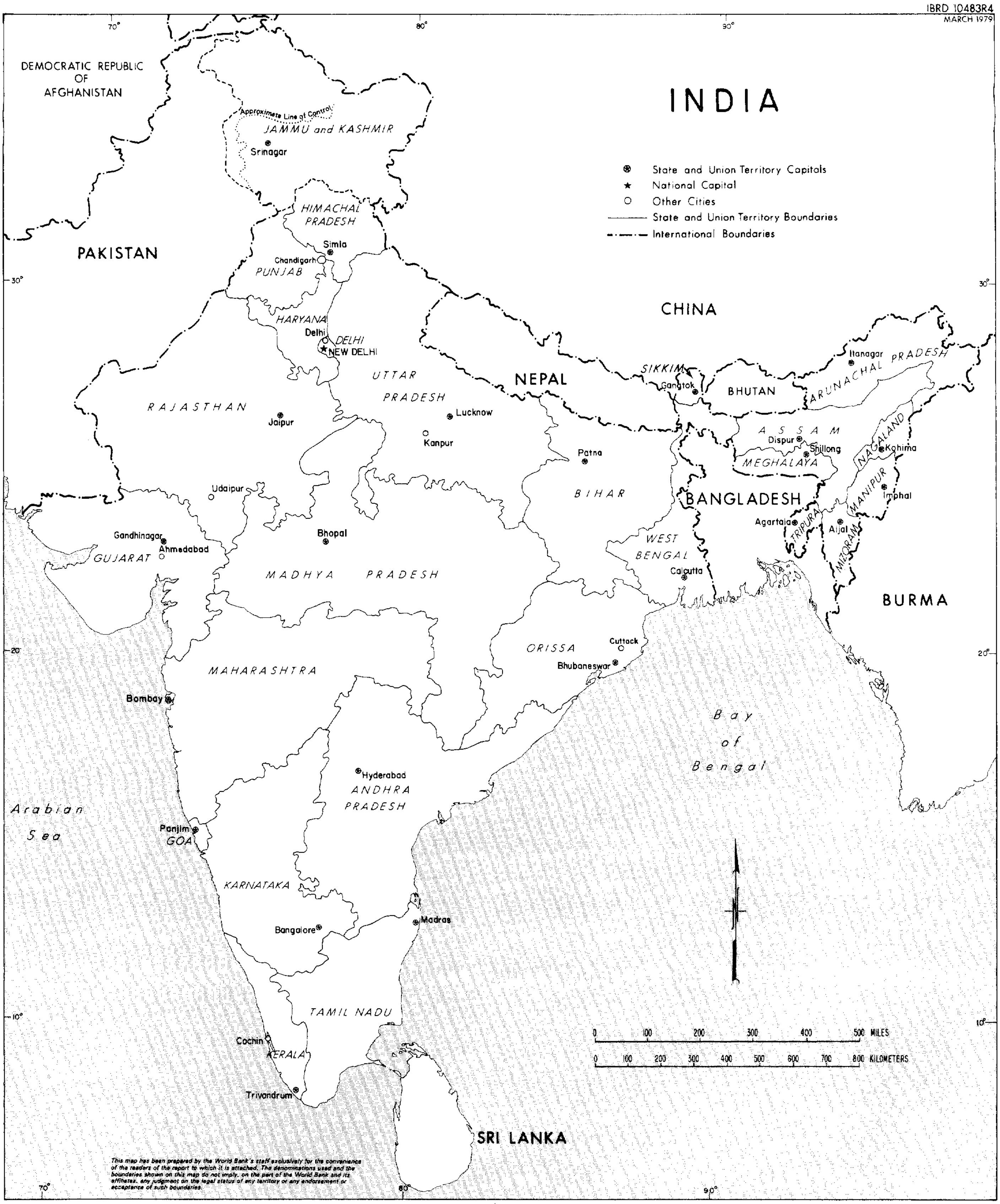
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ABBREVIATIONS AND ACRONYMS

CEA	-	Central Electricity Authority
REB		Regional Electricity Board
SEB	-	State Electricity Board
REC	-	Rural Electrification Corporation
APA	-	Atomic Power Authority
NTPC	-	National Thermal Power Corporation
NHPC	-	National Hydro Power Corporation
APS	-	Annual Electric Power Survey
NDP	-	National Domestic Product
KWh	-	Kilowatt hour (energy)
KW	-	Kilowatt (Power)
MW	-	KW x 10^3
MWh	-	KWh x 10^3
GWh	-	KWh x 10^6
TWh	-	KWh x 10^9
HP	-	Horse power
HT	-	High tension
LT	-	Low tension
km	-	Kilometers
V	-	Volts
KV	-	Kilovolts
KVA	-	Kilovolts-amperes
EHV	-	Extra high voltage

Since September 24, 1975, the Rupee has been officially valued relative to a "basket" of currencies. As these currencies are now floating, the US Dollar/Rupee exchange rate is subject to change. Currently, the value of the Rupee is about US$0.12.

SUMMARY

i. Background: Economic growth in India depends critically on the development of the power sector. As the rest of the Indian economy expands, demand for power grows roughly twice as fast and, because power is relatively capital intensive, its share in total fixed asset formation is increasing rapidly.

ii. The institutional structure of the electricity supply industry is complex. The Ministry of Energy in the Government of India, and the Central Electricity Authority -- the technical arm of Central Government for the power sector -- are responsible for broad issues of policy, planning and other matters affecting the power sector at the national level. In addition there are two new generating companies at the Center, the National Thermal Power Corporation and the National Hydro-electric Power Corporation, which are planned to grow into important wholesalers of power in the coming years. The Atomic Power Authority, reporting to a separate Ministry of Atomic Energy, is responsible for all commercial nuclear power generation in India. The Regional Electricity Boards, standing between the Center and the States, have begun to coordinate operations among the utilities within their regions. The most important agencies in the power sector are the State Electricity Boards, which own and operate three-quarters of the Indian power system.

iii. Consumption: The demand for power has increased rapidly over the last two decades. Most of the increase has originated with industry, both because of industrial growth and increases in the intensity of power use in the industrial sector. Agricultural demand for power has in fact grown more rapidly than industrial demand but, starting from an almost negligible base, it still constitutes only a modest fraction of total demand.

iv. Not only has there been a change in the composition of power demand among sectors, but also among different areas of the country. As the Western Region industrialized more rapidly than the Eastern Region, the proportion of electricity consumed in the West has risen. A similar shift in the growth of capacity is apparent. In the country at large there has been a shift in electricity demand towards rural areas, for industrial as well as agricultural use.

v. Shortages of both power and energy have been pervasive for several years. While their exact extent is hard to measure, some States and regions clearly have been more seriously affected than others. Shortages appear to be somewhat seasonal, being most severe in the period preceding the monsoon replenishment of hydro reservoirs. There was an estimated supply shortfall of about 15% in 1977/78, and about 10% in the first 9 months of 1978/79.

vi. Shortages fall largely on industry. Since 1968/69, downturns in the supply of electricity to industry have preceded industrial downturns by a year; while other factors such as the performance of agriculture are undoubtedly important determinants of industrial performance, electricity supply appears to be a major constraint on industrial growth. In the last

few years, value lost as a result of power shortages probably represented between 1 and 3% of GDP. The cost of power shortages is not only value-added foregone but also misallocation of capital resources. A substantial investment in small uneconomic generating sets, mainly by industrial enterprises, appears to have been undertaken in the last five years to help cope with shortages of supply of electricity from the utilities.

vii. In the Indian economy, power consumption is high relative to the level of economic activity, and the rate at which electricity consumption has been growing relative to GNP is much higher than is typical in other countries. This power-intensity is particularly marked in industry where it appears that both the intensity of power use within subsectors and the composition of the industrial sector have contributed to the overall intensity of power use.

viii. Electricity tariffs vary from State to State; generally they are complex and low relative to marginal costs. There is evidence they have been simplified to a limited extent in the last four years or so, and over the longer term power rates have been increased, but they have not kept pace with other prices in the energy sector or the general level of prices throughout the economy.

ix. Power forecasting in India is complicated by past shortages which make it difficult to relate the level of economic activity to (unsuppressed) electricity demand. In any case demand forecasting is very uncertain, whether in India or elsewhere. The most recent detailed official forecast was prepared by the Tenth Annual Power Survey Committee. The aggregate forecasts incorporated into the Draft Plan (1978/79-1982/83) are, however, much lower. The regression analysis undertaken in this review produces forecasts that fall between those of the Annual Power Survey and the Draft Plan.

x. Investment: Rs 157 billion (US$18.3 billion) is allocated to the power sector in the Draft Plan. The proportion of Plan resources devoted to the power sector has risen to a point where it now represents 35% of the State Plans and 23% of the State and Central Plans taken together. Most of these resources come from borrowings and general tax revenues and a very small proportion is estimated to be generated internally from the retained earnings and depreciation of the State Electricity Boards. In the past, physical investment targets have not been met while expenditure forecasts have often been exceeded, and the ex-post share of Plan expenditure has been higher than the ex-ante share of allocations.

xi. The planning process for the power sector is integrated into the process of preparing the Annual and Five-Year Plans for the whole economy. As in other sectors, it involves a lengthy series of discussions between the Center and the States and among the concerned central ministries, until a concensus is reached. While generation projects included in the power plan are vetted from a technical viewpoint, they are not currently being reviewed from a systems viewpoint to judge their economic merit. Sophisticated planning of the transmission system is just being introduced.

xii. Investment in hydro-electric generation has fallen behind investment in thermal generation in recent years. Despite its long gestation and high capital costs, in a number of cases hydro-electricity may offer a better return than thermal. Similarly, investment in transmission and distribution has been low relative to investment in generation and, correspondingly, losses on the power system have been high.

xiii. Conclusions. Investment in the power sector to meet India's needs will be massive, at least over the medium term. The demand forecasts of the Planning Commission seem conservative and the investment program should be pitched a little above the demand forecasts to allow for slippages that inevitably arise. These considerations suggest that the investment target of the Draft Plan should be raised, perhaps by as much as 3,700 MW to roughly 22,000 MW, in the expectation that roughly 21,000 MW would actually be commissioned. The planning of investment should look farther into the future, say 10 to 20 years ahead, than has been the case in the past. One advantage of planning further ahead is the opportunity to fit into the investment program more hydro-electric capacity, which may have been underexploited due to its long gestation period relative to that of thermal capacity. The proportion of overall investment in transmission relative to generation capacity should rise to approach one-half of total investment, compared to its past level of roughly one-third. Increased expenditure on transmission is important not only to enhance regional integration of State systems but also to reduce system losses which have grown. Financing this large investment program will require larger Plan outlays on power, which have already reached quite high proportions. However, the funds should not come solely from the public purse. Tariffs should be increased not only to increase the internal cash generation of the State Electricity Boards but also to provide consumers of all kinds with the incentive to conserve.

BACKGROUND

1. Electricity and the Economy

1. The power sector is a vital part of the infrastructure of the Indian economy. The performance of the electricity supply industry and the economy at large are closely linked, since the bulk of electricity generated is consumed in one of the other productive sectors of the economy. Because electricity cannot easily be traded internationally and because its use is instantaneous and it cannot be stored readily, a shortage of electricity supply has an almost immediate effect on the rest of the economy. In the longer term, the substantial resources devoted to developing the power sector influence the availability of resources for other purposes: electricity supply is one of the most capital-intensive sectors in India. If, as in the last two decades, the sector continues to grow at more than twice the rate of the economy as a whole, both its draw on resources and the economy's capital-intensity will grow more critical. Constraints affecting the power sector are among the most important constraints on accelerated development in India today.

2. Electricity consumption has grown by about 10% a year since 1951 (Annex B.1.1). Though this is discussed in more detail later, it is worth noting here that about two-thirds of this consumption is by industry; agriculture accounts for less than 15% and services (other than power itself) for about 10%. The remaining 10% or so is consumed by private households and in public lighting. Total consumption was about 66 TWh in 1976/77.

3. Electricity is, of course, not the only form of commercial energy available in India, and commercial energy only recently has become as important as traditional forms -- vegetable and animal. Commercial energy now accounts for something over 55% of total estimated energy consumption (using coal replacement measurement of energy to aggregate different types). In proportion to the total consumption of commercial energy, electricity consumption has steadily risen from about 10-15% in the early 1950s to about 25% by 1975/76.

4. There is some degree of substitutability between electricity and other forms of energy. After the 1973/74 oil crisis, the Government adopted the policy of substituting coal and electricity for petroleum products wherever feasible in the public sector. The Government used relative prices within the energy sector to encourage the electrification rather than dieselization of pumpsets. However, the number of technical options for substitution that are both feasible and economical, is limited.

5. Since machinery is almost always built specifically for one type of energy use, a response to price changes or to any other stimulus to substitute is usually slow and difficult to measure. Electricity tariffs have fallen relative to coal and petroleum product prices, but the precise impact of these price changes on demand is impossible to discern with the available data.

6. Electricity generation uses considerable quantities of resources. Apart from hydro-electricity, generation involves the depletion of non-renewable fuels: mainly coal, and small amounts of oil and gas and nuclear fuel. In 1977/78 about 56% of gross electricity generation was in conventional thermal plants, 41% in hydro-electric plants and 3% in nuclear plants (Annex B.1.2). The great bulk of fuel used in conventional power stations is coal. In 1976/77, 28 million tons were used to generate electricity (Annex B.1.3). Measured in coal replacement terms, this constituted about 86% of all fuel used for thermal generation, compared with 4% from lignite and 10% from oil. The percentage of oil rose until 1973 (13%) and has fallen steadily, if only slightly, since then.

7. India's official reserves of coking and non-coking coal stand at 20 and 60 billion tons respectively. This probably understates the total that is economically available and if coal in thinner seams and at greater depth than that included in the official estimate is added, coking and non-coking coal reserves would be about 22.5 billion tons and 89 billion tons, respectively. At present, just under one-third of all coal produced is used to generate power. The great bulk of this is non-coking coal, but the middlings from beneficiation of coking coal are also used. Assuming coal production increases from its present level of about 100 million tons per annum to about 500 million tons per annum in the next 30 years, and then levels off, identified reserves should last for roughly a century.

8. Reserves of hydro electric power are considerable. The last complete survey was done by the Central Water and Power Commission between 1953-60, and it placed the hydro potential of the country at 41,000 MW at 60% load factor. Thus, the total energy generating capability was estimated as 222 TWh per annum (excluding available secondary energy). New data indicate that the hydro-electric potential of India may be much higher because more schemes are now economically attractive, with the rise in energy prices and the improvements in techniques of site exploration and investigation. These suggest total hydro-electric resources may be as much as 66,000 MW at a 60% load factor, representing an annual generating capability of about 345 TWh. About 10,000 MW of hydro capacity have been commissioned in India to date, and the present level of generation is about 38 TWh per annum. The unexploited potential lies mostly in the North and North-eastern Regions.

9. Uranium is the only primary fuel that can be used directly in nuclear reactors at the moment. The most important region in India for uranium ore so far discovered is in Bihar. The reasonably well assured uranium resources in India are equivalent to about 20,000 to 30,000 tons of yellow cake nuclear fuel.

10. The long-range atomic power programme in India will depend on thorium rather than uranium. Thorium reserves are the largest in the world and are estimated at 450,000 tons. The development of fast breeder reactors based on thorium will pose many technical problems, but when they can eventually be introduced on a commercial basis there should be virtually no limit to the capability to generate electricity from a resources point of view.

The presently known thorium resources in India represent 2.4 million TWh of energy. If at the end of the century 10 TWh of power were produced annually from this source, and production were to increase by 10% per annum thereafter, these resources would not run out until the first decade of the twenty-first century.

11. The electricity sector has expanded rapidly since Independence. The installed generating capacity throughout India (utilities and non-utilities) has increased from about 2,300 MW in 1950 to over 26,000 MW by the end of 1977/78. This represents an average annual rate of growth of just over 9%. The bulk of this increase has been in the capacity owned by the utilities, which has increased from roughly 75% to over 90% of total capacity. The growth rate of capacity in the utility sector has been about 10% over this period. This comprised a 10.8% growth in hydro-electric capacity and a 9.5% growth rate in conventional thermal plants (Annex B.1.1).

12. While long-term growth rates have been high, in recent years growth has been less impressive. Since 1971, installed capacity has grown annually by only 7% (7.2% in the utility sector) and the average annual growth rate of hydro electricity capacity has fallen to only 6.6%. The long-term trend, of hydro expansion being faster than thermal, has been reversed in the 1970s.

13. NDP statistics on the value of capital investment in the power sector are not available for recent years, but one can trace the increase in net tangible assets in the power sector and the economy as a whole between 1950 and 1971. This shows the power sector accounted for 11.5% of all investment over this period, and rose from accounting for 1% of the capital stock in the economy to about 5% (Annex B.1.4). In the power sector, the capital stock increased almost three times as fast as it did in the rest of the economy.

2. The Institutional Framework

14. As early as the turn of the century it was possible, in certain parts of India, to buy electricity from a public utility company. Electricity supply was, of course, hardly widespread in 1900, and, indeed, was not recognized as a separate industry by Government; legislation governing its development was introduced in the Indian Telegraph Act of 1885.

15. As the sector has grown and developed over the years, major institutional developments have usually been accompanied by new legislation. In 1910, the Indian Electricity Act empowered the State governments to grant licenses to those supplying or planning to supply electricity. Licensees were then required to conform to certain basic operational procedures and to submit their accounts to their State governments. This Act also served to establish the State Advisory Boards responsible for advising State governments on matters of electricity policy, and the Central Electricity Board, responsible for policing the Act on behalf of the Central Government.

16. In those early days, public power supply in India developed much like that in most other countries. Generating plants were constructed next

to load centers and transmission lines were only used to evacuate power from more remote hydro-electric schemes. A multitude of operating undertakings sprang up, some of which were local authorities, but many of which were private ventures.

17. With Independence, the principle that both the Central Government and the States should be able to legislate on power was embodied in the Constitution. Shortly after this, legislative authority was more formally divided in the Electricity Supply Act of 1948. The Act provided for the establishment of the Central Electricity Authority (CEA) and of State Electricity Boards (SEBs) which were to become the main supplying agencies for power throughout India. The mandate for the CEA was spelt out clearly in the Act: to develop national power policy, to report the progress of the electricity supply industry, to provide technical assistance, to train personnel in the sector, to promote research and, in general, to facilitate efficient power supply. Its role, however, was essentially advisory rather than executive.

18. Much more effective authority was vested in the SEBs. Appointed by their State governments, the Boards were given authority to build, own and operate power systems and sell power to the public. The SEBs are largely autonomous in matters relating to operations, but are subject to State government direction in many other areas such as investment and tariff policy. The Boards are, of course, empowered to incur financial liabilities, hold assets and undertake transactions. Subject to audit of financial practices and the requirement to meet certain financial performance criteria, the Boards are, in principle, free to set tariffs as they choose, though their financial obligations are to be met in a particular order. Prior to the 1978 amendment to the Electricity Supply Act, which is discussed below, the order was, first, interest on unguaranteed debt, then depreciation, interest on guaranteed debt, write-offs, contributions to general reserves, interest on debt from the State government and finally amortization of State government debt from a development fund. Amortization of non-State government debt was, and is, paid out of the depreciation reserve. Net earnings over and above those required to meet these priorities are subject to Central income tax under the 1922 Income Tax Act, for which purpose Boards are treated as companies. (The 1948 Electricity Supply Act specifically excludes the possibility of any of these taxes going to the State government.)

19. The SEBs were usually staffed in the first instance by officers of the State Department of Power, and in many States, a number of responsibilities remained with that Department. Among these it was common for hydro-electric development to stay mainly with the government because many of the schemes also served irrigation needs. Morever, experienced civil engineers were often more readily available in the Irrigation Department of the State government concerned.

20. The Damodar Valley Corporation (DVC) was established in 1948 by the Central Government to manage all the water resources for hydro-generation and irrigation, and conserve and develop other resources of the Damodar Valley as

an integrated development scheme. Part of its responsibility was to generate and sell electricity. Its sales are confined to bulk HT customers mainly within the Damodar Valley area of West Bengal and Bihar.

21. While the CEA was formally created in 1950, its functions and responsibilities were for many years carried out by the Central Water and Power Commission, the technical arm of the Ministry of Irrigation and Power. In 1974, Presidential notification created a new Ministry of Energy which comprised two departments, one dealing with coal and the other with power. The CWPC was split in the subsequent year and its departments dealing with power became the nucleus of a revitalized CEA, reporting to the Department of Power in the Ministry of Energy.

22. This evolution of the machinery of government was paralleled by the growth of the electricity supply industry. By 1951, there were over 300 undertakings operated by private licensees and about 270 by State governments and municipalities. This must have been close to the maximum number of institutions in the sector, since with the subsequent gradual non-renewal of licenses the SEBs have slowly but surely absorbed many of the smaller utilities in their States. By the end of 1976/77, only 49 private licensees and 21 municipal undertakings were still supplying electricity. Only 12 were generating as well as distributing electricity. The SEBs alone accounted for 74% of total utility sales of energy in 1976/77; the public sector accounted for 86% (Annex B.2.1). Licensees are becoming less important with time. 1/

23. In 1962, the Atomic Energy Act was brought into law, making the development of atomic power resources for electricity generation the sole preserve of Central Government. A Department of Atomic Energy was set up, with the Prime Minister holding its portfolio, which delegated authority for operating commercial nuclear power generation to a statutory body, the Atomic Power Authority (APA). Responsibility for the construction and commissioning of new nuclear power installations remained with the Department itself.

24. This development recognized a major new technological opportunity in the power supply industry. No less significant, but more gradual in its impact was the additional realization that conventional technology could deliver electricity more economically if the scale of the supply system could be increased. It was recognized that interconnected systems require less generating capacity due to diversity among daily peak demands, because larger and more efficient generating plants can be built, because higher voltage transmission (with lower losses) becomes economical and because thermal and hydro-electric generating plants can be operated more economically in combination. Between May 1964 and February 1966, the State and Central Governments thus established by common resolution five Regional Electricity Boards (REBs). The REBs were established to help develop integrated power systems in their respective regions (see paragraphs 43-46).

1/ Some new licensees are still being created: in 1976/77, two new rural electricity supply cooperatives were established.

25. As the benefits of electricity supply became more widely recognized, the SEBs began to electrify rural areas as well as urban. The burden in terms of capital cost was so high, however, that special financing arrangements were needed. Thus, in 1969, the Rural Electrification Corporation (REC) was set up as a public sector financial institution. The main objectives of the Corporation are to finance rural electrification schemes and to promote rural electric cooperatives throughout India. The lending policies of the REC are governed by Department of Power directives requiring, among other things, that REC adopt an area development approach with emphasis on under-developed areas, that it adopt standard viability criteria for projects and that every effort be made to coordinate electrification with the development of other elements of rural infrastructure to ensure the best possible impact of rural electrification on agricultural productivity.

26. In 1975, the Central Government established two power generating undertakings, the National Thermal Power Corporation (NTPC) and the National Hydro-electric Power Corporation (NHPC). The NHPC has taken responsibility for three ongoing hydro-electric schemes. 1/ The NTPC intends to build, own and operate large regional or "super thermal" power stations with capacities of 1,000 MW to 2,100 MW each. Five of these stations are planned and all will be located close to coal mines to minimize coal transportation costs.

27. In 1976, the 1948 Electricity Supply Act was amended with the main effects of extending the authority of the CEA and of providing for generating companies to be set up in the public sector. Under this amendment, the NTPC and NHPC were given statutory recognition. 2/

28. The 1976 amendments required the States and the new generating companies to submit for sanction to the CEA any schemes costing Rs 10 million or more. Since almost all generation and transmission schemes do cost more than this, the CEA is now in a better position to plan and control investment. The CEA now has effective authority to require that schemes be modified or postponed or moved forward in the investment programs and, in principle, could choose not to approve uneconomic schemes submitted to it by the states.

29. The most recent legislation to affect the power sector was the amendment of the financial provisions of the 1948 Act, passed in mid-1978. These amendments provide various ways of strengthening the finances of the SEBs. They permit State governments to convert outstanding debt ("contingent liability") accrued to them into equity. The amendments also reverse the priority of liabilities so that, in effect, cash outlays such as debt servicing must be honored before transfers such as those to depreciation and general reserve. More importantly, the Boards are now required to generate a surplus after meeting all expenses properly chargeable to revenues, including operation and maintenance expenses, taxes, depreciation and interest.

1/ These are the Loktak, Baira Siul and Salal Hydro projects of the Central Government.

2/ Since about 1970, Karnataka has had a separate generating company, the Karnataka Power Corporation, which was also given statutory recognition by the amendments.

30. Many of the initiatives for new legislation arise at the annual conferences of State Power Ministers and Chairmen of the SEBs. The Power Ministers' Conference, usually held in January, provides a forum for co-ordinating policy between the Center and the States. For example, the 1978 Conference concentrated on the utilization of generation capacity, the financial and managerial performance of the SEBs and power project construction, and recommended reviews or immediate policy changes in each of these critical areas. The Conference of Chairmen of SEBs, which meets immediately before that of the State Power Ministers, tends to concentrate on more technical matters. Given that control of the sector is shared, these conferences are of critical importance.

31. Thus, the electricity sector has now developed a complex institutional structure, the most important elements of which are the Ministry of Energy, Department of Power and Central Electricity Authority at the Center and the responsible government departments and the SEBs at the State level. The central generating corporations -- NTPC and NHPC in particular -- and the REBs should have particularly important roles in the future, if the significant economies of operating a power system on a large-scale are to be realized.

32. The Department of Power in the Ministry of Energy. The Department of Power is responsible to Parliament for laying down national policy for the development and regulation of the power sector. Since the energy crisis, emphasis on conservation of power resources has been added. All the technical aspects of the Department's responsibilities are met by the CEA, under the Department's guidance and authority. The Department itself has only 50 to 60 gazetted officers.

33. The Department is organized under a Secretary to the Government of India. The functions of the Department are divided among five wings, four of which are headed by Joint Secretaries and the fifth by a Financial Advisor of Joint Secretary rank. The wings are in turn subdivided into divisions and sections.

34. The allocation of responsibilities within the Department is kept flexible. This permits it to respond to circumstances as they develop by bringing to bear the necessary experience and expertise, wherever it may be in the Department. This expertise must cover broad matters of policy, planning, energy legislation, research and development (including non-traditional energy supply sources such as solar and tidal energy), and relations with outside organizations such as the World Bank, and with neighboring countries for such matters as the coordination of the development of hydro-electric resources. The Department must also administer energy supply in the union territories and the execution of Central schemes such as the Beas-Sutlej link and DVC's new projects. It must oversee, on behalf of the Government, Central agencies such as NTPC, NHPC and REC, and coordinate relations between the Center and the States. The Financial Advisor is responsible for advising the Ministry on investment and expenditure in the Central sector. Special attention is also given to the operation of thermal generating plants throughout the country. This involves, for example, expediting coal supplies with the Department of Coal as and when necessary, and overseeing through the CEA

research and design aimed directly at improving thermal power station operations. Finally, the internal personnel functions both within the Department and the CEA, must be administered.

35. Thus, while the Department is not directly responsible for the operation of the power system, it does address both short-term and long-term problems that range from consideration of broad policy to assistance with the minutae of system operations. As the apex organization in the sector with the most direct access to other branches of Government, its role is central in initiating and coordinating the activities of the organizations throughout the power sector.

36. The CEA. The CEA consists of a chairman and five full time members and a staff of about 2,300 officers, divided among six operating departments, or "wings". The chairman is responsible for the Planning Wing and each member is responsible for one of the other departments:

Chairman, CEA	-	Planning Wing
Member Thermal	-	Thermal Generation Wing
Member Hydro	-	Hydro Generation Wing
Member Systems	-	Power Systems Wing
Member Operations	-	Operations Wing
Member Commercial	-	Economic and Commercial Wing

37. The recently established Planning Wing covers a wide range of activities including load forecasting, the identification of power resources and their optimum development, the formulation of capacity and energy balance studies, the development of reliability criteria, and the techno-economic appraisal of all power generation and transmission and distribution schemes (in collaboration with the Hydro, Thermal, and Power Systems Wings submitted by SEBs and the Central Sector.

38. The Hydro and Thermal Wings comprise specialist engineering organizations which provide comprehensive project engineering services to the electricity supply industry. As well as assisting in the techno-economic appraisal of hydro and thermal projects, they monitor projects under construction.

39. The Power Systems Wing is responsible for the planning and design of high voltage transmission systems and the integrated operation of State and regional power systems. Like the Hydro and Thermal Wings, it monitors the progress of transmission and distribution projects under construction.

40. The Operations Wing is responsible for monitoring the performance of thermal power stations, and has underway a program to identify remedial measures needed to help to maximize generation. In addition, this Department operates four training institutes for thermal power station personnel.

41. The Economics and Commercial Wing deals with the commercial, legal and economic aspects of the power supply industry and is also responsible for the inspection of electrical installations belonging to the Government of India.

42. The CEA is organized according to specialization rather than function. Among its major functions, planning, sanctioning projects and providing technical assistance to the SEBs all cut across its departmental organization. While it is a statutory body, its role is indirect: it may help develop policy proposals, but it cannot very well promote them without the Ministry; it may sanction projects, but it does not build them. Thus, despite its central position and considerable technical resources, the CEA role in the power sector is limited to a large extent to the use other organizations choose to make of it.

43. The REBs. The REBs comprise the chairmen of their constituent SEBs together with representatives of other major electricity supply undertakings in the regions and a member secretary provided by the CEA. The SEB chairmen take turns annually to chair the REBs. Each Regional Board is supported by a small seconded staff.

44. The REBs were established to coordinate planning and operation of the electricity supply undertakings in their regions. Their responsibilities include: reviewing progress of projects in their regions; planning integrated operation among the State systems; preparing coordinated maintenance schedules for their regions; determining the availability of power for inter-state transfer; prescribing generation schedules; and determining a suitable tariff for inter-state exchange of power.

45. As forums for discussion, the REBs could function with only a small staff. The role of the REBs is limited by their being 'voluntary' associations of their SEBs. Nonetheless, their role is growing more operational. In all but the North-Eastern Region, interim Regional Load Dispatch Centers have been set up in the last five years or so. These centers collect system operation data, prepare daily generation schedules, coordinate emergency power exchange, and provide special and regular monthly reports on the performance of the regional grid. At the present time, only the Southern Regional Load Dispatch Center is equipped for fully integrated regional operations. Equipment for the other regions should shortly be in place so that all the regions are expected to have fully integrated operations by the early 1980s.

46. The REBs constitute the leading edge of institutional change needed to integrate the operation of India's power systems. Their future evolution will be critical to the effort to improve the efficiency of the power sector through the realization of economies of scale.

I. CONSUMPTION

1. Past Patterns of Demand

47. Consumption of electricity has grown rapidly in relation to net domestic product. Between 1960/61 and 1975/76, the annual average growth rate of the former was 10.2%, while that of the latter was 3.4% (Annex I.1.1). In most countries electricity consumption increases faster than the economy as a whole and in the early stages of development, when all forms of commercial energy are tending to replace non-commercial sources, this difference in rates may be large. Nonetheless, India stands out for the exceptional rate at which reliance on electricity has increased.

48. Since the early 1960s, the major cycles in the economy and electricity consumption have gone hand in hand (graph I). Roughly speaking, the economy was performing best at the very beginning, at the middle and towards the end of the period 1960/61-1975/76, with troughs during the poor monsoon years of 1965 and 1966 and again during the commodity crisis in 1973 and 1974. Electricity consumption followed the same broad pattern, but differed in detail. The explanation of these differences lie in the performance of individual sectors of the economy.

49. The structure of the economy has changed over this period, with a marked shift to industry in the 1960s and then a period of relatively rapid agricultural growth in the 1970s, particularly in the last three years. Between 1960/61 and 1968/69, agriculture grew at an average annual rate of only 1%, compared with industry at 5.4%; between 1968/69 and 1975/76, the corresponding rates were 2.8% and 3.7% 1/ (Annex I.1.1). Industry's growth has of course been far more steady than agriculture's (graph II), and has risen from accounting for about one-fifth of net domestic product to its present position, where it provides about one-quarter of value added. 2/

50. The shift in the pattern of electricity consumption has been in the opposite direction. Agricultural demand accounted for only 5% at the beginning of the period, but now constitutes 13%; industrial demand has fallen from 78% to 65%. The respective growth rates of agricultural and industrial consumption over this period average 17% and 10% (Annex I.1.1. and I.1.2). In both these dominant sectors (and in the residual tertiary subsectors) power use intensified. While electricity input per unit of value-added (measured in 1960/61 prices) increased in agriculture from roughly 12

1/ We use 1968/69 as the dividing year because in subsequent years the relationship between value added and electricity consumption changed markedly as power shortages became a feature of life.

2/ Industry throughout this review refers to both manufacturing and mining. "Services", the "residual" or "other" sector are terms used interchangably to cover all other sectors of the economy (or sources of electricity consumption) apart from agriculture.

GWh/Rs billion to 90 GWh/Rs billion, the increase in industry was from 470 GWh/Rs billion to 840 GWh/Rs billion: agricultural use of electricity intensified far more rapidly than industry, but from a much lower level, so that industry is still clearly - and not surprisingly - the electricity sector's most important customer (Annex I.1.3).

51. It is instructive to see how much of the increase in electricity consumption can be ascribed to increases in value-added alone, to changes in the co-efficient relating electricity use to value-added and to the combined effect of these two factors. Annex I.1.4 shows this for the 1960/61-1975/76 period and for three five year sub-periods, by sector and for the whole economy 1/. Certain observations follow. Firstly, the contribution of industry to electricity consumption growth has fallen from about three-quarters of the total change to less than half between the two periods 1960/61-1965/66 and 1970/71-1975/76; the contribution of agriculture has tripled from 8% to 24% between the same two periods. This change in demand from agriculture is heavily dominated by the change in the electricity coefficient. The relatively slow growth of the sector compared with its rapid increase in power use is hardly surprising considering the rapid rate at which bullock and other traditional forms of energy have been superceded by electricity. Indeed, across all sectors the change in the electricity coefficient has been the single most important factor in electricity consumption growth; about half of this increase has been in industry alone. This reflects a combination of such factors as changes in efficiency in particular industries, substitutions for other forms of energy by electricity, and changes in the composition of products manufactured.

1/ Annex I.1.4 is most easily explained by an algebraic formula. If we use E to stand for electricity consumption, V for value-added and K for electricity consumption per unit of value-added, then it is true at any time that E=KV. If we use the subscript 1 for the beginning and 2 for the end of a period, if follows that:

$$(E_2 - E_1) = (V_2 - V_1)\,K_1 + (K_2 - K_1)\,V_1 + (K_2 - K_1)\,(V_2 - V_1)$$

or	Total Change	=	Change due to change in value-added alone	+	Change due to change in electricity coefficient	+	Change due to change in electricity co-coefficient applied to the value added change

As the text makes clear, this formulation reflects changes due to factors other than those of a technological kind. This equation should not be confused with an apparently similar formulation that might be derived for a single industry where E might once again stand for electricity consumption, V for physical output and K for consumption per unit of physical output. The algebra would look the same, but such a relationship would be governed entirely by technological considerations.

52. The geographic pattern of electricity demand has changed since the 1960s. Electricity statitics are readily available on the five regions and we have compiled comparable value-added statistics 1/ to provide the background for a discussion of the differences among the regions (Annex I.1.5-I.1.9). These data, for 1975/76, are summarized in Annex I.1.10. The following conclusions can be drawn. Firstly, the Western Region is the largest consumer of electricity, followed by the Southern and the Northern Regions, with the Eastern Region trailing somewhat and the North Eastern Region clearly smaller by a different order of magnitude. (To avoid repeating this last point in every context, the North Eastern Region is excluded from the subsequent discussion). This does not reflect weight in net domestic product as much as the concentration of one-third of Indian industry in the Western Region; only one-fifth remains in the Eastern Region, somewhat less than is now in the South. Secondly, in agriculture, over half of production and almost three-quarters of electricity consumption is concentrated in the Northern and Southern Regions. Of the two, the Northern accounts for a hair's breadth more output, but substantially more electricity use, reflecting the higher incidence of electrified pumpsets in the North than in the South.

53. This was not always the order of things (Annex I.1.11). In 1960/61, the Eastern Region was more prominent as a user of electricity (it ranked second as opposed to fourth now) and in terms of its contribution to net domestic product (even then it ranked fourth, but closer to the other major regions). In the intervening years, fully one-third of the increase in electricity consumption was in the Western Region, where one-half of that increase (one-sixth of the total) can be ascribed to the increase in the intensity of electricity use. Only 16% of the increase originated in the Eastern Region -- a very low share of growth. At the same time these has been a comparable shift in the distribution of generating capacity.

54. The geographic distribution of electricity consumption has also shifted between rural and urban areas. The more rapid than average growth of agricultural consumption has already been noted. There is also the evidence of village and pumpset electrification. Between 1951 and 1975/76 the number of villages electrified increased from 3,060 to 185,810; this is roughly an 18.7% increase in electrified villages each year. From 1960/61 to 1977/78 the number of electrified pumpsets grew from 200,000 to 3.2 million -- roughly a 20% annual growth rate. While the general phenomenon of rural electrification is readily apparent, it is not widely recognized that a significant part of this has affected rural industry. The census data for 1960 and 1970 show that the proportion of rural establishments using electricity throughout India increased from 1.2% to 5.4% over this period, compared with an increase from 14.1% to 18.9% among urban establishments (Annex I.1.12).

2. The Incidence and Impact of Shortages

55. Shortages of electricity have intermittently affected the majority of States in India for some time. As far back as 1962 shortages were

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1/ See the RBI Bulletin of April 1978 and the footnotes to tables.

recognized as an undesirable aspect of the power supply situation. The Energy Survey of India Committee, which reported in that year, discussed at some length the manner in which shortages were managed and the types of measures that might be taken to overcome them. While shortages -- and unreliability -- were sporadic problems in the 1960s, by 1970 the situation had grown more serious. A chronic shortage of capacity had appeared in a number of States and the problem of electricity shortages had taken on a national dimension. This was the result not so much of any sudden surge in demand as a shortfall in new capacity during the latter half of the Fourth Plan and the beginning of the Fifth. Subsequently the investment program did not catch up.

56. To monitor the severity of shortages, data on their incidence has been gathered in the last few years at the all-India level. These data record the extent of shortages in three ways: (i) in data summarizing notified percentage restrictions on energy and power consumption in different States; (ii) in statements that compare "requirement" and "availability" of power and energy; and (iii) in data on unscheduled load-shedding. These three measures may still understate the full severity of shortages since percentage restrictions on consumption and unscheduled load-shedding have been preceded in most states by administrative measures aimed at spreading the load over the day and the week. These measures have included scheduled tripping of particular feeders, rostering of consumers during the day, staggering of work weeks in industry and cutting back the voltage and frequency of supply at time of system peak. Such measures vary among States and over time and are intrinsically difficult to quantify and compare. 1/

57. Load-spreading administrative arrangements affect the power requirements on the system more than the energy requirement. Therefore, it is more useful to concentrate on percentage energy restrictions which present a more representative picture of the incidence of shortages. Annex I.2.1 summarizes monthly data on energy restrictions in 1977/78.

1/ Indeed, it is difficult to say precisely what the available statistics on shortages mean. They should represent the difference between the supply (availability) and demand (requirement) curves of electricity at the prevailing electricity tariff. One must take it that the demand curve represents what demand would have been had there been no shortages in the period in question.

The measurement of shortages is fraught with problems. In the first place, when restrictions are imposed on certain categories of consumers, their level of consumption is held at some fraction of their consumption during an earlier base period. The data in Annex I.2.1 presents the raw data on restrictions specified in this way. To estimate the extent of shortage, the SEBs can take the shortfall in supply equal to these percentage restrictions and inflate it by a factor that reflects suppressed growth in demand since the base period and the impact of unscheduled load shedding. The figures in Annexes I.2.3 and 1.2.4 have been compiled by such a method, but there is little to guarantee that the methodology is uniform among States.

58. The range of percentages given in this Annex refer to the percentage of energy restriction on consumers in the major affected categories. In the Northern Region, the most seriously affected States appear to be Haryana, Uttar Pradesh and Punjab; at the other end of the spectrum, only Himachal Pradesh suffered no notified energy restrictions during this period. In the Western Region, only Gujarat appears to have been free from restrictions, but Maharashtra and Madhya Pradesh -- which between them account for about a quarter of India's value-added in industry -- were seriously affected. Karnataka was the only State persistently faced with shortage in the Southern Region. In the Eastern Region, notified restrictions throughout 1977/78 only affected power demand in West Bengal, but the situation was nonetheless serious because the Eastern Region was the most seriously affected by unscheduled load shedding amounting to 50% of the total load during 1977/78 and into 1978/79 (Annex I.2.2).

59. As well as variation among States there is also variation seasonally in the incidence of shortages. When capacity is short, there is cause in an emergency to draw down hydro-electric reservoirs if this alleviates the short-run situation, even if this means lowering the water to a level below that for which the hydro-electric schemes were designed. Thus, in April, May and the first half of June, the months at the beginning of the monsoon when the reservoirs serving hydro-electric schemes are likely to be particularly low, shortages are usually most difficult.

60. These observations are supported with slightly different data in Annex I.2.3. The regions most seriously affected are the Eastern and North Eastern Regions, though all except the Western Region appear to have had a 20% or more deficit in some months at least. Peak requirements come when the agricultural pumping load is heaviest and is superimposed on the substantial industrial load in the winter months. In the South of India, the peak demand period is usually November and December, while January to March is the peak period in the West and North. Thus, there is some interregional seasonal diversity around the all-India peak. This is usually in January, a month when the deficit in supply also appears to be high.

61. In recent years, the shortage situation was most serious in 1974/75 and 1977/78 (Annex 1.2.4). Throughout India the estimated deficit of energy in 1974/75 was 14.1%; this fell in 1975/76 (to 10.3%) and again in 1976/77 (to 5.8%), but rose considerably to 15.5% in 1977/78. Partial data for 1978/79 suggest shortages in this most recent year may be less severe -- of the order of 10% rather than 15%, though the situation may change toward the end of the year.

62. Though the effects of sustained shortages are hard to measure precisely, their impact is undoubtedly severe. Individual enterprises react to shortages in different ways. Mild shortages of power and energy may not lead to loss of production, since it may be possible to reschedule production or reduce prime mover speeds and the use of ancillary units without losing much output. To meet sustained shortages or chronic conditions of unreliable supply, some enterprises find it worthwhile to install their own generating plant. In any event, for most enterprises, sustained shortages of electricity eventually force a cut-back in production.

63. Captive generating plant is installed in some industries almost as an inherent part of the process, sometimes to use waste products as fuel and at other times to generate electricity in association with steam. Furthermore, it may be installed as insurance to protect vital equipment that would be damaged in the event of even a minor power interruption. The official statistics at the national level, which show at least 10% of electricity consumed in industry throughout India is generated in captive plants, refer mainly to the first two types of installation (Annex I.1.13). These are both registered and licensed. But there are a large number of generating sets, usually much smaller, that are licensed but not registered and do not appear in the national statistics. For example, in one eight-month period in 1978, in Andhra Pradesh 18,400 KVA, or about 15.5 MW of stand-by diesel generating sets were recorded by the SEB, all with capacity below 0.5 MW (Annex I.3.8). This was thought to be representative of the rate of installation throughout the last four or five years, and moreover Andhra Pradesh is a State with a relatively good record of electricity supply from its Board. Such small captive generating sets are inefficient and can generate electricity only at a high cost relative to that bought from the grid, though this cost to the industrialist is sometimes lowered indirectly by interest rate and installation subsidies. Nonetheless, it reflects a significant opportunity cost of electricity on the one hand and a misallocation of investment resources -- from the viewpoint of the economy in the longer run -- on the other.

64. At the aggregate level, there is evidence that industrial growth is constrained by electricity supply. The rate of increase in industrial electricity consumption is closely related to the rate of industrial growth: before 1968/69 turning points of electricity and industry are roughly synchronized, but after that -- when shortages became endemic -- industry follows electricity with a lag of one year (graph III).

65. Of course, changes in electricity supply are not the only cause of the industrial cycle. In India agricultural incomes and production will affect the demand for industrial goods and the supply of industrial raw materials. Variations in agricultural performance will influence industrial cycles, though the lags and the exact pattern of causality are complex. Industrial enterprises sometimes overestimate the impact of electricity shortages by failing to take into account what is sometimes a weak order book position and demand failures, which have both contributed to past industrial down-turns.

66. There is also the problem of explaining why industry should lag behind electricity supply by as much as a year, given that electricity use is instantaneous. The explanation at the top of the industrial cycle may be that industry cuts back on inessential uses first and reacts in the manner outlined above when a shortage is mild (paragraph 62). A slow down in the production of intermediate goods will not immediately affect other sectors because inventories -- often kept prudently long -- can be run down before production of final goods will be slowed. At the bottom of a cycle, the same process running in reverse may explain the lag. There may also be a shift during a full cycle in the composition of industrial production so that it

is less power-intensive than average during downswings, and at the transition points -- the turning points in the cycle -- it may be that a lag between electricity supply and industry develops.

67. For the nine years 1960/61 - 1968/69, electricity consumption increased at 3.6 times the rate of GDP growth; subsequently, from 1968/69 - 1976/77, consumption grew at only 2.1 times the GDP growth rate. Thus, one of the major effects of shortages in the 1970s has been an adaptation of consumption patterns so that incremental electricity consumption has been more effectively used. This same pattern can be observed at the sectoral level in the residual sector and to a more marked extent, in industry: there, the elasticity was 2.2 for 1960/61 - 1968/69, and fell to 1.4 for 1968/69 - 1976/77. This shift may in part reflect a change in structure, but in part it must be that less essential uses of electricity have been cut back (Annex I.5.6).

68. It is possible to make a very crude estimate of the impact of recent electricity shortages on industry and GDP (Table I.1). In the first place it is reasonable to assume for this estimation exercise that all the energy shortage falls on industry and there will be virtually no GDP lost on account of power shortage in either the agricultural or residential service sectors: restrictions are hard to enforce in both sectors and cuts in agricultural supply at least are a last resort in the great majority of States. Then one may argue that if industrial electricity supply were increased at a given moment, the level of industrial activity (measured as value-added) would increase as it has under shortages in the last few years. Thus, in 1974/75 the shortage of 14.1% for all consumption could be taken to be a shortage of 21.4% for industry, since 66% of total electricity consumption was in the industrial sector. Using the 1.4 elasticity from the 1968/69 - 1976/77 period, this would suggest there had been a 15.3% shortfall in industrial activity on account of power shortages. While this would be unrealistically high if shortages were a factor for one year only, it is quite plausible that the impact would gradually have built up to this level in the preceding five or six years. Thus, lost value-added in 1974/75 appeared to be about Rs 16.3 billion or about 2.6% of GDP. In the subsequent two years -- 1975/76 and 1976/77 -- lost value-added appears to have fallen to 2.0 and then 1.1% of GDP and then risen to about 3% in 1977/78.

Table I.1: IMPACT OF RECENT POWER SHORTAGES ON INDUSTRY AND GDP

	1974/75	1975/76	1976/77	1977/78
1. Recorded percent of electricity energy shortage	14.1	10.3	5.8	15.5
2. Percent of electricity consumption by industry	65.8	65.7	65.7	65.7
3. Crude estimate of shortage faced by industry (percentage)	21.4	15.7	8.8	23.6
4. Crude estimate of impact on industry (percentage)	15.3	11.2	6.3	16.9
5. Crude estimate of impact on industry (Rs billions)	16.3	13.1	8.1	23.6
6. Crude estimate of impact on GDP (percentage)	2.6	2.0	1.1	3.0

Notes: Row 1: Annex I.2.4. Row 2: Annex I.1.2 and estimates. Row 3: Row 1 as a percentage of Row 2. Row 4: Row 3 divided by 1.379, the 1968/69-1976/77 crude elasticity for industry in Annex I.5.6. Row 5 and 6: Row 4 applied to GDP at factor cost figures from the 1979 Economic Report of the World Bank on India.

69. These estimates will overstate the impact of electricity shortages to the extent that the percentage shortage may itself have been overestimated. Against this consideration, the disruptive effect of shortages, especially where they have been administered through unscheduled load shedding, may be understated in these estimates. It must be emphasized that these are rough and ready figures and that they should be taken as indicative of an order of magnitude only. Nonetheless, they serve to dramatize the substantial cost of power shortages. Even if, conservatively, only 1% of the GDP is lost, this is equal to about Rs 8 billion (GDP was Rs 782 billion in 1977/78), or almost 5% of the Draft Plan program for power. It would therefore warrant an increase of almost one half again in the investment program if that was necessary to overcome comparable power shortages in the future. 1/ It would be desirable to refine these estimates, both by further work on the incidence of shortages -- in particular, the estimation of requirements -- and by cross-checking their impact at the micro-economic, firm level through sample studies.

1/ Were the costs of shortages to remain at or near Rs 8 billion for the next 30 years or more, the present value of these costs would be very roughly Rs 80 billion (using a discount rate of 10%). This is over half the proposed outlay in the Draft Plan. There would of course be a resource constraint which might make such a course impractical; or in other words general rather than partial analysis would be necessary to justify any change in the investment program of this order of magnitude.

3. The Efficiency of Power Use

70. Since electricity is particularly scarce in India, it is natural to ask whether the available supply is being used efficiently. It is important to know as much as possible about how much waste of electricity there is and where. 1/ Are there times when it is too costly to use? Could more goods and services be produced with a given supply of electricity if redistribution among uses were encouraged? Would technological improvements in user sectors aimed at economizing on electricity be worthwhile? Are there situations where electricity should be substituted with another type of energy, or vice versa 2/?

71. At the outset, it may be as well to observe that the direct evidence needed to resolve the issues conclusively is not available. What is possible in some instances is to show what are the more critical problems, and how severe they are.

72. Is there evidence that electricity is used when its economic cost exceeds the benefits of its supply? The only evidence available on this score is indirect. It is observed elsewhere in this review that electricity tariffs understate the marginal cost of supplying electricity; consequently, one would expect that, on occasion, consumers will derive a net benefit when using electricity supplied at prevailing tariffs that is smaller than the difference between the cost and the tariff. This is likely to be true both where electricity is consumed domestically and personal benefits are less than costs of supply and in productive uses of electricity where the marginal value of output falls short of the costs of electricity.

73. In India, the level of electricity consumption relative to the level of economic activity appears high by international standards (Annex I.3.1). 3/ Almost, exactly 1 KWh/US$ of GNP was produced in India in 1975. In the Subcontinent, this compared with 0.9 KWh/US$ in Pakistan and only 0.2 KWh/US$ in Bangladesh. Some developing countries--for example, Egypt--may have comparable levels of electricity use, but in general India is high by developing country standards and falls in the range of developed countries.

1/ We do not have in mind waste in the sense that the electricity goes unused, but rather waste in the sense of misapplication: electricity being used where other energy forms might be cheaper, machines being run at uneconomic rates and so forth.

2/ These questions are an informal statement of the partial conditions for efficiency: (i) the marginal product equals the marginal costs; (ii) the marginal product is equal in all uses; (iii) the marginal cost of increasing efficiency -- changing technology -- equals the marginal value of electricity saved; and (iv) the marginal cost of electricity equals that of substitutes. Marginal product should be read as marginal benefit when these conditions apply to final consumption of electricity, as in some consumption of domestic or street lighting.

3/ Only production statistics as opposed to consumption statistics were readily available for the sample of countries referred to in Annex I.3.1.

74. The rate of growth of electricity consumption has been fast in relation to GNP. Data are available for the period 1970-75 for a sample of developed and developing countries (Annex I.3.2). Over this period, electricity consumption grew at about 2.7 times the rate of GNP in India. 1/ (This elasticity was of course higher in earlier periods before shortages of power became so widespread.) Among the developed countries, only Germany and Sweden have elasticities greater than 2 (2.1 and 2.2, respectively), and most have elasticities quite close to 1. Among the poorer countries in the sample, the elasticity may to some extent be a function of the stage of economic development, but even so, India's elasticity is higher than that of every single country except Afghanistan.

75. The explanation of this apparently high level of consumption and high rate of growth of consumption lies in a number of factors. No doubt part of the difference is only apparent since official exchange rates must be used to compare GNP in different countries, which it is well known under-represent the purchasing power of, for example, the Indian rupee relative to that of the U.S. dollar. 2/ This is, prima facie, of more concern in comparing developed and developing countries than similar developing countries. Secondly, there has been in India a marked substitution of other forms of energy by electricity. This has been a matter of conscious policy in agriculture at least, so that part of the explanation may be that electricity represents a high and growing share of total energy consumption. Thirdly, India's pattern of industrialization in the last several years may have been one which called for a higher level of electricity consumption than was typical among developing countries.

76. One may ask generally whether more goods and services could have been produced with a given supply of electricity if redistribution between uses were encouraged through marginal cost based tariffs or other reallocative measures. As was noted in an earlier section, the industrial sector uses two-thirds of all available electricity and the cost of electricity represents between 6 and 8% of value-added in the industrial sector, compared with about 1% throughout the economy. Industry's predominance as a user of electricity means the greatest scope for reducing power intensity may well be in and among different industrial users (Annex I.3.3).

77. There are a handful of industries which are known to be particularly power-intensive. Annex I.3.4 summarizes data on electricity consumption in relation to value-added and the value of output for seven such industries for four recent years. The unit cost of electricity is roughly the same for these industries as for industry as a whole, though there is some variation.

1/ This compares with 2.1 times the GDP growth rate for 1968/69 - 1976/77, mentioned in paragraph 66. GNP rather than GDP is used here for the sake of international comparability; for the same reason the period under consideration is shorter.

2/ See, for example "International Comparisons of Real Product and Purchasing Power", Kravis, Heston and Summers; 1978.

This will reflect particular arrangements between large manufacturers and their supplying utilities, as well as differences in voltage of purchase and individual load factors. In terms of value-added, fertilizers and cement are the most power intensive sectors -- something close to ten times more power-intensive than industry on average. 1/ Non-ferrous basic metals and chemicals are also particularly power-intensive and of the other three industries in the sample, castings and forgings of iron and steel is more power-intensive than either synthetic fibre production or the manufacture of iron and steel metals.

78. Some of the more power-intensive industries have grown particularly rapidly (Annex I.3.5). Production of aluminum has averaged 16% annual growth between 1960/61 and 1976/77, almost four times faster than the industrial sector as a whole. Power consumption in aluminum manufacture has risen by roughly 15% a year during this period, compared with 9% for industry as a whole. Fertilizers should also be singled out as a very power-intensive industry, where production has grown by 19% annually over this 16-year period and electricity consumption by close to 15% each year. Thus, while there has been a decline in electricity use per unit of production in both aluminum and fertilizers, their rates of growth have been high enough to contribute significantly to the overall increase in electricity intensity in industry. The consumption of electricity in chemicals has also risen rapidly, but statistics are not available on the growth of production over this period. Cotton textiles also warrant a mention since growth has been rather slow -- 1.4% annually in terms of final production -- but electricity consumption has risen by almost 6% per annum. For example, over this period the textiles industry has changed, with more firms devoted to producing synthetics and less to coarser counts of cloth. Many of the older mills were designed to use steam as a prime mover and many have either changed to using electricity or closed down. Factors such as these may have accounted for the observed trend.

79. The pattern of past industrial growth has been determined partly by the physical planning of the Government in successive Plans (particularly in heavy industry -- the "core" sector) and partly by the reactions of individual private entrepreneurs to market opportunities and the prevailing price regime. A stronger recognition of the real economic cost of scarce inputs such as electricity has been one of the factors leading to a shift in strategy in the 1978-83 Draft Plan: it "is designed to achieve, as one of its objectives, a restraint on further increase in the intensity of energy consumption in industry" (Page 162 of the Draft Plan). If electricity tariffs were raised to more closely reflect marginal costs, the effect on the public sector might be minimal since major production decisions are governed by many factors among which cost considerations are but one. The effect on the private sector, however, while modest in the short run, might in the medium term affect the pattern of industrial development for the better.

1/ Value added is, of course, measured at domestic prices here. For fertilizer, more than other industries perhaps, international prices are different.

80. That there are major differences in the productivity of electricity in different sectors can also be illustrated with the Planning Commission input/output model 1/. Table 1 of Annex I.3.6 shows the electricity input per Rs 100 of value-added (column 8). These figures must be interpreted cautiously because the coefficients of the input/output model were derived from data relating to the mid-1960s, albeit modified and updated to reflect anticipated input/output relationships for the period 1974/1979, expressed at 1971/72 producer prices during the preparation of the Fifth Plan. Thus the relative prices in the model all predate the energy crisis. However, the basic point that certain manufacturing industries such as engineering goods (machine tools, motor vehicles, locomotives and rolling stock) and cotton textiles use far less power than others such as fertilizers, inorganic heavy chemicals and paper is still valid. From the coefficients in column 8 of Table 1, Annex I.3.6 ($100 \times 28.21 \div 7.38$) it is apparent that Rs 100 of fertilizer production makes use of the same quantity of electricity as Rs 380 of cotton textile production. If the strict constraints of the input/output model were to be observed and textiles production increased one would expect the excess textiles to be exported and the deficit in fertilizer production to be made up with increased imports: the net gain to the economy would then be Rs 280 of additional value-added for each Rs 100 of fertilizer production cutback.

81. Further clues are also available through international comparisons, particularly of the manufacturing sector in India and other countries. The object of examining the composition of value-added in the manufacturing sector alongside figures reflecting the intensity of electricity use in these subsectors is to determine to what extent the intensity of power use in Indian industry is the result of inefficiency within subsectors, or the pursuit of an industrial strategy that emphasized subsectors that were intrinsically and unduly electricity-intensive.

82. Before examining the data, however, there are a number of caveats that should be noted. Firstly, data from the United Nations on electricity consumption is available only from 1968 onwards, while for India, it has only been possible to collect comparable electricity consumption data up to 1966. This has been adjusted somewhat roughly to reflect price changes in India in the two subsequent years, and the international comparisons have been made for 1968. Secondly, data both for India and other countries cover only the Census sector; that is, small units have not been covered and the extent of coverage will vary among countries. So may the treatment of captive generation: since this accounts for at least 10% of electricity use in India, this is not a negligible factor (Annexes I.1.13 and I.3.8). Thirdly, the conversions at official exchange rates used here are quite unlikely to reflect real

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1/ The categorization of manufacturing concerns in the input/output model is not ideally suited to the purpose at hand. Nevertheless this approach is interesting because it allows one in principle to see throughout the economy what the differences in electricity productivity are.

relationships between values of units of account, but this is a general problem for international comparisons. 1/

83. The data from the international comparison are analyzed in Annex I.3.7. The Chenery-Taylor classification of manufacturing is used. 2/ This annex presents India's composition of value-added in manufacturing and compares it with other countries in the first three columns, and presents India's electricity consumption per unit of value-added and compares that with other countries in the second set of three columns. Where an "S" appears in the fifth column, this indicates a judgment that the importance of this power-intensive sector (or insignificance of this power-sparse sector) is evidence of structural composition of Indian industry contributing to overall power-intensity; where an "$\bar{S}$" appears, this reflects an assessment that this industry has been de-emphasized and is power-intensive or vice versa; and an "I" reflects a judgment that the industry in question is power-intensive by international standards. The basis for these judgments is more precisely spelt out in the footnote to the annex.

84. Thus, for example, the paper products industry is clearly electricity intensive -- 11.5 KWh/US$ of value added in India -- and is in fact 64% more intensive than the average in the sample of countries available. It has, however, a relatively modest position in India's manufacturing sector, accounting for only 2.1% of value-added, as opposed to about 3% on average in the sample countries ($\bar{S}$). On the other hand, the basic metals industry, while not particularly power-intensive by international standards is considerably more power-intensive than average for Indian industry. At the same time, it is relatively very prominant -- accounting for 12% of value-added in manufacturing, about twice what is typical in the sample (S).

85. Eight of the thirteen subsectors of manufacturing identified here are either prominant and power-intensive or relatively insignificant and power "scarce"; against this only three are clearly prominant to a degree that one would expect under a free market system and more efficient price regime. There are therefore grounds to believe that India's choice of industries, i.e., strategy of industrialization, has contributed towards the overall

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1/ A fundamental difficulty with the type of inference it is proposed to make here is that the efficiency or inefficiency of a particular pattern of industrial production depends on the relative availability of basic factors of production -- land, labor, capital and other national resources -- and these of course vary from country to country. This difficulty is perhaps less serious when discussing power in India than it might be in general because the power sector is a capital-intensive sector and India is a capital-scarce economy, so that, were relative endowments of factors of production taken into account, there is a fair chance that the inferences we wish to make regarding the over-intensity of power use would be reinforced.

2/ This classification is explained in Hollis Chenery and Lance Taylor, "Development Patterns among Countries and over time," in Review of Economics and Statistics, November, 1968, Vol. I, No. 4, pp. 391-416.

power-intensity of the industrial sector. At the same time, eight out of the thirteen sub-sectors considered here appear to be particularly power-intensive by international standards, so the efficiency with which power is used within sub-sectors has also contributed to overall power-intensity.

86. To conclude this subsection, India's economy, particularly its industry, seems to use greater quantities of electricity than other countries. Certain power-intensive industries have grown particularly fast, and others have shown a marked increase in their power-intensity over the past two decades. There is probably scope to reduce overall intensity by increasing tariffs. As long as power continues to be a binding constraint on overall industrial growth, such increases would not lead to reduced production in the short run in the majority of industries. (Some -- a very few -- might warrant special treatment, with lump sum countervailing subsidies, if their operations were efficient but the financial burden of their sunk costs and the increased tariff would together be too great to meet from revenues). Indeed, improving the allocation of power through the tariff mechanism should in fact spur industrial production since it should improve the allocation of power. The available international evidence supports the view that there is scope for greater efficiency.

4. Tariffs

87. Retail electricity tariffs in most States have evolved in a somewhat haphazard manner over the past 20 years as the SEBs themselves have developed. The guiding principles were usually financial and, for want of a better word, "moral." It was usually the intention of policy makers that the level of tariffs be such as to meet certain financial criteria and the structure should in some sense be fair, and not penalize certain groups arbitrarily. (The latter argument is still used to justify low agricultural tariffs since it is said that the farmer should not suffer for the fortuitous circumstance that he is remote and costly to service.) But despite these guiding principles, marginal changes have been introduced from time to time on an ad hoc basis: sometimes old tariffs may have been retained when a licensee was taken over; sometimes a declining block tariff was introduced to promote electricity consumption; on other occasions, special tariffs may have been negotiated to encourage industry to locate in the State in question; and it must often have been the case that anomalies crept into tariff structures when it was necessary to raise tariffs for financial reasons while minimizing the social and political repercussions. The cumulative effect of such forces had by about 1970 created a very complex picture of tariffs throughout India.

88. Annexes I.4.1 to I.4.18 summarize the structure of electricity tariffs found in various States in 1972 and 1976. Most electricity tariffs for low tension industrial 1/ and agricultural 2/ consumers in both 1972 and

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1/ Exceptions are found in the states of Assam, Gujarat, Himachal Pradesh, and Kerala, where there are decreasing block rates for energy consumption.

2/ In Himachal Pradesh, there was a decreasing block energy charge in both 1972 and 1976.

1976 were made up of a flat energy charge per KWh consumed, plus a demand or minimum charge per HP or KW of connected or contracted load. Tariffs for high tension industrial consumers typically consisted of a decreasing block energy charge plus a demand charge per KVA or KW. Electricity tariffs for domestic and commercial consumers were roughly split between flat energy charges and decreasing block energy charges. Furthermore, there was usually a monthly minimum charge; but, this charge was not related to demand, rather to overheads of one kind and another. There was little change in this basic pattern of domestic and commercial tariffs between 1972 and 1976.

89. Some simplification of the tariff structure has occurred in a number of States over this period. Firstly, in Andhra Pradesh, Assam, Haryana, Kerala, Maharashtra, Punjab, Rajasthan, and Tamil Nadu, the number of declining blocks in the energy charges for domestic, commercial or high tension industrial consumers have been reduced and in one or two instances replaced by a flat rate. Thus, the incentive to consume large quantities of electricity at successively lower block rates has been reduced. This change is appropriate given the capacity and energy shortages which exist in many States. Secondly, the different energy charges for electricity supplied by thermal plants, as opposed to hydro plants, which existed in Orissa, Rajasthan and Tamil Nadu in 1972, were removed by 1976. Thus, the trend of tariffs to grow more complex appears to some extent to have been reversed.

90. The figures presented in Annexes I.4.1 to I.4.18 indicate that energy charges are typically lowest for agricultural consumers. Since the costs of supplying electricity are likely to be high in rural, agricultural areas, this provides but one indication that tariffs do not at the moment correspond even loosely to the marginal cost principle. However, there may be valid social reasons for having tariffs below costs, and in some States many of the villages are electrified under the Minimum Needs Program, which represents an attempt to provide service to very backward, underdeveloped regions.

91. With respect to average tariffs for different types of consumers, the statistics presented in Annex I.4.19 indicate that they are lowest for agricultural consumers and next lowest for large industrial consumers. Conversely, average tariffs are highest for commercial and domestic consumers.

92. Electricity prices have changed relative to those of other types of energy and to the general price level (Annexes I.4.20). Relative to the general price level, as measured by the wholesale price index for all commodities (WPI), the tariff level of electricity has fallen slightly in the last 17 years: the shift is of the order of 23% or 1.3% per annum. In the 1960s, the shift was more marked as electricity prices fell by about 2.2% annually. Coal prices increased very slowly within the WPI in the 1960s but more rapidly thereafter; since 1960 their annual rate of increase has been 1-2% higher than that of electricity prices. Oil fell in price against the WPI and other forms of commercial energy until 1970/71, but subsequent increases have been much greater than those in any other sector as a result

of the change in international prices. Over the period as a whole, electricity has become cheaper than other types of commercial energy. 1/

93. Tariffs and Incremental Costs. The argument in favor of electricity tariffs reflecting long run marginal costs of supply is based on a general proposition about the way consumers of any product or service determine the level of their consumption. Every consumer chooses to consume more of a product until the benefit of additional consumption falls below the price he pays; this establishes his personal optimum. This choice will also be optimal from the viewpoint of the economy as a whole if, among other conditions, the price he pays reflects the cost of supplying the product. Applying the argument to the power sector, a tariff which is close to long-run marginal costs is likely to discourage waste and encourage the efficient use of electricity by the many individual consumers supplied by utilities. The tariff in this context is seen as a signal to the consumer, and to facilitate "reading the signal" the structure of tariffs should be kept fairly simple.

94. India has many individual consumers making decisions independently about electricity use. In 1977 there were 24 million consumers: about 1 million industrial (16,000 high tension), 3 million agricultural, 3.5 million commercial, 16 million domestic and about 0.5 million in other consumer categories. What is not known is how responsive consumers in each of these categories are to changes in power tariffs. In most industries, the level of electricity consumption is largely settled as part of an investment decision when electricity tariff levels can affect the choice of product to be manufactured and the technology to be adopted. Subsequently, plant may be modified in response to tariffs -- power factor correction equipment may be installed, for example -- but the level of consumption is by and large determined. Subsequently, the structure of tariffs -- when, for example, there are seasonal or daily changes in tariff level -- can affect the choice of time when an enterprise chooses to consume power, but, given how small an element in costs electricity usually is, the overall level of consumption is unlikely to be affected greatly by changes in tariff levels. The same constraint -- of prior commitment at the time of investment -- affects all consumers of electricity to a greater or a lesser degree so that in the short run changes in tariff levels are unlikely to affect demand greatly. But in the long run, over a period of years, the pattern of investment and consequently the growth of power demand will probably be responsive to the level of electricity tariff.

95. In practice a number of other factors play a part in determining actual tariff policy. Apart from being a signal to consumers, electricity tariffs are linked to SEB revenues, and therefore, financial considerations

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1/ Of course, cost decreases relative to the average price level are to be expected as technological advances improve the efficiency of power systems. These may be offset, most obviously in hydro-electric generation, by the increasing difficulty of exploiting limited natural resources. In any case, tariffs have not been based on -- and have not reflected -- economic costs.

must play a part in determining the tariff levels. Tariff policy also reflects conscious policies to subsidize certain consumer categories -- such as agricultural consumers -- for a variety of reasons: for example, in the case of agriculture, that the farmer should not be 'penalized' for being expensive to supply, and that cheap electricity should be one of the elements in programs to develop remote or backward rural regions. Thus, long run marginal costs are a reference point in considering tariff policy, and the divergence between long-run marginal costs and actual tariffs is an indication of the cost of subsidizing particular consumer groups.

96. What are the level and structure of long-run marginal costs? In any power system there are two elements: a capacity cost that reflects the cost of expanding the system to meet an extra KW of power demand; and an operating cost, which is sometimes referred to as an energy cost since fuel accounts for most of it, that reflects the cost of supplying an extra KWh of energy. In India, all the States face some variation in demand during the day, so that there is a definite peak of system load for one or two periods: outside the system peak period(s) the cost of meeting an extra KW of demand is nil, since the generation and system capacity must be there anyway to accommodate the peak; but a steady increase over the long run of an extra KW of demand during the peak period can only be met by the system incurring the long-run marginal cost of expanding the generation, transmission and distribution capacity. Long-run marginal costs also vary among consumers: it is more costly than average to build networks to supply remote consumers and losses tend to be higher so that more capacity is used and energy generated to supply a KW or KWh to a distant customer. Conversely, a large consumer taking power at high tension close to a power station is relatively cheap to supply with extra electricity.

97. Long run marginal costs, like the existing structure of tariffs, vary among States. In a number of States hydro-electric schemes are used for peaking capacity. Since costs vary among schemes, it follows that the long run marginal cost for capacity will differ among States. For this reason, long run marginal capacity costs may be higher than average in the North and North Eastern States where hydro-electric development will be a major component of generation costs. Similarly marginal energy costs typically depend on coal costs and the efficiency of marginal stations, and this too will be different in different States. These differences will tend to diminish as regional systems integrate, since the marginal costs of the cheapest State system then become the marginal costs of the Region as a whole.

98. The 1975 World Bank study of electricity tariffs in Andhra Pradesh gave an indication of the long-run marginal costs of electricity supply in that State. The HT costs were 12 paise/KWh and 38 Rs/KW per month at time of system peak and the LT costs were correspondingly higher at 14 paise/KWh and 82 Rs/KW per month during the system peak. At that time, actual tariffs ranged from 60% below long run marginal costs in the case of agricultural consumers, to 20% in the case of dometic bulk supply consumers. Since then, a number of other state studies have been undertaken, which have yet to be finalized. Their preliminary results are similar to those of the Andhra Pradesh study in that the long-run marginal costs were almost without exception higher than present tariffs.

99. There is indeed, at the national level, reason to think long-run marginal costs are generally greater than existing tariffs. It is possible to show algebraically that the average revenue realized from the capacity component of tariffs that exactly reflected long-run marginal costs would be greater than the annuitized value of the investment program divided by the increase in consumption during the program period (Annex I.4.21). Based on the forecasts of the Draft Plan, this is roughly 28 paise/KWh. In addition, the energy component of long run marginal cost based tariffs should yield on average more than 12 paise/KWh. Thus a lower limit for the average revenue realized by long-run marginal-cost-based tariffs applied throughout India would be about 40 paise/KWh. The average revenue among public utilities in 1976/77 was only 24.5 paise/KWh, and although it has risen since then, it is still below 40 paise/KWh.

100. To bring actual tariffs closer to long-run marginal costs, marginal costs can be reduced through improvements in efficiency and tariffs can be increased. The rate at which costs can be brought down is contrained by the rate at which economies of scale in the investment program can be realized and that at which more efficient operational practices can be introduced. Tariffs will have to increase in real terms, that is, faster than the rate of inflation, if they are to bear a closer relationship to costs.

101. To summarize, electricity tariffs are set by the SEBs independent of the Center or one another. There was in most States a tendency for tariffs to grow more complex as ad hoc changes were introduced from time to time. But between 1972 and 1976 there is evidence that this tendency was reversed, and tariffs were for the most part gradually being simplified. The average level of tariff has risen in nominal terms, but not as rapidly as other energy prices or the general price level. In those States in which studies have been made, tariffs appear low in relation to long-run marginal costs, and at the national level, the average revenue realized by present tariffs is below that which would be realized by tariffs that more nearly reflected long-run marginal costs in each region or State. Tariffs should reflect long-run marginal costs if they are to act as an incentive signal to consumers to avoid waste and encourage the efficient use of electricity. Given the rapid rate of increase in consumption in relation to the growth of the economy as a whole and the pervasiveness of electricity shortage, this argument for increasing tariffs appears particularly relevant.

5. Demand Forecasts

102. At the all-India level, forecasts of electricity requirement and demand are made by the Planning Commission and the Annual Electric Power

Surveys (APS) convened by the Ministry of Energy. 1/ These are not independent forecasts in as much as there is extensive discussion between the two groups producing them, which has usually led to a reconciliation of results. But there are different methodologies employed that can be broadly associated with the Planning Commission, on the one hand, and the Central Electricity Authority (CEA) -- in its capacity as secretariat for the APS -- on the other.

103. The Planning Commission projects electricity demand as part of its macro-economic analysis for all sectors of the economy. Industrial requirements are derived for a set of 'major' industries -- mostly large scale or very electricity-intensive -- by applying consumption norms to production targets. In the Draft Plan, consumption in the rest of the industrial sector is assumed to be proportional to that in the major industries (60% of that for major industries). Railway and irrigation requirements are also estimated by using sectoral targets and norms of electricity use. Consumption in other sectors -- domestic, commercial, public lighting, water works and miscellaneous -- is based on trend growth rates or on regression analysis that relates sector growth rates to electricity demand. Using the input-output model, the Planning Commission is able to check the consistency of the resultant macro-forecast with its expectations for the economy at large.

104. By contrast, the APS begins with a detailed survey of industrial establishments that demand 1 MW or more of electricity, to solicit their views on how rapidly their requirements for power will increase. The methods used to derive forecasts for other consumer categories are much the same as those employed by the Planning Commission -- many of the coefficients relating output to electricity consumption are identical -- but with two differences. Regression analysis as opposed to trend analysis has not been used in the past, and the exercise is conducted State-wise and then region-wise before being aggregated to the national level. The views the APS forms about the prospects for power in each State form the basis for the involvement of the SEBs and State Governments in the demand forecasting exercise. Since forecasts underpin the State-wise investment programs and these in turn influence the case for Central Plan assistance, there is a fundamental concern with the APS position. The process of preparing the APS forecast provides occasions when the States' views can be taken into account and a concensus can be reached.

1/ Certain distinctions are important. Following normal conventions, "energy" is used to denote KWh and "power" to denote KW. "Requirements" and "availabilities" are measured at the bus-bar: This is the point at which the APS usually discusses electricity forecasts. "Demand" and "supply" of electricity are measured at the point of consumption; they refer to the electricity wanted for use (or ready for use) after transmission and distribution losses are subtracted from requirements or availabilities. "Demand" and "supply" are the concepts used more frequently in the Planning Commission and by us in the subsequent subsection dealing with regression analysis.

105. Both the Planning Commission and APS rely heavily for forecasting on the targets for other sectors -- major industries, agriculture (irrigation), railway traction -- and then use electricity consumption norms to derive electricity forecasts. Thus, they are both often characterized as end-use forecasting methods. The major difference is that the Planning Commission's analysis begins with macro-economic considerations and the APS' with completely disaggregated data. To assess the two forecasts that have been published for the Draft Plan period, a third method is employed in this review, namely regression analysis on the major economic sub-sectors -- industry, agriculture and services. For industry and the residual sector, this sectoral regression model relates electricity consumption to value-added and to time. Roughly speaking it formalizes the proposition that consumption will grow faster if value-added grows faster, but will grow anyway over time, principally because of technological change. Consumption of electricity by the agricultural sector is related to the pumpset electrification program, since agricultural production (or value-added) is a poor indicator of electricity use.

106. There are advantages and disadvantages associated with all three methodologies. Forecasts based on the end-use methods, in the sectors where end-use coefficients are applied, have the advantage that they are not affected by uncertainties about the extent of shortages, past or present. But the regression and trend elements of the APS and Planning Commission approaches are affected, as is the sectoral regression model, firstly in the estimation of the regression coefficients and secondly in the choice of base period values. The Planning Commission approach has the virtue of strong consistency with the overall Plan, but the disadvantage of not providing any clues to levels of consumption in individual States or in particular load centers. The APS, while providing disaggregated data, suffers from its length of preparation and the considerable cost involved in organizing a detailed survey of so many units throughout India. Furthermore, as discussed below, it may be upwardly biased. The sectoral regression model has the advantage of implicitly taking into account lags in the execution of projects in other sectors since the regression coefficients are estimated on the past performance of the economy, where the relationship between electricity consumption and sectoral output was indeed affected by such lags. All three approaches take sectoral shifts or structural change in the economy into account, and all three make allowance in different ways for changes in technology in the consuming sectors.

107. Past Forecasts. How have past APS medium-term forecasts compared with the level of demand that it was subsequently possible to meet? Annex I.5.1 shows forecasts for all the earlier power surveys except the eighth, which was not published. Forecasts exceed the demand met by between 20 and 80% among the earlier forecasts, and the divergence generally increases in the later years, as might be expected. In the Ninth APS forecast, the divergence in the third and most recent year is about 20%, roughly on a par with its immediate predecessors. One reason for these divergences is that since the beginning of the decade, it has not been possible to meet all the demand for electricity, so the forecasts may have reflected unsuppressed demand more

faithfully than realized demand. Electricity demand forecasts based on the end-use method are dependent on the achievement of investment and production targets in other sectors: to the extent that lags occur for reasons unconnected with electricity supply, unsuppressed electricity demand would in any case fall below the forecasts. However, the APS forecasting methodology may itself lead to an upward bias. This is so, since there is a strong incentive for every reporting unit (individual factories and SEBs) to overstate demand expectations in the hope that their real demands will still be met if the investment program falls short of target. With shortages seriously affecting consumers in recent years, it is impossible to judge the relative influence of these two factors on the divergence between forecasts and demand met.

108. The Present Forecasts. The Tenth APS met in 1976 and 1977 to produce medium-term electricity forecasts for 1982/83 and intervening years. A report was published in 1977, but it did not constitute a consensus of opinion of those represented and notes of dissent were attached by the Planning Commission, the Ministry of Finance, and the Chairmen of the Western, Eastern and Southern Regional Electricity Boards. Among the most critical, the Planning Commission's note argued for lower forecasts, compatible with the global forecasts for the economy that were then being built into the Draft Plan, while the Western and Southern Regions argued for much higher forecasts: 33% higher for the former, and 17% higher for the latter. Subsequently, the Draft Plan has been published and reviewed by the National Development Council, and the Planning Commission with the assistance of the CEA has undertaken an exercise to disaggregate the global Plan forecast to regional and State level forecasts.

Table I.2: ENERGY AND PEAK LOAD (POWER) REQUIREMENTS (UTILITIES ONLY): 1982/83

Region	Tenth APS Forecast		Disaggregated Planning Commission Forecast		Percentage Reductions	
	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy ----- %	Power ----
Southern	40,989	7,349	37,571	6,751	8.3	8.1
Northern	47,309	9,175	41,700	8,205	11.9	10.6
Western	49,151	8,439	43,624	7,481	11.2	11.4
Eastern	28,360	4,889	25,727	4,440	9.3	9.2
North Eastern	2,562	532	2,189	453	14.6	14.8
All India /a	168,392	30,390	150,811	27,330	10.4	10.1

/a Including Andaman, Nicobar and Lakshadweep.

109. As Table I.2 indicates, the disaggregated Planning Commission forecast resulted in cuts to the APS forecasts of about 10% in all the regions. The all-India figures from this exercise are almost exactly those of the Draft Plan. The cuts were also disaggregated by State and by category of consumer

(but not by both) showing that the brunt of the reduction fell on industry, for which, of course, the Draft Plan production targets were more modest than before. Thus, the divergence between the disaggregated Planning Commission forecast and the Regions' own forecasts are about 45% and 25% for the Western and Southern Regions, respectively. It is important that these differences should be reconciled and a consensus reached on future electricity demand prospects as soon as possible.

110. Regression Analysis. This sub-section discusses in greater detail some of the basic features of the sectoral regression model. This is not the first or the most sophisticated attempts to forecast electricity demand using regression techniques (Annex I.5.2). A more formal, algebraic statement of the model is given in Annex I.5.3, together with a discussion of why these particular forms were preferred over other possibilities.

111. In India, the effect of power shortages cannot be ignored. Shortages affect forecasts based on regression analysis first when coefficients are estimated and then in choosing values for the base period. The data here span the 17-year period from 1960/61 to 1976/77 and, as can be seen below, the relationships between electricity consumed and economic growth changed in the second half of this period, when power shortages became endemic (Table I.3).

Table I.3: SECTORAL REGRESSION MODEL: SUMMARY OF REGRESSION RESULTS

	Industrial Sector		Service Sector		Agricultural Sector
	Time	Industrial Value-added	Time	Service Value-added	Pumpsets Electrified
1960/61-1976/77					
Coefficient	0.042	0.974	0.048	0.835	2.857
$\bar{R}^2$ /a	0.90	0.80	0.93	0.85	0.98
1960/61-1968/69					
Coefficient	0.067	0.974	0.065	0.835	2.894
$\bar{R}^2$	0.99	0.80	0.99	0.85	0.99
1968/69-1976/77					
Coefficient	0.014	0.974	0.038	0.835	3.184
$\bar{R}^2$	0.66	0.80	0.97	0.85	0.95

Source: Annex I.5.6

/a There are $\bar{R}^2$ values for each coefficient in the industrial and service sectors, because each coefficient is estimated in a separate regression -- the value-added coefficients using cross-section analysis and the time coefficients using time series analysis.

For example, considering the coefficients for the industrial sector, these results suggest that electricity consumption increases at about 0.974 times the rate industrial value-added grows, and, in addition, over the total period 1960/61-1976/77, there was a 4.2% average annual growth due to technological change and other similar factors. The results for the two sub-periods show that this residual growth was at first much higher at 6.7%, but that with the advent of widespread chronic shortages, it adjusted to 1.4%.

112. The same downturn phenomenon is observed in the service sector. Agricultural demand, however, shows an upturn in relation to the number of pumpsets electrified: this suggests that either new pumpsets are larger or more marginal pumpsets are being electrified -- where for example the groundwater level is falling -- or pumpsets are being used more intensively with the gradual evolution of agricultural practices. While the rise might have been higher in the absence of shortages, that there was any rise at all supports the observation made elsewhere that agriculture has to some extent been shielded from shortages of electricity.

113. A case can be made for using the 1960/61-1968/69 coefficients for forecasting, by arguing that they more nearly reflect the unrestrained relationship between the economy at large and the electricity demand. However, this would mean abandoning the more recent observations. Should a forecast into the 1980s be based solely on the evidence of the 1960s? Moreover, the more recent data do reflect what is feasible (though not necessarily desirable) in terms of economizing on electricity use. Thus, the opposite, somewhat extreme case could be made for using the coefficients derived from the observations of the second sub-period. The coefficients based on the full period represent a pragmatic (though far from conceptually satisfactory) compromise, and it is these that are used below for forecasting demand.

114. The second way shortages complicate forecasting is in choosing the base period values. The base year used here is 1977/78, for which total consumption from the utilities was provisionally estimated as 68,963 Gwh; the sectoral breakdown is given in Annex I.1.1. Also, there is an estimate of the extent of shortages in this year -- 15.5% (Annex I.2.2). Using the sectoral distribution of (suppressed) demand in 1976/77 as a basis, and allocating 70% of the impact of shortage to industry, 20% to services and 10% to agriculture, an estimate of unsuppressed demand in 1977/78 is derived. This, together with the sectoral growth rates of the Draft Plan, are summarized in Table I.4.

Table I.4: ESTIMATES OF UNSUPPRESSED DEMAND FOR ELECTRICITY IN 1977/78 AND ANNUAL GROWTH RATES OF VALUE ADDED FROM THE PLAN

	Agriculture	Industry	Services	Total NDP
Electricity Demand in 1977/78 (GWh)	11,326	51,309	18,978	81,613
Historical Average Rate of Growth: 1961/62-1976/77 (%)	2.10	4.12 (4.03) /a	4.33	3.34
Forecast Average Rate of Growth: 1977/78-1982/83 (%)	2.76	5.03	6.66	4.70
Forecast Average Rate of Growth: 1982/83-1987/88 (%)	3.92	6.80	6.36	5.50
Increase in Growth Rates 1977/78-1982/83 over 1961/62-1976/77 (%)	30	20	55	40

/a 4.12 for the secondary sector and 4.03 for mining.

For the sectoral model forecasts shown in Table I.5, the Plan value-added and NDP rates are used, together with the Plan target of electrifying two million agricultural pumpsets. To convert our forecast of demand into a requirements forecast, the Planning Commission estimate of future transmission and distribution losses of 18% of energy at the bus-bar is used (Table I.5). The forecasts of the sectoral regression model fall between those of the Tenth APS and the Draft Plan. They are about 4% above the Plan figures for 1982/83 and about 7% by 1987/88.

Table I.5: FORECASTS OF ENERGY DEMAND AND REQUIREMENTS (UTILITIES ONLY): 1982/83 and 1987/88

	Sectoral Model				Tenth APS	Draft Plan
	Industry	Agri-culture	Services	Total		
Demand (GWh)						
1977/78	51,309	11,326	18,978	81,613	-	-
1982/83	79,305	17,040	31,069	127,414	-	-
1987/88	132,573	25,641 /a	50,289	208,503	-	-
Requirements (GWh)						
1982/83	96,713	20,780	37,889	155,383	168,392	150,046 /b
1987/88	161,674	31,269	61,328	254,272	272,055	239,282 /b
Growth Rates (%)						
1977/78-1982/83	9.1	8.5	10.4	9.3	10.9 /c	8.4 /c
1982/83-1987/88	10.8	8.5	10.1	10.4	10.1	9.8

/a Assuming same growth rate as that between 1977/78 and 1982/83.
/b Taken from the Draft Plan; the forecast of 1982/83 is close (within 0.5%) to the disaggregated Planning Commission forecast, but not exactly the same.
/c Assuming losses in 1977/78 would have been about 20% of unsuppressed demand.

115. Four points should be made in concluding this discussion of forecasting. Firstly, forecasting is essentially uncertain and forecasts should define a range around a central estimate within which it is agreed there is a high probability unsuppressed demand will actually fall. In evaluating the APS and Planning Commission forecasts, only central estimates have been discussed, but for capacity planning purposes, a range of values would more accurately reflect our extent of knowledge about the future. Secondly, forecasts should be principally concerned with estimating demand more than five years ahead. The Draft Plan includes a forecast ten years forward and the APS does carry out a perspective forecast beyond the five-year horizon, but the larger part of the discussion is focussed on the near future in both documents. Generation projects in particular take a long time to gestate and such large commitments of capital that initial decisions must be made at least four to eight years before the project can be commissioned,

and generation projects typically have a life of at least 30 years. Forecasts should in future concentrate on the period, say, five to 15 years ahead. Thirdly, the Draft Plan forecast does appear to be conservative. The uncertainties surrounding the incidence of shortages at present and their importance in the sectoral regression model does not permit any categorical conclusions, but nonetheless do suggest that the central estimate of the Plan may be conservative in relation to the other sectoral forecasts in the Plan.

116. Finally, there is a need to develop a single, generally acceptable demand forecast (a single exercise that defines a single range of demand to be expected) in the context of the Eleventh APS, which is now at an early stage of preparation. A first step would be to reach a concensus on the methodology to be employed for short-run forecasts. Is the end-use method to be employed? If it is, could the costly and time-consuming survey be replaced by a sample analysis that would yield the same information more cheaply? Can the incidence of lags in investment in relation to plans for the power-using sectors (at the firm, the State or the national level) be analyzed and methodicially taken into account? Over what period should trends, or regressions, be studied -- the longest available period, the period of most recent rapid growth, or some other period? Is it worth taking groundwater availability, cropping patterns and so forth into account, as well as the pumpset electrification program in forecasting the requirements of the agricultural sector? Should the State-level end-use forecasts be checked against sectoral regression models based on State data? Can the measures of shortages currently available be standardized and improved? In the medium run -- 10 to 20 years ahead -- the choice lies between a methodology similar to the sector regression model, which can reflect structural changes, and some trend or modified trend method such as the Scheers' formula approach.1/ We would argue in favor of a sectoral regression model as the basic analytical tool for making longer run forecasts. The more basic point is that an acceptable position needs to be reached on these many diverse issues before the computation of forecasts begins so that the subsequent discussion of computed forecasts between the CEA, the Planning Commission and the States rests on a firmer basis that it has formerly.

II. INVESTMENT PLANNING AND RESOURCE ALLOCATION

1. The Resources Devoted to Power Sector Development

117. Almost all the assets of the power sector are publicly owned and operated. Only 6% of capacity among power utilities was privately owned in

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1/ This is a long-term forecasting method that projects electricity demand as a function of population. It is characterized by a growth rate which falls gradually over time, something which has been observed in the long run in developed countries. However, using reasonable population forecasts for India, this method produces results almost indistinguishable from those of the crude trend method.

1977, and it had been falling for some time. While registered captive capacity was a somewhat higher percentage of the total at that time -- about 10% -- quite a significant proportion will in any case be in public sector enterprises in the basic industries of steel, fertilizers and chemicals. Therefore, it is likely that close to 95% of fixed asset formation in the power sector is publicly financed; this proportion is likely to rise.

118. Delineating the responsibility for public investment in power is a task made complex by the plethora of institutions in the sector. With the creation of the NTPC and NHPC, Central investment in generation will in the foreseeable future be channeled through these corporations; transmission, for example for inter-State transmission links, will continue as the direct responsibility of the Central Department of Power. At the State level, most investment is carried out by the State Electricity Boards. The most important exception in some states is investment in hydro-electric schemes which has been retained in the State Departments of Irrigation and Power. Finally, there are, in one or two States, local municipalities and small supply undertakings other than the SEB, that make investments usually to extend the distribution system in their domain.

119. Almost all fixed asset formation in the power sector is financed under the Plans. Prior to the Fifth Plan, outlays in all sectors were only for net fixed asset formation (net investment), but in the Fifth and Draft Plans, gross fixed asset formation (gross investment including depreciation) is the relevant concept. In addition, the Plans for power include expenditure on surveys and the investigation of power schemes which, though they are not part of fixed asset formation, are an integral step in developing the investment program and are also of the same once-for-all nature as expenditures on fixed assets.

120. Plan outlays on power have risen fairly steadily from 12% of all outlays in the First Plan to 23% in the Draft Plan (Annex II.1.1). This percentage dipped in the Second Plan period and increased thereafter, accelerating quite sharply after the Fourth Plan. Parenthetically, it is worth noting that power, as a category of Plan outlay, is relatively easy to define; the only difficulty arises with respect to multi-purpose river projects, for which some fairly arbitrary apportionment of outlays must be made.

121. The bulk of Plan outlays on power occur at the State level. Since 1974/75 over 85% of power expenditures have consistently been in the State Plans, compared with between 1 and 2% in the Union Territories and the remainder of between 10 and 13% in the Central Plan (Annex II.1.2). In the last two Plan periods, this represented about 5% of total resources from the Central Plan compared with 30% of total State resources in the Fourth Plan and 35% in the Fifth Plan (Annex II.1.3). While there are no statistics available for allocations in the Draft Plan, it seems likely that this considerable burden on the States will increase further. Firstly, the provision for power for Center, States and Union Territories taken together is 4% more of the total provision that in the Fifth Plan. Secondly, we know that certain sizable individual States -- Andhra Pradesh, Maharashtra and Madhya Pradesh -- are already spending over 40% of their Plans on power development.

122. Plan outlays at the State level are of course funded in part by transfers of Central assistance to the States, but this is not earmarked for particular sectors and is fungible within the Plan for each government. Budget surpluses on current account provide additional resources that may be directly applied to the power investment program undertaken departmentally, or lent along with Central assistance to the SEB. The Boards also have access to market borrowing and internally generated resources. At the moment, the one financial resource normally available to public utilities but denied to the Boards is share capital, though under the 1978 financial amendments to the Electricity Supply Act State governments may now convert debt into equity if they wish.

123. Some indication of the relative importance of these different sources of capital can be gleaned from the General Statistical Review (see Sources in the Annexes). Table II.1 shows how important loans are in financing the assets of the power sector, and underlines what a small contribution is made by internally generated resources (reserves and surplus), other than through depreciation.

Table II.1: THE AGGREGATED LONG-TERM LIABILITIES OF THE STATE ELECTRICITY BOARDS, POWER DEPARTMENTS AND THE KARNATAKA POWER CORPORATION ON March 31, 1975

(Rs Millions)

	Absolute Amounts	Percentage Distribution
Loans	56,638	82
Reserves and Surplus - Depreciation	9,293	13
- Other	2,419	3
Consumer Contributions	1,127	2
Total	69,477	100

124. This point is perhaps more clearly made in the following table relating to financial performance of utilities during the Fourth Plan period.

Table II.2: ANNUAL AVERAGE INTERNALLY GENERATED RESOURCES IN THE FOURTH PLAN PERIOD: 1969/70 - 1973/74
(Rs millions)

		Public Sector	Utilities Total
1.	Internally Generated Resources	1,104	1,377
1a.	- Surplus	120	304
1b.	- Depreciation	984	1,073
2.	Gross Fixed Investment	4,331	4,774
2a.	- Net Fixed Investment	3,347	3,701
	- Depreciation	984	1,073
Memo Items			
3.	Total Annual Revenue	6,496	8,044
4.	Average Annual Plan Expenditure	5,862	-

Note: Revenues, depreciation and surplus are estimated from Annex II.1.4. Revenues reported here include revenue from sources other than electricity sales; these constitute less than 10% of the total. The public sector covers SEBs, Power Departments, the Karnataka Power Corporation and municipalities. Net fixed asset formation is estimated from Annex II.1.5 for the utilities total, and directly from the General Reviews of Public Electricity Supply Statistics for the public sector. Plan expenditures are deduced from Annex II.1.6. Note that net fixed capital formation is taken to be the net change in fixed generation, transmission and distribution assets and therefore must be a marginal understatement, since fixed assets such as headquarters buildings are not included in these categories.

In the public sector the surplus averaged less than 2% of total revenues and less than 4% of net fixed investment.

125. In comparing aggregated revenue and capital account figures for public sector undertakings and figures of Plan expenditure some caution is in order because: (i) conceptually there is some inconsistency since non-capital account expenditures are included in the Plan figure, and there are capital expenditures excluded from the Plan; and (ii) statistically there must be some discrepancy, since, despite the conceptual difference, we would expect net fixed asset formation and Plan expenditure to be much closer than the table suggests. Since in the Fourth Plan, Plan expenditures encompassed only net capital formation, the proper comparison to make is between the surplus in the public sector and Plan expenditure. This suggests that only 2% of the Plan expenditure on power was funded from internally generated resources. (On a gross basis, adding depreciation to both the denominator and the numerator, this increases to 16%).

126. The Plan documents distinguish among four major categories of expenditure on power. These are generation, transmission and distribution, rural electrification and a residual category. Since the First Plan, over 50% of Plan expenditures have been on generation, and 20-30% on transmission and distribution and the bulk of remaining resources has typically been devoted to rural electrification (Annex II.1.6).

127. The pattern of expenditure in the power sector is somewhat different from that provided for in the plans (Annex II.1.7). Expenditure on transmission and distribution relative to that on generation has been less than the provision. In the Fourth Plan, the transmission and distribution allocation was equal to almost 60% of the generation allocation but expenditure was 51%. Similarly, in the Fifth Plan, planned expenditure on transmission and distribution was 60% of generation, whereas actual expenditure was only 40%. Thus, there is some evidence that transmission and distribution receives a lower priority in implementation than at the planning stage.

128. The Five-Year Plan process has never made allowance for the impact of inflation in estimating the requirement for funds. The argument against such a policy is that the Plan is an exercise intended to divide real resources between different types of investment and it would be worthwhile to take inflation into account only if relative price changes could be forecast. In the case of the power sector, planning without inflation has serious consequences because generation projects have long gestation periods. Funds are locked into them early in a planning period, and if there is subsequent inflation it makes sense to meet the increased requirements of the generation projects which have begun and -- with limited funds available -- to cut back on transmission, distribution and rural electrification investment which can be fragmented more easily. The result is an unbalanced investment program.

129. It is striking that actual expenditure has always exceeded planned expenditure, 1/ while physical achievements have always fallen short of targets (Annex II.1.9). In the Fourth Plan, for example, actual expenditure on generation was 24% higher than planned. By contrast, new capacity added was only 50% of the original Plan at the beginning of the Plan period. This has been generally true of all the Plans since the Second and supports the view that finance is a constraint on the power program.

130. Two main points have thus emerged: (i) the share of investment in power in the Plans has been large and is financed from borrowing and public tax revenues; and (ii) finance has constrained the program in the past. On the basis of past experience, it is possible that actual expenditure on power during the Draft Plan period could be substantially higher (in current prices) than the allocation in the Draft Plan document. In any case, the argument is strong that internal resource generation in the SEBs should be increased.

1/ This was not altogether surprising since the increase of expenditure over allocation was slightly less than the increase in the general level of prices due to inflation: this was so for every Five-Year Plan except the Fifth, where expenditure outpaced inflation.

This in turn provides one of the strongest arguments for raising the electricity tariff -- to relieve the burden of financing the power sector from general revenue soures.

2. The Investment Planning Process

131. Planning in the power sector follows much the same process as in other sectors of the Indian economy. The national Plan for power forms part of the Annual and Five-Year Plans. The principal differences between the power sector and other sectors are, first, that the sector is jointly controlled by the States and the Central Government and second, that the level of investment is high and takes a long time to gestate. The former point means that the process of consultation and coordination between the Center and the States as the Plan is formulated is more intense than is typical in other sectors; the latter point results in major problems of planning resource allocation between the power sector and other uses.

132. The first stage in the Five-Year Plan process is the development of what is called a general approach to the formulation of the Five-Year Plan. This begins to be drafted about three years in advance of the Plan period. In principle, this should outline the general directions in which the Plan will be developed and the areas in which a more intensive effort than formerly will be required. The general approach is prepared by the Planning Commission and submitted to the Cabinet and the National Development Council for review. It is followed by a "Draft Memorandum" on the physical content of the Five-Year Plan. The orders of magnitude and the basic inter-relationships among sectors are outlined in this document. The Planning Commission at this stage constitutes a series of Working Groups, among them one which deals with power sector development. The Draft Memorandum attempts to summarize the contributions of the different Working Groups. Once again this document is reviewed by the Central government and the National Development Council. Comments are duly noted by the Planning Commission and the Draft Plan is then prepared, which is the basis for the first working level dialogue between the States and the Center. In the meantime, the State governments will have made preliminary assessments of their Plan programs and as the Draft Plan is under preparation, the State Planning Departments discuss with the Planning Commission the integration of different State objectives into the overall Plan framework. Lastly, the final Plan is prepared and submitted to the Cabinet, Parliament and the National Development Council for general approval and authorization for its implementation.

133. The Annual Plan cycle is similar to that of the Five-Year Plan, excepting that the whole cycle takes about six months and is carefully coordinated with the annual budgets of the Central and State governments. The Annual Plan is not submitted to the National Development Council and is finalized after discussion between the State Cabinet and the Planning Commission.

134. In the past, the Annual Plans provided an opportunity to modify the particular allocations of the Five-Year Plan and to accomodate cost escalations and emergency developments. But, in most sectors other than power, projects were not added and the basic framework of the Five-Year Plan was adhered to. With the introduction of the new rolling Plan procedure the later years of the

rolling Plan should, in time, become the early years of a subsequent rolling Plan. The Annual Plans will become the more detailed elaboration of the first years of the current rolling Plan. The rolling Plan framework should permit more fundamental reassessment of priorities more frequently than in the past.

135. The power sector Plan has in effect always been rolled over every one or two years. When a new APS has been prepared the orders of magnitude of the investment program have been revised accordingly. And of course projects are continuously being identified, appraised, sanctioned and implemented. The Five-Year Plan used in effect to take a slice out of an on-going rolling Plan process in the case of the power sector.

136. Apart from the Planning Commission, the Department of Power in the Ministry of Energy and the Central Electricity Authority (CEA) are the two Central Government agencies most closely associated with the development of the Plans for power. The Ministry is responsible for Central policy in the field of energy and under this imperative has Central responsibility for the Plan of the power sector. Within the CEA the Planning Department is, appropriately enough, the main group responsible for the development of power plans. The Department comprises three directorates: the Power Survey Directorate, the Progress and Plan Directorate and the Technical Examination and Coordination Directorate. The first is responsible for preparing the Annual Power Survey, with the help of four regional offices. The second provides the secretariat for the Working Groups convened on power. The third is responsible for the techno-economic appraisal of all power generation and transmission schemes submitted by State governments for clearance and inclusion in the Plan. The technical examination and coordination directorate has therefore to work very closely with the Hydro, Thermal and Systems Wings of the CEA.

137. In preparation for the Five-Year Plans, a Working Group on power has usually been convened. The group typically comprised representatives of the Planning Commission, the Department of Power, the Ministry of Finance and the departments dealing with two or three of the major electricity using sectors, under the chairmanship of the Secretary of Power.

138. The Plan for power begins with a forecast of demand. The APS methodology applies both a load factor and a loss factor, converting demand for energy into a requirement for power at the bus-bar in each and every State. Then margins for spinning reserves, forced and partial outages and ancillaries raise the power requirement figure to a target for generating capacity, from which the annual need for new capacity can be worked out. The Working Group is responsible for meeting these needs with a schedule of specific generation and transmission projects.

139. The SEBs at the State level undertake most of the prefeasibility and preparatory work for power projects. Geological and other specialized functions are of course carried out by the concerned State government department or agency, but the Board usually coordinates these efforts. Projects at the feasibility stage and thereafter are reviewed by and discussed with the State Government's Planning Department, the Department of Irrigation and Power and the technical examination and coordination directorate in the CEA. The

State Planning Department is concerned mainly to place the power investment program into perspective in the State Plan: to see that sectoral allocations reflect State development priorities. The State Irrigation and Power Department has similar concerns, but focused somewhat more narrowly on the trade-offs to be made in water management between irrigation and hydro-electricity generation. The parts of the power program that may affect inter-State river disputes are also the subject of the Irrigation and Power Department, and in fact projects in this part of the program are usually prepared and executed by the Department and not the Board. The CEA is concerned with the technical feasibility, the overall justification (narrowly construed to mean whether or not there is a market for the power to be generated) and the financial justification; their review concentrates on the unit cost per KWh and the internal rate of return of the project, both calculated using unadjusted financial data.

140. Individual projects originating with a State must be approved by the CEA and santioned by the Planning Commission, for inclusion in the Plan. Central Government projects are also received and approved by the CEA and passed on to the Planning Commission, but are sanctioned by the Public Investment Board. This is a continuing process so that when a Working Group reviews the needs for five years ahead, there are projects already sanctioned as well as those underway that form the kernel of the investment program.

141. Thus, the responsibility for investment decisions and, therefore, the application of investment criteria, is shared between the Center and the States. The investment program has grown so large that some increased sophistication in the investment planning process is now warranted. Individual State generation projects are usually assessed primarily on the basis of whether their capacity is needed to meet State-level load -- and, of course, on their technical soundness. That financial analysis which is now carried out should be supplemented by an economic analysis that analyzes potential fuel savings throughout the regional system concerned (even in shortage regions this is relevant hopefully in the next 10 years or so, well within the life of new investments), and their costs and potential benefits should be shadow priced. Shadow pricing may have a marked affect on the comparison of hydro versus thermal projects and generation versus transmission projects, because costs composition over time and in terms of labor content are so different. Coal should be shadow priced at the long-run marginal extraction and transport cost rather than the selling price. Multipurpose hydro-projects should be subjected to the closest scrutiny to identify the best design and operation characteristics to trade off generation and irrigation benefits optimally. And of course, power itself can be shadow priced. 1/ Finally, State projects should not be justified so much as the least-cost way of meeting State loads but should be fitted under the regional load curves and shown to be least-cost for the region as a whole. Economic analysis of this kind could not replace financial analysis as a decision-making criterion, but it should as soon as possible come to play a part in deciding on new investment.

1/ The Planning Commission has used shadow pricing for the appraisal of the super-thermals. Their shadow pricing of power took into account daily and seasonal variations in opportunity costs.

142. The second major tool of investment analysis available to power planners is system modelling. Such modelling requires careful integration with "system planning" exercises, a term usually used more narrowly to connote the technical analysis of transmission system development. 1/ Transmission system planning has already been initiated in the CEA. However, the CEA has yet to introduce systematic modelling that can analyze location choices, phasing of projects, trade-offs between additional transmission and generation and can thereby help establish the very rough initial parameters within which the system planning exercise can best take place. As such, these mathematical modelling techniques can primarily be used for forward planning -- for sketching out and analyzing investment choices ten to twenty years away -- since system planning considerations, and highly technical design questions relating to such issues as system stability and reliability dictate what alternatives are feasible within a shorter time horizon. Despite the remoteness of their concerns, such modelling exercises can be useful as an aid to long-term investment planning.

3. Present Investment Plans

143. This section reviews present investment plans in the power sector. As discussed earlier, there are substantial differences between the Center and the States regarding demand forecasts for electricity and these differences extend to the investment program. The consultative process had reached an advanced stage in analyzing the program when the more modest national targets of the Draft Plan were formulated. The Working Group set up to review the development prospects of the power sector in the Sixth Plan therefore went ahead, basing its demand expectations on the Tenth APS, and produced a detailed background report on the power investment program, which was generally more ambitious than that of the Planning Commission in the Draft Plan.

144. The Working Group was formed in September 1977 to recommend a program for power development for the five-year period 1978/79 - 1982/83. Its terms of reference called for it to indicate:

(a) phased requirements of capacity and of funds;

(b) key materials and manpower requirements to implement the program; and

(c) strategies for implementing the program.

145. While the Working Group Report must carry less authority than the Draft Plan, it is discussed here for two reasons: (i) it is far more detailed than the Plan; and (ii) it represents a compromise position between

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1/ Models have been developed for both the Southern and Northern Regions by outside students of the power sector (Annex I.2.1). But, for various reasons, these have not been applied to decision making.

the strictures of the Center and the aspirations of the States. Before reviewing the investment program it is useful to briefly look over the progress of physical investment and the extent of the present system.

146. Past Investment. During the period 1950 to 1973/74 total installed generating capacity increased from 2,300 MW to about 18,500 MW in 1973/74 at the end of the Fourth Plan (Annex II.3.1). Basic transmission and distribution systems were also developed during the period: transmission from roughly 29,000 circuit km to 691,000 circuit kms for the HT voltage network (Annex II.3.2).

147. Despite this massive increase in generating capacity during the first four Plan periods, power availability has not kept pace with growing demand, and shortages became acute during the latter part of the Fourth Plan. One of the main reasons for these shortages was the inadequate expansion of generation facilities.

148. The power program in the Fifth Plan (1973/74 - 1978/79) was also beset with implementation difficulties. The problems encountered in keeping to commissioning schedules included difficulties with civil works, with the regular flow of equipment and with the availability of funds. In general, the administration of the program was weak. A system of monitoring projects under construction was initiated by the CEA during the Fifth Plan. This measure may have helped raise the tempo of additions to installed capacity to between 1,700 and 1,800 MW during the last three years. However, this is much below the average 3,000 MW or so that must be commissioned annually to meet Plan targets.

149. Progress of past programs has also been substantial in rural electrification (Annex II.3.3). About 40% of all of India's villages have been electrified, a tenfold increase since 1960. This comparatively recent surge in investment has in part been aimed at exploiting groundwater potential through the electrification of pumpsets: growth on this front has been even more impressive with over 3 million pumpsets electrified, compared with less than 25,000 in the early 1950s.

150. The Present System. The present system is large and extensive (Annexes II.3.2 to II.3.4). Installed generating capacity is about 26,000 MW, with about 15,500 MW of conventional thermal stations, almost 10,000 MW in hydro-electric plants and 640 MW in nuclear plant. About 2,200 MW of the conventional thermal plant is registered captive, in industrial establishments. Among utilities, something like 7% is Centrally owned (including all the nuclear plant) and about 5% is owned by private licensees; the remainder is operated at the State or municipal level, mostly in the SEBs. About 7,000 MW of capacity are in the Northern Region, 6,000 MW in each of the Western and Southern Regions and 4,500 MW in the Eastern Region. The North-Eastern Region accounts for but 280 MW. Correspondingly, about 300,000 circuit km of transmission and distribution lines are in the Northern Region, about 200,000 circuit km in both the Western and Southern Regions and about 110,000 in the

Eastern Region 1/ (Annex II.3.5). The North-Eastern Region system is still rudimentary comprising only 14,000 circuit km.

151. Strategy for Power Development. The Draft Plan and the Working Group Report enunciate essentially the same strategy for future power development, inasmuch as both recognize the desirability of overcoming shortages. Emphasis is laid on the development of pit-head thermal power stations as opposed to load center stations, of as much hydro potential as possible and of a strong high-voltage (EHV) transmission network through which the benefits of greater system integration can be realized.

152. Both hydro and nuclear resources are potentially cheap sources of additional electricity. However, the Plan notes that both are capital-intensive and long gestating. The planned additions to conventional thermal power plant far exceed those of these two types combined. The Working Group Report makes special mention of hydro electric investigations as an activity that must be intensified in the next few years if the hydro-electric program is to be developed in a timely fashion in succeeding plans.

153. To make the best use of existing and planned generating capacity, improvements in the transmission and distribution system are advocated, since it is recognized that system losses are high presently, partly on account of theft but largely for technical reasons. The advantages of extending the transmission network also include those of more economical operation of an integrated system at the regional, and eventually, national levels through exchange of power for peak assistance, more economic merit order operation of more stations and so forth. The REBs are recognized as having a key role in this gradual integration process.

154. The efficiency of both program implementation and operations is also addressed. These major responsibilities are largely borne by the SEBs, which are thought to be often weak in organization and management. More functional specialization, better staff and officer training and improved organizational structure are seen as the main ingredients needed to improve this situation.

155. The Draft Plan also recognizes the importance of solving the problem of financing the power program and proposes two parallel, complementary approaches. The SEBs' financial performance must improve markedly and their contribution to their investment programs increase. The second approach is to consider creation of a power finance institution to finance projects by SEBs or the State Governments outside the Annual Plan budgets. Such an institution could tailor the disbursement of funds to the increasingly large and lumpy requirements of power projects, thereby easing the shocks and tensions presently placed on the State Plans and assuring that finance would not delay project implementation as it has in the past.

1/ Above 500 V; i.e., excluding low tension distribution in townships and urban areas.

156. Thus, the strategy for the next several years, as enunciated at the Center, contains all the major elements required to address sensibly the problems of the power sector. But a tremendous effort will be necessary to implement this strategy. With a view to identifying how this broad strategy can be translated into specific measures, the Central Government has recently established a committee to review the problems of the power sector. Under the chairmanship of one of the members of the Planning Commission, the committee largely comprises administrators from the power sector; an independent secretariat has been set up to support their deliberations with detailed research. The committee's terms of reference call for an examination of "all aspects of the functioning of State Electricity Boards and Central Organizations engaged in electricity generation, transmission and distributions, including organizational structure, management practices, planning systems, efficiency of operations, financial performance, tariff structure and legislative framework and make recommendations for improving them". Given its seniority and wide purview, this committee could have far reaching impact when it reports towards the end of 1979.

157. The Investment Program. The program of new investments in the power sector devised in the Working Group Report was considerably more detailed than anything in the Draft Plan. Nevertheless a comparison of broad orders of magnitude is possible. The Plan involved an overall reduction of the level of resources stipulated in the Working Group Report of about 25% (Annex II.3.6). This fell heavily in the physical program in transmission, distribution and rural electrification where the reductions were about 35%. In the program as a whole, however, the most severe cuts were in research, investigations and surveys where the proposed expenditure was cut in half. The cut in the target for capacity increases from 22,600 MW to 18,555 MW was largely in the conventional thermal program which was cut back from 16,400 MW to 12,900 MW, but still the conventional thermal capacity investment constitutes two-thirds of the total planned generation investment. The rural electrification program, which initially called for the electrification of 110,000 villages and 3 million pumpsets has been cut to 100,000 villages and 2 million pumpsets. (It is worth noting that the Draft Plan is nonetheless large in relation to past achievements -- to reach even a capacity increase of 18,500 MW will require the rate of capacity commissioning to be double that of the Fifth Plan).

158. It is possible to use the Working Group Report as a touchstone to assess the Plan, not so much with regard to the size of the Plan which is of course to a large extent determined by demand expectations but with regard to its composition. The Working Group Report laid emphasis on catching up in the transmission program, which had been neglected in the past. The composition of the Plan program in transmission and distribution by voltage level is not available, but it seems likely that much of the cut will have to fall on the 400 KV system. The strategic objectives of reducing system losses and integrating system operations are likely to be delayed.

159. The hydro program in both the Draft Plan and the Working Group Report was very small relative to the conventional thermal program. This runs counter to the sector development strategy, but reflects the constraints imposed by

a short shelf of hydro projects. The natural course of action should then be to undertake a major program of investigation with all due haste, and thereby to accelerate the rate of hydro-electric development in subsequent Plans. How large such a program should be is hard to say, but if the original estimate of the Working Group was at all accurate, then the cut imposed in the Plan is somewhat draconian. The choice between competing uses of limited resources may seem to favor faster-gestating thermal projects, but the price in terms of long-term development costs may well be high. The matter could do with closer study and most detailed review.

160. The comparison at the end of Chapter I between the results of the regression analysis and the forecasts of the Draft Plan suggest that the Plan forecasts may be conservative -- of the order of 4% too low, using the sectoral model results. The implications for the level of investment depend upon the planning assumptions made about plant margins for outages, spinning reserves, auxilliaries and so forth. The Planning Commission margins tend to be demanding and reflect the higher standards of operation that should be possible, while those of the Boards and the CEA (in the Tenth APS and the Working Group Report) tend to allow larger margins which reflect past achievement. Since the Planning Commission margins are themselves quite generous by international standards, it is theirs which are applied in the next few paragraphs (Annex II.3.7).

161. The Draft Plan calls for an investment in about 18,200 MW of new capacity to bring total capacity to about 42,100 MW by 1982/83 (Annex II.3.8). Since this was deemed sufficient to meet the Plan demand forecast, to meet one 4% higher, a total capacity of about 43,800 MW -- 1,700 MW more -- would be needed. This is not a large increase in an investment program the size of India's, but it suggests that roughly 20,000 MW of new capacity should be commissioned if the demand forecast on the basis of regression analysis were to be met.

162. This, however, makes no allowance for three important factors that affect the investment program in any power sector. First, there is around a "best-guess" demand forecast a range of uncertainty with some chance -- usually quite large -- that unsuppressed demand would (if it could) exceed the forecast. Unlike most other sectors, power shortfalls cannot be made up with imports at short notice. So, to achieve an acceptable level of security of supply, the capacity built should in fact exceed that necessary to meet the "best-guess" forecast by some allowance -- perhaps 1,000 MW or so in the Indian system. Secondly, the lumpiness of power investments implies that, between the commissioning of large units, there will be time for demand to grow. The investment program should be sufficiently large and flow sufficiently smoothly for demand to be met just before new units are commissioned as well as just after. Thirdly, some allowance is required for delays in plant commissioning. Certain delays cannot be identified and predicted at the plant level, yet in a large program some delay in one or two of the projects is inevitable. This is certainly borne out by past experience. (It should be noted, however, that planning for this kind of contingency is not condoning poor project implementation and is compatible with penalties at

the project level for poor project implementation performance.) In a program this size, an additional allowance of the order of 1,000 MW might suffice for this purpose. Thus, a program of about 22,000 MW could be planned and commenced in the expectation that about 21,000 MW could be commissioned by the end of the Plan period. 1/

163. The Composition of the Investment Program: Thermal and Hydro-Electric Projects. The share of hydro-electricity in generating capacity increased quite steadily during the first three Plans, and between 1959 and 1969 it almost doubled (Annex II.3.10). Since then, however, the trend has been reversed and, if the Draft Plan program is realized, the share will fall to only 33% by 1982/83, compared with over 40% in the late 1960s. Over the next twenty or thirty years, some such decline in the share of hydro-electricity is inevitable because the known potential for hydro-electric projects is limited. Yet at the moment, only a small proportion is developed -- some 10,000 MW of a total potential of as much as 66,000 MW -- and only an additional 5,000 MW are to be developed by 1982/83. Most of the remaining 51,000 MW potential is in the north and north-western parts of India in the Himalayan region.

164. It is difficult to assess how rapidly this potential should be exploited because there is insufficient information about the individual schemes concerned. The experience of schemes already completed, underway or just investigated is not a good guide to the potential costs and benefits of the remainder. Costs depend critically on site location and geological characteristics, and on the benefits derived from a scheme depend not only on its capacity, but also on the hydrological conditions affecting the scheme. These in turn determine whether the scheme will be designed to meet part of the base load or be used seasonally or for peaking purposes. Nevertheless, it is reasonable to suppose that a number of new schemes would prove sufficiently attractive to warrant rapid development and that, with a more complete knowledge of these hydro opportunities, long term investment plans could be formulated more economically.

165. There are indeed a number of reasons why the tempo of hydro-electric investigation and development has fallen off. Firstly, in the present system there is a chronic shortage of capacity and the case for diverting funds from the more quickly gestating thermal generation investment program is, therefore, weak. Secondly, the initial costs of site investigation programs in the north of India can appear to be high. Moreover, these costs do not necessarily yield a worthwhile return since it must be expected that some investigated sites will prove unattractive. (It should be emphasized that these costs are small compared to either total development costs or potential benefits in most hydro-electric schemes.) Thirdly, the geology of the Himalayas is more difficult than that of the Deccan. The Himalayas are young and consequently

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1/ This is a rough and ready estimate; all the types of allowances referred to here may be estimated with much greater precision using available analytical techniques.

surface geology does not necessarily reflect the types of problems which may be met in tunneling or preparing dam foundations. It is impossible, therefore, even after a project has been investigated to predict with much accuracy how long a hydro-electric project will take to build, or how much it will in fact cost. Fourthly, hydro schemes at the very best take seven to eight years to complete and, therefore, they usually span more than one Plan period. It is difficult to mobilize a strong political commitment to highly capital-intensive schemes that yield benefits so far in the future. Fifthly, relocation of persons displaced by the flooding of areas behind a dam is difficult. It may take much time -- as much as the civil works or more -- to resolve the issues surrounding this type of social upheaval. Finally, hydro-electric development involves the use of waters which in India are often the subject of inter-State river disputes. In the north of India, international water management problems are also an issue. Despite the efforts spent on solving inter-State problems since Independence, there are still situations in which hydro-electric development could be held up for this reason.

166. The costs of developing the larger hydro resources of northern India may well be less than the similar hydro-electric schemes that have been exploited in the past, but the uncertainties of costs and timing may be much greater. To minimize these risks, an intensive program of project identification and investigation is called for. In the past, the investigation of hydro-electric projects has been insufficient. Some States, especially in the North-Eastern Region where there is a large potential, do not have the proper organization for carrying out the necessary investigations. Moreover, the remoteness of the Himalayan sites will lead to a host of logistic problems affecting communications and the transportation of men, equipment and materials. To cope with these difficulties, the advisability of establishing some special organization at the Center, capable of providing specialist support to the States, should be reviewed and, as the Draft Plan is replaced by succeeding rolling Plans, the allocation for investigations should be increased.

167. <u>The Composition of the Investment Program: Transmission and Distribution</u>. Planning transmission and distribution requires detailed studies of individual schemes and of the system as a whole. In some instances new interconnections can be justified as a way of economizing on peaking capacity; in others system reinforcement will be warranted to reduce losses; and in yet others, it may be right to argue in favor of new transmission capacity for the increased reliability and stability brought to the system. In this last instance, especially, there may be so many different alternative technological solutions that nothing short of a study of the relative merits of many different possible configurations of the transmission network will suffice to settle the matter.

168. With this basic consideration in mind, CEA have already initiated system planning studies in collaboration with M/S Teshmont Consultants Inc. of Canada. The overall scope of the studies is broad:

(a) forecast power requirements up to 1998/1999, identification of load centers and the power demand in these centers;

(b) capacity -- hydro, conventional thermal and nuclear -- to meet future demands;

(c) evolution and design of EHV systems, keeping in view the long term needs and system security considerations; and

(d) determination of generator parameters and design criteria for control and protection equipments.

But in the first phase of this work the consultants developed only a transmission system plan, taking the demand forecasts of the Tenth APS and the generation program of the Working Group Report as given. This became the basis for the transmission program for the Working Group Report.

169. While the 400 KV and 220 KV lines have been individually identified, the provisions for lower voltages in the overall transmission and distribution program were computed on the basis of total network requirements assessed on the basis of previous experience. The network details at these lower voltages are being planned and will be executed by the SEBs within the framework the EHV system developed on the basis of the system studies carried out by the CEA.

170. There is some evidence that the present transmission and distribution system is inadequate. There is the evidence of the steady build-up of system losses to what is now, many assert, an unacceptably high level. From representing between 14 and 15.5% of generation between 1961 and 1965, the percentage rose sharply to about 20% by 1972/73 at which level it has remained roughly stable (Annex B.1.5).

171. It has been argued that much of the increase in losses has been due to the intensive program of rural electrification, and this may indeed be so in part (Annex II.3.11). Between 1965/66 and 1975/76 total losses increased by about 10,000 Gwh, compared with an increase of about 7,000 Gwh in agricultural consumption. If agricultural losses were steady at about 30%, then losses for the remainder of consumers would have risen from about 14.3% to only 17.3%: thus two-fifths of the increase in losses could be ascribed to agriculture. In order that all the increase in losses be ascribed to agriculture the average or the marginal rate of losses in supplying agriculture would have to be just over 50%, neither of which is likely. The rate of losses, it should be noted, is aggravated by shortages in two ways. Firstly, rostering concentrates load on feeders into particular periods; since losses increase roughly with the square of the power delivered, the ratio of lost energy to energy delivered will increase. Secondly, industrial loads -- especially those of HT consumers -- tend to be cut back more than average during shortages; since some of the load associated with lower losses is cut, the average of the remainder rises.

172. Voltage in many areas is low during system peak periods, so that the use of voltage regulators by consumers is widespread. These voltage drops are used in some States to stretch the available power supply when

there is an unanticipated capacity outage, but their pervasive incidence must be in large part a reflection of the over-extension and inefficiency of the distribution network.

173. If these factors suggest the transmission and distribution system might be inadequate, this may well reflect an inadequate level of investment in transmission and distribution in the past. Since the First Plan, when over 50% of expenditure was devoted to transmission and distribution, this percentage has been much lower -- between 23 and 26% (Annex II.1.6). If rural electrification is included too, this percentage has still been less than 50% in every Five-Year Plan after the First. The Draft Plan provision for transmission and distribution is almost exactly one-third of the total: somewhat more than in the Fifth Plan but still quite low. In every Plan except the Third, expenditure on transmission and distribution has been a smaller proportion of the total than was the provision.

174. The present rate of losses of roughly 20% is high by international standards. Data from 1970 show that system losses in the developed world tend to be in the range of 5 to 10% (Annex I.3.12). This comparison should not be made without noting that one of the main determinants of losses is load density: with the exception of Sweden, the country with highest losses in the sample considered here was Canada, where load density is 18 kwh/year/sq. km, compared with 15 KWh/year/ sq. km in India. The U.K. by contrast is a country of very high load density -- 883 KWh/year/sq. km and losses are proportionately lower. Nonetheless, there is a statistical relationship that shows losses rise as the proportion of investment spent on transmission and distribution falls.

175. Investment in transmission and distribution should bear some relation to investment in generating capacity. In a country the size of India, with its generally low load density and with its new sources of power (pithead stations and more remote hydro schemes) being some distance from load centers, one would expect at least one-half of the investment program to be devoted to transmission and distribution.

III. CONCLUSIONS

176. Because the power sector is such an important part of the economy, the issues raised in this review have far-reaching implications for India's development prospects. The efficiency of power use in the economy and the effect of shortages, electricity tariffs and their impact on efficient consumption and resource mobilization, demand forecasting and its implications for the level of future investment, the process of investment planning and the range of investment choices, and the financing of the growth of the power sector -- all are subjects of central concern for India.

177. In the Indian economy, power consumption is high relative to the level of economic activity, and the rate at which electricity consumption has

been growing relative to GNP is much higher than is typical in other countries. This power-intensity is particularly marked in industry, which consumes two-thirds of total supply. A number of the most power-intensive manufacturing industries, including fertilizers and aluminum, have grown more quickly than average in recent years. Other industries, particularly textiles, appear to have increased their intensity of electricity use.

178. In the past, tariff increases have not kept pace with general price increases in the economy, and have also fallen relative to electricity costs. Tariff increases are not easy to implement in any of the energy sectors and, were electricity to take the lead in the immediate future, some distortion in relative prices might result; but this would be a small cost compared with the long-run advantage of providing a better price signal to consumers of electricity, so that their decisions regarding when additional electricity consumption is worthwhile would correspond more closely to the same judgment made from the standpoint of the economy as a whole.

179. In the meantime, electricity is in short supply and shortages are both severe and costly. Shortages have probably grown less severe than they were in the first half of the decade, but they are still serious: the estimated extent was 15% in 1977/78 and was roughly 10% in the first nine months of 1978/79. While it is impossible to pinpoint the cost of shortages precisely, their impact in recent years has been in the range of 1 to 3% of GDP. The burden of shortages has undoubtedly had the most severe impact on industry, and it is no coincidence that in the Eastern Region, where power shortages have been particularly disruptive, industrial performance has been particularly lacklustre.

180. An additional cost imposed by shortages is the misallocation of resources when captive generating sets are installed by industry and commerce. While it makes sense in the short run for the industries concerned, it would be cheaper for the economy to provide additional power from the grid.

181. Part of any solution to shortages of power will be increased capacity to supply power. Improved management and increased efficiency in the power system will also be necessary, and indeed the assumptions made in this review (the same as those in the Draft Plan that relate capacity increases to demand increases) allow for improvements in efficiency.

182. The demand for electricity is the main determinant of the need for future system expansion. There are three major demand forecasts discussed in this review: the Tenth Annual Electric Power Survey forecast, the forecast incorporated in the Draft Plan and the sectoral model based on regression techniques. The Tenth APS is the highest forecast, based on a disaggregative approach and on pre-Draft Plan forecasts of economic growth. The Draft Plan forecasts are most conservative, also derived using the enduse method, but from aggregated analysis and somewhat lower forecasts of economic growth. The sectoral regression model, which has been used to assess these two end-use approaches, results in a forecast that falls between that of the Draft Plan and the APS. From the standpoint of the sectoral model, the Draft Plan forecast seems conservative.

183. To improve the quality of forecasting, forecasts should define a range around a central estimate, within which it is agreed there is a high probability unsuppressed demand will actually fall. This would more accurately reflect the state of knowledge about the future. Secondly, forecasts should be principally concerned with demand more than five years ahead. The period 5 to 15 years ahead is more important for investment decision-making. The Eleventh APS, which is now at an early stage of preparation, should provide a context to settle some of the methodological points discussed here. As the basis for the longer-term forecast, a five-year forecast based on the end-use method in sectors where that is applicable and on regression analysis techniques in other sectors may be most appropriate: for the 5 to 15 forecast, a methodology based on regression analysis is probably to be preferred. The investment program should be pitched above the central estimate forecast by margin that reflects a trade-off between the advantages of additional security of supply (which are considerable considering the costs of shortages) against the costs of an expanded investment program. Additional margins to allow for the lumpiness of investment and inevitable lags in commissioning should also be provided. It must be emphasized that power is an input to the economy for which temporary shortages cannot be met by drawing down stocks or by importing extra supplies: cutting less essential uses of power is an expedient open to few, which provides little insulation against electricity shortages.

184. These considerations suggest that the investment target of the Draft Plan should be raised perhaps by as much as 3,700 MW to roughly 22,000 MW for the utilities sector, in the expectation that on the order of 21,000 MW would actually be commissioned. Naturally, the feasibility of this course of action is critical. This review has not examined the feasibility of implementing even the proposed program, and this is a subject for further study.

185. The investment program has grown so large that some increased sophistication in the investment planning process is now warranted. The financial analysis to which State projects are usually subjected should be supplemented by an economic analysis of potential fuel savings throughout the regional system concerned. Project costs and potential benefits should be shadow priced. Shadow pricing should have a marked affect on the comparison of hydro versus thermal projects and generation versus transmission projects, because the cost composition over time and in terms of labor content are so different. Coal should be shadow-priced at least at the full extraction and transport cost rather than at the selling price. Multi-purpose hydro projects should be subjected to the closest scrutiny to identify the best design and operation characteristics to trade off generation and irrigation benefits optimally. Finally, State projects should not be justified on the grounds that they are the least-cost way of meeting State loads but should be fitted under the regional load curves and shown to be least-cost for the region as a whole.

186. The second major tool of investment analysis available to power planners is system modelling for forward planning -- sketching out and analyzing investment choices ten to twenty years away -- since system planning considerations, and highly technical design questions relating to such issues as system stability and reliability dictate what alternatives are

feasible within a shorter time horizon. Despite the remoteness of its concerns, such modelling exercises can be useful as an aid to long-term investment planning.

187. The broader characteristics of an investment plan such as the distribution of funds between major categories of expenditure, should be determined by detailed considerations such as those outlined above. Without that depth of examination, nothing definitive can be said about the composition of the investment program. Nonetheless, two features of the Plan are worth noting and the consideration of broader issues does raise serious questions about them. The first is the division of the generation investment program between hydro and thermal.

188. If the Draft Plan program is realized, the share of hydro in total generating capacity will fall to only 33% by 1982/83, compared with over 40% in the late 1960s. Over the next twenty or thirty years, some such decline in the share of hydro-electricity is inevitable because the known potential for hydro-electric projects is limited. Yet at the moment, only a small proportion is developed -- some 10,000 MW of a total potential of as much as 66,000 MW -- and only an additional 5,000 MW are to be developed by 1982/83. Most of the remaining 50,000 MW potential is in the Himalayan region.

189. The costs of developing the larger hydro resources of northern and north-eastern India may well be less than the similar hydro electric schemes that have been exploited in the past, but the risks involved may be much greater. To minimize these risks, an intensive program of project identification and investigation is called for. To cope with these, the advisability of establishing some special organization at the Center, capable of providing specialist support to the States, should be reviewed and as the Draft Plan is replaced by successive rolling Plans, the allocation for investigations should be increased.

190. The second major feature of the investment program is the division between generation on the one hand and transmission and distribution on the other. Planning transmission and distribution requires detailed studies of individual schemes and of the system as a whole. The CEA has already initiated system planning studies. The first phase of this work has become the basis for the transmission program for India.

191. There is the evidence of the steady build-up of system losses to what is now, many assert, an unacceptably high level. From representing between 14 and 15.5% of generation between 1961 and 1966, the percentage rose sharply to about 20% by 1972/73 at which level it has remained roughly stable. While some of this increase may have been caused by the rapid progress in rural electrification, there is almost certainly a sizable remainder caused by a deterioration in the efficiency of the transmission and distribution system as a whole. This may well reflect an inadequate level of investment in transmission and distribution in the past. This view is supported by international data. Since the First Plan, when over 50% of expenditure was devoted to transmission and distribution, this percentage has been much lower -- between 23 and 26%. If rural electrification is included too, this

percentage has still been less than 50% in every Five-Year Plan after the first. The Draft Plan provision for transmission and distribution is almost exactly one-third of the total: somewhat more than in the Fifth Plan, but still quite low. In every Plan except the Third, expenditure on transmission and distribution has been a smaller proportion of the total than was the provision. Investment in transmission and distribution should bear some relation to investment in generating capacity. In a country the size of India, with its generally low load density and with its new sources of power (pit head stations and more remote hydro schemes) being some distance from load centers, one would expect at least one-half of the investment program to be devoted to transmission and distribution.

192. The new rolling Plan framework calls for an annual revision in the five-year economic program for the country, including the power sector. This planning system has yet to become fully effective. In the power sector, it may be difficult to undertake a complete reassessment so frequently, partly because the State planning agencies and the SEBs play so vital a role (the process of consultation in preparation for past Five-Year Plans has taken two to three years in the past) and partly because circumstances in the sector do not change that much that often. The Draft Plan provides for the first time a discussion of the ten-year demand prospects and investment program, and this is a step in the right direction. But for power planning, a still longer perspective is needed, since investments about which decisions are made now are not commissioned for at least four years and occassionally as much as ten years, and their economic life is at least another thirty years. The long-term plans must also be rolled forward and, of course, are likely to undergo more radical change than the five-year rolling Plan between revisions, but nonetheless, they should serve to ensure as far as possible that short-term plans make sense over the long term.

193. A larger power program will require more resources and the level of resources devoted to the power program in the Plan is already high: 35% of State Plans and 23% of the Central and State Plans taken together is presently devoted to power. The opportunity cost to the rest of the Plan is already considerable. The Draft Plan has proposed, and other Central Government sources have suggested, that a channel for funds other than the Plan assistance from the Center to the States may be needed. Specifically, the Draft Plan suggests that the feasibility of segregating funds for power generation schemes from the general flow of Plan funds, by creating a new national level financial institution if necessary, be examined. This proposal warrants careful consideration.

194. However, the requirement for funds cannot be met solely from the public purse. Increased internal resource generation in the SEBs is essential. Tariffs must be increased and rationalized not only so that they may more closely reflect marginal costs but perhaps more importantly to increase resources for power development. This will become crucial if more hydroelectricity is eventually deemed worth developing. The converse of the vicious circle of low tariffs, rapidly expanding demand and inadequate financial resources for expansion of capacity would be a regime of tariffs based on marginal costs leading to the more efficient use of power and generating adequate resources to expand investment and overcome the power shortages of the past.

ANNEXES

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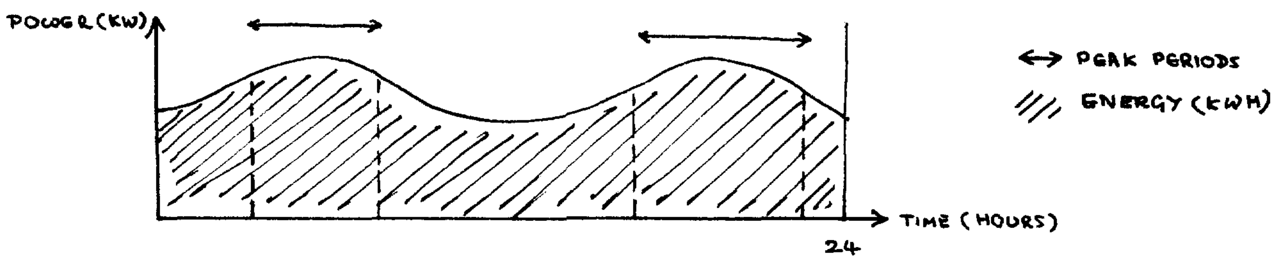
A NOTE ON POWER ENGINEERING TERMS FOR THE NON-ENGINEER

The distinction between power and energy is important at some points in this review. Power is the rate of consumption of energy; in discussing the supply of electricity, power is the amount supplied instantaneously while energy is the amount supplied over a period. Power is measured in KW or MW, while energy is measured in kwh or Mwh. Thus, with power on the vertical axis and time of day on the horizontal axis, if a graph is plotted to show the supply of power at each instant in a given power system, the area under the curve -- which is the daily load curve -- equals the energy supplied by the system.



The capacity of the system is the main determinant of the maximum power that can be supplied. Because daily load curves are typically peaked, it is usually possible to flatten the curve, lower the peaks and keep the same area under the curve. Thus, when capacity is short, administrative measures can sometimes be used to cut back the power demanded on the system without greatly affecting the energy demanded.

In discussing forecasts or the supply situation, there is also a distinction between "demand" and "supply" on the one hand and "requirements" and "availabilities" on the other. The former pair of terms is measured at the point of consumption, while the latter pair is measured at the bus bar, where power leaves the power station. The difference is losses in transmission and distribution.

A NOTE ON ECONOMIC TERMINOLOGY FOR THE NON-ECONOMIST

1. GNP, GDP, NDP and Value-added. GNP (Gross National Product), GDP (Gross Domestic Product) and NDP (Net Domestic Product) are all measures of the level of economic activity throughout the economy in any given year. Each measure is built up by summing the net value of production in different sectors. For example, in industry, from the value of production in each sub-sector is subtracted the value of inputs from other industries, from agriculture and the service sectors. This net value, the value-added for an industry can be added to that of other industries without double counting the activity of raw material and intermediate-input industries, to derive a value-added figure for all industry. Similarly, the value-added in each branch of agriculture and services can be defined, estimated and aggregated, and the grand total, the sum of value-added from all the branches or sectors of the economy is the GDP. The distinctions between GDP, GNP and NDP are: (i) the gross measures -- GDP and GNP -- make no allowance for the depreciation of capital as a cost to be subtracted in estimating value-added; NDP does, and is the more relevant though less easily estimated measure for most purposes; (ii) the domestic measures -- GDP and NDP -- are the sum of value-added of activities within the country, whereas the GNP includes for example income from labor working abroad -- the value-added due to the efforts or assets of nationals wherever they may be. GNP includes for example worker's remittances from abroad, while GDP and NDP do not.

2. SDP and RDP. The SDP (State Domestic Product) and RDP (Regional Domestic Product) are defined in a way exactly analagous to NDP at national level: the sum of value-added in all economic activities within the borders of the relevant unit concerned.

3. Industry, Agriculture and Services. Industry is defined in this Review to include mining and manufacturing. Agriculture is defined to include forestry and fishing as well as livestock and crop farming. Services, or the "other" or "residual" sector, embraces all other economic activities.

4. Constant Prices and Current Prices. The value of GDP has risen over the last several years both because economic activity has increased and prices have risen. In many circumstances, it is useful to concentrate on the increase in economic activity alone, and then the GDP figures must be adjusted to remove the effect of inflation. Suppose, for example, GDP in a given country was Rs 20 billion in 1960 and Rs 50 billion in 1970, and the level of prices increased by 50% over this period. Then Rs 50 billion in 1970 was worth Rs 50 ÷ 1.5 or Rs 33 billion in 1960. Thus the "real" or "actual" increase in GDP was from Rs 20 billion in 1960 to Rs 33 billion in 1970, measured in "constant 1960" prices. To make the distinction quite clear, in some contexts one can say by contrast that the "nominal" increase in GDP was from Rs 20 billion in 1960 to Rs 50 billion in 1970; here GDP is measured in "current" prices. The distinction between constant and current prices can be drawn in measuring changes in many other economic indicators apart from GDP.

5. Efficiency. "Efficiency" in an economic discussion has a broader connotation than in a technical context. While a process may be efficient in that energy is converted with least loss, or a product is manufactured with minimum energy use, the activity is inefficient from the economic viewpoint if the service or product could be produced more cheaply by using different inputs, or by using a different technology and combination of inputs. In general, an activity is efficient if it provides a particular product or service at the least resource cost to the economy as a whole.

6. Market Prices, Opportunity Costs and Shadow Pricing. Market prices are simply the price an individual or organization must pay for a particular service or product in the course of a normal market transaction. Shadow pricing is a technique used in the analysis of investment alternatives whereby so-called "shadow" prices are used in place of market prices to evaluate project costs and benefits. The object is to more accurately reflect the costs and benefits to the economy at large, rather than merely the private costs to the individual parties to each transaction. For example, consider a situation where unemployment or underemployment is a feature of the district in which a project is to be sited. The analysis of the investment calls for a comparison between two alternatives, one of which uses a good deal more labor than the other. Then, if costs are valued at market prices, -- the market price for labor being the hourly or daily wage actually paid -- they will overstate the cost to the economy at large. This is so since if more labor were employed, little is lost: GDP would not fall appreciably since labor is not being taken out of other employment. In other words, the opportunity cost of this additional employment is small. To reflect this in calculating costs of the two alternatives, a lower wage rate, the "shadow wage" rate, below the market wage rate, can be assigned to labor employed. Similarly, raw materials, capital, foreign exchange and infrastructure costs can all be shadow priced, so that the choice of project or project design reflects the real costs and benefits to the economy as a whole.

7. Long Run Marginal and Incremental Costs. Marginal or incremental cost is simply the first derivative of cost. In manufacturing, marginal costs are the costs to the enterprise of making one extra unit of output. In the power sector, the marginal cost is the cost of providing one extra KW of capacity or supplying one extra kwh of energy.

The distinction between the short run and the long run is whether or not additional investment is taken into account. The short run marginal cost includes only operating cost: it is not possible in the short run to add to capacity to meet extra, unanticipated demand. Long run marginal costs comprise both capital and recurrent, operating costs; in the long run the capacity expansion program can be accelerated to meet extra demand.

8. Coal replacement measure. In order to aggregate or compare different types of energy, a method of rendering them equivalent is needed. Since the Energy Survey Committee of India (1962), the common unit of energy most widely used in India is that of coal replacement. Products manufactured from coal, such as coke, are measured by the amount of coal needed to produce one ton. Electricity is measured in terms of how much coal is required to generate one kwh in a representative thermal power station. In the case of petroleum products, the quality of coal needed to substitute in a particular application is taken to measure the energy value. For example, the Energy Survey Committee determined that about 9 tons of coal were needed to replace one ton of diesel oil for locomotive use on Indian railways. In this manner, energy in a variety of forms and applications can be reduced to one standard unit of value and compared or aggregated.

It should be noted that other measures for aggregating energy exist, and in particular there are two or three which rely on the heat value of different energy forms. Clearly comparisons and aggregations performed using these alternative measures can lead to different results that may sometimes affect the inferences to be drawn from a discussion.

A NOTE ON ANNEX SOURCES

The main sources for the statistical data in these Annexes are listed below. To refer to these sources in the Annexes themselves, the acronyms given in brackets are used.

(i) Public Electricity Supply, All India Statistics, General Review;

Central Electricity Authority, Ministry of Energy; various years (GR)

(ii) The National Accounts;

Central Statistical Office, January 1978 (NA)

(iii) The Reserve Bank of India Bulletin, Supplement on State Domestic Product and Other Economic Accounts;

The Reserve Bank of India, May 1978 (RBI)

(iv) The Working Group Report on Power Development: 1978/79 to 1982/83;

Ministry of Energy, February 1978 (WGR)

(v) The Report of the Working Group for Assessing the Revised Power Demand and Energy Requirement for the Five Year Plan: 1978-83;

Planning Commission and the Central Electricity Authority; May 1978 (DPCF) 1/

(vi) The Draft Plan: 1978-83;

Planning Commission (DP)

1/ Referred to in Volume I as the disaggregated Planning Commission Forecast.

(vii) <u>All India Electricity Rate Books; 1972 and 1976</u>;

Central Electricity Authority, Ministry of Energy (ERB)

(viii) <u>The Power Supply Position in the Country:</u>

The Central Electricity Authority, Ministry of Energy; various months (PSP)

GROWTH RATES OF BASIC ELECTRICITY SECTOR INDICATORS

	The Longer Term		The 1970s	
	Period	Average Annual Growth Rate	Period	Average Annual Growth Rate
1. Installed Capacity	1950-1977/78		1970/71-1977/78	
1.1 Hydro		10.8%		6.6%
1.2 Conventional Thermal		9.5%		8.0%
1.3 Nuclear		-		6.2%
1.4 Total (Utilities)		9.9%		7.2%
1.5 Total (including non-utilities)		9.1%		7.0%
2. Gross Electricity Generation				
2.1 Utilities	1951-1977/78	11.1%	1970/71-1977/78	7.4%
2.2 Total (including non-utilities)	1951-1976/77	10.7%	1970/71-1976/77	7.7%
3. Electricity Consumption				
3.1 Total	1951-1976/77	10.3%	1970/71-1976/77	7.4%
3.2 Per Capita	1960/61-1976/77	7.4%	1971/72-1976/77	4.9%

Source: GR

GROSS ELECTRICITY GENERATED ACCORDING TO PRIMARY FUELS
(Utilities Only)1/

	1951	1956	1960/61	1965/66	1968/69	1970/71	1971/72	1972/73	1973/74	1974/75	1975/76	1976/77	1977/78
1. Absolute amounts (GWh)													
Hydro	2,860	4,295	7,837	15,225	20,723	25,248	28,024	27,196	28,972	27,875	33,302	34,836	38,001
Conventional Thermal	2,779	5,135	8,732	17,372	26,394	27,797	31,237	35,614	34,853	39,539	42,760	49,744	50,560
Nuclear	-	-	-	-	-	2,417	1,189	1,132	2,396	2,206	2,627	3,252	2,272
Other 2/	219	233	368	393	317	366	475	603	468	571	542	501	453
Total	5,858	9,662	16,937	32,990	47,434	55,828	60,925	64,546	66,689	70,191	79,231	88,333	91,286
2. Relative shares 3/ (percentages)													
Hydro	49	44	46	46	44	45	46	42	43	40	46	39	41.5
Conventional Thermal	47	53	52	53	56	50	51	55	52	56	49	56	55.5
Nuclear	-	-	-	-	-	4	2	2	4	3	4	4	2.5
Other 2/	4	2	2	1	1	1	1	1	1	1	1	1	0.5
Total	100	100	100	100	100	100	100	100	100	100	100	100	100

1/ Almost all generation by non-utilities is from conventional thermal stations
2/ Gas turbine and diesel
3/ Subtotals may not add up to totals because of rounding.

Source: GR

ANNEX B.1.2

CONVENTIONAL THERMAL POWER STATIONS: CONSUMPTION OF PRINCIPAL FUELS; 1965/66 - 1976/77

	Units	1965/66	1971/72	1973/74	1974/75	1975/76	1976/77	Trended Annual Growth Rate (1965/66-1976/77)
Amounts Consumed								
Coal	(million tonnes)	10.27	16.19	18.31	21.68	24.29	28.27	8.9%
Lignite	(million tonnes)	2.18	3.02	2.88	2.45	2.39	3.13	1.9%
Fuel Oil	(million kilolitres)	0.61	1.42	1.81	1.97	1.87	1.91	11.0% 3/
Gas	(million cu.meters)	n.a.	142	153.781	113.41	143.33	172.0	2.2% 2/
Shares in Primary Energy Consumed 1/								
Coal		85	82	82	84	86	86	
Lignite		7	6	5	4	3	4	
Oil		8	12	13	12	11	10	
Total		100	100	100	100	100	100	

1/ Excluding gas, which in 1971/72 accounted for less than 2%; these figures are estimated using the same conversion factors as used by D. Henderson in "India: The Energy Sector", which in turn was based on data on heat input into steam power stations by state.

2/ 1971/72 - 1976/77

3/ The level of fuel oil consumption is thought to have fallen in 1977/78, due to conservation efforts.

Source: GR

ELECTRICITY AND NDP: CAPITAL AND GROWTH: 1950-1971

		1950	1950-61 Increments	1961	1961-71 Increments	1971	Average Annual Growth Rate 1950-1971
		(millions of 1960/61 Rupees)					(%)
Electricity	- Capital 1/	3220	8560	11780	21130	32910	11.7
	- Value Added 2/	180	520	700	1310	2010	12.2
	- COR 4/	17.9	-	16.8	-	16.3	-
	- ICOR	-	16.5	-	16.1	-	-
Other Sectors	- Capital 1/	237490	109840	347330	224210	571540	4.3
	- NDP 2/	91430	45370	136800	54500	191300	3.6
	- COR 4/	-	-	-	-	-	-
	- ICOR	-	2.4	-	4.1	-	-
Total 3/	- Capital 1/	240710	118400	359110	245340	604450	4.5
	- NDP 2/	91610	45890	137500	55810	193310	3.6
	- COR 4/	2.6	-	2.6	-	3.1	-
	- ICOR	-	2.6	-	4.4	-	-

Source: Tables 1 and 2 of "Capital and Growth in India: 1950-71".

1/ Capital is reproducible tangible assets, which is roughly the same as net fixed assets for the electricity sector.

2/ The revised figures for 1950/51 are used; the NDP figures whown are in fact for 1950/51, 1961/62 and 1971/72.

3/ Total here includes house property and other services but not "actual" agriculture as distinct from agriculture reported in the national accounts.

4/ COR stands for the average capital output ratio.

ELECTRICITY GENERATED, GROSS AND NET

	1951	1956	1960/61	1965/66	1968/69	1970/71	1971/72	1972/73	1973/74	1974/75	1975/76	1976/77	1977/78
1. Absolute amounts (Gwh)													
Utilities: Public sector	2,458	5,294	11,016	26,072	40,391	49561	53,990	57,216	60,683	63,910	72,572	81,995	n.a.
Private sector	3,400	4,368	5,921	6,918	7,043	6,267	6,935	7,330	6,006	6,281	6,659	6,338	n.a.
Total, utilities	5,858	9,662	16,937	32,990	47,434	55,828	60,925	64,546	66,689	70,191	79,231	88,333	91,286
Non-utilities 1/	1,656	2,210	3,186	3,835	4,208	5,384	5,459	5,970	6,107	6,488	6,695	7,282	7,900 3/
Total gross generation	7,514	11,872	20,123	36,825	51,642	61,212	66,384	70,516	72,796	76,679	85,926	95,615	99,186 3/
Less consumption of power station auxiliaries 2/	218	386	722	1,647	2,532	3,433	3,723	4,036	3,615	4,130	4,556	5,334	5,526 3/
Total net generation	7,296	11,486	19,401	35,178	49,110	57,779	62,661	66,480	69,181	72,548	81,370	90,381	93,660 3/
Less line losses	864	1,335	2,486	4,621	7,215	9,306	10,862	12,230	12,931	13,556	14,526	16,446	16,855
Electricity consumption	6,432	10,151	16,915	30,557	41,895	48,473	51,799	54,250	56,250	58,991	66,844	74,335	76,805 3/
2. Relative shares (percentages)													
Utilities: Public sector	33	45	55	71	78	81	82	81	83	83	84	86	n.a.
Private sector	45	37	29	19	14	10	10	10	9	9	8	6	n.a.
Total, utilities	78	81	84	90	92	91	92	92	92	92	92	92	92
Non-utilities	22	19	16	10	8	9	8	8	8	8	8	8	8
Total gross generation	100	100	100	100	100	100	100	100	100	100	100	100	100
Total net generation	97	97	96	96	95	94	94	94	95	95	95	94	94
Line losses	11	11	12	13	14	15	16	17	18	18	17	17	17
Electricity consumption	86	86	84	83	81	79	78	77	77	77	78	77	77
3. Losses													
Line losses as a percentage of electricity sent out by utilities	15.3	14.4	15.3	14.7	16.1	17.8	19.0	20.2	20.5	20.5	19.4	19.8	19.6

1/ For non-utilities, the figures for 1951, 1956 and 1960/61 exclude the amounts generated by the railways, which, however, are a very small fraction the total.

2/ Figures apply to utilities only.

3/ Mission Estimates.

n.a. = not available

Source: GR

SALES OF ENERGY TO ULTIMATE CONSUMERS BY DIFFERENT SUPPLYING AGENCIES

	1971/72		1974/75		1975/76		1976/77	
	Amount Supplied (GWH)	Relative Share (%)	Amount Supplied (GWH)	Relative Share (%)	Amount Supplied (GWH)	Relative Share (%)	Amount Supplied (GWH)	Relative Share (%)
1. State Electricity Boards	31.28	66	37.02	70	43.66	73	48.96	74
2. Other public sector;	6.12	13	6.05	12	7.20	12	7.84	12
(a) Municipalities	(2.58)	(5.5)	(2.98)	(6)	(3.02)	(5)	(3.26)	(5)
(b) Corporations and governmental departments	(3.54)	(7.5)	(3.07)	(6)	(4.18)	(7)	(4.58)	(7)
Total, Public Sector	37.40	79	43.07	82	50.86	85	56.80	86
3. Private Sector	9.66	21	9.57	18	9.39	15	9.81	14
Total, all utilities	47.06	100	52.63	100	60.25	100	66.61	100

Source: GR

GROWTH OF NDP AND ELECTRICITY CONSUMPTION

FOR ALL INDIA

Year	Pumpset Electrification ('000)	Electricity Consumption: Agriculture	Electricity Consumption: Industry 1/	Electricity Consumption: Services	Electricity Consumption: Total	Net Domestic Product: Agriculture	Net Domestic Product: Industry	Net Domestic Product: Services	Net Domestic Product: Total
		Gwh				(Rs Million 1960/61 prices)			
1960/61	199	833	9696	3424	13953	68310	26830	38210	133350
1961/62	241 2/	991	11545	3912	16448	68890	28870	40490	138250
1962/63	291 2/	1104	13110	4465	18679	67080	30910	43040	141030
1963/64	351 2/	1153	15842	4799	21794	68980	33860	45980	148820
1964/65	424 2/	1397	17379	5443	24219	75160	36330	48790	160280
1965/66	513	1892	18876	5967	26735	64790	37410	50140	152340
1966/67	659 2/	2107	20391	6630	29128	64000	37820	51830	153650
1967/68	847 2/	2585	22852	7300	32737	73770	39020	53650	166440
1968/69	1089	3466	25891	7995	37352	74140	40730	56250	171120
1969/70	1332 2/	3774	28379	8909	41062	78770	44140	59110	182020
1970/71	1629	4470	29579	9675	43724	85450	45260	62110	192820
1971/72	1901	5006	31637	10420	47063	83700	45700	65460	194860
1972/73	2185	5918	32244	10926	49088	77630	47460	67260	192350
1973/74	2426	6310	32481	11455	50246	84410	48770	69630	202810
1974/75	2614	7763	32690	12179	52632	82240	49930	71740	202810
1975/76	2792	8721	37568	13957	60246	90163	52701	77366	220230
1976/77 3/	3029	9634	41501	15418	66553	85399	57168	81959	224526
1977/78 3/	-	10061	42454	16448	68963	-	-	-	-
Annual Growth Rates									
1960/61-1968/69	23.7%	19.5%	13.1%	11.2%	13.1%	1.0%	5.4%	5.0%	3.2%
1960/61-1975/76	19.3%	16.9%	9.4%	9.8%	10.2%	1.9%	4.6%	4.8%	3.4%

1/ Excluding captive generation
2/ Estimate
3/ Provisional
Source: GR, NA

ANNEX I.1.1

RELATIVE SHARES IN NET ELECTRICITY CONSUMPTION[1/]

(PERCENTAGES)

	1960/61	1965/66	1968/69	1970/71	1971/72	1972/73[2/]	1973-74[2/]	1974/75	1975/76	1976/77
Agriculture and irrigation	5.0	6.3	8.4	9.2	9.7	10.9	11.3	13.3	13.2	13.2
Railway traction	2.7	3.5	3.0	2.8	3.2	3.4	2.8	2.6	2.8	3.0
Industry	74.5	74.0	72.1	70.9	70.2	68.9	68.0	65.8	65.7	65.7
Commercial and government	5.1	5.4	5.2	5.3	5.7	5.1	5.4	5.3	5.3	5.7
Public lighting	1.2	0.9	0.9	1.0	0.9	1.0	1.0	1.0	0.9	0.8
Domestic	8.9	7.8	7.8	7.9	7.9	8.0	8.4	8.9	8.8	8.7
Public water works, drainage and miscellaneous	2.6	2.1	2.6	2.9	2.4	2.7	3.1	3.1	3.3	2.9

1/ Including non-utilities, of which the output goes almost entirely to industry.
2/ The percentages shown for the years 1972-73 and 1973-74 are actuals taking into account purchase and captive generation.

Source: GR

INDIA - THE RELATIONSHIP BETWEEN VALUE ADDED AND CONSUMPTION: 1960/61 - 1975/76

	1960/61			1965/66			1970/71			1975/76		
	Value added (Rs billion at 1960/61 prices)	Electricity Consumption (Gwh)	Electricity per unit of value added (Gwh/Rs billion)	Value added (Rs billion at 1960/61 prices)	Electricity Consumption (Gwh)	Electricity per unit of value added (Gwh/Rs billion)	Value added (Rs billion at 1960/61 prices)	Electricity Consumption (Gwh)	Electricity per unit of value added (Gwh/Rs billion)	Value added (Rs billion at 1960/61 prices)	Electricity Consumption (Gwh)	Electricity per unit of value added (Gwh/Rs billion)
Agriculture	68.3	833	12.2	64.8	1892	29.2	85.5	4470	52.3	90.1	8721	96.8
Industry 1/	26.8	12696	473.7	37.4	22609	604.5	45.3	34926	771.0	52.7	44225	839.2
Other	38.2	3424	89.6	50.1	5967	119.1	62.1	9675	155.8	77.4	13957	180.3
Total	133.3	16953	127.1	152.3	30468	200.1	192.8	49071	254.5	220.2	66903	303.8

1/ Including captive generation in electricity consumption figures.

Sources: GR, NA

THE DECOMPOSITION OF CHANGES IN ELECTRICITY CONSUMPTION BY SECTOR: 1960/61 - 1975/76
(Gwh)

	1960/61 - 1965/66				1965/66 - 1970/71				1970/71 - 1975/76				1960/61 - 1975/76			
	Change in Value Added Alone	Change in Electricity Coefficient	Change in Electricity Coefficient Applied to Value Added Change	Total Change	Change in Value Added Alone	Change in Electricity Coefficient	Change in Electricity Coefficient Applied to Value Added Change	Total Change	Change in Value Added Alone	Change in Electricity Coefficient	Change in Electricity Coefficient Applied to Value Added Change	Total Change	Change in Value Added Alone	Change in Electricity Coefficient	Change in Electricity Coefficient Applied to Value Added Change	Total Change
Agriculture	-43 (-0.3)	1161 (8.6)	-60 (-0.4)	1059 (7.8)	604 (3.2)	1497 (8.0)	478 (2.6)	2578 (13.9)	241 (1.1)	3805 (17.7)	205 (1.0)	4251 (19.7)	266 (0.5)	5778 (11.6)	1844 (3.7)	7888 (15.8)
Industry	5021 (37.2)	3505 (25.9)	1386 (10.3)	9913 (73.3)	4776 (25.7)	6227 (33.5)	1315 (7.1)	12317 (66.2)	5705 (26.5)	3089 (14.3)	505 (2.3)	9299 (43.2)	12269 (24.6)	9795 (19.6)	9466 (19.0)	31529 (63.1)
Other	1066 (7.9)	1127 (8.3)	351 (2.6)	2543 (18.8)	1429 (7.7)	1839 (9.9)	440 (2.4)	3708 (19.9)	3251 (15.1)	3066 (14.2)	1671 (7.8)	7990 (37.1)	3512 (7.0)	3465 (6.9)	3555 (7.1)	10533 (21.1)
Total	6044 (44.7)	5793 (42.9)	1677 (12.4)	13515 (100.0)	6809 (36.6)	9563 (51.4)	2233 (12.0)	18603 (100.0)	9197 (42.7)	9960 (46.2)	2381 (11.1)	21540 (100.0)	16047 (32.1)	19038 (38.1)	14865 (29.8)	49950 (100.0)

Source: Annex I.1.3

GROWTH OF NDP AND ELECTRICITY CONSUMPTION IN THE NORTHERN REGION

Year	Pumpset Electrification	Electricity Consumption				Net Domestic Product			
		Agriculture	Industry	Services	Total	Agriculture	Industry	Services	Total
	('000)	Gwh				(Rs. Million 1960/61 prices)			
1960/61	23.1	285	1069	735	2089	18690	3230	11290	33210
1961/62	28.5 1/	346	1892	860	3098	19190	3450	11870	34510
1962/63	35.1 1/	332	2407	1069	3808	18440	3620	12300	34360
1963/64	43.2 1/	300	3428	1072	4800	17470	3760	12650	33880
1964/65	53.2 1/	351	3801	1153	5305	20320	3970	13650	37940
1965/66	65.6	554	3932	1172	5658	18510	4200	14000	36710
1966/67	95.4 1/	679	4518	1356	6553	17800	4370	14070	36240
1967/68	138.8 1/	657	4584	1875	7116	21720	4100	14750	40570
1968/69	201.9	1110	5877	1795	8782	19800	4530	15150	39480
1969/70	253.1 1/	1333	6436	2016	9785	22590	5050	16260	43900
1970/71	317.2 1/	1614	5693	2123	9430	25150	5230	17400	47780
1971/72	397.5 1/	1797	6128	2199	10124	22690	5430	18010	46130
1972/73	498.2	2194	6274	2421	10889	22730	5640	18870	47240
1973/74	567.3	2383	6194	2623	11200	23060	5830	19520	48410
1974/75	611.8	2830	5771	2780	11381	23350	6100	19580	49030
1975/76	653.8	3576	7408	3482	14466	26120	6750	20970	53840
Annual Growth Rate									
1960/61 -1968/69	31.1%	17.0%	19.9%	11.8%	17.1%	0.7%	4.3%	3.7%	2.2%
1960/61 -1975/76	25.0%	18.4%	13.8%	10.9%	13.8%	2.3%	5.0%	4.2%	3.3%

1/ Estimated.

Note: The data are for Haryana, Jammu and Kashmir, Rajasthan, Delhi and Uttar Pradesh. Himachal Pradesh is excluded for lack of data on the level of economic activity there.

Sources: GR, RBI

ANNEX 1.1.5

GROWTH OF NDP AND ELECTRICITY CONSUMPTION IN THE WESTERN REGION

Year	Pumpset Electrification ('000)	Electricity Consumption: Agriculture	Electricity Consumption: Industry	Electricity Consumption: Services	Electricity Consumption: Total	Net Domestic Product: Agriculture	Net Domestic Product: Industry	Net Domestic Product: Services	Net Domestic Product: Total
		Gwh				(Rs. Million 1960/61 prices)			
1960/61	16.0	39	2960	1111	4110	14830	6230	10610	31670
1961/62	21.3 1/	60	3534	1222	4816	14430	6690	11200	32320
1962/63	28.4 1/	71	3878	1332	5281	14100	6850	11660	32610
1963/64	37.8 1/	72	4432	1159	5663	14840	7370	12340	34550
1964/65	50.3 1/	137	4933	1653	6723	15600	7880	12910	36390
1965/66	67.0	202	5587	1755	7544	12070	8320	13190	33580
1966/67	95.1 1/	325	6082	1952	8359	12300	8720	13750	34770
1967/68	135.0 1/	398	6789	2325	9512	15550	8900	14330	38780
1968/69	191.7	610	6841	3191	10642	14220	9010	15440	38670
1969/70	243.4 1/	714	8497	2583	11794	15130	9820	15820	40770
1970/71	308.9 1/	826	9184	2845	12855	16540	10260	16740	43540
1971/72	392.2 1/	920	9907	3226	14053	16780	10710	17600	45090
1972/73	497.8	1239	10491	3330	15060	12480	11400	17890	41770
1973/74	560.9	1242	10898	3261	15401	15980	11880	18920	46780
1974/75	627.9	1839	11489	3617	16945	15420	11960	19310	46690
1975/76	680.7	1842	12032	4017	17891	19200	12300	20670	52170
Annual Growth Rates									
1960/61-1968/69	36.4%	41.0%	11.0%	14.1%	12.6%	-0.5%	4.7%	4.8%	2.5%
1960/61-1975/76	28.4%	29.3%	9.8%	8.9%	10.3%	1.7%	4.6%	4.5%	3.4%

Note: Data are for Gujarat, Maharashtra and Madhya Pradesh.
Sources: GR and RBI

GROWTH OF NDP AND ELECTRICITY CONSUMPTION IN THE SOUTHERN REGION

Year	Pumpset Electrification ('000)	Electricity Consumption: Agriculture	Industry	Services	Total	Net Domestic Product: Agriculture	Industry	Services	Total
		------------------ Gwh	------------------			------- (Rs. Million	1960/61 prices)		-----
1960/61	155.2 1/2/	485	2431 2/	742	3658	17970	3500	10470	31940
1961/62	184.0 1/	553	2686 2/	995	4214	18120	3810	11020	32950
1962/63	218.1 1/	662	2968 2/	864	4512	18220	4030	11420	33670
1963/64	258.5 1/	747	3280 2/	951	4978	18410	4350	12120	34880
1964/65	306.4 1/	867	3624 2/	1144	5635	19310	4680	12530	36520
1965/66	363.2 1/	1082	4005 2/	1315	6402	17070	4990	13030	35090
1966/67	438.5 1/	1029	4560 2/	1247	6836	18160	5130	13610	36900
1967/68	529.3 1/	1425	5191 2/	1627	8243	18990	5360	14780	39130
1968/69	639.0 1/	1631	5910	1686	9227	18400	5640	15580	39620
1969/70	691.5 1/	1606	6893	1874	10373	19280	6020	16110	41410
1970/71	748.3 1/	1903	7738	2196	11837	21510	6380	16820	44710
1971/72	809.9 1/	2179	8421	2199	12799	22000	6720	17640	46360
1972/73	876.4	2333	8141	2212	12686	20750	7030	17880	45660
1973/74	1170.6	2543	8315	2552	13410	22800	7160	19320	49280
1974/75	1241.1	2920	8196	2580	13696	22060	7680	19600	49340
1975/76	1309.2	2744	9760	2906	15410	24160	8130	20350	52640
Annual Growth Rate									
1960/61 -1968/69	19.4%	16.4%	11.7%	10.8%	12.3%	0.3%	6.1%	5.1%	2.7%
1960/61 -1975/76	15.3%	12.2%	9.7%	9.5%	10.1%	2.0%	5.8%	4.5%	3.4%

1/ Estimated.

2/ Tamil Nadu data was not available for industry for these years; Therefore we have estimated these values to fit log linear trends between the available more comprehensive observations of other years.

Note: Data are for Andhra Pradesh, Karnataka, Kerala and Tamil Nadu
Sources: GR and RBI

ANNEX I.1.8

GROWTH OF NDP AND ELECTRICITY CONSUMPTION IN THE EASTERN REGION

Year	Pumpset Electrification ('000)	Electricity Consumption				Net Domestic Product			
		Agriculture	Industry	Services	Total	Agriculture	Industry	Services	Total
		Gwh				(Rs. Million 1960/61 prices)			
1960/61	3.3	20	3042	860	3922	13040	4730	9290	27060
1961/62	4.2 1/	24	3274	945	4243	13260	4790	9630	27680
1962/63	5.4 1/	26	3826	1137	4989	13070	5470	10110	28650
1963/64	6.8 1/	24	4570	1234	5828	13930	5960	10240	30130
1964/65	8.7 1/	26	4979	1415	6420	14470	6320	11030	31820
1965/66	11.1	35	5289	1651	6975	13280	6710	11300	31290
1966/67	18.5 1/	58	5271	1839	7168	12020	6510	11420	29950
1967/68	31.0	75	5583	1847	7505	13760	6170	11310	31240
1968/69	51.7	86	5076	3367	8529	14310	6370	11730	32410
1969/70	59.7 1/	93	5146	3298	8537	14580	6830	12090	33500
1970/71	69.0 1/	101	6653	2185	8939	15510	6700	12300	34510
1971/72	79.7 1/	81	6969	2280	9331	15730	6810	12760	35300
1972/73	92.0	119	7097	2386	9602	15280	7030	12810	35120
1973/74	106.2	112	6883	2314	9309	15520	7820	12800	36140
1974/75	115.2	124	7035	2450	9609	15610	8030	13080	36720
1975/76	133.3	515	8642	2721	11363	16640	8010	13330	37980
Annual Growth Rates									
1960/61 - 1968/69	39.5%	20.6%	7.7%	15.6%	10.0%	0.4%	4.1%	3.0%	2.0%
1960/61 - 1975/76	31.1%	29.8%	16.0%	9.9%	6.9%	1.6%	3.1%	2.3%	2.3%

1/ Estimated

Note: Data are for Bihar, Orissa and West Bengal.

Sources: GR and RBI

ANNEX 1.1.9

GROWTH OF NDP AND ELECTRICITY CONSUMPTION IN THE NORTH EASTERN REGION

Year	Pumpset Electri-fication ('000)	Electricity Consumption: Agri-culture	Electricity Consumption: Industry	Electricity Consumption: Services	Electricity Consumption: Total	Net Domestic Product: Agri-culture	Net Domestic Product: Industry	Net Domestic Product: Services	Net Domestic Product: Total
		Gwh				(Rs. Million 1960/61 prices)			
1960/61	-	-	12	19	31	1920	640	920	3480
1961/62	-	-	15	20	35	1900	690	1040	3630
1962/63	-	-	18	22	40	1890	750	1140	3780
1963/64	-	-	23	28	51	1880	810	1250	3940
1964/65	-	-	31	31	62	1870	880	1340	4090
1965/66	-	-	24	36	60	1870	960	1440	4270
1966/67	-	-	42	48	89	1990	1020	1400	4410
1967/68	-	0.0	47	65	112	2060	1080	1420	4560
1968/69	0.1	0.4	99	95	194	2160	1150	1410	4720
1969/70	0.2 1/	0.4	139	119	258	2250	1220	1410	4880
1970/71	0.3 1/	0.3	164	129	293	3210	1300	1440	5050
1971/72	0.4 1/	1.0	212	143	356	2360	1310	1550	5220
1972/73	0.7	2.0	240	167	409	2670	1360	1600	3650
1973/74	0.7	2.0	192	226	420	2720	1400	1750	5870
1974/75	0.9	5.0	199	256	460	2700	1510	1960	6170
1975/76	1.0	6.0	241	272	519	2810	1570	2110	6490
Annual Growth Rates									
1960/61-1968/69	n.a.	n.a.	30.2%	22.3%	25.8%	1.5%	7.6%	5.5%	3.9%
1960/61-1975/76	n.a.	n.a.	22.1%	19.4%	20.7%	2.6%	6.2%	5.7%	4.2%

1/ Estimated

Note: Data are for Assam and Manipur only. Data on NDP are not available for the other states in the North Eastern Region for this period.

Sources: GR and RBI

ELECTRICITY CONSUMPTION AND VALUE ADDED BY REGION AND BY SECTOR (UTILITIES ONLY): 1975/76

	Absolute Amounts				Percentage Distribution			
	Agriculture	Industry	Other	Total	Agriculture	Industry	Other	Total
Value-added (Rs billion - 1960/61 prices)								
Northern Region	26.1	6.8	21.0	53.8	29.4	18.4	27.1	26.5
Western Region	19.2	12.3	20.7	52.2	21.6	33.4	26.7	25.7
Southern Region	24.2	8.3	20.4	52.6	27.3	22.4	26.3	25.9
Eastern Region	16.4	8.0	13.3	38.0	18.5	21.6	17.2	18.7
North Eastern Region	2.8	1.6	2.1	6.5	3.2	4.3	2.7	3.2
Total	88.7	37.0	77.5	203.1	100.0	100.0	100.0	100.0
Electricity Consumption (Gwh)								
Northern Region	3576	7408	3482	14466	41.2	19.5	26.0	24.3
Western Region	1842	12032	4017	17891	21.2	31.6	30.0	30.0
Southern Region	2744	9760	2906	15410	31.6	25.6	21.7	25.8
Eastern Region	515	8642	2721	11363	5.9	22.7	20.3	19.0
North Eastern Region	6	241	272	519	0.1	0.6	2.0	0.9
Total	8683	38083	13398	59649	100.0	100.0	100.0	100.0

Source: Annexes I.1.5-I.1.9

THE DECOMPOSITION OF CHANGES IN ELECTRICITY CONSUMPTION BY REGION (UTILITIES ONLY): 1960/61-1975/76

Region	1960/61			1975/76			1960/61-1975/76			
	Value Added (Rs billion at 1960/61 prices)	Electricity Consumption (Gwh)	Electricity per unit of Value Added (Gwh/Rs billion)	Value Added (Rs billion at 1960/61 prices)	Electricity Consumption (Gwh)	Electricity per unit of Value Added (Gwh/Rs billion)	Change in Value Added Alone	Change in Electricity Coefficient	Change in Electricity Coefficient Applied to Value Added Change	Total Change
Northern	33.2	2089	62.9	53.8	14466	268.9	1296 (2.7)	6839 (14.5)	4244 (9.0)	12377 (26.3)
Western	31.7	4110	129.7	52.2	19200	367.8	2659 (5.6)	7548 (16.0)	4881 (10.4)	15090 (32.0)
Southern	31.9	3658	114.7	52.6	15410	293.0	2374 (5.0)	5688 (12.1)	3691 (7.8)	11752 (24.9)
Eastern	27.1	3922	144.7	38.0	11363	299.0	1577 (3.3)	4182 (8.9)	1682 (3.5)	7441 (15.8)
North Eastern	3.5	31	8.9	6.5	519	79.8	27 (0.1)	248 (0.5)	213 (0.5)	488 (1.0)
TOTAL 1/	127.4	13810	108.4	203.1	60958	300.1	1933 (16.8)	24505 (52.0)	14711 (31.2)	47148 (100.0)

1/ Totals do not correspond exactly to all India data, because certain states -- Manipur and Tripura in the North Eastern Region -- have not been covered in Annexes I.1.5-I.1.9.

Source: Annex I.1.10

THE MOVEMENT OF ELECTRICITY INTO RURAL MANUFACTURING : THE EVIDENCE OF THE CENSUSES

There has been a marked increase in the proportion of industrial establishments using electricity in rural areas. While the general phenomenon of rural electrification is readily apparent from data on agricultural use, pumpset and village electrification, it is not widely recognised that a significant part of this shift has affected rural industry. The census data for 1960 and 1970 show that the proportion of rural establishments using electricity throughout India increased from 1.2% to 5.4% over this period, compared with an increase from 14.1% to 18.9% in the comparable urban figures (Table 1).

There are certain difficulties in using the census data in this way. First, the character and size of different establishments is not reflected in these statistics: the larger establishments are likely to constitute a higher proportion of urban establishments than rural. Second, the census does not cover all household and factory enterprises: establishments below a certain size are not included, with the result that the proportion of establishments using electricity will be over-stated, especially in rural areas. Third, the definition of what constitutes rural areas is not necessarily comparable with the areas covered by rural electrification schemes. Moreover, between censuses an area which was formerly classified rural may develop to such an extent that it is re-classified by the time of the second census as urban.

Despite all these caveats the evidence from the census is at least highly suggestive. In 1960 there were only four states where more than 6% of rural establishments used electricity (Table 2). These were Kerala in the Southern Region and Punjab, Haryana and Himachal Pradesh, taken together, in the Northern Region. These four states had fairly high percentages of urban establishments using electricity, but so did Gujarat, Maharashtra, West Bengal, Karnataka, Andhra Pradesh, Rajasthan and Jammu & Kashmir, with over 10% of their urban industrial establishments electrified. These seven states had only one or two percent of their rural establishments electrified.

By 1970, the number of states that had reached the point where about 10% of their rural establishments used electricity, had increased and included Maharashtra, Gujarat and Karnataka. While the proportion of establishments using electricity in urban areas did indeed rise in almost every state between 1960 and 1970, the rate of increase is more modest. The exception was West Bengal, perhaps reflecting the depressed state of the electricity supply industry and of the Eastern Region economy as a whole.

The most important industry groups using electricity in 1960 in rural areas were food products, petroleum and coal products, and machinery (Tables 1 and 3). These three industries all show about 5% of establishments using electricity in urban areas but the proportion of electricity-using establishments in these industries was high. But it is also high in other chemicals, paper products and petroleum and coal products both increased the proportion of establishments using electricity. The proportion for machinery appears to have declined in both rural and urban areas, which is surprising. It seems likely that some marginal redefinition of this particular industry may account for this decline in electricity use. In rural areas paper products emerged as the leading industry in terms of electricity use by 1970. This contrasted with its ranking as the third most electricity using industry in urban areas.

While, in general, the rate of increase in the proportion of rural establishments using electricity was rapid over this period, and while it was spread geographically among the major regions of India, it seems to have been confined to relatively few industries.

THE PERCENTAGE DISTRIBUTION BY INDUSTRY OF ESTABLISHMENTS USING ELECTRICITY:

1960 and 1970

	Rural		Urban		Total	
	1960	1970	1960	1970	1960	1970
Food Products	4.8	22.4	32.1	43.8	11.6	28.6
Beverages and tobacco products	0.4	0.3	7.2	2.2	2.0	0.8
Cotton textiles	0.3	1.1	8.3	11.3	2.7	4.7
Wool and synthetic textiles	1.6	1.1	12.2	32.9	2.8	12.5
Jute textiles	1.0	0.6	15.0	8.2	3.5	1.8
Textile products	0.3	0.4	4.9	3.3	2.4	1.6
Wood products	0.4	1.6	13.0	4.7	2.4	4.4
Paper products	9.6	30.4	41.6	49.4	39.3	48.0
Leather and fur products	0.1	0.1	1.1	1.3	0.3	0.3
Petroleum and coal products	10.8	21.2	35.6	51.2	29.7	45.2
Other chemicals	4.1	6.1	23.6	17.6	16.4	12.8
Non-metallic mineral products	0.4	0.6	7.3	7.5	1.2	1.5
Basic metal and metal products	0.4	1.5	20.8	29.2	5.1	10.2
Machinery	32.7	14.5	67.7	66.9	64.4	51.6
Transport equipment	2.0	4.8	12.2	47.0	9.0	29.5
Other	0.4	1.5	6.4	9.2	3.2	5.4
Miscellaneous	-	2.6	-	11.7	-	8.4
Total	1.2	5.4	14.1	18.9	5.0	10.1

Source: 1960 and 1970 Census of Industrial Establishments

THE PERCENTAGE DISTRIBUTION OF INDUSTRIAL ESTABLISHMENTS USING ELECTRICITY:
1960 and 1970

	Rural		Urban		Total	
State/Union Territory	1960	1970	1960	1970	1960	1970
Northern Region						
Punjab, Haryana & Himachal Pradesh 1/	6.0	9.9	23.9	28.0	14.9	17.0
Jammu & Kashmir	0.5	2.9	11.3	10.8	2.4	4.8
Rajasthan	0.7	2.3	14.0	16.5	6.3	6.9
Delhi	neg.	29.4	51.8	34.4	51.8	34.2
Uttar Pradesh	1.5	6.1	9.9	15.8	4.4	9.3
Western Region						
Gujarat	3.7	7.1	27.1	29.8	17.3	17.9
Madhya Pradesh	0.1	1.8	8.4	16.4	1.5	4.7
Maharashtra	0.7	8.1	14.5	25.6	5.8	15.6
Southern Region						
Andhra Pradesh	1.1	3.6	10.9	13.0	3.4	6.1
Karnataka	3.4	10.2	13.6	17.3	8.0	13.1
Kerala	6.2	10.5	10.9	17.1	7.8	12.4
Tamil Nadu	4.1	8.4	8.8	11.5	6.7	10.1
Eastern Region						
Bihar	1.2	5.7	9.6	16.3	2.6	8.2
West Bengal	1.0	2.5	23.2	18.3	10.1	9.1
Orissa	0.1	1.6	4.3	12.5	0.3	3.0
North Eastern Region						
Assam	1.5	5.1	9.3	10.0	4.6	6.8
All other union territories & areas	0.2	4.4	3.1	12.4	0.5	6.8
All India						

1/ Including Chandigarh / Source: 1960 and 1970 Census of Industrial Establishments

ANNEX I.1.12
Table 3

- 90 -

PERCENTAGE AND ABSOLUTE CHANGES IN THE NUMBER OF ESTABLISHMENTS

IN RURAL AND URBAN AREAS: 1960 - 1970

	Increase in All Establishments			Increase in Electrified Establishments			Percentage of Increased Establishments Electrified		
	Rural	Urban	Total	Rural	Urban	Total	Rural	Urban	Total
Food Products	143.4	80.9	224.3	67.3	32.7	100.0	46.9	40.4	44.6
Beverages and tobacco products	8.6	14.7	23.3	- 0.2	- 1.8	- 2.0	-	-	-
Cotton textiles	40.8	52.9	93.7	2.7	9.7	12.4	6.6	18.3	13.2
Wool and synthetic textiles	10.7	14.6	25.3	0.0	5.3	5.3	0.1	36.3	20.9
Jute textiles	2.0	0.6	2.6	0.0	0.0	0.0	-	-	-
Textile products	10.0	71.2	81.2	0.5	0.6	1.1	5.0	0.8	1.4
Wood products	59.7	35.7	95.4	3.7	6.1	9.8	6.2	17.1	10.3
Paper products	1.1	15.7	16.8	0.6	9.0	9.6	54.6	57.3	57.1
Leather & fur products	28.2	9.4	37.6	0.1	0.1	0.2	3.5	1.1	0.5
Petroleum and coal products	2.2	9.5	11.7	0.5	5.2	5.7	22.7	54.7	48.7
Other chemicals	6.8	7.8	14.6	0.6	0.7	1.3	8.8	9.0	8.9
Non-metallic mineral products	73.7	13.1	86.8	0.7	1.0	1.7	1.0	7.6	2.0
Basic metal and metal products	-17.6	20.7	3.1	1.7	10.6	12.3	-	-	-
Machinery	13.3	23.8	7.1	1.7	15.8	17.5	12.8	66.4	47.2
Transport equipment	-19.0	-43.1	-62.1	- 0.2	- 2.5	- 2.7	-	-	-
Other	0.6	16.5	17.1	1.2	3.9	5.1	200.0	23.0	29.8
Miscellaneous	91.5	159.5	251.0	2.4	18.6	21.0	2.6	11.7	8.4
Residual	125.3	0.0 1/	123.5	17.9	14.6	32.5	14.3	-	26.3
Total	581.3	503.5	1084.8	101.2	129.6	230.8	17.4	25.8	21.3

1/ Figure inconsistent with residual of electrified establishments

Source: 1970 and 1970 Census of Industrial Establishments

CAPTIVE GENERATION IN INDUSTRY

(Gwh)

	Captive 1/ Generation	Purchased From Utilities	Total	Captive Generation as a Percentage of Total
1960/61	3000 2/	9696	12696	23.6
1961/62	3287	11545	14832	22.2
1962/63	3862	13110	16972	22.8
1963/64	3659 2/	15842	19501	18.8
1964/65	3466	17379	20845	16.6
1965/66	3733	18876	22609	16.5
1966/67	4048	20391	24439	16.6
1967/68	4039	22852	26891	15.0
1968/69	4136	25891	30027	13.8
1969/70	4703 2/	28379	33082	14.2
1970/71	5347	29579	34926	15.3
1971/72	5416	31637	37053	14.6
1972/73	5741 2/	32244	37985	15.1
1973/74	6086 2/	32481	38567	15.8
1974/75	6452	32690	39142	16.5
1975/76	6657	37568	44225	15.1

1/ Gross generation in selected industries; coverage may be neither complete nor consistent in different years.

2/ Estimated

Note: Gross generation overstates what is used in industry because of (i) auxilliary consumption and (ii) sales to utilities or other consumers. In the years for which data is available, the former accounts for about 10% of gross generation, the latter for considerably less. Thus all that can be said with confidence is that, in recent years, at least 10% of electrical energy used in industry is captively generated.

Source: GR

PER CAPITA ELECTRICITY CONSUMPTION BY STATE
(KWH)

	1960/61	1965/66	1971/72	1972/73	1974/75	1975/76	1976/77	1977/78 1/
Andhra Pradesh	19	31	57	54	62	66	77	82
Assam	4	8	25	27	27	28	34	36
Bihar	42	57	65	66	71	84	89	89
Gujarat	52	85	140	152	177	180	192	207
Haryana	NA	NA	111	130	125	153	174	173
Himachal Pradesh	NA	9	44	49	59	61	65	55
Jammu & Kashmir	14	NA	40	40	53	58	69	65
Karnataka	44	55	115	119	122	141	148	135
Kerala	29	42	74	79	83	90	93	100
Madhya Pradesh	20	38	58	64	71	83	90	95
Maharashtra	52	85	168	173	177	178	199	210
Manipur	NA	4	5	NA	8	9	10	5
Meghalaya	NA	NA	NA	NA	27	34	33	33
Nagaland	NA	2	11	17	27	27	26	31
Orissa	43	79	97	93	91	109	112	117
Punjab	33	102	169	165	155	232	242	227
Rajasthan	12	21	53	60	65	73	83	87
Tamil Nadu	51	89	135	131	133	144	147	159
Tripura	NA	3	NA	NA	6	8	8	10
Uttar Pradesh	15	30	60	64	61	73	86	82
West Bengal	84	114	115	121	114	119	125	119
Delhi	187	206	283	305	322	318	338	346
All India	38	61	94	97	99	110	119	121

1/ Provisional

NA = Not Available
Source: GR

NOTIFIED ENERGY RESTRICTIONS IN 1977/78
(percentages)

	April	May	June	July	August	September	October	November	December	January	February	March
Northern Region												
Haryana	—	50-100*	25*	—	40-100*	25-50*	0-25*	—	—	0-40	0-40	—
Himachal Pradesh	—	—	—	—	—	—	—	—	—	—	—	—
Jammu & Kashmir	—	2/	—	—	—	—	*	*	—	13-18*	12-18*	3-16*
Rajasthan	—	—	25*	—	—	0-10*	—	0-20	0-30	10-30	10-30	10-30
Delhi	—	* 1/	*1/	0-10	—	—	—	—	—	10	10	10
Chandigarh	—	1/2/	40-601/*	—	—	—	—	—	—	—	—	—
Uttar Pradesh	25-50*	25-50*	25-100*	25-100*	33*	33*	33-50*	25-50*	25-50*	25-50*	25-50*	25-50*
Punjab	—	40*	40*	20-40*	20-25*	10-25*	0-25*	—	*	—	—	—
Western Region												
Gujarat	—	—	—	—	—	—	—	—	—	—	—	—
Madhya Pradesh	5-15*	5-15*	5-15*	5-15*	5-15*	5-15*	10-15*	10-15*	10-15*	10-15*	10-15*	10-15*
Maharashtra	15-30*	10-20*	10-20*	10-20*	10-20*	10-20*	10-20*	10-20*	10-20*	10-20*	10-20*	10-20*
Goa	25-40	25-40	25-40	25-40	25-40	25-40	25-40	25-40	25-40	25-40	25-40	25-40
Southern Region												
Andhra Pradesh	—	—	—	—	0-30*	—	—	—	—	—	—	—
Karnataka	25-50	25-50	25-50	25-50	25-50	25-50	10-55	10-55	10-55	10-55	10-55	10-55
Kerala	—	—	—	—	—	—	—	—	—	—	—	—
Tamil Nadu	30-40*	25-30*	25-30*	—	—	—	—	—	—	—	—	—
Eastern Region												
Bihar	—	—	—	—	—	—	—	—	—	—	—	—
West Bengal	*	*	*	*	*	*	*	*	*	*	*	*
Orissa	—	—	—	—	—	—	—	—	—	—	—	—
D.V.C.	—	—	—	—	—	—	—	—	—	—	—	—
North Eastern Region												
Assam	10-25*	10-25*	10-25*	10-25*	10-25*	10-25*	10-25*	10-25*	10-25*	10-25*	10-25*	10-25*

* Demand restrictions
1/ No use of air conditioner
2/ Load shedding day to day

Note: The figures in this table refer to the percentage restrictions on energy consumption in different major categories of consumer. Thus, for example, the entry "10-55" for Karnataka for December means that certain consumer groups were subject to a 10% restriction, others to 55% restriction and yet others to levels of restriction in between.

Source: PSP

ANNEX I.2.1

ANNEX I.2.2

LOAD SHEDDING IN THE EASTERN REGION 1977/78 AND PART OF 1978/79

	Name of State/System							
	Bihar S.E.B.		D.V.C.		West Bengal S.E.B.		C.E.S.C.	
Month	Load Shedding in MW	No.of days	Load Shedding in MW	No.of days	Load Shedding in MW	No.of days	Load Shedding in MW	No.of days
1977/78								
April	40-180	28	n.a.	27	2-136	15	2-170	27
May	40-180	31	n.a.	14	4-55	25	5-118	27
June	60-180	30	n.a.	22	8-79	25	3-90	24
July	30-200	25	n.a.	20	3-98	22	3-158	23
August	30-190	31	16-128	29	2-75	12	9-158	27
September	50-100	30	35-150[1/]	29	3-91	24	7-125	25
October	30-200	30	50-190[1/]	29	9-79	19	31-180	24
November	30-250	30	15-190[1/]	30	4-79	27	8-150	30
December	30-300		n.a.	28	4-57	20	14-120	29
January	24-125	29	n.a.	28	16-117	30	28-141	29
February	60-200	28	30-120[1/]	22	31-93	28	18-136	28
March	30-200	31	n.a.	26	6-102	31	60-180	29
1978/79								
April	40-100	30	n.a.	26	22-76	26	6-165	28
May	50-300	31	n.a.	29	2-87	26	16-200	26
June	10-250	29	6-100	20	5-58	8	4-147	25
July	30-230	29	13-90	12	5-76	19	15-120	29
August	20-100	29	n.a.	30	13-92	30	5-185	29
Memo item: The Installed Capacity in Each System in March 1978	845		1241.5		619		328	

1/ MVA rather than MW

Note (1) The region comprises these four systems and the Orissa SEB and Dugapur Projects Limited. CESC and DPC are usually included in WBSEB for statistical purposes, though not in this instance. The total capacity in the region in March, 1978 was 4193.5 MW.

(2) This table indicate the number of days when shedding affected operations in these systems. Clearly this hides any distinction between occasions when there were many disruptions in one day or where disruptions were short and few.

Source: The Monitoring and Information Directorate, CEA

ANNEX I.2.3

MONTHLY NET REQUIREMENTS AND AVAILABILITY OF ELECTRICITY FOR THE FIVE REGIONS:

1977/78 and part of 1978/79

	1977/78												1978/79			
	April	May	June	July	August	September	October	November	December	January	February	March	April	May	June	July
Northern Region																
Requirement (Gwh/day)	67.4	74.1	74.2	73.1	65.6	70.5	73.5	76.0	84.4	84.0	80.8	83.7	78.5	74.9	73.8	73.8
Availability (Gwh/day)	57.9	55.3	56.3	56.5	58.1	59.3	60.5	65.5	65.9	67.2	64.3	63.4	70.4	75.1	71.4	70.1
Deficit (Gwh/day)	-9.5	-18.8	-17.9	-16.6	-7.5	-11.2	-13.0	-10.5	-18.5	-16.8	-16.5	-20.3	-8.1	-0.2	-2.4	-3.7
Percentage Deficit	-14.1	-25.4	-24.1	-22.7	-11.4	-15.9	-17.7	-13.8	-21.9	-20.0	-20.4	-24.3	-10.3	-0.3	-3.3	-5.0
Western Region																
Requirement (Gwh/day)	75.3	82.0	78.9	75.1	75.1	79.5	84.8	88.5	88.8	93.4	88.6	85.1	86.1	84.9	78.2	78.0
Availability (Gwh/day)	72.3	71.4	68.4	65.2	66.1	68.6	75.3	76.4	77.9	78.9	79.5	81.0	81.5	80.8	69.4	71.9
Deficit (Gwh/day)	-3.0	-10.6	-10.5	-9.9	-9.0	-10.9	-9.5	-12.1	-10.9	-14.5	-9.1	-4.1	-4.6	-4.1	-8.6	-6.1
Percentage Deficit	-4.0	-12.9	-13.3	-13.2	-12.0	-13.7	-11.2	-13.7	-12.3	-15.5	-10.3	-4.8	-5.3	-4.8	-11.3	-7.8
Southern Region																
Requirement (Gwh/day)	69.5	66.8	67.4	67.2	68.9	68.7	69.4	70.8	70.8	72.2	77.2	78.2	77.0	74.9	75.2	75.2
Availability (Gwh/day)	56.1	50.9	54.2	59.6	60.5	63.9	57.0	54.2	62.6	65.2	69.6	72.3	68.2	64.5	68.0	66.0
Deficit (Gwh/day)	-13.4	-15.9	-13.2	-7.6	-8.4	-4.8	-12.4	-16.6	-8.2	-7.0	-7.6	-5.9	-8.8	-10.4	-7.2	-9.2
Percentage Deficit	-19.3	-23.8	-19.6	-11.3	-12.2	-7.0	-17.9	-23.4	-11.6	-9.7	-9.8	-7.5	-11.4	-13.9	-9.6	-12.2
Eastern Region																
Requirement (Gwh/day)	43.2	49.8	47.0	47.5	50.4	48.3	48.4	49.6	49.6	49.6	43.8	48.2	49.5	48.9	48.7	48.7
Availability (Gwh/day)	40.1	40.0	40.4	40.3	40.5	41.9	38.5	39.1	38.2	38.9	39.6	39.7	40.4	40.3	44.1	41.3
Deficit (Gwh/day)	-3.1	-9.8	-6.6	-7.2	-9.9	-6.4	-9.9	-10.5	-11.4	-10.7	-4.2	-8.5	-9.1	-8.6	-4.6	-7.4
Percentage Deficit	-7.2	-19.7	-14.0	-15.2	-19.6	-13.3	-20.5	-21.2	-23.0	-21.6	-9.6	-17.6	-18.4	-17.6	-9.4	-15.2
North Eastern Region																
Requirement (Gwh/day)	2.5	2.5	2.5	2.5	2.5	2.5	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Availability (Gwh/day)	2.0	2.0	2.0	2.0	2.2	2.2	2.3	2.3	2.2	2.0	2.2	2.0	2.1	2.2	2.5	2.3
Deficit (Gwh/day)	-0.5	-0.5	-0.5	-0.5	-0.3	-0.3	-1.0	-1.0	-1.1	-1.3	-1.1	-1.3	-1.2	-1.1	-0.8	-1.0
Percentage Deficit	-20.0	-20.0	-20.0	-20.0	-12.0	-12.0	-30.3	-30.3	-33.3	-39.4	-33.3	-39.4	-36.4	-33.3	-24.2	-30.3
All India																
Requirement (Gwh/day)	257.9	275.2	270.1	265.3	262.5	269.4	279.4	288.2	297.0	302.5	293.7	298.4	294.4	286.8	279.0	279.1
Availability (Gwh/day)	228.2	219.6	221.3	223.6	227.5	235.8	233.6	237.5	246.8	252.2	255.2	258.4	262.6	263.2	255.5	251.7
Deficit (Gwh/day)	-29.7	-55.6	-48.8	-41.7	-35.0	-33.6	-45.8	-50.7	-50.2	-50.3	-38.5	-40.0	-31.8	-23.6	-23.5	-27.4
Percentage Deficit	-11.5	-20.2	-18.1	-15.7	-13.3	-12.5	-16.4	-17.6	-16.9	-16.6	-13.1	-13.4	-10.8	- 8.2	-8.4	-9.8

Source: PSP

THE NET REQUIREMENT AND AVAILABILITY OF ELECTRICITY PUBLIC UTILITIES ONLY: 1974/75-1977/78

(Gwh: figures in brackets are percentages)

State Electricity Board/Utility	1974/75 Requirement	1974/75 Availability	1974/75 Deficit	1975/76 Requirement	1975/76 Availability	1975/76 Deficit	1976/77 Requirement	1976/77 Availability	1976/77 Deficit	1977/78 2/ Requirement	1977/78 2/ Availability	1977/78 2/ Deficit
Northern Region												
Haryana	2446	635	811(33.2)	2528	2055	473(18.7)	2523	2332	191(7.6)	2804	2354	450(16.0)
Himachal Pradesh	315	280	35(11.1)	316	305	11(3.5)	336	306	30(8.9)	325	289	36(11.1)
Jammu and Kashmir	455	331	124(27.3)	484	375	109(22.5)	493	413	80(16.2)	560	541	19(3.4)
Rajasthan	2284	2256	28(1.2)	2558	2486	72(2.8)	2861	2841	20(0.7)	3336	3008	328(9.8)
Delhi	1700	1625	75(4.4)	1834	1795	39(2.1)	1984	1923	61(3.1)	2104	1998	106(5.0)
Chandigarh	191	130	61(31.9)	194	166	28(14.4)	170	162	8(4.7)	186	173	13(7.0)
Uttar Pradesh	9135	7253	1882(20.6)	10080	8716	1364(13.5)	10829	10593	236(2.2)	13150	9668	3482(26.5)
Punjab 1/	3532	2636	896(25.4)	4290	3964	326(7.6)	4511	4299	212(4.7)	5124	4163	961(18.8)
Total Northern Region	20058	16146	3912(19.5)	22284	19862	2422(10.9)	23707	22869	838(3.5)	27589	22194	5395(19.6)
Western Region												
Gujarat	6084	5856	228(3.7)	6501	6110	391(6.0)	6793	6719	74(1.1)	7873	7761	112(1.4)
Madhya Pradesh	3460	3476	16(0.5)	4331	4100	231(5.3)	4706	4518	188(4.0)	5322	4978	344(6.5)
Maharashtra	12107	11147	960(7.9)	12984	11467	1517(11.7)	13847	13088	759(5.5)	16790	14010	2780(16.6)
Goa	236	143	93(39.4)	238	165	73(30.7)	237	183	54(22.8)	283	198	85(30.0)
Total Western Region	21887	20622	1265(5.8)	24054	21842	2212(9.2)	25583	24508	1075(4.2)	30265	26792	3473(11.5)
Southern Region												
Andhra Pradesh	4355	3269	1086(24.9)	4603	3782	821(17.8)	4757	4662	95(2.0)	5255	5012	243(4.6)
Karnataka	6021	4635	1386(23.0)	6289	5353	935(14.9)	6952	4680	1272(18.3)	7876	5215	2661(33.8)
Kerala	2470	2268	202(8.2)	2585	2474	111(4.3)	2704	2606	98(3.6)	2910	2853	57(2.0)
Tamil Nadu	8656	7338	1318(15.2)	8952	7917	1035(11.6)	9026	8042	994(10.9)	9713	8965	748(7.7)
Total Southern Region	21502	17510	3992(18.6)	22428	19526	2902(12.9)	23439	20990	2449(10.4)	25761	22081	3680(14.3)
Eastern Region												
Bihar	2029	1797	232(11.4)	2286	2154	132(5.8)	2600	2526	74(2.8)	3710	2603	1107(29.8)
West Bengal	4867	4068	799(16.4)	5367	4658	709(13.2)	5560	5040	520(9.4)	6183	5021	1162(18.8)
Orissa	2261	1898	363(16.1)	2558	2527	31(1.2)	2698	2606	92(3.4)	2868	2719	149(5.2)
D.V.C.	4357	4049	308(7.1)	3784	3705	79(2.1)	3989	4090	- 101(-2.5)	4738	4151	587(12.4)
Total Eastern Region	13514	11812	1702(12.6)	13995	13044	951(6.8)	14847	14262	585(3.9)	17498	14515	2983(17.0)
North Eastern Region	639	557	82(12.8)	747	635	112(15.0)	913	736	177(19.4)	1058	772	286(27.0)
Total	77600	66647	10953(14.1)	83508	74909	8599(10.3)	88489	83365	5124(5.8)	102171	86357	15814(15.5)

Source: CEA, Operations and Monitoring Information Directorate and PSP

Note: A minus sign in one of the deficit columns denotes a surplus

1/ Including Nangal Fertilizer Plant

2/ Provisional: Some of the changes in availabilities and requirements at the State level between 1976/77 and 1977/78 are anomolous. It seems unlikely that requirements might fall in Himachal Pradesh or increase by 25% in Uttar Pradesh. The data should therefore not be interpreted as showing any trends so much as the state of affairs in four recent years.

ANNEX 1.2.4

ANNEX I.3.1

ELECTRICITY PRODUCTION PER UNIT OF GNP: 1975

	GNP	Electricity Production	Electricity Production Per Unit of GNP
	(US$ millions)	(Gwh/year)	(Kwh/US$)
India	85,965	85,926	1.000
Nigeria	25,600	3,211	0.125
Egypt	9,540	10,386	1.089
Ethiopia	2,730	666	0.244
Japan	496,260	475,794	0.959
Bangladesh	7,280	1,703	0.234
Pakistan	11,270	10,072	0.894
Thailand	14,600	8,866	0.607
Sri Lanka	3,540	1,149	0.325
USSR	649,470	1,038,625	1.599
Germany (FR)	412,480	301,802	0.732
UK	211,700	272,082	1.285
Italy	156,590	147,333	0.941
France	314,080	185,312	0.590
USA	1,519,890	2,003,002	1.318
Canada	158,100	273,392	1.729
Mexico	63,200	43,298	0.685
Brazil	110,130	78,068	0.709
Indonesia	29,120	4,030	0.138

Sources: World Energy Supplies: 1972-1976
World Bank Atlas, 1977

CRUDE ELASTICITIES OF ELECTRICITY DEMAND IN A SAMPLE OF COUNTRIES: 1970-1975

	GNP per Capita (US$)	Annual Growth Rate of GNP 1970-75	Annual Growth Rate of Electricity Consumption 1970-75	Elasticity of Electricity Consumption
India	140	2.6	7.1	2.7
Sweden	8150	2.7	5.8	2.2
U.S.A.	7120	2.4	4.1	1.7
Canada	6930	4.7	5.9	1.3
Norway	6760	4.0	5.8	1.5
Federal Republic of Germany	6670	2.1	4.4	2.1
France	5950	4.2	5.6	1.3
Japan	4450	5.3	6.3	1.2
United Kingdom	3780	2.2	1.8	0.8
Yugoslavia	1550	6.8	9.0	1.3
Brazil	1030	9.1	11.6	1.3
Taiwan	930	7.7	10.4	1.3
Thailand	350	6.5	14.6	2.2
Kenya	220	5.9	14.9	2.5
Indonesia	220	5.9	11.7	2.0
Sri Lanka	190	2.8	6.6	2.3
Pakistan	160	3.8	5.3	1.4
Afghanistan	150	4.3	11.8	2.8

Sources: 1977 World Bank Atlas and U.N. Energy Supply Statistics; Series J, 1973 and 1976

ELECTRICITY COSTS AS A PERCENTAGE OF VALUE ADDED IN INDUSTRY

	Industrial Value Added	Electricity Consumption 2/	Average Cost per kwh 1/	Electricity Costs as a percent of Value Added
	(Rs millions) 3/	(Gwh)	(paise)	
1970/71	50,580	34,926	9.7	6.7
1971/72	55,580	37,053	9.9	6.6
1973/74	73,380	38,567	11.5	6.0
1974/75	97,180	39,142	15.4	6.2
1975/76	104,640	44,225	18.8	7.9

Sources: 1/ Annex I.4.22
2/ Annex I.1.15
3/ January 1978 national accounts: manufacturing and mining at current prices

Note: Data for 1972/73 is not fully available

ANNEX I.3.4

ELECTRICITY CONSUMPTION IN SELECTED INDUSTRIES: SELECTED INDICATORS

	1969	1970	1971	1973
Inorganic Fertilizers				
- Value of electricity consumed per unit of value added (percent)	36.9	30.0	50.8	48.5
- Value of electricity consumed per unit of value of output (percent)	6.6	6.8	7.4	8.5
- Unit value of electricity (paise/kwh)	4.1	5.5	6.2	11.6
Inorganic Heavy Chemicals				
- Value of electricity consumed per unit of value added (percent)	27.9	28.2	27.9	34.7
- Value of electricity consumed per unit of value of output (percent)	7.9	8.3	8.1	9.0
- Unit value of electricity (paise/kwh)	6.7	7.4	7.9	16.7
Synthetic Fibres				
- Value of electricity consumed per unit of value added (percent)	12.8	12.5	10.0	11.2
- Value of electricity consumed per unit of value of output (percent)	3.8	3.9	3.4	4.0
- Unit value of electricity (paise/kwh)	10.3	9.3	9.5	16.2
Iron and Steel (metal)				
- Value of electricity consumed per unit of value added (percent)	18.7	17.3	22.9	NA
- Value of electricity consumed per unit of value of output (percent)	3.5	3.4	3.5	NA
- Unit value of electricity (paise/kwh)	8.3	8.5	8.9	11.3
Iron and Steel (castings and forgings)				
- Value of electricity consumed per unit of value added (percent)	16.0	25.2	17.4	27.2
- Value of electricity consumed per unit of value of output (percent)	4.2	4.3	4.3	7.2
- Unit value of electricity (paise/kwh)	12.4	11.9	12.4	17.3
Non-Ferrous Basic Metal (Industries)				
- Value of electricity consumed per unit of value added (percent)	21.4	23.2	36.4	41.3
- Value of electricity consumed per unit of value of output (percent)	6.2	6.2	6.9	6.8
- Unit value of electricity (paise/kwh)	4.1	6.4	5.6	5.9
Hydraulic Cement				
- Value of electricity consumed per unit of value added (percent)	33.5	35.8	42.9	60.7
- Value of electricity consumed per unit of value of output (percent)	6.5	8.2	8.0	9.2
- Unit value of electricity (paise/kwh)	9.1	9.1	9.0	11.3

Note: The figures in this table that show value of electricity consumed per unit of value added are of course higher than the value of electricity consumed per unit of product value.

Source: Central Statistical Office

ELECTRICITY CONSUMPTION, TOTAL PRODUCTION AND ELECTRICITY CONSUMPTION/UNIT PRODUCTION IN SELECTED MANUFACTURING INDUSTRIES: 1960/61 - 1976/77

	1960/61	1965/66	1970/71	1973/74	1974/75	1975/76	1976/77	Annual Average Rates of Growth 1960/61-1970/71	1970/71-1976/77	1960/61-1976/77
Electricity Consumption										
Aluminium (Gwh)	448	1,566	3,375	2,825	2,962	3,695	4,021	22.4	3.0	14.7
Iron and Steel (Gwh)	1,613	2,545	3,195	3,796	4,326	4,798	5,480	7.1	9.4	7.9
Cotton Textiles (Gwh)	2,088	2,783	3,138	4,056	4,393	4,780	5,124	4.2	8.5	5.8
Fertilizers (Gwh)	477	1,828	2,531	3,115	3,048	4,473	4,302	18.2	9.2	14.7
Chemicals (Gwh)	404	642	1,614	1,545	2,028	2,338	3,108	14.9	11.5	13.6
Cement (Gwh)	936	1,059	1,371	1,284	1,707	1,755	2,340	3.9	9.3	5.9
Paper (Gwh)	508	666	899	1,059	1,188	1,272	1,335	5.9	6.8	6.2
Engineering (Gwh)	n.a.	298	839	651	817	898	1,117	n.a.	4.9	n.a.
Production										
Aluminium (thousand tonnes)	18.3	62.1	166.8	147.9	126.6	187.3	208.7	24.7	3.8	16.4
Iron and Steel 2/ (thousand tonnes)	10,120.0	18,130.0	17,640.0	17,230.0	18,920.0	22,800.0	25,610.0	5.7	6.4	6.0
Cotton Textiles (million meters)	6,740.0	7,440.0	7,596.0	7,946.0	8,267.0	8,319.0	8,399.0	1.2	1.7	1.4
Fertilizers (thousand tonnes)	150.0	344.0	1,059.0	1,379.0	1,512.0	1,855.0	2,380.0	21.6	14.4	18.9
Chemicals (1970 base index)	n.a.	n.a.	112.2	125.3	131.7	155.5	170.5 1/	n.a.	7.2	n.a.
Cement (million tonnes)	8.0	10.8	14.4	14.7	14.7	17.2	18.8	6.1	4.5	5.5
Paper (thousand tonnes)	350.0	558.0	755.0	776.0	836.0	836.0	891.0	8.0	2.8	6.0
Engineering (1970 base index)	n.a.	n.a.	105.4	129.3	120.2	126.6	146.5 1/	n.a.	5.6	n.a.
Electricity Consumption Per Unit of Production										
Aluminium (Gwh per thousand tonnes)	24.5	25.2	20.2	19.1	23.4	19.7	19.3	-1.9	-0.8	-1.5
Iron and Steel (Gwh per thousand tonnes)	0.2	0.1	0.2	0.2	0.2	0.2	0.2	1.4	3.0	1.9
Cotton Textiles (Gwh per million meters)	0.3	0.4	0.4	0.5	0.5	0.6	0.6	3.0	6.8	4.4
Fertilizers (Gwh per thousand tonnes)	3.2	5.3	2.4	2.3	2.1	2.4	1.8	-3.4	-5.2	-4.2
Chemicals (Gwh per unit production)	n.a.	n.a.	14.4	12.3	15.4	15.0	18.2	n.a.	4.3	n.a.
Cement (Gwh per million tonnes)	117.0	98.1	95.2	87.4	116.1	102.0	124.5	-2.2	4.8	0.4
Paper (Gwh per thousand tonnes)	1.5	1.2	1.2	1.4	1.4	1.5	1.5	-2.1	4.0	0.2
Engineering (Gwh per unit production)	n.a.	n.a.	8.0	5.0	6.8	7.1	7.6	n.a.	-0.7	n.a.

1/ Through October
2/ Includes pig iron, steel ingots and finished steel

Sources: Electricity Consumption; GR:
Production in Selected Industries; Table 1.14, the Economic Survey 1977/78

n.a. = not available

Note: The data are subject to the qualification that the vategorization of production used by the State Electricity Boards in collecting the electricity consumption figures is not necessarily strictly compatible with the Economic Survey categorization.

THE USE OF AN INPUT/OUTPUT MODEL TO GAUGE ELECTRICITY-INTENSITY

The estimates in Table 1 of this Annex are based on the input/output model for the Fifth Five-Year Plan. This model may be summarized in a single equation as:

$$X = (A - M)X + F \qquad (1)$$

where

$X = (x_i)$	=	gross output vector,
$A = (a_{ij})$	=	the technical production coefficient matrix,
$M = (m_{ij})$	=	the coefficient matrix of intermediate imports,
$F = (f_i)$	=	final demand (net of imports); that is the sum of consumer, government, exports, investment and stock change demands.

Thus, equation (1) states that the gross output X is divided between final demand F and direct and indirect inputs $P = (p_i) = (A - M)X$. Equation (1) implies that

$$X = BF \qquad (2)$$

where $B = (b_{ij}) = [I - (A - M)]^{-1}$

We may use equation (2) to express P as a function of F, for equation (1) can be rewritten:

$$P = X - F = BF - F = (B - I)F \qquad (3)$$

To produce x_j, $a_{ij}x_j$ of i must be used and since $\sum_i a_{ij}x_j$ is the value of all inputs, value-added, v_j, is given by:

$$v_j = x_j - \sum_i a_{ij}x_j = (1 - \sum_i a_{ij})x_j \qquad (4)$$

Thus:
$$\frac{\partial x_k}{\partial v_j} = 0 \qquad \forall \quad k \neq j \qquad (5.1)$$
$$= (1 - \Sigma a_{ij})^{-1} \qquad \forall \quad k = j \qquad (5.2)$$

Now, there are two ways to estimate the change in power input (subscripted e) associated with the change in value added in a given sector. In the partial equilibrium approach, what happens to final demand (and hence price changes that would be needed to continue to absorb the surplus produced in demand) is ignored and the definition of P is derived from an expression for $\partial p_e / \partial v_j$.

Thus:
$$P = (A - M) X$$

implies
$$\frac{\partial p_e}{\partial x_k} = a_{ek} - m_{ek}$$

But
$$\frac{\partial p_e}{\partial v_j} = \sum_k \left(\frac{\partial p_e}{\partial x_k} \cdot \frac{\partial x_k}{\partial v_j} \right)$$

$$= (a_{ej} - m_{ej})(1 - \sum_i a_{ij})^{-1} \text{ (from 5.1 and 5.2)}$$

$$= a_{ej}(1 - \sum_i a_{ij})^{-1} \quad \text{because no electricity is imported.} \qquad (6)$$

Alternatively, using a general equilibrium approach, and keeping final demand unchanged, except for a small change in one component, f_j, one may argue that

(3) implies
$$\frac{\partial p_e}{\partial f_l} = b_{el} - \delta_{el}$$

where δ_{el} is the Kronecker delta,

and (2) implies
$$\frac{\partial x_m}{\partial f_l} = b_{ml}.$$

These statements in turn mean that a change df_l will lead to a change

$$dx_m = b_{ml}\,df_l \qquad \text{and} \qquad dp_e = (b_{el} - \delta_{el})\,df_l$$

Thus, $$dp_e = \frac{b_{el} - \delta_{el}}{b_{jl}}\,dx_j \qquad \text{when } j = m. \qquad (7)$$

(5.1) and (5.2) imply that dx_m will be associated with a change dv_j,

given by $$dv_j = (1 - \sum_i a_{ij})\,dx_j \qquad (8)$$

Thus, (7) and (8) imply

$$\frac{dp_e}{dv_j} = \frac{b_{el} - \delta_{el}}{b_{jl}(1 - \Sigma_i a_{ij})}$$

If only f_j changes, that is if $j = l$, this becomes

$$\frac{dp_e}{dv_j} = \frac{b_{ej} - \delta_{ej}}{b_{jj}(1 - \Sigma_i a_{ij})} \qquad (9)$$

In Table 1 column (3) is a_{ej}, column (4) is v_j/x_j,

column (5) is $1 - \sum_i a_{ij} = v_j/x_j$, column (6) is b_{jj},

column (7) is $\partial p_e/\partial v_j$ as defined in equation (6) above and column (8) is

$\frac{dp_e}{dv_j}$ as defined in equation (9) above.

Coefficients of Power Intensity in a Sample of Sectors

Sector		Subsector	Electricity Input Per Rs 100 of Gross Output	Electricity Input Per Rs 100 of Final Output	Value Added Per Rupee of Gross Output	Gross Output Per Rupee of Final Output	Electricity Input Per Rs 100 of Value Added 1/ (Partial)	Electricity Input Per Rs 100 of Value Added 2/ (General)
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
Agriculture	- 1.	Foodgrains	1.09	1.85	0.780	1.060	1.40	2.24
	2.	Jute, Cotton, Sugarcane, Etc.	0.36	0.69	0.775	1.168	0.46	0.76
Mining	- 6.	Coal	2.82	3.71	0.873	1.009	3.23	4.21
	7.	Misc. Coal & Petroleum Prods.	1.60	3.42	0.494	1.022	3.24	6.77
	8.	Iron Ore	1.82	2.55	0.861	1.000	2.11	2.96
	9.	Crude Oil	1.53	2.10	0.945	1.001	1.62	2.22
Manufacturing	- 15.	Cotton Textiles	1.65	2.97	0.392	1.027	4.21	7.38
	20.	Paper & Paper Products	5.07	7.92	0.167	1.019	30.36	46.54
	23.	Fertilizers	7.43	11.15	0.374	1.057	19.87	28.21
	24.	Inorganic Heavy Chemicals	5.89	8.56	0.466	1.049	12.64	17.51
	25.	Organic Heavy Chemicals	1.01	2.66	0.417	1.016	2.42	6.28
	26.	Plastics	3.85	6.26	0.353	1.035	10.91	17.13
	30.	Petroleum Products	0.03	0.61	0.158	1.004	0.19	3.85
	31.	Cement	0.70	2.16	0.434	1.001	1.61	4.98
	34.	Iron and Steel	1.99	4.08	0.416	1.209	4.78	8.11
	35.	Non-ferrous Metals	2.64	5.29	0.388	1.363	6.80	10.00
	42.	Machine Tools	1.79	3.22	0.541	1.000	3.31	5.95
	53.	Motor Vehicles	0.24	1.59	0.318	1.578	0.75	3.17
	56.	Locomotives & Rolling Stock	1.95	3.90	0.408	1.058	4.78	9.03
Electricity	- 62.		18.44	23.13	0.514	1.231	35.88	36.56
Construction	- 63.		0.55	1.95	0.485	1.018	1.13	3.95
Railways	- 64.		4.48	5.91	0.692	1.005	6.47	8.50
Other Transp.	- 65.		0.00	0.10	0.892	1.009	0.00	0.11
Services	- 66.		0.44	0.61	0.953	1.021	0.46	0.63

Source: Technical Note to the Fifth Five-Year Plan; Planning Commission April 1973.

1/ (7) = (3) ÷ (5) ; (see Annex I.3.6)

2/ (8) = (4) ÷ ((5) x (6)) ; (see Annex I.3.6)

THE MANUFACTURING SECTOR IN INDIA - INTERNATIONAL COMPARISONS OF POWER INTENSITY: 1968

	Share in Manufacturing Value-Added		Electricity Consumption per Unit of Value-Added		Evidence of Structural (S) or Internal (I) Reasons for Power Intensity	
	Indian Percentages	Indian Value as % of Average	Indian (Kwh/US$)	Indian Value as % of Average		
	(1)	(2)	(3)	(4)	(5)	
Food Products	12.30	42.6	1.850	151.6	S	I
Textiles	22.29	204.7	5.047	246.2	S	I
Clothing & Footwear	0.31	7.9	0.742	153.0	S	I
Leather Products	0.39	96.3	0.244	23.2		
Wood Products	1.07	22.2	0.997	95.9	S	
Paper Products	2.14	70.6	11.514	163.9	$\overline{S}$	I
Printing	2.63	68.1	0.711	149.4	S	I
Chemicals	15.04	129.9	8.196	170.4	S	I
Rubber Products	2.46	110.8	2.245	146.9		I
Non-metallic Minerals Industries	4.05	69.6	8.490	184.6	$\overline{S}$	I
Basic Metals Industries	11.98	208.0	9.166	81.6	S	
Metal Products	23.44	127.3	1.472	91.6	$\overline{S}$	
Miscellaneous	1.91	39.6	1.059	72.5	S	
Total Manufacturing	100.00		4.615	173.9		

Notes: 1. The last two columns, under heading (5), interpret the rest of the table. If the values in column (2) are greater than 120.0 and in (3) greater than 5.0 or if the values in (2) are less than 80.0 and in (3) less than 4.0, this is denoted by S in column (5). If the values in (2) are less than 80.0 and in (3) greater than 5.0 or in (2) greater than 120.0 and in (3) less than 4.0, this is denoted by S in column (5). If the value in column (4) is greater than 125.0, this is denoted by I in column (5).

2. Both interntional samples were as large as possible and sample size was constrained primarily by the availability of data.

Source: Central Statistical Office and World Bank Research Project: "Patterns of Industrial Development".

ANDHRA PRADESH: STAND-BY DIESEL SETS INSTALLED IN 1978[1/]

Capacity Range (KVA)	Installed Capacity in each Range (KVA)
Less than 9	345
10-24	1726
25-49	1809
50-99	2212
100-199	7106
200-399	2781
400-599	2415
600-999	0
1000	0
All ranges	18394

1/ Installation of captive plant permitted in an eight month period in 1978.

Souce: Andhra Pradesh State Electricity Board

ELECTRICITY TARIFFS FOR SEBs FROM 12-31-72 to 12-31-76: ANDHRA PRADESH

(energy charge and tariff are in paise/kwh and demand charge and minimum charge are in rupees)

	Domestic	Industrial L.T.	Industrial H.T.	Agricultural	Public Lighting	Commercial
End of 1972	First 50 Kwh 35 Next 50 Kwh 27 Balance 22 Minimum Charge Rs 3/mo.	First 500 Kwh 22 Balance 20 Minimum Charge Rs 7/KW/mo. Rs 7.5 HP/mo for rice mills	Demand Charge First 500 KVA Rs 15/KVA/mo. Next 1500 Rs 14/KVA mo. Balance Rs 12/KVA mo Energy Charge First 50,000 Kwh 11.5 Next 150,000 Kwh 11 Next 300,000 Kwh 10.5 Next 500,000 Kwh 8.5 Next 1,000,000 Kwh 8 Balance 4.5/(L.F.xP.F.) 1/	16 Minimum Charge 60/HP/year	24 plus Rs 1.8/mo/ fixture	Demand Charge First 500 KVA Rs 18.75/KVA/mo Next 1500 Rs 17.50/KVA/mo Balance Rs 15/KVA/mo Energy Charge First 5000 Kwh 58 Next 5000 Kwh 52 Balance 47
End of 1976	First 200 Kwh 40 Balance 45 Minimum Charge Rs 5/mo.	32-35 depending on specific industry Minimum Charge Rs 7-10/HP/mo	Demand Charge First 1000 KVA Rs 21/KVA/mo Balance Rs 19/KVA/mo Energy Charge First 100,000 Kwh 21 Next 100,000 Kwh 19 Next 1,800,000 kwh 18 Balance 15	16 Fixed Charge Rs 3/HP/mo Minimum Charge Rs 60/HP/mo	38 plus Rs 1/mo/ fixture Minimum Charge Rs 2/point	75 Minimum Charge Rs 10/mo

1/ L.F. = Load Factor, P.F. = Power Factor; this rate or 8 paise/Kwh was charged, whichever was less.

Source: ERB

ANNEX I.4.2

ELECTRICITY TARIFFS FOR SEBs FROM 12-31-72 to 12-31-76: ASSAM

(energy charge and tariff are in paise/kwh and demand charge and minimum charge are in rupees)

	Domestic	Industrial L.T.	Industrial H.T.	Agricultural	Public Lighting	Commercial
End of 1972	For lights and fans 40 For heat and small power 22 Minimum Charge Rs. 3/kw/month	First 5000 Kwh 16 Next 5000 Kwh 15 Balance 14 Minimum Charge Rs 5/kw/month	For demand 100 KVA - 500 KVA Demand Charge First 100 KVA Rs 13/KVA/mo. Next 200 Rs 12/KVA/mo. Balance Rs 11/KVA/mo. Energy Charge First 50,000 Kwh 9 Next 50,000 Kwh 8 Balance 7 Minimum Charge Rs 7/KVA/mo. For demand greater than 500KVA Demand Charge First 500 KVA Rs 11/KVA/mo. Next 500 KVA Rs 9/KVA/mo. Next 1,000 KVA Rs 8/KVA/mo. Balance Rs 6/KVA/mo. Energy Charge First 100,000 KWH 7.5 Next 200,000 Kwh 7 Next 200,000 Kwh 6.5 Next 500,000 Kwh 6.25 Balance 6 Overall Maximum Rate 12 paise/Kwh	17 Minimum Charge Rs.36/KW/year	34	For lights and fans 43 Heat & Small Power 28 Cold Storage 15 Minimum Charge Rs 10/KW/mo.
End of 1976	Lights, Fans 48 Heat and Power 30 Minimum Charge Rs 5/KW/month	First 5,000 Kwh 22 Balance 21 Minimum Charge Rs 10/KVA/month	Demand Charge First 500 KVA Rs 14/KVA/month Next 1,000 KVA Rs 13/KVA/mo. Balance Rs 12/KVA/month Energy Charge First 1,000,000 Kwh 18 Next 2,000,000 17 Next 2,000,000 16 Balance 15 Overall Maximum Rate 23/paise/Kwh	21 Minimum Charge Rs. 5 /KVA/mo.	34	Lights and fans 60 Heat and Power 45 Minimum Charge Rs. 15/KW/month

Source: ERB

ANNEX 1.4.3

ELECTRICITY TARIFFS FOR SEBs FROM 12/31/72 to 12/31/76 : BIHAR

(Energy Charge and Tariff are in Paise/kwh and Demand Charge and Minimum Charge are in Rupees)

	Domestic	Industrial L.T.	Industrial H.T.	Agricultural	Public Lighting	Commercial
End of 1972						
	First 50 KWH 30 Balance 35, plus Fixed Charge Rs 3/month	20 Minimum Charge Rs 160/BHP/year	Demand Charge[1/] Rs 14/KVA/month Energy Charge 8.5	18	Metered Street Lighting 25 plus 50 P/lamp/month Unmetered Street Light 40 w lamp Rs 3/month 60 w lamp Rs 4/month 75 w lamp Rs 5/month 100 w lamp Rs 6/month 200 w lamp Rs 12/month	First 100 KWH 30 Balance 35, plus Fixed Charge Rs 5/month
End of 1976						
	First 50 KWH 32 Balance 37, plus Fixed Charge Rs 3/month	For consumption over 200/BHP 20 For consumption between 100-200/ BHP/month 22 For consumption less than 100/ BHP/month 24 Minimum Charge Rs 67/BHP/month	Demand Charge Rs 20/KVA/month Energy Charge If over 340/KWH/ KVA/month 12.5 If between 280-340 KWH/KVA/month 14.5 If between 220-280 KWH/KVA/month 15.5 If less than 220 KWH/KVA/month 17	3 Fixed Charge Rs 10/BHP/month for private tubewells Rs 15/BHP/month for state tube-wells	48 plus Rs 1/lamp/month	First 100 KWH 42 Balance 52 plus Fixed Charge Rs 30/month

1/ Other tariffs apply to other specific categories of high tension consumers.

Source: ERB

ELECTRICITY TARIFFS FOR SEBs FROM 12/31/72 to 12/31/76: GUJARAT

(Energy Charge and Tariff are in Paise/kwh and Demand Charge and Minimum Charge are in Rupees)

	Domestic	Industrial L.T.	Industrial H.T.	Agricultural	Public Lighting	Commercial
End of 1972	Lights 31 Minimum Charge Rs 1.5/month Heat and Power 15 Minimum Charge Rs 4/month	First 100 BHP Contracted/Connected Load 17.50P/KWH/month Next 150 BHP 16P/KWH/month Balance 13P/KWH/month Minimum Charge Rs 6/BHP/month	Demand Charge First 500 KVA Rs 12/KVA/month Next 500 KVA Rs 11/KVA/month Next 4000 Rs 10/KVA/month Balance 8.5/KVA/month Energy Charge First 200 Kwh 8 Next 150 Kwh 7.5 Next 150 Kwh 6 Balance 5	Fixed Charge First 5 BHP Contracted/Connected loan Rs 1.25/BHP/mo. Next 10 Rs 1.5/BHP/mo. Next 10 Rs 1.75/BHP/mo. Balance 2/BHP/mo. Energy Charge Balance 14	Fixed Charge Rs 1/pole plus Balance 20 Minimum Energy Charge 2200 KWH Consumption/ KWF connected load	Lights 31 Minimum Charge Rs 1.5/month Heat and Power 15 Minimum Charge Rs 4/month
End of 1976	Lights & fans First 40 kwh 31 Balance 34 Minimum Charge Rs 1.5/mo Heat & Power 21 Minimum Charge Rs 4/mo for single phase; Rs 10/mo for three phase	Demand Charge Rs 7/KW/mo Energy Charge First 150 kwh/KW/mo 15 Balance 10 Additional Charges on all consumption 11	Demand Charge First 500 KVA Rs 12/KVA/mo Next 500 KVA Rs 11/KVA/mo Next 4000 KVA Rs 10/KVA/mo Balance Rs 8.5/KVA/mo Energy Charge First 200 8 Next 200 7 Next 150 6 Balance 5 Additional Charge 8 kwh	Fixed Charge First 5 BHP Rs 1.25/BHP/mo Next 10 BHP Rs. 1.5/BHP/mo. Next 10 BHP Rs 1.75/BHP/mo Balance Rs 2/BHP/mo Energy Charge 14 Additional charge on all consumption 8	Energy Charge 20 Fixed Charge Rs 1/pole	same as domestic

Source: ERB

ELECTRICITY TARIFFS FOR SEBs FROM 12-31-72 to 12-31-76: HARYANA

(energy charge and tariff are in paise/kwh and demand charge and minimum charge are in rupees)

	Domestic	Industrial L.T.[2]	Industrial H.T.	Agricultural	Public Lighting	Commercial
End of 1972	First 15 kwh 34 Next 25 kwh 15 Balance 13 Minimum Charge Rs 2/mo	First 500 Kwh 11 Next 1000 Kwh 10.5 Balance 9.00	Demand Charge First 1000 KVA Rs 6.5/KVA/mo Balance Rs 5.5/KVA/mo Energy Charge First 1,000,000 kwh 5 Next 2,000,000 kwh 4.5 Balance 4	15 [1] Demand Charge Rs 1.5/BHP/mo	Energy Charge 21.6 Fixed Charge Rs 2.5-3/lamp/mo	First 30 kwh 37 Next 50 kwh 21 Balance 16 Minimum Charge Rs 3/mo
End of 1976	First 15 kwh 37 Next 25 kwh 22.5 Balance 31.25 Minimum Charge Rs 2/mo	21 Minimum Charge Rs 10.50/KW/mo	Demand Charge Rs 15 /KVA/mo Energy Charge 10	Demand Charge Rs 2/BHP/mo Energy Charge 20	Energy Charge 25 Fixed Charge Rs 3 to 4.125/lamp	First 80 kwh 40 Balance 50

1/ Other tariffs apply to other specific categories of agricultural consumers.

2/ For small LT Industrial consumers.

Source: ERB

ELECTRICITY TARIFFS FOR SEBs FROM 12-31-72 to 12-31-76: HIMACHAL PRADESH

(energy charge and tariff are in paise/kwh and demand charge and minimum charge are in rupees)

	Domestic	Industrial L.T.1/	Industrial H.T.	Agricultural	Public Lighting	Commercial
End of 1972	Urban Areas First 15 Kwh 34 Next 25 Kwh 15 Balance 8 Rural Areas First 15 Kwh 15 Next 25 Kwh 20 Balance 8	First 500 Kwh 11 Balance 10	Demand Charge Rs 6.5/KVA/mo. Energy Charge First 100,000 Kwh 5.5 Next 200,000 Kwh 5.25 Balance 5 Overall Maximum Rate 8 paise/Kwh	Demand Charge Rs.0.5/BHP/mo. Energy Charge First 1,500kwh 9 Balance 8	14 plus Rs 1.5/ month/bulb	First 30 Kwh 35 Next 50 Kwh 20 Balance 12
End of 1976	First 15 Kwh 37 Next 25 Kwh 27 Balance 17	First 500 Kwh 18 Next 1000 Kwh 15.5 Balance 13	Demand Charge Rs. 17/KVA/mo. Energy Charge First 100,000 Kwh 12 Next 200,000 10 Balance 8	First 1,500 Kwh 9 Balance 8	25 plus Rs 3/bulb	First 30 Kwh 45 Next 50 Kwh 35 Balance 28

1/ For small industrial consumers.

Source: ERB

ANNEX I.4.6

ELECTRICITY TARIFFS FOR SEBs FROM 12-31-72 to 12-31-76: JAMMU & KASHMIR

(energy charge and tariff are in paise/kwh and demand charge and minimum charge are in rupees)

	Domestic	Industrial L.T.	Industrial H.T.	Agricultural	Public Lighting	Commercial
End of 1972						
	First 50 Kwh 25 Next 50 Kwh 20 Balance 15 Minimum Charge Rs. 3.5-6	Demand Charge Rs. 4/KVA/mo. Energy Charge 4 for Kashmir 6 for Jammu	Demand Charge Rs. 4/KVA/mo. Energy Charge 2.5 for Kashmir 4 for Jammu	10 Minimum Charge Rs. 24/H.P./year	Energy Charge Rs. 1.5-9/lamp/ month depending on wattage Maintenance charge Rs. 1-11 depending on wattage	First 200 Kwh 35 Next 300 Kwh 30 Balance 25
End of 1976						
	First 50 Kwh 28 Next 150 Kwh 33 Balance 38 Minimum Charge Rs.4-6.75/mo.	Demand Charge Rs. 4/KVA/HP/mo. Energy Charge 4 (Kashmir) 6 (Jammu)	Demand Charge Rs.4/KVA or HP/month Energy Charge 2.5 (Kashmir) 4 (Jammu)	10 Minimum Charge Rs.24/H.P./year		First 200 Kwh 38 Balance 40 Minimum Charge Rs.6.75/Kw/mo.

Source: ERB

ANNEX I.4.7

ANNEX I.4.8

ELECTRICITY TARIFFS FOR SEBs FROM 12-31-72 to 12-31-76: KARNATAKA

(Energy charge and tariff are in paise/kwh and demand charge and minimum charge are in rupees)

	Domestic	Industrial L.T.	Industrial H.T.	Agricultural	Public Lighting	Commercial
End of 1972	Lights 30 Minimum Charge Rs 2/mo Heat & Power 12 Minimum Charge Rs 8/KW	12 Rs 7/BHP/mo	Demand Charge First 500 KVA Rs 9/KVA/mo Next 500 8 Next 2000 7 Next 3000 6 Balance 5 Energy Charge First 100 kwh 5 Next 100 4 Next 100 3.5 Balance 3	11 Minimum Charge Rs 36/HP/year	15 Minimum Charge Rs 30/KW of connected load	First 120 kwh 40 Balance 35 Minimum Charge Rs 3/250 W of connected load
End of 1976[1/]	Lights First 30 kwh 30 Balance 35 + Demand Charge Rs 1/installation/mo Heat & Power 14 Demand Charge Rs 10/installation/mo Minimum Charge Rs 8/KW/mo	Demand Charge Rs 10/installation/mo Energy Charge 15 Minimum Charge Rs 7/NHP/mo	Demand Charge Rs 10/KVA/mo Energy Charge 6	Demand Charge Rs 10/installation/mo Energy Charge 15 Minimum Charge Rs 50/HP/year		Demand Charge Rs 3/installation/mo Energy Charge First 30 kwh 40 Balance 50 Minimum Bill Rs 3/installation/mo

1/ There was a 15% surcharge on both demand and energy charges in 1976 for every consumer category except agriculture.

Source: ERB

ELECTRICITY TARIFFS FOR SEBs FROM 12-31-72 to 12-31-76: KERALA

(energy charge and tariff are in paise/kwh and demand charge and minimum charge are in rupees)

	Domestic	Industrial L.T.	Industrial H.T.	Agricultural	Public Lighting	Commercial
End of 1972	First 60 Kwh 30 Balance 15 Minimum Charge Rs. 4/mo.	First 2,000 Kwh 15 Balance 14 Minimum Charge Rs. 4/KW	Demand Charge First 500 KVA Rs 11/KVA/mo. Next 500 KVA Rs 10/KVA/mo. Balance Rs 9KVA/mo. Energy Charge First 50,000 Kwh 7 Next 50,000 Kwh 6.75 Next 50,000 Kwh 6.5 Next 50,000 Kwh 6.25 Next 50,000 Kwh 6 Next 50,000 Kwh 5.75 Balance 5.5 Minimum Charge Rs 4/KW	9 Minimum Charge Rs. 7/month	Rs.1-603/year/bulb depending on wattage and hours of use	38 Minimum Charge Rs. 6/mo.
End of 1976	First 50 Kwh 25 Next 50 Kwh 15 Balance 10 Fixed Charge Rs.4/month	First 2,000 Kwh 15 Balance 14 Minimum Charge Rs.4/KW/mo.	Demand Charge Rs.22KVA/mo. Energy Charge First 250KWH/KVA/mo. 6 Next 250KWH/KVA/mo. 5 Balance 4	Single-phase Fixed charge Rs.5 meter/mo. Energy Charge 10 Three Phase Fixed Charge Rs. 10/meter/mo. Energy Charge 10	Energy Charge 30 Fixed Charges Rs 4.25 to Rs 8.50 per lamp	Lighting 38 Minimum Charges Rs.6/mo. Heat and Power 24 Minimum Charge Rs. 8/mo.

Source: ERB

ELECTRICITY TARIFFS FOR SEBs FROM 12-31-72 to 12-31-76: MADHYA PRADESH

(energy charge and tariff are in paise/kwh and demand charge and minimum charge are in rupees)

	Domestic	Industrial L.T.	Industrial H.T.	Agricultural	Public Lighting	Commercial
End of 1972						
	28 Minimum Charge Rs 2/mo	15.5 1/ Minimum Charge 30Kwh/BHP/mo	Demand Charge First 500 KW Rs 10/KW/mo Next 1000 KW Rs 9.5/KW/mo Balance Rs 8.5/KW/mo Energy Charge First 50000 kwh 7.7 Next 150,000 kwh 7.5 Next 300,000 kwh 7.25 Balance 6.8	13 Minimum Charge 360Kwh/BHP/year	First 12000 kwh 31 Next 36,000 kwh 29 Balance 21.5	Same as domestic
End of 1976						
	First 50 kwh 30 Balance 32 Minimum Charge Rs 6.25/mo	22 Minimum Charge Rs 10.75/BHP/mo	Demand Charge First 500 KW 13.85 Next 1000 KW 13.3 Balance 11.9 Energy Charge First 50,000 Kwh 12.2 Next 1,500,000 11.9 Next 3,000,000 11.6 Balance 10.95	16 Minimum Charge Rs 3.75-6.25/mo depending on BHP	First 12000 Kwh 37 Next 36000 Kwh 34.8 Balance 25.8	Lighting 40 Minimum Charge Rs 3/mo Power 25 Minimum Charge 30 Kwh/BHP/mo

1/ Alternative tariffs are available

Souce: ERB

ELECTRICITY TARIFFS FOR SEBs FROM 12-31-72 to 12-31-76: MAHARASHTRA

(Energy charge and tariff are in paise/kwh and demand charge and minimum charge are in rupees)

	Domestic	Industrial L.T.	Industrial H.T.	Agricultural	Public Lighting	Commercial
End of 1972	First 30 Kwh 31 Balance 25 Minimum Charge Rs 2.00	18 Minimum Charge Rs 4.95/BHP/mo	Demand Charge First 1000 KVA Rs 12/KVA/mo Balance Rs 11/KVA/mo Energy Charge First 100,000 Kwh 8 Next 200,000 Kwh 7 Balance 6.5	18 Minimum Charge Rs 40/BHP/year	Energy Charge First 200 kwh/mo/KW 20 Balance 6 Fixed Charge Rs 1 lamp/mo for street lights on distribution lines Rs 2.5 lamp/mo for street lights not on distribution lines	35 Minimum Charge Rs 3.5/mo
End of 1976	Lights & fans First 30 kwh 31 Balance 35 Minimum Charge Rs 4 /mo Heat & Power 20 Minimum Charge single phase supply Rs 10/mo three phase supply Rs 20 /mo	25 Minimum Charge Rs 5/BHP/mo	Demand Charge Rs 16/KVA/mo Energy Charge 11	22 Minimum Charge Rs 40/BHP/mo	First 100 Kwh/mo/KW 18 Next 100 Kwh/mo/KW 22 Balance 10	Lights & fans 40 Minimum Charge Rs 4 /mo Heat & Power 30 Minimum Charge single phase supply Rs 15 /mo three phase supply Rs 30 /mo

Source: ERB

ELECTRICITY TARIFFS FOR SEBs FROM 12-31-72 to 12-31-76: ORISSA

(energy charge and tariff are in paise/kwh and demand charge and minimum charge are in rupees)

	Domestic	Industrial L.T.	Industrial H.T.	Agricultural	Public Lighting	Commercial
End of 1972						
	Hydro First 30 Kwh 28 Next 50 Kwh 20 Balance 13 Minimum Charge Rs.1.5 for first KW and Rs 1 for each additional KW Diesel 44-50	Hydro 14 Minimum Charge Rs.6.5/kw/mo. or Rs.5/BHP/mo. Diesel 25 Minimum Charge Rs.5/BHP/mo.	Hydro Demand Charge First 4000 KVA Rs. 9/KVA/mo. Balance Rs. 8/KVA/mo. Energy Charge First 1,000,000 Kwh 8 Balance 7 Overall Maximum Rate 10 paise/Kwh	Hydro 12 Minimum Charge Rs.24/BHP/year Diesel 25 Minimum Charge Rs.5/BHP/mo.	Hydro 21 plus maintenance charge of between Rs.1-5.5/lamp/mo. according to type and wattage Diesel 19 plus maintenance charge of Rs.12/ lamp/year	Hydro First 100 KWH 28 Balance 23 Minimum Charge Rs. 2.5 for the first KW and Rs. 2 for each additional KW
End of 1976						
	First 30 KWH 31 Next 50 Kwh 23 Balance 16 Minimum Charge Rs.5 for first KW and Rs.6 for each additional KW	First 200 KWH/KW/mo. 18 Balance 17 Minimum Charge Rs.10/KW/mo. Rs.7.5/BHP/mo.	Demand Charge First 4000 KVA Rs.10/KVA/mo. Balance Rs.9/KVA/mo. Energy Charge First 400KWH/KVA/mo. 12 Balance 11 Overall Maximum Rate 14.5 paise/Kwh	16 Minimum Charge June - Oct. Rs.1/BHP/mo. Nov. - May Rs3/BHP/mo.	26 Fixed Charge Rs 1-8.00/lamp	First 100 KWH 34 Balance 29 Minimum Charge Rs.4.5,5, and 10 for the first one half KW, second one half KW, and remaining KW's.

Source: ERB

ANNEX I.4.12

ELECTRICITY TARIFFS FOR SEBs FROM 12-31-72 to 12-31-76: PUNJAB

(energy charge and tariff are in paise/kwh and demand charge and minimum charge are in rupees)

	Domestic	Industrial L.T. 1/	Industrial H.T.	Agricultural	Public Lighting	Commercial
End of 1972	First 15 KWH 32.81 Next 25 KWH 14.06 Balance 7.81 Minimum Charge Rs.1/mo.	First 500 Kwh 11.0 Next 1000 Kwh 10.5 Balance 9.0 Minimum Charge Rs 2.50/KW	Demand Charge First 1,000 KVA Rs. 6.5/KVA/mo. Balance Rs.5.5KVA/mo. Energy Charge First 100,000 KWH 5 Next 200,000 KWH 4.5 Balance 4	Fixed Charge Rs.7-9/BHP/mo. depending on BHP Demand Charge Rs.1/BHP/mo.	Energy Charge 15 Maintenance Charge Rs.1-17/lamp/mo. depending on type of lamp and wattage	First 30 KWH 32.81 Next 50 KWH 14.06 Balance 10.94 Minimum Charge Rs. 1.5/mo.
End of 1976	First 15 KWH 35 Next 25 KWH 20 Balance 18 Minimum Charge Rs. 3/mo.	18.5 Minimum Charge Rs 9.00/KW	Demand Charge Rs.14/KVA/mo. Energy Charge 11 Overall Maximum Rate 18 paise/Kwh	Demand Charge Rs.1.5/BHP/mo. Energy Charge 19.0 Minimum Charge Rs.9/BHP/mo.	25 Fixed Charge Rs 3.25-4.50/lamp	First 80 KWH 40 Balance 50 Minimum Charge Rs.5/month

1/ Small Industrial LT consumers.

Source: ERB

ELECTRICITY TARIFFS FOR SEBs FROM 12-31-72 to 12-31-76: RAJASTHAN

(energy charge and tariff are in paise/kwh and demand charge and minimum charge are in rupees)

	Domestic	Industrial L.T.	Industrial H.T.	Agricultural	Public Lighting	Commercial
End of 1972	Hydro & Steam 37 Minimum Charge Rs.2/mo. Diesel 50 Minimum Charge Rs.2/mo.	Hydro & Steam 13.5 Minimum Charge Rs.42/BHP/year 15% surcharge in effect from 6-1-69 Diesel 26 Minimum Charge Rs.84/BHP/year	Hydro & Steam Demand Charge First 600 KVA Rs.8.25/KVA/mo. Next 1,200 KVA Rs.8/KVA/mo. Rs. 7.5/KVA/mo. Energy Charge First 50,000 7 Next 150,000 6.75 Next 300,000 6.5 Balance 6.25	Hydro & Steam 13 Minimum Charge Rs.42/BHP/year Diesel 13 Minimum Charge Rs.42/BHP/year	Hydro & Steam 28 Minimum Charge Rs.2/lamp/mo. Diesel 35 Minimum Charge Rs. 2.5/lamp/mo.	Hydro & Steam Lighting 40 Minimum Charge Rs.2/mo. Heat and Power 22 Minimum Charge Rs.5/mo. Diesel Lighting 53 Minimum Charge Rs.2/mo. Heat and Power 28 Minimum Charge Rs.2/mo.
End of 1976	Light 43 Heat and Power 30	28 Minimum Charge Rs.10/HP/mo.	Demand Charge Rs.18/KVA/mo. Energy Charge First 300,000 KWH 16 Next 500,000 KWH 15 Next 700,000 KWH 14 Next 1,000,000 KWH 12 Balance 11 Minimum Charge Rs. 110-130/KVA/mo.	30 Minimum Charge Up to 3HP Rs. 90/HP/year 3HP-5HP Rs. 100/HP/year 5HP - 7.5HP Rs. 140/HP/year 7.5-10HP Rs. 160/HP/year above 10HP Rs.175/HP/year	Energy Charges 33 Minimum Charge Rs 3.00/point	First 500 KWH 55 Next 500 KWH 50 Next 500 KWH 45 Balance 35 Minimum Charge Rs.10/KW/mo.

Source: ERB

ANNEX I.4.14

ELECTRICITY TARIFFS FOR SEBs FROM 12-31-72 to 12-31-76: TAMIL NADU

(Energy charge and tariff are in paise/kwh and demand charge and minimum charge are in rupees)

	Domestic	Industrial L.T.[1/]	Industrial H.T.	Agricultural	Public Lighting	Commercial
End of 1972	First 50 kwh 35 Balance 30 Minimum Charge Rs 3/mo	18 Minimum Charge Rs 5.00/HP/mo	Hydro Demand Charge First 500 KVA Rs 12.5/KVA/mo Next 500 KVA Rs 11.5/KVA/mo Balance Rs 9.5/KVA/mo Energy Charge First 50,000 kwh 9.25 Next 50,000 kwh 8.75 Next 200,000 kwh 7.75 Next 500,000 kwh 6.25 Balance 6 Thermal Demand Charge First 1000 KVA Rs 14.5/KVA/mo Balance Rs 14/KVA/mo Energy Charge First 50,000 kwh 11.75 Next 450,000 11.5 Next 500,000 11.25 Next 500,000 10.75 Next 1,000,000 10.25 Balance 7.5	First 100 kwh 12 Balance 11 Minimum Charge Rs 20/HP/year	Filament lamps First 16,000 kwh 18 Balance 15 Mercury Vapour lamps Rs 1.75-5/mo Fluorescent lights Rs 5-8/mo	First 500 kwh 45 Balance 40 Minimum Charge Rs 5/mo
End of 1976	35 Minimum Charge Rs 3/mo	20 + 50% surcharge + 1P/kwh special surcharge Minimum Charge Rs 5/HP/mo	Demand Charge 15/KVA/mo Energy Charge First 500,000 kwh 12 Balance 11.5 + 50% surcharge + 1P/kwh special surcharge Minimum Charge Rs 225/KVA/year	16 Fixed Charge Rs 2.50/HP/mo	Energy Charge 27 Fixed Charge Rs 1.25-5.00/lamp	45 + 50% surcharge + 1P/kwh special surcharge

1/ Small industrial consumers.

Source: ERB

ELECTRICITY TARIFFS FOR SEBs FROM 12-31-72 to 12-31-76: UTTAR PRADESH

(energy charge and tariff are in paise/kwh and demand charge and minimum charge are in rupees)

	Domestic	Industrial L.T.[1/]	Industrial H.T.	Agricultural	Public Lighting	Commercial
End of 1972	Lights 30 Minimum Charge Rs.3/month Power 19 Minimum Charge Rs.3/month	20	Demand Charge Rs.12/KW/mo. Energy Charge First 200 KWH 9.25 Next 200 KWH 7.75 Balance 6.75	Energy Charge 20 Fixed Charge Rs.36/BHP/year	26 Minimum Charge Rs.1.5/lamp/mo.	Rs.3/mo. same as domestic
End of 1976	Lights 46 Minimum Charge Rs.5/mo. Power 36 Minimim Charge Rs.5/mo.	24 Minimum Charge Rs.15/BHP/mo.	First 200 KWH/KW 19 Balance 13 Minimum Charge Rs.25/KW/mo.	Rs.15/BHP/mo.	28	Light 56 Minimum Charge Rs.50/mo. Power 46 Minimum Charge Rs.50/mo.

1/ Small Industrial consumers only

Source: ERB

ELECTRICITY TARIFFS FOR SEBs FROM 12-31-72 to 12-31-76: WEST BENGAL

(Energy charge and tariff are in paise/kwh and demand charge and minimum charge are in rupees)

	Domestic	Industrial L.T.	Industrial H.T.	Agricultural	Public Lighting	Commercial
End of 1972						
	Lights 36 Minimum Charge Rs 2/mo Heat & Power 15 Minimum Charge Rs 2/mo	First 2000 kwh 11 Balance 10 Minimum Charge Rs 36/HP/year	Demand Charge First 100 KVA Rs 13/KVA/mo Next 200 KVA Rs 12/KVA/mo Balance Rs 11/KVA/mo Energy Charge First 10,000 kwh 7 Next 20,000 kwh 6.5 Balance 6	First 500 kwh 16 Balance 14 Minimum Charge Rs 50/HP/year	Rs 3-11.5/lamp/mo depending on wattage Minimum Charge 75P/lamp/mo.	Same as domestic
End of 1976						
	Lights 45 Minimum Charge Rs 4.5/mo Heat & Power 32 Minimum Charge Rs 4.5/mo or Rs 6/HP/mo depending on use	Same as agricultural	6/11 KV Demand Charge Rs 30/KVA/mo Energy Charge 12 33 KV Demand Charge Rs 30/KVA/mo Energy Charge 9.5	32 Minimum Charge Rs 75/HP/year	Fixed Charge Rs 4.50-16.30/lamp	Lights 55 Minimum Charge Rs 5.5/mo Heat & Power 40 Minimum Charge Rs 6/mo or Rs 8/HP/mo depending on use

Source: ERB

ANNEX I.4.17

ANNEX I.4.18

ELECTRICITY TARIFFS FOR SEBs FROM 12-31-72 to 12-31-76: DELHI (DESU)

(Energy charge and tariff are in paise/kwh and demand charge and minimum charge are in rupees)

	Domestic	Industrial L.T.	Industrial H.T.	Agricultural	Public Lighting	Commercial
End of 1972	Lighting & fans 18 Minimum Charge Rs 1.5/mo Power 14 Minimum Charge Rs 2.5/mo if below 5KW Rs 3/mo if above 5KW	15 Minimum Charge Rs 5/KW	Demand Charge Up to 500 KW Rs 10/KW/mo Up to 1000 KVA Rs 8/KVA/mo Next 4000 KVA Rs 7/KVA/mo Balance Rs 6/KVA/mo Energy Charge First 500 kwh 9.5 Next 500,000 kwh 9 Next 1,000,000 kwh 8.5 Balance 8 Overall Maximum Rate 13.50 paise/Kwh	same as industrial L.T.	15 + maintenance charge Rs 3/lamp/mo	22 Minimum Charge Rs 3/mo
End of 1976	25 Minimum Charge Rs 3/mo	22 Minimum Charge Rs 6/HP/mo	Demand Charge For 500 KW Rs 20/KVA/KW/mo For 1000 KVA Rs 16.5/KVA/KW/mo Next 5000 KVA Rs 16/KVA/KW/mo Balance Rs 15.5/KVA/KW/mo Energy Charge First 500,000 kwh 19.5 Next 500,000 19 Next 1,000,000 18.5 Balance 18	20	22 Fixed Charge Rs 5.50/lamp	35 Minimum Charge Rs 5/KW/mo

Source: ERB

ANNEX I.4.19

AVERAGE REVENUE REALISED FROM SALE OF ELECTRICITY BY STATE ELECTRICITY BOARDS

(Paise per Kwh)

Year	Region	Domestic	Commercial	Agricultural	Small Industry	Large Industry	Average
1974/75							
	Northern	29.07	45.97	18.44	20.47	18.84	20.99
	Western	30.12	35.48	19.16	20.28	16.75	19.20
	Southern	35.79	59.48	13.23	21.99	17.37	21.09
	Eastern	37.24	41.01	18.35	23.07	18.64	21.21
	Total	32.78	49.53	16.61	21.17	17.64	20.57
1975/76							
	Northern	29.84	46.51	19.72	20.78	19.06	21.61
	Western	30.11	35.49	22.12	23.49	19.54	21.91
	Southern	37.49	65.39	16.52	24.38	19.37	23.92
	Eastern	38.85	47.02	15.39	28.61	23.43	25.41
	Total	33.68	52.47	18.94	23.38	20.06	23.01
1976/77							
	Northern	35.78	47.06	19.99	22.09	22.27	23.78
	Western	30.46	36.35	22.91	25.03	22.15	23.87
	Southern	37.56	65.93	17.50	24.49	20.45	25.11
	Eastern	38.68	47.35	15.91	28.56	23.87	25.40
	Total	35.56	53.21	19.60	24.00	21.87	24.46

Notes: The average electric rates used are: (1) Domestic lighting (30 kwh/month), (2) Commercial lighting (200 kwh/month), (3) Agricultural 10 HP, 15% LF (817 kwh/month), (4) Small Industry, 10 KW, 20% LF (1460 kwh/month), (5) Large Industry, 250 KW, 40% LF (73,000 kwh/month).

Northern Region - Haryana, Himachal Pradesh, Punjab, Rajasthan and Uttar Pradesh
Western Region - Gujarat, Madhya Pradesh & Maharashtra
Southern Region - Andhra Pradesh, Karnataka, Kerala & Tamil Nadu
Eastern Region - Bihar, Orissa & West Bengal.

Sources: Average Electric Rates and Duties in India, August 1976, Central Electricity Authority and GR

PRICE INDICES IN THE ENERGY SECTOR
(1970/71=100)

	1961/62	1962/63	1963/64	1964/65	1965/66	1966/67	1967/68	1968/69	1969/70
All Commodities(WPI) (1000.00)	55.2	55.4	59.7	67.4	72.8	84.4	88.3	91.3	94.7
Coal (11.47)	59.6	62.5	66.8	69.3	72.5	76.5	88.1	100.2	98.9
Electricity (24.00)	66.6	72.6	76.6	79.7	83.2	91.4	92.2	95.4	95.8
Petroleum (6.02)	71.8	73.3	80.9	81.2	83.5	88.6	91.7	93.8	97.1

	1970/71	1971/72	1972/73	1973/74	1974/75	1975/76	1976/77	1977/78	Growth Rates 1961/62-1970/71	Growth Rates 1970/71-1977/78
All Commodities(WPI)	100.0	105.6	116.2	139.7	174.9	172.9	176.6	185.6	6.8	9.2
Coal	100.0	103.2	112.5	122.9	146.6	185.0	197.6	197.6	5.9	10.2
Electricity	100.0	102.5	105.7	111.3	137.2	158.1	171.6	181.4	4.6	8.9
Petroleum	100.0	130.2	142.0	317.1	686.5	700.3	740.3	785.2	3.7	34.2

Source: RBI Bulletins, various 1977 editions and the Fuel Policy Committee Report, 1974.
The index for 1961/62 to 1970/71 for petroleum is only for petrol and diesel oil, weighted with the 1970 weights from the WPI. Thereafter, it is the index for crude petroleum and natural gas.

Note: Figures for 1961/62 to 1970/71 are based 1960, spliced into the 1970/71=100 WPI by dividing by the index value to the last year.

ANNEX I.4.21

AVERAGE REVENUE PER UNIT OF POWER SOLD
(paise/kwh)

	1970/71	1971/72	1973/74	1974/75	1975/76
Domestic	25.0 2/	24.8	26.0	27.0	29.0
Commercial	-	25.1	27.2	35.7	38.8
Industrial	9.7 3/	9.9	11.5	15.4	18.8
Public Lighting	-	24.8	25.0	26.8	31.8
Traction	-	11.5	12.8	16.2	19.7
Agricultural	14.2	14.4	16.0	18.9	21.9
Water Supply and Sewerage	-	9.2	13.0	14.8	18.6
Average 1/	12.4	12.7	14.5	18.4	21.6

1/ The average revenue per unit sold excludes miscellaneous revenue not directly attributable to any particular class of consumer, e.g., rent.

2/ Includes Commercial.

3/ Includes Traction.

Note: Regarding the 1970/71 figures, while it is not clear from the source tables if public lighting and traction are included under industry this seems likely. The per unit revenue for industry excluding these categories would be less than that given here, but not very much so, since public lighting and traction are relatively small classes of consumer.

Source: GR

THE LEVEL OF LONG RUN MARGINAL COST BASED (LRMC) TARIFFS

This note is in three parts. The first two parts deal with long run marginal capacity costs, the third with LRMC tariffs as a whole. The first part shows that the average revenue realized from the capacity element of LRMC tariffs bears a simple relationship to the total size of the investment program and the expected increase in demand. The second part shows that this in turn is almost unaffected by considering only a short time slice of the investment program in a steady state growth situation. The third part uses the conclusions of the first two parts to calculate a lower bound for the average revenue that would be realized by LRMC tariffs.

Part I

This discussion is in terms of the average incremental cost concept rather than any other approach to LRMCs. This is not to argue that this is the best or most applicable way to calculate long run marginal costs, but, given the system characteristics in India (by and large mixed hydro-thermal systems) it is reasonable to assume that this concept yields values close enough for our purposes here to those that might otherwise be derived.

Let AIC = average incremental costs per KW of demand at time of system peak.

G = present value of future generation expansion costs

N = present value of future transmission expansion costs

S = present value of future distribution expansion costs

D = demand (KW) at time of system peak

$\tilde{D}$ = energy demanded (kwh) per year

L = low tension, or distribution

H = high tension, or transmission

λ_g = capacity margins

λ_L, λ_H = losses

θ = annuitizing factor

z = $\tilde{D} / D$

a = $\theta / z = \theta D / \tilde{D}$

AR = average revenue from the capacity component of a LRMC tariff per kwh sold, and

Δ = the present value of increments in...

Then $$AIC_H = (G(1+\lambda_g)(1+\lambda_H)+N)/\Delta D_H \tag{1}$$

$$AIC_L = (G(1+\lambda_g)(1+\lambda_H)(1+\lambda_L)+N(1+\lambda_L)+S)/\Delta D_L \tag{2}$$

and $$AR = (AIC_H a_H \tilde{D}_H + AIC_L a_L \tilde{D}_L)/\tilde{D} \tag{3}$$

Rearranging (3), substituting (1) and (2) and expanding the $1+\lambda$ terms implies

$$AR.\tilde{D} > (G+N)a_H\tilde{D}_H/\Delta D_H + (G+N+S)a_L\tilde{D}_L/\Delta D_L + M \tag{4}$$

where $$M = G(\lambda_g+\lambda_H)a_H\tilde{D}_H/\Delta D_H + [G(\lambda_g+\lambda_H+\lambda_L)+N\lambda_L]\tilde{D}_L a_L/\Delta D_L$$

Rearranging terms,

$$M = \frac{G a_H \tilde{D}_H}{\Delta D_H}\left\{\lambda_g + \lambda_H + (\lambda_g+\lambda_H+\lambda_L)\frac{\tilde{D}_L a_L \Delta D_H}{\tilde{D}_H a_H \Delta D_L} + \frac{N}{G}\lambda_L \frac{\tilde{D}_L a_L \Delta D_H}{\tilde{D}_H a_H \Delta D_L}\right\}$$

Conservative estimates of the values of the terms in $\{\ \}$ are:

$$\lambda_g = 0.36,\ \lambda_H = 0.01,\ \lambda_L = 0.15,\ \frac{\tilde{D}_L}{\tilde{D}_H}.\frac{\Delta D_H}{\Delta D_L} = 0.5,\ \frac{N}{G} = 0.2 \text{ and } \frac{a_L}{a_H} = 1.2.$$

Thus, $$M \geqslant \frac{G a_H \tilde{D}_H}{\Delta D_H}\left\{0.37 + 0.52 \times 0.5 \times 1.2 + 0.2 \times 0.15 \times 1.2 \times 0.5\right\}$$

$$= \frac{G a_H \tilde{D}_H}{\Delta D_H} \times 0.7$$

In India, it is reasonable to assume $S < 0.7G$, and so $M > S\dfrac{a_H\tilde{D}_H}{\Delta D_H}$.

Substituting into (4) implies $\tilde{D}.AR > (G+N+S)\left\{\dfrac{a_H\tilde{D}_H}{\Delta D_H} + \dfrac{a_L\tilde{D}_L}{\Delta D_L}\right\}$

But $a_H\tilde{D}_H = \Theta D_H$ and $a_L\tilde{D}_L = \Theta D_L$:

Therefore $AR > \dfrac{\Theta(G+N+S)}{\Delta D}\left\{\left(\dfrac{D_L}{\Delta D_L} + \dfrac{D_H}{\Delta D_H}\right).\dfrac{\Delta D}{D}\right\}.\dfrac{D}{\tilde{D}} > \Theta\dfrac{(G+N+S)}{\Delta D}.\dfrac{D}{\tilde{D}}$,

since $\dfrac{D_L}{\Delta D_L}.\dfrac{\Delta D}{D}$ and $\dfrac{D_H}{\Delta D_H}.\dfrac{\Delta D}{D}$ are together greater than 1. Furthermore, $a.\Delta\tilde{D} \doteqdot \Theta\Delta D$;

so it follows that

$$AR > \frac{\Theta(G+N+S)}{\Delta\tilde{D}} \tag{5}$$

(5) may be restated in words as: the average revenue realized from the capacity component of LRMC tariffs is greater than the annuitized present value of the investment program divided by the present value of the increase in kwh of consumption. Since this is true using the average incremental cost method of calculating LRMCs, it is an indication of the relationship for other methods of calculating incremental system costs in India, since peaking capacity in Indian systems is largely hydro; gas turbines are not being widely advocated for peaking in long term expansion plans.

Part II

The relationships in Part I are all defined in terms of present values of long investment streams. The purpose of this part is to show that the relationships are likely to be well approximated by summing investment in consecutive years and by considering just a short time period, i.e. 5 rather than 15 or 20 years.

It is reasonable to assume that increments in capacity costs (X) and consumption (Y) will grow at about the same rate, α, and that, as a first approximation, both will grow logarithmically. If i is the continuous discount rate and t the time subscript, then consider the expression U, where

$$U = \{ \int_0^{20} X_t e^{-it} dt \} / \int_0^{20} Y_t e^{-it} dt \} \qquad (6).$$

Since $X_t \doteq X_0 e^{\alpha t}$ and $Y_t = Y_0 e^{\alpha t}$,

$$U \doteq \{ \int_0^{20} X_0 e^{(\alpha - i)t} dt \} / \{ \int_0^{20} Y_0 e^{(\alpha - i)t} dt \}.$$

Removing the constants X_0 and Y_0 from the integration, the integrals in the denominator and numerator are the same, so that $U \doteq X_0 / Y_0$. Multiplying top and bottom by a simpler integral, it follows:

$$U \doteq \{ X_0 \int_0^5 e^{\alpha t} dt \} / \{ Y_0 \int_0^5 e^{\alpha t} dt \}$$

and taking the constant terms into these integrals, this implies

$$U \doteq \{ \int_0^5 X_t \, dt \} / \{ \int_0^5 Y_t \, dt \}. \qquad (7)$$

(7) has been shown to approximately equal to (6) when the discount factor i is removed and the period is shortened from 30 to 5 years. Applying this logic to expression (5) it is now shown to be true when G+N+S is simply the cost of the investment program for the next 5 years and $\Delta\tilde{D}$ is the increase in consumption (kwh) expected over this period. (5) has now become a very simple formula it is possible to apply in Part III of this note.

Part III

LRMC have of course two elements, a capacity cost and a recurrent cost and they vary from category to category of consumer. The average revenue per kwh sold for any consumer category or for all consumers taken together will be the sum of the average revenue of the capacity cost component of the tariff (A_1) and a recurrent cost component (A_2). Using (5), we can derive a lower bound for A_1, for all consumers taken together.

The New Draft Plan calls for an investment of Rs 157,500 million in the 5 years, 1978/79 to 1982/83. (This is the value of G+N+S in (5).) The annuitized cost of this investment is about Rs 16,700 million, when it is annuitized over 30 years at a 10% discount rate. Over the Plan period, total consumption (from the utility system) is expected to rise from 69,000 Gwh to 129,000 Gwh, per year, or by 60,000 Gwh. Thus, dividing Rs 17,000 million by 60,000 Gwh, a lower bound for A_1 of about 28 paise/kwh is derived. In the original Andhra Pradesh study , marginal energy was considered to be generated from the older plant on the system, at an operating cost of roughly 10 paise/kwh. The study estimate was in 1975 prices, so that 10 paise/kwh is probably a conservative estimate of marginal energy costs in 1977/78 prices, in most States in India. (More recent work on tariffs in Andhra Pradesh, undertaken as part of a review of all aspects of the State power sector, suggests that between 11 and 13 paise/kwh is the cost of energy supplied to H.T. and L.T. consumers respectively.) Allowing for sytem losses that average 18% throughout India (as forecast in the New Draft Plan), A_2 for all consumers probably exceeds 12 paise/kwh. Thus, the average revenue realized by LRMC tariffs would be greater than 40 paise/kwh.

FORECAST AND ANNUAL ENERGY REQUIREMENTS FOR ALL INDIA IN THE ANNUAL ELECTRIC POWER SURVEYS

(Twh at the bus-bar)

		1962/63	1963/64	1964/65	1965/66	1966/67	1967/68	1968/69	1969/70	1970/71	1971/72	1972/73	1973/74	1974/75	1975/76	1976/77	Annual Percentage Gvmt Rates
Actuals		23.7	25.4	28.1	30.5	34.6	39.2	45.0	49.3	53.6	58.2	62.1	64.1	66.9	75.6	84.1 2/	9.1
Forecasts																	
Date of Publication	Number of Power Survey																
1963	I		29.2 (15.0)	35.1 (24.9)	44.9 (47.2)	52.6 (52.0)	61.0 (55.6)	70.6 (56.9)	81.4 (65.1)	95.1 (77.4)							1[illegible].6
1964	II			33.3 (18.5)	42.9 (40.7)	51.5 (48.8)	62.0 (58.2)										20.5
1965	III				39.3 (28.9)	48.8 (41.2)	59.0 (50.5)	70.6 (56.9)									19.5
1966	IV					38.5 (11.3)	46.3 (18.1)	54.8 (21.8)	62.5 (26.8)	76.0 (41.8)							16.6
1968	V							48.4 (7.6)	56.3 (14.2)	66.2 (23.5)	74.5 (28.0)	85.1 (37.0)	99.3 (54.9)				19.4
1969	VI								53.9 (9.3)	61.3 (14.4)	68.3 (17.4)	75.7 (21.9)	87.7 (36.8)				11.8
1970	VII										60.9 (4.6)	68.1 (9.7)	76.3 (19.0)	86.1 (28.7)			11.5
1974	IX													80.3 (20.0)	91.0 (20.4)	102.3 (21.6)	11.7

Notes: 1. Figures in brackets are percentage deviations from actuals. For a number of years, the later ones especially, the actuals reflect shortages, that is they represent restricted requirements. The series of actuals is taken from successive Annual Electric Power Surveys and therefore does not correspond exactly to any of the series in the other tables of this report. There is a deviation in some observations of about 2% from the series for net generation by utilities, to which the actual series should correspond; this deviation is unexplained.

2. The Eighth Annual Electric Power Survey was not published.

Source: The Annual Electric Power Surveys of India: various volumes.

ANNEX 1.5.1

EARLIER EFFORTS AT REGRESSION ANALYSIS

This annex takes note of earlier attempts at using regression analysis to forecast power demand. A number of European countries have used this general method, including Austria, Belgium and the Netherlands. Indeed, it is such an obvious technique to apply, there must be very few developed countries where the method has not been tried out.

In India, the Fuel Policy Committee experimented with regression techniques for long-term forecasting. Subsequently, the Planning Commission has used regression analysis to forecast energy demand as part of the work of the Energy Policy Group. Though the details of their work are not yet available, their approach is broadly similar to that used in this review (and the review of the Andhra Pradesh Power Sector). A more elaborate approach was recently adopted in a study for Andhra Pradesh undertaken by the Administrative Staff College (ASC) in Hyderabad.

The ASC study disaggregated electricity demand into seven major categories and one miscellaneous, for each of which two equations were fitted: one for the number of customers and one for the number of kwh consumed per customer. The equations were either linear or log linear depending on which fitted better, and were estimated starting with a large number of explanatory variables that was eventually reduced by stepwise elimination to 12 1/.

The strength and weakness of this model lay in its flexibility. With so many explanatory variables that could be related to various state government

1/ In addition, there were 9 lagged endogenous variables.

policy instruments (as well as external factors such as the weather), it was possible to illustrate the likely effect of different policies: for example, the impact an increase in the number of L.T. Industrial consumers, which might have been the expected result of a policy of promoting small scale industry, could be readily analyzed. Its weaknesses as a tool for forecasting were two-fold. First, a statistical problem the model faced was multicollinearity. The effect is to render many of the explanatory variables next to valueless in forecasting: many could be eliminated and the model simplified and virtually the same forecast result.

The second problem was one of practicality. Any decision-maker using an analytical tool likes to know where errors are likely to arise and be able to make allowances for them. In statistical forecasting models there are five commonly recognised reasons why forecasts may go astray. These are: (i) the wrong equation or variables are used (specification error); (ii) coefficients are inaccurately estimated (estimation error); (iii) one-off shocks to the economy may alter the underlying situation (e.g.: the oil crisis or a change in State boundaries); (iv) more gradual changes in the economic structure may not be anticipated (e.g. an acceleration of rural electrification with a new Government); and (v) the exogenous variables -- the weather, the level of economic activity and so forth -- may be incorrectly forecast. In a relatively simple model it is easier to make allowances for errors of types (iii) to (v). Analysing the possible errors in the final demand forecast that may result from faulty forecasts of 12 exogenous variables in a relatively complex business: there are 12 assumptions to dispute instead of two or three in a simpler model. It is our judgment that, at the risk of maying type (i) specification errors, a simpler forecasting model is much to be preferred.

THE REGRESSION ANALYSIS: TECHNICAL DESCRIPTION

This annex provides a more technical description of the regression model used in this review and acts as a guide to the statistical annexes that summarize the results of the regression.

The model divides the economy and the consumption of power into three sectors: agriculture, industry and a residual or service sector. The industry and services parts of the sector model can be formally described by equation (1):

$$E = a V^{x} e^{bt} \qquad (1)$$

where E is consumption in industry or in services,

V is value-added in industry or services,

t is the year in question,

and a, x and b are coefficients to be determined by statistical regression.

The agricultural part of the model is even more simple:

$$dE = c.\, dP \qquad (2)$$

Where dE is the increase in electricity consumption in a given year in Kwh

dP is the increase in pumpsets -- i.e. the number of sets in the pumpset program, and

c is a coefficient to be determined by regression.

Cross-section analysis among States has been used to avoid multicoll-earity between value-added and time. The coefficient X in equation (1) is in fact estimated from the data in Annex I.5.4 using a truncated form of the equation: $E = aV^{x}$ (1')

Annex I.5.5 presents the results of alternative approaches to analysing the available data. Approach 1 analyses the relationship between value-added and electricity consumption using time series data but not taking time as an exogenous variable. The value-added coefficient, the simple elasticity, corresponds to x in equation (1'). The results for agriculture are not reported because the statistical fit was too poor. The elasticities for different sectors and time periods are quite high, and may overstate the relationship of value-added to electricity consumption to value-added, a view borne out to some extent by the results of the cross-section analysis; these are summarized in column (8) of Annex I.5.5.

One of the most obvious alternatives to the sectoral model is that of fitting equation 1 to time series data alone. The results of such an exercise are summarized as approach 2 in Annex I.5.5. As the Annex shows, while the explanatory power of the two variables taken together is good, the significance of the coefficient estimate is generally in doubt, and negative values have no clear and acceptable economic interpretation. The sectoral model, the results for which are summarized under Approach 3, are therefore preferred.

Annex I.5.6 presents analagous results for the five regions and for India (a) for the period 1960/61-1975/76, for which regional data are available, and (b) for regressions where captively generated electricity is included in the electricity consumption of both industry (based on the data in Annex I.1.15). As can be seen from that Annex, including captive generation makes little difference.

Cross-section Data on Electricity Consumption: 1974/75 and 1975/76

State Domestic Product at Current Prices (Rs Millions)

	Agriculture		Industry		Other		Total	
	1974/75	1975/76	1974/75	1975/76	1974/75	1975/76	1974/75	1975/76
Andhra Pradesh	27,418	22,149	4,685	4,936	14,981	17,081	47,084	44,166
Assam	8,006	8,539	2,364	2,697	2,781	2,974	13,151	14,210
Bihar	25,155	N.A.	6,960	N.A.	11,247	N.A.	43,362	N.A.
Gujarat	10,230	14,050	9,000	8,850	10,890	12,600	30,120	35,500
Haryana	8,021	8,386	1,701	1,174	3,669	44,165	13,391	14,625
Himachal Pradesh	2,373	2,361	187	191	1,348	1,442	3,908	3,994
Jammu & Kashmir	2,540	2,712	249	271	1,433	1,594	4,222	4,577
Karnataka	17,816	17,253	2,598	3,038	5,027	5,767	25,441	26,058
Kerala	11,055	10,753	1,957	2,010	7,306	8,579	20,318	21,342
Madhya Pradesh	22,959	20,815	5,997	6,601	8,685	9,360	37,641	36,776
Maharashtra	23,922	24,703	16,366	17,175	29,438	32,874	69,726	74,752
Orissa	11,545	12,855	1,389	1,621	3,665	4,298	16,599	18,774
Punjab	13,411	13,384	2,162	2,534	6,262	7,378	21,835	23,296
Rajasthan	14,171	15,926	2,024	2,284	6,628	7,372	22,823	25,582
Tamil Nadu	13,932	13,920	9,192	9,718	14,806	16,735	37,930	40,373
Uttar Pradesh	45,507	40,732	6,987	7,089	24,329	26,961	76,823	74,782
West Bengal	20,182	18,663	11,762	11,949	18,572	21,124	50,516	51,736

Electricity Consumption by Sector (gwh)

	Agriculture		Industry		Other		Total	
	1974/75	1975/76	1974/75	1975/76	1974/75	1975/76	1974/75	1975/76
Andhra Pradesh	674.2	616.7	1,307.7	1,537.0	587.1	642.8	2,569.0	2,796.5
Assam	5.0	5.0	192.5	219.0	226.8	212.4	424.3	436.4
Bihar	75.1	454.2	2,188.6	2,598.5	617.5	711.9	2,881.2	3,764.6
Gujarat	1,008.7	869.0	3,055.3	3,347.8	728.7	795.3	4,792.7	5,012.1
Haryana	527.6	594.6	520.4	777.9	191.0	229.2	1,239.0	1,601.7
Himachal Pradesh	2.1	2.6	40.5	47.7	166.6	170.2	209.2	220.5
Jammu & Kashmir	20.3	22.3	90.1	100.5	150.9	168.1	261.0	290.9
Karnataka	295.0	312.4	2,770.0	3,330.0	675.6	771.9	3,740.6	4,414.3
Kerala	101.1	120.5	1.395.1	1.497.4	332.9	379.1	1,829.1	1,997.0
Madhya Pradesh	161.8	170.5	2,082.7	2,660.0	534.9	555.6	2,779.4	3,386.1
Maharashtra	667.9	802.7	6,274.0	5,934.6	2,429.3	2,753.2	9,371.2	9,490.5
Orissa	8.9	9.0	1,426.6	1,844.5	194.7	241.9	1,630.2	2,095.4
Punjab	695.9	897.2	1,191.6	2,048.4 1/	331.9	434.2	2,219.4	3,379.8
Rajasthan	347.0	353.9	878.8	1.092.5	334.5	374.9	1,560.3	1,821.3
Tamil Nadu	1,849.8	1,694.0	2,673.8	3,341.4	1,035.5	1,169.3	5,559.1	6,204.7
Uttar Pradesh	1,233.4	1,702.2	2,535.0	2,790.7	913.5	1,432.0	4,681.9	5,924.9
West Bengal	40.3	51.6	3,419.9	3,683.1	1,634.8	1,768.5	5,095.0	5,503.2

1/ Nangal Fertilizer Project consumption of electricity is excluded from the 1974/75 figure and included in the 1975/76 figure.

Sources: CSO for state domestic product
CEA General Review, all India Statistics, 1974/75 and 1975/76

ANNEX I.5.5

RESULTS OF REGRESSION ANALYSIS: ALL INDIA

	Approach 1		Approach 2					Approach 3			
	Value Added Coefficient (1)	$\bar{R}^2$ (2)	Value Added Coefficient (3)	Time Coefficient (4)	Standard Error of (3) (5)	Standard Error of (4) (6)	$\bar{R}^2$ (7)	Value Added Coefficient (8)	Time Coefficient (9)	Standard Error of (9) (10)	$\bar{R}^2$ (11)
1960/61-1976/77											
Industry	1.989	0.983	2.222	-0.010	0.402	0.017	0.983	0.974	0.042	0.004	0.899
Services	2.002	0.993	1.572	0.194	0.566	0.025	0.993	0.835	0.048	0.002	0.931
Agriculture 1/	-	-	-	-	-	-	-	2.857	-	-	0.981
1960/61-1968/69											
Industry	2.216	0.980	1.077	0.062	0.226	0.012	0.996	0.974	0.067	0.003	0.989
Services	2.169	0.987	0.546	0.079	0.295	0.014	0.998	0.835	0.065	0.002	0.994
Agriculture 1/	-	-	-	-	-	-	-	2.894	-	-	0.989
1968/69-1976/77											
Industry	1.379	0.967	1.491	-0.004	0.472	0.017	0.963	0.974	0.014	0.004	0.661
Services	1.704	0.998	2.017	-0.014	0.249	0.011	0.998	0.835	0.038	0.002	0.973
Agriculture 1/	-	-	-	-	-	-	-	3.184	-	-	0.948

1/ Coefficient relates electricity consumption to pumpset electrification

RESULTS OF REGRESSION ANALYSIS: 1960/61-197 /76

		Approach 1		Approach 2								
		Value Added Coefficient (1)	$\bar{R}^2$ (2)	Value Added Coefficient (3)	Time Coefficient (4)	Standard Error of (3) (5)	Standard Error of (4) (5)	$\bar{R}^2$ (6)	Value Added Coefficient (7)	Time Coefficient (8)	Standard Error of (9) (10)	$\bar{R}^2$ (11)
North Eastern Region	- Industry	3.781	0.938	2.045	0.105	1.701	0.101	0.938	0.974	0.168	0.015	0.898
	- Services	4.028	0.811	-1.358	0.256	0.282	0.013	0.934	0.835	0.163	0.010	0.953
	- Agriculture 1/								4.815			0.860
Northern Region	- Industry	2.076	0.756	0.124	0.912	2.269	0.105	0.753	0.974	0.523	0.014	0.489
	- Services	2.275	0.957	-0.953	0.134	1.091	0.045	0.973	0.835	0.604	0.005	0.928
	- Agriculture 1/								4.455			0.972
Eastern Region	- Industry	1.748	0.886	0.858	0.032	0.371	0.012	0.920	0.974	0.028	0.005	0.738
	- Services	3.298	0.782	4.770	-0.036	2.187	0.052	0.775	0.835	0.055	0.012	0.599
	- Agriculture 1/								1.928			0.536
Western Region	- Industry	2.042	0.991	2.200	-0.007	0.512	0.024	0.991	0.974	0.049	0.003	0.955
	- Services	2.060	0.934	2.237	-0.008	2.688	0.117	0.930	0.835	0.053	0.006	0.831
	- Agriculture 1/								2.589			0.977
Southern Region	- Industry	1.784	0.970	1.796	-0.001	1.031	0.056	0.968	0.974	0.044	0.005	0.864
	- Services	1.967	0.978	2.712	-0.034	1.098	0.050	0.977	0.835	0.051	0.004	0.924
	- Agriculture 1/								2.103			0.973
All India	- Industry	2.045	0.985	2.277	-0.010	0.367	0.016	0.985	0.974	0.044	0.004	0.902
	- Services	2.029	0.993	1.737	0.013	0.568	0.025	0.993	0.835	0.053	0.002	0.978
	- Agriculture 1/								2.740			0.983
	-(Industry 2/	2.001	0.980	2.541	-0.024	0.484	0.021	0.981	0.974	0.043	0.004	0.883)

1/ Coefficient relates electricity consumption to pumpset electrification.

2/ Includes self-generation in industry in captive plants

ANNEX II.1.1

OUTLAYS ON POWER IN RELATION TO THE TOTAL PLANS

	Power Sector		Total Plan		Power as a Percentage of the Total Plans	
	Provision	Expenditure	Provision	Expenditure	Provision	Expenditure
First Plan	260	260	2219	2166	11.7	12.0
Second Plan	427	460	5025	4993	8.5	9.2
Third Plan	1039	1252	8449	8938	12.3	14.0
Annual Plans	1065	1223	6665 3/	6879	16.0	17.8
Fourth Plan	2447	2931	16427	16273	14.9	18.0
Fifth Plan	7294	5716 1/	39303	29571 1/	18.6	19.3
Draft Plan	15750	-	69380	-	22.7	-

1/ First four years

2/ Estimated

3/ P.74 Fourth FFP = resources for the Annual Plans: original estimate

Source: Various Plan Documents, Planning Commission

ACTUAL PLAN EXPENDITURES: 1968/69-1978/79

(Rs. Millions)

	States	Union Territories	Center	Total	States	Union Territories	Center	Total	Investment Price Index [1/]
	------------ Current Prices			------------	--------- Constant 1970/71 Prices			--------	
1968/69	2846.5	161.0	380.5	3388.0	3238.3	183.2	432.9	3854.4	87.9
	(84.0)	(4.8)	(11.2)	(100.0)					
1969/70	3036.5	155.5	479.2	3671.2	3265.1	167.2	515.3	3947.5	93.0
	(82.7)	(4.2)	(13.1)	(100.0)					
1970/71	3758.3	179.5	886.3	4824.1	3758.3	179.5	886.3	4824.1	100.0
	(77.9)	(3.7)	(18.4)	(100.0)					
1971/72	4136.6	123.0	1030.1	5289.7	3795.0	112.8	945.0	4852.9	109.0
	(78.2)	(2.3)	(19.5)	(100.0)					
1972/73	4565.9	110.3	1352.4	6028.3	3798.6	91.8	1124.9	5015.2	120.2
	(75.7)	(1.8)	(22.4)	(100.0					
1973/74	5320.3	173.6	1380.0	6873.9	3849.6	125.6	998.6	4973.9	138.2
	(77.4)	(2.5)	(20.1)	(100.0)					
1974/75	6577.0	149.0	939.6	7665.6	3799.5	866.1	542.8	4428.4	173.1
	(85.8)	(1.9)	(12.3)	(100.0)					
1975/76	9664.1	161.6	1190.1	11015.8	5423.2	90.7	667.8	6181.7	178.2
	(87.7)	(1.5)	(10.8)	(100.0)					
1976/77	12709.7	187.2	1637.1	14534.0	6933.8	102.1	893.1	7929.1	183.3
	(87.4)	(1.3)	(11.3)	(100.0)					
1977/78	16524.0	249.0	2343.2	19116.2	8812.8	132.8	1249.7	10195.3	187.5
(estimated)	(86.4)	(1.3)	(12.3)	(100.0)					
1978/79	19194.3	365.2	2612.1	22171.6	9748.2	185.5	1326.6	11260.3	196.9 [1/]
(anticipated)	(86.6)	(1.6)	(11.8)	(100.0)					
Annual Average Growth Rate	-	-	-	-	10.9%	(2.8%)	7.0%	10.0%	9.1%

1/ The investment price index is from the World Bank Economic Report on India (for 1978, Table 6.113 the index for 1978/79 is estimated assuming a 5 percent increase in prices over the previous year.

Source: Planning Commission

FINANCING THE PLANS: THE BURDEN ON THE CENTRE AND THE STATES

(Rs billion)

	Fourth Plan	Fifth Plan
Centre		
Expenditure on Power	5.1	8.7 1/
Total Resources for the Plan	87.9 3/	205.9 2/
Power as a Percentage of Total	5.8%	4.2%
States		
Expenditure on Power	21.6 4/	65.8 1/ 4/
Total Resources for the Plan	73.7 3/	187.2 2/
Power as a Percentage of Total	29.3%	35.1%
Total		
Expenditure on Power	26.7	74.5 1/
Total Resources for the Plan	161.6 3/	393.0 2/
Power as a Percentage of Total	16.5%	18.9%

1/ Including 1978/79, i.e. the first year of the Rolling Plan

2/ Provision in the Finalized Fifth Five Year Plan

3/ Estimated resources given in the Draft Fifth Five Year Plan

4/ Including Union Territories

Source: Planning Commission and World Bank Analysis

REVENUE AND OPERATING COSTS: 1969/70 - 1975/76

(Utilities Only: Rs Millions)

	Revenue	Expenses	Depreciation	Interest 1/	Total	Surplus
1969/70	5,930	3,650	825	1,368	5,843	87
-Public	4,659	2,663	740	1,309	4,712	-63
-Private	1,271	987	85	59	1,131	140
1970/71	7,640	4,419	930	1,412	6,760	880
-Public	6,228	3,297	841	1,353	5,491	737
-Private	1,412	1,122	89	59	1,269	143
1971/72	7,671	4,880	1,084	1,461	7,425	246
-Public	6,139	3,666	993	1,400	6,059	80
-Private	1,533	1,214	91	61	1,366	167
1972/73	8,951	5,801	1,252	1,652	8,705	246
-Public	7,248	4,436	1,161	1,587	7,184	64
-Private	1,703	1,365	91	65	1,521	182
1973/74	10,030	6,922	1,272	1,899	10,093	63
-Public	8,249	5,410	1,185	1,834	8,429	-220
-Private	1,821	1,512	87	65	1,664	157
1974/75	13,288	9,566	1,478	1,866	12,910	378
-Public	10,964	7,602	1,392	1,796	10,790	174
-Private	2,324	1,964	86	70	2,120	204
1975/76	17,234	12,013	1,796	2,487	16,296	938
-Public	14,498	9,701	1,709	2,410	13,820	678
-Private	2,736	2,312	87	77	2,476	260

1/ Interest paid rather than owed.

Source: GR

CONSOLIDATED CAPITAL ACCOUNT OF THE POWER SECTOR: ALL UTILITIES

(Rs Millions)

	Fixed Assets 1/				Net Fixed Asset Formation			
	Generation	Trans-mission	Distribution	Total	Generation	Trans-mission	Distribution	Total
1960/61	3675	806	2594	7075	221	44	167	432
1961/62	4349	1174	2940	8463	674	368	346	1388
1962/63	4734	1693	3051	9478	385	519	111	1015
1963/64	5490	1754	3556	10800	756	61	505	1322
1964/65	6015	2335	4500	12850	525	581	944	2050
1965/66	7051	3045	5343	15439	1036	710	843	2589
1966/67	8941	3379	6517	18837	1890	334	1174	3398
1967/68	10260	3727	7551	21538	1319	348	1034	2701
1968/69	10583	4956	9211	24750	323	1229	1660	3212
1969/70	11776	5254	10002	27032	1193	298	791	2282
1970/71	12504	5458	11776	29738	728	204	1774	2706
1971/72	13796	6218	13667	33681	1292	760	1891	3943
1972/73	17278	7111	15578	39967	3482	893	1911	6286
1973/74	18154	7508	17593	43255	876	397	2015	3288
1974/75	20624	8267	19514	48405	2470	759	1921	5150

Source: GR

1/ Leaving out general assets, intangible assets and special items from all assets.

ANNEX II.1.6

PLAN PROVISIONS AND EXPENDITURE ON POWER (Utilities Only)

(Rs Millions)

	Generation	Transmission and Distribution	Rural Electrification	Other	Total	Percentage Distribution: Generation	Transmission and Distribution	Rural Electrification	Other	Total
First Plan										
- Provision	n.a.	n.a.	200	-	2,600	-	-	7.7	-	100.0
- Actual	1,050	1,320	80	150	2,600	40.4	50.8	3.1	5.8	100.0
- Percentage Excess	n.a.	n.a.	n.a.	n.a.	0.0					
Second Plan										
- Provision	2,350	1,170	750	-	4,270	55.0	27.4	17.6	-	100.0
- Actual	2,500	1,150	750	200	4,600	54.3	25.0	16.3	4.3	100.0
- Percentage Excess	6.4	-1.7	0.0	n.a.	7.7					
Third Plan										
- Provision	7,120	2,220	1,050	-	10,390	68.5	21.4	10.1	-	100.0
- Actual	7,740	3,010	1,530	240	12,520	61.8	24.0	12.2	1.9	100.0
- Percentage Excess	8.7	35.6	45.7	n.a.	20.5					
Annual Plans										
- Provision	6,440	2,730	1,480	-	10,650	60.5	25.6	13.9	-	100.0
- Actual	6,760	2,910	2,370	190	12,230	55.3	23.8	19.4	1.6	100.0
- Percentage Excess	5.0	6.6	60.1	n.a.	14.8					
Fourth Plan										
- Provision	12,550	7,210	4,450	260	24,470	51.3	29.5	18.2	1.1	100.0
- Actual	15,050	7,680	6,170	410	29,310	51.3	26.2	21.1	1.4	100.0
- Percentage Excess	19.9	6.5	38.7	57.7	19.8					
Fifth Plan										
- Provision 3/	43,950	20,810	6,850	1,330	72,940	60.3	28.5	9.4	1.8	100.0
- Actual 1/	35,770	15,080	5,240	1,070	57,160	62.6	26.4	9.2	1.9	100.0
- Percentage 2/ Excess	1.7	-32.7	-4.4	0.6	-2.0					
Rolling Plan										
- Provision	87,500	53,000	14,500	2,300	157,500	55.6	33.7	9.2	14.6	100.0

1/ Anticipated Expenditure for first four years.

2/ Five-fourth of anticipated expenditure over planned expenditure.

3/ From the Finalized Fifth Five Year Plan.

n.a. = not available

- = negligible.

Source: Planning Commission

ANNEX II.1.7

ACTUAL PLAN EXPENDITURE ON THE POWER SECTOR
(Rs millions)

Five Year Plan and Annual Plans	Absolute Amounts: Generation	Transmission & Distribution	Rural Electrification	Investigations & Miscellaneous	Total	Percentage Distribution: Generation	Transmission & Distribution	Rural Electrification	Investigations & Miscellaneous
I Plan (1951/56)	1050.0	1320.0	80.0	150.0	2600.0	40.4	50.8	3.1	5.8
II Plan (1956/61)	2500.0	1150.0	750.0	200.0	4600.0	54.3	25.0	16.3	4.3
III Plan (1961/66)	7740.0	3013.0	1530.0	240.0	12523.0	61.8	24.0	12.2	1.9
1966/67	2400.0	832.0	734.0	72.0	4038.0	59.4	20.6	18.4	1.8
1967/68	2212.7	1032.2	747.9	66.0	4058.8	54.5	25.4	18.4	1.6
1968/69	2149.5	1042.4	887.1	47.3	4126.3	52.1	25.3	21.5	1.1
1969/70	2472.6	1330.9	853.4	46.5	4703.4	52.7	28.3	18.1	1.0
1970/71	2536.7	1258.9	1354.1	44.3	5194.0	48.8	24.2	26.1	0.9
1971/72	2864.3	1614.7	1466.4	97.5	6042.9	47.4	26.7	24.3	1.6
1972/73	3018.3	1640.0	1280.0	90.0	6028.3	50.1	27.2	21.2	1.5
1973/74	3900.0	2110.0	1210.0	120.0	7340.0	53.1	28.7	16.5	1.6
1974/75	5581.9	2353.7	1177.9	112.4	9225.9	60.5	25.5	12.8	1.2
1975/76	7688.5	3238.4	1196.4	188.6	12311.9	62.4	26.3	9.6	1.5
1976/77	9047.1	4238.4	1662.1	224.7	15172.3	9.6	27.9	11.0	1.5
1977/78 (anticipated)	10911.1	5164.1	1771.3	280.9	18127.4	60.2	28.5	9.8	1.5

Source: Planning Commission, Power and Energy Division

THE DISTRIBUTION OF PLAN PROVISIONS IN THE FOURTH, FIFTH AND ROLLING PLANS

(Rs Millions)

	Generation	Transmission & Distribution	Rural Electrification	Other 1/	Total	Percentage Distribution
Fourth Plan						
(1969/70-1973/74)						
States	9741 (50.8)	6455 (33.6)	2852 (14.9)	144 (0.8)	19191 (100.0)	78.4
Union Territories	255 (31.2)	443 (54.2)	95 (11.6)	25 (3.1)	818 (100.0)	3.3
Centre	2551 (57.1)	318 4/ (7.1)	1500 (33.6)	98 (2.2)	4467 (100.0)	18.3
Total	12546 (51.3)	7216 (29.5)	4447 (18.2)	267 (1.1)	24476 (100.0)	100.0
Fifth Plan						
(1974/75-1978/79)						
States	37227 (58.4)	18977 (29.8)	6746 5/ (10.6)	749 (1.2)	63699 (100.0)	87.3
Union Territories	65 (6.6)	788 (79.8)	107 (10.8)	27 (2.7)	988 (100.0)	1.4
Centre	6652 (80.6)	1047 (12.7)	0 (0.0)	552 (6.7)	8252 (100.0)	11.3
Total	43945 (60.2)	20813 (28.5)	6853 (9.4)	1329 (1.8)	72939 (100.0)	100.0
Rolling Plan 2/						
(1978/79-1982/83)						
States	-	-	-	-	125800	79.9
Union Territories	-	-	-	-	200	0.1
Centre	-	-	-	-	31500	20.0
Total	87500 3/ (55.6)	53000 (33.7)	14500 (9.2)	2500 (1.6)	157500 (100.0)	100.0

1/ Surveys and Investigations
2/ Provisional
3/ Excludes investment in non-utilities
4/ Includes Rs 220 million of centrally sponsored schemes
5/ Including REC
6/ Excludes Rs 3000 million of institutional finance

- = not available

Source: Planning Commission

POWER GENERATION -- TARGETS AND ACHIEVEMENTS

	Financial Outlays (Utilities Only)			Installed Generating Capacity					
				Capacity at Period End		Additions during Period			
	Plan Allocation (Rs Million)	Actual Expenditure (Rs Million)	Percentage Excess	Target (MW)	Achievement (MW)	Target (MW)	Achievement (MW)	Percentage Shortfall	Investment Price Index (1970/71=100; Mid Year of Plan Period)
First Plan (1951/52-1955/56)	-	1,050	-	3,600	3,400	1,300	1,100	15.4	49.9
Second Plan (1956/57-1960/61)	2,350	2,500	6.4	6,900	5,650	3,500	2,250	35.7	55.7
Third Plan (1961/62-1965/66)	7,120	7,739	8.7	12,690	10,170	7,040	4,520	35.8	68.9
Annual Plans (1966/67-1968/69)	6,438	6,762	5.0	15,600	14,300	5,430	4,130	23.9	85.6
Fourth Plan (1969/70-1973/74)	12,546	15,050	20.0	23,000	18,880	9,260	4,590	50.4	109.0
Fifth Plan (1974/75-1978/79)	33,238 2/	35,770 1/	34.5 5/	35,420 2/	26,080 3/	16,540 2/	7,120 4/	57.0 5/	183.3
Rolling Plan (1978/79-1982/83)	87,500	-	-	44,630	-	18,550 6/	-	-	220.0 7/

1/ Expenditure anticipated for the first four years of the plan.
2/ As shown in the Draft Fifth Five Year Plan. These figures were respectively revised upwards to Rs. 43,954 million and downwards to 12,500 MW in the finalized Five Year Plan.
3/ Installed capacity at end of 1977/78.
4/ Achievement for 1974/75-1977/78.
5/ Percentage shortfall/excess of five-fourths of the achievement (1974/75-1977/78) behind/ahead the original target (1974/75-1978/79).
6/ The Draft Rolling Plan gives a target end-period capacity of 44,626 MW and target additions of 18,500 MW; these figures are slightly inconsistent; the figure shown of 18,630 MW is the target additions required to meet the target capacity by the end of 1982/83.
7/ Assuming 5% inflation per annum after 1976/77.
\- Not available or not applicable.

Source: Various Plan Documents

POWER INVESTMENT PLANNING MODELS IN INDIA

This annex briefly reviews four power investment planning models that have been produced for India.

Investment planning models for electric power systems can be used to optimize: 1) generation and transmission expansion plans, 2) operating schedules, 3) plant maintenance schedules, 4) the utilization of a fixed amount of hydro energy potential, or 5) the allocation of coal from various mines to alternative thermal plants. Such models are set up as constrained optimization problems. The objective is to minimize system costs, i.e., the present worth of energy and capacity costs over the relevant time horizon, subject to various constraints on capacity and energy generated (both total and plant specific), transmission capacity and energy transmitted, and the reliability of supply.[1/] Solutions are obtained through either marginal, simulation, or global analysis and rely heavily on linear, non-linear, or dynamic programming techniques.

At the theoretical level, several attempts have been made to use formal planning models to determine optimal power system expansion plants for various

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1/ See Ralph Turvey and Dennis Anderson, Electricity Economics, ch. 13, Baltimore: John Hopkins University Press, 1977 for a more complete discussion of investment planning models.

regions in India[1/]. These studies have a number of similarities. First, they all specify a model which minimizes power system costs for either some future time period -- 1971-85 for Gately -- or a future year -- 1979 or 1980 in the other studies -- subject to various system constraints. Second, all of the studies use linear programming techniques to determine solutions. Third, three of the four studies reviewed here are concerned with determining the optimal investment plan for the Northern Region of India in 1979 or 1980 (only Gately's study is an exception). Finally, none of these studies explicitly consider the level of reliability at which electricity is to be supplied.

From the point of view of this review, however, it is more interesting to consider the differences which exist between these studies. Some of these differences are found in : (1) the level of disaggregation of the study, (2) whether or not optimal operating schedules are determined, (3) the methods of dealing with dichotomous variables and non-constant costs, (4) their use of sensitivity analysis, (5) the extent to which the problem of assuring states' cooperation within a region is addressed, and (6) the results obtained.

1/ M.V. Chakravarti, et. al., Optimization Techniques in Power System Planning in Northern Electricity Region, AEC monograph No. 2. 1971; Francis Gately, Investment Planning for the Electric Power Industry: A Mixed Integer Programming Approach, with Application to Southern India, Ph.D. dissertation, Princeton University, May 1971; Shishir K. Mukherjee, A Network Programming Approach for Investment Planning in Electric Power Systems: Case Study for Northern Region of India, Indian Institute of Management, Ahmedabad, December 1974; and Supriya Lahiri, An Investment Programming Model for the Electric Power Industry of Northern India, Ph.D. dissertation, University of Delhi, December 1975.

Of the four studies reviewed here, those by Chakravarti, et. al., and Gately appear to be the least disaggregated.[1/] That is, these studies are concerned with determining power system investment plans that meet total regional demands. Thus there is no consideration given to meeting demands at various load centers within the region. In contrast, the studies by Mukherjee and Lahiri disaggregate regional demand into the demand at a number of load centers -- 43 in the former and 10 in the latter. Similarly, transmission of electricity is dealt with only on a very aggregate basis, if at all, in the study by Gately. Specifically, Gately considers only total transmission between states in a region (implicitly assuming there is only one transmission line), rather than considering various transmission units from supply centers to load centers as is done by Mukherjee and Lahiri.

These studies also differ in terms of the consideration they give to determining optimum operating schedules. The studies by Chakravarti and Mukherjee do not address this issue. Rather, they merely optimize the capacity investments necessary to meet peak demand in the target year. The models specified by Lahiri and Gately do allow optimum operating schedules to be determined. This is accomplished by defining operating decision variables for each new or existing plant and for each mode of operation -- (1) base load, (2) normal peak and (3) super peak. The values of these operation variables, which are determined in the model

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1/ In a number of ways, however, the analysis carried out in these studies is at a disaggregate level. For example, Chakravarti considers 8 categories of power plants, and 4 seasons of the year. Similarly, Gately considers (in his single state model) 3 possible hydrological years (normal, wet, and dry), 4 types of plants and 2 seasons (wet and dry).

indicate the MW output to be sustained by a particular type of plant in a given mode of operation. In addition, the Lahiri study determines the least cost method of transporting seven grades of coal from six mines (in Bihar, West Bengal, and Madhya Pradesh) to the various thermal plants in the Northern Region.

Gately's model includes two innovations not found in the other models. First, hydro investment decision variables are dichotomous, i.e., zero-one rather than continuous. This is indicative of the fact that due to the natural limits to hydro resources, hydro plants cannot be duplicated at close to constant costs as to some extent thermal plants can be. In effect, this modification recognizes the fact that the actual decision to be made is which of a fixed number of potential hydro sites to develop, rather than how much hydro capacity should be developed. Second, this study allows for the fact that per unit capacity costs are likely to decrease over time as capacity increases, rather than remain constant as is typically assumed. This is accomplished by using a "fixed-charge" cost function. Such a function represents capacity cost as being the sum of a fixed cost component plus a variable cost component, which increases at a constant rate with capacity. The result is a capacity cost function characterized by decreasing average costs.

Three of the planning studies attempt sensitivity analysis. That is, they investigate how the findings of their model (the optimal power system design) are affected by changes in key system parameters. For example, Gately allows the estimated growth rate of demand over the planning period to vary between 7.5% to 12.5% per year. In a similar fashion, he varies the discount rate between 10%-15%, and considers three possible kinds of hydrological years (dry, normal, and wet). Mukherjee determines optimal investment plans when actual hydro capacity is reduced to 50% of installed capacity (thus allowing for the possibility of a dry year). Lahiri analyzes how her results change when the prices of coal and nuclear investment costs vary. Specifically, she allows coal prices to increase by as much as 100% and nuclear construction costs to decrease by 20%. In addition, she analyzes the effects on her results of correcting market prices for distortions, i.e., using shadow or efficiency prices. Shadow wage rates for unskilled labor are varied between 0%-100% of market wages and the shadow exchange rate is varied between 110%-150% of the market exchange rate.

Out of the four studies considered here, Gately's is the only one to explicitly consider the issue of regional cooperation between various states. His approach is game-theoretic and clearly this is one of his most interesting contributions.[1/] The problem of how to ensure regional cooperation is appropriately modeled as a n-person non-constant-sum game. Gately uses two game-theoretic concepts, the core and the von Neumann-Morgenstern solution, to determine a set of side payments that would redistribute the benefits of cooperation between states in the Southern Region in such a way that all states are net gainers. Neither of these solution concepts determines one unique set of side payments that is in any sense optimal; but, they do indicate a range of values which might

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1/ If tariffs for interstate transfers of electricity were set equal to appropriately defined long run marginal costs, then this issue would, in principle, be largely resolved. However, the process of negotiating tariffs for the exchange of power has been protracted; the positions the states have taken have reflected the net gains they expect from the resolution of the tariff problem; this process could itself be analyzed using game-theoretic concepts.

facilitate regional cooperation. It is likely that such payments could be integrated with an appropriately defined tariff structure for interstate transfers of electricity.

The actual results obtained in these studies are of interest because they provide an indication of the cost saving[1/] that can result from regional integration of power systems and because they demonstrate how widely optimal solutions can vary according to the specific planning model that is used. The Gately study provides some evidence on this first issue. He determines the optimal investment program for each state in the Southern Region assuming self-sufficiency and when there is regional cooperation. Two of the states, Tamil Nadu and Andhra Pradesh, realize cost savings through regional cooperation, while one "state" Kerala-Karnataka[2/], incurs greater costs. Overall, system costs for the Southern Region between 1971-85 could be reduced by Rs 1530 million (or approximately 19%) by regional cooperation.[3/] However, as discussed above, for this solution to be completed -- i.e., for each state to be a net gainer -- some type of side payment from Tamil Nadu and Andhra Pradesh to Kerala-Karnataka must be included.

1/ In all studies other than Gately's interest and depreciation costs are included among economic costs. Such costs actually represent a transfer of payment and thus really should not be included as economic costs.

2/ In his analysis, Gately treats Kerala-Karnataka as one state.

3/ Of course, the cost savings resulting from regional cooperation as compared to state self-sufficiency without a formalized planning program would be even greater.

The three models for the Northern Region produce different solutions for an optimal, least cost investment program. Lahiri's model, using market prices, suggests the capacity expansion program should be predominantly conventional thermal; using shadow prices, it suggests the program should be mostly hydro. Mukerjee's optimal investment program emphasizes nuclear development and hydro exploitation, with conventional thermal development coming much later on. The study by Chakravarti suggests roughly half the program should be conventional thermal, one quarter hydro and one quarter nuclear. That three studies may have such diverse results does not imply that modelling is futile. It reflects to some extent differences in analytical approach and no doubt differences in the data bases used. In practice, to apply any methodology to investment planning will undoubtedly require a major effort to ensure the realism of the data and a careful choice of methodology towards identifying the one most appropriate to the problems of the Indian situation.

ELECTRICITY SUPPLY - INSTALLED CAPACITY

(MW)

	Dec. 1950	Dec. 1955	March 1961	March 1966	March 1969	March 1971	March 1972	March 1973	March 1974	March 1975	March 1976	March 1977	March 1978
Utilities													
(a) By ownership													
-Public	628	1518	3297	7288	11335	13222	13769	14812	15253	16989	18815	20179	22596
-Private	1085	1177	1356	1739	1622	1487	1485	1469	1411	1327	1302	1290	1288
(b) By type of stations													
-Hydro	559	940	1917	4124	5907	6383	5612	6785	6965	7529	8464	9025	9977
-Conventional Thermal	1005	1547	2436	4417	6640	7508	7818	8468	8652	9753	10579	11433	12924
-Nuclear	-	-	-	-	-	420	420	620	640	640	640	640	640
-Other 1/	149	208	300	486	410	398	404	428	407	394	434	371	343
Utilities total	1713	2695	4653	9027	12957	14709	15254	16281	16664	18316	20117	21469	23884
Non-Utilities	588	723	1001	1146	1339	1562	1635	1708	1792	2029	2132	2287	2200
Total	2301	3418	5654	10173	14296	16271	16889	17990	18456	20345	22249	23756	26084

1/ Diesel and gas turbine.

2/ The March 1978 figures refer to sets which have been rolled and are operational by that date. Data for previous years refer to sets which have been rolled, are operational and are commercially commissioned -- i.e., deemed to be revenue earning. The March 1978 figure for all commercially commissioned sets is 25,519 MW as opposed to the 26,084 MW shown here. Rolled and operational but not commercially commissioned sets in March 1977 had a capacity totalling 24,127 MW as opposed to the 23,756 MW shown. Thus the increase in capacity over 1977/78 may be reckoned as either 1,763 MW (rolled, operational and commercially commissioned) or 1,957 MW (rolled and operational).

Source: GR

ANNEX II.3.1

LENGTH OF TRANSMISSION AND DISTRIBUTION LINES CONSTRUCTED

(circuit km)

Period	400 KV	220 KV	132/110 KV	66 KV & Below 1/	Total
Beginning First Plan (3/1951)	-	-	2708	26593	29271
End of First Plan (3/1956)	-	-	7376	59045	66421
End of Second Plan (3/1961)	-	1099	12802	143986	157887
End of Third Plan (3/1966)	-	3772	24718	262556	291046
End of Annual Plans (3/1969)	-	10225	34056	372639	416920
End of Fourth Plan (3/1974)	-	13932	45041	631604	690577
End of 1977/78 (3/1978) (Anticipated)	718	27881	80175	998708	1107482
End of Rolling Plan 2/ (3/1983) (Planned)	16363	51355	127028	1269857	1464603
Annual Growth Rates					
Since the beginning of the First Plan (1951-1978)	-	-	13.4%	14.4%	14.4%
Since the end of the Second Plan (1961-1978)	-	21.0%	11.4%	12.1%	12.1%
As envisaged in the Working Group Report (1978-1982)	86.9%	13.0%	9.6%	4.9%	5.8%

1/ Excludes L.T. Lines

2/ These figures reflect the physical targets set out in the working group report; corresponding figures are not available for the Draft Plan.

Source: GR

NUMBER OF VILLAGES ELECTRIFIED & IRRIGATION PUMPSETS/TUBEWELLS ENERGISED 1/

	1950/51	1955/56	1960/61	1965/66	1968/69	1970/71	1971/72	1972/73	1973/74	1974/75	1975/76	1976/77	1977/78 (Antici-pated)	1982/83 2/ (Target)
Number of villages electrified	3,100	7,300	21,700	45,100	73,700	104,900	122,100	139,200	156,900	173,500	185,800	202,800	222,900	320,000
Percentage of total villages electrified	0.5	1.3	3.8	8.0	13.0	18.7	21.6	24.5	27.2	30.1	32.3	35.2	38.7	55:6
Number of irrigation pumpsets/tubewells (thousands) energized	21	56	199	513	1,089	1,629	1,901	21,85	2,426	2,614	2,792	3,029	3,341	5,300

1/ Numbers are as at the end of each year, e.g. the figure for 1950/51 is for March 31, 1951. The figures in the first row are rounded to the nearest hundred, while (as stated in the table) the number of irrigation pumpsets and tubewells energised is given to the nearest thousand.

2/ The targets in the Draft Plan are the electrification of one hundred thousand villages and two million pumpsets between April 1978 and March 1983.

Source: GR

ANNEX II.3.4

Installed Generating Capacity at March 31, 1978
(MW)

Region	Conventional Thermal	Nuclear	Hydro	Total
Northern	3,359	220	3,243	6,822
Western	4,112	420	1,662	6,194
Southern	1,985	-	4,118	6,103
Eastern	3,601	-	885	4,486
North Eastern	204	-	69	273
Andaman and Nicobar Lakshadweep	6	-	-	6
Non-Utility Capacity	2,200			2,200
	15,467	640	9,977	26,084

Source: Ministry of Energy, Central Electricity Authority.

TRANSMISSION AND DISTRIBUTION - 1974/75 - 1976/77

	1974/75	1975/76	1976/77
	----- Circuit Kms at Year End -------		
Northern Region			
- 33 KV and above	55516	56270	59251
- below 33 KV and above 500 V	179318	188459	247860
- at 500 V and below	213748	228870	244791
Western Region			
- 33 KV and above	47567	50582	55107
- below 33 KV and above 500 V	129506	135540	148231
- at 500 V and below	192135	216852	238022
Southern Region			
- 33 KV and above	40922	42621	47240
- below 33 KV and above 500 V	162889	169196	179433
- at 500 V and below	411305	429429	456251
Eastern Region			
- 33 KV and above	31578	30763	32015
- below 33 KV and above 500 V	66722	73253	79965
- at 500 V and below	68632	73512	82208
North-Eastern Region			
- 33 KV and above	8121	8729	7328
- below 33 KV and above 500 V	6991	7731	7390
- at 500 V and below	6898	7135	8181
Total			
- 33 KV and above	183704	188965	200241
- below 33 KV and above 500 V	545426	574179	663579
- at 500 V and below	892716	955798	1029453

Source: CR

THE INVESTMENT PROGRAM IN THE WORKING GROUP REPORT AND THE DRAFT PLAN: A COMPARISON: 1978/79-1982/83

	Working Group Report (1)	Draft Plan (2)	Percentage Reduction Between (1) and (2)
Proposed Outlays (Rs billions)			
- Generation	105.9	87.5	17.4
- Transmission and Distribution	78.3	53.0	32.3
- Rural Electrification	23.2	14.5	37.5
- Surveys, Investigation and Research	5.0	2.5	50.0
Total	212.4	157.5	25.8
Targets for Capacity 1/ (MW)			
- Hydro	5067	4680	7.6
- Conventional Thermal	16397	12935 1/	21.1
- Nuclear	1160	925	20.3
Total	22624	18555	18.0

1/ Includes 325 MW of additional capacity in non-utilities.

Source: WGR

CAPACITY MARGINS AND OTHER PLANNING NORMS

1. In moving from a forecast of energy demand for a power system to the increments in capacity needed to meet the build up in power requirements, allowances must be made for transmission and distribution losses, the overall load factor, the incidence of planned, forced and partial outages, a margin for spinning reserve, the consumption of power station auxilliaries and the retirement and derating of existing capacity. In the last stage of actually planning the investment program project by project, it is also necessary to allow for the gradual build up in the load that can be met by new generation equipment.

2. While losses in India are between 19 and 20%, there is reason to expect these to fall because of higher voltage transmission, distribution system reinforcement and efforts to curb theft in the next five years. Increased rural electrification may involve additional losses, offsetting these gains to some extent, but for planning purposes the Draft Rolling Plan assumes losses will be about 18% by 1982/83. This is fractionally lower than the 18.5% in the Tenth APS, and reaching the lower figure will involve a strong commitment to the physical targets in the transmission and distribution program.

3. The average load factor throughout India is about 61%.[1/] In the Tenth APS, this is assumed to improve to 63.5% because of measures designed to encourage off peak consumption. The margin for spinning reserve is taken as 5%, and auxiliaries for thermal power stations are assumed to be 10% as against 1/2% for hydro stations. The thermal figure is set so high to reflect the electricity used to handle and crush coal, and supply the power

1/ This is the average of load factors in different States and does not take into account the effects of interstate diversity.

station colonies. These two figures correspond roughly to the 6.35% margin for auxillaries -- both hydro and thermal -- assumed in the Draft Rolling Plan.

4. Outages are mainly a problem for thermal plants. Monitoring of past performance by the CEA suggests margins on thermal plant of 3.5% for planned outages, 18.5% for forced outages and 10% for partial outages may be appropriate for planning purposes. The Tenth APS argues for 10% for forced outages and 10% for planned outages without making any separate assumption about partial outages; though different in composition, the total allowances for forced and planned outages is about the same. It is generally agreed however that hydro availability during system peak can be much higher, the margin falling between say 10 and 15%, depending on the characteristics of the particular schemes in question. The Draft Plan makes no specific assumptions about either thermal or hydro availability during peak periods, but, assuming a 5% spinning reserve and a load factor of 63.5%, the Plan forecasts of capacity (42101 MW) and energy generated (160220.5 Gwh) by utilities in 1982/83, imply an overall margin for outages for both hydro and thermal of 28%. The ratio of installed capacity to peak load in the Tenth APS is 33.1%, which implies their margin for outages in hydro and thermal plant averages is 29.5%. This difference may be explained in part by different views about the efficiency of station operation and system management in the future, but this is not necessarily so; the APS assumed higher overall capacity by 1982/83 than the Planning Commission, and therefore a higher proportion of thermal plant, so the average level of efficiency might

be lower for the Tenth APS than the Planning Commission anyway.

5. The rate assumed for retirement and derating of old capacity is also critical for forecasting the need for new capacity. The CEA has observed generally that 1% of capacity throughout the system is lost annually through retirement and derating. The Planning Commission argues that 0.5% should be retired each year,[1/] but makes no explicit allowance for derating capacity, which could well be between 0.3 and 0.5% of capacity.

1/ This is about 10%. So in 30 years the system capacity should increase about 17 times, and assuming plant has a 30 year life the 10% added in year 1 will have to be retired in year 31; it will then constitute one one-hundred-and-seventieth of total capacity or about 0.6%.

INSTALLED CAPACITY THROUGHOUT INDIA - THE DRAFT PLAN FOR POWER

(MW)

	Installed March 1978	Planned March 1983	Addition Between 1978 and 1983
Hydro	9,977	14,655	4,678
Thermal	13,267	25,881	12,614
Nuclear	640	1,565	925
Total Utilities	23,884	42,101	18,217
Non-Utilities	2,200	2,525	325
All India	26,084	44,626	18,542

Source: The Draft Plan p. 166, and the Central Electricity Authority.

ENERGY AND CAPACITY REQUIREMENTS (UTILITIES ONLY):1982/83

1982/83	The Working Group Report	The Draft Plan	Regression Analysis
Requirement at the Bus-bar (Gwh)	168392 2/	150046 1/	155615
Capacity Requiremnt (MW)	50500 2/	42100 1/	46300 5/
1987/88			
Requirement at the Bus-bar (Gwh)	272055 2/	239282 1/	260839
Capacity Requirement (MW)	82600 4/	64600 3/	77600 4/

1/ Taken equal to the Planning Commission/CEA Exercise that elaborated on forecast power requirements after the Draft Plan was published.

2/ As in the Tenth APS

3/ The test of the Plan refers to the need for between 20,000 and 25,000 MW of additional capacity between 1982/83 and 1987/88; the table uses 22500 MW.

4/ Applying the same load factor and margins as in 1982/83.

5/ Applying the same load factor and margins as in the Draft Plan.

Sources: The Draft Plan and WGR

The Shift Away From Hydro Electric Development

(MW)

		Hydro	Thermal 1/	Total
Actual				
	December 1950	559	1742	2301
		(24.3)	(75.7)	(100.0)
	March 1969	5907	8389	14296
		(41.3)	(58.7)	(100.0)
	March 1971	6383	9888	16271
		(39.2)	(60.8)	(100.0)
	March 1978	9977	16107	26084
		(38.2)	(61.8)	(100.0)
Forecast: Draft Plan				
	March 1983	14655	29975	44630
		(32.8)	(67.2)	(100.0)

1/ Including nuclear

Sources: WGR and the Draft Plan

TRANSMISSION AND DISTRIBUTION LOSSES FOR ALL INDIA: 1965/66-1975/76

(Gwh)

	1965/66	1975/76
Net Generation 1/	31355	74772
Total Consumption 2/	26735	60246
- Agricultural	1892	8721
- Other	24843	51525
Total Losses	4621	14526
Percentage Losses	14.7%	19.4%
Memo Items		
Agricultural Generation	3846	17726
Other Generation	27509	57046
Agricultural Percentage Losses 3/	50.8%	50.8%
Other Percentage Losses 3/	9.7%	9.7%
Agricultural Losses	1954	9005
Other Losses	2666	5521

1/ Utilities only (including energy purchased from non-utilities).

2/ Excludes self-generated electricity.

3/ These items show the level of losses for agriculture and other types of consumer that would have had to be realized, for the increase in agricultural load to be the only factor explaining the increase in overall losses (see text).

Sources: GR and World Bank Analysis

INTERNATIONAL COMPARISON OF TRANSMISSION AND DISTRIBUTION LOSSES AND OTHER SYSTEM CHARACTERISTICS: 1970

	Population 1/ (Millions)	Area ('000 80, Kms)	Consumption 1/ (Twh)	Percentage Losses	Consumption per Capita (Kwh)	Consumption per Sq. Km (Kwh)	Investment in Transmission and Distribution as a Percentage of All Investment in Power
Belgium	9.7	31	27.7	5.6	2856	894	62.1
Federal Republic of Germany	61.2	248	220.7	5.9	3606	890	76.3
France	50.7	547	130.2	7.1	2568	238	43.3
Italy	53.6	301	107.0	8.5	1996	355	53.7
Norway	3.9	324	51.0	9.6	13077	157	33.3
Sweden	8.0	450	57.7	12.4	7213	128	35.3
Switzerland	6.2	41	28.6	10.1	4129	624	50.0
U. K.	55.4	244	215.4	7.6	3888	883	46.5
U.S.A.	205.1	9363	1510.4	7.9	7364	161	41.4
Canada	21.3	9976	176.2	11.3	8272	18	40.0 4/
Japan	104.6	372	324.2	6.4	3099	872	49.9
India	548.1	3280	48.5 2/	17.3 2/	88	15	36.7 3/

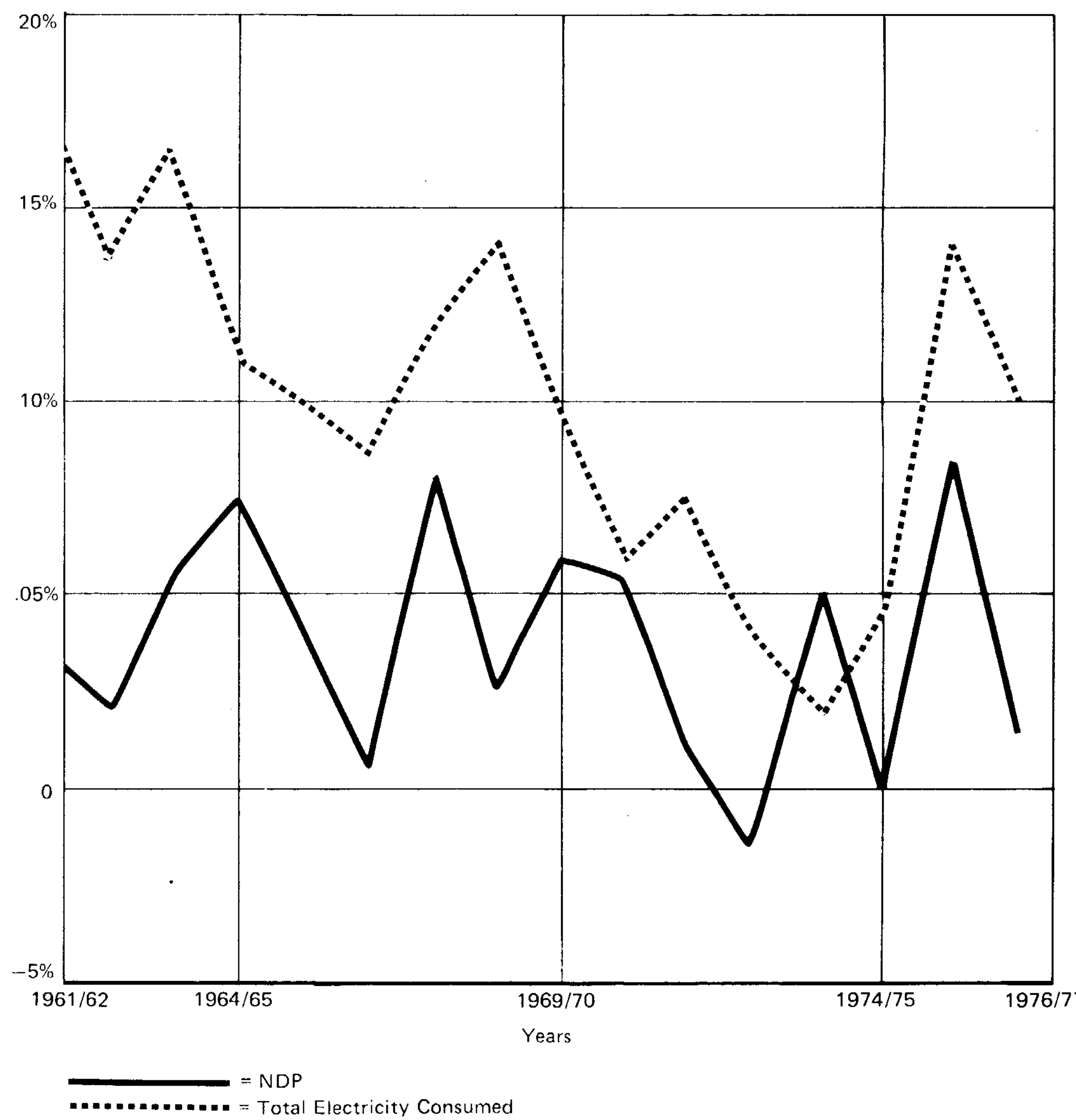
1/ Net of losses 2/ 1970/71

3/ Transmission and distribution expenditures in the Fourth Plan Period were 26.2% of all Plan expenditures on power including rural electrification, the figure was 47.2%; the tabulated figure is the arithmetic average of these two.

4/ Estimated

Sources: Various Plans and "The Electricity Supply Industry", OECD, Various Volumes.

I: ANNUAL PERCENTAGE CHANGES IN NDP AND TOTAL ELECTRICITY CONSUMED



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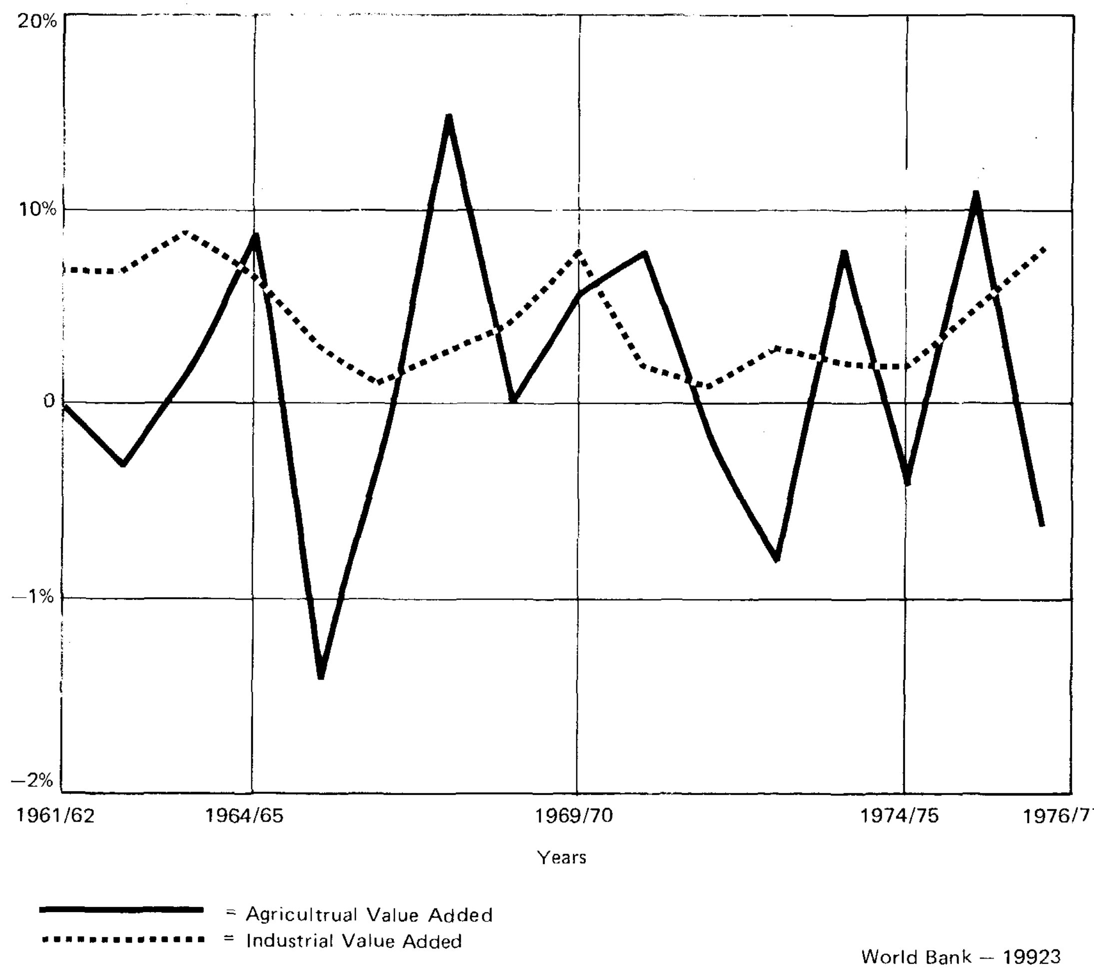
II: ANNUAL PERCENTAGE CHANGES IN AGRICULTURAL AND INDUSTRIAL VALUE ADDED



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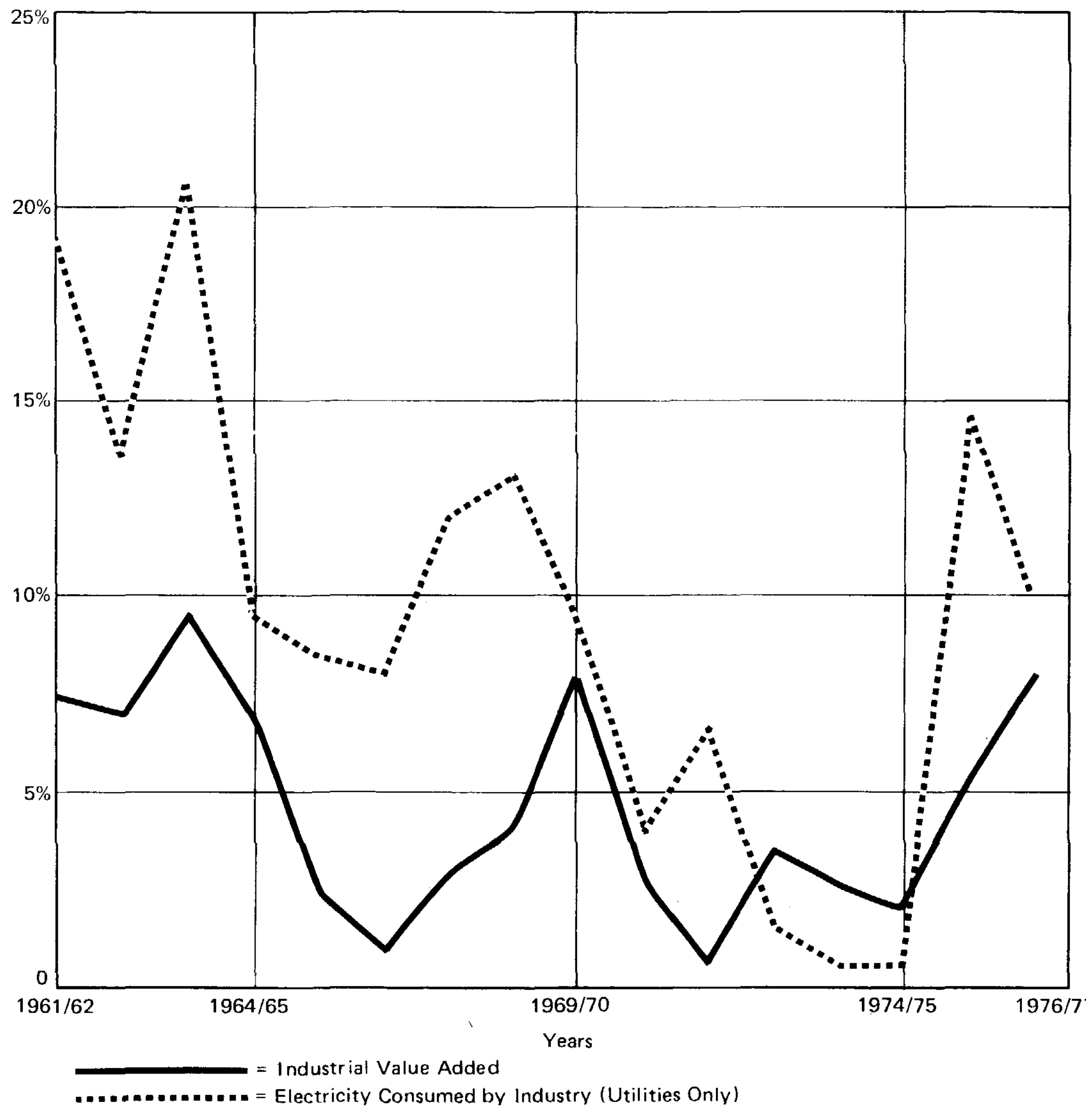
III: ANNUAL PERCENTAGE CHANGES IN INDUSTRIAL VALUE ADDED AND ELECTRICITY CONSUMED BY INDUSTRY



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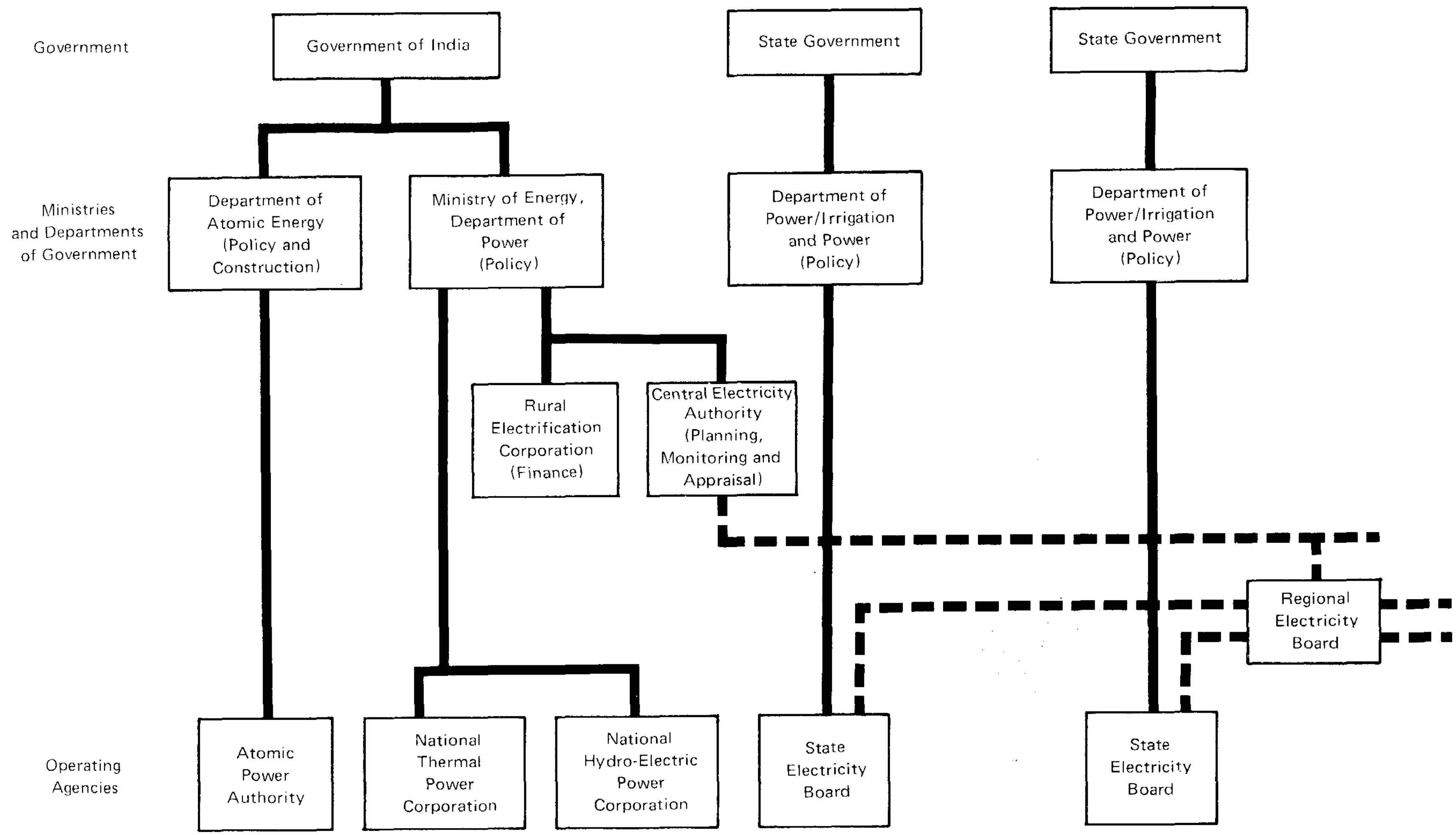
INDIA – PRINCIPAL ORGANIZATIONS IN THE POWER SECTOR



Note: Thee are 5 Regional Electricity Boards and 18 State Electricity Boards.

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