BEFORE THE RAJASTHAN ELECTRICITY REGULATORY COMMISSION

IN THE MATTER OF:

Comments/suggestions on "Draft Rajasthan Electricity Regulatory Commission (Terms and Conditions for Determination of Tariff) Regulations, 2019".

SUBMISSIONS OF PRAYAS (ENERGY GROUP), Pune

The RERC has invited comments and suggestions from all stakeholders on the "Draft Rajasthan Electricity Regulatory Commission (Terms and Conditions for Determination of Tariff) Regulations, 2019" in February 2019.

The present submission is in response to the said notice and the draft regulations published thereunder. We request the Commission to condone the delay in submitting this and to accept this submission on record.

The issues faced by the Rajasthan power sector are unique but at the same time there are many lessons that the utilities can learn from the experience of other states. Our submissions have been informed by our engagement in the past two decades in regulatory processes over multiple states and it is hoped that some of the suggestions can be adopted in the Rajasthan context. Our suggestions are also to ensure the regulations are clear and unambiguous to avoid regulatory uncertainty, unnecessary litigation and costs due to the same.

1 Aims and objectives of MYT process

The multi-year tariff (MYT) regulations are an important aspect of sector regulation and the tariff policy also encourages commissions to adopt this approach. The objectives behind the introduction of a multi-year tariff process can be detailed as follows:

a) Providing regulatory certainty to consumers, utilities and investors.

b) Minimise perception of regulatory risk.

c) Facilitating sound planning practices and processes.

d) Addressing risk sharing mechanism between utility and consumers based on controllable and uncontrollable factors.

e) Improving operational efficiency and reduce tariff in the long run.

Further, the MYT exercise becomes even more crucial in the current sector context with increasing sales migration and resultant loss in cross-subsidy revenue, increasing cost of supply, and the expected increase in demand on account of large scale household electrification. With fast paced changes taking place in renewables and storage, it is crucial for the regulatory commission to provide regulatory certainty for small consumers and investors alike and this underscores the need for a well-designed MYT framework that can help the sector to adapt to this changing environment.

However, as per draft regulation 5 (4) the generating company or the licensee can opt for an annual or a multi-year process for tariff determination. Further, even if the generating company or licensee chooses to go for a MYT process, the draft regulations require it to submit petitions on annual basis for true-up and/or tariff revision during each year of the control period.

Such a requirement defeats the basic purpose of multi-year tariff determination and hence should not be allowed.

a) The Commission would recognise the need for certainty and long-term resource planning, which cannot emerge when different utilities choose different process for tariff determination.
b) Since under the proposed regulations the process of cost determination essentially remains annual, then calculating expenses like O&M annually, will lead to no accountability for the generating company or licensee since there will be scope for deviations every year.

With a mixed approach, the risks and potential cost impact to be borne by consumers will be high while the accountability of the generators and licensees will be much lesser. This consideration should outweigh concerns of the utilities to adopt the MYT framework, more than a decade after it was first introduced in the sector.

Given the above drawbacks, we submit that instead of such mixed approach, the commission should propose a more sound and robust multi-year tariff process which has cost and tariff projections for the entire control period. There should be a provision for mid-term review, which will allow the necessary space and opportunity for any mid-course corrections and a true-up at the end of the control period. Such an approach has been adopted in Maharashtra for the control period between FY17 to FY20.

2 Controllable and uncontrollable parameters:

2.1 Specification of controllable and uncontrollable costs

Draft regulation 9 specifies the uncontrollable factors beyond the control of the licensee or generator. However only illustrative variations in controllable factors are specified. To avoid ambiguity, unnecessary litigation and ensure cost certainty for consumers, the regulations should clearly and explicitly state that all performance parameters, except for those that are defined as "uncontrollable", should be treated as controllable.

2.2 Provision to account for delays for generation projects under Section 62

The model PPA for Section 63 projects allows extension of the scheduled date of delivery only up to a maximum period of one year beyond which force majeure provisions kick-in and the procurer is entitled to terminate the contract if delay seems unavoidable. Such stringent provisions are missing in Section 62 projects, which is perhaps the reason why most of the delayed capacity is regulated capacity with cost-plus tariffs. This important lacuna in Section 62 project approval has not been addressed yet.

It is our submission that RERC while approving any new cost-plus project should impose a condition similar to that enshrined in Section 63 PPAs which gives the procurer opportunity to decide whether it wishes to continue the contract, if a project gets delayed for more than a year. All the Section 63 projects could secure funding and many have been commissioned on time, there is no reason to believe that such provision will affect the cost-plus project's ability to raise funds. It is suggested that regulations be amended to incorporate this provision.

2.3 Data and information with respect to cost pass through due to Change in Law

The draft regulations specify Change in Law events as an uncontrollable factor. In the last few years, various Commissions including RERC, have issued numerous orders dealing with issues concerning change in law events. The said orders have resulted in substantial increase in variable cost of the generating stations, which is borne by electricity consumers. However, there is no clarity in the extent of claims made by the generators and costs allowed by the Commissions and/or APTEL. In this regard, it can be very useful to have a separate data reporting formats for annual costs claimed under various change in law events. The generating companies should be required to submit this data at the time of their tariff revision process and also maintain this data on their website in easily downloadable formats. The requirement of such data reporting should not be limited to Section 62 projects alone, but should also be applicable to Section 63 projects. Such provision can bring about significant clarity in the costs claimed by the generators and actual payments made by the beneficiaries.

2.4 Mechanism for Gain and loss sharing

The mechanism for gain and loss sharing specified in draft regulation 26 and 75 suggests that the gains and losses be shared on a 50:50 basis. However, the benefits or gains shared with consumers (be it final consumers or DISCOM) is subject to income tax. The benefit passed on should translate as a reduction in cost rather than an increase in income for the consumer. If the benefits were being retained by the utility or was linked to the return on equity of the utility such a treatment would be necessary. However, in both cases where the gain and loss sharing formula is specified, this does not seem to be the case. Further the generator or the DISCOM passing on the benefit is not incurring any tax for the benefit passed on and thus such a treatment is unfair to consumers. It is requested that income tax is not applicable on the benefits passed onto consumers but can be applicable for benefits retained.

3 Compliance with environmental norms and regulations:

MOEFCC vide Notification dated 7.12.2015 has notified the Environment (Protection) Amendment Rules, 2015 amending the Environment (Protection) Act, 1986. Through the amendment, the existing/applicable environmental norms for all existing as well as future Thermal Power Plants (TPPs) stand amended.

Even a year after the timeline that was specified for compliance, most plants have not taken steps necessary for ensuring compliance. Ensuring compliance would entail incurring of some capital expenditure by the power plants. Learning from the past experience of non-compliance and monitoring failure, it seems necessary to have intermediate milestones to ensure timely execution of proposed capital expenditure projects. Also, commissioning of some of the PCE may require the plant to be shut down which further underscores the need for tracking of progress and ensuring that such outages are well planned and coordinated across regions.

3.1 Monitoring Compliance by ERCs

Draft regulation 17 (7) deals with additional capitalization on account of revised emission standards. RERC should mandate the power plants to submit detailed information that would enable it undertake due scrutiny of the proposed expenditure. In order to enable smooth and meaningful implementation of the revised norms, the commission should also notify data formats for the purpose of capital expenditure and implementation status reporting. Additionally, the Commission should establish a web-based transparent mechanism for tracking of progress and achievement of the milestones. Non-compliance should be assumed unless the power plant in question reports compliance status to the Commission and submits all the necessary documents.

3.2 Role of regulatory cost approval and treatment of IDC

Draft regulation 17 (7) also defines the procedure for claiming recovery of the capital expenditure necessary for ensuring compliance with the revised norms. Compliance with the said environmental norms being a statutory requirement, it cannot be subject to any regulatory cost approval. In this regard it is essential for the regulations to expressly state that any cost disallowance and/or delay in terms of securing cost approval cannot be the ground for non-compliance with the revised emission standards within the stipulated timelines. If the project delays construction or commissioning of any PCE beyond the final milestone, no interest during construction (i.e. IDC) should be allowed on account of such delay, i.e. in such case no increase in IDC beyond the normative value approved by the

Commission in the original DPR should be allowed to be passed on to the electricity consumers.

3.3 Compliance with water usage norms

The definition of operation and maintenance expenses for thermal power stations includes water charges. It is important to note that the revised environmental standards also prescribe water usage norms for thermal power plants. Therefore, the regulations should include a proviso that explicitly disallows any expenditure on water charges that is over and above the norm prescribed under the revised environmental regulations.

3.4 Need for practice directions

Since all existing and new thermal plants need to comply with the revised environmental regulations, the RERC can consider notifying separate guidelines or practice directions for this purpose.

4 Coal plants using coal from captive mines:

4.1 Treatment of public and private sector coal mine owning generators

As per the Coal Mines (Special Provisions) Act 2015 and associated amendments to the Mines and Minerals (Development and Regulations) Act 1957, coal mines shall be allocated to private sector companies only through auction. As per paragraph 3.2(a) of the directive no 23/9/2015-R&R issued by the Ministry of Power to the Central Electricity Regulatory Commission dated 16th April 2015, the energy or variable charges for coal mines awarded through the auction route, i.e. to private sector companies for the end use of power generation, should be calculated based on the per-ton amount quoted as part of the bid plus Rs. 100 per ton. In light of the above, draft Regulation 11 (8) for determination of transfer price or landed price of fuel should be revised to make this difference between treatment of public and private sector coal mine owning generators explicit.

4.2 Compliance with CMDPA timelines

According to the Coal Mine Development and Production Agreement (CMDPA) signed by the generator upon being allocated the coal mine, there are specific timelines as defined by "Efficiency Parameters" by when the coal mine has to be developed and operational. Therefore, the regulations must ensure that the date of commercial operation of the mine is consistent with the CMDPA and not delayed beyond such timelines. Costs associated with using alternative sources of fuel and any increased interest burden should not be allowed, if these timelines are breached.

4.3 Determination of transfer price

It is not clear how the transfer price at mine mouth mentioned in the proposed regulations would be determined. For example, would it be based on CIL notified prices for a similar grade? This should be made explicit in the regulations to avoid confusion and litigation in future. Further, for filing a petition for determination of transfer price at mine mouth, in addition to the information mentioned in clause 8 of section 11, any additional capital expenditure on the coal mine either before the date of target capacity or after such date should be accompanied by a cost-benefit analysis to justify the additional capital expenditure and such expenditure should be subject to approval from beneficiaries.

To summarise, it is suggested that:

a) The regulations should clearly describe the method and the principles that would be considered for calculation of transfer price at mine mouth.

b) The Commission should notify separate data formats for the same and the price determination process should be a public process.

c) The Detailed Project Report and/or the Mine Plan should include information about expected coal quality in each seam (GCV, ash and moisture content etc.) to enable effective cost estimation.

d) It should be noted that coal from a captive mine may be used in multiple units of multiple stations of the generator. Therefore, the regulations should be applied for determining tariff of all such stations where coal from the captive mine is used.

4.4 Price caps and input price computation

Since one of the purposes of providing captive mines to end users was to lower the price of electricity, the input price determined (inclusive of the Rs 100 / ton allowed) should be capped by the CIL notified price for the power sector for an equivalent grade of coal. Moreover, in case the generator produces more coal from the mine than required for its unit(s), it is expected to transfer the excess coal to CIL. Revenues from such transfer, if any, should be factored in while computing the input price.

5 Demand estimation and Power Procurement Planning

5.1 Demand forecast

Draft regulation 76 specifies the process for estimation of sales by utilities should take place on an annual basis. Given sales migration due to open access and captive options, reduction in demand due to high tariffs in some categories, there is significant uncertainty in demand. As part of the MYT exercise, the estimation of sales and demand should be done for at least a five year period and can be revised every 2 years. This is consistent with the practice prescribed in RERC (Power Purchase & Procurement Process of Distribution Licensees) Regulations, 2004. The DISCOM submission during the tariff determination process should include such a demand forecast finalised in consultation with the 'Energy Assessment Committee' defined in Regulation 3(3) of the RERC (Power Purchase & Procurement Process of Distribution Licensees) Regulations,2004.

A comprehensive review of demand and supply by the DISCOM and regulators for a five to ten year period, should consider the impact of many past and potential changes, account for impact of various future scenarios and should be based on disaggregated historical trends. Therefore, the forecasts should :

a) Have separate medium (5 year), and long-term (10 year) demand forecasts for base, intermediate and peak load;
b) Consider impact of macroeconomic trends, progress of government development programs, historic trends of sales, elasticity of sales to tariffs, and change in appliance usage;
c) Account for impact on demand due to open access and captive generation and use, energy efficiency measures.

5.2 Data formats for sales estimation

Given the uncertainty in demand, draft regulation 76 should also specify data formats which the DISCOMs should fill and submit for the tariff determination process. A suggested format is specified in Table 1 in the Annexure, which includes category-wise, slab-wise details on actual sales for past years, 5 year to year on year CAGRs (compounded annual growth rate), growth rate considered by DISCOM and ERC and reasons for deviation from actuals. Similar information should be provided in orders and petitions on connected load and number of consumers in a consistent fashion. This information has previously been reported in Bihar, Delhi, Uttrakhand and Gujarat orders.

5.3 Data formats for sales migration

In the recent past open access has been significant in state. However, despite significant DISCOM and consumer impacts due to backing down, issues with scheduling and revenue loss, the extent of open access is not captured in the tariff determination process. It is suggested that RERC amend the regulations to specify that DISCOMs report the extent of open access and captive consumption in its network area and also report the revenue earned from such open access and captive consumers in the tariff determination process. Suggested format to record this information is submitted in Table 2, 3, 4 and 5 of the Annexure.

6 Power Procurement and Capacity Addition Planning

Draft regulation 77 proposes that the DISCOMs submit an annual power procurement plan along with its tariff petition in accordance with the RERC (Power Purchase & Procurement Process of Distribution Licensees) Regulations,2004.

Given significant surplus capacity, procurement of renewable energy and demand uncertainty, the procurement plant should be for a period of at least 5 years and should be reviewed at least once in two years as part of the tariff determination process. In addition to the specifications in draft regulation 77, such a process, should also take into account:

a) comprehensive demand assessment as detailed in Section 5 of this submission,
b) renewable energy to meet RPO requirement,
c) retirement of plants,
d) repair and maintenance works of plants
e) possibility of surrender of contracted capacity
f) status of plants in the pipeline to assess impact of costs due to delay in commissioning and deferment due to not getting statutory clearances.
g) Procurement plan considering a mix of strategies (short-term, medium, and long-term contracts as well as banking arrangements, peak contracts) based on a scientific and rigorous assessment of demand and supply.

This would provide a reasonable and realistic assessment of nature, type and quantum of capacity addition required. Such a process could be used to evaluate the need for timely and firm exit from projects which are incessantly delayed and unlikely to come up in the near future. The review capacity in the pipeline could be used to assess impact of costs due to delay in commissioning and deferment due to not getting statutory clearances. A format for reporting capacity in the pipeline is suggested in Table 6 in the Annexure.

7 Power Generation and Purchase

7.1 Capacity charges for low-demand and high-demand seasons

DISCOMs across the country are faced with significant off-peak surplus which consumers are paying significant fixed costs for. Further, generators often do not take sufficient efforts to be fully available during the peak demand periods/season(s).As normative availability is computed on annual basis, they are able to recover their fixed costs, but the distribution companies are forced to buy power from short-term markets at high prices during peak demand periods. To address this, Regulation 42 of the CERC tariff regulations, 2019 specifies separate availability targets for high demand and low demand seasons. RERC, with its significant 'surplus' or backed down capacity can adopt a similar approach for capacity charge payment to generators. Therefore, similar regulations as in the CERC tariff regulations can be introduced by RERC.

7.2 PLF incentive

Regulation 52 specifies a 30 paise/kWh incentive for ex-bus energy in excess of target PLF for thermal power plants. CERC in its 2019 tariff regulations, notified on 7th March 2019, has specified a 65 paise/kWh incentive for ex-bus energy in excess of target PLF during peak periods and a 50 paise/kWh incentive for off-peak hours (Regulation 42 (6)).A similar provision can be adopted by RERC to incentivise generation during peak periods.

7.3 Sale of surplus

Though sale of surplus contracted capacity by generators is desirable, it is difficult to operationalise with the absence of gate closure. Thus, DISCOMs can revise their schedules and retain the right to recall till the time of actual delivery of the power. To provide certainty to generators who want to sell surplus power in the market, RERC can amend the grid code to introduce gate closure 1.5 to 3 hours before actual delivery. This would at least allow plants within the state which have contracted capacity with the DISCOMs to sell power. Though this suggestion is beyond the scope of the tariff regulations, sale of surplus power will be impacted with the introduction of gate closure. To that end, it is suggested that RERC initiate a public process to evaluate the benefits and the feasibility of the same.

7.4 Vetting of fuel surcharge in tariff determination processes

Fuel surcharges can be significant in the state and with the revision of the cap, a typically small consumer can pay 20% more in energy charges without much regulatory scrutiny on a quarterly basis. As this amount is significant, the recovery from levy of fuel surcharges should be reported separately and approved by the regulatory along with any under-recovery or over-recovery from consumers with carrying cost if applicable. A format for reporting fuel surcharge related information in the tariff determination process is suggested in Table 7 of the Annexure. The vetting by the ERCs should be based on invoices and billing information submitted by the DISCOMs.

8 Energy balance

Transmission and Distribution losses have significant impacts on the DISCOMs costs. Thus loss reduction trajectories and regular estimation of losses is specified in Draft Regulation 75. Loss assessment by ERCs and the DISCOMs is reported in the energy balance format. The methodology adopted by the DISCOM and the ERCs for the energy balance should be modified to take into account changing circumstances. Else, there could be up to 4 p.p deviation in losses as compared to energy handled in the system[1]. Some of the changes that need to be incorporated include:

[1] Based on assessment in Prayas (Energy Group)'s upcoming report, The Percentage Problem: A commentary on the methodologies for estimating Transmission and Distribution losses in Indian regulatory practice. An article based on analysis from the report is available here: https://www.thehindubusinessline.com/opinion/whose-td-loss-is-it-anyway/article26390061.ece

8.1 Accounting for open access and off-site captive consumption

Currently, the losses are estimated based on energy input and sales of the DISCOM alone. However, power for open access and off-site captive consumers are also input and wheeled on the network. Not accounting for this energy input and consumption at appropriate voltage levels will lead to an over-estimation of the percentage of losses on the line.

8.2 Energy Requirement for Distribution Franchisees

Distribution franchisees are appointed to manage operations in the DISCOM's high loss pockets. While estimating losses, franchisees are often treated as single consumers drawing power from higher voltage levels. This is not reflective of how energy is handled as DISCOM consumers in the franchised area are connected at lower voltage levels with high percentage losses. This treatment could under-estimate T&D and AT&C loss.

8.3 Treatment of short-term and renewable energy procurement

All short-term and renewable energy (RE) is typically assumed to be procured within the state transmission network. However, DISCOM purchase outside the state has been on the rise. Further, RE generation in the DISCOM network has been growing. Not considering this could potentially overestimate T&D loss and AT&C losses.

It is suggested that the Commission consider these factors while estimating losses to correctly reflect energy has handled in the system.

9 Subsidy payment

Draft Regulation 13 specifies that subsidy payment should be made in advance and should be paid based on a monthly schedule is the amount is greater than Rs. 5 crore. Accountability for timely subsidy payment is crucial to reduce the strain on DISCOMs working capital requirements. In this context, the regulations can also specify that:

a) Interest cost borne by the DISCOM due to delay in subsidy payment should be identified and reported separately.
b) These costs should not be passed on to consumers but accounted for in pending subsidy payments by the state government and added to subsidy commitment.

c) The regulations should also state that in the tariff determination process, DISCOMs should furnish the following details to enable vetting and truing up of subsidy payments.

   i. Subsidy promised , paid and changes in commitment due to sales revision
   ii. Schedule of payment of subsidies and deviation (monthly)
   iii. Delays in days, impact on short-term loans, interest payments
   iv. Break-up of payments including budget payments, adjustments with electricity duties and loans repayments.
   v. Category-wise revenue subsidy including subsidies for tariff, fuel surcharge, rebate and arrears.
   vi. Category wise ssubsidised and unsubsidised per unit tariff

   This is critical and subsidy payments form a significant part of the DISCOMs ARR.

10 Operation & Maintenance Expenses

10.1 Specification of norms

The norms for O&M expenses have been proposed to be fixed for the first year of the control period. The basis for these norms, which are suggested in the Draft Regulation 47 and 82 is not clear. This should be clarified by the Commission, especially if it is not inconsonance with historical performance of the DISCOMs.

10.2 Linking O&M expenses with supply and service quality

The Rajasthan DISCOMs have has very low growth in O&M expenses in the recent past. This can be seen as an indication of operational efficiency only if it is evaluated on the basis of supply and service quality provided in the DISCOM area as well. At present, there seems to be no accountability for supply and service quality provided by the DISCOMs. The commission should report and track supply quality data and in this context. Further, the norms determined for operation and maintenance in draft Regulation 82, can be linked to certain supply and service quality parameters to ensure accountability for performance.

10.3 Detailed calculations for escalation rates

In draft regulation 47 and 82, the escalation rate to be used to determine future O&M costs is suggested as a five year weighted average of increase in CPI and WPI. From the working in the regulations, it is not clear:

a) Which five years are to be considered for the determination? Would it be the past five years before the first year of the control period or the past five years on a rolling basis for determination of the annual escalation rate?

b) Would the annual increase be captured month on month (as the statistics are reported on a monthly basis as well)? If so, which month would be considered? If annual, would it be a weighted average or a simple average?

There have been instances in other states, where different licensees have computed different escalation rates using different assumptions for the methodology prescribed for calculating escalation rates. It is suggested that the Commission specify the format and formula to be used to estimate the escalation rates to avoid ambiguity.

We once again request the Commission to accept this submission on record and to allow us to make further submissions in this matter, if any.

PLACE: Pune

DATE: 19th March 2019

11 Annexure

Table 1: Sales estimation and historical trends

Consumer category	Sales (MU)						CAGR in %					Assumed growth rate for future years		Reasons for deviation from actuals
												DISCOM	RERC	
	FY 16	FY 17	FY 18	FY 19	FY 20	FY 21	5Yr	4Yr	3Yr	2Yr	YoY	(%)	(%)	
	Actuals					Estimates								

Table 2: Extent of open access sales

Consumer category	Open Access (MU)						
	Short-term		Long-term		Medium-term		Total
	RE	Non-RE	RE	Non-RE	RE	Non-RE	
Total							

RE stands for Renewable Energy based open access and Non-RE for non-renewable energy based open access

Table 3: Extent of captive consumption

Type of Industry or Commercial activity*	Captive Power wheeled (MU)			
	Group Captive Power Plants		Conventional Captive Power Plants	
	RE	Non-RE	RE	Non-RE
Total				

**As per three digit level groups specified in the National Industrial Classification - 2008*

RE stands for Renewable Energy based captive consumption and Non-RE for non-renewable energy based captive consumption

Table 4: Sales migration due to roof-top solar systems

Consumer category	Number of consumers with RTPV systems	Total connected load of such consumers	DISCOM sales to consumers with RTPV	Surplus energy generated injected into the grid	Payments/ Adjustments due to injection of power
		(kW)	(MU)	(MU)	(Rs. Cr)

Table 5: Revenue for DISCOMs from open access and captive consumers

Consumer Category	Unit	Consumer category 1	Consumer category 2	Total
Sales via open access	MU			
Standby power to open access consumers	MU			
Revenue from open access charges:				
Wheeling	Rs. Cr			
Cross Subsidy Surcharge	Rs. Cr			
Additional Surcharge	Rs. Cr			
Penalties for exceeding contracted demand	Rs. Cr			
Standby charges	Rs. Cr			
Total	Rs. Cr			
Concessions provided for RE open access:				
Wheeling	Rs. Cr			
Cross Subsidy Surcharge	Rs. Cr			
Additional Surcharge	Rs. Cr			
Any other	Rs. Cr			
Total	Rs. Cr			
Consumption of captive consumers	MU			
Standby power to captive consumers	MU			
Revenue due to captive sales charges				
Wheeling	Rs. Cr			
Parallel Operation charges	Rs. Cr			
Penalties for exceeding contracted demand	Rs. Cr			
Standby charges	Rs. Cr			
Total	Rs. Cr			

Table 6: Status of capacity in the pipeline

Particulars	**Plant 1**	**Plant 2**
Name of Plant		
Location		
Fuel Source		
Ownership		
Original Expected date of commissioning (DD/MM/YY)		
Current expected date of commissioning (DD/MM/YY)		
Reasons for slippage		
Status for Project Milestones		
Board Approval		
Land Acquisition		
Forest Clearance		
Environment Clearance		
Fuel Arrangements		
Water Arrangements		
Financial tie-up		
Financial closure		
Status of Construction (BTG)		

Table 7: Category-wise, month-wise fuel surcharge details

Consumer category	Fuel surcharge												
	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	**Total**
Category 1													
Sales (MU)													
Per unit rate (Rs./kWh)													
Fuel surcharge requirement (Rs. Cr)													
Fuel surcharge recovered (Rs. Cr)													
Category 2													
Sales (MU)													
Per unit rate (Rs./kWh)													
Fuel surcharge requirement (Rs. Cr)													
Fuel surcharge recovered (Rs. Cr)													
Total													