Chapter 7

ELECTRICITY PRICING, POLICIES AND DSM IN INDIA

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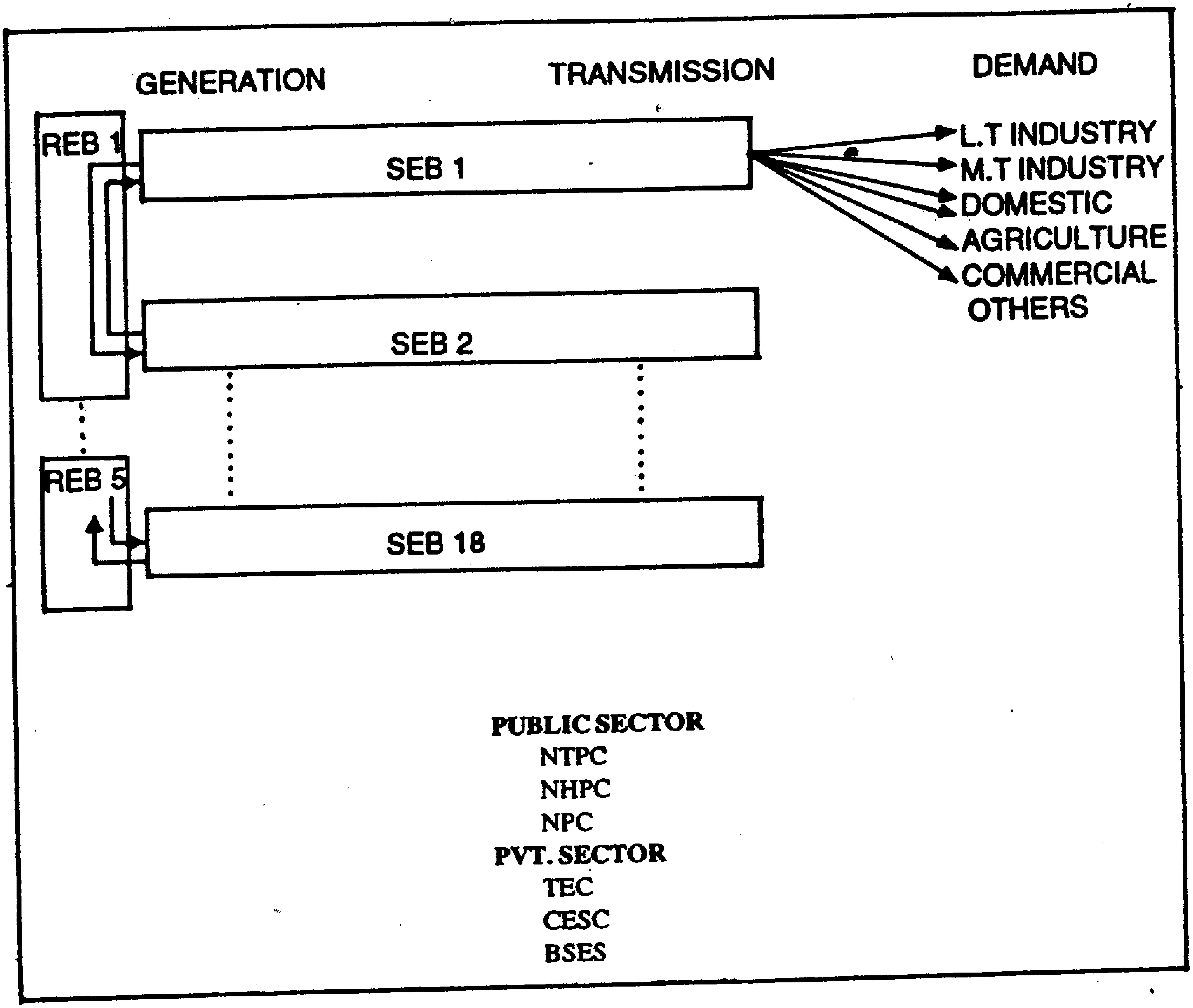
Introduction

Power planning in India has been supply oriented. Till recently, the Indian power sector has been dominated by utilities which have been in the government sector. The power sector is now being thrown open to private investors. There is also an attempt to restructure some of the existing organisations in this sector. The changes being planned in the power sector are still based on a supply oriented approach which emphasises the building of additional power plants to meet the future projected demand requirements. Demand Side Management (DSM) has been talked about but has not been seriously implemented by the State Electricity Boards. In the context of changes in the power sector of the country, this paper analyses the reasons for non-implementation of DSM in India and policies required to rectify the situation.

Indian Power Sector

Figure 1 shows the agencies involved in the Indian power sector (TERY, 1991). In most of the cases the utility responsible for generation, transmission and distribution is the State Electricity Board (SEB). Coordination between State Electricity Boards and issues related to inter-state transfers are the responsibility of Regional Electricity Boards (REBs). These function under the supervision of the Central Electricity Authority which is the regulatory agency for the Indian power sector.

An idea of the magnitudes of energy supply by different sources and the electricity consumption pattern by the different consumer classes for India is given in Figure 2 (Data for 1992-93). In 1993-94 the installed capacity of the Indian power sector was 76,700 MW and the energy consumption was 323,500 million kWh(Banerjee, 1993). The



OTHER AGENCIES

CEA

NATIONAL & REGIONAL TARIFF BOARDS
RURAL ELECTRIFICATION CORPORATION
ENERGY MANAGEMENT CENTRE

Figure 1 : AGENCIES IN INDIAN POWER SECTOR

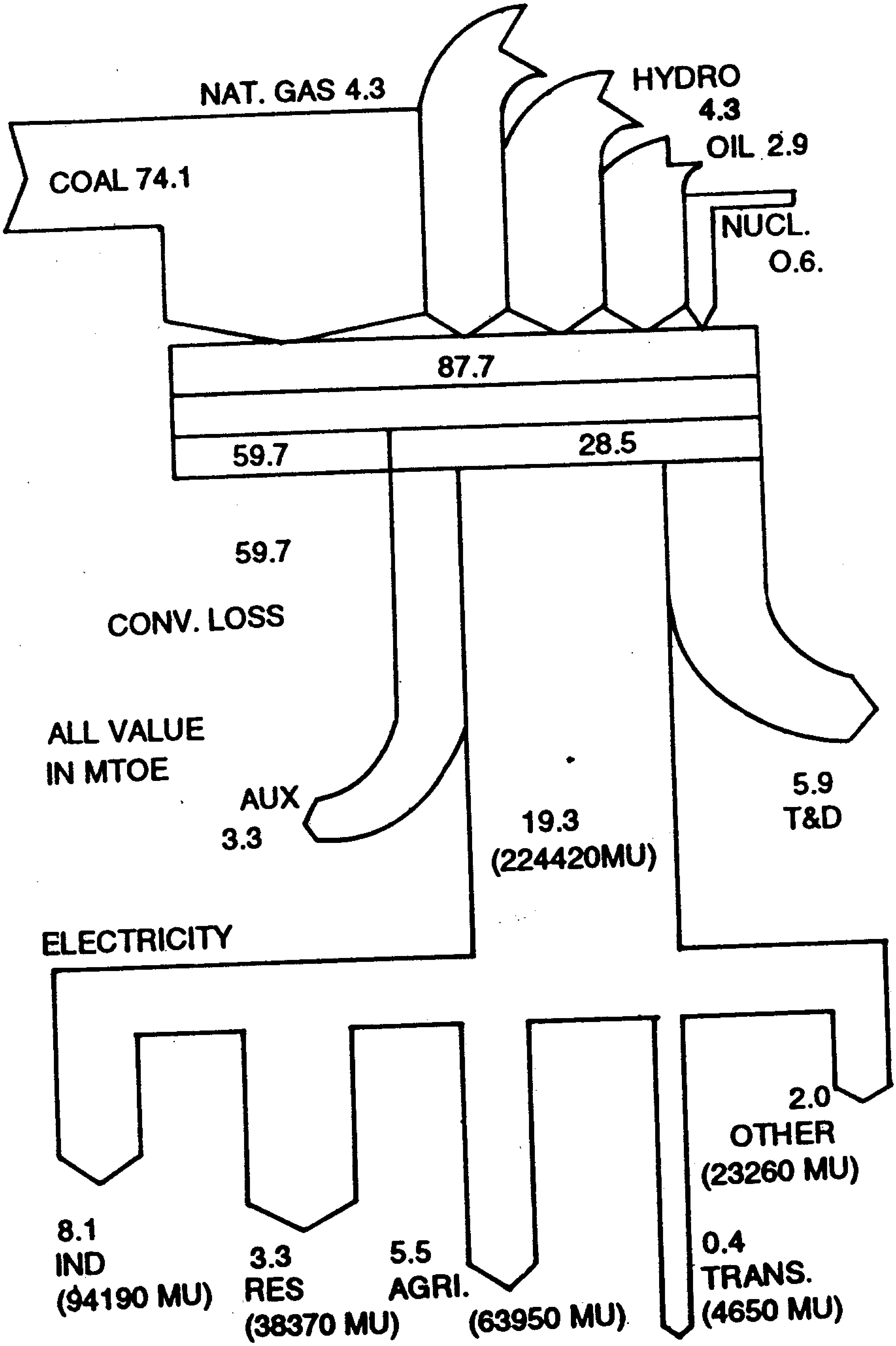


Figure 2 : ENERGY FLOWS IN THE POWER SECTOR - 1992-93

consumption of electricity has been growing at a rate of 8.6% per year (1980-93). Investments in additional capacity have not been able to match the increasing demand for electricity. This has resulted in shortage of electricity which is particularly severe during the system peak periods.

DSM in India

Demand Side Management involves co-operative action by the utility and the customer to achieve customer load modifications resulting in savings to the customer, utility and society. DSM includes energy efficiency, energy conservation as well as utility load shape objectives like load shifting, valley filling and peak clipping.

Reddy *et al* (1991, 1993) proposed a development focussed end-use oriented (DEFENDUS) electricity scenario for Karnataka in 1991. This evolved possibly the first least cost plan for an Indian state. Considering renewable and energy conservation options, Nadel *et al* (1991) examined the potential for improved end-use efficiency in India. A Demand Side Management plan for the high tension industrial segment in Maharashtra was chalked up by Banerjee and Parikh (1994) in 1993. (Details of the plan are reported in Parikh, *et al.*, 1994).

There have been a number of other studies to determine the potential for specific DSM options or DSM potentials for a consumer class or a region (studies by consultants, institutions like Tata Energy Research Institute, International Energy Initiative, non-governmental organisations like *Prayas* (Sant and Dikshit, 1994). However even years after the publications of these studies, very little has been done in terms of implemented DSM programmes. It is often felt that this is caused by the supply bias of the utility. In the current Indian power scenario it will be worthwhile to examine the utility response to DSM.

Utility Response to DSM

For the purpose of analysis, it will be assumed that the decision maker in the utility (State Electricity Board) is rational and is not biased towards supply. Given the existing policies and pricing structure how should the utility react to DSM ?

In formulating the utility response, the following characteristics of the utility should be considered :

(a) The utility is a monopoly.
(b) The utility has a peak shortage and an off-peak surplus.
(c) There are variations in the tariffs to different consumer classes with the industrial and commercial consumers cross subsidising the agricultural and domestic consumers.
(d) There is a limit on the total revenues of the State Electricity Board. A maximum rate of return of 3 % on net fixed assets is permitted by government policy.

Most of the utilities resort to load shedding to control the peak demand. Utilities also find it difficult to raise capital for new power plants. In this context they should be willing to examine DSM as an option.

In order to shortlist possible DSM programmes for implementation the utility would adopt the following criteria:

(a) *Low Transaction Cost*—For the DSM programmes to be viable the transaction cost should be a small proportion of the total programme cost.
(b) *High Potential Saving*—There should be a significant potential for saving for the DSM measures selected.
(c) *Revenue Considerations*—DSM programmes should not adversely affect the revenue balance of the State Electricity Board (SEB).
(d) *Customer Viability*—The customer should be willing to adopt DSM measures, viz. the payback periods for the customer should be low.

The consumption profile of the different customer classes for the Maharashtra State Electricity Board (MSEB, 1994) is shown in Table 1.

TABLE 1
Consumption Profile for MSEB (1992-93)

Consumer Class	No. of Consumers	Energy Consumption kWh/Year/Consumer	% of Sales	Tariff/ Cost of Supply
Domestic	5.5 million	600	13.3	0.5
Commercial	1.4 million	2,100	6.5	1.4
Agricultural	1.8 million	6,200	21.1	0.1
Industrial (low tension)	0.3 million	11,100	7.1	0.7
Industrial (high tension)	7000	2 million	33.2	1.8

Table 1 also shows the ratio of the sectoral tariff to the cost of supply of electricity to different sectors. Banerjee and Shanbhag (1995) analysed sectoral variations in electricity tariffs in India. The cost of supply of electricity at low tension is higher than the cost of supply at high tension. However the maximum tariffs are for the high tension industrial customers. The crossubsidy element is clear from an examination of the ratios of tariff to the costs of supply as shown in Table 1.

It would be worthwhile to examine each of the consumer classes from the point of view of implementation of DSM programmes based on the criteria mentioned earlier.

Low Transaction cost

The transaction cost would depend on the number of consumers to be tapped for DSM programmes and the average energy consumption per customer. A DSM programme which targets the domestic sector will have a high transaction cost and would have relatively small energy savings per consumer. Hence a DSM programme targeted at the domestic sector may be ruled out because of high transaction costs. In terms of this criteria it would be worthwhile to target the high tension industrial customers which have the highest energy consumption per customer and hence would have the lowest transaction costs.

High Potential Saving

This will depend on the efficiency of electricity use and the contribution to the total electricity use. From the point of view of highest share of electricity consumption the high tension (industrial) and agricultural sector seem to be suitable for initiating DSM programmes.

Revenue Considerations

For every kWh of electricity supplied to the high tension industrial sector, MSEB gets a revenue of 1.8 times the cost of supply. Hence any DSM programme which induces the HT industrial customers to conserve electricity will result in a loss of revenue to MSEB. Since the high tension (HT) industrial consumers are the main contributors of revenue to the SEB, the SEB is not keen to start any DSM programme which would cut into this revenue base. In view of the existing tariff structure it is rational for the State Electricity Boards not to induce the HT industrial consumers to use less electricity.

Customer Viability

The viability of a customer will depend on the load factor and the price of electricity. From this consideration DSM measures can be considered in the HT industrial and commercial sector. In the agricultural sector, the price of electricity is low (flat rate or at maximum 50p/kWh) and the customers would not be interested in making any investment in DSM measures. In the domestic sector, low tariffs, usage pattern and high consumer discount rates imply that to make DSM attractive to the consumer the utility must share a major proportion of the DSM option cost.

The high tension industrial sector seems to be preferable for initiating DSM because of its low transaction cost, viability to customer and high potential savings. However the State Electricity Boards would not like to support DSM programmes in this sector as it would affect their revenue balance. The agricultural sector has the next highest share of electricity consumption. The efficiency of electricity use in this sector is low. However the agricultural customers pay very low tariffs (less than 50p/kWh). Hence agricultural customers may not be keen to participate in DSM programmes. The transaction cost is also likely to be high because of the dispersed nature of the load. If DSM programmes can be designed so that the transaction costs are kept within limits, the SEB would be interested in supporting a DSM programme as it would improve the revenue balance (every kWh of electricity saved in the agricultural sector would result in a saving of the subsidy amount = cost of supply minus average realisation. For DSM in the domestic sector the barrier is likely to be the high transaction cost (the average consumption is only 600 kWh/consumer/year).

Consider a State Electricity Board which is making the maximum permissible profits. Suppose it has the option of installing 100 MW of additional generating capacity or investing in 100 MW of various DSM programmes. DSM programmes may require a lower capital outlay as compared to the new power plant. However there is no addition to the assets of the State Electricity Board. The equipments installed and modifications made are on the customer site. For the power plant there is a net addition to the asset base of the SEB. Hence it will be permitted higher profits. A rational SEB's strategy will be to increase its net asset base and maximise sales. It is clear that the present regulatory policy provides a disincentive to DSM.

Before making policy prescriptions we will examine measures for peak load management with an emphasis on Time of Use (TOU) tariffs and industrial cogeneration policies in the Indian context.

Peak Load Management

Most State Electricity Boards face a severe peak power shortage. SEBs are keen to support peak clipping and peak load shifting options. They have attempted peak load management for the high tension industrial customers. The following measures have been implemented by almost all SEBs :

Power Factor Correction

A carrot and stick policy has been followed which provides a penalty for low power factor (less than 0.85) and an incentive (rebate) for very high power factor. As most of the industries avail of the incentive and install capacitor banks to improve their power factor, the incentive for high power factor, is often discontinued. (This has been the strategy followed by the Gujarat Electricity Board).

Two Part Tariff

The normal tariff applied to the high tension industries consists of an energy charge and a demand charge. The demand charge typically is about Rs 90—125/kVA/month. There is often a disincentive in the way the maximum demand charge is levied.

The average kVA demand (D_i) is computed over a time interval Td (usually designated as half an hour) :

$$D_i = \sum_{t=t_i}^{t_i + T_d} (P/T_d)d_t$$

where P is the instantaneous power (kVA) and t_i is the time at the start of the i[th] demand interval.

The maximum demand Dm is defined as

$$D_{m_i} = \text{Max} \{ D_i \}$$

for all the demand intervals during the month.

In MSEB the billing demand is taken as the maximum demand Dm or 75% of the contract demand, whichever is higher. If an industry has Dm less than 75% of its contract demand, it has no incentive to reduce its maximum demand. The industry pays a penalty for retaining a contract demand (CD) in excess of its peak requirement. Industries are reluctant to surrender excess contract demand as they wish to provide for possible future loads. The perception is that excess CD once surrendered, will be difficult to restore. (An extreme case of this attitude is seen in some industries which purposely register higher maximum demands (than required for their plant operation) in a few months, in order to justify their surplus contract demand.

The other problems with the two-part tariff as it is implemented now are :

(i) The maximum demand could be registered at any time of the day. The industry pays the same maximum demand change irrespective of whether Dm is co-incident with the system peak or occurs during the off-peak.

(ii) If a high D_i is registered in the beginning of the month, there is no incentive to curtail the maximum demand (below this level) on the remaining days of the month.

The maximum demand (MD) charge is lower than the marginal cost of addition of new capacity during the peak period (about Rs 600-700/ kVA/month). The MD change needs to be increased, if it is to reflect the actual scarcity of peak capacity.

There exists significant potential for load smoothening and peak load management. This potential can only be realised by the introduction of differential pricing of electricity based on the time of use. Though there is broad consensus amongst policy makers of the power sector regarding the need for the introduction of TOU tariffs, the actual implementation of TOU tariffs has been sluggish.

The barriers to the introduction of TOU tariffs were:

Non-availability of Reliable Meters

SEBs felt that the electronic TOU meters available were not tamper-proof. This is no longer an impediment as reliable electro-mechanical and tamper-proof electronic meters are available at reasonable prices.

Low Load Shifting Potential

In view of the cost of the TOU meter as well as the high transaction cost, SEBs feel that this may be suitable only for the high tension industrial customers. However the SEBs feel that industries may not be able to shift much of their load from peak to off-peak periods. This is the classic chicken and egg problem. Industries perceive electricity to be an evenly priced commodity (i.e. with a price independent of time of use). Hence they have not contemplated the possibility of shifting loads from the system peak to the off-peak. Most industries do not even know their load profiles. Signals about the system peak, off-peak and partial peak periods have not been passed on to the industry. Based on the feedback from industries that they have essentially flat loads with no possibility of load shifting, SEBs are reluctant to experiment with TOU tariffs.

One of the first experiments with TOU tariffs was carried out by MSEB. MSEB introduced a night tariff (a rebate of 25p/kWh). This was applicable only to HT industries which had two-shift operation with one of the shifts being the night shift. This tariff was essentially to encourage consumption during the off-peak period. The tariff was voluntary and only two industries opted for it. Even these industries discontinued this tariff as they had problems with the TOU meters installed by MSEB. Gujarat Electricity Board (GEB) and Tamil Nadu Electricity Board (TNEB) have also started experimenting with TOU tariffs. GEB currently has a peak surcharge of 15p/kWh during the peak period as well as an off-peak rebate

Figure 3 shows a schematic of the steps required to introduce Time of Use tariffs. Initially the system load curve of the utility needs to be analysed to distinguish the different system periods (peak, off-peak and partial peak) and the corresponding time slabs. Mishra and Banerjee [1994] proposed a methodology to identify different time slabs when the system loading varied.

After analysing the average hourly demand for each quarter (during April 1993-March 1994) the off-peak was identified as lasting from 11

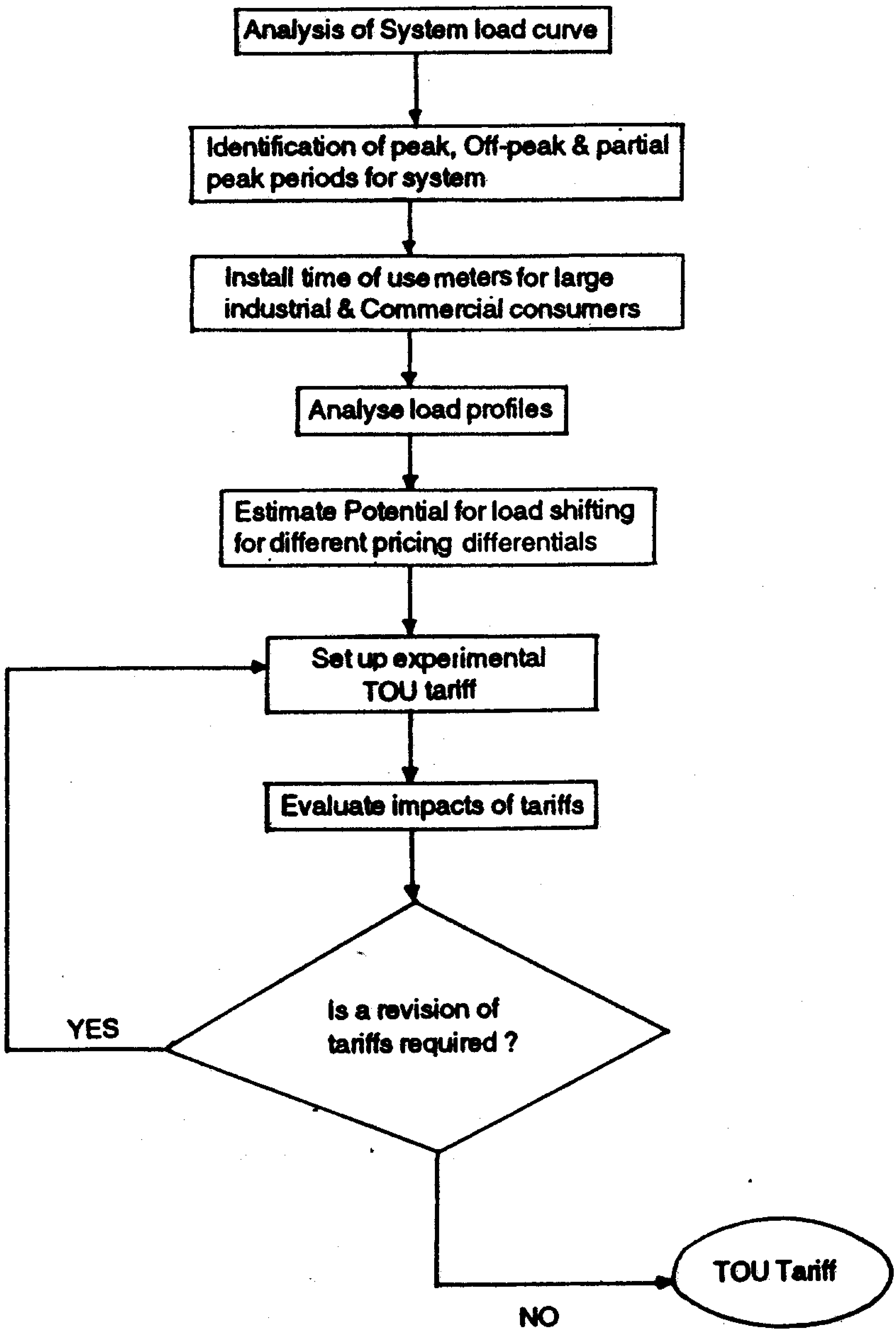


Figure 3 : FLOW CHART FOR SETTING UP TOU TARIFF.

p.m.-7 p.m. in the morning and 5-10 p.m. in the evening. A potential peak reduction of 10% of the system peak was identified (600 MW). After identifying the system peak periods, it is necessary to install time of use meters in the large industrial and commercial consumers. Load profile data needs to be systematically collected. Industrial loads co-incident with the system peak need to be studied, to identify loads which can be shifted to off-peak periods. The feasibility of additional investments required (chilled water, water, fluid storage) to avoid energy consumption during the peak needs to be done to determine the differential to be set by the utility to induce shifting. Internationally differentials of 4:1 (peak, off-peak) are common. SEBs need to set large differentials initially to encourage industries to explore load shifting possibilities and for them to recognize that the price of electricity varies with time of use.

In many industries changes in operating strategies involving sequencing of large loads (so that there is minimum consumption during peak periods) can result in significant load shifting. An illustrative sequencing of furnaces for a mini steel plant (Mishra and Bannerjee, 1994) showed that for the same daily output of molten metal, the industrial maximum demand during the system peak period can be reduced by 26 MW (47% of the initial co-incident peak demand).

SEBs would need to formulate tariffs in an iterative fashion (viz. implement a tariff, assess its impact and make revisions if necessary) till the desired smoothening effect is achieved. Some SEBs, notably Bombay Suburban Electricity Supply (BSES) and MSEB, have started the process of profiling consumer loads. A few demonstration cases need to be made where the industry or commercial establishment is able to shift its load from the system peak period and also achieve net electricity bill savings under hypothetical tariff structures. There is a need to have systematic experimentation with TOU tariffs as this is sure to be an option for meeting the peak power demand.

Cogeneration

Cogeneration of process heat and electricity by industrial customers has significant potential to add to the power generating capacity of the country. Till recently, most SEBs did not encourage cogenerators. Each cogenerator needs to obtain permission from the SEB before starting a cogeneration facility. Utilities consider this as a potential loss of revenue as this will result in a loss of high tension industrial sales (each unit pays for more than the cost of supply). There is no obligation of the SEB to permit paralleling with grid. The cogeneration configuration and the optimum operating strategy for a cogeneration would depend on whether the utility permits selling to the grid and the price of electricity sold.

Some states (Tamil Nadu, Gujarat) have introduced policies to encourage cogeneration. Tamil Nadu has issued a notification for cogeneration in sugar industry. Tamil Nadu Electricity Board (TNEB) will pay the high tension industrial electricity tariff minus a transmission and distribution charge (2%). This payment will be made within 30 days. TNEB permits wheeling i.e. a company can generate at one of its sites and can wheel the power to another side, located elsewhere in the State. A wheeling charge of 10% will be levied by TNEB. Banking is also permitted (TNEB levies a charge of 2%). Hence, if a sugar factory generates surplus during the off season it can bank it with the grid and get it back during the crushing season.

There is a need to have a national policy for cogeneration with clear rules on buyback, wheeling and banking. Cogenerators should be permitted fuel supply on a priority basis (similar to power plants). Incentives offered for private sector participation in this power sector should be extended to industrial cogeneration. It is important that time of use pricing is followed for buying excess power from cogenerators. Otherwise SEBs may be faced with a situation where they are forced to purchase electricity at off-peak periods, by backing down their cheaper generators. Differential pricing will ensure that cogenerators operate their facilities so that they maximise generation of electricity and supply to the grid during the system peak periods. Estimates indicate that an additional 10,000 MW of peak capacity can be supplied through industrial cogeneration in the country.

Conclusions and Policy Recommendations

In this paper, the policies in the electricity sector have been examined with regard to their implications for Demand Side Management (DSM). The following conclusions emerge:

1. A rational utility (SEB) which is profit making would prefer to increase the generating capacity instead of investing in DSM. This is because the SEB is permitted a maximum rate of return on net assets in the existing regulatory framework and investment in DSM does not add to the asset base of the utility.
2. In order to implement successful sectoral DSM programmes the utility would choose programmes which have low transaction cost, high potential savings are viable to the customer and do not adversely affect its revenue balance. Though the high tension industrial segment seems to be suitable (on the basis of the other criteria) for DSM, it is negated by revenue considerations. Because of the cross subsidy component, each kWh of electricity sold to the HT industry results in a revenue equal to 1.8 times the cost of supply.

For the other segments transaction costs are likely to be high. There are no estimates of transaction costs for DSM programmes in different sectors for utilities in India.

3. SEBs have implemented two-part tariffs and programmes to induce power factor correction in the HT industrial sector. These have been reasonably successful. However there has been very little experience with Time of Use Tariffs. There is no systematic estimate of the load shifting potential under different TOU tariffs.
4. The policies for cogeneration vary from state to state with a few SEBs permitting grid paralleling, buyback and wheeling.

From these conclusions, the specific policy recommendations made are :

Change in Rate of Return Clause

Even if the government decides to retain a limit on the maximum rate of return permissible as the utility is likely to remain a monopoly, it is necessary to make changes to ensure a level playing field for DSM. DSM should be treated as

" Deemed capacity additions". The utility should have a benefit in terms of equivalent investment in avoided capacity. Hence if a SEB avoids 100 MW of peak capacity by DSM, its net asset base should be increased by an amount equal to the capital cost of a 100 MW power plant.

This would provide an incentive for DSM. Alternately DSM based incentives could be provided explicitly viz. SEBs could be provided additional rates of return based on their success in implementing DSM.

Pilot Programmes

There is a need to estimate transaction costs of different DSM programmes in different sectors. This should be done by implementing pilot programmes which are closely monitored. The costs incurred and the impacts of these programmes need to be tracked and made available to all the SEBs.

Compensation for Cross-subsidy

DSM programmes in the HT industrial sector are unviable from the utility point of view because of the cross-subsidy component. From equity considerations, if the cross-subsidy policy for electricity is retained, it is necessary to quantify the cross-subsidy in a transparent fashion. For DSM programmes in the HT sector, the revenue lost due to lower HT sales (hence a lower cross-subsidy amount) should be compensated to SEBs by the government.

Experimentation with TOU Tariffs

SEBs need to follow a systematic approach to TOU pricing. This would involve identification of system periods, load profiling and estimating the viability of load shifting under different tariff differentials (by studies on sample customers). SEBs need to initiate TOU tariffs by providing large differentials in electricity prices between peak and off-peak period (4:1 or higher are common internationally) to encourage industrial and large commercial consumers to shift, loads from peak periods. There is a need for information dissemination and training so that the large consumers can orient their operating strategies to account for time of use priced electricity. Well-documented demonstration case studies of consumers who have been able to participate in load shifting programmes and reduced their electricity bill would help in this effort.

Cogeneration Policy

There is a need to have a clear national cogeneration policy which makes it mandatory for SEBs to permit cogenerators to parallel with the grid and provide facilities for buyback, wheeling and banking at rates (depending on the cost structure of the SEB). Incentives which are offered for private power producers should also be extended to cogenerators. SEBs should incorporate TOU tariffs in their buying-selling agreement with cogenerators.

In addition to these policies, measures like labelling (with equipment displaying the likely annual electricity bill on its nameplate) and energy efficiency standards (voluntary or mandatory) can have a role in improving the efficiency of electricity use.

There is a need for the Indian power sector to move from potential studies to implementation of pilot DSM programmes. This will enable utilities to decide on the appropriate mix of DSM programmes and implementation strategies.

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