Discussion Paper

on

Multi Year Tariff Regulations for Second Control Period

Gujarat Electricity Regulatory Commission

December 2010

LIST OF ABBREVIATIONS

AAD	Advance against Depreciation
ABT	Availability Based Tariff
EA 2003	Electricity Act 2003
APR	Annual Performance Review
ARR	Aggregate Revenue Requirement
CBG	Competitive Bidding Guidelines
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
Ckt-Km	Circuit Kilometres
COD	Commercial Operation Date
CPI	Consumer Price Index
CTU	Central Transmission Utility
CUF	Capacity Utilisation Factor
DISCOM	Distribution Companies
DGVCL	Dakshin Gujarat Vij Company Limited
FERV	Foreign Exchange Rate Variation
GFA	Gross Fixed Asset
GoG	Government of Gujarat
GSECL	Gujarat State Electricity Corporation Limited
GETCO	Gujarat Energy Transmission Corporation Limited
GUVNL	Gujarat Urja Vikas Nigam Limited
IWC	Interest on Working Capital
kWh	kilo Watt hour
MNRE	Ministry of New and Renewable Energy
MGVCL	Madhya Gujarat Vij Company Limited
NEP	National Electricity Policy
TP	Tariff Policy
OA	Open Access
O&M	Operation and Maintenance
PLF	Plant Load Factor
PGVCL	Paschim Gujarat Vij Company Limited
RE	Renewable Energy
RLDC	Regional Load Despatch Centre
ROCE	Return on Capital Employed

ROE	Return on Equity
RPS	Renewable Purchase Specification
R&M	Repair and Maintenance
SEB	State Electricity Board
SERC	State Electricity Regulatory Commission
SLDC	State Load Despatch Centre
STU	State Transmission Utility
ToD	Time of Day
TSU	Transmission System User
TPL	Torrent Power Limited
UI	Unscheduled Interchange
UGVCL	Uttar Gujarat Vij Company Limited
WPI	Wholesale Price Index

1 Introduction

The Electricity Act, 2003 (EA 2003), as amended in the year 2007, requires the appropriate Commission to be guided by Multi-Year Tariff (MYT) principles while specifying the Terms and Conditions for determination of tariff. Section 61 of the EA 2003 stipulates:

> *"The Appropriate Commission shall, subject to the provisions of this Act, specify the terms and conditions for the determination of tariff, and in doing so, shall be guided by the following, namely:-*
>
> *(a) The principles and methodologies specified by the Central Commission for determination of the tariff applicable to generating companies and transmission licensees;*
>
> *(b) The generation, transmission, distribution and supply of electricity are conducted on commercial principles;*
>
> *(c) The factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments;*
>
> *(d) Safeguarding of consumers' interest and at the same time, recovery of the cost of electricity in a reasonable manner;*
>
> *(e) The principles rewarding efficiency in performance;*
>
> *(f)* ***Multi year tariff principles****;*
>
> *(g) That the tariff progressively reflects the cost of supply of electricity and also reduces cross-subsidies in the manner specified by the Appropriate Commission;*
>
> *(h) The promotion of co-generation and generation of electricity from renewable sources of energy;*
>
> *(i) The National Electricity Policy and tariff policy" (**emphasis added**)*

The Gujarat Electricity Regulatory Commission (GERC or Commission) notified the Gujarat Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2005 on March 31, 2005 (henceforth 'GERC Tariff Regulations'). Subsequent to notification of GERC Tariff Regulations, GERC notified the Gujarat Electricity

Regulatory Commission (Multi Year Tariff Framework) Regulations, 2007 (henceforth 'MYT Regulations') on December 21, 2007. These Regulations were an appendix to the GERC Tariff Regulations. However, it was specified in the MYT Regulations that in the event of any inconsistency between the two Regulations, the MYT Regulations would prevail.

Regulation 6 of the MYT Regulations specifies that the first Control Period for the Multi-Year Tariffs would be for three financial years beginning April 1, 2008. The Commission has issued the MYT Order for all the Utilities in the State, in accordance with the MYT Regulations, for the first Control Period from April 1, 2008 to March 31, 2011.

The prevalent GERC Tariff Regulations and MYT Regulations were guided by the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2004, which specified the norms and approach for tariff determination for Generation Companies and Transmission Licensees regulated by the CERC for the Control Period from April 1, 2004 to March 31, 2009. The Central Electricity Regulatory Commission (CERC) has subsequently notified the CERC (Terms and Conditions of Tariff) Regulations, 2009, which is applicable for the Control Period from April 1, 2009 to March 31, 2014.

The GERC Tariff Regulations and MYT Regulations do not have any specified applicability period and can theoretically be continued for the next Control Period also.

However, apart from the notification of the CERC (Terms and Conditions of Tariff) Regulations, 2009, there are several Judgments from Appellate Tribunal for Electricity (APTEL) pertaining to the State of Gujarat, on various aspects of above-mentioned Regulations. Hence, the Commission desired to revisit both the above-mentioned Regulations keeping in view Regulations notified by various State Electricity Regulatory Commissions (SERCs), Central Electricity Regulatory Commission (CERC) and Judgments of Appellate Tribunal for Electricity (APTEL). The Commission also desired to review the various study reports prepared by the Forum of Regulators (FOR) on the MYT framework.

Further, during the first Control Period, while issuing the MYT Orders and Annual Performance Review (APR) for the Utilities in the State in accordance with the MYT Regulations, the Commission has noticed certain areas of improvement in the specified MYT framework. The Commission would like to analyse these areas and make necessary modifications to the GERC Tariff Regulations and MYT Regulations, before the next Control Period begins, so that the MYT framework for the next Control Period is in accordance with the modified MYT Regulations.

These MYT Regulations shall extend to the whole of the State of Gujarat. These Regulations shall be applicable for determination of tariff in all cases covered under these Regulations from FY 2011-12 onwards. However, for all purposes including the review matters pertaining to the period till FY 2010-11, the issues related to determination of tariff shall be governed by GERC Tariff Regulations and MYT Regulations, including amendments thereto.

In order to ensure that the desired objectives are achieved, the Commission engaged the services of ABPS Infrastructure Advisory Private Limited (ABPS Infra) to provide consultancy support to the Commission for development of Multi-Year Tariff Regulations for the second Control Period from FY 2010-11 to FY 2014–15.

The Terms of Reference for this assignment are inter-alia:

1. Analysis of the GERC Terms and Conditions of Tariff Regulations and GERC Multi Year Tariff Framework Regulations and identify areas where amendment/s is/are required in consultation with the Commission.
2. Submission of the study report based on the analysis of similar Regulations issued by CERC, various SERCs, study reports of the FOR, and Judgments issued by APTEL, various High Courts, and the Supreme Court on the various aspects of above mentioned Regulation/s.
3. Submission of Discussion Paper along with draft Regulations on the amendment(s) proposed.
4. To assist in finalization of the amended Regulations.

ABPS Infra has studied all the relevant documents, viz., CERC Tariff Regulations, 2009, Tariff Policy, FOR Recommendations on MYT Framework, APTEL Judgments, etc., for preparing this Discussion Paper.

The Discussion Paper is organised in the following Sections:

Section 1: Introduction

Section 2: MYT General Principles

Section 3: Broad Financial Principles

Section 4: Norms and Principles for determination of Revenue Requirement and tariff for Generation Companies

Section 5: Norms and Principles for determination of Revenue Requirement and Transmission Tariff

Section 6: Norms and Principles for determination of Revenue Requirement and Wheeling Charges and Losses for Distribution Wire Business

Section 7: Norms and Principles for determination of Revenue Requirement and Retail Supply Tariff for distribution licensees

2 MYT Overview - General Principles

This Discussion Paper discusses the contours of the Multi-Year Tariff (MYT) principles for formulation of Regulations for determination of tariff for the next Control Period. The broad objectives of any MYT framework are:

- Provide regulatory certainty to the Utilities, investors and consumers by promoting transparency, consistency and predictability of regulatory approach, thereby minimizing the perception of regulatory risk.
- Address the risk sharing mechanism between Utilities and consumers based on controllable and uncontrollable factors.
- Ensure financial viability of the sector to attract investment, ensure growth and safeguard the interest of the consumers.
- Review operational norms for Generation, Transmission, Distribution and Supply businesses, related issues and recommend suitable measures to address such issues.
- Promote operational efficiency.
- Rationalise tariffs in the long-term through improvement in operational efficiency.

Multi Year Tariffs (MYT) or Long Term Tariff principles are intended to give clarity to the Transmission Licensees, Distribution Licensees and Generating Companies, consumers, and the other stakeholders regarding the principles governing the determination of revenue requirement and tariffs in the State of Gujarat. Further, it should detail the tariff methodologies, which can be understood by all, and give a fair idea of the future path. In this way, all stakeholders are made aware of the outcome of various actions/events for the defined future time period (Control Period), and are able to make their plans accordingly.

For the Licensees and Generating Companies, the principles provide clarity in rules applied over a long-term, and help finance growth and operations better, and facilitate improvement in supply quality and customer service. Secondly, the design of efficiency incentives helps promote operational efficiency. Since efficiency improvements need time to take effect, these incentives should be applicable for a reasonably long period of time.

For consumers, improvement in operational efficiency translates into more cost-effective tariffs, as efficient licensees can provide better supply and service, and remain viable.

2.1 Contours of Multi-Year Tariff

2.1.1 Cost plus Regulation vs Performance based Regulations

Historically, the State Government was the owner as well as the Regulator of the power sector in most States, by virtue of being the owner of the vertically integrated State Electricity Boards. Realising the importance of having an independent Regulator of the electricity sector, and in response to the relevant legislation enacted in this regard, most States established the State Electricity Regulatory Commission to regulate the electricity sector in the respective State, while the Central Government constituted the Central Electricity Regulatory Commission to regulate the Central sector Utilities as well as inter-State projects.

The SERCs have generally adopted the approach of 'cost-plus' regulation, whereby tariffs are determined in such a manner so as to enable the Utilities to recover their expenses and earn a pre-determined return on the equity investment or the capital employed. It should be noted that most SERCs do not approve all the expenses, and undertake prudence check on the expenditure with the objective of improving the Utility's efficiency and thereby, reducing tariffs. This introduces an element of 'performance- based' regulation within the overall framework of 'cost-plus' regulation.

The alternative approach to the Cost Plus approach to regulation discussed above is Performance Based Regulation (PBR). Rather than frequent reviews of Utility costs and determining tariffs to reimburse Utilities for what they spend, PBR takes a longer term view and focuses on how Utilities perform. In a well-designed PBR, good performance should lead to higher profits, while poor performance should lead to lower profits. In general, PBR mechanisms provide Utilities with a fixed price or a fixed level of revenues, as opposed to a predetermined level of profits. As a result, Utilities can earn higher, or lower, profits depending upon how efficiently they plan for and operate their systems. The most commonly discussed PBR mechanism is the 'price cap'. Price caps differ from the cost plus approach in two fundamental ways. First, prices are put in place for longer periods of time (e.g., four to six years) as compared to the annual tariff determination usually undertaken under the cost plus approach. The fixed prices over longer periods are intended to provide incentives to reduce costs. Second, Utilities are allowed to lower their prices to some customers, as long as all prices stay within the cap (or caps). This flexibility allows the Utilities to provide competitive price discounts to customers that might otherwise leave their system.

In this context, the FOR Report on MYT framework and distribution margin recommends

> *"6.1.1 Annual revision of performance norms and tariff might not be desirable. During the first control period, which should not be more than three years, the opening levels of performance parameters should be specified as close to the actual level of performance as possible and* ***a trajectory of improvement of norms to desired level be provided with an incentive and disincentive mechanism to share efficiency gains with consumers."***

The FOR Report recommends that the norms for the first Control Period should be specified as close to actual level of performance as possible. The FOR Report also emphasises on specifying a trajectory to achieve desired levels of norms, which entails fixing of performance trajectory on normative basis rather than at actual levels for the second Control Period onwards.

However, it should be noted that internationally, PBR has been introduced only for the Wires Business (Wheeling Business), and the retail supply business is subjected to open competition. However, in India, the retail supply business is not presently subjected to competition in the real sense, save for certain Open Access transactions and presence of parallel licensees in certain areas.

While selecting the appropriate model of PBR, it will be useful to look at the structure of the electricity industry in Great Britain and compare it with that prevailing in India.

Electricity Industry Structure in Great Britain (GB)

1. Generation

Traditionally, electricity has been generated by large power stations connected to the transmission system, but in recent years, there has been increased focus upon the deployment of distributed generation (DG). Electricity generation is a competitive activity and there are a number of players that operate in this area of the industry. Thus, generation of electricity is a deregulated activity.

2. Transmission/System Operation (SO)

Once electricity is generated, it is transmitted through the high voltage electricity transmission network, which is owned by National Grid Electricity Transmission (NGET), Scottish Hydro Electricity Transmission Limited (SHETL) and Scottish Power Electricity Transmission Limited (SPTL). Despite the disparate ownership of the electricity transmission network, the overall transmission system in Great Britain GBis operated by NGET. NGET has the responsibility for ensuring that the GB electricity transmission network remains in balance and within safe operational limits.

NGET is subject to SO incentive arrangements, under which a target for SO costs, associated with its role as residual balancer and its other SO activities, is set. Under the provisions of the SO incentives, NGET is permitted to retain a proportion of savings against the targets set, but must pay a proportion of any additional costs incurred, in line with the sharing factors agreed.

The costs of providing services that are covered by the regulated price control also include incentives toward efficiency as well as incentives to deliver against a specified quality of service.

3. Distribution of electricity

The electricity distribution networks are medium voltage transportation networks, which are used to carry electricity from the high voltage electricity transmission network to the majority of final customers. In line with the differential voltages for transmission in Scotland as compared with England and Wales, the distribution networks in England and Wales operate at a maximum voltage of 132 kV while the Scottish distribution networks have the potential to operate at a maximum voltage of 66 kV.

There are 14 electricity Distribution Network Operators (DNOs) and these were all historically owned by the Public Electricity Suppliers (PES') at the time of privatisation, who also owned the corresponding supply business in their incumbent supply area. However, since privatisation, there has been significant merger/takeover activity and many of the electricity DNOs are now held within common ownership.

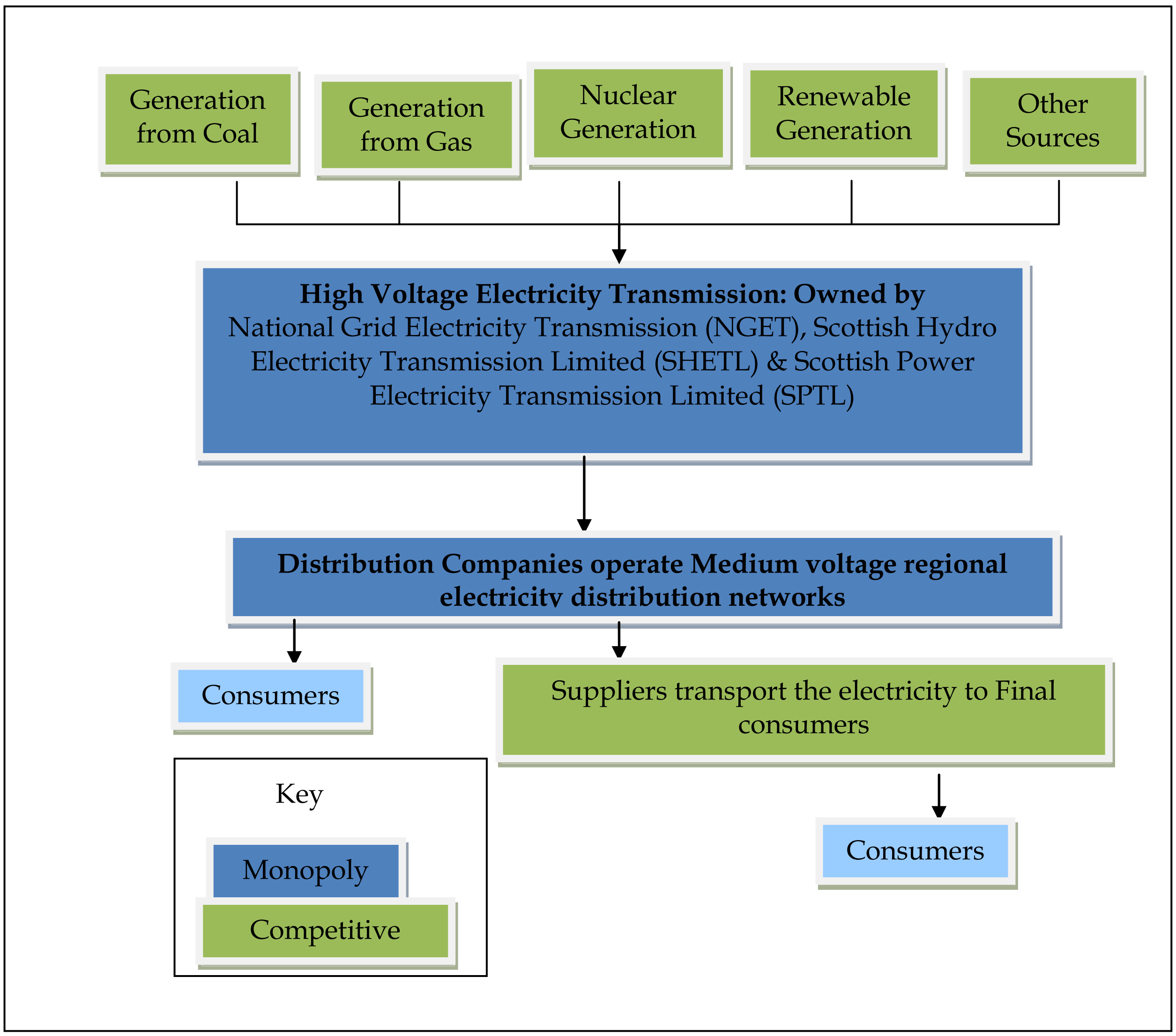
The DNOs, as parties operating on the electricity transmission network, have a role in ensuring that their positions remain in balance and, in this respect, the volume of electricity that they inject into the system is equivalent to the amount that they draw. The DNOs also have a role in delivering the required capacity to ensure that suppliers can transport electricity to their final consumers. Required revenues are made available to fund the provision of this capacity, through the regulated price control mechanism, which incentivises the DNOs to deliver this capacity in the most economic and efficient way.

4. Supply of electricity

At the time of privatisation, each of the PES' held an effective monopoly in the supply of electricity within their respective PES areas and therefore, the PES' were subject to an RPI-X price control. By May 1999, competition had been rolled out at the level of domestic electricity customers, and in April 2002, the supply price controls were lifted, as competition was deemed to have developed sufficiently to protect the interests of consumers. By this point, the domestic market shares of the PES' in their incumbent areas had reduced as a proportion of customer numbers, from an average of 90% in September 1999 to 70% in September 2001. There were also between 12 and 14 suppliers offering domestic tariffs in each of the PES areas. There are currently six large energy supply companies.

Generation tariff and retail tariff are deregulated in the electricity industry of Great Britain, which means that there is no price cap for these segments. Only transmission and distribution segments are regulated under price cap mechanism, where regulator regulates the price chargeable to DNOs and Suppliers.

Hence, price cap controls are applicable to the network related distribution and transmission activity in Great Britain. Broad overview of electricity industry structure is shown in the block diagram below:



Selection of Performance Based Regulation Model for Gujarat

Industry Structure

In the Indian context, generation activity has become partly competitive with introduction of competitive bidding, while transmission is a monopoly activity and distribution and retail supply is still largely an area-specific monopoly, despite provisions of open access and parallel licensing provisions. All the three segments are regulated by Electricity Regulatory Commissions (ERCs) in India and mainly regulated through Cost-Plus Regulation.

However, for providing regulatory certainty to consumers, Utilities and various stakeholders of power sector in Gujarat, it is proposed to continue the existing efforts for improved performance based regulation.

2.2 Prescribing Norms Vs Prescribing Principles in the Regulations

There are two options to specify trajectories for performance parameters under the MYT framework, which are as under:

a. Prescribing Norms, based on the analysis of past performance levels and approved trajectory of last Control period.
b. Prescribing principles outlining the approach that needs to be followed to be used in the MYT/ APR Orders for determination of ARR.

Both the approaches have their merits and demerits. However, prescribing Norms based on the analysis of past performance levels and approved trajectory of last Control period, provides clarity about the roadmap of tariff, to the Utilities as well as to the consumers. Regulatory certainty is one the key objectives of any MYT framework. Hence, it is proposed to prescribe norms for performance parameters, including O&M expenses, wherever possible.

2.3 Business Plan

The Forum of Regulators (FOR), in its report on MYT framework and Distribution Margin, has recommended as under:

"2.5.4 Distribution licensees should submit the business plan and power purchase plan, for approval of the Commission, at least six months prior to submission of MYT petitions, comprising the following aspects:

- *Category-wise sales projections*
- *Load growth details*
- *Power Procurement Plan from short-term and long-term sources*
- *Capital expenditure and capitalisation plans, financing pattern and impact on related expenses*
- *Employee rationalisation*

2.5.5 The Commission should issue its order on the business plan and power procurement plan within four months of submission, so that the licensee submits the MYT petition based on the approved plan"

The Chapter-5 of MYT Regulations stipulates as under:

> *"The filing under MYT by the Generating Company or licensee shall be done not less than 120 days before the commencement of the ensuing financial year or control period in such form as prescribed by the Commission in the Tariff Regulation. The filing shall be for the entire control period with year wise details, duly complying with the principles for determination of ARR as specified in the Tariff Regulation and MYT Regulation"*

This effectively requires the Utilities to submit their MYT Petitions on or before 30th November of the previous year for which tariff has to be determined. The FOR recommendations provides for submission of Business Plan six months prior to submission of MYT Petition, i.e., 30th November. Hence, date for submission of Business Plan would be 31st May. It is proposed that the since the target date of submission of Business Plan is already over, Business Plan for the second Control Period may be filed latest by December 31, 2010 for the Commission's approval along-with MYT Petition, and for the third Control Period, the timelines recommended by FOR may be applicable.

Since, the concept of submission of comprehensive Business Plan is proposed to be implemented for the first time, it is proposed that a mid-term review of the Business

Plan/Petition may be sought by the Generating Company, Transmission Licensee and Distribution Licensee through an application filed three (3) months prior to the filing of Petition for truing up for the second year of the Control Period and tariff determination for the fourth year of the Control Period.

The scope of mid-term review of Business Plan may include inter alia, proposal for change in Sales/power procurement plan, Proposal for change in base line values for various elements of ARR, Proposal for change in performance trajectories, Proposal for change in Capitalisation Plan, Proposal for approval of additional capitalisation at the discretion of the utilities concerned.

The above mentioned items are representative and not exhaustive. The provision for mid-term review is an enabling provision intended to facilitate the Generating Company, Transmission Licensee and Distribution Licensee to approach the Commission in case of mid-term correction of their Business Plans due to any reason, which would need to be factored into subsequent Tariff Orders.

2.3.1 Duration of Multi-Year Tariff Period

The Control Period means a multi-year period typically ranging from 3 to 5 years, fixed by the Commission from time to time for the duration of which, the principles for determination of Aggregate Revenue Requirement (ARR) and tariff will be fixed.

Clause 5.3 (h)(1) of the Tariff Policy notified by the Ministry of Power, Government of India on January 6, 2006 stipulates:

> *"Section 61 of the Act states that the Appropriate Commission, for determining the terms and conditions for the determination of tariff, shall be guided inter-alia, by multi-year tariff principles. The MYT framework is to be adopted for any tariffs to be determined from April 1, 2006.* ***The framework should feature a five-year control period. The initial control period may however be of 3 year duration for transmission and distribution if deemed necessary by the Regulatory Commission on account of data uncertainties and other practical considerations.*** *In cases of lack of reliable data, the Appropriate Commission may state assumptions in MYT for first control period and a fresh control period may be started as and when more reliable data becomes available."*

Chapter- 6 of MYT Regulations specifies:

> *"The applicant shall submit a forecast of his aggregate revenue requirement and expected revenue from tariff and charges for the approval of the Commission for each financial year within a control period of five (5) financial years:*
>
> *Provided that for the first application made to the Commission under this Part, the control period shall be three (3) financial years i.e. April 1, 2008 to March 31, 2011.*
>
> *Provided further that the Commission may, based on the experience gained with implementation of multi-year tariffs in the State, extend or reduce the duration of subsequent control periods, as it may deem appropriate:*
>
> *Provided also that the Commission shall not so extend or reduce the duration of subsequent control periods without hearing the parties affected:*
>
> *Provided also that the Commission shall not extend or curtail the duration of any control period during such control period."*

The GERC has issued the MYT Order for all the Utilities in the State, in accordance with the GERC Tariff Regulations and MYT Regulations, for the first Control Period from April 1, 2008 to March 31, 2011. Thus, the second Control Period is due to begin on April 1, 2011. In accordance with the Tariff Policy and MYT Regulations, it is suggested that the Control Period should be of five years, over the period from April 1, 2011 to March 31, 2016. Hence, it is proposed to accept the above recommendations that the second Control Period may be of five years.

2.3.2 Baseline Values Determination

The baseline data available with the Commission while defining the trajectory of different performance and financial parameters for the Control Period needs to be accurate and reliable. Such baseline data will have to be compiled based on audited accounts of the Utilities and operational and financial parameters of the Utility. The existing performance levels of the Utilities regulated by the Commission also need to be borne in mind while defining the baseline values for the second Control Period.

2.4 Revision in Operational Norms

A suitable performance trajectory for improvement in operational parameters has to be evolved along with an appropriate arrangement for sharing the gains and losses on account of superior and inferior performance vis-à-vis target performance, with the consumers. This will ensure protection of consumers' interests as well as provide motivation to the Utilities for improving the efficiency of operations.

While setting the norms, due regard has to be given to the existing performance levels and the desired performance levels, and the performance improvement trajectory has to be designed in such a manner that sufficient time is given to the Utilities to achieve the desired operational efficiency, while at the same time ensuring that the performance trajectory is not slack and is easily achievable by the Utilities. Further, as discussed subsequently in this Discussion Paper, the mechanism for sharing the gains and losses due to controllable factors vis-à-vis desired operational norms has to be formulated. The Generating Companies and Licensees are entitled to retain a portion of the gains earned in this manner. However, since one of the basic objectives of the MYT regime is to ensure that the consumer tariffs are rationalised in the long-term, the operational norms have to be revised at the beginning of each Control Period, on the basis of the actual performance achieved during the previous Control Period, so that the benefits of operational efficiency improvement are passed on the consumers. Under this mechanism, the Utilities are allowed to retain the incentive earned during the Control Period, and at the end of the Control Period, the operational norms are revised, so that there is continuous improvement and the Utilities are incentivised to further improve their operational efficiency, with a provision of mid-term review of Business Plan as discussed above in paragraph 2.3 of this Discussion Paper.

2.5 Controllable and Uncontrollable Factors

While formulating the MYT framework, it is essential to clearly specify the controllable factors and uncontrollable factors and their treatment. The impact on the Utility due to uncontrollable factors are generally considered as a pass-through element in tariffs, while the impact – gain or loss – on account of controllable factors has to be shared between the Utility and the consumers in a specified manner.

2.5.1 Controllable factors

Controllable factors are those considered to be under the Utility's control. The Commission needs to define these factors under the MYT framework. GERC, in Regulation 9.6.2 of its MYT Regulations, has specified various controllable parameters, which are proposed to be retained and with certain addition as listed below:

1. Financing Pattern:

   This includes the mix of debt and equity, which is usually allowed on normative basis as 70:30. However, the capital cost itself is a controllable factor and has to be approved by the Commission, which will have a bearing on the debt: equity ratio considered by the Commission. Also, financing pattern is relevant in case the Return on Equity approach is adopted for giving returns to the Utility. Under the ROCE approach, the Utility would have to take a decision on the best financing mix considering its ability to raise funds through equity and debt and the associated costs. Hence, impact of financing pattern is a pass-through in ROE Approach, whereas in ROCE approach, it is not a pass-through.

2. Variation in Wires Availability:

   As mandated under the Tariff Policy, the Commission has to increasingly focus on regulation of the supply quality and service standards, rather than the regulation of costs. The Standards of Performance stipulated by the Commission under its GERC (Standards of Performance of Distribution Licensees) Regulations, 2005 have to be considered as controllable factors, and any variation from the same has to treated as controllable and suitable incentive/disincentive mechanism has to be undertaken.

   In this context, the FOR Report on MYT framework and distribution margin has recommended that "***SERCs may initially fix a lower norm for network availability for rural areas keeping in view the present levels of service with trajectory for time bound improvement***. ***For every 1% under-achievement in composite availability for urban or rural areas, ROE shall be reduced by 0.1% of equity***. *The SERC shall specify the mechanism of computing Composite Index of Supply Availability and Network Availability.*"

Since, under the proposed framework, the Wires Business and Supply Business are being segregated, the performance indices of both Businesses may be kept separate, rather than determining a Composite Index.

Wires Network Availability

In accordance with the above FOR recommendations, based on past performance of Wires Business of distribution Utilities, it is proposed that the distribution licensees need to ensure Wires Availability of at least 90% and 95% for rural and urban areas, respectively. For every 1% under-achievement in Wires Availability, ROE rate shall be reduced by 0.1%. Similarly, if there is 1% over-achievement in Wires Availability, ROE rate shall be increased by 0.1%. Proposed formulae for calculation of Wires Availability, is as under:

Wires Availability = (1- (SAIDI / 8760)) x 100

where

SAIDI will be calculated as per formulae specified in Gujarat Electricity Regulatory Commission (Standard of Performance of Distribution Licensee) Regulations, 2005

Wires Availability is proposed to be measured over the course of a year and will be expressed in percentage terms.

In case the actual wires availability is higher than the normative level, then the Distribution Licensee will be entitled to an incentive, and conversely, if the actual wires availability is lower than the normative level, then the Distribution Licensee will be subjected to a dis-incentive.

3. Transit loss in procurement of coal by generating stations:

   Very often, the Generating Companies submit that they have no control over the transit losses that occur outside the premises of the generating station, as the coal is transported through open wagons and the Railways insist on coal weighment at the loading point rather than the receiving point, and all losses due to theft, pilferage, and moisture losses have to be borne by the Generating Station, since the Railways do not give any guarantee for the quantity of coal delivered. While this is partly correct, experience of generating stations in several States shows that transit losses can be minimized with adequate efforts of joint weighment, and ensuring electronic weighbridges at the coal loading point, apart from taking up the issue with the Railways. Hence, it is proposed to consider coal transit losses as a controllable factor.

4. Capital Cost over-run due to delay by equipment supplier:

Sometimes, the Generating Companies submit that time and cost over-run incurred while setting up new generation facilities is on account of delays in delivery of the equipment by the equipment supplier and hence, the impact of such delays should be considered as an uncontrollable factor. In this context, the Generating Companies should ensure that the contract for procurement of equipment is drafted in such a manner that there are adequate safeguards to protect the Utility from incurring losses due to the delay in supply of equipment. Since this is a contractual matter, and considering that it would be difficult for the Commission to establish whether the delay is on account of delay in equipment supply or due to some delay on the part of the Generating Company, which is often a matter which goes for arbitration, it is proposed to consider the impact of time and cost-overrun in capital expenditure projects as a controllable factor, irrespective of whether the delay is attributed to delay in equipment supply or otherwise.

However, it is also proposed that cost incurred by Utilities due to change in law or policy of Government , viz., Impact of Pay revision, Change in Water Charges, etc., shall be considered as an uncontrollable expense subject to the prudence check of the Commission on annual basis at the time of truing up exercise. As these costs are beyond the control of the Companies, it is proposed to be treated as an uncontrollable expense.

It is also proposed that any factor/variable other than categorised as an uncontrollable factor, shall be categorised as a controllable factor.

2.5.2 Uncontrollable factors

PBR mechanism allows for recovery of specific costs that are not controllable. Uncontrollable costs usually include costs over which the Utility has no control, such as fuel cost variation, etc. They also include costs that are not meant to be subject to cost-cutting pressures, such as Demand Side Management (DSM) related expenses. The costs that are chosen to be recovered through the Uncontrollable factors can have important planning implications. This is amply clear from the Tariff Policy stipulation of Clause 4.5 (h)(4) as mentioned below:

> *"Uncontrollable costs should be recovered speedily to ensure that future consumers are not burdened with past costs. Uncontrollable costs would include (but not limited to) fuel costs, costs on account of inflation, taxes and cess, variations in power purchase unit costs including on account of hydro-thermal mix in case of adverse natural events."*

It is proposed to consider to fix the uncontrollable factors as under:

1. <u>Interest Expense:</u> Interest expense is considered as an uncontrollable factor under the RoE approach for computing return. However, if ROCE approach is adopted, the Utility has to optimise the financing mix and hence, the interest expense under ROCE approach is a controllable factor;
2. Force Majeure events;
3. Change in law, judicial pronouncements and Orders of the Central Government, State Government or Commission;
4. Variation in the price of fuel and/ or price of power purchase according to the FCA/FPPPA formula approved by the Commission from time to time;
5. Variation in the number or mix of consumers or quantities of electricity supplied to consumers. It may be noted that where there is more than one Distribution Licensee within the area of supply of the applicant, then any variation in the number or mix of consumers or in the quantities of electricity supplied to consumers within the area served by two or more such Distribution Licensees shall be attributable to controllable factors. However where any consumer or category of consumers within the area of supply of the applicant is eligible for open access under sub-section (3) of Section 42 of the Act, then any variation in the number or mix of such consumers or quantities of electricity supplied to such eligible consumers shall be attributable to controllable factors;

6. Variation in market interest rates;
7. Taxes and Statutory levies;
8. Taxes on Income.

However, the Distribution Licensee shall undertake his power procurement during the year in accordance with the power procurement plan, which is proposed to be part of Business Plan for the Control Period, which may include long-term, medium-term and short-term power procurement approved by the Commission in accordance with these Regulations, in normal circumstances.

It is also proposed that any factor/variable other than categorised as an uncontrollable factor mentioned above, shall be categorised as a controllable factor.

2.6 Sharing of Gains and losses

In this Section, the mechanism of sharing the gains and losses on account of controllable factors has been discussed.

The clause 8.1 (2) of the Tariff Policy stipulates as under:

> *"The State Commissions should introduce mechanisms for sharing of excess profits and losses with the consumers as part of the overall MYT framework. In the first control period the incentives for the utilities may be asymmetric with the percentage of the excess profits being retained by the utility set at higher levels than the percentage of losses to be borne by the utility. This is necessary to accelerate performance improvement and reduction in losses and will be in the long term interest of consumers by way of lower tariffs."*

The profit sharing mechanism is thus intended to share the benefits of better performance of the Utility with the consumers, while at the same time ensuring that the Utility has enough incentive to improve its operational efficiency. The proposed sharing of gains and losses in case of controllable factors is discussed below:

2.6.1 Sharing of gains or losses on account of controllable factors

The GERC in Chapter-11 of MYT Regulations provides for sharing of aggregate gain to the Generating Company or Licensee on account of controllable factors.

In this context, the FOR Report on MYT Framework and Distribution Margin has recommended as under:

> ***"6.2 Sharing of benefits of efficiency gains with consumers***
>
> *6.2.1*
>
> *The losses on account of under achievement in controllable parameters shall not be shared with consumers as norms are being fixed at close to actual levels, except in extraordinary circumstances if decided by the SERC.*
>
> *6.2.2*
>
> *Efficiency gains with respect to controllable parameters shall be shared between the licensee and the consumer in the ratio of two-third and one-third at the end of every year during the truing up exercise."*

However, keeping in view the above, it is proposed to keep the proposed mechanism for sharing of gain/losses as under-

(A) The proposed mechanism for sharing the gains:

a. In case of Generation Company, Transmission Licensee or Distribution Licensee, one-third of such gain may be passed on to the consumers as a rebate in tariffs over a period of time as may be specified by the Commission

b. The balance amount, which will amount to two-thirds of such gain for Generation Company, Transmission Licensee or Distribution Licensee, may be utilised by the Utility at its discretion.

(B) The Proposed mechanism for sharing the losses:

a. In case of Generation Company, Transmission Licensee or Distribution Licensee, one-third of such loss may be passed on to the consumers.

b. The balance amount, which will amount to two-thirds of such loss for Generation Company, Transmission Licensee or Distribution Licensee, shall be borne by the Utility.

2.6.2 Mechanism for pass through of gains or losses on account of uncontrollable factors

The GERC MYT Regulations provides for pass through of aggregate gain or losses to the Generating Company or Licensee on account of uncontrollable factors as under:

> *"10.1 The approved aggregate gain or loss to the Generating Company or Licensee on account of uncontrollable factors shall be passed through as an adjustment in the tariff of the Generating Company or Licensee over such period as may be specified in the Order of the Commission passed under Regulation 9.7(a):"*

In this context, the FOR Report on MYT framework and distribution margin has recommended as under:

> *"6.2.3 The entire gains and losses on account of uncontrollable factors shall be passed on to consumers during the truing up process."*

It is proposed to adopt the FOR recommendations in this regard, and the gain or loss to the Generating Company or Transmission Licensee or Distribution Licensee on account of uncontrollable factors shall be passed through as an adjustment in the tariff of the Generating Company or Transmission Licensee or Distribution Licensee.

2.7 Annual Determination Vs One-time Determination of Tariff

During the first MYT Control Period of three years from FY 2008-09 to FY 2010-11, Annual Performance Review (APR) of a Generating Company/Licensee has been undertaken by the Commission. In accordance with the MYT Regulations, the provisional truing up of current year, and final truing up of the previous year's expenses and revenue is undertaken, while determining the annual tariff for the ensuing year. However, the process of provisional truing up followed by annual truing up may defeat the purpose of Multi Year Tariff framework. It is observed that Utilities tend to revise their estimates of sales, expenses and revenue for every year of the Control Period. In Gujarat, parameters like sales and power purchase have not been stipulated in the MYT Orders, due to the uncertainty on account of the prevailing supply shortages in the State and the respective licence area. Consequently, the tariff has been specified for only one year, rather than the Control Period, which is also in accordance with the MYT

Regulations, which specifies that tariff will be determined annually. Moreover, as a result of the provisional truing up and final truing up, the ARR of any particular year effectively gets determined three times, viz., first at the time of tariff determination for the prospective year, second at the time of provisional truing up, and third at the time of final truing up.

It is observed that the annual review process requires very high regulatory oversight and is very time-consuming and is almost equal and some-times more strenuous than the earlier approach of annual tariff determination.

Hence, it is proposed that for the second Control Period, Annual Performance Review (APR) exercise of a Generating Company or Transmission Licensee or Distribution Licensee shall not be undertaken in the present manner and only truing up of previous year's expenses and revenues shall be undertaken based on audited actuals, subject to prudence check. .Another issue is that whether the tariff, once determined at the beginning of the Control Period, will be applicable for the entire Control Period, or is there a need to determine the tariffs on an annual basis.

The Multi-Year Tariff framework proposed for the State of Gujarat primarily envisages the stipulation of a performance trajectory for operational norms for generating Companies and licensees, projection of the Aggregate Revenue Requirement for the Control Period, and determination of the Aggregate Revenue Requirement and tariff for the ensuing year of the year in which Truing up Petition is filed.

The filing for the first Control Period under these Regulations shall be as under:

a) MYT Petition shall comprise of:

   i. Truing up for FY 2009-10;

   ii. Annual Performance Review for FY 2010-11;

   iii. Multi-year Aggregate Revenue Requirement for the entire Control Period with year-wise details;

   iv. Revenue from the sale of power at existing tariffs and charges and projected revenue gap, for the first year of the first Control Period under these Regulations, viz., FY 2011-12;

   v. Application for determination of tariff for FY 2011-12.

b) From the first year of the Control Period and onwards, the Petition shall comprise of:

   i. Truing Up requirement of the previous year;

   ii. Revenue from the sale of power at existing tariffs and charges for the ensuing year;

   iii. Revenue gap for the ensuing year calculated based on ARR approved in the MYT Order and truing up requirement for previous year;

   iv. Application for determination of tariff for ensuing year.

c) After mid-term review of business plan, the Petition shall comprise of:

   i. Truing Up requirement of the previous year;

   ii. Modification of the ARR for the remaining years of the Control Period, if any, with adequate justification for the same;

   iii. Revenue from the sale of power at existing tariffs and charges for the ensuing year;

   iv. Revenue gap for the ensuing year calculated based on ARR approved in the MYT Order and truing up requirement for previous year;

   v. Application for determination of tariff for ensuing year.

2.8 Truing Up

During the next MYT Control Period, it is proposed that the Commission may issue a MYT Order at the beginning of Control Period and annually issue a Truing up Order for previous year based on Audited Accounts for each year of the Control Period. It is proposed that Annual Performance Review (APR) of a Generating Company or Transmission Licensee or Distribution Licensee may be discontinued and replaced by Truing Up of previous year. It is proposed that annual truing up exercise shall comprise of

1. Pass-through of uncontrollable factors like variation in interest expenses (limited to interest rate variation), Reimbursement of Income tax, Non-tariff Income and Income from Other Business, that have not already been passed through.

2. Sharing of Gain and losses for controllable parameters of previous year based on Audited Accounts, subject to prudence check of the Commission.

3. Based on above mentioned exercise, the Commission shall determine the tariffs for ensuing year of the Control Period.

4. Review of compliance with directives.

The Truing up exercise will comprise a comparison of the performance of the Generating Company or Transmission Licensee or Distribution Licensee, with the approved forecast of aggregate revenue requirement and expected revenue from tariff and charges and shall have the following components:

- Comparison of the audited performance of the Utility for the previous financial year with the approved forecast for such previous financial year and truing up of the expenses and revenue subject to prudence check including pass through of impact of uncontrollable factors;
- Computation of sharing of gains and losses on account of controllable factors for the previous year.

2.9 Determination of Tariff

The issue here is whether the tariff, once determined at the beginning of the Control Period, will be applicable for the entire Control Period, or is there a need to determine the tariffs on an annual basis.

The Multi-Year Tariff framework proposed for the State of Gujarat primarily envisages the stipulation of a performance trajectory for operational norms for generating Companies, transmission licensees and distribution licensees, projection of the Aggregate Revenue Requirement for the Control Period, and determination of the Aggregate Revenue Requirement and tariff for the ensuing year. In view of the data uncertainty and evolution of the MYT framework, **it is proposed that the tariff should be determined on an annual basis, after considering the effect of the ARR determined by the Commission in the MYT Order for that particular year, truing up of previous financial year and sharing of gains and losses due to controllable factors.**

The Commission may determine the tariff for the Generating Company or Transmission Licensees or Distribution Licensees, covered under the multi-year tariff framework for each Financial Year during the Control Period, at the commencement of such Financial Year, having regard to the following:

(a) The MYT principles specified in the GERC MYT Regulations
(b) The approved forecast of aggregate revenue requirement and expected revenue from tariff and charges for such financial year, including approved modifications to such forecast;
(c) Impact of truing up for previous financial year
(d) Approved gains and losses to be passed through in tariffs, following the Truing up exercise.

A similar approach has been followed in other States also by the respective State Electricity Regulatory Commissions (SERCs) as shown in the Table below:

State	Effectiveness	First Control Period	Tariff Determination
Maharashtra	2007-08	3 years	Annual
Madhya Pradesh	2006-07	3 years	Annual
New Delhi	2007-08	4 years	Annual
Andhra Pradesh	2006-07	3 years	Annual
Kerala	2007-08	3 years	Annual
Karnataka	2007-08	3 years	Annual

The format for prior publication of the ARR and Tariff Petition, and the data formats which need to accompany the ARR and Tariff Petition to be submitted every year will be issued by the Commission through a separate Order, for generation, transmission, and distribution business. This will facilitate standardization of the information to be published for information of the Public and to minimize the time between submission of the Petition and the Public Notice. However, the data and information sought through the above Format is the minimum information, and the Commission may require additional information to be published, if required, and the Utility could also add to the information being presented.

2.10 MYT Framework

Based on the discussion earlier in this chapter, treatment of various parameters under proposed MYT framework is tabulated below:

Particulars	Controllable	Adjustment
Cost of power generation/power purchase;	Uncontrollable	Quarterly
Transmission charges;	Uncontrollable	Annual
Return on Equity	Controllable	One-time at the Start of MYT, based on Business Plan, with a provision of mid-term review.
Interest Expenses		
a) Due to variation in capitalisation	Controllable	One-time at the Start of MYT, based on Business Plan, with a provision of mid-term review.
b) Due to interest rate variation	Uncontrollable	Annual
Depreciation	Controllable	One-time at the Start of MYT, based on Business Plan, with a provision of mid-term review.
Operation and Maintenance expenses	Controllable	Annual
Interest on working capital	Controllable	Annual
Interest on deposits from consumers	Uncontrollable	Annual
Contribution to contingency reserves	Controllable	One-time at the Start of MYT, based on Business Plan, with a provision of mid-term review.
Provisioning for bad debts	Controllable	Annual

Particulars	Controllable	Adjustment
Non-tariff income	Uncontrollable	Annual
Income from Other Business	Uncontrollable	Annual
Income Tax	Uncontrollable	Annual Reimbursement
Performance Parameters	Controllable	Annual

2.11 Filing based on Standardised Regulatory Accounts

Forum of Regulators (FOR) has been taking steps towards ensuring that the provisions in the Electricity Act 2003 and the policies, i.e., National Electricity Policy (NEP) and Tariff Policy are well implemented. During various deliberations in the FOR, the need was felt to recognize Regulatory Accounts as distinct from Statutory Accounts and to ensure uniformity of approach on Regulatory Accounts.

FOR is currently undertaking a study for Standardization of Regulatory Accounts. This study involves

1. Analysis of present system of accounting followed by ten different entities in power sector across India.
2. Analysis of the requirement of Regulatory Accounting Guidelines (RAG) and identification of the gaps.
3. Harmonise the present system of accounting with RAG.
4. Development of Uniform Regulatory Accounting Manual, Charts of accounts, Accounting policies and Rules including the treatment of Regulatory Assets and Liabilities Reporting system.
5. Develop methodology for separation of accounts
6. Develop basis for allocation and apportionment of various elements of revenue, cost assets and liabilities to regulated and non-regulated business
7.

It is proposed that based on FOR recommendations, as and when published, GERC may notify the Regulatory Accounts for the State of Gujarat. Accordingly, the enabling clause for facilitating filing of MYT/APR Petitions based on the Regulatory Accounts notified by GERC, has been included in the GERC (Terms and Conditions of Multi-Year Tariff) Regulations, 2010 (GERC MYT Regulations, 2010).

3 Broad Financial Principles

The broad financial principles envisaged under the MYT framework proposed for the second Control Period starting from FY 2011-12 in the State of Gujarat have been discussed in this Section. These broad financial principles are required to be specified for the State of Gujarat considering various factors such as investments required in the sector, risks involved in the sector, sector structure, extent of private participation in the sector, investments that have materialized in the sector in the recent past, etc.

The existing GERC Tariff Regulations, 2005 also address the broad financial principles. However, these financial principles need to be revisited while establishing the Multi-year Tariff framework for the second Control Period, in view of the developments subsequent to the notification of the above-said GERC Tariff Regulations. The broad financial principles discussed in this Section are:

- Approach for Giving Returns – Equity or Capital Employed
- Capital Cost
- Depreciation
- Interest on Working Capital
- Deposit works, consumer contribution and grants

3.1 Approach for Giving Returns

In any business, in addition to recovery of the costs incurred, the investors are entitled to earn an appropriate return on their investment, since there are alternative investment opportunities, and the investor has to choose between these alternative investment opportunities, in view of his risk-return profile.

The Rate Base is defined as the Capital Base on which the rate of return is applied to compute the permissible return to the investors. There are two Options for considering the Rate Base, viz.,

1. Return on Equity (ROE) approach, where the Rate Base is equal to the equity or the net-worth invested in the business,
2. Return on Capital Employed (ROCE) approach, where the Rate Base is the total capital employed (Equity and Debt) by the Utility.

3.2 *Merits and Demerits of ROE approach*

The ROE approach has been preferred by the CERC as well as majority of SERCs, as it is a simple approach to understand and adopt; the return is computed on the equity approved by Commission. If the actual equity infusion is higher than the normative level, then the return is computed on the normative equity level. However, in case the actual equity infused is below normative level, the actual equity infused is used to compute return on equity. The rate base is computed by applying the debt: equity mix to the approved capital cost of project.

The merits of ROE approach are:

i) It is easy to compute and simple to implement, and is hence, easily understood by all stakeholders.

ii) The investor gets assured returns on equity investment for ever, once the investment is done.

iii) The Utility is protected against the risk of fluctuation of interest rates, since interest expense is allowed as a pass through expense at actuals.

The demerits of ROE approach are:

i) No incentives for companies to bring down cost of capital, as return on equity invested is guaranteed and actual interest expenses expenditure incurred is also pass through.

ii) Utilities are not encouraged to practice financial engineering and optimise the financing mix by restructuring debt and equity, since the debt: equity ratio is allowed on normative basis (usually 70:30)

iii) Utilities may tend to inject more equity and try to reach normative equity allowed in order to maximize their profits, which in turn results in higher cost of capital.

iv) Even if assets are depreciated fully, Utilities get assured return on equity invested, unless specific provisions are built-in to ensure that the corresponding equity is also reduced.

v) In case the equity on the Balance Sheet of the Utility is low, which is the case with quite a few State-owned Utilities as they have been largely funded through loans, then the resultant claim for RoE is also reduced, which may hamper the Utility's efforts to invest in future capital expenditure.

3.3 Merits and Demerits of ROCE approach

The merits of ROCE approach are:

i) The ROCE approach incentivises financial planning to optimize the debt-equity mix and bring down the cost of capital.

ii) This approach recognises that the consumers should pay for the capital employed to fund the assets used to serve the consumers.

iii) The consumers are insulated from changes in debt-equity mix and changing interest rates, etc.

iv) It also makes it easier for the Regulators as they do not have to monitor debt and equity component separately.

v) Since the returns are linked to the investment in the business, once the asset is fully depreciated, then the Utility does not earn any return on its investment, and hence, the tariffs would also reduce to that extent.

vi) State-owned Utilities, which may have a lower equity base, would not be adversely affected, since the Returns would be given on the total capital employed, rather than the equity invested in the business.

The demerits of ROCE approach are:

i) The ROCE approach requires an estimation of the normative cost of debt and benchmarking of the debt-equity ratio, which could lead to windfall profits or abnormal losses depending on the ability of the Utility to undertake financial engineering to restructure its debt and equity.

ii) The Public Sector entities may find it difficult to manage the inherent risks under the ROCE approach.

iii) The ROCE approach may also pose an entry barrier for new entrants as they may not be able to achieve the desired debt: equity mix and also may not be able to source cheaper loans, as compared to existing Companies with stronger Balance Sheets.

3.4 ROCE Vs ROE Approach

The Commission has adopted the RoE approach while formulating the GERC Tariff Regulations, which is presently allowed to Generating Companies, Transmission Licensees and Distribution Licensees, for the first Control Period.

In this context, Clause 5(a) of the Tariff Policy notified on January 6, 2006 stipulates:

> *"Balance needs to be maintained between the interests of consumers and the need for investments while laying down rate of return. Return should attract investments at par with, if not in preference to, other sectors so that the electricity sector is able to create adequate capacity. The rate of return should be such that it allows generation of reasonable surplus for growth of the sector.*
>
> *…."*

CERC, in its Approach Paper, published along with the draft Tariff Regulations for the Control Period from FY 2009-10 to FY 2013-14, has stated:

> *"The Commission, while framing regulations for the previous periods, had recognized that Return* ***on Capital Employed (RoCE) approach is preferable but because of lack of benchmarking for Debt-Equity mix, fluid situation in regard to interest rate and debt market in India, had decided to adopt Return on Equity (RoE) approach.*** *With the listing of major power utilities on stock exchanges, permission for 100% FDI in power sector, development of debt market in India, stabilizing trends of interest rate and accessibility of Indian companies to foreign market for debt and equity, the ground situation has changed to a great extent.* ***As such, a fresh look is required to be given towards the approach for rate of return, that is, whether RoE approach vis-à-vis RoCE approach." (emphasis added)***

In Delhi, the principle for providing return to the transmission licensees and distribution licensees is based on the principle of Return on Capital Employed (RoCE) on a regulated rate base, with the weighted average cost of capital to be determined independently for each year of the Control Period. In case of generating companies, Return on Equity has been considered.

Relevant extracts of Consultative paper on MYT Regulations published by DERC are reproduced below:

"2.94 ***The ROCE concept gives incentives to the licensees to optimise the debt equity ratio. The approach recognises that the consumers should pay for the capital employed in the assets being used to serve the consumers, and ensure that the financing decisions of the distribution licensee do not affect consumer tariffs. It also makes it easier for the regulators as they do not have to monitor the debt and equity component separately and can concentrate on the overall performance of the licensees****."* ***(emphasis added)***

3.4.1 Experiences from other Sectors in India

3.4.1.1 Ports

Overview:

The Tariff Authority for Major Ports (TAMP) was constituted in April 1997 to provide for an independent Authority to regulate all tariffs, both vessel related and cargo related, and rates for lease of properties in respect of Major Port Trusts and the private operators located therein. The Major Ports Trust Act, 1963 was amended by Port Laws (Amendment) Act 1997 to constitute the TAMP.

TAMP had organized a national level Workshop in February 1998 at Chennai to deliberate upon the concepts, principles, approaches and modalities of Tariff Regulations for major ports as well as private terminals at these ports. As a result of the deliberations in the Workshop, a set of guidelines for tariff regulation was adopted. These guidelines are generally followed by this Authority so far.

TAMP had notified tariff fixation guidelines on March 31, 2005, which provides for Return on Capital Employed (ROCE), both for Major Port Trusts and Private Terminal Operators, at the same pre-tax rate fixed in accordance with the Capital Asset Pricing Model (CAPM).

3.4.1.2 Gas transportation pricing

Overview

Ministry of Petroleum and Gas (MoPNG) has constituted Petroleum & Natural Gas Regulatory Board (PGNRB) under the Petroleum & Natural Gas Regulatory Board Act, 2006. PGNRB's responsibilities include regulating the refining, processing, storage, transportation, distribution, marketing and sale of petroleum products and natural gas excluding production of crude oil and natural gas. Presently, there are no specific guidelines for tariff determination and tariff is determined on project specific criterion. PGNRB is presently evaluating "Draft Regulations for Determination of Pipeline Tariff of Natural Gas Pipelines, which, is still in discussion phase. Regulation 4 and 5 of abovementioned Regulations allows reasonable rate of return on the total capital employed in the CGD network, CGD stations and related facilities. The total capital employed shall be calculated by using formulae- Gross Fixed Assets less accumulated Depreciation plus normative Working Capital (twenty days of operating cost excluding Depreciation).

CERC has noted in the Explanatory Memorandum that the ROCE approach is preferable over the RoE approach, as this approach induces efficiency in fund management and encourages competition. However, CERC has cited fluctuations in the debt market and difficulty in assigning the same normative interest rate for all the Companies across the board, as the reason for continuing with the existing RoE approach. It may also be noted that most of the other State Electricity Regulatory Commissions are following ROE approach, in line with the CERC Tariff Regulations, 2009. Hence, **it is proposed that the present approach used by the Commission, i.e., ROE approach, may be continued for the second Control Period**.

Further, it is observed that in the existing GERC (Terms and Conditions of Tariff), Regulations, 2005, the methodology to be followed for computing Return On Equity (ROE), Depreciation, Interest on Long-term Loans, etc., in case of investment schemes involving replacement of old assets with new assets, is not specifically dealt with.

The existing Regulation 17 (4) of GERC (Terms and Conditions of Tariff), Regulations, 2005, specifies as under:

> *"…*
>
> ***Note 2***
>
> *Any expenditure on replacement of old assets shall be considered after writing off the gross value of the original assets from the original project cost, except such items as are listed in clause (3) of this regulation.*
>
> **…**

Note 4

Any expenditure admitted by the Commission for determination of tariff on renovation and modernization and life extension shall be serviced on normative debt-equity ratio specified in regulation 19 after writing off the original amount from the original project cost if any replacement of existing assets are involved."

However, there is no related reference regarding the methodology/treatment for ROE calculation under the GERC Tariff Regulations.

If the capital cost of the Capex schemes involving replacement of old assets by new assets is approved as it is, the Generating Company, Transmission Licensee or Distribution Licensee would continue to earn ROE perpetually on the capital cost of the old asset also as the original (opening) equity is considered for calculation of ROE, and there is no reduction in the same to account for the reduction in the equity component of the GFA due to the retirement of the assets. This is not procedurally correct as the old asset, which is no more in service is not serving the consumer in any manner.

In view of the above, it is proposed to adopt the following methodology while approving Capex schemes involving replacement of old assets by new assets:

a. GFA to be reduced to the extent of old asset replaced, and increased to the extent of new asset cost
b. ROE to be allowed after reducing opening equity equivalent to 30% (or actual equity component based on documentary evidence) of the original cost of old asset and adding 30% (or actual equity, if lower than 30% of GFA) of the cost of the new asset.
c. Depreciation to be allowed on the entire capitalized amount of the new asset; however, reduction in GFA of old asset will reflect in reduction in depreciation to that extent.
d. Debt to be considered as 70% (or actual %, if higher) of the entire capitalized amount of the new asset; however, if any loans are outstanding on the old asset that has been retired, then the corresponding loan should be retired and set off against the salvage value.
e. The balance of salvage value, if any, should be considered as Non-Tariff Income.

3.5 Rate of Return

The Commission has adopted the RoE approach while formulating the GERC Tariff Regulations, 2005. The GERC Tariff Regulations stipulates that the Generation Companies, Transmission and Distribution Licensees shall be allowed a return at the rate of 14 per cent per annum, on the amount of approved equity capital.

In this context, the Tariff Policy stipulates:

> ***"a) Return on Investment***
>
> *Balance needs to be maintained between the interests of consumers and the need for investments while laying down rate of return. Return should attract investments at par with, if not in preference to, other sectors so that the electricity sector is able to create adequate capacity. The rate of return should be such that it allows generation of reasonable surplus for growth of the sector."*

In this context, CERC in its Statement of Objects and Reasons of CERC Tariff Regulations, 2009, has stated as under:

> *"13.10 The Commission allowed rate of return on equity of 16% and 14% for the tariff period 2001-04 and 2004-09 respectively. The PLRs of State Bank of India during 2001 and 2004 were 11.50% and 10.25% respectively. But as on 1st January 2009, the PLR of State Bank of India is 12.25%. After considering the rise in the PLR of the public sector banks, 10-year G-Sec, etc and also in order to help the entities to build up sufficient internal accruals for the purpose of investment in capacity addition and to ensure better cash flow, the Commission considered & deliberated to restore the rate of return at 16% as was existing prior to 1.4.2004. After consultations & deliberations it was decided to increase the base rate from 14% to 15.5% and an additional 0.5% for timely competition as explained below…"*

Regulation 15 of CERC (Terms and Conditions of Tariff) Regulations, 2009 specifies Return on Equity to be allowed.

It is felt that the risk associated with regulated businesses like the electricity sector is much lower when compared to the risks associated with the stock market. Hence, return expectations should be commensurate with the risk associated with the business.

Looking to the larger interest of consumers, it is felt that the return provided in existing GERC Tariff Regulations, 2005 is sufficient for the second Control Period as well. Hence, it proposed that the return on equity of 14% may be adopted, in line with the Commission's philosophy for allowing same rate of return to Generation Companies, Transmission Licensee and Distribution Licensees.

3.5.1 Tax on Income

It is proposed that the Commission in its MYT Order shall provisionally approve Income Tax payable for each year of the Control Period, if any, based on the actual income tax paid as allowed by the Commission on permissible return related to business of electricity as per latest Audited Accounts available for the applicant, subject to prudence check. Variation between Income Tax actually paid and approved, if any, on the income stream of the regulated business of Generating Companies, Transmission Licensees and Distribution Licensees shall be reimbursed to/recovered from the Generating Companies, Transmission Licensees and Distribution Licensees, based on the documentary evidence submitted at the time of truing up of each year of the Control Period, subject to prudence check.

It may be noted that the under-recovery or over-recovery of any amount from the beneficiaries or the consumers on account of such tax having been passed on to them shall be adjusted every year on the basis of income-tax assessment under the Income-Tax Act, 1961, as certified by the statutory auditors. The Generating Company, or the Transmission Licensee or Distribution Licensee, as the case may be, may include this variation in its truing up Petition.

It is also proposed that as in the existing Regulations, any liability arising out of tax on any income stream other than the core business shall not constitute a pass through component in tariff and tax on such other income shall be borne by the Generating Company or Transmission Licensee or the Distribution Licensee, as the case may be.

3.6 Capital Cost

The Forum of Regulators (FOR), in its Report on MYT for Distribution Licensees, has recommended as under:

> *"6.1.3 The distribution licensee should submit the business plan and power purchase plan for approval of the Commission, at least six months prior to submission of the MYT petition."*

The GERC MYT Regulations also clearly bring out the need to file separate investment plan for approval of capital expenditure. This is critical, since the capital expenditure has a significant bearing on the tariff payable by the consumers, on account of the pass through of the related expenses like depreciation, interest on long-term loans, return on equity/capital employed, etc. Presently, in Gujarat, Capital Expenditure plan is approved by the Commission as a part of tariff determination exercise.

However, it proposed that the investment plan for the second Control Period needs to be submitted to the Commission, as a part of the Business Plan, for approval of capital expenditure.

Variation between approved and actual values of capital expenditure and capitalisation significantly influences computation of tariff. Since capital expenditure has a tremendous bearing on several expenditure elements, some additional issues to be addressed under this aspect include:

a) Whether the actual capital cost or the approved capital cost, subject to prudence check, is to be considered?

b) Expenditure on Renovation & Modernisation and life extension of Plant

c) Expenditure involving replacement of asset/works arising out of contingency/accident, e.g., Floods, fire, etc.

3.7 Depreciation

The principles behind the charging of depreciation and the depreciation rates have been a subject of debate over the years, including the linkage of depreciation to creation of a reserve fund for replacement of assets versus the linkage of depreciation to providing cash flow for repayment of loans taken by the Utility.

In this context, Clause 5 (c) of the Tariff Policy stipulates:

> *"**The Central Commission may notify the rates of depreciation in respect of generation and transmission assets**. The depreciation rates so notified would also be applicable for distribution with appropriate modification as may be evolved by the Forum of Regulators.*

The rates of depreciation so notified would be applicable for the purpose of tariffs as well as accounting.

There should be no need for any advance against depreciation.

Benefit of reduced tariff after the assets have been fully depreciated should remain available to the consumers. " ***(emphasis added)***

The GERC Tariff Regulations has stipulated the straight line method for determination of Depreciation expenses for the Generation, Transmission, Distribution Wire, and Retail Supply business, and a residual value of 10%, and provides for Advance against Depreciation (AAD) in case the cumulative loan repayment exceeds the cumulative depreciation.

In this context, CERC in its Statement of Objects and Reasons of CERC Tariff Regulations, 2009, has stated as under:

"16.14 Accordingly, the Commission feels that the loan repayment period be treated as 12 years for all normative loans and accordingly this repayment period of 12 years be linked to depreciation. For 12 years during which the loan capital would be refunded to the investors in the form of depreciation, the rate of depreciation shall be as specified in appendix-III of the regulation and thereafter the remaining depreciable value shall be spread over the balance useful life of the assets.

...

16.16 It has been the practice since 1948 to specify rates of depreciation for various assets used in electricity business separately either by Government of India or the Commission. So, in order to bring an uniformity in the rates of depreciation, while providing a higher rates of depreciation during the initial years of useful life of the projects, the Commission decides to specify rates of depreciation for various assets in a separate schedule. ***The depreciation rates for different assets have been so assigned as to arrive at the weighted average rate approximating*** **5.28%***. The depreciation rates as given in Appendix-III of the regulation have no bearing on the useful life of the projects as defined in regulation 3(42).*

16.17 During hearing some of the developers like NHDC, SJVNL, THDC indicated that the land which gets submerged and used for reservoir are not capable of being reclaimed or retrieved and hence cost of such land should be treated as depreciable asset. Normally land is considered to be a non-depreciable asset for accounting purposes. However, due to the peculiar nature of hydro project where the land area gets submerged and land used for

> *reservoir are not available for any other use, the Commission considered the request to be genuine and accordingly decided that land other than the land held under lease and the land for reservoir in case of hydro generating stations shall not be a depreciable asset and its cost shall be excluded from the capital cost while computing the depreciable value of the assets."(**emphasis added**)*

The CERC (Terms and Conditions of Tariff) Regulations, 2009, has stipulated that the depreciation rates for different assets have been so assigned as to arrive at the weighted average rate approximating 5.28%. However, the remaining depreciable value of an asset as on 31st March of the year closing after a period of 12 years from date of commercial operation shall be spread over the balance useful life of that asset.

The Tariff Policy stipulates that the depreciation rates specified by the CERC should be adopted for generation and transmission business, and may be adopted for the distribution business also, after suitable modification to be undertaken by the Forum of Regulators. The Tariff Policy also states that the same rate of depreciation should be considered for tariff purposes as well as accounting purposes and that there should be no need of providing Advance Against Depreciation (AAD) while determining the tariff. CERC Tariff Regulations have also removed the provision of AAD. **Hence, it is proposed to discontinue the allowance of AAD.**

It is proposed to adopt the CERC specified asset life, philosophy of linking depreciation with repayment of loan, and depreciation rates specified in CERC Tariff Regulations, 2009.

It needs to be emphasized that scheme-wise tracking of capital expenditure, capitalisation, financing pattern, repayment obligations and depreciation expenses, needs to be done, for generation, transmission, distribution wire, and retail supply business. Also, depreciation may be charged from the first year of commercial operation. It is proposed to charge depreciation only on the average of opening and closing Gross Fixed Assets of the year, since it may not be feasible for the Commission to validate the exact date of capitalisation of the asset, in case of operation of the asset for part of the year.

However, depreciation will be re-calculated during truing-up exercise, based on documentary evidence of asset capitalised by the Applicant, subject to the prudence check of the Commission, such that the depreciation is calculated proportionately from the date of capitalisation.

3.8 Interest on Working Capital (IWC)

The issues to be addressed as regards treatment of IWC are:

(i) Whether IWC should be allowed on normative basis or on actuals?

(ii) Whether working capital should be computed by taking into account both current assets and current liabilities, as being done presently?

(iii) Whether amount and stock of fuel oil/O&M expenses/maintenance spares/receivables specified in the existing Regulations should continue or, any change is required?

(iv) Whether maintenance spares should form a part of the working capital along with O&M expenses in the existing methodology?

The above-mentioned issues and the merits and demerits of the options have been discussed below.

Currently, IWC is being allowed on a normative basis rather than actuals. Since IWC is treated as a controllable factor, IWC would have to continue to be allowed on normative basis. If IWC is allowed on actuals, it will amount to considering IWC as an uncontrollable factor. Since it is desired to improve the operational and financing efficiency in this aspect, **it is desirable to continue allowing IWC on normative basis**.

It may be noted that in case of integrated Utilities, the issue of assessment of receivables and payables needs to be addressed. Also, it is necessary to ensure that there is no double accounting of the same, as the receivables of the Generating Business (revenue from sale to the Distribution Business) would form part of the power purchase expenses of the Distribution Business Hence, it is necessary to clarify that receivables and payables pertaining to 'Own Generation' will not be allowed.

The Commission, in its Tariff Order in the matter of "Annual Performance Review for FY 2008-09 & Aggregate Revenue Requirement for FY 2009-10 for Torrent Power Limited" dated December 9, 2009, ruled that merger of all the entities under one common legal entity was expected to bring in economies and bring down common costs like working capital, since a Company cannot have receivables from itself. As the Commission has allowed the generation business to claim receivables, the Commission expressed the view that the normative working capital of the distribution business should be computed after deducting the component of receivables of the generation business. In this regard the Commission has taken note of the fact that the entire generation of TPL is consumed within its own licensed area; so there could be no scenario for receivables from third party.

In case of integrated Utility, it is proposed that receivables pertaining to own generation shall be deducted from the receivables of the Distribution Business, while computing the working capital requirement for distribution business.

The experience in Gujarat shows that the normative IWC computed in accordance with the GERC Tariff Regulations, works out to be very high as compared to the actual IWC expense incurred by the Utility, for generation, transmission and distribution business. Hence, **there is a need to revise the norms considered for computing the working capital requirement for generation, transmission, distribution wire, and retail supply businesses, such that the normative levels reflect the actual working capital requirement more closely**, and do not result in unnecessarily increasing the expenses and hence, tariff charged to the consumers. Further, due to the increase in number of payment modes, including electronic billing and payment, the requirement of providing for two months receivables is also reduced. Also, majority of consumers are billed on monthly basis. In case of gas stations, the gas is delivered through pipelines and is not stored.

The monthly coal reports published by Central Electricity Authority (CEA) shows that the thermal generating stations are maintaining coal stock of around 10 days and are not maintaining the coal stock as specified in Regulations, which is as high as two months, for non pit head power plants. Hence, there is no need to provide for two months coal stock.

The security deposit is a current liability and has to be deducted from the current assets, for computing the working capital requirement. Hence, for calculating Working capital, suitable adjustment for security deposit has been proposed.

It is also observed that current Tariff Regulations do not provide for deduction of the One month equivalent of cost of power purchased from the Working Capital Requirement, for a Distribution Licensee. However, Distribution Licensee generally gets credit for at least a month from the generators. Hence, it is proposed to incorporate suitable modification in the Tariff Regulations.

The proposed norms for computation of working capital, after incorporating the above suggestions for generation, transmission, and distribution business, are given below:

Working capital (for Generating Stations)

The Working capital shall cover:

a) **In case of coal based/oil-based/lignite-fired generating stations, working capital shall cover:**

   (i) Cost of coal or lignite for one (1) month for pit-head generating stations and one and a half (1½) months for non-pit-head generating stations, corresponding to target availability; plus

   (ii) Cost of oil for one (1) month corresponding to target availability; plus

   (iii) Cost of secondary fuel oil for two (2) months corresponding to target availability; plus

   (iv) Operation and Maintenance expenses for one (1) month; plus

   (v) Maintenance spares at one (1) per cent of the historical cost escalated at 6% from the date of commercial operation; plus

   (vi) Receivables for sale of electricity equivalent to two (2) months of the sum of annual fixed charges and energy charges calculated on target availability:

   Provided that in case of own generating stations, no amount shall be allowed towards receivables, to the extent of supply of power by the Generation Business to the Retail Supply Business, in the computation of working capital in accordance with these Regulations; minus

   (vii) Payables for fuel (including oil and secondary fuel oil) to the extent of one (1) month of the cost of fuel calculated on target availability.

b) **In case of Gas Turbine/Combined Cycle generating stations, working capital shall cover:**

(i) Fuel cost for one (1) month corresponding to target availability factor, duly taking into account the mode of operation of the generating station on gas fuel and /or liquid fuel; plus

(ii) Liquid fuel stock for fifteen (15) days corresponding to target availability; plus

(iii) Operation and maintenance expenses for one (1) month; plus

(iv) Maintenance spares at one (1) per cent of the historical cost escalated at 6% from the date of commercial operation; plus

(v) Receivables equivalent to two (2) months of capacity charge and energy charge for sale of electricity equivalent calculated on normative plant availability factor, duly taking in to account mode of operation of the generating station on gas fuel and liquid fuel:

Provided that in case of own generating stations, no amount shall be allowed towards receivables, to the extent of supply of power by the Generation Business to the Retail Supply Business, in the computation of working capital in accordance with these Regulations;

minus

(vi) Payables for fuel (including liquid fuel stock) to the extent of one (1) month of the cost of fuel calculated on target availability.

c) In case of hydro power generating stations, working capital shall cover:

(i) Operation and maintenance expenses for one (1) month;

(ii) Maintenance spares at one (1) per cent of the historical cost escalated at 6% from the date of commercial operation; and

(iii) Receivables equivalent to one and half months of fixed cost:

Provided that in case of own generating stations, no amount shall be allowed towards receivables, to the extent of supply of power by the Generation Business to the Retail Supply Business, in the computation of working capital in accordance with these Regulations.

Interest on working capital shall be allowed at a rate equal to the State Bank Advance Rate (SBAR) as on 1st April of the financial year in which the Petition is filed.

d) Transmission:

1. The Transmission Licensee shall be allowed interest on the estimated level of working capital for the financial year, computed as follows:

   (i) Operation and maintenance expenses for one month; plus

   (ii) Maintenance spares at one (1) per cent of the historical cost escalated at 6% from the date of commercial operation; plus

   (iii) Receivables equivalent to two months of transmission charges calculated on target availability level; minus

   (iv) Amount, if any, held as security deposits from Transmission System Users.

2. Interest shall be allowed on the amount held as security deposit from Transmission System Users at the Bank Rate as at the date on which the application for determination of tariff is made.

e) Distribution Wires Business

1. The Distribution Licensee shall be allowed interest on the estimated level of working capital for the Distribution Wires Business for the financial year, computed as follows:

   (i) Operation and maintenance expenses for one month; plus

   (ii) Maintenance spares at one (1) per cent of the historical cost escalated at 6% from the date of commercial operation; plus

   (iii) Receivables equivalent to two (2) months of the expected revenue from charges for use of Distribution Wires at the prevailing tariffs; minus

   (iv) Amount, if any, held as security deposits under clause (b) of sub-section (1) of Section 47 of the Act from Distribution System Users except the security deposits held in the form of Bank Guarantees.

f) Retail Supply of Electricity

1. The Distribution Licensee shall be allowed interest on the estimated level of working capital for the financial year, computed as follows:

   (i) Operation and maintenance expenses for one month; plus

   (ii) Maintenance spares at one (1) per cent of the historical cost escalated at 6% from the date of commercial operation; plus

(iii) Receivables equivalent to two (2) months of the expected revenue from sale of electricity at the prevailing tariffs; minus

(iv) Amount held as security deposits under clause (a) and clause (b) of sub-section (1) of Section 47 of the Act from consumers except the security deposits held in the form of Bank Guarantees; minus

(v) One month equivalent of cost of power purchased, based on the annual power procurement plan:

Provided that in case of power procurement from own generating stations, no amount shall be allowed towards payables, to the extent of supply of power by the Generation Business to the Retail Supply Business, in the computation of working capital in accordance with these Regulations.

(a) Interest shall be allowed on the amount held as security deposit held in cash from Distribution System Users at the Bank Rate as on 1stApril of the financial year in which the Petition is filed.

It is proposed that the interest shall be allowed at a rate equal to the State Bank Advance Rate (SBAR) as on 1stApril of the financial year in which the Petition is filed.

3.9 Treatment of Contributions/Donations

It is proposed that expenses incurred by distribution licensees or Utilities towards contributions/donations would not be considered while determining the A&G expenses, as social initiatives undertaken by Utilities are primarily driven by social responsibility and an urge to serve the society. Cost associated towards social causes and other corporate responsibility shall be funded by profits of that Utility, and shall not be reimbursed by consumers.

4 Norms and Principles for Determination of Generation Tariff

This Chapter deals with the issues related to the tariff applicable for Generating Companies supplying power to the Distribution Licensees from conventional generation projects in the State of Gujarat.

The Gujarat State Electricity Generation Company Limited (GSECL) and Torrent Power Limited - Generation Business (TPL-G) are the Generating Companies in the State of Gujarat, who own and operate Coal thermal, Gas and Hydel based generating assets in the State of Gujarat and supply power to Distribution Licensees on a long-term basis. The brief summary of generating stations of GSECL and TPL-G is given in the following Tables:

Table: Generating Stations of GSECL

Station Name	Stage	Installed Capacity (MW)	Units (No. x Cap.MW)	Year of Commissioning
Ukai TPS	I	870	2x120	1976
	II		2x210	1979
	III		1x210	1985
Gandhinagar TPS	I	870	2x120	1977
	II		2x210	1990-91
	III		1x210	1998
Wanakbori TPS	I	1470	3x210	1982-84
	II		3x210	1986-87
	III		1x210	1998
Sikka TPS	I	240	1x120	1988
	II		1x120	1993
Kutch Lignite	I	290	2x70	1990-91
	II		1x75	1997
	III		1x75	2009
Dhuvaran Oil Based TPS	I	220	2x110	1972
Dhuvaran CCPP-1		106.6	1x67.85 + 1x38.77	2004
Dhuvaran CCPP-2		112.45	1x72.51 + 1x39.94	2007
Utran CCPP		135	3x30 (GT) + 1x45(ST)	1992-93
Utran CCPP Extn		375	375	2009
Ukai Hydro		300	4x75	1974-75
Ukai LBC Hydro		5	2x2.5	1987-88
Kadana Hydro		240	4x60	1990-1998
Panam Canal mini Hydro		2	2x1	1994
Total		**5216.05**		

Table: Generating Stations of TPL- G

Station Name	Installed Capacity (MW)	Units (No. x Cap.MW)	Year of Commissioning
Sabarmati 'C'	60	2x30	1997
Sabarmati 'D'	120	1x120	1978/2004
Sabarmati 'E'	110	1x110	1984
Sabarmati 'F'	110	1x110	1988
Vatva CCPP	100	2x32.5 (GT) + 1x35 (ST)	1991
Total	**500**		

This Chapter of the Study Report deals with the issues related to determination of tariff for conventional generation projects.

It may be noted that the Commission may modify the norms specified in these Regulations, if the Commission has issued an Order based on suitable justification provided by the Generating Company in its Petition to amend the norms specified in these Regulations.

4.1 *Thermal Generating Stations*

4.1.1 Capital Cost and Means of Finance

As per the existing practice, the Commission has been approving the capital cost for new generation projects as a part of Tariff Determination process. GSECL is implementing new projects to bridge the demand-supply gap and to meet the increasing electricity demand. Determining the normative per MW capital expenditure would be a complex issue as the Commission, in the next Control Period, has to decide tariff for existing projects and new projects. For new projects being developed under the competitive bidding route, the Commission will have to adopt the tariff quoted by the successful bidder, subject to the Competitive Bidding Guidelines being followed by the Procurer.

Currently, as per Regulation 16 of the GERC Tariff Regulations, 2005, the Commission accords the final approval for tariff after commissioning of the project based on actual capital expenditure incurred up to the date of commercial operation of the generating station, duly audited and certified by the statutory auditors, subject to prudence check.

The Capital Cost of the project thus determined also includes capitalised initial spares subject to ceiling norms as percentage of original cost for the coal-based/lignite fired, gas turbine/combined cycle and hydro power generating stations.

The Tariff Policy notified by the Government of India stipulates that all future requirement of power should be procured competitively by Distribution Licensees except in cases of expansion of existing projects or where there is a State controlled/owned Company as an identified developer and in such cases, the Regulatory Commissions will have to resort to tariff determination based on norms. Further, expansion of generating capacity by private developers up to one-time addition of not more than 50% of the existing capacity also qualifies under the normative tariff determination approach. Even for Public Sector Generating Companies, the Tariff Policy provides that tariff of all new generation projects should be decided on the basis of competitive bidding after a period of five years or when the Regulatory Commission is satisfied that the situation is ripe to introduce such competition.

Under these circumstances, the scope for approving the Capital Cost and Means of Finance will be limited, as the Distribution Licensees will have to gradually move towards procurement of power only on competitive bidding basis. However, till such time the entire power requirement is procured competitively, the Commission may have to approve the Capital Cost and Means of Finance for following types of Projects:

- Expansion Project of Generating Companies
- Renovation and Modernisation Project of Generating Companies

The present methodology of final approval of capital cost based on actual capital expenditure is proposed to be continued.

In case of hydro generating stations being awarded to a developer (not being a State controlled or owned Company), CERC Tariff Regulations, 2009 has specified as under:

> *"Provided also that in case the site of a hydro generating station is awarded to a developer (not being a State controlled or owned company), by a State Government by following a two stage transparent process of bidding, any expenditure incurred or committed to be incurred by the project developer for getting the project site allotted shall not be included in the capital cost:*

Provided also that the capital cost in case of such hydro generating station shall include:
(a) cost of approved rehabilitation and resettlement (R&R) plan of the project in conformity with National R&R Policy and R&R package as approved; and
(b) cost of the developer's 10% contribution towards Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) project in the affected area:"

It is appropriate that any costs incurred by the Project Developer for getting the Project, including costs incurred for bidding purposes, cannot be considered as part of Project cost, as the Developer has to absorb such cost if he does not win the Project. Further, the premium payable to the State Government for getting the Project also cannot be considered as part of Project Cost, as consideration of the same may result in the Developers quoting very high premium to win the Project, which will increase the overall cost of generation of such projects. Accordingly, it is proposed to consider the above provisions as per CERC Tariff Regulations, 2009 in case of hydro generating station being awarded to a developer (not being a State controlled or owned company).

4.1.2 Renovation and Modernisation

As regards Renovation and Modernisation, the National Electricity Policy of Government of India provides as follows:

"5.2.21 – One of the major achievements of power sector has been significant increase in availability and plant load factor of thermal power stations specially over the last few years. Renovation and modernisation for achieving high efficiency levels needs to be pursued vigorously and all existing generation capacity should be brought to minimum acceptable standards. The Govt. of India is providing financial support for this purpose.

5.2.22 For projects performing below acceptable standards, R&M should be undertaken as per well defined plans featuring necessary cost - benefit analysis. If economic operation does not appear feasible through R&M, then there may be no alternative to closure of such plants as the last resort.

5.2.23 In cases of plants with poor O&M record and persisting operational problems, alternative strategies including change of management may need to be considered so as to improve the efficiency to acceptable levels of these power stations."

Para 5 (g) of the Tariff Policy notified by the Government of India stipulates as under:

> *"Renovation and modernization (it shall not include periodic overhauls) for higher efficiency levels needs to be encouraged. A multi year tariff (MYT) framework may be prescribed which should also cover capital investments necessary for renovation and modernisation and an incentive framework to share the benefits of efficiency improvement between the utilities and the beneficiaries with reference to revised and specific performance norms to be fixed by appropriate Commission. Appropriate capital costs required for pre-determined efficiency gains and/or for sustenance of high level performance would need to be assessed by appropriate Commission."*

The expected or rated 'useful' life of power plants has historically been considered as 25 years for Thermal Generating Stations, 35 years for Hydel Generating Stations, and 15 years for Gas Turbine based Generation Stations. For the purpose of tariff, this denotes the period over which 90% of the capital cost is allowed to be recovered through depreciation. Among the power plants, tariff determination of which is in the Commission's jurisdiction, all the Units of Dhuvaran Oil based Thermal Power Station (TPS) owned by GSECL have already outlived their initial rated 'useful' life.

Further, many Units of the power stations owned by GSECL are in operation for more than 25 years. In view of this, it has been felt necessary to lay down the principles regarding R&M beyond the original useful life.

As the plant approaches the end of its specified rated 'useful' life, the outages may increase due to wear and tear, and the plants may require increased maintenance and spares. Besides the reduction in plant availability, its energy conversion efficiency, i.e., station heat rate, may also deteriorate. However, the status does not suddenly change in any way on the day the plant completes its rated 'useful' life. The plant continues to operate, and the gradual changes mentioned earlier also continue. At the end of 'useful' life of the plant, following three options are available with the Generating Company:

- (i) Keep the plant in operation at deteriorated efficiency, availability and reliability with increasing O&M cost and with risk of catastrophic failure;
- (ii) Scrap the plant and replace it with a new plant;
- (iii) Extend its beneficial life through a planned one-time Renovation and Modernisation.

Renovation and Modernisation plan with definite life extension is a major exercise requiring detailed planning. Even the costs involved undergo change to some extent when the actual works are undertaken. For a poorly maintained plant, Renovation and Modernisation results in better efficiency and performance. On the other hand, in case of an well maintained old plant, just enhanced repair and maintenance may be adequate to maintain the performance and efficiency.

The decision for Renovation & Modernisation (R&M) has to be primarily based on comprehensive techno-economic considerations, after carrying out the required Residual Life Assessment (RLA) study and cost-benefit analysis. The Generating Company is, therefore, required to come up with a detailed proposal for in-principle approval with estimation of R&M expenditure along with cost benefit analysis and definite extended life from a reference date and if in-principle approval is granted, the Commission may allow the prudently incurred Renovation and Modernisation expenditure to be included in the capital cost for the purpose of tariff during extended life.

While it is important that the plant owner is duly compensated for any fresh investment and risks, it is equally important that the consumers pay according to the benefits derived from the plant in future years.

The Central Electricity Regulatory Commission (CERC) has addressed the issue of Renovation and Modernisation vide Regulation 10 of CERC (Terms and Conditions of Tariff) Regulations, 2009.

As regards Renovation & Modernisation expenses, Regulation 17 of GERC Tariff Regulations specifies as under:

> *"Any expenditure on replacement, renovation and modernization or extension of life of old fixed assets shall be serviced on normative debt-equity ratio specified in regulation 19 after writing off the original amount from the original project cost if any replacement of existing assets are involved:*

It is also proposed that any expenditure on replacement, renovation and modernization or extension of life of old fixed assets, as applicable to Generating Companies and Licensees, shall be considered after writing off the net value of such replaced assets from the original capital cost. Further, the corresponding equity component and Consumer

Contribution, if any, of the replaced asset, should also be reduced from the opening equity, so that the Utility does not continue to earn RoE on equity for an asset that is no longer in service.

It is suggested that the following two options may be provided to the Generating Companies for Renovation & Modernisation of the Generating Units/Stations:

Option-1

The Generating Company, for meeting the expenditure on Renovation & Modernisation for extending the useful life of the generating station or a unit thereof, shall make an application before the Commission for approval of the proposal with a Detailed Project Report giving complete scope, justification, cost-benefit analysis, estimated life extension from a reference date, proposed means of finance, phasing of expenditure, schedule of completion, reference price level, estimated completion cost including foreign exchange component, if any, record of consultation with beneficiaries and any other information considered to be relevant by the Generating Company.

Option-2

The Generating Company can avail a 'special allowance' as compensation for meeting the requirement of expenses including Renovation & Modernisation beyond the useful life of the generating station or a Unit thereof, and in such an event, approval of the capital cost shall not be considered and the operational norms shall not be relaxed but the special allowance shall be included in the annual fixed charges. In this option, the Generating Companies, in case of thermal generating stations, may be allowed special allowance of Rs. 5 Lakh/MW/year in FY 2011-12 and thereafter, escalated @ 5.72% every year during the next Control Period from FY 2011-12 to FY 2015-16, on the similar lines as specified by CERC, so that the plant owner remains incentivised to maintain the Unit/Stations availability at a good level after its useful life.

4.1.3 Components of Tariff

The tariff determined by the Commission is the prime source of revenue for a Generating Company and hence, the mechanism of cost recovery needs to be designed to ensure cost recovery at normative levels prescribed by the Commission.

Typically, the tariff for thermal generating stations has two components, i.e., fixed (capacity) charge and variable charge. The variable charge component is intended to cover the fuel costs for the primary and secondary fuel consumption at normative parameters.

The CERC Tariff Regulations, 2009 has stipulated the following elements as a part of the Annual Fixed Cost:

(a) Return on equity;
(b) Interest on loan capital;
(c) Depreciation;
(d) Interest on working capital;
(e) Operation and maintenance expenses;
(f) Cost of secondary fuel oil (for coal-based and lignite fired generating stations only);
(g) Special allowance in lieu of Renovation & Modernisation or separate compensation allowance, wherever applicable.

It may be observed from the above that apart from other elements of annual fixed cost, CERC has also considered cost of secondary fuel oil as a part of the fixed cost. However, since the consumption of the secondary fuel oil is linked with generation and the norm of secondary fuel oil is also specified in terms of per unit of generation, it is suggested that the secondary fuel oil consumption may not be included as a part of the fixed cost and may be considered as a part of the variable cost as per the existing practice in Gujarat.

It is suggested that the fixed charge (capacity charge) shall comprise of the following elements:

a) Depreciation
b) O&M Expenses
c) Return on Equity
d) Interest Expenses
e) Interest on Working Capital
f) Special allowance in lieu of Renovation & Modernisation or separate compensation allowance, wherever applicable.

   Less:

g) Non-tariff income

Income tax, as discussed in earlier section, will be reimbursed based on actuals, on submission of documentary proof for the same, subject to prudence check of the Commission and will not form part of the ARR.

It may also be noted that Non-tariff Income is proposed to be deducted from the ARR for determination of Fixed Charges. Any income earned by Generating Company can be categorised as income from the assets or activities, for which all the expenses have been allowed to be recovered from the tariffs. Since all the legitimate costs are allowed to be recovered through tariffs, it is important that the income earned by Generating Companies other than income from sale of power should be considered and adjusted from Fixed (Capacity) charges as otherwise it will lead to additional profit to Generating Company in excess of permissible return. This issue is discussed in detail later in this section.

4.1.4 Fixed Cost Recovery

The two alternative mechanisms that can be adopted for recovery of full fixed cost are as follows:

- Fixed Cost Recovery linked to Plant availability
- Fixed Cost Recovery linked to Plant Load Factor or Actual Generation

Fixed cost recovery linked to plant availability is a tested method, which has been widely adopted by CERC (in both the earlier Tariff Regulations) as well as other SERCs. In this regard, GERC Tariff Regulations stipulates target availability of 80% for recovery of full fixed cost for all thermal stations. Regulation 15(i) of the existing GERC Tariff Regulations stipulating fixed charge recovery linked to plant availability factor is reproduced below:

> ***"(i)Target Availability for recovery of full Capacity (Fixed) charges***
>
> *(a) All thermal power generating stations, 80%*
>
> ***Note***
>
> *Recovery of capacity (fixed) charges below the level of target availability shall be on pro rata basis. At zero availability, no capacity charges shall be payable.*
>
> *Further, where existing PPAs (including any changes, in the norms or parameters, made in the PPA following renegotiation between the Board and concerned generating company) lay down a different parameter like PLF for the recovery of the full fixed*

charges, such a parameter shall continue to govern the parties for the term of the contract, but not for any renewal of the contract or any extension of the term of the contract in accordance with its terms. Upon the expiry of the term of the existing PPA (including any changes, in the norms or parameters, made in the PPA following renegotiation between the Board and concerned generating company), the parties shall be governed by the terms of the Regulations for the time being in force."

While computing the Availability, the actual ability of the Station/Unit to generate should be considered after taking into consideration the loadability of machines and fuel related aspects, rather than considering plant availability on the basis of machine availability, which considers only the readiness of machine/equipments for generating electricity but in reality, the plant may not be available due to inter-alia, lack of fuel or loadability issues. Normally, in case of supply shortage scenario, the PLF should be almost equivalent to plant availability, since the plants would not be backed down and would be utilised fully when available. In the existing GERC Tariff Regulations, Availability has been defined as actual availability after taking into account the availability of fuel. In view of the above, it is proposed that the Definition of Availability may be continued as defined in existing Regulations as follows:

"…

*'**Availability**' in relation to a thermal generating station for any period means the average of the daily average declared capacities for all the days during that period expressed as a percentage of the installed capacity of the generating station minus normative auxiliary consumption in MW, as specified in the Regulations, and shall be computed in accordance with the following formula …"*

*'**Declared Capacity**' or DC means the capability of the generating station to deliver ex-bus electricity in MW declared by such generating station in relation to any period of the day or whole of the day, duly taking into account the availability of fuel;"*

However, in case the Generating Company has made adequate arrangements for procurement of fuel and if there is reduction in supply of fuel due to shortage of fuel, for instance, in case of actual gas supply lower than the gas linkage, the reduction in availability due to shortage of fuel needs to be appropriately considered for allowing fixed cost recovery, provided the generating company is able to substantiate with documentary proof and other details as may be required by the Commission for ascertaining that such reduction in fuel supply due to industry-wide shortage is an uncontrollable factor for the Generating Company.

The Plant Availability is linked to the vintage and the technology of the Plant. As the Plant becomes older, the time taken for overhaul of the Plant increases and the Availability of the Generating Station/Unit reduces. CERC Tariff Regulations, 2009, has specified lower availability norm for some Units of Neyveli Lignite Corporation [TPS-I (72%) and TPS-II, Stage I & II (75%)] and for some of the stations of Damodar Valley Corporation (DVC) [Durgapur TPS (74%), Bokaro TPS (75%), Chandrapura TPS (60%)] while for other Generating Stations, CERC has specified the Availability norm of 85% for thermal generating stations, as compared to the earlier norm of 80%.

GERC has also approved lower Availability Factor for older Generating Stations of GSECL, in the MYT Order for Control Period FY 2008-09 to FY 2010-11, dated January 17, 2009, by considering the vintage effect as under:

Table: Target Availability approved by GERC for Older generating stations.

Availability Factor (%)			
Station Name	**2008-09**	**2009-10**	**2010-11**
Ukai TPS	72	74	74
Gandhinagar 1-4	65	70	80
Sikka TPS	75	75	75
KTPS 1-3	72	75	78

(Source: MYT Order for GSECL, Dated January 17, 2009, Page no.31)

TPL has filed Appeal before Appellate Tribunal for Electricity (APTEL) (Appeal No 996/2009) in the matter of target Availability for recovery of fixed charges approved by the Commission being higher than that specified in the GERC Tariff Regulations, 2005. TPL contended that the Commission has misconstrued the Statutory Regulations resulting in non-consideration of Actual PAF and PLF for generating stations.

The normative Plant Availability approach ensures that the Generating Company is able to recover its fixed cost, if the plant is available for generation. It is beneficial for those plants whose variable cost is high and their generation may be curtailed under merit order despatch principles. In principle, fixed cost recovery should not be linked to generation, and only variable cost recovery should be linked to the generation.

CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009 has stipulated the following principles for recovery of fixed charge including the incentive component:

"(a) Generating stations in commercial operation for less than ten (10) years on 1st April of the financial year :
AFC x (NDM / NDY) x (0.5 + 0.5 x PAFM / NAPAF) (in Rupees);

Provided that in case the plant availability factor achieved during a financial year (PAFY) is less than 70%, the total capacity charge for the year shall be restricted to

AFC x (0.5 + 35 / NAPAF) x (PAFY / 70) (in Rupees).

(b) For generating stations in commercial operation for ten (10) years or more on 1st April of the financial year:

AFC x (NDM / NDY) x (PAFM / NAPAF) (in Rupees).
Where,
AFC = Annual fixed cost specified for the year, in Rupees.
NAPAF = Normative annual plant availability factor in percentage
NDM = Number of days in the month
NDY = Number of days in the year
PAFM = Plant availability factor achieved during the month, in percent:
PAFY = Plant availability factor achieved during the year, in percent"

At this stage, it is proposed to continue the existing practice of fixed cost recovery based on the normative plant availability. Accordingly, full fixed charge recovery should be allowed at normative plant availability specified by the Commission. Recovery of fixed charges below the normative target availability should be on pro-rata basis and accordingly at zero availability, no recovery of fixed charges should be allowed.

As regards the normative availability for full recovery of fixed charges, it is proposed that for generating stations to be commissioned after notification of the GERC MYT Regulations, 2010, the normative availability for recovery of fixed costs may be specified as 85%, as specified by CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009.

As regards the Normative Availability for recovery of fixed charges of generating Units/Stations, it is proposed to formulate targets based on CEA recommendations. CEA, in its Study Report, has made the following recommendations in this regard:

"3.5.2 Following is stated in this regard:

a. As per CERC tariff regulation for 2009-14, normative Plant Availability Factor for coal & gas based thermal generating stations has been prescribed as 85% whereas for lignite based stations based upon CFBC technology, availability factor has been prescribed as 75% for first three years after COD and 80% thereafter. For some stations lower availability factor has been prescribed based on site specific constraints. GERC in its tariff regulations (Notification No. 12 of 2005) have stipulated availability factor of 80 % for recovery of full charges.

b. It is seen from Table-14 that normative value of availability factor in some cases is far above the value prescribed in GERC regulations. It is suggested that GERC may limit the maximum value to 85 % availability except where PPA provision have stipulated higher value.

c. It is seen that for some stations value lower than 85% have been specified based on site specific constraints & Projected R&M Program.

d. Regarding PLF values prescribed in GERC order, it is felt that since PLF does not have any bearing on tariff, it is not necessary to stipulate these values."

Accordingly, it is suggested that the target availability for GSECL and TPL's stations may be specified based on the CEA recommendations as given in following Table:

Table: CEA recommended Target Availability for GSECL & TPL generating stations.

Station Name	Stage	Units (No.x Cap.MW)	Target Availability (%)
GSECL Stations			
Ukai TPS	I	2x120	74
	II	2x210	74
	III	1x210	74
Gandhinagar TPS	I	2x120	80
	II	2x210	80
	III	1x210	85
Wanakbori TPS	I	3x210	85
	II	3x210	85
	III	1x210	85
Sikka TPS	I	1x120	75
	II	1x120	75
Kutch Lignite	I	2x70	78
	II	1x75	78
	III	1x75	75

Station Name	Stage	Units (No.x Cap.MW)	Target Availability (%)
Dhuvaran Oil	I	2x110	80
Dhuvaran CCPP-1		1x106.6	85
Dhuvaran CCPP-2		112.45	85
Utran CCPP		3x30 (GT) + 1x45 (ST)	85
Utran CCPP Extn		375	85
TPL Stations			
Sabarmati 'C'		2x30	85
Sabarmati 'D'		1x120	85
Sabarmati 'E'		1x110	85
Sabarmati 'F'		1x110	85
Vatva CCPP		2x32.5 (GT) + 1x35 (ST)	85

(Source: CEA Study report – Recommendation to GERC on operation norms for TPS in Gujarat)

Further, as regards incentive, it is proposed to provide incentive linked to actual generation as discussed later in this Chapter.

4.1.5 Norms of Operation

Apart from Target Availability for recovery of Fixed Costs, the other Performance norms to be specified for a thermal generating station are:

- **Station Heat Rate**
- **Auxiliary Power Consumption**
- **Secondary Fuel Consumption**
- **Transit Losses**

It is proposed to formulate operational norms for existing Stations, based on the findings of the CEA Study for Performance norms for a thermal generating station.

4.1.6 Norms for New Generating Unit/Stations to be commissioned after the date of effectiveness of the new GERC (Terms and Conditions of Multi-Year Tariff) Regulations, 2010

4.1.6.1 Relaxed Norm during Stabilisation Period

The existing GERC Tariff Regulations stipulate separate norms for some of the operational parameters of the thermal generating stations such as Station Heat Rate, Auxiliary Consumption and Secondary Fuel Oil Consumption, during stabilization period. However, CERC in its third Amendment to Tariff Regulations, viz., CERC (Terms and Conditions of Tariff) (Third Amendment) Regulations, 2007, has amended this provision and specified that

> *"The stabilization period and relaxed norms applicable during stabilization period shall cease to apply from April 1, 2006".*

Further, CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009, has not stipulated any relaxed norm during the stabilisation period. In view of the above, it is proposed not to specify the stabilization period and relaxed norms during stabilization period for new thermal generating Unit/Stations to be commissioned after the date of effectiveness of the new GERC (Terms and Conditions of Multi-Year Tariff) Regulations, 2010 (GERC MYT Regulations, 2010).

4.1.6.2 Station Heat Rate

For new generating Units/Stations to be commissioned after the date of effectiveness of the GERC MYT Regulations, the Station Heat Rate norm is proposed in accordance with the norms specified by CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009, for various technologies and Unit sizes as well as considering the technological advances and improvement, with manufacturers' committing design heat rates stipulated as under:

a) Coal-based and lignite-fired Thermal Generating Stations

= 1.065 X Design Heat Rate (kcal/kWh)

Where the Design Heat Rate of a Unit means the Unit heat rate guaranteed by the supplier at conditions of 100% Maximum Continuous Rating (MCR), zero percent make up, design coal and design cooling water temperature/back pressure.

Provided that the design heat rate shall not exceed the following maximum design unit heat rates depending upon the pressure and temperature ratings of the Units:

Pressure Rating (kg/cm2)	150	170	170	247	247
SHT/RHT (^{0}C)	535/535	537/537	537/565	537/565	565/593
Type of BFP	Electrical Driven	Turbine driven	Turbine driven	Turbine driven	Turbine driven

Pressure Rating (kg/cm2)	150	170	170	247	247
Max Turbine Cycle Heat rate (kcal/kWh)	1955	1950	1935	1900	1850
Min. Boiler Efficiency					
Sub-Bituminous Indian Coal	0.85	0.85	0.85	0.85	0.85
Bituminous Imported Coal	0.89	0.89	0.89	0.89	0.89
Max Design Unit Heat rate (kcal/kWh)					
Sub-Bituminous Indian Coal	2300	2294	2276	2235	2176
Bituminous Imported Coal	2197	2191	2174	2135	2079

However, in case pressure and temperature parameters of a Unit are different from above ratings, the maximum design unit heat rate of the nearest class shall be taken:

Note:

For generating stations having combination of 200/210/250 MW sets and 500 MW and above sets, the normative gross station heat rate shall be the weighted average station heat rate.

b) Gas-based / Liquid-based thermal generating Unit(s)/block(s)

= 1.05 X Design Heat Rate of the unit/block for Natural Gas and RLNG (kcal/kWh)

= 1.071 X Design Heat Rate of the unit/block for Liquid Fuel (kcal/kWh)

Where the Design Heat Rate of a Unit shall mean the guaranteed heat rate for a Unit at 100% MCR and at site ambient conditions; and the Design Heat Rate of a block shall mean the guaranteed heat rate for a block at 100% MCR, site ambient conditions, zero percent make up, design cooling water temperature/back pressure.

4.1.6.3 Auxiliary Consumption

For new generating Unit/Stations to be commissioned after the date of effectiveness of the GERC MYT Regulations, the auxiliary consumption norm is proposed in accordance with the norms specified by CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009 for various technologies and Unit sizes as under:

(a) Coal-based generating stations:

Auxiliary consumption	With Natural Draft cooling tower or without cooling tower
(i) 200 MW series	8.5%
(ii) 500 MW & above	
Steam driven boiler feed pumps	6.0%
Electrically driven boiler feed pumps	8.5%

Provided further that for thermal generating stations with induced draft cooling towers, the norms shall be further increased by 0.5%.

(b) Gas Turbine/Combined Cycle generating stations:

(i) Combined cycle : 3.0%

(ii) Open cycle : 1.0%

(c) New lignite-fired thermal generating stations:

(i) All generating stations with below 200 MW sets: 12%;

(ii) All generating stations with 200 MW sets and above:

The auxiliary energy consumption norms shall be 0.5 percentage point more than the auxiliary energy consumption norms of coal based generating stations above. Provided that for the lignite fired stations using CFBC technology, the auxiliary energy consumption norms shall be 1.5 percentage point more than the auxiliary energy consumption norms of coal based generating stations at above.

4.1.6.4 Transit Loss

CERC Tariff Regulations, 2009, do not specifically exclude imported coal for allowing transit loss and zero transit loss as reported by some Generating Companies on imported coal could be on account of accounting system (wherein the losses are included in consumption) or contractual arrangement (delivery basis). It is also observed that procurement of coal on delivery basis amounts to inland sale and attract additional taxes. However, a detailed study for ascertaining the advantages and disadvantages of contracting imported coal on delivery basis, needs to be carried out separately and if such analysis indicate a lower cost of procurement, than all generating companies may be advised by the Commission to follow the same.

However, the concept of allowing transit loss separately is applicable particularly for procurement of domestic coal from Coal India Limited (CIL), as the CIL measures and charges for quantity of coal at the loading point. However, if the coal is being procured on delivery basis, no transit losses shall be applicable. Accordingly, it is suggested that in case of procurement of coal on delivery basis, no transit loss may be allowed and in cases where the coal is procured on the basis of measurement at loading point, normative transit loss may be allowed.

It is suggested that the transit loss norms for new generating Unit/Stations may be specified as per CERC (Terms and Conditions of Tariff) Regulations, 2009 as under:

Transit losses for coal based generating stations, as a percentage of quantity of coal dispatched by the coal supply company during the month shall be as given below:

i. Pit head generating stations : 0.2%
ii. Non-pit head generating stations : 0.8%

4.1.6.5 Secondary Fuel Oil Consumption

For new generating Unit/Stations to be commissioned after the date of effectiveness of the GERC MYT Regulations, the auxiliary consumption norm is proposed in accordance with the norms specified by CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009 as under:

(a) Coal-based generating stations : 1.0 ml/kWh
(b) Lignite-Fired generating stations except stations based on CFBC technology : 2.0 ml/kWh
(c) Lignite-Fired generating stations based on CFBC technology : 1.25 ml/kWh

4.1.7 Norms for Generating Unit/Stations commissioned/to be commissioned after the date of effectiveness of GERC Tariff Regulations, 2005 and before the date of effectiveness of new GERC MYT Regulations

There are only three generating Units, which have achieved commissioning after the effectiveness of GERC Tariff Regulations, 2005, i.e., Dhuvaran CCPP-2 of capacity 112.45

MW commissioned in FY 2006-07, Utran Extension of capacity 375 MW commissioned in FY 2008-09, and KLTPS-4 of capacity 75 MW commissioned in FY 2009-10.

CERC, in its CERC Tariff Regulations, 2009, has categorised the plants in two categories, i.e., plants commissioned before the effectiveness of said Regulations and plants to be commissioned after the effectiveness of the said Regulations. Hence, it is suggested that generating stations may be classified under two categories, viz., new Units/Stations commissioned and expected to be commissioned before the date of effectiveness of the GERC MYT Regulations, 2010, and Units/Stations commissioned after the date of effectiveness of the GERC MYT Regulations, 2010.

4.1.8 Norms for Existing Generating Unit/Stations – Existing before the date of effectiveness of GERC MYT Regulations, 2010.

As regards the performance parameters to be specified for the existing generating Unit/Stations of GSECL and TPL, the Commission, in its MYT Order for the first Control Period of 3 years from FY 2008-09 to FY 2010-11 specified the trajectory for various performance parameters based on past performance of the generating stations.

For assessment of actual and achievable performance parameters, the Commission appointed Central Electricity Authority (CEA) to carry out a detailed study of the various performance parameters. The CEA has completed its study and submitted its report to the Commission. It is proposed that for existing stations of GSECL and TPL, the norms may be approved based on the recommendations made by CEA in its Study Report.

4.1.8.1 Station Heat Rate

Heat rate is an indicator of power plant efficiency and depends on the vintage, generation capacity, and technology of the generating unit. In the existing GERC Tariff Regulations, 2005, the Commission has specified the norms for the Gross Station Heat Rate.

CERC, in its CERC (Terms and Conditions of Tariff) Regulations, 2009 has considered the technology, configuration, and operating level of different power plants and has accordingly fixed different heat rates for thermal and gas turbine/combined cycle power plants. The practice followed by CERC covers all the dimensions of a generating unit, which may have a bearing on the Station Heat Rate. The experience of many other SEBs/SERCs and the data available in this regard suggests that the various factors affecting the Heat Rate are vintage, size, past generating history, past maintenance practices, condition of plant, etc.

Clause 5.3(f) of the Tariff Policy stipulates:

> ***"Operating Norms***
>
> *Suitable performance norms of operations together with incentives and dis-incentives would need be evolved along with appropriate arrangement for sharing the gains of efficient operations with the consumers. Except for the cases referred to in para 5.3 (h)(2), the operating parameters in tariffs should be at "normative levels" only and not at "lower of normative and actuals". This is essential to encourage better operating performance. The norms should be efficient, relatable to past performance, capable of achievement and progressively reflecting increased efficiencies and may also take into consideration the latest technological advancements, fuel, vintage of equipments, nature of operations, level of service to be provided to consumers etc. Continued and proven inefficiency must be controlled and penalized.*
>
> *The Central Commission would, in consultation with the Central Electricity Authority, notify operating norms from time to time for generation and transmission. The SERC would adopt these norms. In cases where operations have been much below the norms for many previous years, the SERCs may fix relaxed norms suitably and draw a transition path over the time for achieving the norms notified by the Central Commission."*

CEA, in its Study Report, has suggested station heat rate for the existing stations based on its assessment and actual past performance of Generating Stations.

GSECL

The recommendations of CEA Study Report for the Operating Norms for existing generating stations of GSECL are reproduced as under:

Table: CEA recommended station heat rate for GSECL generating Stations.

Stations	Units (No.x Cap.MW)	Design Heat Rate (kcal/kWh)	CEA Recommendation	
			2010-11	Remarks
Ukai TPS	2x120	2411	2670#	# 2670 kcal/kWh (1.075x new design heat

Stations	Units (No.x Cap.MW)	Design Heat Rate (kcal/kWh)	CEA Recommendation	
			2010-11	Remarks
				rate) after stabilization of Unit # 1 which has recently undergone R&M. Unit#2 has undergone shutdown for R&M. For unit#2 '1.075xnew design heat rate ' after R&M.
	2x210	2404	2650	To reduce to 2600 kcal/kWh in 2011-12 and further to 2500 kcal/kWh after capital overhaul
	1x210	2373	2650	
Gandhinagar TPS@	2x120	2382	2800#	#1.075 x new design heat rate ' after R&M.
	2x210	2319	2600	To reduce to 2550 kcal/kWh in 2011-12 and further to 2500 kCal/kWhr after capital overhaul
	1x210	2319	2460	As per PPA provision
Wanakbori TPS	3x210	2396	2600	To reduce to 2550 kCal/kWh in 2011-12 and further to 2500 kCal/kWh after capital overhaul
	3x210	2306	2600	
	1x210	2252	2460	As per PPA provision
Sikka TPS	1x120	2410	2750	To reduce to 2700 kCal/kWh in 2011-12 and further to 2620 kCal/kWh after capital overhaul
	1x120	2349	2750	
Kutch Lignite	2x70	3245	3300	
	1x75	NA	3300	
	1x75	2859	3000	
Dhuvaran Oil	2x110	2555	3000	
Dhuvaran CCPP-1	1x106.6	1862	1950	
Dhuvaran CCPP-2	112.45	1850	1950	
Utran CCPP	3x30 (GT) + 1x45 (ST)	2150	2200	
Utran CCPP Extn	375	NA	5 % above Design Heat Rate*	

* CEA noted that design heat rate for Utran CCPP ext is not available. Hence, CEA has recommended that 5% margin may be given over Design Heat Rate as per CERC Norm.

As regards Station Heat Rate, CEA recommendations are reproduced as under:

"i) In general, it has been recommended that 200/210 MW units should eventually operate with normative heat rate of 2500 kCal/kWhr. Since the units are not complying with these norms presently as per reported data, higher norms have been stipulated. It has also been brought out that there is a lot of scope of improvement of heat rate by better O&M and these stations may be targeted to improve by 100 kcal/kWhr over next two years. Further, during capital overhaul most of the problems being faced can be addressed and these units may be targeted to achieve heat rate of 2500 kcal/kWhr after capital overhaul. However, Wanakbori-7 and Gandhinagar 5, which have been consistently operating at improved level and governed by PPA, may be given normative value of 2460 kcal/kWhr as per PPA stipulation.

120 MW units in GSECL are reporting very high deviation in heat rates. R&M activity in Ukai#1 has been recently completed and unit is under stabilisation. Ukai#2 & Gandhinagar#1&2 are also slated for R&M. Normative value of '1.075 times new guaranteed design heat rate' is recommended after R&M of these units. For Sikka TPS, it has been recommended to improve heat rate by 100 Kcal/kWh over next two years and target value corresponding to 10% deviation from design heat rate after capital overhaul. For Kutch lignite, values projected by GSECL are about 5% higher than design heat rate which are considered to be in order. Dhuvaran oil TPS is already included in the proposed list identified by CEA for retirement. Till such time, this station is retired, a normative heat rate of 3000 Kcal/kWh is proposed. "

As regards Station Heat Rate (SHR), GERC in its Tariff Order for FY 2010-11 for GSECL dated March 31, 2010, has approved the SHR based on CEA recommendations. Accordingly, the norms for SHR for next Control Period have been proposed based on the CEA recommendations, as tabulated below:

Table: Proposed Station Heat Rate for GSECL Stations for Second Control Period.

(in kcal/kWh))

Stations	Units (No.x Cap.MW)	Design Heat Rate	FY 2011-12	FY 2012-13	FY 2013-14	FY2014-15	FY 2015-16
Ukai TPS	2x120	2411	2670	2670	2670	2670	2670
	3x210	2404	2600	2500	2500	2500	2500
Gandhinagar TPS	2x120	2382	2800	2800	2800	2800	2800
	2x210	2319	2550	2500	2500	2500	2500
	1x210	2319	2460	2460	2460	2460	2460
Wanakbori TPS	6x210	2396	2550	2500	2500	2500	2500
	1x210	2252	2460	2460	2460	2460	2460
Sikka TPS	2x120	2410	2700	2620	2620	2620	2620
Kutch Lignite	2x70	3245	3300	3300	3300	3300	3300
	1x75	NA	3300	3300	3300	3300	3300
	1x75	2859	3000	3000	3000	3000	3000
Dhuvaran Oil	2x110	2555	3000	3000	3000	3000	3000
Dhuvaran CCPP-1	1x106.6	1862	1950	1950	1950	1950	1950
Dhuvaran CCPP-2	112.45	1850	1950	1950	1950	1950	1950
Utran CCPP	3x30 (GT) + 1x45 (ST)	2150	2150	2150	2150	2150	2150
Utran CCPP Extn	375	NA	1850	1850	1850	1850	1850

TPL-G

CEA recommendation for TPL-G station heat rate is reproduced as under:

> *"In case of TPL stations GERC has asked CEA to establish whether heat rate values being furnished by TPL-G are based on Gross Calorific Value or Net Calorific Value. In para 3.2.7 above, it has been brought out that deviation in heat rate from design heat rate being reported by TPL are technically unexplainable given the operating parameters and operation of units near full load conditions. However, the proposed methodology for arriving at normative heat rate is based on providing % margin over the design heat rate value based on GCV. Accordingly, the issue of GCV and NCV is not considered relevant for determining the heat rate values for the control period under consideration.*

For stations E & F a normative heat rate of 10 % above their design value can be targeted. For station D which has undergone a major R&M activity in year 2004, a margin of 7.5% is proposed over new design heat rate. Station C, however, is already included in the proposed list identified by CEA for retirement. Till such time, this station is retired, a normative heat rate maximum of 20% deviation from design heat rate is proposed."

Table: Heat Rate recommended by CEA for TPL-G generating stations.

Station Name	Units (No.x Cap.MW)	Design Heat Rate (kcal/kWh)	CEA Recommended Heat Rate (kcal/kWh)
Sabarmati 'C'	2x30	2702	3240
Sabarmati 'D'	1x120	2339	2515
Sabarmati 'E'	1x110	2538	2790
Sabarmati 'F'	1x110	2538	2790
Vatva CCPP	2x32.5 (GT) + 1x35 (ST)	1910	2200

GERC, in its Tariff Order for TPL-G for FY 2010-11 dated March 31, 2010, has approved SHR based on TPL-G estimation on GCV basis. Accordingly, it is proposed that the norms for SHR for next Control Period shall be based on the norms approved for the FY 2010-11, as tabulated below:

Table: Proposed SHR for TPL-G generating stations for second Control Period.

(in kcal/kWh)

Stations Name	Units (No. x Cap.MW)	FY 2011-12	FY 2012-13	FY 2013-14	FY2014-15	FY 2015-16
Sabarmati 'C'	2x30	3150	3150	3150	3150	3150
Sabarmati 'D'	1x120	2450	2450	2450	2450	2450
Sabarmati 'E'	1x110	2725	2725	2725	2725	2725
Sabarmati 'F'	1x110	2725	2725	2725	2725	2725
Vatva CCPP	2x32.5 (GT) + 1x35 (ST)	2165	2165	2165	2165	2165

4.1.8.2 Auxiliary Consumption

GERC has specified norms of auxiliary consumption in its GERC Tariff Regulations, 2005.

Further, where existing PPAs (including any changes, in the norms or parameters, made in the PPA following renegotiation between the Board and concerned generating company) lay down a different parameter of auxiliary consumption, such a parameter shall continue to govern the parties for the term of the contract, but not for any renewal of the contract or any extension of the term of the contract in accordance with its terms. Upon the expiry of the term of the existing PPA (including any changes, in the norms or parameters, made in the PPA following renegotiation between the Board and concerned generating company), the parties shall be governed by the terms of the Regulations for the time being in force.

GSECL Stations

CEA, in its Study Report, has suggested that Auxiliary Consumption for the existing stations may be determined based on its assessment and past actual performance of generating stations. The recommendations of CEA Study Report regarding the Auxiliary consumption for generating stations of GSECL are as under:

> *"In regard to Auxiliary Energy Consumption (AEC) and specific oil consumption (SFC), recommendations are generally based on CERC norms. However for certain stations, some time has been given to improve their performance and achieve the normative levels. AEC for gas based stations 3.00% (same as CERC norm) but in case where gas boosters are provided, additional AEC corresponding to actual auxiliary consumption for gas boosters may be provided for"*

Table: CEA recommended Auxiliary Consumption for GSECL generating Stations.

Stations	Units (No. x Cap.MW)	FY 2010-11 (%)	Remarks by CEA
Ukai TPS	2x120	10.00	9.00 % approved by GERC as weighted average value of
	3x210	8.50	

Stations	Units (No. x Cap.MW)	FY 2010-11 (%)	Remarks by CEA
			120/210 MW units
Gandhinagar TPS	2x120	10.75	10.50% in 2011-12
	2x210	10.00	9.00% in 2011-12
	1x210	9.00	
Wanakbori TPS	6x210	9.00	
	1x210	9.00	
Sikka TPS	2x120	10.50	
Kutch Lignite	2x70	12.00	
	1x75	12.00	
	1x75	12.00	
Dhuvaran Oil	2x110	9.50	
Dhuvaran CCPP-1	1x106.6	3.00	Additional Aux. consumption for gas boosters, if any.
Dhuvaran CCPP-2	112.45	3.00	
Utran CCPP	3x30 (GT) + 1x45 (ST)	3.00	
Utran CCPP Extn	375	3.00	

GERC, in its Tariff Order for FY 2010-11, has approved auxiliary consumption for GSECL stations based on CEA recommendations. The Commission's analysis in the Order is reproduced as under:

"Commission Analysis

The Commission has taken note of the submission made by the petitioner. The Commission is of the view that the auxiliary consumption should now be considered based on the recommendation of the CEA except for the PPA based stations.

Auxiliary consumption for PPA based stations shall be governed as per the respective PPA.

The Commission has further observed that the petitioner has made a separate submission with regard to auxiliary consumption for KLTPS -4. The petitioner has submitted that the actual auxiliary consumption of the KLTPS-4 is 18% where as the submission made in the petition is 15%. According to the manufacturers prescription the auxiliary connected with this unit is of 12 MW (16%). The petitioner has requested that the auxiliary consumption for KLTPS-4 should be considered at 18% based on the actual auxiliary consumption observed.

The Commission has taken note of the submission made by the petitioner. The Commission is of the view that as per the CEA recommendation the auxiliary consumption of the station should be considered at 12%. The Commission has been *guided by the CEA recommendations in approving the auxiliary consumption for all the stations."*

Table: GERC approved auxiliary consumption (%) for GSECL stations

Stations	**GERC Approved FY 2010-11 (%)**
Ukai TPS	9.10
Gandhinagar 1-4	10.27
Gandhinagar 5	9.00
Wanakbori 1-6	9.00
Wanakbori 7	9.00
Sikka TPS	10.50
Kutch Lignite 1-3	12.00
Kutch Lignite 4	12.00
Dhuvaran Oil	9.50
Dhuvaran CCPP-1	3.00
Dhuvaran CCPP-2	3.00
Utran CCPP	3.00
Utran CCPP Extn	3.00

Accordingly, the norms for auxiliary consumption for the next Control Period have been proposed based on the CEA recommendations, as tabulated below:

Table : Proposed Auxiliary Consumption for GSECL Stations for Second Control Period

Stations	**Units (No.x Cap.MW)**	**2011-12 (%)**	**2012-13 (%)**	**2013-14 (%)**	**2014-15 (%)**	**2015-16 (%)**
Ukai TPS	2x120	10.00	10.00	10.00	10.00	10.00
	3x210	8.50	8.50	8.50	8.50	8.50
Gandhinagar TPS	2x120	10.50	10.50	10.50	10.50	10.50
	2x210	9.00	9.00	9.00	9.00	9.00
	1x210	9.00	9.00	9.00	9.00	9.00

Stations	Units (No.x Cap.MW)	2011-12 (%)	2012-13 (%)	2013-14 (%)	2014-15 (%)	2015-16 (%)
Wanakbori TPS	6x210	9.00	9.00	9.00	9.00	9.00
	1x210	9.00	9.00	9.00	9.00	9.00
Sikka TPS	2x120	10.50	10.50	10.50	10.50	10.50
Kutch Lignite	2x70	12.00	12.00	12.00	12.00	12.00
	1x75	12.00	12.00	12.00	12.00	12.00
	1x75	12.00	12.00	12.00	12.00	12.00
Dhuvaran Oil	2x110	9.50	9.50	9.50	9.50	9.50
Dhuvaran CCPP-1	1x106.6	3.00	3.00	3.00	3.00	3.00
Dhuvaran CCPP-2	112.45	3.00	3.00	3.00	3.00	3.00
Utran CCPP	3x30 (GT) + 1x45 (ST)	3.00	3.00	3.00	3.00	3.00
Utran CCPP Extn	375	3.00	3.00	3.00	3.00	3.00

TPL-G:

In the latest Tariff Order dated March 31, 2010 for TPL-G, the Commission has adopted CEA recommendations while approving the Auxiliary Energy Consumption for FY 2010-11.

CEA in its study report has recommended station wise Auxiliary Energy Consumption as under:

Table: Auxiliary consumption recommended by CEA

Stations	Units (No. x Cap.MW)	FY 2010-11 (%)
Sabarmati 'C'	2x30	9.50
Sabarmati 'D'	1x120	9.00
Sabarmati 'E'	1x110	9.00
Sabarmati 'F'	1x110	9.00
Vatva CCPP	2x32.5 (GT) + 1x35 (ST)	3.00

Accordingly, the norms for auxiliary consumption for the next Control Period have been proposed based on the CEA recommendations, as tabulated below:

Table: Proposed Auxiliary consumption for Second Control Period.

Stations	Units (No.x Cap.MW)	2011-12 (%)	2012-13 (%)	2013-14 (%)	2014-15 (%)	2015-16 (%)
Sabarmati 'C'	2x30	9.50	9.50	9.50	9.50	9.50
Sabarmati 'D'	1x120	9.00	9.00	9.00	9.00	9.00
Sabarmati 'E'	1x110	9.00	9.00	9.00	9.00	9.00
Sabarmati 'F'	1x110	9.00	9.00	9.00	9.00	9.00
Vatva CCPP	2x32.5 (GT) + 1x35 (ST)	3.00	3.00	3.00	3.00	3.00

4.1.8.3 Secondary Fuel Consumption

The norms for secondary fuel consumption specified in the GERC Tariff Regulations, 2005, are as under:

a) ***Coal Based generating stations***

During Stabilization period	*Subsequent period*
4.5 ml/kWh	*2.0 ml/kWh*

b) ***Lignite- fired generating stations***

During Stabilization period	*Subsequent period*
5.0 ml/kWh	*3 ml/kWh*

The existing norms specified by the Commission are relaxed norms as compared to the norms specified by CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009, for coal based generating stations (1 ml/kWh) and lignite based generating stations.

As regards the norms for secondary fuel oil consumption, for the existing generating stations, which have been commissioned or expected to be commissioned before the effectiveness of the GERC MYT Regulations, 2010, it is suggested that the same may be considered based on the norm specified under CERC Tariff Regulations, 2009, as stipulated below:

(a) Coal-based generating stations : 1.0 ml/kWh
(b) Lignite-Fired generating stations except stations based on CFBC technology : 2.0 ml/kWh
(c) Lignite-Fired generating stations based on CFBC technology : 1.25 ml/kWh

As discussed in previous paragraphs, for such stations, which have not been able to achieve the performance targets as specified by the Commission, the norms may be specified on the basis of CEA recommendation.

GSECL:

In its Study Report, CEA has made the following suggestions regarding Secondary Fuel Oil Consumption:

Table: Secondary Fuel Oil Consumption recommended by CEA

(*In* ml/kWh)

Stations	Units (No.x Cap.MW)	FY 2010-11	FY 2011-12
Ukai TPS	2x120	1.50	1.00
	3x210	1.50	1.00
Gandhinagar TPS	2x120	1.50	1.00
	2x210	1.50	1.00
	1x210*	3.50	3.50
Wanakbori TPS	6x210	1.00	1.00
	1x210*	3.50	3.50
Sikka TPS	2x120	1.50	1.00
Kutch Lignite	2x70	2.50	2.00
	1x75	2.50	2.00
	1x75	2.50	2.00

*Norm of 3.5 ml/kWh is specified in PPA and the same is recommended by CEA, hence, adopted.

From the above Table, it is observed that the Auxiliary Consumption recommended by CEA is in line with that specified by CERC in CERC Tariff Regulations, 2009, as mentioned above.

GERC in its Tariff Order for FY 2010-11 for GSECL dated March 31, 2010, has ruled that:

"Commission Analysis

The Commission has observed that the petitioner has revised the secondary fuel oil consumption for Ukai 1-5 compared to the specific oil consumption approved under the MYT Order. The Commission has also examined the reasons and justifications submitted by the petitioner. The Commission has further drawn reference to the recommendations of the CEA with regard to the specific oil consumption. The Commission is of the view that the specific oil consumption should be considered as per the recommendations of the CEA study"

Accordingly, the norms for Secondary Fuel consumption for the next Control Period have been proposed based on the CEA recommendations, as tabulated below:

Table: Proposed SFC for GSECL generating stations for second Control Period

Stations	Units (No.x Cap.MW)	2011-12 (ml/kWh)	2012-13 (ml/kWh)	2013-14 (ml/kWh)	2014-15 (ml/kWh)	2015-16 (ml/kWh)
Ukai TPS	2x120	1.00	1.00	1.00	1.00	1.00
	3x210	1.00	1.00	1.00	1.00	1.00
Gandhinagar TPS	2x120	1.00	1.00	1.00	1.00	1.00
	2x210	1.00	1.00	1.00	1.00	1.00
	1x210	3.50	3.50	3.50	3.50	3.50
Wanakbori TPS	6x210	1.00	1.00	1.00	1.00	1.00
	1x210	3.50	3.50	3.50	3.50	3.50
Sikka TPS	2x120	1.00	1.00	1.00	1.00	1.00
Kutch Lignite	2x70	2.00	2.00	2.00	2.00	2.00
	1x75	2.00	2.00	2.00	2.00	2.00
	1x75	2.00	2.00	2.00	2.00	2.00

TPL-G

As discussed earlier, CEA has recommended secondary fuel consumption for Coal based and Lignite based generating stations. Recommendation of CEA for TPL-G generating stations is provided as under:

Table: CEA Recommended SFC for TPL-G generating Stations

Stations	Units (No.x Cap.MW)	2010-11 (ml/kWh)
Sabarmati 'C'	2x30	2.00
Sabarmati 'D'	1x120	1.00
Sabarmati 'E'	1x110	1.00
Sabarmati 'F'	1x110	1.00

Accordingly, the norms for Secondary Fuel consumption for the next Control Period have been proposed based on the CEA recommendations, as tabulated below:

Table: Proposed SFC for Second Control Period for TPL-G Stations

Stations	Units (No.x Cap.MW)	2011-12 (ml/kWh)	2012-13 (ml/kWh)	2013-14 (ml/kWh)	2014-15 (ml/kWh)	2015-16 (ml/kWh)
Sabarmati 'C'	2x30	2.00	2.00	2.00	2.00	2.00
Sabarmati 'D'	1x120	1.00	1.00	1.00	1.00	1.00
Sabarmati 'E'	1x110	1.00	1.00	1.00	1.00	1.00
Sabarmati 'F'	1x110	1.00	1.00	1.00	1.00	1.00

4.1.8.4 Transit losses

Transit and handling losses are very common in fuel transportation, especially for coal transportation. These losses happen mainly due to theft, leakage, weight reduction due to moisture evaporation, improper stacking, etc., and the losses are higher in load centre based generating stations as compared to that in pit head stations. The norms specified in GERC Tariff Regulations, 2005, are as under:

> *"Subject to Regulation 2 (2) above, the landed cost of coal shall include price of coal corresponding to the grade/quality of coal inclusive of royalty, taxes and duties as applicable, transportation cost by rail/road or any other means, and, for the purpose of computation of energy charges, shall be arrived at after considering normative transit and handling losses as percentage of the quantity of coal dispatched by the coal supply company during the month as given below:*
>
> *Pit head generating stations : 0.3%*

Non-Pit head generating stations : 0.8%"

The transit loss norms specified by CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009 are as under:

i. *"Pit head generating stations - 0.2%*

ii. *Non-pit head generating stations - 0.8%"*

The actual and approved transit losses of GSECL and TPL-G Stations is tabulated below:

Table: Transit loss Actual & approved by Commission for generating stations.

Stations	Actual (%)			Approved by Commission (%)			
GSECL	**2006-07**	**2007-08**	**2008-09**	**2006-07**	**2007-08**	**2008-09**	**2009-10**
Ukai	1.20	2.05	1.20	1.20	1.20	1.20	1.20
Gandhinagar 1-4	1.40	3.05	1.40	1.40	1.40	1.40	1.40
Gandhinagar –5	1.40	3.05	1.40	1.40	1.40	1.40	1.40
Wanakbori 1-6	2.05	3.21	1.50	1.50	1.50	1.50	1.50
Wanakbori –7	2.050	3.21	1.50	1.50	1.50	1.50	1.50
Sikka	2.55	2.00	2.00	2.00	2.00	2.00	2.00
TPL-G		3.39	2.73		1.40	1.40	1.40

As observed from the above Table, GSECL has managed to reduce the transit losses substantially for most of the existing Stations. In APR Order for FY 2008-09 for GSECL, the Commission observed that the actual transit loss during FY 2008-09 has been exactly equal to the approved level. The Commission therefore, directed GSECL to submit the computation of the actual transit loss. Subsequently, the Commission also raised this issue of transit loss during the course of technical validation and sought clarification from GSECL regarding whether transit loss reported in based on actuals. However, the Commission, in its Order, observed that the GSECL has failed to submit the desired information.

In the absence of the actual computation, the Commission approved the transit losses at the level approved in its MYT Order of 17th January 2009.

In APR Order for FY 2009-10 for GSECL, the Commission has approved transit loss as submitted by GSECL, i.e., 0.8 %. It is observed that the transit loss for FY 2010-11 approved in the APR Order is higher than the original target fixed by the Commission in its MYT Order. Hence, it is proposed that the trajectory approved for reduction of transit loss for the first Control Period, may be adopted for the second Control Period.

Based on above observations, transit loss for GSECL and TPL stations are proposed as under:

Table: Proposed Transit Loss for Second Control Period

Stations	Transit Loss (%)				
GSECL	**2011-12**	**2012-13**	**2013-14**	**2014-15**	**2015-16**
Ukai	0.80	0.80	0.80	0.80	0.80
Gandhinagar 1-4	0.80	0.80	0.80	0.80	0.80
Gandhinagar –5	0.80	0.80	0.80	0.80	0.80
Wanakbori 1-6	0.80	0.80	0.80	0.80	0.80
Wanakbori –7	0.80	0.80	0.80	0.80	0.80
Sikka	0.80	0.80	0.80	0.80	0.80
TPL-G	1.40	1.20	1.00	0.90	0.80

4.1.9 Operation & Maintenance (O&M) Expenses

The O&M expenses comprise of Employee Expenses, R&M Expenses and A&G expenses, and all three together constitute a significant part of the Aggregate Revenue Requirement of any power sector Utility.

In terms of developing the framework for the components of O&M expenses, various Regulatory Commissions have mainly adopted the following two approaches:

- Actual O&M expenses in the previous year with certain escalation factor for ensuing years
- O&M expenses based on certain performance benchmarks

The CERC Tariff Regulations, 2009 specifies norms for overall O&M expenses, for each year of the Control Period, and linked to the capacity.

In the traditional approach, the Commission has specified the O&M expenses based on the actual expenditure incurred during the previous year, escalated using certain escalation factors for projecting the ensuing years' O&M expenses. Before deciding on the approach for O&M expenses, it is important to analyse the components of O&M expenses.

a. Employee Expense

Employee expenses include salaries, allowances payable to employees, wage arrears, terminal benefits, etc. Employee expense varies every year due to salary increase, promotion of employees and due to retirement/addition of employees. The increase in salary expenses would be expected to be such that it offsets the effect of inflation. One such indicator denoting the inflation is Consumer Price Index (CPI), reflecting the increase in price of consumer goods.

b. A&G Expenses

Administrative & General (A&G) expenses comprise expenses on office administration, rentals, travel, communication, telecommunication and other overheads, etc. The general indicators reflecting the variation in cost of general commodities are the Wholesale Price Index (WPI) and Consumer Price Index (CPI).

c. Repair & Maintenance (R&M) Expense

R&M, in terms of scheduled and break-down maintenance, is a part of any running business. Suitable provision for R&M expenses needs to be provided for smooth operation of generating stations. R&M expenses generally increase with the vintage of the plant. In initial years of operation, R&M cost is low due to new components, which increases with the increase in plant life. For escalation of R&M expenses, the WPI can be an indicator reflecting the increase in the cost of machinery and machine tools.

After going through each component of O&M expense, the issue is whether the Commission should detail the normative parameters and escalation factors for each of the expense heads or provide a normative framework for consolidated O&M expenses.

Regulation 20(iv) of GERC Tariff Regulations, 2005, specifies the normative O&M expenses. It is observed that O&M expenses have increased over the years for various generating stations of GSECL and TPL. Further, the O&M expenses of smaller Unit stations in Rs Lakh/MW terms are much higher as compared to large Unit size thermal stations. The O&M expenses for thermal stations also depend upon vintage of stations and hence, the O&M expenses of older vintage stations are higher as compared to new stations.

It is felt that it would be appropriate to fix the norms for O&M expenses on consolidated basis instead of specifying the norms for individual components of O&M expenses as it will give flexibility to the Utility to manage its expenditure.

CERC has specified the O&M Norms in Regulation 19 of its CERC (Terms and Conditions of Tariff) Regulations, 2009.

For new stations to be commissioned after the date of effectiveness of GERC MYT Regulations, 2010, it is proposed to specify the norms of O&M expense as specified in CERC Tariff Regulations, 2009.

As regards insurance expenses, the Commission has been considering the insurance cost as a part of O&M expenses. Accordingly, it is suggested that O&M expenses for generation may be defined in the MYT Regulations as under:

> *'operation and maintenance expenses' or 'O&M expenses' means the expenditure incurred on operation and maintenance of the project, or part thereof, and includes the expenditure on manpower, repairs, spares, consumables, insurance, and overheads.*

For existing Stations, it is desirous that norm for O&M expenses may be specified in the Regulations itself. However, the Audited Accounts of various generating companies do not provide the station-wise segregation of O&M expenses, which is required to determine station-wise O&M norm. However, if Utilities are able to provide certified actual Station-wise O&M expenses during the finalisation of these Regulations, it may be considered by the Commission for determination of norms.

Hence, in absence of desired data for station-wise norm determination, it is proposed to determine O&M expenses in the MYT Order for the second Control Period, based on the following principles:

a) The Operation and Maintenance expenses including insurance, shall be derived on the basis of the average of the actual Operation and Maintenance expenses for the three (3) years ending March 31, 2010, subject to prudence check by the Commission.
b) The average of such operation and maintenance expenses shall be considered as operation and maintenance expenses for the financial year ended March 31, 2009 and shall be escalated based on the escalation factor as approved by the Commission

for the respective years to arrive at operation and maintenance expenses for the year commencing April 1, 2011.

c) The O&M expenses for each subsequent year will be determined by escalating the base expenses determined above for FY 2010-11, at the escalation factor 5.72 % to arrive at permissible O&M expenses for each year of the Control Period:

For new stations commissioned and which have not achieved the operation of three years from the date of commissioning and for stations expected to be commissioned before the date of effectiveness of the GERC MYT Regulations, 2010, the O&M expenses may be considered based on norms specified in the existing GERC Tariff Regulations, which shall be escalated at the escalation factor to arrive at permissible O&M expenses for each year of the second Control Period.

As regards the O&M expenses for new generating stations to be commissioned after the effectiveness of the GERC MYT Regulations, 2010, it is suggested that the O&M expenses for first year of the second Control Period may be specified based on norms in the existing GERC Tariff Regulations,2005, escalated based on escalation factors to arrive at permissible O&M expenses for each year of the first Control Period as follows:

i. O&M Expenses for 210/250 MW Unit

Particulars	FY 12	FY 13	FY 14	FY 15	FY 16
O&M Expenses for 210/250 MW (Rs. Lakh/MW)					
Escalation rate	5.72 %	5.72 %	5.72 %	5.72 %	5.72 %
O&M Expenses (Rs. Lakh/MW)	14.38	15.20	16.07	16.99	17.96

ii. O&M Expenses for 500 MW and above Unit

Particulars	FY 12	FY 13	FY 14	FY 15	FY 16
O&M Expenses for 500 MW and above Unit (Rs. Lakh/MW)	12.94	13.68	14.46	15.29	16.16

Note:

For the generating Units/Stations having combination of 200/210/250 MW sets and 500 MW and above set, the weighted average value for O&M expenses shall be adopted

iii. O&M Expenses for lignite based generating Units/Stations:

Particulars	FY 12	FY 13	FY 14	FY 15	FY 16
O&M Expenses (Rs. Lakh/MW)	14.38	15.20	16.07	16.99	17.96

iv. O&M Expenses for Gas Turbine/Combined Cycle generating Unit/Stations

Particulars	Gas Turbine/Combined Cycle Generating Stations		Small Gas Turbine Generating Stations (less than 50 MW unit size)
	With warranty spares for 10 years	Without warranty Spares	Without warranty Spares
FY 2011-12	7.18	10.78	13.08
FY 2012-13	7.60	11.39	13.83
FY 2013-14	8.03	12.04	14.62
FY 2014-15	8.49	12.73	15.46
FY 2015-16	8.97	13.46	16.34

4.1.10 Non-tariff Income

The Generating Companies can earn non-tariff income through sale of ash generated from coal based generating stations, sale of scrap, rent received from part of land given on lease, interest income on investments, etc. Therefore, any income earned by Generating Company can be categorised as income either from the assets or activities, for which all the expenses have been allowed to be recovered from the tariffs. Since all the legitimate costs are allowed to be recovered through tariffs, it is important that the income earned by Generating Companies other than income from sale of power should be considered and adjusted from Fixed (Capacity) charges as otherwise it will lead to additional profit to Generating Company in excess of permissible return. However, while considering the Non-tariff Income, the income corresponding to interest on investment made out of permissible Return on Equity should not be considered as Non-tariff Income. Some of the heads, which should be considered under Non-tariff Income for adjustment from the fixed (capacity) charges, are as follows:

- Income from rent of land or buildings

- Income from sale of scrap
- Income from statutory investments
- Income from sale of Ash/rejected coal
- Interest from consumers (Interest on delayed or deferred payment on bills)
- Interest on advances to suppliers/contractors
- Interest on Income tax refund
- Rental from staff quarters
- Rental from contractors
- Income from hire charges from contactors and others
- Gain on Foreign Exchange Fluctuation
- Income from advertisements, etc.

4.1.11 Incentive Mechanism

It is proposed that an appropriate incentive mechanism should be designed after taking into consideration the merits and demerits of various alternatives and the long-term benefits to the sector. For incentive purpose, the following three approaches can be considered:

- Additional Return on Equity or Return on Capital Employed linked with increase in target PLF
- Paise/unit linked to scheduled generation beyond normative PLF
- Availability based incentive linked to Annual Fixed Charge

In case incentive is provided in terms of additional Return on Equity (RoE) or Return on Capital Employed (RoCE) linked with increase in target PLF, the incentive will vary for each Generating Station based on capital cost and means of finance (in case of RoE approach) of the Generating Station, which does not appear logical. Further, this approach will also conversely provide more incentive to generating stations with higher capital cost.

Incentive in terms of paise/kWh beyond the normative PLF has been a mechanism widely adopted by the various Regulatory Commissions due to simplicity in implementation, and the fact that it ensures uniform incentive to all generating stations.

CERC Tariff Regulations, 2009 has specified the availability based incentive scheme for the thermal generating stations. For coal based stations, CERC has kept the target availability for payment of incentive same as the target availability for recovery of full fixed charges.

As regards the suggestions made regarding linking incentive to Availability and Annual Fixed Charges, a generator should be incentivised for actual generation rather than availability to generate, as for distribution licensees, the actual generation has the utmost importance. Moreover, the generator is allowed to recover the fixed cost, if it achieves the target availability. Further, the approach to link the incentive to the AFC on some proportion will also conversely provide more incentive to generating stations with higher AFC.

The existing GERC Tariff Regulations, 2005, provides for incentive mechanism linked to the scheduled generation in excess of target PLF.

> *"22. **Incentive**: Incentive shall be payable at a flat rate of 25.0 paise/kWh for ex-bus scheduled energy corresponding to scheduled generation in excess of ex-bus energy corresponding to target Plant Load Factor"*

As regards target PLF, it has been observed that GERC in its APR Order for FY 2008-09 for TPL (page no 47-48), has approved incentive based on achieved PLF above the MYT approved PLF. TPL has also filed an appeal before APTEL under case no 996/2009 as discussed above.

CEA has recommended that it is not necessary to stipulate PLF value in the Order as PLF does not have any bearing on tariff. The relevant extract from CEA study report is as under:

> ***"Regarding PLF values prescribed in GERC order, it is felt that since PLF does not have any bearing on tariff, it is not necessary to stipulate these values."***

Hence, based on CEA recommendation, it is proposed that the Commission may provide incentive to the generating stations for scheduled generation above the target PLF specified in Regulations.

As regards target PLF for incentive purposes, it is proposed that target PLF of 85% may be specified for providing incentive to generating stations.

It is proposed that the mechanism for incentive may be specified in the GERC MYT Regulations, 2010. It is proposed that the incentive may be linked to the scheduled generation.

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4.1.12 Treatment of Infirm Power

The power generated prior to commercial operation of the Unit of a generating station is treated as infirm power. CERC Tariff Regulations, 2009 has linked the infirm power price with the Unscheduled Interchange (UI) rate under the Availability Based Tariff (ABT) mechanism. The stated objective behind this linkage was to increase the availability of power in the grid. However, pricing of infirm power linked to frequency leads to de-linking of the tariff and the cost incurred and may lead to artificially increasing the price, when the cost of generation is far lower than the prevailing UI rate. Also, linking the price with the frequency may create uncertainty over the price of the power that the generating station would get for injection of power. Further, it should not result in a situation where the Generating Company delays the commissioning of the Plant, since the rate available for infirm power injection at UI rate may be more remunerative.

It is suggested that the price of infirm power from thermal generating stations may be fixed at variable cost to recover the fuel costs only. If the revenue from sale of infirm power is higher than the fuel cost, the recovery in excess of fuel cost needs to be adjusted from the capital cost. The pricing of infirm power at variable charge is a simple mechanism and will avoid complications in tariff determination. This will also ensure that the capital cost recovery in terms of Fixed (Capacity) charge is allowed after COD of the Generating Station.

4.1.13 Cost of Fuel and Calorific Value

For determining the variable charge component of tariff for thermal stations, the cost of fuel to be considered should be the landed cost of fuel, which should include price of fuel corresponding to the grade/quality/calorific value of fuel including royalty, taxes and duties as applicable, transportation, coal washing charges as applicable, and the normative transit losses.

While determining the tariff for ensuing years, it will be preferable to consider the landed cost of fuel and gross calorific value -as fired based on actual values for the most recent three to four months. The variation in landed price of fuel and gross calorific value of fuel may be allowed as a pass-through as per present Fuel and Power Purchase Price Adjustment mechanism.

GERC, in its APR Order for TPL for FY 2009-10 dated March 31, 2010, observed that many objectors have raised objected that TPL has calculated the SHR on the basis of Net Calorific Value of coal, which is not the right practice. It is noted that because of the methodology followed by TPL for calculation of SHR on NCV basis, there is a increase the fuel cost.

As regards heat rate for TPL stations, GERC had asked CEA to establish whether the heat rate figures being furnished by TPL, are based on GCV or NCV.

CEA in its study report mentioned as below:

> *"The industry practice in India is to define and calculate the operational parameters, including boiler efficiency and turbine cycle heat rate for coal fired stations on GCV basis. Accordingly, the operational parameters are invariably specified on GCV basis by the equipment manufacturers and other regulators.*
>
> *If the operating heat rate is considered to have furnished on NCV basis, the corresponding heat rate on GCV basis would increase further by about 5-7%. It may be seen that in Station C &D the deviation in heat rate is already very much on higher side, even up to 40% in Station C and up to 15% in Station D and this would further increase if the furnished heat rate value are considered on NCV basis making it technically unexplainable to incur such high heat rate when these units are operating at or near full load condition.*
>
> *The proposed methodology for arriving at normative heat rate is based on providing % margin over the design heat rate value based on GCV. Accordingly the issue of GCV, and NCV is not Considered relevant for determining heat rate values for control period under consideration."*

CEA, in its study report, has also stated that the method used by TPL to measure coal calorific value at the railway wagon end rather than as fired basis, gives a wrong value of SHR.

As regards station heat rate measurement, it is proposed compute station heat rate on calorific value of fuel arrived on as fired basis (GCV basis) and thus compute the fuel cost. Though it would not make any difference in the fuel cost as computed by TPL in previous years, it would be an appropriate methodology as far as industry practices in India and equipment manufacturer specifications are concerned.

4.2 Hydro Generating Stations

4.2.1 Capital Cost and Means of Finance

The capital cost in hydro generating stations includes the cost of dam, intake water system, turbines, generators and discharge water system. The critical issue with respect to capital cost of hydro projects is ascertainment of total capital cost of hydro project apportioned to power generation.

As discussed earlier, the current methodology is to approve the capital cost as a part of tariff determination process, based on actual capital expenditure subject to prudence check. However, in future, the capital cost would have to be approved as part of the Business Plan.

4.2.2 Components of Tariff and Recovery of Costs

The existing GERC Tariff Regulations stipulate two-part tariff for sale of electricity from a hydro power generating station comprising of Capacity Charges and Primary Energy Charges in the following manner:

(i) Annual Capacity Charges = Annual Fixed Charges - Energy Charge
Provided further that the Energy Charge shall not exceed the Annual Fixed Charge.

(ii) Annual Fixed Charges comprises the following elements:

a. Interest on Loan Capital
b. Depreciation including Advance Against Depreciation and amortisation of intangible assets
c. O&M Expenses
d. Return on Equity Capital
e. Interest on Working Capital
f. Taxes on Income

As regards rate of Energy Charges, GERC Tariff Regulations stipulates that the rate of energy for hydro stations shall be worked out on the basis of paise per kWh rate on ex-bus energy scheduled to be sent out from the hydro generating stations. The GERC Tariff Regulations further stipulate that recovery from Energy Charges shall not exceed the Annual Fixed Charges.

As regards the computation of tariff for hydel generating stations, CERC, in its CERC (Terms and Conditions of Tariff) Regulations, 2009 has stipulated as under:

> *"(2) The capacity charge (inclusive of incentive) payable to a hydro generating station for a calendar month shall be*
> *AFC x 0.5 x NDM / NDY x (PAFM / NAPAF) (in Rupees)*
> *Where,*
> *AFC = Annual fixed cost specified for the year, in Rupees.*
> *NAPAF = Normative plant availability factor in percentage*
> *NDM = Number of days in the month*
> *NDY = Number of days in the year*
> *PAFM = Plant availability factor achieved during the month, in Percentage*
> *(4) The energy charge shall be payable by every beneficiary for the total energy scheduled to be supplied to the beneficiary, excluding free energy, if any, during the calendar month, on ex power plant basis, at the computed energy charge rate. Total Energy charge payable to the generating company for a month shall be :*
>
> *(Energy charge rate in Rs. / kWh) x {Scheduled energy (ex-bus) for the month in kWh} x (100 – FEHS) / 100.*
>
> *(5) Energy charge rate (ECR) in Rupees per kWh on ex-power plant basis, for a hydro generating station, shall be determined up to three decimal places based on the following formula, subject to the provisions of clause (7) :*
>
> *ECR = AFC x 0.5 x 10 / { DE x (100 – AUX) x (100 – FEHS)}*
> *Where,*
> *DE = Annual design energy specified for the hydro generating station, In MWh, subject to the provision in clause (6) below. FEHS = Free energy for home State, in per cent, as defined in regulation 32."*
> *...*

(7) In case the energy charge rate (ECR) for a hydro generating station, as computed in clause (5) above, exceeds eighty paise per kWh, and the actual saleable energy in a year exceeds { DE x (100 – AUX) x (100 – FEHS) / 10000 } MWh, the Energy charge for the energy in excess of the above shall be billed at eighty paise per kWh only:

> *Provided that in a year following a year in which total energy generated was less than the design energy for reasons beyond the control of the generating company, the energy charge rate shall be reduced to eighty paise per kWh after the energy charge shortfall of the previous year has been made up."*

CERC in the above mentioned Regulations, allows for recovery of 50% of fixed costs through the capacity charge and 50% of the fixed costs through the energy charge corresponding to design energy. Further, the mechanism stipulated by CERC also provides for incentive towards generation in excess of the design energy.

In view of the above, it is proposed that the tariff mechanism for hydro stations may be specified as stipulated in the CERC Tariff Regulations, 2009.

It is suggested that the Annual Fixed Cost (AFC) for a Hydro Generating Station shall comprise of the following elements:

- Depreciation
- O&M Expenses
- Return on Equity
- Interest Expenses
- Interest on Working Capital

  Less:
- Non-tariff income

4.2.3 Norms of Operation

Normative Capacity Index for Recovery of Annual fixed Charges

The normative capacity index as specified by the Commission in the existing GERC Tariff Regulations for hydro generating stations are as under:

Particulars	First Year of Commercial Operation	After First year of Commercial Operation
Purely Run-of-river power station without pondage	85%	90%
Storage type and Run-of-river power stations with pondage	80%	85%

It is proposed that operating norms for pumped storage stations may be specified on case to case basis while determining the tariff based on Petition filed for determination of tariff for such station.

As it is proposed to adopt the tariff mechanism specified in CERC (Terms and Conditions of Tariff) Regulations, 2009, it will be preferable to specify the norms of operation as stipulated in CERC (Terms and Conditions of Tariff) Regulations, 2009. For new generating stations to be commissioned after the date of effectiveness of the GERC MYT Regulations, the Normative Plant Availability Factor (NAPAF) may be specified in accordance with the norms specified by CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009 as under:

Particulars	Normative Availability
Storage and Pondage type plants with head variation between Full Reservoir Level (FRL) and Minimum Draw Down Level (MDDL) of up to 8%, and where plant availability is not affected by silt	90%
Storage and Pondage type plants with head variation between FRL and MDDL of more than 8%, where plant availability is not affected by silt	Plant-specific allowance to be provided in NAPAF for reduction in MW output capability as reservoir level falls over the months. As a general guideline the allowance on this account in terms of a multiplying factor may be worked out from the projection of annual average of net head, applying the formula: (Average head / Rated head) + 0.02 Alternatively in case of a difficulty in making such projection, the multiplying factor may be determined as: (Head at MDDL/Rated head) x 0.5

	+ 0.52
Pondage type plants where plant availability is significantly affected by silt	85%
Run-of-river type plants	to be determined plant-wise, based on 10-day design energy data, moderated by past experience where available/relevant

Note:

A further allowance may be made by the Commission in NAPAF determination under special circumstances, e.g., abnormal silt problem or other operating conditions, and known plant limitations.

For existing stations, it is proposed that the NAPAF may be specified in the MYT Order after considering the past performance and based on methodology stipulated in CERC (Terms and Conditions of Tariff) Regulations, 2009.

<u>Auxiliary Energy Consumption</u>

The auxiliary energy consumption as specified by the Commission in its existing GERC Tariff Regulations for hydro generating stations are as under:

(a) Surface hydro electric power generating stations with rotating exciters mounted on the generation shaft – 0.2% of energy generated
(b) Surface hydro electric power generating stations with static excitation system - 0.5% of energy generated
(c) Underground hydro electric power generating stations with rotating exciters mounted on the generator shaft - 0.4% of energy generated
(d) Underground hydro electric power generating stations with static excitation system - 0.7% of energy generated

The existing GERC Tariff Regulations stipulates transformation losses of 0.5% from generation voltage to transmission voltage.

It is suggested that the auxiliary consumption norm may be specified (which includes transformation losses also) as specified by CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009 for various types of stations, as follows:

(a) Surface hydro generating stations

i. With rotating exciters mounted on the generator shaft: 0.7%

ii. With static excitation system: 1%

(b) Underground hydro generating stations

i. With rotating exciters mounted on the generator shaft: 0.9%

ii. With static excitation system: 1.2%

4.2.4 Operation and Maintenance Expenses

CERC has specified the basis of computation of)&M norms n its CERC (Terms and Conditions of Tariff) Regulations, 2009.

For existing stations, it is suggested that the norm for O&M expenses may be specified based on actual O&M expenses during the last three years, in the MYT Order. The principles for determination of O&M norms are proposed as under:

a) The Operation and Maintenance expenses including insurance, shall be derived on the basis of the average of the actual Operation and Maintenance expenses for the three (3) years ending March 31, 2010, subject to prudence check by the Commission.

b) The average of such operation and maintenance expenses shall be considered as operation and maintenance expenses for the financial year ended March 31, 2009 and shall be escalated based on the escalation factor as approved by the Commission for the respective years to arrive at operation and maintenance expenses for the year commencing April 1, 2011.

c) The O&M expenses for each subsequent year will be determined by escalating the base expenses determined above for FY 2010-11, at the escalation factor 5.72 % to arrive at permissible O&M expenses for each year of the Control Period:

For new stations, the norms for O&M expenses for first year of operation may be specified as 2% of the original project cost (excluding cost of rehabilitation and resettlement works) for the first year of operation.

The O&M expenses for each subsequent year will be determined by escalating the base expenses determined above for FY 2011-12, at the escalation factor to arrive at permissible O&M expenses for each year of the Control Period.

4.2.5 Treatment of Infirm Power

There are two alternative approaches for treatment of infirm power from hydro generating stations:

- Rate of Infirm Power equivalent to Primary Energy Rate
- Supply of Infirm Power free of charge

In case of hydro generating stations, there is no question of fuel cost, and recovery from primary energy rate is intended for part recovery of Annual Fixed Costs. Hence, under Option 1, the revenue earned from sale of infirm power needs to be deducted from the Capital Cost.

The other alternative in case of hydro power generating stations is that the infirm power may be supplied free of cost as there are no fuel costs involved. However, since as a basic principle, any power supplied to the Distribution Licensee should not be free of charge, it is proposed to adopt Option 1 for treatment of infirm power in case of hydro generating stations.

5 Norms and Principles for determination of Revenue Requirement and Tariff for Transmission

5.1 *Brief status of State Transmission Utility (STU) in Gujarat*

The Government of Gujarat (GoG) notified the Gujarat Electricity Industry (Reorganization and Regulation) Act, 2003 in May 2003 for the reorganization of the entire power sector in the State of Gujarat and the erstwhile GEB was divided into seven different entities wherein all its transmission related assets were transferred to the newly created entity Gujarat Energy Transmission Corporation Ltd, herein referred as 'GETCO'.

The Energy and Petrochemical Department, Government of Gujarat vide its Notification Ref: GHU-2004, 31-GEB-1104-2946-K dated the 29th May, 2004 under Section 39 of the Electricity Act, 2003 (36 of 2003) and in super session of Govt. Notification , Energy and Petrochemical Department No:GHU-99-5-GEB-1198-6329-K dated 25th January 1999 has notified that the Gujarat Energy Transmission Corporation Ltd. (GETCO), a subsidiary Company of Gujarat Electricity Board (GEB) as the "State Transmission Utility " w. e. f. 1st June, 2004.

The Energy and Petrochemicals Department, Government of Gujarat vide its Notification No.GHU-2006-91-GUV-1106-590-K dated the 3rd October, 2006 notified the Financial Restructuring Plan (FRP), i.e., final Opening Balance Sheet of all Companies as on 1st April, 2005 in supersession of its earlier Notification No. GHU-2006-53-GUV-1106-590-K dated 6th May, 2006 and in pursuance of the provision of Para (C) of Sub-Clause (6) of Clause 5 of the Gujarat Electricity Industry Re-Organization and Comprehensive Transfer Scheme, 2003, duly notified under the Gujarat Electricity Industry Reorganization and Regulation Act, 2003, thereby substituting the Provisional Opening Balance Sheet notified on 31st December, 2004, 31st March, 2005 and 6th May, 2006 respectively of all the successor transferee Companies including GETCO.

As per provisions of Section 39(2), GETCO, as STU, is responsible to undertake all activities related to transmission planning, co-ordination and ensuring development of an efficient, coordinated and economical system of intra-State transmission for smooth flow of electricity from generating stations to the load centres within the State.

5.2 *Regulatory Framework and Recent Regulatory Developments*

5.2.1 Legal and Regulatory framework for Transmission

As per Section 40 of the EA 2003, the transmission licensee is obliged (a) to build, maintain and operate an efficient, co-ordinated and economical inter-State transmission system or intra-State transmission, as the case may be; (b) to comply with directions of RLDCs and SLDCs as the case may be; (c) to provide non-discriminatory open access to its transmission system for use by any licensee or generating company or any consumer on payment of transmission charges, as and when such open access is provided by State Commission. It is envisaged that Transmission Charges should be determined such that it encourages efficient use of the intra-State transmission system and facilitates open access transactions, while ensuring adequacy of revenue requirement for the transmission licensee.

5.2.1.1 Provisions under NEP and Tariff Policy

National Electricity Policy

The National Electricity Policy (NEP) notified by the Government of India (GoI) in February 2005, in accordance with provisions of Section 3 of the EA 2003, stipulates that the State Commission should determine the Transmission Charges by June 2005. Further, it advocates nationwide uniformity and consistency in Transmission Pricing in order to facilitate cost effective transmission of power across the country. Accordingly, it stipulates that transmission pricing, as far as possible, should be sensitive to distance, direction and related quantum of flow. The relevant extract of the NEP is as under:

> *"Non-discriminatory open access shall be provided to competing generators supplying power to licensees upon payment of transmission charge to be determined by the appropriate Commission. The appropriate Commissions shall establish such transmission charges no later than June 2005.* ***(Cl 5.3.4)***
>
> *To facilitate cost effective transmission of power across the region, a national transmission tariff framework needs to be implemented by CERC. The tariff mechanism would be sensitive to distance, direction and related to quantum of flow. As far as possible, consistency needs to be maintained in transmission pricing framework in inter-State and intra-State systems.*

*Further it should be ensured that the present network deficiencies do not result in unreasonable transmission loss compensation requirements." **(Cl 5.3.5)***

<u>*Tariff Policy*</u>

The Tariff Policy notified by Ministry of Power (MoP), GoI on January 6, 2006 deals with several aspects pertaining to Transmission as under –

- Transmission Planning
- Transmission Pricing
- Infrastructure
- Approach for Transmission Loss
- Other issues in transmission

The relevant extracts of the Tariff Policy are as under:

Clause 7.1 Transmission Planning

"(2) The National Electricity Policy mandates that national tariff framework implemented should be <u>sensitive to distance, direction and related to quantum of power flow.</u> This would be <u>developed by CERC taking into consideration the advice of the CEA</u>. Such tariff mechanism should be <u>implemented by 1st April 2006</u>." (<u>emphasis added</u>)

Clause 7.1 Transmission Pricing

*"(3) Transmission charges, under this framework, can be levied on MWper circuit kilometer basis, zonal postage stamp basis, or some other pragmatic variant, **<u>the ultimate objective being to get the transmission system users to share the total transmission cost in proportion to their respective utilization of the transmission system</u>**. It is necessary that transmission tariff framework gives the right signals for siting of new generation and also ensures that merit order of generating stations does not get distorted. The overall tariff framework should be such as not to inhibit planned development/ augmentation of the transmission system, but should discourage non-optimal transmission investment.*

...

*(5) The **Central Commission would establish, within a period of one year, norms** for capital and operating costs, operating standards and performance indicators for transmission*

lines at different voltage levels. Appropriate baseline studies may be commissioned to arrive at these norms.

(6) Investment by transmission developer other than CTU/STU would be invited through competitive bids. ***The Central Government will issue guidelines in three months for bidding process for developing transmission capacities.*** *The tariff of the projects to be developed by CTU/STU after the period of five years or when the Regulatory Commission is satisfied that the situation is right to introduce such competition (as referred to in para 5.1) would also be determined on the basis of competitive bidding.*

(7) After the implementation of the proposed framework for the inter-State transmission, ***a similar approach should be implemented by SERCs in next two years for the intra-State transmission****, duly considering factors like voltage, distance, direction and quantum of flow."*

Thus, the proposed transmission pricing framework under MYT regime will have to be in line with National Electricity Policy guidelines and in conformity with the conditions outlined under the Tariff Policy. Further, the proposed transmission pricing framework will have to be compatible with various provisions pertaining to Transmission Capacity Rights of Transmission System Users (TSUs), their trading, non-utilisation, part-utilisation, excess utilization, etc., as outlined under Open Access Regulations notified by the Commission from time to time. It would be equally important to identify various elements and components comprising the Intra-State Transmission System in order to establish Transmission Capacity Rights and utilization thereof, for which, transmission charges shall be levied.

Regulation 57 of GERC Tariff Regulations, 2005, stipulates as under:

> *"57.* ***Sharing of charges for intra-state assets:*** *In case of more than one long-term transmission customer of the state transmission system, the monthly transmission charges leviable on each long-term transmission customer shall be computed as per the following formula:*

Transmission Charges for intra-regional system payable for a month by a long-term transmission customer of that transmission system

$$= \left(\sum_{i=1}^{n} \left(\frac{TCi}{12} \right) - TRSC \right) X \frac{CL}{SCL}$$

Where TCi = Annual Transmission Charges for the i^{th} project in the state computed in accordance with regulation 56

n = Number of projects in the region

TRSC = Total recovery of transmission charges for the month from Short-term transmission customers for the regional transmission system in accordance with the Gujarat Electricity Regulatory Commission (Open Access in Intra-State Transmission Regulations, 2005).

CL = Allotted Transmission Capacity to the long-term transmission customer

SCL = Sum of the Allotted Transmission Capacities to all the long-term transmission customers of the state transmission system."

CERC has notified the CERC (Sharing of Inter State Transmission Charges and Losses) Regulations, 2010, which will have to be considered separately by the Commission, while formulating the transmission pricing framework for the State, keeping in view the industry structure and the transmission network.

5.3 Key issues in Transmission for the next Control Period

5.3.1 Objectives of Transmission Pricing

The Transmission pricing framework under MYT regime, in addition to meeting the transmission revenue requirement, needs to be guided by key considerations such as economic and efficient use of transmission network, non-discriminatory approach, encouraging investment, supporting the development of market/trading opportunities, etc. A well designed Transmission pricing scheme should:

- Provide economic signals for efficient use of transmission resources;
- Provide economic signals for investment in transmission;

- Provide economic signals for location of new generation and loads;
- Promote efficient day to day operation of the bulk power market including power trading;
- Compensate the owner of the transmission system by meeting its revenue requirement including returns; and
- Be simple and practical.

5.3.2 Key Issues related to Transmission in next Control Period

Key issues to be addressed in respect of Transmission during next Control Period can be classified into two broad categories as under:

A] Regulating performance of transmission licensees

- What should be operating norms and performance standards for transmission licensees within State?

B] Regulating Transmission System Usage

- How should transmission system usage be defined and monitored in case of usage by various transmission system users (TSUs)?
- Whether distinction in transmission pricing should be made depending on tenure of usage (long term/medium term/short term)?

The above issues are deliberated in detail in subsequent sections.

5.4 Regulating Transmission Licensees & Performance Standards

5.4.1 Regulating Capital Investment

5.4.1.1 Business Plan

As discussed in earlier section, the transmission licensees need to submit a Business Plan, which shall cover the following factors.

a) Capital Investment Plan

b) Financing Plan

Such Business Plan should be formulated in a way to ensure the following

a) Improvement in efficiency and availability of transmission system;

b) Reduction in transmission loss;

c) Increase system reliability, safety and security;

d) Increase transparency and accountability of operations;

e) Improve metering to achieve optimal control of the transmission system;

5.4.2 Regulating Operating Performance: O&M Norms

The O&M norms are proposed to be formulated for the transmission business, based on past trends and a benchmarking exercise to derive O&M expenses per bay and lines.

5.4.2.1 Norms for O&M expenditure for Intra State Transmission Licensee(s) as per GERC (Terms And Conditions Of Tariff) Regulations 2005:

The norms specified in GERC (Terms and Conditions of Tariff) Regulations 2005, for Intra State Transmission Licensees are reproduced below:

Norms for O&M expenses per ckt-km and per bay

	Year				
	2004-05	2005-06	2006-07	2007-08	2008-09
O&M expenses (Rs. in lakh per ckt-km)	0.227	0.236	0.246	0.255	0.266
O&M expenses (Rs. in lakh per bay)	28.12	29.25	30.42	31.63	32.90

The above norms were in line with the norms specified for O&M expenditure for Inter-State Transmission Licensee as per CERC (Terms and Conditions of Tariff) Regulations, 2004.

However, GETCO, in its Tariff Petition for FY 2006-07 submitted that O&M expenditure if calculated on the basis of norms specified in GERC Tariff Regulations, will be substantially higher than actual O&M expenses.

Similarly, in the MYT Petition and subsequent APR Petitions, GETCO has claimed O&M expenditure on actual basis and projected for ensuing years on the basis of certain escalation on actual expenses.

It is observed that in Gujarat, 66 kV substations are part of Transmission Licensee's assets, due to which number of bays and Ckt.Km substantially increases, when compared with PGCIL which has 220 kV and above assets , for which CERC had specified norms.

Therefore, it is preferable to customise the norms for O&M expenditure specified in GERC (Terms and Conditions of Tariff) Regulations 2005 and specify norms appropriate for the Transmission Licensee(s), which will be suitable considering their network topology/configuration, historical growth pattern and cost structure for the State of Gujarat.

5.4.2.2 Norms for O&M expenditure for Inter State Transmission Licensee(s) as per CERC(Terms And Conditions Of Tariff) Regulations 2009-

Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2009 notified on January 19, 2009 has specified the norms for O&M expenses for Transmission Licensees handling Inter State Transmission of power. CERC has specified voltage wise norms and separate norms for line assets and substation assets.

The total allowable operation and maintenance expenses for the transmission system is to be calculated by multiplying the number of bays and km of line length with the applicable norms for the operation and maintenance expenses on per bay and per km basis, respectively. Since SERCs are supposed to be guided by the basis of formulation of norms specified by CERC, it would be preferable to develop norms for O&M expenditure in terms of per ckt. Km and per bay basis.

5.4.2.3 Norms for O&M expenditure for Intra State Transmission Licensee(s) for the next Control Period (FY 2011-12 to FY 2015-16)

Various components of O&M expenses such as number of employees and employee related expenses thereof, R&M expense, A&G expense depend on the physical network parameters such as substations, transmission lines, etc. The transmission line length (ckt-km) and number of substations (or bays) represents important cost drivers for the O&M expenses. The norms for O&M expenses can be derived considering these two important cost drivers in terms of Rs Lakh per bay and Rs Lakh per ckt-km. O&M expenses need to be allocated amongst substation bays and ckt-km in some ratio depending on ratio of gross fixed asset base (GFA) for substation/lines and manpower required to cater to bays/lines. However, in the absence of information about asset base, manpower allocation, etc., the ratio for allocation of O&M expense between transmission bays and transmission lines has been considered as 70:30 for the purpose of comparative analysis of derived O&M norms across State transmission utilities.

While voltage-wise distinction in terms of norms is desirable as R&M component of O&M expenses varies significantly depending on the voltage level, however, at this stage, it will be preferable to make distinction in terms of key cost drivers such as transmission line length and number of bays.

For the purpose of deriving O&M norms, the 'Bay' has been considered as a set of accessories that are required to connect an electrical equipment such as Transmission line, Bus Section Breakers, Potential Transformers, Power Transformers, Capacitors and Transfer Breaker and the feeders emanating from the bus. Further, the Bays considered here include only the ones of a Transmission substation and thus excludes any bays of the Generating Station switchyard whose maintenance is usually the responsibility of the Generating Company.

The methodology for formulation of O&M norms is elaborated as under:

a) The year-wise approved O&M expenses (from FY 2008-09 to FY 2010-11) have been allocated among bays and transmission line length (ckt. km) in the ratio 70:30. This ratio should be on the basis of share of substation related asset base and transmission line related asset base, out of the total asset base. In the absence of data related to share of substation related asset base and transmission line related asset base, a ratio of 70:30 has been considered for calculation of O&M norms.

   The O&M expenses approved by the Commission for GETCO for previous years are as under:

(in Rs. Cr)

Particulars	FY 2008-09	FY 2009-10	FY 2010-11
Employee Cost excl. Impact of Pay revision	*246.00*	*381.08*	*398.71*
Impact of Pay revision	*90.46*	*30.15*	*-*
Total Employees cost	**336.46**	**411.23**	**398.71**

Particulars	FY 2008-09	FY 2009-10	FY 2010-11
Repair & Maintenance expenses	**91.85**	**97.36**	**103.20**
A & G expenses	**45.85**	**47.57**	**47.78**
O&M Expenses	**474.16**	**556.16**	**549.69**

It may be noted that the impact of pay revision, which has been considered as an uncontrollable factor, and other O&M expenses have been considered as approved by the Commission in its APR Order of FY 2008-09 and FY 2009-10. However, if the Utilities are able to submit the audited data for actual O&M expenses, the Commission may consider the same while finalisation of GERC MYT Regulations, 2010.

The O&M Expenses for bays and lines have been derived by allocating O&M Expenses between bays and lines in the ratio of 70:30, as shown below:

O&M Expenses for Bays & Lines (Rs. Cr)

Particulars	FY 2008-09	FY 2009-10	FY 2010-11
O&M Expenses for Bays	331.91	389.31	384.78
O&M Expenses for Lines	142.25	166.85	164.91

b) Based on the above allocation to bays and transmission lines, O&M expense per circuit-km and O&M expense per bay has been computed for each year of the last Control Period (FY 2008-09 to FY 2010-11) by dividing the O&M expenses for lines/bays with the total line length in km/total number of bays in respective years.

The O&M Expenses per Bay and per Ckt. Km so derived are shown below:

Particulars	FY 2008-09	FY 2009-10	FY 2010-11	Average
O&M Expenses/Bay (Rs. Lakh/Bay)	5.00	5.63	5.35	**5.33**
O&M Expenses/Ckt. Km. (Rs Lakh/ Ckt.Km)	0.39	0.43	0.42	**0.41**

c) The norm for the next Control Period has been derived based on the average of the norms for the period from FY 2008-09 to FY 2010-11 in terms of Rs Lakh/ckt km and Rs Lakh/bay for GETCO. The average norm so derived has been escalated by applying suitable inflation indices comprising weighted average of wholesale price index (WPI) and consumer price index (CPI) to arrive at the norms for FY 2011-12. O&M norms for rest of the new control period from FY 2012-13 to FY 2015-16 have been arrived at by further applying suitable inflation indices comprising weighted average of wholesale price index (WPI) and consumer price index (CPI).

CERC, in its CERC Tariff Regulations, 2009 has specified a escalation factor of 5.72% for projecting O&M expenses for the next Control Period.

It is proposed to accept the escalation factor specified by CERC. Accordingly, the derived O&M norms are shown below:

Table: O&M Expense norms from FY 2011-12 to FY 2015-16 in Rs. Lakh/Bay and Rs. Lakh/Ckt. Km

Particulars	2011-12	2012-13	2013-14	2014-15	2015-16
O&M Expenses/Bay	5.63	5.95	6.29	6.65	7.04
O&M Expenses/Ckt Km	0.44	0.46	0.49	0.51	0.54

5.4.3 Transmission pricing methodology sensitive to Distance

Presently, the intra State transmission pricing framework in the State of Gujarat is based on a "Postage Stamp" approach which is in line with the previous CERC Regulations, which is insensitive to the distance but offering significant other advantages such as simplicity, ease in understanding/usage, and is also a time tested approach. However the same approach is not in accordance with the National Electricity Policy (NEP) and the Tariff Policy (TP) notified by the Central Government.

The CERC has recently notified new Regulations on pricing methodology for Inter State transmission, to make it in line with the requirements of NEP and TP. The salient features of the Approach Paper are given below.

a. All users of ISTS network (called as DICs or Designated ISTS Customers) would have to pay charges and bear loss compensation depending on where they are placed in the national network. Such charges will be called PoC (Point of Connection) Charges. For example, for generators located close to a load centre, the charges would be relatively less, and vice-versa. Similarly, demand customers located near generation hubs would have relatively lesser charges or losses allocated to them.

b. The PoC charges will be a hybrid of charges determined through the Marginal Participation and the Average Participation Methods of determination of Transmission Charges.

c. The Implementing Agency (IA) (agency designated by the CERC to undertake the estimation of the transmission charges and transmission losses at the various nodes/zones) shall collect the basic network data pertaining to the network elements and the generation and load at the various network nodes from all concerned entities including DICs, generating stations/companies, transmission licensees, distribution licensees, NLDC, RLDCs, SLDCs, RPCs.

d. The IA will run the PoC methodology to allocate transmission charges and losses.

e. No differentiation in rates is proposed between the long-term, medium-term and short-term users of the transmission system. However, these would be accorded in decreasing order of priority in event of system constraints.

f. No transmission charges for the use of ISTS network shall be charged to solar based generation. This shall be applicable for the useful life of the projects commissioned in next three years.

g. The RPCs shall maintain accounts of the ISTS charges to be collected from each DIC of the ISTS based on information provided by the CTU. The bills would be raised based on the final accounts certified by the RPCs.

h. In the case of transactions through the Power Exchange, the demand DIC shall pay the zonal PoC charges applicable to the zone where such demand customer is physically located and the generator DIC shall pay the transmission charges as per the PoC transmission charge applicable to the zone where such a generator is located.

i. The constituents and service providers on the ISTS shall enter into new transmission services agreement or modify the existing BPTAs to incorporate the new tariff and related conditions. Such agreement shall govern the provision of transmission services and charging for the same shall be called the transmission Connection and Use of Service Agreement (CUSA).

j. The CTU shall be responsible for raising the transmission bills for the entire ISTS irrespective of ownership, collection and disbursement of transmission charges to all other transmission licensees, whose assets have been used for the purpose of inter-State transmission of power. For such services, the CTU shall be entitled to levy and recover a charge from DICs as approved by the Commission.

k. For implementation, in the first two years, it is proposed that the Commission will apply transmission charges and losses based on a combination of PoC methodology and a Postage Stamp methodology in a ratio of 50:50. The Commission may consider increasing the locational signal by reducing the proportion of the postage stamp component over time.

CERC notified Regulations on the same and after due consideration of the alternative methodologies for allocation of transmission charges and the comments received from various stakeholders has considered implementation of the Point of Connection (PoC) methodology based on a hybrid method, which brings together the strengths of both the Marginal Participation and the Average Participation Method discussed in the Approach Paper.

Under the recently notified Regulations for sharing of transmission charges and losses for inter-State regional transmission system, in the first two years, the Commission will apply transmission charges and losses based on a combination of PoC methodology and a Postage Stamp (i.e., one single charge / loss percentage for all DICs - Designated Inter-State Customers) methodology in a ratio of 50:50. The Commission may consider increasing the locational signal by reducing the proportion of the postage stamp component over time.

However, the selection of distance sensitive approach would require careful evaluation of implications for various distribution companies (DISCOMs) on account of power flow from source (generating stations) to various regions.

Besides, as highlighted under earlier section, CERC has initiated process for review of Transmission Pricing framework for regional transmission system. The same may be evaluated by Forum of Regulators before introduction at State level, as per provisions of the Tariff Policy.

Hence, at this stage, it may be preferable to continue uniform Postage Stamp approach across the State.

5.5 Target Transmission Availability for recovery of ARR of Transmission Licensee

The Commission in its GERC (Terms & Conditions of Tariff) Regulations, 2005 (GERC Tariff Regulations) had stipulated the target Transmission Availability norms for full recovery of ARR of a Transmission Licensee in the State of Gujarat, as under:

*"50. **Target Availability for recovery of full transmission charges**:*

(1)	*AC system*	*: 98%*
(2)	*HVDC bi-pole links and HVDC back-to-back stations*	*: 95%*

Note 1

Recovery of fixed charges below the level of target availability shall be on pro rata basis. At zero availability, no transmission charges shall be payable."

Subsequently, CERC in its CERC (Terms & Conditions of Tariff) Regulations, 2009, has specified Normative Annual Transmission System Availability Factor (NATAF) for HVDC bi-pole links for recovery of ARR of Central Transmission Utilities (CTUs) from Transmission System Users (TSUs), as under:

(1)	AC system	: 98%
(2)	HVDC bi-pole links	: 92%
(3)	HVDC back-to-back Stations	: 95%

The Commission, in its Order dated January 17, 2009, has approved availability for GETCO, as under:

Table 4.13

Availability of GETCO Transmission system 2007-08 and 2008-09 to 2010-11

Description	2007-08	2008-09	2009-10	2010-11
		Projections		
400 kV lines	98.37%	99.38%	99.39%	99.40%
220 kV lines	98.80%	98.87%	98.94%	99.00%
132 kV lines	98.88%	98.91%	98.94%	98.98%
66 kV lines	99.58%	99.62%	99.66%	99.70%
Sub stations	99.83%	99.87%	99.89%	99.94%
GETCO system availability	99.29%	99.33%	99.36%	99.40%

Commission's view

The GETCO operates only A.C. system and the availability of its system is over 99% and is higher than the norm of 98% specified by the Commission. The reliability is considered good.

In this regard, the Commission in its APR Order for FY 2009-10 dated December 14, 2009 ruled that:

"The Commission has examined the submission of the petitioner. The Commission has observed that the target availability for FY 2008-09 approved under the MYT Order is 99.33%. In this regard the Commission has noted that Regulation 8.2 of the MYT Regulations provides that trajectory provided under MYT Regulations shall replace trajectories fixed under any other regulation.

Based on the approach adopted, and the method described under the GERC's Terms and Conditions, the Commission has computed the incentive for FY 2008-09 as Rs 0.042 crores."

It is worthwhile here to analyse the Transmission Availability achieved by GETCO during the last Control Period, as shown in the Table below:

(In Percent)

FY	FY 2008-09 (Actual)	FY 2009-10 (Actual)	FY 2010-11 (Approved)
Transmission Availability of GETCO	99.56	99.61	99.62

It can be seen that the actual Transmission Availability of GETCO in FY 2008-09 and FY 2009-10 was higher than the normative Transmission Availability stipulated in the MYT Order, as mentioned above.

It is proposed to accept the norms specified in CERC (Terms & Conditions of Tariff) Regulations, 2009. The Transmission Licensee shall be eligible for receiving incentive from Transmission System Users (TSUs) if the actual Transmission Availability is more than the target Availability. If the actual Transmission Availability is less than the target norms, then ARR shall be recoverable on pro-rata basis. For zero Transmission Availability, no transmission charges shall be payable by Transmission System Users (TSUs).

GERC Tariff Regulations, 2005 specifies the incentive mechanism as under:

> *"58. Incentive :*
>
> *(1) The transmission licensee shall be entitled to incentive @ 1% of equity for each percentage point of increase in annual availability beyond the target availability prescribed under regulation 51, in accordance with the following formula:*
>
> *Incentive = Equity x [Annual availability achieved – Target availability] / 100*
>
> *(2) Incentive shall be shared by the long-term customers in the ratio of their average allotted transmission capacity for the year."*

For the next Control Period, it is proposed to continue with the incentive mechanism as outlined under GERC Tariff Regulations, 2005.

5.6 Transmission Pricing based on tenure of usage (Long term, Medium term and Short term)

Tenure of Usage and charges payable for Open Access charges shall be in accordance with the Gujarat Electricity Regulatory Commission (Open Access in Intra-state Transmission and Distribution) Regulations, 2005 and as amended through Orders issued by the Commission from time to time.

6 Norms and Principles for Determination of Wheeling Charges for Distribution Wires Business

6.1 Brief historical background of Distribution Sector in Gujarat-

The Government of Gujarat notified the Gujarat Electricity Industry (Reorganization and Regulation) Act 2003, in May 2003, for the reorganization of the entire power sector in the State of Gujarat. Pursuant to the above, Government of Gujarat in its letter vide GO/19th August, 2003, had directed the erstwhile Gujarat Electricity Board (GEB) to form four Distribution Companies (DISCOMs), based on geographical location of the circles. Accordingly, the four distribution companies were incorporated with the Registrar of Companies on 15th September, 2003.

The DISCOMs are:

a. Paschim Gujarat Vij Company Ltd.(PGVCL)
b. Uttar Gujarat Vij Company Ltd.(UGVCL)
c. Madhya Gujarat Vij Company Ltd.(MGVCL)
d. Dakshin Gujarat Vij Company Ltd.(DGVCL)

On 15th October, 2003, all the DISCOMs obtained their certificate of Commencement of Business. However, the Companies started their commercial operation from 1st April, 2005.

In addition to above mentioned Distribution Licensees, Torrent Power, a company incorporated under Companies Act, 1956 is carrying on the business of generation and distribution of electricity, distributes power to around 1.9 million customers in the cities of Ahmedabad, Gandhinagar and Surat, spanning an area of 408 Sq. Km. These cities are major industrial and commercial hubs of Gujarat State

TPL is an amalgamation of Torrent Power AEC Limited (TPAL), Torrent Power Surat Limited (TPSL) and Torrent Power Generation Limited (TPGL). Torrent Power Limited is a deemed licensee for distribution of electricity under Section 19 (1) (d) read with Section (19) (1) (i) of Gujarat Electricity Industry (Reorganization and Regularization) Act 2003 and under Section 14 of Electricity Act 2003. The Commission had granted approval to the transfer/assignment of licenses granted to Torrent Power AEC Limited and Torrent Power SEC Limited so as to incorporate the name of TPL as a licensee in place of TPAL and TPSL in their respective licenses.

The Commission has also issued distribution licensees to three other entities, viz., MPSEZ Utilities Pvt. Ltd. (MUPL), Torrent Energy Limited (TEL) and Kandla Port Trust (KPT).

Thus, the State has a mix of public and privately owned as well as old and new distribution licensees.

6.2 Separate Petition by each Distribution Licensee

It is observed that TPL holds two separate licences for the two areas of supply, i.e., Ahmedabad/Gandhinagar and Surat. However, TPL files a single Petition for the purpose of tariff determination, for both licence areas

In this context, GERC its Tariff Order dated March 31, 2010, ruled that ARR and tariff for each area should be determined separately.

Hence, it is proposed that this issue may be clarified very clearly in GERC MYT Regulations, 2010.

6.3 Components of ARR for Wires Business of Distribution Licensee

The distribution licensees in the State of Gujarat receive electricity at the Transmission - Distribution (T< >D) interface points through the Intra-State Transmission System. From the T< >D interface, the electricity is distributed to the individual consumers' premises using the distribution network. The business of owning and operating the distribution network is called as the Distribution Wires Business (Wires Business), as distinct from the Retail Supply Business, which has a contract with the consumer for supply of electricity and enters into long-term and short-term power purchase contracts for the required quantum of electricity. For the second Control Period, it is proposed that Aggregate Revenue Requirement of the Wires Business shall be recovered through the wheeling charges of the Distribution Licensee and shall comprise of the following:

a) Return on Equity;

b) Interest Expenses.

c) Depreciation;

d) Operation and maintenance expenses;

e) Interest on working capital and deposits from Distribution System Users;

f) Contribution to contingency reserves

Wheeling charges = Aggregate Revenue Requirement, as computed above, minus:

g) Non-tariff Income;

h) Income from Other Business;

i) Receipts on account of additional surcharge on charges of wheeling.

6.4 Distribution Loss vs. AT&C loss

Technical Losses: Every element in a power system (a line or a transformer, etc.) offers resistance to power flow and thus, consumes some energy while performing the duty expected of it. The cumulative energy consumed by all these elements is classified as **"Technical Loss".**

Commercial Losses: Losses that occur on account of non-performing and under-performing meters, wrong application of multiplying factors, defects in CT and PT circuitry, meters not read, pilferage by manipulating or by-passing of meters, theft by direct tapping, etc., correspond to energy consumed but not metered or billed and are hence, categorised as "**commercial losses**".

The combination of "Technical" and "Commercial" losses in the electricity distribution business is termed as **Distribution loss.**

It is unfortunate that in addition to the above, there is also a loss in revenue collected due to non-realisation of amount. The aggregate of Distribution loss and revenue loss due to non-realisation (collection inefficiency) is termed as **"AT&C loss"** (Aggregate Technical and Commercial loss). Therefore, AT&C loss of the distribution licensee is the combination of technical losses, commercial losses and collection inefficiency.

Since the beginning of the reform process, distribution loss reduction has been one of the primary benchmarks for measuring the performance of a distribution Utility. The SERCs have either adopted distribution losses reduction or AT&C loss reduction approach as a performance benchmark. The Commission, in the existing GERC Tariff Regulations as well as in Tariff Orders, has adopted the distribution loss reduction approach for measuring the performance of distribution licensees. At this point, it would be appropriate to analyse the merits and demerits of each approach.

Distribution loss reduction is a widely used approach at the national and international level to measure the performance of the distribution licensee. Distribution loss is simple to compute as it takes into account the energy input and energy billed to the consumers, thereby taking into consideration the technical losses and unaccounted energy due to theft and misuse. However, in many cases, the actual distribution losses are estimated to be higher than the reported losses, on account of the assessment of un-metered agricultural consumption. Thus, distribution loss method has certain limitations, particularly in case of significant un-metered consumption.

On the other hand, AT&C loss method covers the whole basket of losses of the distribution system and includes technical losses, billing inefficiency, theft, and collection inefficiency. If units sold, units billed and units collected can be computed accurately, then AT&C loss method would be the best indicator of measuring the efficiency of the distribution licensee. However, computation of AT&C losses leads to creation of complexities as it combines technical and commercial parameters, i.e., energy input in units and amount collected in Rupees. Some other issues in AT&C loss computation are as follows:

- Units realised have to be derived based on units billed and collection efficiency
    - Units billed may not be measured accurately due to un-metered consumption, thus having the same deficiency as distribution loss method
    - Revenue collected may include the past arrears
    - Amount collected against other charges may not be separately accounted for
    - If AT&C loss computation is attempted on cash basis alone (Total amount collected/total amount spent), it can lead to distorted results.

Considering the high commercial losses in the Indian power system, the Tariff Policy framed under Section 3 of Electricity Act 2003 has favoured the adoption of the AT&C loss method, as reproduced below:

"5(a) The State Commission may consider 'distribution margin' as basis for allowing returns in distribution business at an appropriate time. The Forum of Regulators should evolve a comprehensive approach on "distribution margin" within one year. ***The considerations while preparing such an approach would, inter-alia, include issues such as reduction in Aggregate Technical and Commercial losses****, improving the standards of performance and reduction in cost of supply."* ***(Emphasis added)***

However, till date, only few SERCs like Delhi Electricity Regulatory Commission have adopted the AT&C loss approach for approving the ARR and tariff of distribution licensees. The Orissa Electricity Regulatory Commission has recognised AT&C Loss as a performance parameter for measuring, monitoring and controlling the efficiency of the operation of the distribution licensees, however, for approving the ARR and tariff, OERC has considered distribution loss targets and not the AT&C loss targets.

The Commission has specified the Distribution Loss reduction trajectory while determining the ARR of the distribution licensees.

In this context, the FOR report on MYT framework and distribution margin recommends as under:

"2.4.13 After discussing the merits and demerits of measuring losses in terms of AT&C loss or Transmission and Distribution (T&D) loss, ***it was agreed that it is only the distribution loss which could be measured, and transmission losses should be dealt with separately****. For purposeful measurement of distribution loss, Automated Meter Reading (AMR) based feeder metering and transformer metering is essential…."*

The question to be asked here is whether the distribution licensees' collection inefficiency should also be passed on to the consumers. It appears illogical that the other consumers should pay for the licensees' inability to collect the billed amounts from the consumers to whom it has sent the bills. Further, the inclusion of collection inefficiency by determining the tariffs on the basis of AT&C loss will result in further increase in the consumers' tariff, if collection efficiency is less than 100%. Also, in cases where collection efficiency is equal to 100%, AT&C losses would be equal to distribution loss.

Considering this aspect and in view of issues discussed above, **it is proposed to continue with Distribution Loss approach for approving the ARR and Tariff of Distribution Licensees in the State**.

6.5 Wheeling Loss determination

For determination of wheeling loss, the technical loss of distribution system needs to be projected by the Utilities in their respective Business Plans and it is proposed that based on prudence check of the existing and approved losses, capital investment proposed in this regard, etc., the Commission shall determine the wheeling loss trajectory for the Utilities.

6.6 Separation of Accounts for Wire related and Retail Supply related business

Section 62 of the EA 2003 requires the State Electricity Regulatory Commission (SERC) to determine the tariff for Wheeling and Retail supply of electricity. Section 42 of the EA 2003 requires the SERC to introduce open access in the distribution system in a phased manner and stipulates that the duties of the distribution licensee with respect to such supply shall be of a common carrier providing non-discriminatory open access. Also, under Section 9 of the EA 2003, captive consumers are required to pay wheeling charges for availing open access, and are exempted from payment of cross-subsidy surcharge and additional surcharge. Therefore, wheeling charges are to be paid by any person for availing open access using the distribution licensee's network.

It is proposed to emphasise on the separation of the accounting of wires related costs and supply related costs, which is essential for un-bundling of cost and tariff components and forms a pre-requisite for appropriate determination of wheeling charges and affects open access transactions as mandated under the EA 2003.

The existing GERC MYT Regulations also stipulate that the distribution licensees should submit separate ARR for Wheeling Business and Retail Supply Business.

Apportioning of wires and supply cost

In addition to the expense heads to be excluded while determining the wires cost, the portion of the O&M expenses related to the supply business needs to be excluded. On the other hand, the majority of the capital expenditure related expenses, viz., depreciation, interest and Return on Equity/Capital Employed, would have to be included under the Wires Business rather than the Supply Business, since the Wires Business is required for the purpose of wheeling electricity from the point of injection to the point of drawal. The Supply Business would require only a small component of the capital expenditure towards billing and collection activity.

GERC has determined the wheeling charges for State Owned Distribution Utilities in Gujarat by considering all the costs except power purchase cost (which included Transmission Charges) as attributable to wires (wheeling) business. The allocation matrix adopted by the Commission for allocating costs between wires and supply business for State-owned DICSOMs is as shown below:

Particulars	Wires Business (%)	Supply Business (%)
Total Power Purchase Cost	0%	100%
Employee Expenses	100%	0%
A&G expenses	100%	0%
R&M expenses	100%	0%
Depreciation	100%	0%
Interest on Long Term Loans	100%	0%
Interest on Consumer Deposit	100%	0%
Interest on Working Capital	100%	0%
Provision of Bad Debts	100%	0%
Contingency Reserve	100%	0%
Income Tax	100%	0%
Return on Equity	100%	0%
Non-tariff Income	0%	100%

The total power purchase cost for the State Distribution Utilities in Gujarat would consist of (As per GERC Tariff Orders for State DISCOMs, FY 2010-11):

a) Cost of the energy or power purchase cost based on PPA allocation and merit-order despatch

a. Transmission charges of GETCO and PGCIL

b. SLDC fees and charges

c. Allocated gap/surplus of GUVNL

d. E-Urja Cost (part of GUVNL cost).

While apportioning the cost between Wires Business and Supply Business for Torrent Power Ltd., the Commission has followed the following allocation matrix for determination of wheeling charge, based on the submissions made by TPL:

Particulars	Wires Business (%)	Supply Business (%)
Power Purchase	0%	100%
Employee Expenses	50%	50%
A&G expenses	40%	60%
R&M expenses	80%	20%
Depreciation	80%	20%
Interest on Long Term Loans	80%	20%
Interest on Consumer Deposit	0%	100%
Interest on Working Capital	20%	80%
Provision of Bad Debts	0%	100%
Contingency Reserve	80%	20%
Income Tax	80%	20%
Return on Equity	80%	20%
Non-tariff Income	0%	100%

Source: GERC Tariff Orders for TPL (FY 2008-09 & FY 2010-11)

Here, it is worthwhile to analyze each component of the ARR for apportioning costs between Wires Business and Supply Business.

a. Power Purchase Cost- The cost incurred for procuring power for supply can be entirely allocated to supply business.

b. Employee Expenses- Employee Expenses are related directly to the employees of the business and comprise of basic salary, dearness allowance, overtime, other allowances, earned leave encashment, terminal benefits, etc. Most of the employees posted at sub-stations and field offices are for operation and maintenance purpose and the employees engaged in supply functions are less in comparison to employees for operation and maintenance. Therefore, the proportion of employee cost allocated to wires business should be higher than the proportion allocated to supply business.

c. A&G expenses- A&G expenses consist of rents, telephone & electricity charges, postage, printing and stationery, computer and other charges.

Expenses incurred for bill printing, postage and collection relate to supply business, while other A&G costs are incurred for operation and maintenance purpose. Therefore, the proportion of A&G expenses allocated to supply business may be same as that allocated to wires business.

d. R&M expenses- R&M expenses are incurred for preventive maintenance, improvement in system conditions and reduction of breakdowns. Most of these expenses relate to maintenance of distribution lines and sub-station equipments and a small fraction is attributable to supply business. Therefore, the proportion of R&M expenses that can be allocated to wires business and to supply business may be taken as 90:10.

e. Depreciation – Depreciation should ideally be derived by applying appropriate depreciation rates to the fixed assets separately employed for wires business and supply business. In the absence of data regarding Gross Fixed Assets (GFA) rated to both the businesses, depreciation expense can be allocated using a suitable proportion. Since most of the assets of a Distribution Utility are for wires business, the ratio of depreciation allocated between the two businesses may be taken as 90:10.

f. Interest on Long Term Loans- Since the term loans taken by utilities are for expansion of network infrastructure or for strengthening of power transmission facilities, a major portion of this expense should be allocated to wires business. The proportion of interest on long term loans allocated between two businesses may be taken as 90:10.

g. Interest on Working Capital and on Consumer Deposit- Security deposits are collected by the DISCOMs from the consumers for supplying electricity to them. Similarly, a major part of working capital is required for supply business. So the ratio of Interest on Working Capital and on Consumer Deposit allocated between the wires and supply business may be taken as 10:90.

h. Provision for bad debts- This provision is made for recognising that a part of the receivable will not be recoverable in future. Major part of this expense is attributable to non recovery dues from consumers. However, a small part can be allocated to wires business also. The proportion between wires business and supply business may be taken as 10:90.

i. Contingency Reserve- This provision is created for meeting any contingency in future. Since most of the assets employed are for wires business of the utility, the proportion between wires business and supply business can be 90:10.

j. Income Tax- Tax should be allocated based on the returns from business. Since a major part of equity or capital invested by the utility is for wires business, the ratio of allocation of income tax between two functions may be taken 90:10.

k. Return on Equity - Since a major part of equity or capital invested by the utility is for wires business, the ratio of allocation of income tax between two functions may be taken 90:10.

l. Non-tariff Income- Non-tariff Income is because of interest on consumer arrears, interest on delayed payments, recoveries from theft of power, rebate on power purchase, interest on other investments, income from rents, etc. A major part of this income corresponds to supply business and therefore, the allocation between wires business and supply business should be done in the ratio 10:90.

Hence, it is proposed that the following allocation matrix may be followed for the purpose of calculation of wheeling charge:

Table 1: Proposed allocation matrix for expense segregation of Wires and Supply Business

Particulars	**Wires Business (%)**	**Supply Business (%)**
Power Purchase Expenses	0%	100%
Standby Charges	0%	100%
Employee Expenses	60%	40%
Administration & General Expenses	50%	50%
Repair & Maintenance Expenses	90%	10%
Depreciation	90%	10%
Interest on Long-term Loan Capital	90%	10%
Interest on Working Capital and on consumer security deposits	10%	90%
Bad Debts Written off	10%	90%
Income Tax	90%	10%
Transmission Charges intra-State	0%	100%
Contribution to contingency reserves	90%	10%
Return on Equity	90%	10%
Non-tariff Income	10%	90%

6.7 *Operation & Maintenance Expenses - Norm for Wires Business*

The O&M expenses comprise of Employee Expenses, R&M Expenses and A&G expenses, and constitute a significant part of the Aggregate Revenue Requirement of the distribution licensee.

In this context, the FOR Report on MYT framework and distribution margin has recommended as under:

> *"2.5.14 O&M expenditure should be allowed on a normative basis by prescribing this in the regulations."*

Approaches for determining the normative O&M expenses

The methodology for formulation of O&M norms is elaborated as under:

a) The year wise approved O&M expenses have been compiled based on the latest Tariff Orders issued for FY 2008-09, FY 2009-10 and FY 2010-11. An escalation factor of 5.72% has been applied to the average of these years to re-compute norm for FY 2010-11.

b) Based on approved sales for FY 2010-11, O&M expense per unit is calculated. The calculation is tabulated below:

In Rs Crore

Particulars	FY 09	FY 10	FY 11	3-Year Average	Normalised for FY 2010-11	O&M Expense FY 11 (Rs/kWh)
PGVCL	387.68	426.54	420.85	411.69	435.24	0.31
DGVCL	153.1	180.02	178.2	170.44	180.19	0.18
UGVCL	296.72	321.97	314.8	311.16	328.96	0.26
MGVCL	200.51	293.40	283.4	259.10	273.92	0.44
TPL-Ahmedabad	167.57	177.63	188.29	177.83	188.00	0.33
TPL-Surat	84.84	89.92	95.32	90.03	95.18	0.30

c) O&M expense per unit so derived, is segregated into wires and supply business based on weighted average allocation, based on proposed allocation matrix and is tabulated below:

In Rs/kWh

Particulars	FY 2010-11			
	Wires Business	Supply Business	Wires Business	Supply Business
PGVCL	64%	36%	0.20	0.11
DGVCL	62%	38%	0.11	0.07
UGVCL	63%	37%	0.17	0.10
MGVCL	62%	38%	0.27	0.17
TPL-Ahmedabad	69%	31%	0.23	0.10
TPL-Surat	64%	36%	0.20	0.11

d) Projection of Wires Business O&M expenses has been done by using escalation of 5.72%. Proposed Norms for wires business are tabulated below:

In Rs/kWh*

Particulars	FY 12	FY 13	FY 14	FY 15	FY 16
PGVCL	0.21	0.22	0.24	0.25	0.26
DGVCL	0.12	0.13	0.14	0.14	0.15
UGVCL	0.18	0.19	0.20	0.21	0.22
MGVCL	0.29	0.30	0.32	0.34	0.36
TPL-Ahmedabad	0.24	0.26	0.27	0.29	0.30
TPL-Surat	0.21	0.22	0.23	0.24	0.26

Note: O&M Norm will be calculated by multiplying the above norm with Energy Handled by Wires Business.

6.8 Wheeling Charge Determination

The wheeling charges of the Distribution Licensee shall be determined by the Commission on the basis of an Application for determination of tariff made by the Distribution Licensee in accordance with the MYT Regulations. It is proposed that the Wheeling Charges may be denominated in terms of Rupees/kWh or Rupees/kW/month, for the purpose of recovery from the Distribution System User, or any such denomination, as stipulated by the Commission from time to time.

Linking the recovery of wheeling costs to the number of units (kWh) wheeled would be very simple to understand and easy to implement. However, the Distribution Licensee would run the risk of under recovery of costs in case the actual energy units wheeled is less than the base energy units assumed for determination of wheeling charge. Also there will be over recovery, in case the actual energy units wheeled is more than the base energy units assumed for determination of wheeling charge. Recovery of wheeling costs on the basis of capacity contracted (kW) would eliminate such under recovery and over recovery problems.

TPL has filed an Appeal with APTEL challenging the Tariff Order passed by GERC dated December, 2009 in Case no. 966 of 2009 relating to APR for FY 2008-09. TPL contended that the Commission has erred in the computation of wheeling charges. TPL submitted that GERC should have calculated wheeling charges based on capacity reserved. However, the Commission has approved wheeling charges in terms of Rs/kWh instead of Rs/kW/Month. TPL also submitted that it is not is conformity with GERC (Open Access in Intra-State Transmission and Distribution) Regulations, 2005.

However, in order to simplify the pricing mechanism and encourage procurement of power through short term bilateral transactions or power exchange and from renewable sources of power, the wheeling charges may be denominated in Rs/kWh terms.

Therefore, it is proposed that the Regulations for determination of wheeling charge may be introduced as under:

> *"Determination of Wheeling Charges*
>
> *The Commission shall specify the wheeling charge of Distribution Wires Business of the Distribution Licensee in its Order passed under sub-section (3) of Section 64 of the Act:*
>
> *Provided that the charges payable by a Distribution System User may comprise any combination of fixed/demand charges, and variable charges, as may be stipulated by the Commission in such Order."*

7 Norms and Principles for Determination of Revenue Requirement and Tariff for Retail Supply Business

The Tariff of a Distribution Licensee shall provide for the recovery of the aggregate revenue requirement of the Distribution Licensee for the financial year, as reduced by the amount of non-tariff income, income from Other Business and receipts on account of cross-subsidy surcharge and additional surcharge, as approved by the Commission. The aggregate revenue requirement shall comprise the following: -

a) Cost of power generation/power purchase;

b) Transmission charges;

j) Return on Equity or Return on Capital Employed;

k) Interest Expenses (In-case ROE Approach is selected);

c) Depreciation;

d) Operation and Maintenance expenses;

e) Interest on working capital and deposits from consumers;

f) Contribution to contingency reserves.

g) Provisioning for bad debts;

Minus:

h) Non-tariff Income;

i) Income from Other Business;

j) Receipts on account of cross-subsidy surcharge; and

7.1 Distribution loss trajectory for Retail Supply Business

In the multi-year tariff regime, the Commission is required to set year-wise benchmarks for distribution loss reduction, which may be in terms of percentage reduction with respect to opening loss level or by stipulating absolute numbers. The issues, which need to be addressed for the next Control Period, are the criteria for determining the base level losses and loss reduction trajectory.

The issue here is whether the actual distribution losses or the targets specified by the Commission should be considered as the base level of distribution losses for stipulating the loss reduction trajectory for the next Control Period. In this context, the Tariff Policy notified by the Government of India in January 2006 stipulates,

> *"5(h) 2) In cases where operations have been much below the norms for many previous years the initial starting point in determining the revenue requirement and the improvement trajectories should be recognized at "relaxed" levels and not the "desired" levels. Suitable benchmarking studies may be conducted to establish the "desired" performance standards. Separate studies may be required for each utility to assess the capital expenditure necessary to meet the minimum service standards."*

In this context, the FOR report on MYT framework and distribution margin recommends as under:

> *"6.1.10 **Only the distribution loss should be measured**, essentially by AMR- based feeder metering and DT metering. Transmission losses should be dealt with separately.*
>
> *6.1.11 Data on distribution loss levels should be verified through a third party as envisaged in the Tariff Policy. The services of accredited energy auditors and academic institutions such as IITs and other engineering colleges could be utilised for this.*
>
> *6.1.12 The loss levels may be considered at actual level at the start of the first control period and an achievable trajectory may be given under the MYT framework. **However, the loss level at the start of the subsequent control periods may be fixed keeping in view the targets set in the previous control period, actual performance and efforts at achievement. The norms should be revised after every MYT period with prospective effect**.*
>
> *6.1.13 If the distribution licensee does not reduce the losses in accordance with the specified trajectory, despite undertaking capital expenditure towards reducing the losses, this would amount to violation of the direction and in such cases action under section 142 may be considered by the SERC.*
>
> *6.1.14 To accelerate loss reduction, an incentive and dis-incentive mechanism for field staff of the utility at the circle and sub-division level should also be put in place." (**emphasis added**)*

Hence, for the second Control Period, it is proposed that the normative distribution losses, as approved by the Commission for the first Control Period, or the actual distribution losses, whichever is lower, shall be considered for setting opening loss levels and loss reduction trajectory for the next Control Period, after giving due consideration to the actual distribution loss levels achieved by the distribution licensees, and efforts taken to reduce the distribution losses.

The Commission, in its MYT Orders, has specified the percentage reduction trajectory for the Control Period for all the distribution licensees. It is proposed that the same practice will continue, and the **percentage loss reduction targets for each year of the Control Period would be specified, along with the absolute loss levels for ease of reference.**

Distribution Loss reduction is a key efficiency parameter for determining the performance of any distribution licensee over a period of time. The distribution licensees in the State have been given loss reduction targets by the Commission in their respective Multi-Year Tariff (MYT) Orders. The distribution loss targets approved by the Commission and the estimated loss levels of State distribution Utilities over the years in the State of Gujarat are as shown below:

	DGVCL		PGVCL		MGVCL		UGVCL	
FY	Approved by Commission	Actuals/ Estimated	Approved by Commission	Actuals/ Estimated	Approved by Commission	Actuals/ Estimated	Approved by Commission	Actuals/ Estimated
2006-07	16.59%	16.52%	34.22%	32.54%	18.24%	15.10%	18.24%	15.82%
2007-08	15.45%	15.45%	32%	32.80%	15.86%	15.86%	16.74%	17.31%
2008-09	14.45%	14.78%	30.00%	32.11%	15.00%	14.52%	16%	14.57%
2009-10	13.45%	14.53%	28.00%	31.50%	14.00%	13.86%	15%	18%
2010-11	12.45%	_	26.00%	_	13.00%	_	14%	_

Similarly, the distribution loss targets approved by the Commission and the estimated loss levels of Torrent Power Ltd., for distribution areas of Ahmedabad and Surat over the years are as shown below:

Utility	TPL- Ahmedabad		TPL-Surat	
	Approved by Commission	Estimated	Approved by Commission	Estimated
2008-09	10.43%	8.69%	6.00%	5.51%
2009-10	10.25%	10.25%	6.00%	6.00%
2010-11	10%	_	6.00%	_

From the above table, it is observed that the approved distribution loss level of all the distribution licensees, except PGVCL, is less than 15% for FY 2010-11 (last year of first Control Period). Hence, it is proposed to determine the trajectory for the distribution licensees based on their own past performance.

However, reduction of distribution loss will require capital expenditure and other operational strategies to be proposed by Utilities to reduce technical and commercial loss. Hence, it is proposed that the Commission may determine the distribution loss trajectory for the Utilities after considering the Business Plan submitted by the Utilities.

7.2 *Operation & Maintenance Expenses Norm for Supply Business*

The norms for O&M expenses for Supply Business will have to be formulated, based on the allocation matrix proposed earlier for apportioning the O&M expenses pertaining to supply business. The allocation of different components of O&M expenses are reproduced again below:

Particulars	**Wires Business (%)**	**Supply Business (%)**
Employee Expenses	60%	40%
A&G Expenses	50%	50%
R&M	90%	10%

As elaborated in previous Chapter, proposed norms for O&M Expenses for Supply Business of Distribution Utilities for second Control period is summarised as under :

In Rs/kWh

Particulars	FY12	FY13	FY14	FY15	FY16
PGVCL	0.12	0.13	0.13	0.14	0.15
DGVCL	0.07	0.08	0.08	0.09	0.09
UGVCL	0.10	0.11	0.12	0.12	0.13
MGVCL	0.18	0.19	0.20	0.21	0.22

TPL-Ahmedabad	0.11	0.12	0.12	0.13	0.14
TPL-Surat	0.12	0.12	0.13	0.14	0.14

7.3 Fuel and Power Purchase Price Adjustment

It is proposed that any variation in the price of fuel and/ or price of power purchase shall be dealt in accordance with the FCA/FPPPA formula approved by the Commission from time to time.