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Dynamic Tariff Structures for Demand Side Management and Demand Response

This white paper highlights a Dynamic tariff structure which may help in the wider application of smart grid technologies such as demand side management and demand response.

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Dynamic Tariff Structures for Demand Side Management and Demand Response: An Approach Paper from India

Contributors (Name, Title, Affiliation, Country):
1. **Sanjeev Kumar, Director, MoP, GoI, India**
2. **N.S. Sodha, Executive Director, POWERGRID, India**
3. **Kumud Wadhwa, Dy. General Manager, POWERGRID, India**

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Abstract

To glean the benefits of Smart Grid concepts of Demand Side Management and Demand Response to the fullest, it is imperative that innovative dynamic tariff structures be designed through which the benefits of Smart grids can be realized by all the stakeholders at the revenue generation end of the electricity value chain right from consumer, distribution company, state governments and the nation. This white paper highlights one such Dynamic tariff structure which may help in the wider application of smart grid technologies such as demand side management and demand response. Proposed Dynamic tariff structure includes frequency based tariff component as well as preannounced Time of Day tariff charging higher price for peak load periods based on historical data. Reliability surcharge and discounts on pre-payment are also proposed to be included in the tariff. Consumers may be given an option to participate in the new tariff scheme with a cap that the revised bill amount will not exceed the amount payable as per existing tariff plan in that area.

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Introduction

For decades, dynamic tariffs, in combination with customer engagement and price-responsive technologies at the point of consumption, have been an important avenue for managing electricity supply and demand balance. As an example, in conjunction with construction of relatively “inflexible” large-scale nuclear power generation capacity in the 1970s and 1980s, utilities in France established a nighttime discounted rate and distribution companies installed electric water heaters that would automatically switch on during these low-rate periods–thus providing a load for the power and allowing the high capacity operation of the plants (Boivin, 1995). The overall effect of this coordinated tariff and technology system flattened overall demand, shifting load from daytime peak periods to nighttime low-demand periods; it provided greater alignment between electricity generation and consumption (see Figure 1).

Further, utilities around the world have tested the impact of price-based customer feedback systems on consumer behavior for at least four decades (see e.g., (Faruqui, Sergici, & Sharif, 2010); (Darby, 2006).) Such studies consistently demonstrate that direct feedback can strongly motivate energy conservation through consumer behavior.

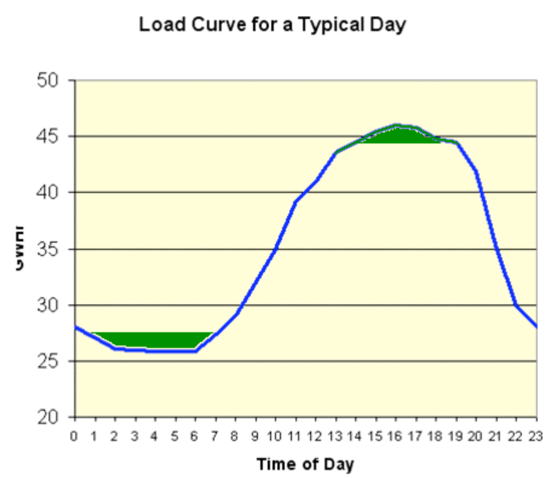

Figure 1 Load Curve for a typical day

Building on the foundation of these types of integrated policies and systems, the addition of information and communication technologies (ICTs) across electricity networks dramatically expand the range of these systems to affect change. Innovative dynamic tariff structures can help unlock benefits of smart grids to a wide range of stakeholders all along the electricity value chain, including the revenue generation end to consumers, distribution companies and local & national governments.

This paper investigates these new possibilities insofar as they hold promise to reduce system instability and improve electricity supply service in rapidly growing economies, such as the country of India, which features high rates of electricity demand growth, limited generation reserve capacity, significant reliability problems, and growing rates of distributed energy generation and network congestion. In this context, reducing shortage and congestion-related outages is a high priority besides peak load management. This paper will outline some of the specific dynamic tariff structures that can be adopted in such distribution networks, likely benefits to stakeholders from dynamic interventions, and recommendations for potential collaboration from ISGAN member nations.

Ultimately, it is anticipated that such systems might increase the quality and quantity of power to consumers in rapidly growing countries like India, accelerating inclusive growth.

Issue Background and Overview

Indian electricity generation capacity has grown at a rapid pace--from 1.3 GW in 1947 to around 210 GW today. Even with the dramatic growth, the deficit in power supply in the country, in terms of peak availability and of total energy availability, is around 11% and 10% (Central Electricity Authority, 2012-13)respectively. In addition, there remains enormous unmet demand of upwards of 200 million people. Per capita consumption is only about 870 kWh per annum against the world average of about 2500 kWh (and an OECD average of roughly double that). But this is set to change. India plans to expand generating capacity by almost 50% by the end of the twelfth plan period (2012-2017). Moreover, at the current trends of 8-10% economic growth, the installed capacity requirement of the country should be around 575 GW by the year 2027, which is nearly triple today's capacity (see Table 1).(Source: Planning commission report)

Table 1 Sector-Wise and Mode-Wise Capacity Addition (Provisional) During the Twelfth Plan (MW)

Sector	Hydro	Total Thermal	Thermal Breakup			Nuclear	Total
			Coal	Lignite	Gas/ Liquefied Natural Gas *		
Central	6,004	14,878	13,800	250	827.6	5,300	26,181.6
State	1,608	13,922	12,210	0	1,712.0	0	15,530.0
Private	3,285	43,540	43,270	270	0.0	0	46,825.0
Total (excluding RES)	10,897	72,340	69,280	520	2,539.6	5,300	88,536.6
Renewables	—	—	—	—	—	—	30,000
Total (including RES)	10,897	72,340	69,280	69,280	520	5,300	118,536.6

Current practice for managing the energy deficit is rolling blackouts, also referred to as load shedding (i.e., an intentionally engineered electrical power shutdown where electricity delivery is stopped for non-overlapping periods of time over different parts of the country). This can be viewed as a crude, but effective, form of demand response. Some of the utilities taking cues from the legislative and legal frameworks in India have also implemented time of day (ToD) tariffs, generally for large industrial and commercial category consumers, but this does not support real time control of power supply imbalances because the ToD tariffs are preannounced almost three months in advance. Transitioning to widespread practice of less disruptive forms of demand response is a high priority, leading to the interest in dynamic tariff setting empowered by smart grids.

Power System Challenges in India

In order to meet the enormous power needs in the coming decades, the Government of India (GoI) has launched various initiatives such as the Ultra Mega Power Projects (UMPPs), facilitating increased private sector participation via IPP in power generation by allotting projects under tariff-based competitive bidding routes. UMPPs are very large projects, with approximately 4000 MW each using super critical coal technology and involving an estimated investment of about US$ 4 billion. As a result, the share of private sector in Generation installed capacity is set to increase from 19% in the Eleventh plan to around 57% in the Twelfth plan. Transmission needs of the power sector are being catered to by POWERGRID, and from January 2011 onward, transmission sector has also been opened up for competitive bidding for private participation in the sector. But the critical link of distribution is turning out to be the 'Achilles' heel' of the Indian power sector. As per the 13th Finance Commission Report of the Government of India (pg 105), the net losses of the State Transmission and Distribution (T&D) Utilities at 2008 tariffs, considering increase in power purchase costs, etc.. , are estimated to increase from over INR 68000 Crore i.e., €9710 million/12830 million USD in FY 2010-11 to over INR 116000 Cr i.e. €16571 million/21886 million USD in FY 2014-15 even after considering reasonable reduction in losses based on historical performance of some of the better performing utilities The distribution sector is plagued with problems such as:

- High Aggregate Technical and Commercial (AT&C) losses. The national average stands at 28.44 % as of 2008-09 according to the Power Finance Corporation Report on Performance of State Power Utilities, which is about 4-6 times higher than levels seen in OECD countries on average.
- Tariff inadequacy or the , absence of cost-reflective tariffs. Tariff increase requirements aim to meet the burgeoning financial losses even in the better performing states, and considering subsidy at the 2007-08 levels, they are as much as 7% per annum on average while in the case of some of the poorly performing states the increase requirement is as much as 19% per annum (pg 105). The cross subsidies built into tariff structures further stretches the economic viability of the sector. Agricultural consumer is mostly getting free unmetered supply for which utility gets grant from state govt. Also, industrial consumer in India is paying higher tariffs to subsidise lower tariffs for domestic consumers. Direct subsidies provided to a specific category of consumers is often a better method of providing subsidies--rather than asking one category of consumers to cross-subsidize another set of consumers.
- High cost of short term power purchases. Several utilities have not planned capacity addition in time and are relying on short term purchases at high rates (an average of INR. 5.19 per kWh [i.e., €0.075/ USD 0.1 per kWh in 2009-10]). The inability to reduce T&D losses has further increased the purchase levels and supply costs. For all the buyers/ utilities, the maximum price through UI transaction has gone as high as INR 17.46 per kWh (i.e., €0.25/0.33 USD per kWh through power exchange to INR 20 per kWh i.e. €0.28/0.38 USD per kWh (CERC) and through traders to INR 8.04 per kWh i.e. €0.11/0.15 USD per kWh).

- Inept energy accounting and auditing. This has led to large gaps in billing and realization--billing and collection efficiencies are in the range of 71% and 94%, respectively, compared to X in OECD.
- Unmetered (free) power to certain categories of consumers. These include consumers like the agricultural sector, which has a large load, on the order of up to 40% in some states.
- Poor infrastructure. The distribution system infrastructure is very old and has inadequate reactive power managing resources. Proper distribution network planning and periodic distribution system capacity augmentation is generally missing. During last summer the power supply for end consumers was below 130Volts as compared to nominal supply voltage of 220 Volts in some areas. Infrastructure has not been maintained or augmented to meet the growing power needs.
- Poor demand side management- The utility mostly resorts to complete load shedding in certain areas to meet supply shortages
- Customer dissatisfaction.-Market segmentation based on customer profession or category of connection in terms of voltage level or bulk power requirements.. The market is currently segmented broadly into industrial, commercial, domestic, and agricultural sectors. If this can be further segmented according to consumer requirements, their ability to pay, and the ability of the utility to serve so as to design flexible service packages to address their specific priority requirements.

Utilities' poor financial health has resulted in underinvestment in the distribution network, causing poor upkeep and maintenance. Consequently, the quality of supply is hampered, leading to customer dissatisfaction and poor recovery. This, in turn, leads to further deterioration of financial health of utilities. This vicious cycle needs to be broken, and one mechanism can be appropriate tariff design. GOI has stressed that it is absolutely vital that the distribution system is made financially viable during the Twelfth Plan. Accordingly, the key focus of the Twelfth Plan is to strengthen the performance of the distribution system to achieve improved financial viability of distribution companies (discoms) and to expand access to power in rural areas. Introduction of smart grid to allow effective demand side management (DSM) is to be taken up earnestly. (Draft report of planning commission, p.152)

To improve performance of distribution companies, the smart grid in India will aim at:-

- Reducing aggregate AT&C losses and bringing them to around 5-7% matching with the benchmark losses across the best utilities around the globe
- Ensuring minimum lifeline supply for all, ensuring there are no power cuts
- Managing and reducing peak power demand
- Utilizing the abundant potential of renewable power by integration of renewables/ distributed generation to the Grid efficiently
- Enabling proliferation of prosumers using rooftop solar PV generation.

Tariff Determination in India

The terms and conditions for tariff setting in India are generally guided by the principles contained in the Electricity Act 2003. Though the legislation under the act provides for differentiation of tariffs, even among the same category of consumers (according to, e.g., basis of load factor, power factor, and even the time at which supply is required), the tariff currently set by State Commissions is mostly at fixed rates (barring a few instances where ToD tariff is being implemented for bulk consumers). The main reason for this is a lack of information and communication technology in the Indian distribution network for capturing consumption data in near real time. All this is set to change with implementation of smart grid technologies in the Indian distribution sector.

The GoI formulated the tariff policy in January 2006 under Section 3 (1) of the Electricity Act 2003 with the following objectives:

(a) Ensure availability of electricity to consumers at reasonable and competitive rates

(b) Ensure financial viability of the sector and attract investments

(c) Promote transparency, consistency, and predictability in regulatory approaches across jurisdictions and minimize perceptions of regulatory risks

(d) Promote competition, efficiency in operations, and improvement in quality of supply.

Balancing these conflicting cost/viability objectives while implementing dynamic rates to increase power quality is the key challenge. With the present distribution system operating with average AT&C losses of around 28%, there is ample scope for the discoms to balance the conflicting objectives of providing electricity at competitive rates while ensuring financial viability of the sector making operations more efficient. With introduction of dynamic pricing, the discoms can avert costly peak power purchases and reduce their power purchase costs.

Under the provisions of the Electricity Act, the Central Government established the Forum of Regulators which would, inter alia, facilitate interstate consistency in approach, especially in the area of distribution.

The distribution tariff provides for recovery of prudent cost incurred in licensed wheeling (i.e., the creation, maintenance, upkeep, renewal, and development, including replacement and expansion of the wire network and supply of the distribution licensee plus Return on Equity (RoE) at prescribed level of performance). State Electricity Regulatory Commissions (SERCs) determine the allowable tariffs and operating and cost parameter norms for a tariff period after considering past operational and financial performance (Tariff order).

The Aggregate Revenue Requirement (ARR) for the generating company, transmission company, and the distribution companies forms the primary basis for recovery of charges from consumers through retail tariffs. The ARR for a discom is broadly comprised of an assessment of power purchase cost (fixed and variable cost) for existing stations and for future capacities, power purchase requirements, inter-state and inter-regional transmission charges to be paid for transmission system usage, Load Despatch Centre (LDC) charges, Operation and Maintenance (O&M) expenses, cost for depreciation of assets of the distribution system, interest and finance charges on project loans, return on equity, interest on working capital, interest on consumer security deposit, bad and doubtful debts, regulatory commission fees, miscellaneous income on account of rent or charges imposed on consumers, etc. which are determined by the discom in accordance with the prevailing tariff regulations of the SERC.

The distribution licensee has to present its selected ARR to the Regulatory Commission through a petition in three distinct parts (first for the energy cost, i.e., power purchase cost including transmission and distribution losses and inter-state and intra-state transmission charges; second, for wheeling expenses; and third, for expenses pertaining to supply of energy to consumers, including customer services). The licensee can also recover a supply reliability charge for un-interruptible supply, which at present is generally through Extra High Tension (EHT) voltage and also at 33kV.

- The expenses pertaining to wheeling activity cover sub-stations, conductors, transformers, plants, and apparatuses used in the distribution system by the distribution licensee.
- The costs associated with the distribution licensee's supply activity will include establishment cost for arranging the power to the consumers and for providing consumer services, which may involve expenses for metering, billing, recovery, and associated activities.

To promote efficiency in licensee system operation, provisions state that any financial loss on account of power purchased by the licensee in any year to meet additional losses over and above the approved level of losses has to be borne by the licensee itself and is not passed on in the tariff.

State commissions are also required to have a mechanism in place for uncontrollable expense of fuel and power purchase cost adjustment in terms of Section 62(4) of the act. Ideally, the fuel and power purchase cost adjustment has to be done on a monthly basis in accordance with the Central Commission's regulations, but in no case exceeding a quarter. Fuel Cost Adjustment (FCA) charges are uniformly applicable to all categories of the distribution companies' consumers; the rate and amount of FCA charge is required to be shown separately in the consumer bills.

Status of Current Efforts and Deployment Case Studies

Policy Provisions for Dynamic Tariffs

Current legislative frameworks to promote implementation of ToD as an important DSM tool are as follows:

Electricity Act 2003

Section 62(3) guides SERCs to incorporate ToD tariff:

> "The Appropriate Commission shall not, while determining the tariff under this Act, show undue preference to any consumer of electricity but may differentiate according to the consumer's load factor, power factor, voltage, total consumption of electricity during any specified period or the time at which the supply is required or the geographical position of any area, the nature of supply and the purpose for which the supply is required." (Electricity Act, 2003, p.49)

National Tariff Policy, 2006

Provisions such as 8.4 of the National Tariff Policy define the tariff components and their applicability:

> "8.4 Definition of tariff components and their applicability

1. Two-part tariffs featuring separate fixed and variable charges and Time differentiated tariff shall be introduced on priority for large consumers (say, consumers with demand exceeding 1MW) within one year. This would also help in flattening the peak and implementing various energy conservation measures." (National Tariff Policy, 2006, p.18)

National Electricity Policy, 2005

Provision 5.4.9 of the National Electricity Policy encourages metering for ToD:

"5.4.9 The Act required all consumers to be metered. The SERCs may obtain from the Distribution Licensees their metering plans, approve these, and monitor the same. The SERCs should encourage use of pre-paid meters. In the first instance, ToD meters for large consumers with a minimum load of one MVA are also to be encouraged. The SERCs should also put in place independent third-party meter testing arrangements." (National Electricity Policy, 2005)

Forum of Regulators (FOR) Recommendations, 2009

FOR has also given the following recommendations in its Working Group Report on "Metering Issues":

"Time of the day metering is important while propagating and implementing Demand Side Management (DSM) and achieving energy efficiency. Hence, ToD metering and automatic meter reading system should be introduced wherever it has not already been done. High-end consumers with the connected load of 25KW and above should be covered under TOD metering." (Forum of Regulators (FOR) Recommendations, 2009, p.23)

Central Electricity Authority (CEA) Regulations

With respect to ToD metering, CEA Installation and Operation of Meters Regulations, 2006 have stated:

"20. Adoption of new technologies -

The distribution licensee shall make out a plan for introduction and adoption of new technologies such as pre-paid meters, ToD meters, automatic remote meter reading system through appropriate communication system with the approval of the Appropriate Commission or as per the regulations or directions of the Appropriate Commission or pursuant to the reforms programme of the Appropriate Government." (Central Electricity Authority (CEA) Regulations, p.14, 2006)

Smart Grid Initiatives

The process for implementing smart grids in the distribution sector has already been initiated through pilots with interested utilities across India on Demand Response and DSM through Automated Metering Infrastructure for residential and industrial consumers, outage management, peak load management, power quality, micro grid, and distributed generation. Fourteen smart grid pilot projects have been shortlisted for partial funding by GOI. Before proceeding further with the pilots, the state utilities are required, with the help of regulators, to set up the regulatory framework for the pilot area for tariff mechanisms, remote connection/disconnection, load curtailment, etc.

Most of the proposals received entail development of a ToD/dynamic pricing mechanism for achieving DSM.

TATA Power Demand Response

The TATA Power Demand Response program allows the consumers to curtail the load when utility demands and to pay on a per- kWh basis. This is a voluntary curtailment of up to 100 hours in a year. The load curtailment is triggered a) when TATA Power is incurring high cost toward power purchase or b) when the distribution network is congested.

The consumers benefit from the reduced burden of costly power of discom and can save on their monthly bills. TATA Power is offering up to Rs 2.25 per kWh of curtailed electrical energy compared to a defined baseline. The customers handle the load curtailment with help from the demand response (DR) service provider who aggregates the load of all customers and provides bulk load relief to TATA Power. (TATA Power) TATA Power has enrolled the customers who can curtail load (more than at least 50 kW) for a short span of 2 hours when requested.

Critical Areas for Research and Collaboration

The proposed dynamic pricing structure in the next few paras can be further augmented based on Experience of other member nations.

In India, the industry, domestic, and agriculture sectors contribute 39%, 24%, and 19% respectively to the total electricity consumption (CEA 2010-11). Further, the compounded annual growth rate of consumption for the domestic sector is set at a maximum of 9.6% over a period from 1970-71 to 2010-11; this can be attributed to improved access of power in the rural sector and an increase in per capita consumption in the urban sector because of changes in lifestyle and a rise in income. The charts below show the consumption pattern and compound annual growth rate.

Whereas attempts are being made for DSM for industrial and bulk consumers in the commercial sector by introducing ToD tariffs based on some utilities' predetermined peak load charges(further details in ISGAN paper on People, Process, Policy), there is ample scope for DSM in the domestic sector and the rest of the commercial sector as well. This DSM administered through ToU or Real time pricing can help in peak load management as well as reduction in load shedding.

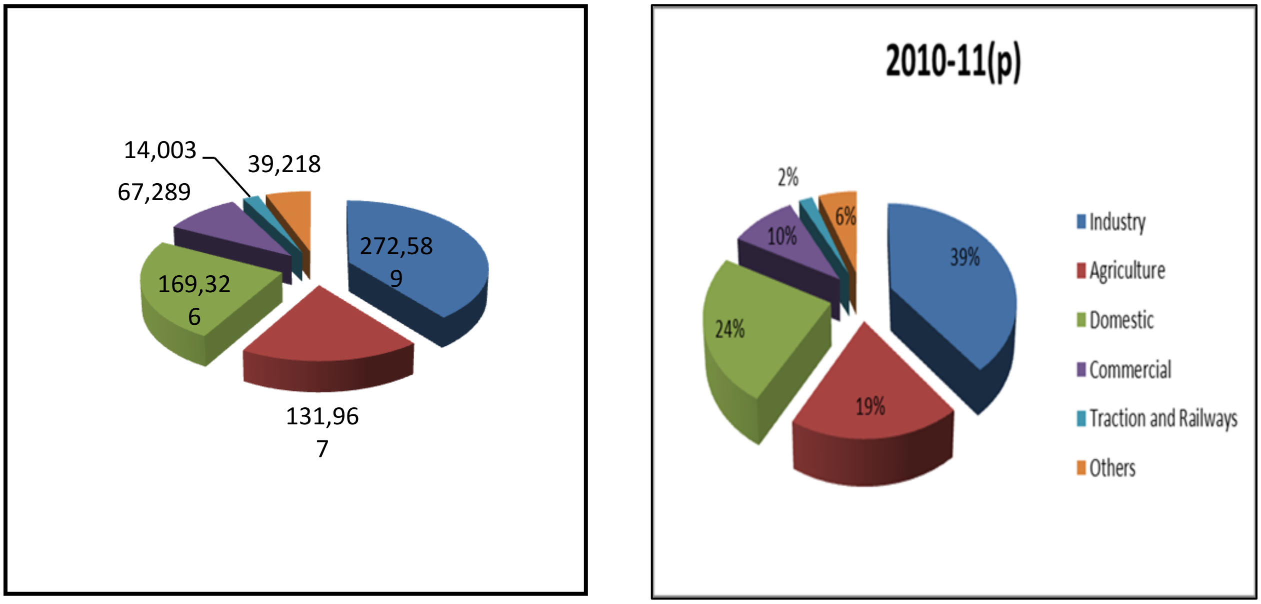

Figure 2 Consumption of electricity (from utilities) by sectors in India (Provisional data)

(gigawatt-hour) = (10^6 x kilowatt-hour)

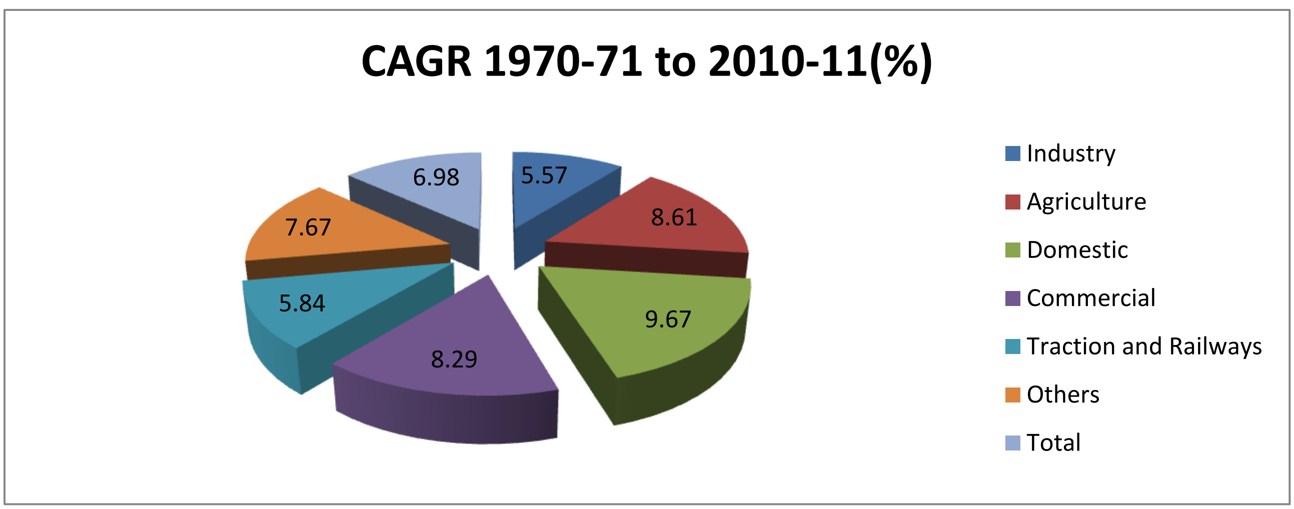

Figure 3 Load growth pattern 1970-71 to 2010-11(%)

For designing the Dynamic pricing for DSM for residential peak load management in India, a survey was conducted to gauge the extent of awareness among consumers about smart grid functionalities, their electricity consumption pattern, charges they pay for electricity and for back-up power, amenability to shifting their electricity usage from peak to off peak, willingness to pay premium for reliable and quality power supply, inclination to installing rooftop generation, etc.

An online survey link was published on the India Smart Grid Knowledge Portal and emails were sent to around 500 people for their responses on the questionnaire. A summary of the responses, received from around 63 participants in about a week's time, is given in Annexure 'A'.

Though the analysed data is for a very insignificant sample size, still if consider the same to get some insight about customer behavior it indicates that:

A. 87% of respondents are willing to shift their part load to avail some discount on the tariff
B. Only 16% respondents were not willing to pay premium for reliability charges.
C. 66.7% respondents are willing to install rooftop solar panels whereas for 22.2% of respondents, installation of rooftop panels was not applicable–perhaps because they live in apartments. The average rooftop area for participants willing to install rooftop panels is 1,481 sq. ft.
D. As depicted in Fig. 1, there is no direct relationship between the discount for shifting the load and premium for getting reliable power (Premium_SLA) supply; 19% of respondents want 20-30% discount to shift load and are willing to pay 5-10% premium for reliability. Meanwhile, 17.5% of respondents want 20-30% discount and are willing to pay premium above 10%. The rest, around 50%, are willing to shift even for lower values of discount.
E. There is not a significant relationship between discount to shift vs. salary or age (Fig.2).
F. Only 51% of respondents have ranked price as very high priority (5 on a scale of 1-5) for selection of service provider, whereas 70% of respondents have rated less outages as very high and 63% have rated quality of supply- voltage etc. as very high priority.

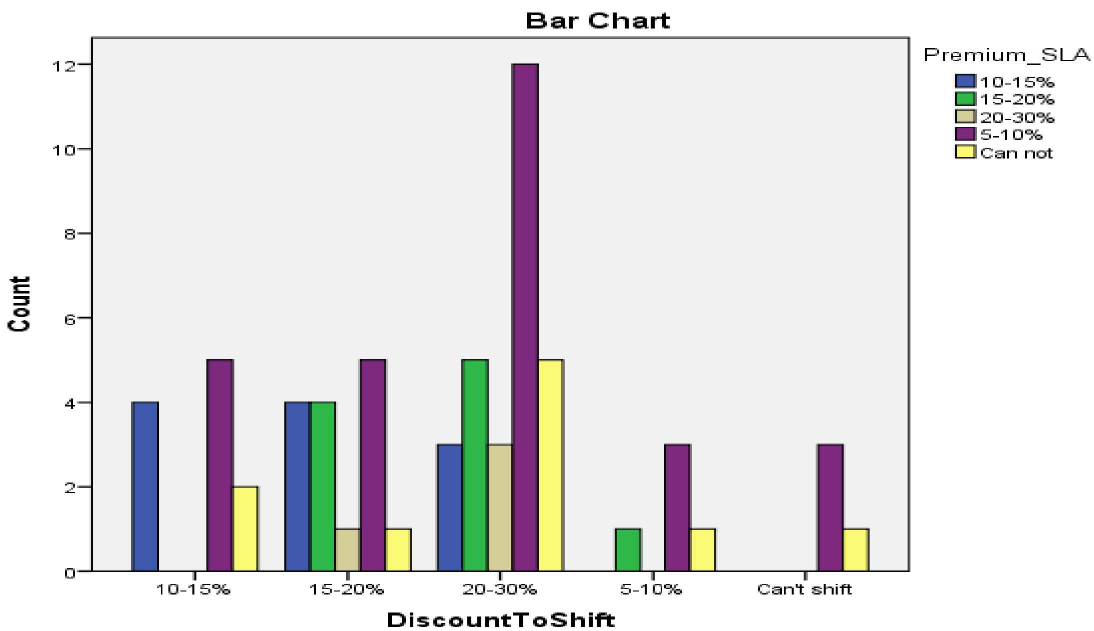

Figure 4 Number of consumers willing to shift their loads with varying discounts

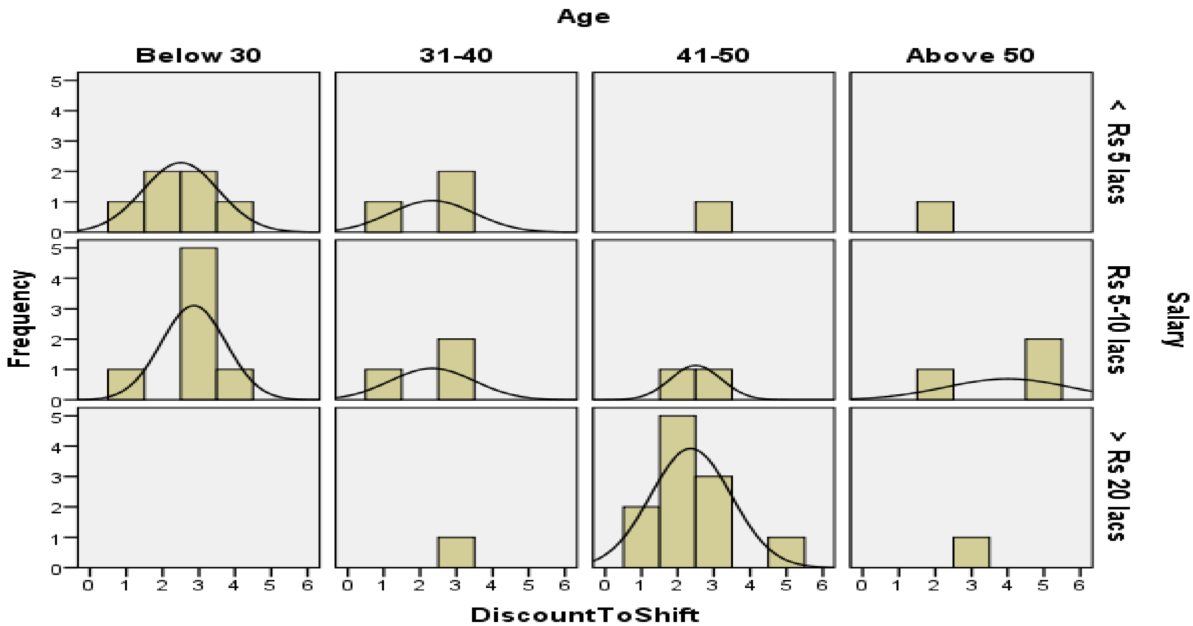

Figure 5 Number of consumers willing to shift load vs. Age vs. income

The survey results indicate likelihood of interest and active consumer participation in smart grid functionalities of Demand Response, DSM, and distributed generation. However, the above inferences are drawn on the basis of a very limited sample size of only 63 respondents. Administering this survey further in partnership with interested utilities and conducting focus group interviews with residential welfare bodies or main representative consumers would improve the analysis.

Design of Dynamic Tariff

As already explained in preceding paras, the current pricing mechanism for Indian consumers is primarily focusing on recovery of cost of generation and service cost and as it is highly cross subsidized it does not provide appropriate signal to end consumer for judicious use of electricity. If we add some price component to existing tariff that could reflect the real time imbalances, the end consumers may shift their load to get some incentive or to avoid disincentives. This necessitates design of Dynamic tariff that will not always remain same to encourage participation of end consumers in DR/DSM programs.

The components that may be considered for dynamic tariff design include:

i. Cost of generation and transmission
ii. Service cost of discom
iii. Reactive power consumption
iv. Voltage level
v. Sanctioned/contracted load
vi. Subsidy
vii. Unscheduled Interchange charges for deviation from agreed drawal and generation schedule
viii. ToD or pre-announced prices based on a forecast for peak load hours

ix. ToU/CPP that can be linked to frequency or to an average of daily maximum demand
x. Power supply quality- based on voltage fluctuations, reliability and harmonics.

The ideal case scenario would be to offer a predetermined mix of aforementioned components in order to suit the requirements of different consumer segments., The conventional tariff design (to a certain extent) covers elements i. to vi. as mentioned above. UI charges can be partially recovered through incorporating a frequency-based price component in the consumer tariff as in Real time pricing mechanism(RTP). Some Consumers would prefer some prior notice of price variations in a day which might help them plan consumption for the day as incorporated in ToD pricing wherein higher charges are applicable for peak load times announced by Utility beforehand based on historical data.. It is t proposed by authors that Dynamic pricing mechanism for DSM can be designed by including both ToD tariff in the form of peak load surcharge and ToU/RTP (i.e. frequency-based price component) in addition to the tariff determined as per ARR. As per the grid code for transmission sector issued by CERC, SLDC/STU , discoms shall initiate restriction of the amount withdrawn from its control area from the grid whenever the system frequency falls to 49.7 Hz. This frequency can be the trigger for upward revision of the ARR tariff by some amount .Same amount of discount can be offered on ARR tariff for consumption at frequency above 49.95Hz. For frequencies between 49.7Hz and 49.95Hz ARR tariff rates can be set.

ToD can be announced by SERC weekly or fortnightly based on the utility's forecasted/projected peak load time periods. Consumers can be informed through portal, SMS, and email about ToD prices in advance.

For effecting DSM for peak load management in this context, the possible Dynamic tariff components could be:

a. **Frequency-based, ToU pricing**, Availability-based tariff (ABT) and UI charges are already deployed for Transmission sector. Indian version of Availability Tariff comprises of three components: (a) capacity charge, towards reimbursement of the fixed cost of the plant, linked to the plant's declared capacity to supply MWs, (b) energy charge, to reimburse the fuel cost for scheduled generation, and (c) a payment (UI charge) for deviations from schedule, at a rate dependent on frequency. ABT could bring discipline in transmission sector in abiding to agreed-upon schedules worked per the Indian Electricity Grid Code (IEGC) by the constituents of Indian Power grid. The same can be tweaked for Distribution sector and accordingly this ToU tariff is proposed to be +/- 20% of tariff calculated on the basis of ARR to be levied in case frequency falls below 49.7Hz and rises above 49.95Hz.

   ToU will aim for near real-time load-supply balancing. As suggested above, three rates can be administered:

   I. ARR rate for frequency in acceptable band (e.g., Rs 4.5 per kWh)
   II. ARR x 1.2 for frequency below lower limit of acceptable band (i.e., Rs 5.4 per kWh)
   III. ARR x 0.8 for frequency above upper limit of acceptable band (i.e. Rs 3.6 per kWh).

   Smart meters can communicate with simple LED based display units that may be provided in multiple rooms to show the above three rates as RED/YELLOW/GREEN colors to the end consumer, and this can also be published on a utility's portal. Consumers can also be notified about a change in rates through a small beep sound from the meter.

b. Pre-determined ToD pricing for the utility-specific peak load time zones, to be announced weekly by the Regulatory Commission based on forecast peak load time/ past data from Regional load dispatch centres RLDCs. This can be 10% of the tariff calculated as per existing ARR petition.

c. A reliability surcharge-Utility may consider levying a surcharge of 10% over total bill amount in the areas that have rugged distribution infrastructure so as to provide reliable power supply based on service level agreement (SLA) with consumers of that area. In case SLA is violated no surcharge will be admissible for that month. Reliability can be maintained by switching to load curtailment (with commitment to supply lifeline supply for that premises) in place of load shedding in those areas. In order to increase available power, installation of roof top solar panels can be promoted by utilities' floating suitable incentive schemes. Smart consumers can also store solar energy during the day time and use it during evening peak times to avoid purchase of costly power during peak load time.

d. Discount of 2% to 5% on pre–paid bills depending on AT&C losses for that area. The higher the losses, the lower the discount for pre-paid bills that may encourage people of that area to identify theft.

In order to test the monetary impact of ToU price as described at 'a.' above, a simulation study was done to determine monetary impact of actual frequency variation on sample consumption, as given in Table 1 below, for the months of July 2012 and January 2012 (summer and winter seasons)

Table 2 Sample Consumption Profile

a.Electrical Appliance put to use	b.Qty. of appliances (No.)	c.UseStartTimeofDay	d.UseEndTimeOfDay	e.TimePeriod (h) (d-c)	f.PowerRating of each unit appliance (kW)	g.Energy (kWh) b*f*e
Light	3	0600	0800	2	60	360
CFL	3	0600	0900	3	15	135
Stereo	1	0630	0730	1	100	100
Geyser (January 2012)	1	0630	0830	2	1,100	2,200
Air Conditioner (July 2012)	2	2200	0600	5	1,500	15,000
Food Processor	1	0700	0715	0.25	1,100	275
Microwave	1	0730	0745	0.25	1,800	450
Toaster	1	0730	0745	0.25	1,100	275
Iron	1	0730	0745	0.25	1,100	275
Chimney	1	0730	0745	0.25	1,000	250
Exhaust	2	0730	0745	0.25	200	100
Washing machine	1	0830	0930	1	1,500	1,500
Refrigerator	1			24	70	1,680
TV	1	1800	2200	4	200	800

Tubelight	4	1800	2200	4	60	960
CFL	2	1800	2200	4	15	120
Chimney	1	0730	0745	0.25	1,000	250
Microwave	1	2000	2015	0.25	1,800	450
Mobile charging	3	2000	2400	0.5	100	150
Laptop charging	2	1900	2000	2	100	400

For Simulation studies, three rates (i.e., 5.4 for f< 49.7, 4.5(ARR rate); 3.6 for f >49.95; as part of ToU tariff) were applied on 15-minute time blocks based on actual frequency for that time block. The percent distribution of three rates for both the months is as given in Fig 6. It was also estimated how many times a day the proposed ToU rate was changing based on actual frequency and it was found that the same rate is mostly applicable for at least half an hour, which gives the consumer flexibility and some convenience to switch load (Frequency Data from NRLDC).

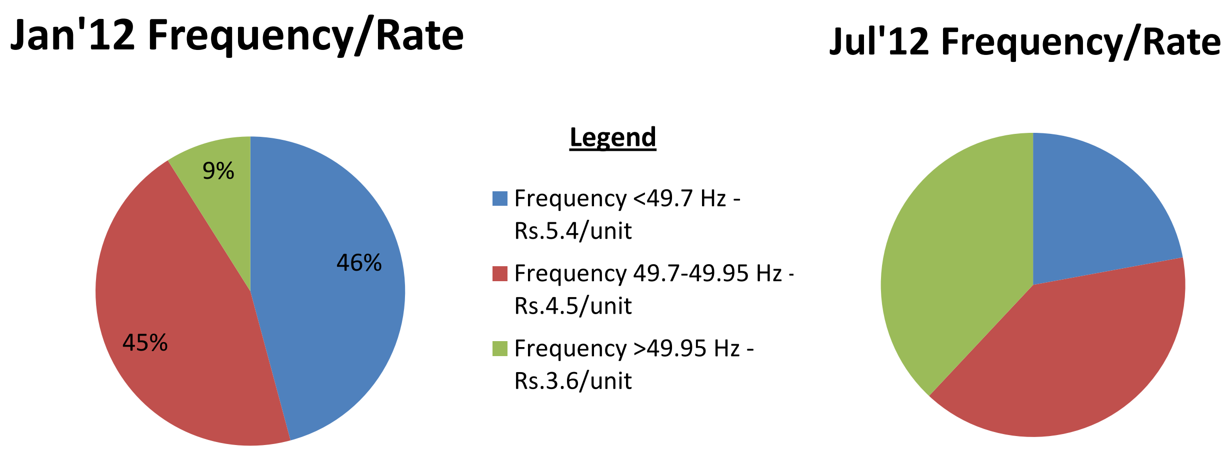

Figure 6 Distribution of frequency in three ranges for the month

In Jan'12 morning Peak hours, frequency is below 49.7 implying higher rates for morning peak hours		
In July'12 night frequency is mostly below 49.7 implying higher rates during night time		
Simulated Bill for Sample consumption profile	**Jan'12**	**Jul'12**
ToU Bill	1555.67025	3250.829

Normal Bill	1581.58125	3177.934

Simulation study for computing the bills based on proposed dynamic tariff vis-à-vis existing tariff indicates that the net impact on consumer bill on account of aforementioned ToU charges will be almost negligible if the consumer does not make any change in consumption pattern.

In various pilot smart grid projects in the United States, participating customers were guaranteed a neutral bill impact from participation, which may be a relevant design consideration for other jurisdictions. As supported by survey data, there is probability that consumers will shift/reduce their loads when ToU tariff is high during the day (and/or if there is a discount at night). Indian consumers like at any other place in world are price conscious and try to maximize the value preposition by switching to lower rates, if possible. This anticipated shift in load presents a beneficial situation for both utility and customer, as the utility will also be saving on account of reduction in purchasing costly power to serve peak loads.

International experience indicates varying impacts of tariff schemes and a degree of sensitivity to the way in which customers interact with the tariff (for example, via in-home devices). Faruqui and Sergici (YEAR) compile the varying impacts experienced by utilities in Canada and the United States, shown in Figure 7.

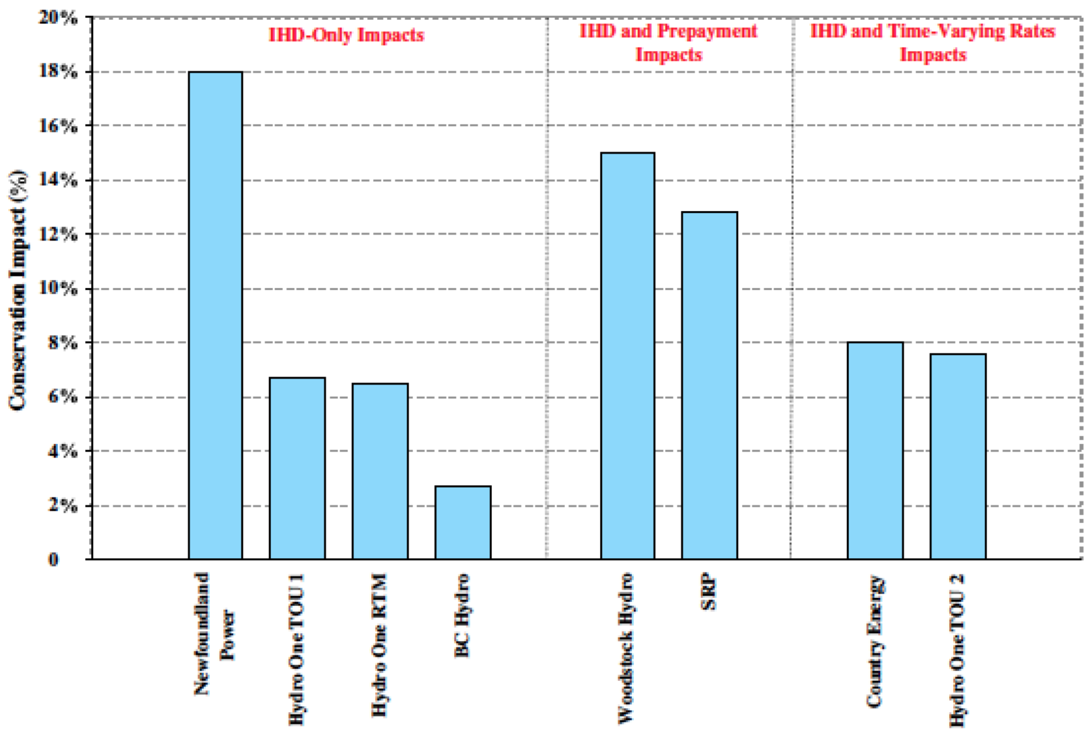

Figure 7 Varying impacts experienced by US and Canada utilities due to different tariff schemes and consumer interaction methods

Conclusion

After further discussions with utilities, the proposed dynamic price structure can be implemented for smart grid pilots in parallel to the existing billing mechanism in order to test actual impact on load profile, tariff, and revenue for the utility from that area. In order to avoid resistance to change, consumers may be given an option to opt out of the new price structure and a commitment that the bill as per new tariff structure shall not exceed the bill as per conventional tariff structure except for reliability surcharge that will be payable only if agreed mutually by a group of consumers served by same Distribution transformer. Further improvement of the price mechanism can be based on the outcome of pilots.

Appendix A: ARR Details

Major Components

a. Power purchase: assessment of power purchase cost (fixed and variable cost) for existing stations and for future capacities is performed.
b. Power purchase: requirements for discoms are worked out after incorporating the allowable distribution losses as specified in regulations, intra-state transmission losses, and the interstate transmission losses in the projected total sales of energy.
c. CTU charges: The inter-state and inter-regional transmission charges to be paid by the state consists of charges to be paid for CTU transmission system usage. The inter-state transmission charges are projected as per the actual bills of the past year. These charges are allocated to respective discoms based on their firm capacities as per the state government notification and the capacities of generating stations available through Tradeco, which are allocated to state Tradeco.
d. Inter-state transmission charges associated with existing capacities and for new and upcoming capacities are projected.
e. State 19ransco charges: Intra-state transmission charges are also projected.
f. SLDC Charges
g. O&M cost: the O&M expenses comprise employee cost, repairs and maintenance (R&M) cost, and administrative and general (A&G) expenses.
h. Depreciation is to be calculated annually based on a 'straight line method' and at the rates specified in relevant regulations for the assets of the distribution system considering the date of declaration of commercial operation.
i. Interest and finance charges on project loans: regulations allow interest charges only for those loans to be a pass through in the ARR for which the associated capital works have been completed and put to use.
j. Return on equity: regulations provide that Return on equity shall be computed on pre-tax basis at 16%. The Return on equity allowed for an FY ARR is determined by applying the specified rate to the total equity identified in accordance with regulations as allocated to GFA.
k. Interest on working capital: regulations provide that the working capital shall consist of expenses that are required for supply activity and wheeling activity based on prescribed parameters. Rate of interest on working capital shall be equal to the state bank base rate as of 1 April of that year plus 4%.
l. Interest on Consumer Security Deposit (CSD):
m. Bad and doubtful debts regulations specify that these debts shall be allowed to the extent that the distribution licensee has actually written off bad debts subject to a maximum limit of 1% of the yearly revenue.
n. SERC fees: fees for filing tariff petition before commission have been paid.
o. Less Other Income – Retail and Wheeling: This amount includes, inter alia, meter rent, recovery from theft of energy, and miscellaneous charges from consumers.
p. The recovery of true costs on account of increase or decrease of tariff for generation or transmission from past years is suitably incorporated for computing ARR for FY.
q. Tradeco charges are applied if applicable.

Annexure B: Survey Results

Table 3 Percentage of Respondents Willing to use ToU

		Frequency	Percent	Valid Percent	Cumulative Percent
Valid	Yes	55	87.3	87.3	87.3
	No	8	12.7	12.7	100.0
	Total	63	100.0	100.0	

Table 4 Percentage of Respondents Willing to use Rooftop Solar

		Frequency	Percent	Valid Percent	Cumulative Percent
Valid	Blank	3	4.8	4.8	4.8
	No	4	6.3	6.3	11.1
	Not applicable	14	22.2	22.2	33.3
	Yes	42	66.7	66.7	100.0
	Total	63	100.0	100.0	

Table 5 Discount To Shift Consumption vs. Premium for Reliable Power Supply

Count							
		Premium SLA					Total
		10%–15%	15%–20%	20%–30%	5%–10%	Cannot	
Discount To Shift	10%–15%	4	0	0	5	2	11
	15%–20%	4	4	1	5	1	15
	20%–30%	3	5	3	12	5	28
	5%–10%	0	1	0	3	1	5
	Can't shift	0	0	0	3	1	4
Total		11	10	4	28	10	63

Table 6 Range of average monthly electricity bill

Electricity Bill				
	Frequency	**Percent**	**Valid Percent**	**Cumulative Percent**
Below 500	4	6.3	6.3	6.3
501–1,000	19	30.2	30.2	36.5
1,001–2,000	14	22.2	22.2	58.7
2,001–3,000	9	14.3	14.3	73.0
Above 3,000	17	27.0	27.0	100.0
Total	63	100.0	100.0	

Table 7 Backup source of power

		Frequency	Percent	Valid Percent	Cumulative Percent
Valid	Missing	1			
	Inverter/own DG set	24	38.1	38.1	39.7
	None	17	27.0	27.0	66.7
	Shared DG set with essential load back-up	16	25.4	25.4	92.1
	Shared DG set with full back-up	5	7.9	7.9	100.0
	Total	63	100.0	100.0	

Table 8 Range of amount of bill for Backup Power sources

		Frequency	Percent	Valid Percent	Cumulative Percent
Valid	<500	35	55.6	68.6	68.6
	500–1,000	10	15.9	19.6	88.2
	1,000–2,500	6	9.5	11.8	100.0
	Total	51	81.0	100.0	
Missing	System	12	19.0		
Total		63	100.0		

Table 9 Age Profile of Respondents

		Frequency	Percent	Valid Percent	Cumulative Percent
Valid	Below 30	19	30.2	30.2	30.2
	31–40	16	25.4	25.4	55.6
	41–50	19	30.2	30.2	85.7
	Above 50	9	14.3	14.3	100.0

Table 10 List of places from which responses were received

		Frequency	Percent	Valid Percent	Cumulative Percent
Valid	Bahadurgarh	1	1.6	1.6	1.6
	Bangalore	9	14.3	14.3	15.9
	Bhubaneswar	2	3.2	3.2	19.0
	Bhubneswar	1	1.6	1.6	20.6
	Chennai	1	1.6	1.6	22.2
	Cuttack	1	1.6	1.6	23.8
	Delhi	14	22.2	22.2	46.0
	Faridabad	1	1.6	1.6	47.6
	Gandhinagar	1	1.6	1.6	49.2
	Ghaziabad	1	1.6	1.6	50.8
	Gurgaon	16	25.4	25.4	76.2
	Jabalpur	1	1.6	1.6	77.8
	Jaipur	1	1.6	1.6	79.4
	Kolkata	2	3.2	3.2	82.5
	Kota	1	1.6	1.6	84.1
	Lucknow	1	1.6	1.6	85.7
	Mumbai	2	3.2	3.2	88.9
	Mysore	4	6.3	6.3	95.2
	Noida	1	1.6	1.6	96.8
	Sangli	1	1.6	1.6	98.4
	Vadodara	1	1.6	1.6	100.0

Table 11 Consumption of Electricity in Gigawatt hour (from utilities) by Sectors in India

Year	Industry	Agriculture	Domestic	Commercial	Traction and Railways	Others	Total
1970–1971	29,579	4,470	3,840	2,573	1,364	1,898	43,724
1975–1976	37,568	8,721	5,821	3,507	1,855	2,774	60,246
1980–1981	48,069	14,489	9,246	4,682	2,266	3,615	82,367
1985–1986	66,980	23,422	17,258	7,290	3,182	4,967	123,099
1990–1991	84,209	50,321	31,982	11,181	4,112	8,552	190,357
1995–1996	104,693	85,732	51,733	16,996	6,223	11,652	277,029
2000–2001	107,622	84,729	75,629	22,545	8,213	17,862	316,600
2005–2006	151,557	90,292	100,090	35,965	9,944	24,039	411,887
2006–2007	171,293	99,023	111,002	40,220	10,800	23,411	455,749
2007–2008	189,424	104,182	120,918	46,685	11,108	29,660	501,977
2008–2009	209,474	109,610	131,720	54,189	11,425	37,577	553,995
2009–2010(p)	236,752	120,209	146,080	60,600	12,408	36,595	612,645
2010–2011(provisional)	272,589	131,967	169,326	67,289	14,003	39,218	694,392
Growth rate of 2010–2011 over 2009–2010 (%)	15.14	9.78	15.91	11.04	12.85	7.17	13.34
CAGR 1970–1971 to 2010–2011 (%)	5.57	8.61	9.67	8.29	5.84	7.67	6.98

(Gigawatt hour) = (10^6 x Kilowatt hour)

Table 12 Actual Power Supply Position in Terms of Energy Requirement Vis-à-vis

Region / State / System	Requirement	Availability	Surplus / Deficit(-)	
	(MU)	(MU)	(MU)	(%)
All India	937,199	857,886	-79,313	-8.5
Northern Region	276,121	258,382	-17,739	-6.4
Chandigarh	1,568	1,564	-4	-0.3
Delhi	26,751	26,674	-77	-0.3
Haryana	36,874	35,541	-1,333	-3.6
Himachal Pradesh	8,161	8,107	-54	-0.7
Jammu & Kashmir	14,250	10,889	-3,361	-23.6
Punjab	45,191	43,792	-1,399	-3.1
Rajasthan	51,474	49,491	-1,983	-3.9
Uttar Pradesh	81,339	72,116	-9,223	-11.3
Uttarakhand	10,513	10,208	-305	-2.9
Western Region	290,421	257,403	-33,018	-11.4
Chhattisgarh	15,013	14,615	-398	-2.7
Gujarat	74,696	74,429	-267	-0.4
Madhya Pradesh	49,785	41,392	-8,393	-16.9
Maharashtra	141,382	117,722	-23,660	-16.7
Daman & Diu	2,141	1,915	-226	-10.6
Dadra & Nagar Haveli	4,380	4,349	-31	-0.7
Goa	3,024	2,981	-43	-1.4
Southern Region	260,302	237,480	-22,822	-8.8
Andhra Pradesh	91,730	85,149	-6,581	-7.2
Karnataka	60,830	54,023	-6,807	-11.2
Kerala	19,890	19,467	-423	-2.1
Tamil Nadu	85,685	76,705	-8,980	-10.5
Puducherry	2,167	2,136	-31	-1.4
Eastern Region	99,344	94,657	-4,687	-4.7
Bihar	14,311	11,260	-3,051	-21.3
Damodar Valley Corporation	16,648	16,009	-639	-3.8
Jharkhand	6,280	6,030	-250	-4.0
Orissa	23,036	22,693	-343	-1.5
West Bengal	38,679	38,281	-398	-1.0
Sikkim	390	384	-6	-1.5
North-Eastern Region	11,011	9,964	-1,047	-9.5
Arunachal Pradesh	600	553	-47	-7.8
Assam	6,034	5,696	-338	-5.6
Manipur	544	499	-45	-8.3
Meghalaya	1,927	1,450	-477	-24.8
Mizoram	397	355	-42	-10.6
Nagaland	560	511	-49	-8.8
Tripura	949	900	-49	-5.2

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Glossary

Abbreviation	Expansion
A&G	Administrative and General
ABT	Availability Based Tariff
ARR	Aggregate Revenue Requirement
AT&C	Aggregate Technical And Commercial Losses
CAGR	Compound Annual Growth Rate
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CPP	Critical Peak Pricing
CSD	Consumer Security Deposit
DG	Diesel Generator
Discom	Distribution Company
DR	Demand Response
DSM	Demand Side Management
EHT	Extra High Tension
FCA	Fuel Cost Adjustment
FOR	Forum of Regulators
GoI	Government of India
ICT	Information And Communication Technology
IEA	International Energy Agency
IHD	In Home Display
ISGAN	International Smart Grid Action Network
LDC	Load Despatch Centre
MPERC	Madhya Pradesh Electricity Regulatory Commission
NREL	National Renewable Energy Laboratory
NRLDC	Northern Region Load Despatch Centre
O&M	Operation and Maintenance
OECD	Organization for Economic Co-operation and Development
POWERGRID	Power Grid Corporation of India Limited
R&M	Repairs and Maintenance
RES	Renewable Energy Sources
RLDC	Regional Load Despatch Centre
SERC	State Electricity Regulatory Commission
SLA	Service Level Agreement
SMS	Short Message Service
T&D	Transmission and Distribution
ToD	Time of Day
ToU	Time of Use
UI	Unscheduled Interchange