



ABPS INFRASTRUCTURE ADVISORY PRIVATE LIMITED

Discussion Paper

on

**Multi Year Tariff Regulations for
Third Control Period**

Submitted to

Gujarat Electricity Regulatory Commission

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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 (Multi Year Tariff) Regulations, 2011 on March 22, 2011 (henceforth ‘GERC MYT Regulations, 2011’), which superseded the Gujarat Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2005” and “Gujarat Electricity Regulatory Commission (Multi Year Tariff Framework) Regulations, 2007”.

The GERC MYT Regulations, 2011 are applicable for determination of tariff in all cases covered under these Regulations from April 1, 2011 onwards.

Regulation 2(19) of the GERC MYT Regulations, 2011 defines the "Control Period" as the period of five years from April 1, 2011 to March 31, 2016, and every block of five years thereafter, for submission of forecast in accordance with Chapter-2 of the Regulations. The Commission has issued the MYT Order for all the Utilities in the State, in accordance with the GERC MYT Regulations, 2011 for the Control Period from April 1, 2011 to March 31, 2016, and has also issued the Truing Up Orders for the Utilities for the initial two years of the Control Period.

The present GERC MYT Regulations, 2011, were guided by the CERC (Terms and Conditions of Tariff) Regulations, 2009, 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, 2009 to March 31, 2014. The Central Electricity Regulatory Commission (CERC) had subsequently notified the CERC (Terms and Conditions of Tariff) Regulations, 2014, which is applicable for the Control Period from April 1, 2014 to March 31, 2019, which needs to be incorporated, as appropriate, in the amended GERC MYT Regulations.

Further, there are some Judgments issued by the Hon'ble Appellate Tribunal for Electricity (ATE), Hon'ble High Court, and Hon'ble Supreme Court, during the last three years after the notification of the GERC MYT Regulations, 2011, on different aspects of the above-mentioned Regulations. Hence, the Commission desired to amend the GERC MYT Regulations, 2011 keeping in view the Regulations notified by various State Electricity Regulatory Commissions (SERCs), Central Electricity Regulatory Commission (CERC) and Judgments of Appellate Tribunal for Electricity (APTEL), High Court, and Supreme Court. The Commission also desired to review the various Study Reports prepared by the Forum of Regulators (FOR) during this period, as relevant to the MYT framework.

Further, during the second Control Period, while issuing the MYT Orders and Truing Up/annual Tariff Orders for the Utilities in the State in accordance with the GERC MYT Regulations, 2011, the Commission has observed certain areas where improvements can be made in the specified MYT framework. The Commission desired to analyse these areas and make necessary modifications to the existing GERC 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.

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 amending the GERC MYT Regulations, 2011 for the third Control Period from FY 2015-16 to FY 2019-20.

The Terms of Reference for this assignment are:

1. Analysis of the GERC MYT Regulations, 2011 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. Preparation of formats for collection of actual data for FY 2011-12 to FY 2013-14 (four Years) and analysis/use of the data in preparation of Discussion Paper.
4. Submission of Discussion Paper along with draft Regulations on the amendment(s) proposed.
5. To assist the Commission in analyzing the objections, suggestion and preparing the reasoned analysis.
6. To assist in finalization of the amended regulations and editing the Regulations in English & Gujarati language.

ABPS Infra has studied the relevant documents, viz., CERC Tariff Regulations, 2014, Tariff Policy, relevant FOR study reports on the aspects of above said Regulations, etc., for preparing this Study Report. The Study Report is organised in the following Sections:

- Section 1:** Introduction
- Section 2:** MYT Overview - 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 Tariff for SLDC
- Section 7:** Norms and Principles for determination of Revenue Requirement and Wheeling Charges and Losses for Distribution Wire Business

Section 8: Norms and Principles for determination of Revenue Requirement and Retail Supply Tariff for distribution licensees

2 MYT Overview - General Principles

This Study Report 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 to:

- 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 Wires and Supply businesses, related issues and recommend suitable measures to address such issues.
- Promote operational efficiency.

2.1 *Contours of Multi-Year Tariff*

2.1.1 Cost plus Regulation vs Performance based Regulations

The SERCs have generally adopted the approach of modified 'cost-plus' regulation, whereby tariffs are determined in such a manner so as to enable the Utilities to recover prudent 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 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.

However, it should be noted that internationally, PBR has been introduced only for the Wires Business (Transmission Business and 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.

The modified 'cost-plus' approach followed in the State of Gujarat as specified in the GERC MYT Regulations, 2011, is well understood by all the stakeholders and has stood the test of time, and has also been largely effective in achieving the desired objectives.

Hence, for providing regulatory certainty to consumers, Utilities and various stakeholders of the power sector in Gujarat, it is proposed that the modified 'cost-plus' regulation, subject to prudence check of the expenses may be continued, in line with the approach followed in the second Control Period.

2.1.2 Prescribing Norms Vs Prescribing Principles in the Regulations

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

- 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/ Tariff Orders/ mid-term review 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.

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.

Further, Para 5.3 (f) of the Tariff Policy states as under:

“f) 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.

....” (emphasis added)

In the GERC MYT Regulations, 2011, the Commission has specified operational norms as well as expense norms, wherever possible, in order to minimise the ambiguity in interpretation of the Regulations, which has largely achieved the objective.

Hence, it is proposed to prescribe norms for operational performance parameters and O&M expenses, in line with the approach followed in the GERC MYT Regulations, 2011. In case of distribution business, the Commission in GERC MYT Regulations, 2011 has considered the O&M expenses in a consolidated manner, and has specified the principles for allowing the O&M expenses rather than specifying the norm. However, in this Study Report, we have explored the feasibility of prescribing the norms for O&M expenses for distribution business as well.

2.2 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*
- *Details of load shedding*
- *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 GERC MYT Regulations, 2011, specified as under:

“16 Multi-Year Tariff framework

...

16.2 *The Multi-Year Tariff framework shall be based on the following elements, for determination of Aggregate Revenue Requirement and expected revenue from tariff and charges for Generating Company, Transmission Licensee, Distribution Wires Business and Retail Supply Business:*

- (i) *A detailed Business Plan based on the principles specified in these Regulations, for each year of the Control Period, shall be submitted by the applicant for the Commission's approval:*

Provided that the performance parameters, whose trajectories have been specified in the Regulations, shall form the basis of projection of these performance parameters in the Business Plan:

Provided further that a Mid-term Review of the Business Plan 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;

- (ii) *Based on the Business Plan, the applicant shall submit the forecast of Aggregate Revenue Requirement (ARR) for the entire Control Period and expected revenue from existing tariffs for the first year of the Control Period, and the Commission shall determine ARR for the entire Control Period and the tariff for the first year of the Control Period for the Generating Company, Transmission Licensee, Distribution Wires Business and Retail Supply Business;*

...

19. Business Plan

- 19.1 *The Generating Company, Transmission licensee, and Distribution Licensee for Distribution Wires Business and Retail Supply Business, shall file a Business Plan for the Control Period of five (5) financial years from 1st April 2011 to 31st March 2016, which shall comprise but not be limited to detailed category-wise sales and demand projections, power procurement plan, capital investment plan, financing plan and physical targets, in accordance with guidelines and formats, as may be prescribed by the Commission from time to time:*

Provided 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 specified date of 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

- 19.2 *The capital investment plan shall show separately, on-going projects that will spill over into the Control Period, and new projects (along with justification) that will commence in the Control Period but may be completed within or*

beyond the Control Period. The Commission shall consider and approve the capital investment plan for which the Generating Company, Transmission Licensee, and Distribution Licensee for the Distribution Wires Business and Retail Supply Business, may be required to provide relevant technical and commercial details.

19.3 The Distribution Licensee shall project the power purchase requirement based on the Merit Order Despatch principles of all Generating Stations considered for power purchase, the Quantum of Renewable Purchase Obligation (RPO) under Regulation 4 of Gujarat Electricity Regulatory Commission (Procurement of Energy from Renewable Sources) Regulations, 2010 and the target set, if any, for Energy Efficiency (EE) and Demand Side Management schemes.

19.4 The Generating Company, Transmission Licensee, and Distribution Licensee for the Distribution Wires Business and Retail Supply Business, shall get the Business Plan approved by the Commission.

...

29 Filing Procedure

...

29.8 The applicant shall file his Petition for approval of truing up of previous year and tariff for ensuing financial year by 30th November of the current financial year:

Provided that the MYT Petition for FY 2011-12 to FY 2015-16 shall be filed along-with the Business Plan.

“

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.

The objective in requiring the filing of Business Plan around 3 to 6 months prior to the submission of the MYT Petition is that the Utilities will be required to prepare a long-term plan for the critical aspects of their business, mainly, capital investment, sales projections, power purchase planning and contracting, etc., and also provide various scenarios for these aspects for the Commission's consideration. Once the Commission approves the Business Plan after due regulatory process, the Utilities are required to file their MYT Petition in accordance with the Business Plan approved by the Commission.

While framing the GERC MYT Regulations, 2011, the above target date of submission of Business Plan was already over, and hence, it was specified that "*the MYT Petition for FY 2011-12 to FY 2015-16 shall be filed along-with the Business Plan*". All the Utilities accordingly filed the MYT Business Plan along with the MYT Petition, and the Commission issued a combined Order on both these Petitions for each Utility.

The requirement and effectiveness of the submission of Business Plan in the present form needs to be reviewed in view of the experience gained while issuing the MYT Orders and annual True-Up/Tariff Orders for the Utilities in the State, in accordance with the GERC MYT Regulations, 2011.

We have analysed the merits and demerits of filing a separate Business Plan, as under:

Merits

1. It requires the Utility to undertake long-term planning for the Control Period, rather than having a short-term view of say 1 year, which is essential in case of key aspects like sales projections, power procurement, and capital expenditure.
2. Different scenarios can be analysed in the Business Plan for the consideration of the Commission, and the Commission can take a view on the most likely scenario.

Demerits

1. Separate filing of the Business Plan and MYT Petition necessitates two separate regulatory processes, with similar end objectives, though the tariffs are not determined in the MYT Business Plan.
2. In case of separate filing of the Business Plan and MYT Petition, the MYT Petition is based on the approved Business Plan. The filing of any review petition or appeal against the Business Plan Order may impinge on the subsequent ARR and tariff determination exercise.
3. The necessary objectives of long-term planning can be achieved without separate filing of the MYT Business Plan.

There is no benefit in filing the MYT Business Plan along with the MYT Petition, as specified in the GERC MYT Regulations, 2011, which was necessitated because of the circumstances at that point in time. For the submission of MYT Business Plan to have

any real benefit, the MYT Business Plan has to be submitted well in advance, so that all the necessary planning and deliberations are completed before submission of the MYT Petition, which has to be based on the approved Business Plan. However, this necessitates two separate regulatory processes, with similar end objectives, though the tariffs are not determined in the MYT Business Plan. Since, the necessary objectives of long-term planning has effectively been achieved without separate filing of the MYT Business Plan, it is proposed to discontinue with the requirement for submission of a separate MYT Business Plan.

In view of the above, Regulation 17 of existing GERC MYT Regulations, 2011 is revised as:

"The Multi-Year Tariff framework shall be based on the following elements, for determination of Aggregate Revenue Requirement and expected revenue from tariff and charges for Generating Company, Transmission Licensee, SLDC, Distribution Wires Business and Retail Supply Business:

- (i) A detailed Multi Year Tariff Application comprising the forecast of Aggregate Revenue Requirement for the entire Control Period and expected revenue from existing tariffs for the first year of the Control Period to be submitted by the Applicant:

Provided that the performance parameters, whose trajectories have been specified in the Regulations, shall form the basis for projection of these performance parameters in the Aggregate Revenue Requirement for the entire Control Period:

Provided further that a Mid-term Review of the Aggregate Revenue Requirement shall be undertaken for the Generating Company, Transmission Licensee, SLDC and Distribution Licensee on an application that shall be filed by the utilities along with the Petition for truing-up for the second year of the Control Period and tariff determination for the fourth year of the Control Period;

- (ii) Determination of Aggregate Revenue Requirement by the Commission for the entire Control Period and the tariff for the first year of the Control Period for the Generating Company, Transmission Licensee, SLDC, Distribution Wires Business and Retail Supply Business;
- (iii) Truing up of previous year's expenses and revenue by the Commission based on Audited Accounts vis-à-vis the approved forecast and categorisation of variation in performance as those caused by factors

within the control of the Applicant (controllable factors) and those caused by factors beyond the control of the Applicant (uncontrollable factors):

Provided that once the Commission notifies the Regulations for submission of Regulatory Accounts, the applications for tariff determination and truing up shall be based on the Regulatory Accounts;

- (iv) The mechanism for pass-through of approved gains or losses on account of uncontrollable factors as specified by the Commission in these Regulations;
- (v) The mechanism for sharing of approved gains or losses on account of controllable factors as specified by the Commission in these Regulations;
- (vi) Annual determination of tariff for the Generating Company, Transmission Licensee, SLDC, Distribution Wires Business and Retail Supply Business, for each financial year within the Control Period, based on the approved forecast and results of the truing up exercise."

Accordingly, Regulation 21 of existing GERC MYT Regulations, 2011 which defines the Multi Year Tariff Application has been revised as under:

- a) "The Applicant shall submit the forecast of Aggregate Revenue Requirement for the entire Control Period and tariff proposal for the second year of the Control Period, in such manner, and within such time limit as provided in these Regulations and accompanied by such fee payable, as may be specified under the Gujarat Electricity Regulatory Commission (Fees, Fines and Charges) Regulations, 2005, as amended from time to time.
- b) The Applicant shall develop the forecast of Aggregate Revenue Requirement using the assumptions relating to the behaviour of individual variables that comprise the Aggregate Revenue Requirement during the Control Period, including inter-alia detailed category-wise sales and demand projections, power procurement plan, capital investment plan, financing plan and physical targets, in accordance with guidelines and formats, as may be prescribed by the Commission from time to time.
- c) The capital investment plan shall show separately, on-going projects that will spill over into the Control Period, and new projects (along with justification) that will commence in the Control Period but may be completed within or beyond the Control Period. The Commission shall consider and approve the

capital investment plan for which the Generating Company, Transmission Licensee, SLDC, and Distribution Licensee for the Distribution Wires Business and Retail Supply Business, may be required to provide relevant technical and commercial details.

- d) The Distribution Licensee shall project the power purchase requirement based on the Merit Order Despatch principles of all Generating Stations considered for power purchase, the Quantum of Renewable Purchase Obligation (RPO) under Regulation 4 of Gujarat Electricity Regulatory Commission (Procurement of Energy from Renewable Sources) Regulations, 2010 and the target set, if any, for Energy Efficiency (EE) and Demand Side Management (DSM) schemes.
- e) The Applicant shall develop the forecast of expected revenue from tariff and charges based on the following:
 - (i) In the case of a Generating Company, estimates of quantum of electricity to be generated by each Unit/Station for ensuing financial year within the Control Period;
 - (ii) In the case of a Transmission Licensee, estimates of transmission capacity allocated to Transmission System Users for ensuing financial year within the Control Period;
 - (iii) In the case of SLDC, estimates of services to be extended to the beneficiaries.
 - (iv) In the case of a Distribution Licensee, estimates of quantum of electricity to be supplied to consumers and to be wheeled on behalf of Distribution System Users for ensuing financial year within the Control Period;
 - (v) Prevailing tariffs as on the date of making the application.
- f) Based on the forecast of Aggregate Revenue Requirement and expected revenue from tariff and charges, the Generating Company, Transmission Licensee, SLDC, and Distribution Licensee for the Distribution Wires Business and Retail Supply Business, shall propose the tariff that would meet the gap, if any, in the Aggregate Revenue Requirement.
- g) The Applicant shall provide full details supporting the forecast, including but not limited to details of past performance, proposed initiatives for achieving efficiency or productivity gains, technical studies, contractual arrangements and/or secondary research, to enable the Commission to assess the reasonableness of the forecast.
- h) On receipt of application, the Commission shall either:

- (i) issue an Order approving the Aggregate Revenue Requirement for the entire Control Period and the tariff for the second year of the Control Period, subject to such modifications and conditions as it may specify in the said Order; or
- (ii) reject the application for reasons to be recorded in writing, as the Commission may deem appropriate:

Provided that the Applicant shall be given a reasonable opportunity of being heard before rejecting his application."

2.3 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- 1 of MYT Regulations specifies as under:

"Control Period" means the period of five years from April 1, 2011 to March 31, 2016, and for every block of five years thereafter, for submission of forecast in accordance with Chapter-2 of these Regulations."

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 second Control Period from April 1, 2011 to March 31, 2016. Thus, the third Control Period is due to

begin on April 1, 2016. In accordance with the Tariff Policy and MYT Regulations, it is suggested that the Control Period should continue to be of five years, over the period from April 1, 2016 to March 31, 2021. It may be noted that the CERC Tariff Regulations, 2014, is applicable till March 31, 2019, and the Tariff Regulations for the next Tariff Period are likely to be notified by CERC sometime between January 2019 to March 2019. This will give the Commission sufficient time to incorporate any necessary modifications before mid-2020, for the GERC MYT Regulations for the fourth Control Period.

2.3.1 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 prudence check and operational and financial parameters of the Utility based on true-up Orders issued by the Commission. 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 next Control Period. At this stage, the true-up Orders for FY 2013-14 have been issued by the Commission. Hence, we have analysed the operational and financial data for a period of three years from FY 2011-12 to FY 2013-14, based on the true-up Orders for the respective years, for determining the norms for the third 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.

In this context, Torrent Power Limited TPL has filed an Appeal on the Commission's Order in Case No. 1366 of 2013. In the said Appeal, TPL has submitted that at the beginning of the Control Period, the Commission had determined the trajectory for reduction of distribution losses. TPL has performed better than the said trajectory by reducing the distribution loss. However, the Commission on its own revised the distribution loss trajectory for FY 2014-15 and FY 2015-16. TPL has contended that GERC has, contrary to the GERC MYT Regulations, 2011 and the very objectives of MYT framework, acted in a manner such that if the Utility performs better, the

Regulator would revise the benchmark, with the result that there is no incentive for the Utility to improve its performance. The Judgment in this Appeal is awaited.

In this regard, 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 easily achievable by the Utilities. Further, as discussed subsequently in this Study Report, 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, 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. At the same time, some operational performance norms or O&M norms may also have to be revised upwards to reflect the performance approved by the Commission in the true-up Orders. 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.

Further, as regards specifying operational as well as O&M norms for the parallel distribution licensees (SEZs) for the third Control Period, the same depends on availability of data, as well as the approach proposed to be followed for determining the tariffs for the parallel distribution licensees. If the ceiling tariff approach is continued to be adopted for the parallel distribution licensees, then there will be no need for specifying operational as well as O&M norms for the parallel distribution licensees. However, if the retail tariffs are going to be determined for the parallel distribution licensees based on the respective ARR determined in accordance with the Regulations, then the operational as well as O&M norms/principles will have to be specified for the parallel distribution licensees.

The approach for tariff determination for parallel distribution licensees has been discussed with the merits and de-merits of different approaches, in the section on tariff philosophy for retail tariff determination.

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 the 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. In Regulation 23.2 of the GERC MYT Regulations, 2011, various controllable parameters have been specified, as under:

“23.2 Some illustrative variations or expected variations in the performance of the applicant, which may be attributed by the Commission to controllable factors include, but are not limited to, the following:

- (a) Variations in capitalisation on account of time and/or cost overruns/ efficiencies in the implementation of a capital expenditure project not attributable to an approved change in scope of such project, change in statutory levies or force majeure events;*
- (b) Variation in Interest and Finance Charges, Return on Equity, and Depreciation on account of variation in capitalisation, as specified in clause (a) above;*
- (c) Variations in technical and commercial losses of Distribution Licensee;*
- (d) Variations in performance parameters;*
- (e) Variations in working capital requirements;*
- (f) Failure to meet the standards specified in the Gujarat Electricity Regulatory Commission (Standard of Performance of Distribution Licensee) Regulations, 2005, except where exempted in accordance with those Regulations;*
- (g) Variations in labour productivity;*
- (h) Variation in operation & maintenance expenses;*
- (i) Variation in Wires Availability. “*

Sub-clause (e) specifies that the "Variations in working capital requirements" shall be treated as controllable. It should be noted that in the ARR, interest on working capital rather than the working capital requirement, is allowed for recovery, hence, the controllable parameter is proposed to be modified to specify "Variations in interest on working capital requirement" rather than "Variations in working capital requirements". If done accordingly, then the Utility would have two avenues for reducing the working capital interest, viz., the interest rate on the working capital requirement and the working capital requirement itself. It should be noted that most Utilities do not incur significant interest on working capital, as they efficiently manage the working capital requirement itself, rather than the interest rate on the same. The comparison shall be done between the normative IWC allowed in the Tariff Order and the normative IWC calculated at the time of truing up, based on the trued up components of the working capital requirement. In the GERC MYT Regulations, 2011, sub-clause (i) was 'Variation in Wires Availability', which has now been replaced with 'Bad Debts Written off'.

2.5.2 Uncontrollable factors

Uncontrollable costs usually include costs over which the Utility has no control, such as fuel cost variation, etc.

Clause 4.5 (h)(4) of the Tariff Policy stipulates:

"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."

GERC, in Regulation 23.1 of the GERC MYT Regulations, 2011, has specified the following uncontrollable parameters, which are proposed to be retained:

"23.1 For the purpose of these Regulations, the term "uncontrollable factors" shall comprise of the following factors, which were beyond the control of the applicant, and could not be mitigated by the applicant:

- (a) Force Majeure events;*
- (b) Change in law, judicial pronouncements and Orders of the Central Government, State Government or Commission;*
- (c) Variation in the price of fuel and/ or price of power purchase according to the FPPPA formula approved by the Commission from time to time;*

- (d) *Variation in the number or mix of consumers or quantities of electricity supplied to consumers:*

Provided that where there is more than one Distribution Licensee within the area of supply of the applicant, 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, on account of migration from one Distribution Licensee to another, shall be attributable to controllable factors:

Provided further that if 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;

- (e) *Transmission Loss;*
(f) *Variation in market interest rates;*
(g) *Taxes and Statutory levies;*
(h) *Taxes on Income*

Provided that where the applicant or any interested or affected party believes, for any variable not specified above, that there is a material variation or expected variation in performance for any financial year on account of uncontrollable factors, such applicant or interested or affected party may apply to the Commission for inclusion of such variable at the Commission's discretion, under this Regulation for such financial year."

Besides, 'Income from realisation of bad debts written off' has been added to the list of existing parameters.

2.6 Sharing of Gains and losses

Clause 8.1 (2) of the Tariff Policy stipulates:

"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 mechanism of sharing of gains and losses is intended to share the benefits of better performance of the Utility as well as the impact of poor performance of the Utility with the consumers, while at the same time ensuring that the Utility has enough incentive to improve its operational efficiency.

2.6.1 Sharing of gains or losses on account of controllable factors

Chapter-2 of GERC MYT Regulations, 2011 specifies the mechanism for sharing of gains or losses on account of controllable factors as under:

“25.1 The approved aggregate gain to the Generating Company or Transmission Licensee or Distribution Licensee on account of controllable factors shall be dealt with in the following manner:

(a) One-third of the amount of such gain shall be passed on as a rebate in tariffs over such period as may be stipulated in the Order of the Commission under Regulation 22.6;

(b) The balance amount, which will amount to two-thirds of such gain, may be utilised at the discretion of the Generating Company or Transmission Licensee or Distribution Licensee.

25.2 The approved aggregate loss to the Generating Company or Transmission Licensee or Distribution Licensee on account of controllable factors shall be dealt with in the following manner:

(a) One-third of the amount of such loss may be passed on as an additional charge in tariffs over such period as may be stipulated in the Order of the Commission under Regulation 22.6; and

(b) The balance amount of loss, which will amount to two-thirds of such loss, shall be absorbed by the Generating Company or Transmission Licensee or Distribution Licensee.”

Under the above approach, the Utility gets to retain 2/3rd of the efficiency gains, while at the same time having to bear 2/3rd of the efficiency losses also. Put differently, the consumers/beneficiaries are entitled to 1/3rd share of the efficiency gains, but also have to bear 1/3rd share of the efficiency losses.

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.”

Under the approach recommended by FOR, the licensee gets to retain 2/3rd of the efficiency gains, but has to bear the entire efficiency losses. Hence, another option for sharing the gains and losses may be as under:

- a. In case of Generation Company or Licensees, 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 Companies or licensees, may be utilized by the Utility at its discretion.

However, losses on account of controllable factors have to be borne by the Utility only, since, the operational norms as well as the O&M norms are being specified based on the actual performance of the Utility in the previous Control Period.

The practices followed by selected other SERCs and CERC in this regard have been reproduced below:

The MERC, in its MERC (Multi Year Tariff) Regulations, 2011, has specified as under:

“14.1 The approved aggregate gain to the Generating Company or Transmission Licensee or Distribution Licensee on account of controllable factors shall be dealt with in the following manner:

(a) One-third of the amount of such gain shall be passed on as a rebate in tariff over such period as may be stipulated in the Order of the Commission under Regulation 11.6;

(b) The balance amount, which will amount to two-third of such gain, may be utilised at the discretion of the Generating Company or Transmission Licensee or Distribution Licensee.

14.2 *The approved aggregate loss to the Generating Company or Transmission Licensee or Distribution Licensee on account of controllable factors shall be dealt with in the following manner:*

(a) One-third of the amount of such loss may be passed on as an additional charge in tariff over such period as may be stipulated in the Order of the Commission under Regulation 11.6; and

(b) The balance amount of loss shall be absorbed by the Generating Company or Transmission Licensee or Distribution Licensee.

14.3 *Gains and losses on account of controllable factors during the second Control Period shall be shared with the consumers at the time of Mid-term Performance Review and also at the time of tariff determination process of third Control Period."*

The RERC in its RERC (Terms and Conditions for Determination of Tariff) Regulations, 2014 specified as under:

"9. Gains and Losses on account of Uncontrollable and Controllable factors

...

2) Gain or loss to the Generating Company or Licensee on account of controllable factors shall be retained or borne by the Generating Company or Licensee, as the case may be, except in case of the following:

a) Rate of Interest on working capital requirement, which shall be as per regulation 27;

b) Station Heat Rate, Auxiliary Consumption, and Secondary fuel oil consumption, which shall be as per regulation 57 and

c) Distribution loss, which shall be as per regulation 76.

.....

27. Interest charges on working capital

...

(2) Rate of interest on working capital to be computed shall be on normative basis and shall be 250 basis points higher than the average Base Rate of State Bank of India prevalent during first six months of the year previous to the relevant year. The interest on working capital shall be computed on normative basis notwithstanding that the generating company or licensee has not taken working capital loan from any outside agency. The variation in the interest amount on account of actual vis-a-vis

normative interest rate on normative working capital shall be shared in the ratio of 50:50 between the generating company/licensee and the beneficiary.

....

57. Sharing of gains or losses on account of controllable factors

(1) The financial gains by a generating company on account of Station Heat Rate, Auxiliary Consumption and Secondary Fuel Oil Consumption shall be shared between generating company and the distribution licensee on monthly basis, in the ratio of 60:40 between the generating company and beneficiary as per the following formulae:

$$\text{Net Gain} = (\text{ECRN} - \text{ECRA}) \times \text{Actual Generation}$$

Where,

ECRN – Normative Energy Charge Rate computed on the basis of norms specified for Station Heat Rate, Auxiliary Consumption and Secondary Fuel Oil Consumption.

ECRA – Actual Energy Charge Rate computed on the basis of actual Station Heat Rate, Auxiliary Consumption and Secondary Fuel Oil Consumption for the month

...

76. Distribution Losses & Collection Efficiency

...

(5) The gains arising on account of distribution losses being lower or the losses arising on account of distribution loss being higher than the target fixed for any year by the Commission, shall be shared in the ratio of 50:50 between the distribution licensee and the consumers.”(emphasis added)

The UERC in its UERC (Terms and Conditions for Determination of Tariff) Regulations, 2011 specified as under:

“15. Sharing of Gains and Losses on account of Controllable factors

(1) The approved aggregate gain to the Applicant on account of controllable factors shall be dealt with in the following manner:-

- a) 20% of such gain shall be passed on as a rebate in tariffs over such period as may be specified in the Order of the Commission*
- b) The balance amount of gain may be utilized at the discretion of the Applicant.*

(2) The approved aggregate loss to the Applicant on account of controllable factors shall be dealt with in the following manner:-

- a) 25% of the amount of such loss shall be allowed by the Commission to be recovered through tariffs over such period as may be specified in the Order of the Commission
- b) The balance amount of loss shall be absorbed by the Applicant."

The CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2014 specified as under:

"(2) The generating station shall carry out truing up of tariff of generating station based on the performance of following Controllable parameters:

a) Controllable Parameters :

- i) Station Heat Rate;*
- ii) Secondary Fuel Oil Consumption;*
- iii) Auxiliary Energy Consumption; and*
- iv) Re-financing of Loan*

(3) The Commission shall carry out truing up of tariff of generating station based on the performance of following Uncontrollable parameters:

- i) Force Majeure;*
- ii) Change in Law; and*
- iii) Primary Fuel Cost*

(4) The Transmission Licensee shall carry out truing up of tariff of transmission system based on the controllable parameter of Re-Financing of loans:

(5) The Commission shall carry out truing up of tariff of transmission licensee based on the performance of following Uncontrollable parameters:

- (i) Force Majeure; and*
- (ii) Change in Law.*

(6) The financial gains by a generating company or the transmission licensee, as the case may be on account of controllable parameters shall be shared between generating company/transmission licensee and the beneficiaries on monthly basis with annual reconciliation. The financial gains computed as per following formulae in case of generating station on account of operational parameters as shown in Clause 2(a) (i) to (iii) of this Regulation shall be shared in the ratio of 60:40 between generating station and beneficiaries:

Net Gain = (ECRN- ECRA) x Scheduled Generation

Where,

ECRN – Normative Energy Charge Rate computed on the basis of norms specified for Station Heat Rate, Auxiliary Consumption and Secondary Fuel Oil Consumption.

ECRA – Actual Energy Charge Rate computed on the basis of actual SHR, Auxiliary Consumption and Secondary Fuel Oil Consumption for the month.

Provided that in case of financial gains on account of Clause 2 (a)(iv) and Clause 4 of this Regulation shall be shared in accordance with Clause 7 of Regulation 26 of these regulations

(7) The financial gains and losses by a generating company or the transmission licensee, as the case may be, on account of uncontrollable parameters shall be passed on to beneficiaries of the generating company or to the long term transmission customers/DICs of transmission system, as the case may be.” (emphasis added)

It is seen that most SERCs as well as CERC have adopted the approach of sharing the gains as well as losses, though the percentage shares vary. Hence, it is suggested that the existing sharing approach specified in the GERC MYT Regulations, 2011, be retained.

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.”

Hence, it is proposed to continue with the present approach of passing through the gain or loss to the Generating Company or Licensee on account of uncontrollable factors as an adjustment in the tariff of the Generating Company or Licensee.

2.6.3 Timing of truing up process

The APTEL, in its Judgment dated March 23, 2010 in the Appeal against the Order issued under MYT Regulations for first Control Period ruled that the State Commission is required to take the truing up at the earliest once the actual audited data is available and this exercise need not wait for next Control Period. This approach is in line with the approach specified in the GERC MYT Regulations, 2011, and is proposed to be retained.

2.7 Annual Tariff Determination

The GERC MYT Regulations, 2011, specified 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. This approach of annual tariff determination is being followed by most SERCs under their respective MYT framework. Only the Maharashtra Electricity Regulatory Commission (MERC) has undertaken tariff determination for three years of the Control Period at one time, and has determined the category-wise tariffs for FY 2013-14, and FY 2014-15, and FY 2015-16, for most of the Utilities in the State, except Maha DISCOM (MSEDCL), whose MYT Petition is presently pending before the MERC. The only adjustment to tariff allowed is through the Fuel Charge Adjustment formula, which allows monthly pass through of the variation in the fuel and power purchase costs over and above the tariff determined by the Commission for the three-year Control Period.

In view of the above it is proposed to continue with the existing annual tariff determination process with slight modification, as under:

"The Commission shall determine the tariff of a Generating Company, Transmission Licensee, SLDC and Distribution Licensee covered under a 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 approved forecast of Aggregate Revenue Requirement and expected revenue from tariff and charges of the Generating

Company, Transmission Licensee, SLDC and Distribution Licensee for such financial year, including modifications approved at the time of mid-term review, if any; and

- (b) Approved gains and losses, including the incentive available, to be passed through in tariffs, following the Truing Up of previous year."

2.8 Carrying Costs

The GERC MYT Regulations, 2011, do not specify the carrying cost to be allowed on the trued up amounts or on deferred revenue gaps.

In this context, the APTEL in its Judgment dated May 30, 2014 in Appeal No. 147, 148 and 150 of 2013 in the matter of Torrent Power Limited vs. GERC ruled as under:

"20. *The relevant extracts of the judgment dated 28.11.2013 in Appeal no. 190 of 2011 are reproduced as under:*

"81. *As correctly pointed out by the learned Counsel for the Appellant that while the State Commission passed the tariff order dated 17.1.2009, it had agreed to provide Carrying Cost in future. It is settled law that the carrying cost for legitimate expenditure has to be provided. In fact, this principle has been laid down in Appeal No.203 of 2010 and RP No.13 of 2012 by the Tribunal in its order dated 2.1.2013. The very same issue has been dealt with in another decision in Appeal No.36 of 2008.*

82. *That apart, this Tribunal again in Appeal No.153 of 2009 dated 30.7.2010 reported in 2010 ELR (APTEL) 0891 and Appeal No. 173 of 2009 dated 13.9.2012 has also dealt the very same issue.*

83. *The relevant principles which have been laid down in these decisions are extracted below:*

(a) *We do appreciate that the State Commission intends to keep the burden on the consumer as low as possible. At the same time, one has to remember that the burden of the consumer is not ultimately reduced by under estimating the cost today and truing it up in future as such method also burdens the consumer with carrying cost.*

- (b) *The carrying cost is allowed based on the financial principle that whenever the recovery of cost is deferred, the financing of the gap in cash flow arranged by the distribution company from lenders and/or promoters and/or accruals, has to be paid for by way of carrying cost.*
- (c) *The carrying cost is a legitimate expense and therefore recovery of such carrying cost is legitimate expenditure of the distribution company*
- (d) *The utility is entitled to carrying cost on its claim of legitimate expenditure if the expenditure is:*
 - i) *accepted but recovery is deferred e.g. interest on regulatory assets,*
 - ii) *claim not approved within a reasonable time, and*
 - iii) *Disallowed by the State Commission but subsequently allowed by the Superior authority*
 - iv) *Revenue gap as a result of allowance of legitimate expenditure in the true up.*

The State Commission shall decide the claim of the Appellant regard to carrying cost on the above principles

84. *In view of the settled position of law, in the present case, the Appellant falls under sub-category (iv) as referred to above, and as such the Appellant is entitled for the Carrying Cost as per the Order dated 17.1.2009. Accordingly, ordered."*

21. The above findings of the Tribunal will apply to the present case too. Accordingly, this issue is decided in favour of the Appellant." (emphasis added)

In view of the above, it is suggested that the carrying cost to be allowed on the trued up amounts or on deferred revenue gaps may be specified in the MYT Regulations for the next Control Period.

In this regard, we have studied the practices followed by selected other SERCs in this regard, as under:

The Uttar Pradesh Electricity Regulatory Commission has notified UPERC (Multi Year Distribution Tariff) Regulations, 2014 in May, 2014 and the same will be applicable from April 1, 2015. In the said Regulations, UPERC has specified as reproduced below with regard to carrying cost:

“35. Treatment of Regulatory Assets

...

c) The carrying cost of the regulatory asset shall be in line with the State Bank Advance Rate (SBAR) for the tenure for which regulatory asset has been created...”

The Punjab State Electricity Regulatory Commission has specified as reproduced below in the PSERC (Terms and Conditions for Determination of Tariff), Second Amendment, Regulations, 2012:

“(b1) “Carrying Cost for Regulatory Asset” shall mean the interest on Regulatory Asset at the State Bank of India Advance Rate (SBAR) as on April 1 of the relevant year;”

Accordingly, appropriate clauses have been incorporated in the MYT Regulations for the next Control Period, and Carrying Cost is proposed to be allowed on the amount of Revenue Gap or Revenue Surplus or the amount of Revenue Gap deferred for recovery, if any, on simple interest basis at the weighted average State Bank Base Rate.

3 Broad Financial Principles

The broad financial principles envisaged under the MYT framework proposed for the third Control Period starting from FY 2016-17 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 MYT Regulations, 2011 address the broad financial principles. However, these financial principles need to be suitably modified, wherever necessary, for the third Control Period, in view of the developments subsequent to the notification of the GERC MYT Regulations, 2011. The broad financial principles discussed in this Section are:

- Debt Equity Ratio
- Approach for Giving Returns – Return on Equity or Capital Employed
- Capital Cost
- Depreciation
- Interest on Working Capital
- Treatment of Deposit works, consumer contribution and grants
- Impact of asset de-capitalisation
- Allowance of O&M expenses - to be allowed on consolidated basis or as individual heads of O&M expenses
- Provision for bad debts and write-off of bad debts

3.1 Debt - Equity Ratio

The Commission has specified the debt - equity ratio of 70:30 for financing new capital expenditure on projects. It is proposed to continue with the same debt - equity ratio for tariff determination for generating companies and licensees for the third Control Period also, since, this is the standard practice being followed in the power sector in India. **However, it is clarified that the debt-equity ratio of 70:30 is to be applied on the asset value after reducing the funds received through consumer contribution, grants, and deposit works.** This is required because the issue of funding through debt or equity is relevant only if there is a need for funds for meeting the capex requirement, after utilisation of funds received in the form of

consumer contribution, grants, and deposit works, which have neither any repayment obligation nor any servicing cost. This will ensure that only the amount invested by the Utility in the form of equity or debt, is entitled to returns or interest, as applicable.

The Auditor M/s N.C. Mittal & Co., has mentioned in the audit report that equity and loan are being calculated on the Gross Value of Assets whereas it should be calculated on the net block, since the depreciation is already passed on to the consumer as revenue expense.

At present, in the GERC MYT Regulations, 2011 as well as Tariff Regulations notified by CERC and other SERCs, the debt is considered as 70% of the gross fixed assets, rather than the net fixed assets. The Commission has desired that we analyse the issue of whether debt should be considered as 70% of gross fixed assets or net fixed assets.

We are of the view that the normative debt component should be specified as 70% of the gross fixed assets, rather than the net fixed assets. The initial funding for any asset will require debt equal to 70% of the gross fixed assets, and will typically be required to be repaid in equal instalments over ten to twelve years (though the actual repayment could be on quarterly or half-yearly basis). A part of the loan will get repaid every year and at the same time, the net fixed assets would also reduce every year, due to the accumulated depreciation. Thus, if a ten-year loan repayment period is assumed (i.e., 10% of 70%, i.e., 10% of the loan amount has to be repaid every year) along with a moratorium period of say 2 years, the actual outstanding loan at the end of the fourth year, would be equal to 80% of the original loan amount. Thus, the loan amount to be repaid every year as well as the interest to be paid every year remains the same and does not reduce on the basis of the loan amount actually repaid, hence, it may be more appropriate to specify the normative debt component as 70% of the gross fixed assets, rather than the net fixed assets.

This issue is also linked to the issue of whether the repayment of loan should be equated to the annual depreciation on a normative basis or should be considered on the basis of actual loan repayment, which is discussed subsequently in this Report. Further, regarding the case of de-capitalisation or retirement or replacement of assets, it is proposed the equity capital approved as mentioned above, shall be reduced to the extent of 30% (or actual equity component based on documentary evidence, if it is lower than 30%) of the original cost of the de-capitalised or retired or replaced asset, and the debt capital approved as mentioned above, shall be reduced to the extent of actual debt component,

based on documentary evidence, of the original cost of the de-capitalised or retired or replaced asset.

3.2 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.

The Commission has adopted the RoE approach while formulating the GERC MYT Regulations, 2011, which is presently allowed to Generating Companies, Transmission Licensees and Distribution Licensees, for the second 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.

The Central Commission would notify, from time to time, the rate of return on equity for generation and transmission projects keeping in view the assessment of overall risk and the prevalent cost of capital which shall be followed by the SERCs also. The rate of return notified by CERC for transmission may be adopted by the State Electricity Regulatory Commissions (SERCs) for distribution with appropriate modification taking into view the higher risks involved. For uniform approach in this matter, it would be desirable to arrive at a consensus through the Forum of Regulators.

While allowing the total capital cost of the project, the Appropriate Commission would ensure that these are reasonable and to achieve this objective, requisite benchmarks on capital costs should be evolved by the Regulatory Commissions.

Explanation: For the purposes of return on equity, any cash resources available to the company from its share premium account or from its internal resources that are used to fund the equity commitments of the project under consideration should be treated as equity subject to limitations contained in (b) below.

The Central Commission may adopt the alternative approach of regulating through return on capital.

The Central Commission may adopt either Return on Equity approach or Return on Capital approach whichever is considered better in the interest of the consumers.

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."

CERC, in the Explanatory Memorandum to the draft Terms and Conditions of Tariff Regulations for 2014-19, stated as under:

"8.5.7 As the tariff is determined on multiyear principles, it is important to maintain certainty in approach over each control period to maintain the confidence of investors and regulated entities. In view of the fluctuating interest rate, shallow debt market and considering the financial health of Utilities and the other serious issues faced by Developers in sector such as fuel shortages etc., it appears that it is not desirable to switch to ROCE approach and thus the Commission proposes to continue with the ROE approach for next Tariff Period. Further most of the stakeholders have suggested for continuing the existing ROE approach."

In view of the above, it is proposed to continue with the ROE approach for the third Control Period also. It is proposed to continue with the rate of ROE of 14%, in the third Control Period also.

Further, Regulation 24(2) of CERC Tariff Regulations, 2014, provides for an additional return of 0.5% for projects that are completed within the timeline specified in the Regulations, provided that they are commissioned on or after 1st April, 2014. However, the primary requirement for providing such incentive for timely completion of projects is prescribing the timelines for completion of projects, especially when it comes to Distribution Projects, where it will be very difficult to ascertain timely completion of individual schemes. Hence, it is not proposed to incorporate this provision in the MYT Regulations for the next Control Period.

Further, for the purpose of computation of ROE, the Auditor, M/s N. C. Mittal & Co, has shown two methods for computation of average equity amount for a year, viz., simple average method and weighted average method. In simple average method, the average equity for the year is computed using the following formula:

$$\text{Average Equity} = (\text{Opening Equity} + \text{Closing Equity})/2$$

As per the audit report, in weighted average method, the opening equity for a year is kept static for the first quarter and in the subsequent quarters the inflow and outflow of the funds are considered for deriving closing equities for each quarter. The weighted average equity is then computed considering the closing equity of all the quarters considering the weightage equivalent to number of months in each quarter, i.e., 3. As per the current Regulations, only annual accounting statements are required for computation of ROE, however, if the weighted average method is adopted, quarterly accounts may be required.

It is observed that the weighted average method mentioned by the auditor for computation of ROE is effectively a simple average method of computing average equity by considering the closing equity of all the quarters, since, the weightage shall remain the same for all the four quarters considering that each quarter has equal numbers of months, i.e., 3. Further, if the method of computation of equity based on weighted average method is considered, the review of quarterly accounts of the utilities shall be required for determination of ROE. In view of the same, it is suggested that for computing equity for the purpose of allowing ROE, simple average method may be used. Further, if the average equity computed by this method is more than 30%, the amount of equity for the purpose of tariff shall be limited to 30%, otherwise, the actual equity shall be considered derived from simple average method.

3.2.1 Post-Tax Vs Pre-Tax Rate of Return and method of recovery

The issue is whether the returns to the investor should be allowed on a post-tax basis or on pre-tax basis. Both the approaches have merits and demerits.

Under the post-tax approach, the Commission has to assess the income tax liability at the time of determination of ARR and tariff, which can be complicated in case of entities that are undertaking other non-core businesses also, irrespective of whether they are regulated or not. This problem exists in Gujarat for Utilities like Torrent Power Limited, etc., which have different businesses that are regulated by the Commission, as well as several other businesses in the power sector in other States (Maharashtra, Uttar Pradesh, etc.) as well as other unregulated businesses in Gujarat. Another negative aspect of the post-tax approach is that there is no inducement for

better tax planning. However, in case of post-tax returns, the tax benefits available to the sector are passed on to the consumers.

On the other hand, the pre-tax return approach is aimed at encouraging power sector entities to do better tax planning and also does not have the above de-merits of post-tax return approach. The income tax liability does not have to be projected in advance, and at the end of the year, does not have to be matched with the actual income tax paid, etc. The issue of estimating the income tax for Utilities operating in several States/Businesses will also not arise.

It should also be noted that the erstwhile State Electricity Boards (SEBs) were not liable to pay income tax. However, post EA 2003, most of the erstwhile SEBs have been unbundled and the Successor Companies engaged in the business of generation, transmission and distribution of electricity are liable to pay income tax.

CERC, in the Explanatory Memorandum to its draft Terms and Conditions of Tariff Regulations, 2014, stated as under:

“9.5.7 Pre-tax v/s Post Tax Return on Equity

On the issue of pre-tax vs. post tax return on equity with tax to be allowed as pass through on actual basis, the Commission has received mixed responses from different stakeholders.

9.5.8 Some of the stakeholders submitted that under the current mechanism of pre-tax returns, the benefits of Section 80 IA applicable to new Units are not passed on to the beneficiaries and the tax recovered by Utilities in some cases are more than the actual income tax. Under the regulated business, in general, the profit of the Utilities should be equal to RoE specified because all other elements of tariff are based on the general premise of pass through of costs subject to achievement of normative performance parameters. Practically, however, the profit of the Utilities is influenced by other factors such as profits of non-core business carried out by the Utilities, UI earnings, efficiency gains, incentive earned, difference in the depreciation allowed under tariff and as per Income Tax Act, 1961, income tax holiday allowed in power sector, etc.

9.5.9 Under the regulated business, when the Utilities are allowed specified post tax rate of return on equity in addition to prudently incurred expenses, the recovery of tax on specified Return on Equity by the Utilities needs to be allowed based on actual tax paid on Return on Equity on no profit and no loss basis, as tax on Return on Equity is a sort of reimbursement to ensure the recovery of the specified RoE. Therefore, the Commission proposes to modify the existing provision of pre-tax RoE being grossed up with the Tax Rate, to post tax RoE with income tax to be recovered on actual basis to the extent of return on equity only.”

However, in the final notified CERC Tariff Regulations, 2014, CERC has specified RoE grossed up by the effective rate of Income Tax or MAT rate, whichever is applicable, as compared to the earlier specification of 'applicable tax rate', and has not implemented the approach proposed in the draft Regulations.

Income tax is chargeable on the profit earned by the Company. In every other business, the income taxes are paid from out of the profits earned from the business, and such payment of income tax is not allowed to be charged as an expense under the Income Tax Act, 1961, while computing the taxable profit. In the stock market too, while the risks as well as the returns are higher, income tax has to be paid on the profits earned through purchase and sale of shares. Hence, one option is to not consider income tax at all, and provide returns on a pre-tax basis, while the other option could be to allow income tax on actual basis. Even if the income tax is to be allowed, it may not be appropriate for the income tax to be passed through to the consumers as an expense incurred by the Utility, after grossing up the return with the applicable income tax rate.

Regulation 42 of GERC MYT Regulations, 2011, specifies as under:

“42. Tax on Income:

42.1 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 per latest Audited Accounts available for the applicant, subject to prudence check.

42.2 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.

42.3 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:

Provided that tax on any income stream other than the core business shall not be 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."

The ATE, in its Judgment dated July 3, 2013 in Appeal No. 32 of 2012, analysed the above-said Regulation 42 and ruled as under:

"57. The above Regulation would point out that at the stage of projection of the revenue requirements; the income tax has to be allowed provisionally based on the actual income tax paid as per the latest audited accounts of the licensee. In the present case, the latest audited accounts of the Appellant for the Financial Year 2010-11 shows that no income tax had been paid by the Appellant.

58. Under those circumstances, the State Commission as per the Tariff Regulations has not allowed any income tax provisionally for the control period. However, the State Commission has in the impugned order specifically observed that it would consider the actual income tax paid if any at the time of truing-up in terms of the Regulations 22 of the Multi Year Tariff Regulations of the State Commission. In view of the above statement assuring to consider the same at the time of truing-up in terms of Regulation 22, the State Commission is directed to take note of the actual income tax paid if any at that time of truing-up as observed in the impugned order and pass appropriate orders in accordance with the law."

As per the above mentioned Regulations, actual Income Tax paid by the Utilities is reimbursed by the beneficiaries/consumers. **Since, the present mechanism of recovering income tax separately from the consumers in the form of reimbursement, which is a better approach, has been successfully implemented in the State of Gujarat, it is proposed that the same approach be continued for the next Control Period also. Also, the actual income tax paid including cess and surcharge on the same should be allowed and has been incorporated.** However, the interest on tax, other expenses related to tax, and wealth tax cannot be allowed to be recovered from the consumers, and has not been incorporated.

3.3 Capital Cost

The GERC MYT Regulations, 2011 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 being approved by the Commission as a part of the tariff determination exercise.

With regard to the issue of de-capitalization of assets, the APTEL, in its Judgment dated May 30, 2014 in Appeal No. 147, 148 and 150 of 2013 filed by Torrent Power Limited, has stated as reproduced below:

"The State Commission has, however, deducted the entire cost of the retired asset from the gross capital expenditure. We find that no documentary proof was given by the Appellant regarding outstanding loan component of the retired asset and actual equity deployed on the retired assets. We cannot find fault with the procedure adopted by the State Commission in the absence of the data for the retired asset to deduct the total cost of the retired asset from the gross capital cost which amounts to taking equity and debt amount in the normative ratio of 70:30 for the retired asset."

The following changes are proposed under Capital Cost:

- (i) "The revenue earned from sale of infirm power in excess of fuel cost prior to the COD as specified under Regulation 51, shall be adjusted against the Capital Cost.
- (ii) The capital cost may include initial spares capitalised as a percentage of the Plant and Machinery cost upto cut-off date, subject to following ceiling norms:
 - (a) Coal-based/lignite-fired thermal generating stations - 4.0%
 - (b) Gas Turbine/Combined Cycle thermal generating stations - 4.0%
 - (c) Hydro generating stations including pumped storage hydro generating station. - 4.0%
 - (d) Transmission system and Distribution System
 - (i) Transmission line & Distribution Line - 1.0%
 - (ii) Transmission Sub-station & Distribution Sub-station (Green Field) - 4.0%
 - (iii) Transmission Sub-station (Brown Field) - 6.0%
 - (iv) Series Compensation devices and HVDC Station - 4.0%
 - (v) Gas Insulated Sub-station (GIS) - 5.0%
 - (vi) Communication system - 3.5%"

3.4 Additional Capitalisation

The provisions of Additional Capitalisation are proposed to be modified, based on CERC Tariff Regulations, 2014, as under:

a) "The capital expenditure in respect of the new project or an existing project incurred or projected to be incurred, on the following counts within the original scope of work, after the date of commercial operation and up to the cut-off date may be admitted by the Commission, subject to prudence check:

(i) Undischarged liabilities recognized to be payable at a future date;

(ii) Works deferred for execution;

(iii) Procurement of initial capital spares within the original scope of work, in accordance with the provisions of Regulation 13;

(iv) Liabilities to meet award of arbitration or for compliance of the order or decree of a court of law; and

(v) Change in law or compliance of any existing law:

Provided that the details of works asset wise/work wise included in the original scope of work along with estimates of expenditure, liabilities recognized to be payable at a future date and the works deferred for execution shall be submitted along with the application for determination of tariff.

b) The capital expenditure incurred or projected to be incurred in respect of the new project on the following counts within the original scope of work after the cut-off date may be admitted by the Commission, subject to prudence check:

(i) Liabilities to meet award of arbitration or for compliance of the order or decree of a court of law;

(ii) Change in law or compliance of any existing law;

(iii) Deferred works relating to ash pond or ash handling system in the original scope of work; and

(iv) Any liability for works executed prior to the cut-off date, after prudence check of the details of such undischarged liability, total estimated cost of package, reasons for such withholding of payment and release of such payments etc.

c) The capital expenditure, in respect of existing generating station or the transmission system including communication system, incurred or projected to

be incurred on the following counts after the cut-off date, may be admitted by the Commission, subject to prudence check:

- (i) Liabilities to meet award of arbitration or for compliance of the order or decree of a court of law;
- (ii) Change in law or compliance of any existing law;
- (iii) Any expenses to be incurred on account of need for higher security and safety of the plant as advised or directed by appropriate Government Agencies of statutory authorities responsible for national security/internal security;
- (iv) Deferred works relating to ash pond or ash handling system in the original scope of work;
- (v) Any liability for works executed prior to the cut-off date, after prudence check of the details of such undischarged liability, total estimated cost of package, reasons for such withholding of payment and release of such payments etc.;
- (vi) Any liability for works admitted by the Commission after the cut-off date to the extent of discharge of such liabilities by actual payments;
- (vii) Any additional capital expenditure which has become necessary for efficient operation of generating station other than coal/lignite based stations or transmission system as the case may be. The claim shall be substantiated with the technical justification duly supported by the documentary evidence like test results carried out by an independent agency in case of deterioration of assets, report of an independent agency in case of damage caused by natural calamities, obsolescence of technology, up-gradation of capacity for the technical reason such as increase in fault level;
- (viii) In case of hydro generating stations, any expenditure which has become necessary on account of damage caused by natural calamities (but not due to flooding of power house attributable to the negligence of the generating company) and due to geological reasons after adjusting the proceeds from any insurance scheme, and expenditure incurred due to any additional work which has become necessary for successful and efficient plant operation;
- (ix) In case of transmission system, any additional expenditure on items such as relays, control and instrumentation, computer system, power line carrier communication, DC batteries, replacement due to obsolescence of technology, replacement of switchyard equipment due to increase of fault level, tower strengthening, communication equipment, emergency restoration system, insulators cleaning infrastructure, replacement of porcelain insulator with polymer insulators, replacement of damaged equipment not covered by

insurance and any other expenditure which has become necessary for successful and efficient operation of transmission system; and

(x) Any capital expenditure found justified after prudence check necessitated on account of modifications required or done in fuel receiving system arising due to non-materialisation of coal supply corresponding to full coal linkage in respect of thermal generating station as result of circumstances not within the control of the generating station:

Provided that any expenditure on acquiring the minor items or the assets including tools and tackles, furniture, air-conditioners, voltage stabilizers, refrigerators, coolers, computers, fans, washing machines, heat convectors, mattresses, carpets etc. brought after the cut-off date shall not be considered for additional capitalization for determination of tariff w.e.f. 1.4.2014:

Provided further that if any expenditure has been claimed under Renovation and Modernisation (R&M) or repairs and maintenance under (O&M) expenses, same expenditure cannot be claimed under this Regulation.

- d) In case of de-capitalisation of assets of a generating company or the transmission licensee, as the case may be, the original cost of such asset as on the date of decapitalisation shall be deducted from the value of gross fixed asset and corresponding loan as well as equity shall be deducted from outstanding loan and the equity respectively in the year such de-capitalisation takes place, duly taking into consideration the year in which it was capitalised. It is proposed to adopt the same clause for additional capitalization as specified in CERC Tariff Regulations, 2014."

3.5 Depreciation

The principles behind the charging of depreciation and the depreciation rates have been debated 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 MYT Regulations, 2011 has specified 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%. The average depreciation rate is specified as 5.28% for the first 12 years, and 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 is to be spread over the balance useful life of that asset. Further, the repayment of loan has also been considered on normative basis, and has been considered equal to the annual depreciation allowed, as reproduced below:

"39.4 Notwithstanding any moratorium period availed by the Generating Company or the Transmission Licensee or the Distribution Licensee, as the case may be, the repayment of loan shall be considered from the first year of commercial operation of the project and shall be equal to the annual depreciation allowed."

CERC, in its Terms and Conditions of Tariff Regulations, 2014, has specified the following provisions for allowing interest and depreciation:

"26. ...

(3) The repayment for each of the year of the tariff period 2014-19 shall be deemed to be equal to the depreciation allowed for the corresponding year/period. In case of decapitalization of assets, the repayment shall be adjusted by taking into account cumulative repayment on a pro rata basis and the adjustment should not exceed cumulative depreciation recovered upto the date of decapitalisation of such asset.

(4) Notwithstanding any moratorium period availed by the generating company or the transmission licensee, as the case may be, the repayment of loan shall be considered from the first year of commercial operation of the project and shall be equal to the depreciation allowed for the year or part of the year..."

"27. Depreciation: ...

(2) The value base for the purpose of depreciation shall be the capital cost of the asset admitted by the Commission. In case of multiple units of a generating station or multiple elements of transmission system, weighted average life for the generating station of the transmission system shall be applied. Depreciation shall be chargeable from the first year of commercial operation. In case of commercial operation of the asset for part of the year, depreciation shall be charged on pro rata basis.

...

Provided further that the capital cost of the assets of the hydro generating station for the purpose of computation of depreciated value shall correspond to the percentage of sale of electricity under long-term power purchase agreement at regulated tariff:

Provided also that any depreciation disallowed on account of lower availability of the generating station or generating unit or transmission system as the case may be, shall not be allowed to be recovered at a later stage during the useful life and the extended life.

(4) Land other than the land held under lease and the land for reservoir in case of hydro generating station shall not be a depreciable asset and its cost shall be excluded from the capital cost while computing depreciable value of the asset.

...

(7) The generating company or the transmission license, as the case may be, shall submit the details of proposed capital expenditure during the fag end of the project (five years before the useful life) alongwith justification and proposed life extension. The Commission based on prudence check of such submissions shall approve the depreciation on capital expenditure during the fag end of the project.

(8) In case of de-capitalization of assets in respect of generating station or unit thereof or transmission system or element thereof, the cumulative depreciation shall be adjusted by taking into account the depreciation recovered in tariff by the decapitalized asset during its useful services."

Thus, CERC has retained the approach of linking the normative loan repayment to the depreciation allowed for that year, and has added certain other provisions, which shall be considered and incorporated as appropriate in the amended GERC MYT Regulations. 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. Hence, CERC and all SERCs had increased the rate of depreciation and had removed the provision of AAD in the Tariff Regulations notified after the issuance of the Tariff Policy.

In regulatory perspective, depreciation, being the only cash source available to the Utility after meeting all other expenses, is considered as a source for repayment of loans.

One related issue is the treatment of depreciation in cases where the normative term loan is higher or lesser than the actual term loan. The normative Debt:Equity ratio is 70:30 for all amounts capitalised, and if the actual equity is lower than 30%, then the actual equity is considered, and the balance is considered as the normative debt. Thus, there can never be a situation where the actual debt is higher than the normative debt, unless loans have been taken for amounts more than the amount of capitalisation, which is not allowable as per the Tariff Regulations. The Utility is allowed pass through of the interest expenses, only if the loans are limited to the amount of assets capitalised.

It is proposed to continue the existing approach, except for adding two provisos, first one related to showing depreciation separately for assets added up to March 31, 2016 and second one related to disallowed depreciation not being allowed at a later stage, based on the CERC Tariff Regulations, 2014, as under:

“Provided also that the Generating Company, Transmission Licensee, SLDC and Distribution Licensee shall show the depreciation separately for assets added up to March 31, 2016, for which depreciation has been allowed on the extent of financial support provided through consumer contribution, deposit work, capital subsidy or grant, and which has been offset by considering deferred income”

"Provided that any depreciation disallowed on account of lower availability of the generating station or generating unit or transmission system as the case may be, shall not be allowed to be recovered at a later stage during the useful life".

3.6 Interest on long-term loans

In this regard, M/s. N.C. Mittal & Co. had conducted independent third party audit of annual accounts of FY 2010-11 of the State owned Distribution Licensees as well as generation and distribution business of Torrent Power Limited. The summary of the findings of the report as well as our view on the same in the context of review and amendments to be made to the GERC MYT Regulations, are given in the appropriate sub-sections and paragraphs.

As regards the requirement of long-term loan, the Auditor, M/s N.C. Mittal & Co., has mentioned that in case of TPL – Ahmedabad Distribution, in FY 2010-11, there was a surplus cashflow for the first three Quarters of the Financial Year because of non-utilisation of funds borrowed through loans. On this account, excess interest of

Rs. 64.37 crore was charged and passed on to the consumers. Similar surplus amount was observed in case of TPL – Ahmedabad Generation also. The auditor mentioned that such surplus funds could have been invested and interest could have been earned on the same, which was not done by the Licensee. Further, the Auditor mentioned that TPL - Ahmedabad Distribution had been subsidizing businesses other than regulated business, as it had taken loans on the basis of assets of the regulated business, though substantial chunk of the assets belong to consumers against their contributions, and Grants given by the Government for the assets of the regulated business.

In this regard, it is proposed that the debt-equity ratio of 70:30 is to be applied on the asset value after reducing the funds received through consumer contribution, grants, and deposit works. Hence, since the interest on loan is allowed on debt component derived normatively, higher loan amount on the balance sheet of the Utility would not adversely affect the consumers. TPL's act of giving charge of its entire assets may be beneficial in terms of getting funds at competitive rates, however, the same does not materially affect the consumers. The observation of the auditor can be viewed as whether the loan acquired has been solely used for regulatory business or not, or the loan was required to be employed for carrying out capital expenditure in regulatory business. If a loan has not been utilised for creating assets of the regulated business in a given year, then interest rate on such loan may not be considered in computing the weighted average rate of interest applicable on normative loan amount for computing interest on loan, and the weighted average rate of interest shall be applied on the normative loan allowable, hence, the consumers would not be burdened by the additional loans taken by the Utility, but not utilised.

Based on the experience of the Commission in the second Control Period, and experiences in other States, certain modifications and additional clauses are proposed in the context of Interest on Long-term loans, as under:

- a) " The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year applicable to the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee:

Provided that at the time of truing up, the weighted average rate of interest calculated on the basis of the actual loan portfolio during the year applicable to the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee shall be considered as the rate of interest:

Provided further that if there is no actual loan for a particular year but normative loan is still outstanding, the last available weighted average rate of interest for the actual loan shall be considered:

Provided also that if the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, does not have actual loan, then the weighted average rate of interest of the other business of the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee regulated by the Commission shall be considered:

Provided also that if the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, does not have actual loan, and the other business of the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee regulated by the Commission also does not have actual loan, then the weighted average rate of interest of the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee as a whole shall be considered:

Provided also that if the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee as a whole does not have actual loan, then the Bank Rate plus 200 basis points shall be considered as the rate of interest for the purpose of allowing the interest on the normative loan.

- b) The interest on loan shall be calculated on the normative average loan of the year by applying the weighted average rate of interest:
- c) The above interest computation shall exclude interest on loan amount, normative or otherwise, to the extent of capital cost funded by Consumer Contribution, Grants or Deposit Works carried out by Transmission Licensee or Distribution Licensee or Generating Company, as the case may be."

3.7 Interest on Working Capital (IWC)

The Gujarat Electricity Regulatory Commission (GERC) has specified Working Capital norms vide Regulation 41 of the GERC (Multi Year Tariff) Regulations, 2011, as reproduced below:

“41.1 Generation:

(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 one (1) month 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

(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 one (1) month of capacity charge and energy charge for sale of electricity equivalent calculated on

normative plant availability factor, duly taking into 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.

- (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 (1) month 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.

- (d) *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.*

41.2 Transmission:

- (a) *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 one (1) month of transmission charges calculated on target availability level;*
minus
 - (iv) *Amount, if any, held as security deposits except the security deposits held in the form of Bank Guarantee from Transmission System Users*

- (b) *Interest 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.*

41.3 Distribution Wires Business

- (a) *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 one (1) month 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.*
- (b) *Interest 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.*

41.4 Retail Supply of Electricity

- (a) *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 one (1) month of the expected revenue from sale of electricity at the prevailing tariffs;*
minus
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;
- (b) *Interest 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."*

The Central Electricity Regulatory Commission (CERC) in its CERC (Terms and Conditions of Tariff) Regulations, 2014 has specified the norms for Working Capital for central sector Generation Companies and Transmission Licensees, as reproduced below:

“28. Interest on Working Capital: (1) *The working capital shall cover:*

(a) *Coal-based/lignite-fired thermal generating stations*

(i) *Cost of coal or lignite and limestone towards stock, if applicable, for 15 days for pit-head generating stations and 30 days for non-pit-head generating stations for generation corresponding to the normative annual plant availability factor or the maximum coal/lignite stock storage capacity whichever is lower;*

(ii) *Cost of coal or lignite and limestone for 30 days for generation corresponding to the normative annual plant availability factor;*

(iii) *Cost of secondary fuel oil for two months for generation corresponding to the normative annual plant availability factor, and in case of use of more than one secondary fuel oil, cost of fuel oil stock for the main secondary fuel oil;*

(iv) *Maintenance spares @ 20% of operation and maintenance expenses specified in regulation 29;*

(v) *Receivables equivalent to two months of capacity charges and energy charges for sale of electricity calculated on the normative annual plant availability factor;*

and

(vi) *Operation and maintenance expenses for one month*

(b) *Open-cycle Gas Turbine/Combined Cycle thermal generating stations*

(i) *Fuel cost for 30 days corresponding to the normative annual plant availability factor, duly taking into account mode of operation of the generating station on gas fuel and liquid fuel;*

(ii) *Liquid fuel stock for 15 days corresponding to the normative annual plant availability factor, and in case of use of more than one liquid fuel, cost of main liquid fuel duly taking into account mode of operation of the generating stations of gas fuel and liquid fuel;*

(iii) *Maintenance spares @ 30% of operation and maintenance expenses specified in Regulation 29;*

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

(v) Operation and maintenance expenses for one month

(c) Hydro generating station including pumped storage hydro electric generating station and transmission system including communication system:

(i) Receivables equivalent to two months of fixed cost;

(ii) Maintenance spares @ 15% of operation and maintenance expenses specified in regulation 29; and

(iii) Operation and maintenance expenses for one month.

(2) The cost of fuel in cases covered under sub-clauses (a) and (b) of clause (1) of this regulation shall be based on the landed cost incurred (taking into account normative transit and handling losses) by the generating company and gross calorific value of the fuel as per actual for the three months preceding the first month for which tariff is to be determined and no fuel price escalation shall be provided during the tariff period.

(3) Rate of interest on working capital shall be on normative basis and shall be considered as the bank rate as on 1.4.2014 or as on 1st April of the year during the tariff period 2014-15 to 2018-19 in which the generating station or a unit thereof or the transmission system including communication system or element thereof, as the case may be, is declared under commercial operation, whichever is late.

(4) Interest on working capital shall be payable on normative basis notwithstanding that the generating company or the transmission licensee has not taken loan for working capital from any outside agency."

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

- (i) Whether IWC should be allowed on normative basis or on actuals?
- (ii) How to compute the requirement of maintenance spares as part of the working capital?
- (iii) What should be the rate of interest on working capital, and if linked to SBI Base Rate or RBI Bank Rate, then the prevailing rate as on which date should be considered?

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 it has been proposed that variation in interest on working capital requirement should be 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.**

In this regard, the auditor, M/s. N. C. Mittal & Co., has mentioned that since the receivables = cost + profit, if the working capital is computed based on receivables, the cost should not be considered as the part of working capital, or if the cost is considered as the part of the working capital, the receivables should not be considered as the part of the working capital. Hence, the additional advantages as interest on O&M expenses and maintenance spares on gross fixed assets are passed on to the company and the burden is imposed on the consumers. In view of the same, the auditor has suggested that the O&M expenses for one month and cost of maintenance spares equivalent to 1% of GFA may not be considered as part of the working capital, as these costs are already the parts of receivables.

We are of the view that the formula for working capital requirement is a standard one, being followed by all ERCs including CERC, wherein O&M expenses as well as cost of maintenance spares is allowed, in addition to the receivables, while computing the working capital requirement. Though the statement that the receivables include these cost elements is factually correct, the working capital requirement is allowed as the Utility needs to fund these receivables also, for the specified period, as well as have sufficient cash to meet the regular expenses such as O&M expenses and cost of maintenance spares. Hence, the receivables as well as O&M expenses and cost of maintenance spares have to be considered, while computing the working capital requirement.

Further, the auditor, M/s. N. C. Mittal & Co., has mentioned that the companies are paying interest to the consumers on security deposits, which is being passed on to the consumers as interest expense. Hence, the amount of security deposits should be adjusted towards working capital requirement of the company or towards the equity investment of the Company.

The point raised by the auditor is valid. However, it is observed that the truing-up for FY 2010-11 was done based on the Tariff Regulations, 2005, and hence, the

observation was valid. In the GERC MYT Regulations, 2011, the amount of consumer security deposits have already been adjusted in the working capital requirements as seen in the Regulation 41.4 reproduced above.

As regards the computation of the requirement of maintenance spares as part of the working capital, the GERC MYT Regulations specify that "Maintenance spares at one (1) per cent of the historical cost escalated at 6% from the date of commercial operation" shall be considered. It is easy to compute 1% of the GFA at any point in time, however, the problem may be arising because of the words "escalated at 6% from the date of commercial operation", as each asset would have achieved COD at a different point in time, and there are several assets, hence, it is not feasible to compute the same.

As regards the working capital for FY 2012-13, the Commission in its Order dated 29th April, 2014, in the matter of Truing up for FY 2012-13 and Tariff of FY 2014-15 for GETCO, ruled as under:

“4.10 Interest on working capital for FY 2012-13

...The Commission has examined the computation of normative working capital and interest thereon under GERC (MYT) Regulations, 2011. Regulation 41.2 (b) specifies that interest 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. Regarding 1% Maintenance spares, Regulation 4.2 (a)(ii) of GERC (MYT) Regulations, 2011, specifies maintenance spares as 1% of the historical cost, escalated at 6% from the date of commercial operation. The spares are required for plant machinery and the 1% spares are to be considered on the historical cost of plant and machinery only, instead of the entire GFA. However, the Commission has been considering the maintenance spares at 1% of the opening GFA for the respective year, since it is difficult to keep track of the dates of commercial operation of transmission lines and sub-stations and keep a watch on the requirement of spares escalation. The Commission has, therefore, been considering maintenance spares at 1% of the opening GFA (Historical cost), since there is substantial increase in GFA year on year...”

In this regard, GETCO has filed an Appeal against the Order dated 29th April, 2014 in the matter of Truing up for FY 2012-13 and Tariff of FY 2014-15 for GETCO. The grounds raised by the Appellant in the said appeal, are reproduced below:

“INTEREST ON WORKING CAPITAL:

M. BECAUSE the State Commission erred in not following the MYT Regulations for the purposes of calculation of the appropriate interest on

working capital. The State Commission has failed to appreciate that interest on working capital is to be calculated on a normative basis in terms of the MYT Regulations as under:

“41.2 Transmission:

(a) 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

.....

N. BECAUSE the State Commission erred in not allowing the escalation on the historical cost of the maintenance spares for the calculation of the working capital, as provided for in the MYT Regulations. The State Commission has only considered 1% of the Maintenance Spares for the purposes of calculation of working capital requirements, when the MYT Regulations specifically provides in addition for the inclusion of 6 % escalation on the 1% historical cost of the maintenance spares on a yearly basis.”

The Judgment of APTEL on this Appeal is awaited.

It is proposed to remove the escalation from date of COD and retain the percentage of maintenance spares at 1% of GFA.

The GERC MYT Regulations, 2011, specify the rate of interest as the State Bank Advance Rate (SBAR) as on 1st April of the financial year in which the Petition for determination of tariff is filed. For instance, if the Tariff Petition for FY 2015-16 is filed in November 2014, then the prevailing SBAR as on 1st April 2014 (i.e., the first day of FY 2014-15) shall have to be considered for computing the interest on working capital for FY 2015-16. Thus, there is a gap of one year and beyond, for considering the interest rate, and the interest rates do change during the year. However, at the same time, the SBAR as on 1st April of the financial year for which the tariff is being determined can also not be considered, as this data would not be available at the time of filing the Petition or even at the time of issuing the Tariff Order. One option would be to consider the prevailing SBAR as on the date of filing the Petition, in case of MYT Petition and Mid-term Review Petition, which will ensure that the time gap is reduced and the prevalent SBAR is likely to be considered for computing the IWC. At the time of true-up, the actual SBAR prevalent during different periods of the year may be considered, as this will reflect the actual interest rate applicable.

Further, SBI has moved to the concept of 'Base Rate' from Advance Rate, and gives loans at Base Rate plus a margin. Further, CERC has modified the interest rate to "State Bank Base Rate plus 3.5%", which works out to 13.5%, as the prevailing SBI Base Rate is 10% (w.e.f. 07.11.2013). Hence, the rate of interest for computing IWC may be kept at SBI Base Rate (SBBR) as on 1st April of the financial year in which the Petition is filed plus 250 basis points.

Accordingly, the following modifications are proposed in the context of IWC to be allowed:

"Interest shall be allowed at a rate equal to the State Bank Base Rate (SBBR) as on 1st April of the financial year in which the Petition is filed plus 250 basis points:

Provided that at the time of truing up for any year, interest on working capital shall be allowed at a rate equal to the weighted average State Bank Base Rate (SBBR) prevailing during the financial year plus 250 basis points.

Provided further that at the time of truing up for any year, the working capital requirement shall be re-calculated on the basis of the values of components of working capital approved by the Commission in the truing up;"

"40.7 For the purpose of Truing-up for each year, the variation between the normative interest on working capital computed at the time of Truing-up and the actual interest on working capital incurred by the Generating Company or Transmission Licensee or SLDC or Distribution Licensee, substantiated by documentary evidence, shall be considered as an efficiency gain or efficiency loss, as the case may be, on account of controllable factors, and shared between it and the respective Beneficiary or consumer as the case may be, in accordance with Regulation 24:

Provided that the contribution of delay in receipt of payment to the actual interest on working capital shall be deducted from the actual interest on working capital, before sharing of the efficiency gain or efficiency loss, as the case may be."

Further, for SLDC, the following provisions are proposed:

- (a) The SLDC 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; plus
- (iii) Receivables equivalent to 15 days of the expected revenue from SLDC Charges;

Provided that at the time of truing up for any year, the working capital requirement shall be re-calculated on the basis of the values of components of working capital approved by the Commission in the truing up;

- (b) Interest shall be allowed at a rate equal to the State Bank Base Rate (SBBR) as on 1st April of the financial year in which the Petition is filed plus 250 basis points:

Provided that at the time of truing up for any year, interest on working capital shall be allowed at a rate equal to the weighted average State Bank Base Rate (SBBR) prevailing during the financial year plus 250 basis points.

3.8 Treatment of Deposit works, consumer contribution and grants

The GERC MYT Regulations, 2011 do not clearly specify that depreciation shall not be allowed on assets that have been funded through deposit works, consumer contribution and grants.

However, in the regulated power sector, depreciation is used for repayment of loans and it is not used for replacement of assets. The Utilities may receive Consumer Contribution from their consumers for creation of fixed assets used for serving the consumers. However, such assets remain in the books of the Utility. Similarly, one time grants or capital subsidies are generally given to the State-sector Utilities by the Government for creation of fixed assets. At the end of the life span of such fixed assets created out of grants or Consumer Contribution, normally there is no provision of grants to be provided by Governments or Consumer Contribution to be provided by consumers for their replacement. Replacement of these old fixed assets are generally included in the normal capital expenditure plan and the funding of the same is claimed by the Utilities from the pool of consumers through the ARR and tariff, irrespective of the source of funding of the original fixed assets. When the Utility funds such replacement of old fixed assets, either by its own equity or by loan or by a mix of both, then only it will become eligible to claim returns on the new assets, subject to the specified Debt-Equity norm. Therefore, allowing depreciation

on fixed assets created out of Consumer Contribution or grants will result in making available undue surplus to the distribution licensee at the expense of the consumers.

As regards the depreciation for FY 2011-12, Para 4.4 of the Order dated 28th March 2013 in the matter of Truing up for FY 2011-12 and Tariff for FY 2013-14 for GETCO, stated as under:

“4.4 Depreciation for FY 2011-12

.....GETCO has submitted that the actual depreciation charge for FY 2011-12 was Rs. 454.94 crore, as against Rs. 469.45 crore approved in the MYT Order and worked out the weighted average rate of depreciation as 5.16%. GETCO has explained that it has been booking @ 11.75% of the closing grants, consumer contribution and subsidies towards acquisition of Fixed Assets as income during the year. GETCO has computed depreciation of Rs. 59.49 crore on the asset funded by way of Govt Grant / Consumer Contribution at depreciation rate of 5.16%. It has been further explained that the depreciation on the assets acquired by Govt. Grants / Consumer Contributions, of Rs. 59.40 crore is deducted from depreciation for FY 2011-12, since GETCO proposes not to consider deferred income on Grants / Consumer Contribution as other income. Accordingly GETCO has claimed depreciation of Rs. 395.55 (454.95-59.40) crore and arrived at a gain of Rs. 73.90 crore.....

.....GETCO has mentioned the Accounting Standard No. 12 issued by Institute of Chartered Accountants of India which was above stated in Clause no 44 of the Hon'ble Appellate Tribunal for Electricity order dated 07.04.2011. The relevant para is extracted below.

“Government grants related to specific fixed assets should be presented in the balance sheet by showing the grant as a deduction from the gross value of the assets concerned in arriving at their book value. Where the grant related to a specific fixed asset equals the whole or virtually the whole of the cost of the asset, the asset should be shown in the balance sheet at a nominal value. Alternatively government grants related to depreciable fixed assets may be treated as deferred income which should be recognized in the profit and loss statement on a systematic and rational basis over the useful life of the asset i.e. such grants should be allocated to income over the periods and in the proportions in which depreciation on those assets is charged.” (Emphasis added)

GETCO has further submitted that it has adopted 2nd alternative and transferred 11.75% of yearend balance of Government grants / subsidies and Consumer Contribution for FY 2011-12 as deferred income amounting Rs. 128.69 crore. Since

*the amount of deferred revenue (Rs. 128.69 crore is not same as proportionate depreciation (Rs. 59.40 crore) on assets acquired out of Govt Grants / Subsidies and Consumer Contribution GETCO has proposed to eliminate depreciation amount (Rs. 59.40 crore) from expenses side and deferred income (Rs. 128.9 crore) from income sides. **GETCO has further submitted that MYT Regulations, 2011 are silent about the treatment of depreciation and deferred income booked towards Government Grant and subsidies and requested to consider the approach of GETCO and not to consider depreciation on the assets acquired from Grants / Consumer Contribution and also not to consider deferred income on Grants / Consumer Contribution as other income. (Emphasis added)***

.....

Commission's Analysis

*GETCO has computed the depreciation on the assets funded by Grants / Consumer Contributions and Subsidies towards acquisition of Fixed Assets at Rs. 59.40 crore with the weighted average rate of 5.16% and subtracted this Rs. 59.40 crore from the actual depreciation of Rs. 454.94 crore and claimed the depreciation at Rs. 395.55 crore in the Truing up. **The issue of considering a percentage of consumer contribution Govt. Grants and Subsidies as non-tariff income is common to all the licensees and requires to be carefully examined. The Commission does not want to deliberate on the issue now in the truing up for FY 2011-12.** The Commission has followed the policy of considering portion of grants as non-tariff income consistently for all the licensees and any change in this behalf affects the parameters considered in the MYT order for FY 2011-12 to FY 2015-16"*

In this regard, GETCO has filed an Appeal (Appeal No. 108-2013) against the Order dated 28th March, 2013 in the matter of Truing up of FY 2011-12 and Determination of Tariff for FY 2013-14. Various grounds raised by the Appellant in the said Appeal are reproduced below:

"9. GROUND RAISED WITH LEGAL PROVISIONS

.....

- F.** *The State Commission erred in the treatment of depreciation and deferred income of the Government Grants and Subsidies and consumer contributions towards capital assets. The Appellant receives Government Grants/ Subsidies and Consumer Contributions toward cost of capital assets and offers @ 11.75% of year-end balance as deferred income during the year. This is in line with the recommendations of the Comptroller and Auditor General as adopted by the Board of Directors of the Appellant. Further, the Government*

grants/ subsidies and consumer contributions received during the year is not serviced by means of return on equity or interest on loan.

G. Because the State Commission while allowing the depreciation, includes a sum of 11.75% of such contributions as deferred income and taken to the revenue of the Appellant. However, the above methodology followed by the State Commission creates cash flow problems to the Appellant, even though over the life of the assets, the deferred income will equate to the depreciable value of the assets. This is on account of the fact that the deferred revenue (Rs. 128.69 Cr) is not same as proportionate depreciation (Rs. 59.40 Cr) on assets acquired out of Government grants/ subsidies and consumer contributions. This happens because depreciation is applied on Straight Line method while deferred income is considered on written down value method in books of accounts. In the circumstances, the provision of allowing depreciation amount (Rs. 59.40 Cr) from expense side and deferred income (Rs. 128.69 Cr) from income side may be eliminated to ensure that there is no discrepancy between the amount of depreciation and deferred income to ensure that there is no cash flow problems to the Appellant.”

.....

Further, in this regard, the Forum of Regulators in its Model Regulation for Multi Year Distribution Tariff has suggested as under:

“24. Treatment of Depreciation

..... (b) Depreciation shall not be allowed on assets funded by capital subsidies, consumer contributions or grants”.....

While formulating the Tariff Regulations, a number of SERCs have included specific provisions for not allowing depreciation on fixed assets created out of Grants and Consumer Contribution. The relevant references of Tariff Regulations of some of the SERCs have been tabulated below:

Relevant reference of Tariff Regulations of some of the SERCs

Table 3-1: References to the specific provisions for not allowing depreciation on fixed assets created out of Grants and Consumer Contribution in the Regulations of various SERCs

Sr. No.	SERC	Reference
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Sr. No.	SERC	Reference
1	Andhra Pradesh Electricity Regulatory Commission	Regulation 17 of the APERC (Terms and Conditions of Determination of Tariff for Wheeling and Retail Sale of Electricity) Regulations, 2005
2	Chhattisgarh State Electricity Regulatory Commission	Regulations 18 of the CSERC (Terms and Conditions for Determination of Tariff) Regulations, 2006
3	Delhi Electricity Regulatory Commission	Regulations 5.16 of the DERC (Terms and Conditions for Determination of Wheeling Tariff and Retail Supply Tariff) Regulations, 2011
4	Himachal Pradesh Electricity Regulatory Commission	Regulations 23 of the HPERC (Terms and Conditions for Determination of Wheeling Tariff and Retail Supply Tariff) Regulations, 2011
5	Uttar Pradesh Electricity Regulatory Commission	Regulations 4.9 of the UPERC (Terms and Conditions for Determination of Distribution Tariff) Regulations, 2006
6	Uttarakhand Electricity Regulatory Commission	Regulations 29 of the UERC (Terms and Conditions for Determination of Tariff) Regulations, 2011

Hence, it is proposed that a specific clause be incorporated to the effect that depreciation (as well as ROE and interest) shall not be applicable to the extent of financial support provided through consumer contribution, deposit work, and capital subsidy/grant, and the debt:equity ratio shall be considered after deducting such amounts. If the entire amount of consumer contribution, deposit work, and capital subsidy/grant is deducted from the GFA, then there would be no need to treat any proportion of the same as non-tariff income, and there would be no complications of mismatch between the income considered and the expense considered. This also addresses GETCO's submission that neither should depreciation be considered on assets acquired using grants and consumer contribution nor should deferred income be considered on the grants and consumer contribution.

The following clauses are proposed to be added in this context:

"The expenses on such capital expenditure shall be treated as follows:-

- a) normative O&M expenses as specified in these Regulations shall be allowed;
- b) the debt:equity ratio, shall be considered in accordance with Regulation 33, after deducting the amount of financial support provided through consumer contribution, deposit work, capital subsidy or grant;
- c) provisions related to depreciation, as specified in Regulation 39, shall not be applicable to the extent of financial support provided through consumer contribution, deposit work, capital subsidy or grant;
- d) provisions related to return on equity, as specified in Regulation 37 shall not be applicable to the extent of financial support provided through consumer contribution, deposit work, capital subsidy or grant;
- e) provisions related to interest on loan capital, as specified in Regulation 38 shall not be applicable to the extent of financial support provided through consumer contribution, deposit work, capital subsidy or grant."

3.9 Rebate

In this context, the GERC MYT Regulations, 2011 specifies as under:

"43 Rebate

43.1 *For payment of bills of generation tariff or transmission charges through Letter of Credit or otherwise, within 7 days of presentation of bills, by the Generating Company or the Transmission Licensee, as the case may be, a rebate of 2% on billed amount, excluding the taxes, cess, duties, etc., shall be allowed. Where payments are made subsequently through opening of Letter of Credit or otherwise, but within a period of one month of presentation of bills by the Generating Company or the Transmission Licensee, as the case may be, a rebate of 1% on billed amount, excluding the taxes, cess, duties, etc., shall be allowed."*

"93.4 *The Distribution Licensee shall be allowed to offer a rebate to the consumers on tariff and charges determined by the Commission:*

Provided that the Distribution licensee shall submit details of such rebates to the Commission every quarter, in the manner and format, as stipulated by the Commission from time to time:

Provided further that the impact of such rebates given by the Distribution licensee shall be borne entirely by the Distribution Licensee and impact of such rebate will not be allowed to be passed through to the consumers, in any form:

Provided further that such rebates shall not be offered selectively to any consumer/s, and shall have to be offered to the entire consumer category/sub-category/consumption slab in a non-discriminatory manner."

The Central Electricity Regulatory Commission (CERC) in its CERC (Terms and Conditions of Tariff) Regulations, 2014 specified as under:

"44. Rebate. (1) For payment of bills of the generating company and the transmission licensee through letter of credit on presentation or through NEFT/RTGS within a period of 2 days of presentation of bills by the generating company or the transmission licensee, a rebate of 2% shall be allowed.

(2) Where payments are made on any day after 2 days and within a period of 30 days of presentation of bills by the generating company or the transmission licensee, a rebate of 1% shall be allowed."

As recorded in Daily Order dated July 25, 2014, in the review Petition (Petition No. 1431 of 2014) filed by GSECL, the Petitioner submitted that the rebate is considered as expenditure by the Petitioner, which is not permissible as it defeats the purpose of rebate stated in the PPA. In this context, ATE in its Judgment dated July 30, 2010 in Appeal No. 153 of 2009 (NDPL vs. DERC) ruled as under:

"34. According to the State Commission, the rebate is a part of non-tariff income as per the MYT Regulations which is an essential part of the power purchase cost and the effect of MYT order as well as the impugned order is the same, in so far as treatment of rebate on power purchase cost is concerned and the distribution company would earn a rebate of 1% even if it pays the power purchase bills within 30 days of the due date and that by making the payment on time it cannot be construed that the distribution company are being efficient and on the contrary it has the duty to pay the bills in time. The State Commission relied upon the judgment of the Hon'ble Supreme Court reported in 1986 (1) SCC 264 – LIC of India versus Escorts Limited. We have gone through the said judgment. The perusal of the said judgment would make it evident that this is not applicable to the present facts of the case. In the present case the State Commission itself provided a format for ARR petition to be

submitted by the distribution companies. The format referred to in the ARR petition do not cover rebate income and do not provide for the subtraction of the rebate earned from the power purchase cost. By referring to the said formats, Form-1 and Form-11 and Form-1a, the Appellant is only providing additional documents to substantiate their claim that under MYT Regulations the rebate from the power purchase cost is not to be deducted from Power Purchase Cost and not to be included as a non-tariff income for determination of tariff. The Working Capital includes Power Purchase Cost for only one month. The generation company offers rebate of 2% on payment of presentation which takes place immediately after completion of the month. On the other hand the billing cycle of domestic consumers is bi-monthly and for Industrial and Commercial consumers taking supply at 11 KV and above it is monthly. The consumer also gets 15 days time for payment of bill after issue of bill. Thus there is mismatch between the receipt of payment from consumers and the payment to be made by distribution licensee for power purchase for getting 2% rebate. **Applying the principle that all gains and losses on account of overachievement or underachievement in performance with respect to norms, have to be retained/borne by the distribution licensee, we hold that rebate over and above 1% cannot be considered non-tariff income for reducing the ARR. In view of the same, it has to be concluded that the rebate earned on early payment of power purchase cost cannot be deducted from the power purchase cost and rebate earned only up to 1% alone can be treated as part of non-tariff income.** Therefore, the finding on this issue by the State Commission is contrary to the law and spirit of the MYT Regulations as it defeats the very purpose of allowing cost on normative basis. It is also contrary to the principle of allowing cost on normative basis of working capital. On the one hand, the State Commission has reduced one month power purchase payment from the working capital requirement and on the other hand it has been observed that if the Appellant is making the payment earlier, the benefit of entire rebate is used for reducing the power purchase cost.

35. Therefore, it is clear from the above that treating rebate income for reduction from power purchase cost as per the impugned tariff order is contrary to the MYT Regulations. Rebate only to the extent of 1% is to be considered as non-tariff income. As such, the issue is answered accordingly." **(emphasis added)**

In view of above, the rebate has to be considered as Non-Tariff Income since the cost of paying early are the charges payable on the Letter of Credit, which is allowed separately under the Administrative and General (A&G) Expenses. Accordingly, a proviso stating that 'any rebate earned by a Generating Company or Licensee on account of prompt payment of its dues shall be treated as non-tariff income' is proposed to be

incorporated in the proposed Regulations. The treatment of the rebate by the Generating Company has been discussed in the Chapter on Generation.

As regards the rebate to be offered by the DISCOMs, the same is usually stipulated in the Tariff Orders issued by the Commission.

As regards the rebates such as power factor rebate and prompt payment rebate given by the DISCOMs to their consumers, in accordance with the Tariff Schedule approved by the Commission, these rebates are allowed as expenses for the DISCOMs, and thus, the impact of the rebates is already considered at the time of truing up.

The normative IWC is computed by considering receivables for 1 month, hence, the cost of such receivable is already being allowed. In case, the Generating Company or Transmission Licensee or Distribution Licensee receives payment earlier than one month from its beneficiaries, then the prompt payment rebate given to the beneficiary should not be allowed as an expense, else, it will amount to double-benefit for the Utility.

In view of the above it is proposed that prompt payment rebate given by the Generating Company or the Transmission Licensee or the Distribution Licensee to the beneficiary shall not be allowed as an expense for the Generating Company or the Transmission Licensee or the Distribution Licensee, as the case may be.

The following clauses are proposed to be incorporated:

- a) "For payment of bills of retail tariff by the consumers within 7 days of presentation of bills, a rebate on the billed amount, excluding the taxes, cess, duties, etc., shall be allowed at the rate stipulated in the prevalent Tariff Order;
- b) Such rebate earned by the Distribution Licensee shall be considered under Non-Tariff Income for the Distribution Licensee;
- c) Such rebate given by the Generating Company or the Transmission Licensee or the Distribution Licensee to the beneficiary shall not be allowed as an expense for the Generating Company or the Transmission Licensee or the Distribution Licensee, as the case may be."

3.10 Impact of de-capitalisation of assets

As regards the issue of whether the equity in proportion to the assets de-capitalised should be reduced from the regulated equity considered for the purpose of allowing ROE, we are of the view that the corresponding equity should be reduced from the regulated equity.

The second proviso to Regulation 34.1 of the GERC MYT Regulations, 2011, specifies as under:

"34.1 ...

Provided further that in case of retirement or replacement of assets, the equity capital approved as mentioned above, shall be reduced to the extent of 30% (or actual equity component based on documentary evidence, if it is lower than 30%) of the original cost of the retired or replaced asset:..".

The intention of the above proviso is the same, however, only 'retirement' and 'replacement' of assets have been listed. De-capitalisation is nothing else but retirement of assets. However, for additional clarity, the term 'de-capitalisation' has also been added along with retirement, to ensure that there is no ambiguity in the treatment of such instances.

In order to implement the above proviso for cases of de-capitalisation/retirement, the onus should be on the Utility to submit the actual equity invested in the asset that has been de-capitalised/retired. In the absence of any data submitted by the Utility, due to lack of information and vintage issues, the Commission may consider 30% of the GFA as the equity that would have been invested and reduce the equity accordingly.

3.11 O&M Expenses

While specifying the normative O&M expenses for the generation business, transmission business and distribution business, one of the aspects to be considered is whether the normative O&M expenses should be specified in a consolidated manner or separately, as employee expenses, A&G expenses, and Repair & Maintenance expenses. Both options have their merits and de-merits. If the O&M expenses are specified in a consolidated manner, the utility has the flexibility to manage its expenditure through own resources (which will increase the employee expenses) or through outsourcing (which will increase the A&G expenses), as

appropriate. However, under this dispensation, the variation in the individual heads of employee expenses, A&G expenses, and Repair & Maintenance expenses are difficult to track, and there are occasions when the Commission may wish to consider these separately, due to specific treatment to be given for pay revision, etc. This issue also depends on the nature of the business, i.e., generation, transmission or distribution.

Traditionally, for generation business, the O&M expenses are specified in a consolidated manner, either as a percentage of the GFA or in terms of Rs. lakh/MW of capacity. For transmission business, the consolidated O&M expenses are typically linked to the number of bays and circuit kilometres of transmission lines, however, there is no segregation between employee expenses, A&G expenses, and Repair & Maintenance expenses.

In case of distribution, most other SERCs have adopted the approach of specifying the norms for employee expenses, A&G expenses, and Repair & Maintenance expenses separately, whereas the Commission has considered the O&M expenses in a consolidated manner, and has specified the principles for allowing the O&M expenses rather than specifying the norm. It is proposed to continue with the same approach, in view of the disparity in O&M expenses and trend in expenses of the different DISCOMs.

Another issue to be addressed while specifying the O&M norms is whether the gross expenses or net expenses (after capitalisation) of previous years should be considered for arriving at the O&M norms for the third Control Period. Conceptually, it may be more appropriate to consider the gross expenses of previous years, for arriving at the O&M norms for the third Control Period, since, the capitalisation may vary from year to year, and considering the actual capitalisation of previous years may skew the calculations. In this case, the actual capitalisation of the O&M expenses would have to be reduced at the time of truing up, while in the Tariff Orders, the average capitalisation rate may be considered. On the other hand, if it is assumed that the level of capitalisation is unlikely to vary significantly from year to year, then the net expenses (after capitalisation) of previous years may be considered for arriving at the O&M norms for the third Control Period, in which case, the capitalisation will not have to be deducted separately.

In this context, it is relevant to quote the Hon'ble ATE Judgment dated December 14, 2012, wherein the view has been taken that there was no concept of 'gross O&M' and 'net O&M'. The relevant extract of Judgment is produced herewith:

"19.O&M expenses are the expenses which have been incurred in operation and maintenance of the project and would not include the expenses which

had been incurred in construction of the project. All those expenses, including employees' cost, which have been capitalised and entitles the utility to earn RoE and other benefits for the life time of the project cannot be considered as O&M expenses for that year. Only the expenditure which has been actually incurred in operation and maintenance can form part of O&M expenses. Thus, there is no such term as 'gross O&M' expense or 'net O&M' expenses. The acceptance of the Contention of the Appellant would amount to allowing such amounts both as a revenue expense and also form a part of the capital base on which the Appellant could claim RoE, depreciation etc resulting in to double-accounting and, therefore, not permissible."

Another issue to be addressed is the issue of Corporate Social Responsibility (CSR). As per the Companies Act, 2013, Companies have to incur expenditure under CSR to the extent of at least two percent of the average net profits of the Company during the three immediately preceding financial years. Under the Companies (Corporate Social Responsibility Policy) Rules, 2014, which is effective from April 1, 2014, it is obligatory for profit making Companies to perform activity under CSR.

As regards expenses on CSR, we are of the view that the Companies Act, 2013 clearly requires the Companies to spend 2% of their 'net profit' on CSR. Thus, such expenditure has to be made out of the profits/returns earned by the Company, and should not be booked as an expense that is recoverable from the consumers. In other words, such expenses have to be incurred by the Company out of the returns available for disbursement to its shareholders, and should not be passed on to the consumers of the electricity business. Further, these expenses are towards Corporate Social Responsibility and are not Consumer Social Responsibility, wherein the expenses can be passed on to the consumers. We are of the view that it is immaterial whether such expenses are mandatory or mad out of choice by the Corporate, and have to be incurred by the Corporate, without being passed on to the consumers.

3.12 Write-off of bad debts

In the electricity business, there is an element of bad debt, due to the risk of nonpayment of electricity bills by the consumers, and the distribution licensee has to make suitable provision for bad debts. However, the distribution licensee has access to the consumers' security deposit, which is collected for precisely this reason. The licensee has to ensure that the collection efficiency is maximized and even the arrears, if any, should be collected. The dues actually written off should be reduced from the provision made against outstanding receivables and should not be again charged to the revenue account of the year. Further, it is equally important that such

provisioning is based on study and uniform policy for write off. In support of writing off the bad debts, details such as historical analysis of existing debts, reasons for writing off debts or any norms/benchmarks evolved on actual positions, categorisation of receivables, etc., need to be furnished.

The GERC MYT Regulations, 2011, specify as under:

"98.8.1 The Commission may allow bad debts written off as a pass through in the aggregate revenue requirement, subject to prudence check."

Based on the above, the following provisions for Bad Debts Written off are proposed for the ensuing Control Period:

- 1. The Commission may allow bad debts written off as a pass through in the Aggregate Revenue Requirement, based on the trend of write off of bad debts in the previous years, subject to prudence check:**

Provided that the Commission shall true up the bad debts written off in the Aggregate Revenue Requirement, based on the actual write off of bad debts during the year, subject to prudence check:

Provided further that if subsequent to the write off of a particular bad debt, revenue is realised from such bad debt, the same shall be included as an uncontrollable item under the Non-Tariff Income of the year in which such revenue is realised.

3.13 Contribution to Contingency Reserves

In the existing GERC MYT Regulations, 2011, contribution to contingency reserves is allowed for the Transmission business and Distribution business, as under:

"71.7 Contribution to contingency reserve:

71.7.1 Where the Transmission Licensee has made an appropriation to the Contingency Reserve, a sum not more than 0.5 per cent of the original cost of fixed assets shall be allowed annually towards such appropriation in the calculation of aggregate revenue requirement:

Provided that where the amount of such Contingency Reserve exceeds five (5) per cent of the original cost of fixed assets, no such appropriation shall be allowed, which would have the effect of increasing the reserve beyond the said maximum:

Provided further that the amount so appropriated shall be invested in securities authorised under the Indian Trusts Act, 1882 within a period of six months of the close of the financial year.

71.7.2 The Contingency Reserve shall not be drawn upon during the term of the licence except to meet such charges as may be approved by the Commission as being:

(a) Expenses or loss of profits arising out of accidents, natural calamities or circumstances which the management could not have prevented;

(b) Expenses on replacement or removal of plant or works other than expenses requisite for normal maintenance or renewal;

(c) Compensation payable under any law for the time being in force and for which no other provision is made:

Provided that such drawal from Contingency Reserve shall be computed after making due adjustments for any other compensation that may have been received by the Licensee as part of an insurance cover.

71.7.3 No diminution in the value of contingency reserve as mentioned above shall be allowed to be adjusted as a part of tariff."

The same clauses exist under Clause 85.6 for the Distribution business also.

The concept of creation of Contingency Reserve and investing the same in safe securities is to ensure that such amount is readily available to meet certain emergency requirements, without having to approach the consumers for allowance of the expenses. It is for this reason that the Regulations specify that the amount of Contingency Reserve shall be invested in specified securities, and also specify the manner and heads on which the Contingency Reserve may be utilised. If such Contingency Reserve is not created, then such funds may not be available when really required. Hence, it is proposed to continue with the existing provisions in this regard with some modifications:

69.3 Contribution to contingency reserve:

69.3.1 The Transmission Licensee may make an appropriation to the Contingency Reserve, of a sum not exceeding 0.5 per cent of the original cost of fixed assets at the beginning of the year, for each year, which shall be allowed in the calculation of aggregate revenue requirement:

Provided that where the amount of such Contingency Reserve exceeds five (5) per cent of the original cost of fixed assets, no such appropriation shall be allowed, which would have the effect of increasing the reserve beyond the said maximum:

Provided further that the amount so appropriated may be invested in securities authorised under the Indian Trusts Act, 1882 or any other security within a period of six months of the close of the financial year.:

Provided also that if the amount so appropriated is invested in securities, then the actual interest income earned by the Transmission Licensee shall be included under the Non-Tariff income:

Provided also that if the amount so appropriated is not invested in securities, then the normative interest income, computed at the weighted average State Bank Base Rate for the year, shall be included under the Non-Tariff income of the Transmission Licensee.

69.3.2 The Contingency Reserve shall not be drawn upon during the term of the licence except to meet such charges as may be approved by the Commission as being:

- (a) Expenses or loss of profits arising out of accidents, natural calamities or circumstances which the management could not have prevented;
- (b) Expenses on replacement or removal of plant or works other than expenses required for normal maintenance or renewal;
- (c) Compensation payable under any law for the time being in force and for which no other provision is made:

Provided that such drawal from Contingency Reserve shall be computed after making due adjustments for any other compensation that may have been received by the Licensee as part of an insurance cover and Government Grant, if any.

69.3.3 No diminution in the value of contingency reserve as mentioned above shall be allowed to be adjusted as a part of tariff.

3.14 Delayed Payment Surcharge

In the existing GERC MYT Regulations, 2011, delayed payment surcharge is allowed at the rate of 1.25% per month, for the period of delay, in case the payment of bills of generation tariff or transmission charges by the beneficiary or beneficiaries is delayed beyond a period of 30 days from the date of billing.

We are of the view that the the existing specified rate of 1.25% per month works out to 15% per annum, and is appropriate.

Further, as regards Delayed Payment Charges (DPC), DISCOMs have submitted in their Petitions for truing up that for the purpose of ARR determination, the Commission considers revenue from Tariff on accrual basis, i.e., amount billed by the DISCOM to all the consumers, however, all the consumers do not make timely payments for the bills raised. Because of delays in the payment by the consumers, the

working capital requirements of the DISCOMs are increased, which are funded by DPC. Hence, by considering income on accrual basis and simultaneously considering DPC in the ARR, the DISCOMs are doubly penalised. The DISCOMs have hence, requested the Commission not to consider the DPC in the ARR. The same rationale is applicable for the Generation and Transmission Business also. In view of the same, it is proposed not to consider interest on delayed or deferred payment on bills as part of Non-Tariff Income, for the Generation, Transmission, Distribution Wires and Retail Supply Business.

3.15 Prior period income and expenses

In the existing GERC MYT Regulations, 2011, there is no treatment specified for prior period income and expenses.

We are of the view that the treatment of prior period income and expenses has to be done on a case to case basis, as this is primarily an accounting treatment, and hence, cannot be specified in the Regulations. However, as a principle, in case any excess provisioning or expense has been disallowed in previous years due to allowance of normative expenses, and the same is reported as prior period income due to write-back, then the same ought not to be considered as prior period income, as the expenses have not been allowed in the prior periods. Similarly, prior period expenses pertaining to heads where normative expenses have already been allowed ought not to be allowed, as only the normative expenses can be allowed.

The following proviso is proposed to be added:

"Provided further that prior period income/expenses shall be allowed by the Commission at the time of truing up based on audited accounts, on a case to case basis, subject to prudence check."

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, and whose tariff determination is within the purview of the Gujarat Electricity Regulatory Commission. The brief summary of generating stations of GSECL and TPL-G is given in the following Tables:

Table 4-1: Generating Stations of GSECL

Name of Station	Installed Capacity (MW)	Unit No.	Unit wise installed capacity (MW)	Year of Commissioning
Ukai TPS	1350	1	120	1976
		2	120	1976
		3	200	1979
		4	200	1979
		5	210	1985
		6	500	2013
Gandhinagar TPS	870	1	120	1977
		2	120	1977
		3	210	1990
		4	210	1991
		5	210	1998
Wanakbori TPS	1470	1	210	1982
		2	210	1983
		3	210	1984
		4	210	1986
		5	210	1986
		6	210	1987
		7	210	1998
Sikka TPS	740	1	120	1988
		2	120	1993
		3	250	2014

Name of Station	Installed Capacity (MW)	Unit No.	Unit wise installed capacity (MW)	Year of Commissioning
		4	250	2014
Kutch Lignite TPS	290	1	70	1990
		2	70	1991
		3	75	1997
		4	75	2009
Dhuvaran CCPP	219.07	7-Gas	106.62	2004
		8 - Gas	112.45	2007
Dhuvaran CCPP#3	375.00	1	375	2014
Utran CCPP	135	GT-1	30	1992
		GT-2	30	1992
		GT-3	30	1993
		STG	45	1993
Utran Extension	375	GT-1	375	2009
Ukai Hydro	300	1	75	1976
		2	75	1974
		3	75	1975
		4	75	1976
Ukai LBC	5	1	2.5	1987
		2	2.5	1988
Kadana Hydro	240	1	60	1990
		2	60	1990
		3	60	1998
		4	60	1998
Kadana Panam Canal mini Hydro	2	1	1	1994
		2	1	1994
Total	6371.07			

Table 4-2: Generating Stations of TPL-G

Name of Station	Installed Capacity (MW)	Unit No.	Unit wise installed capacity (MW)	Year of Commissioning
Sabarmati 'C'	60	1	30	1961/1997* (*Trubine retro-fitting)
		2	30	
Sabarmati 'D'	120	1	120	1978/2004* (*Up-rating capacity)
Sabarmati 'E'	110	1	110	1984
Sabarmati 'F'	110	1	110	1988

Name of Station	Installed Capacity (MW)	Unit No.	Unit wise installed capacity (MW)	Year of Commissioning
Vatva CCPP	100	GT-1	32.5	1990
		GT-2	32.5	1991
		STG	35	1991
Total	500			

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

4.1 Annual Fixed Charges

The GERC MYT Regulations, 2011, specify, inter-alia, as under:

"50.1 Components of Annual Fixed charges:

The Annual Fixed Charges shall comprise of the following elements:

(a) Depreciation;

(b) Operation & Maintenance Expenses;

(c) Return on Equity;

(d) Interest and Finance Charges on Loan Capital;

(e) Interest on Working Capital;

minus:

(f) Non-Tariff Income:

Provided that Depreciation, Interest and finance charges on Loan Capital, Interest on Working Capital and Return on Equity for Thermal and Hydro Generating Stations shall be allowed in accordance with the provisions specified in Chapter 3 of these Regulations."

It is proposed to add two extra line items, i.e., "Special allowance in lieu of Renovation & Modernisation, wherever applicable" and "SLDC Fees and Charges" in the list of components. Further it is also proposed to add one proviso for treatment of prior period income/expenses and modify the existing Regulation as under:

"The Annual Fixed Charges shall comprise the following elements:

(a) Depreciation;

(b) Interest and Finance Charges on Loan Capital;

- (c) Interest on Working Capital;
- (d) Operation & Maintenance Expenses;
- (e) Return on Equity;
- (f) Special allowance in lieu of Renovation & Modernisation, wherever applicable
- (g) SLDC Fees and Charges

minus:

- (h) Non-Tariff Income:

Provided that Depreciation, Interest and finance charges on Loan Capital, Interest on Working Capital and Return on Equity for Thermal and Hydro Generating Stations shall be allowed in accordance with the provisions specified in Chapter 3 of these Regulations:

Provided further that prior period income/expenses shall be allowed by the Commission at the time of truing up based on audited accounts, on a case to case basis, subject to prudence check."

4.2 Common Issues for Thermal and Hydro generating stations

4.2.1 Approval of provisional tariff

The GERC MYT Regulations, 2011, specify, inter-alia, as under:

"...

48.4 A Generating Company may file a Petition for determination of provisional tariff in advance of the anticipated Date of Commercial Operation of the Unit or Stage or Generating Station as a whole, as the case may be, based on the capital expenditure actually incurred up to the date of making the Petition or a date prior to making of the Petition, duly audited and certified by the statutory auditors and the provisional tariff shall be charged from the date of commercial operation of such Unit or Stage or Generating Station, as the case may be.

48.5 A Generating Company shall file a fresh Petition in accordance with these Regulations, for determination of final tariff based on actual capital expenditure incurred up to the date of commercial operation of the Generating Station duly certified by the statutory auditors based on Annual Audited Accounts.

48.6 Any difference in provisional tariff and the final tariff determined by the Commission and not attributable to the Generating Company may be adjusted at the time of determination of final tariff for the following year as directed by the Commission..."

Thus, the GERC MYT Regulations, 2011 provide scope for filing Petition for approval of provisional generation tariff in advance, before the anticipated date of commercial operation (COD). However, the advance period has not been specified. Further, the GERC MYT Regulations, 2011 specifies that the Petition for determination of provisional tariff has to be filed based on the capital expenditure actually incurred till date and duly audited and certified by the statutory auditors. Further, the GERC MYT Regulations, 2011 provide that the difference in provisional tariff and final tariff determined by the Commission and not attributable to the generating company may be adjusted at the time of determination of final tariff for the following year. However, the GERC MYT Regulations, 2011 do not clarify on exactly how the difference between the provisional tariff and the final tariff determined by the Commission shall be recovered.

CERC, in the CERC Tariff Regulations, 2014, has elaborated in great detail about this aspect, as under:

"7. Application for determination of tariff:

(1) *The generating company may make an application for determination of tariff for new generating station or unit thereof in accordance with the Procedure Regulations, in respect of the generating station or generating units thereof **within 180 days of the anticipated date of commercial operation.***

(2) *The transmission licensee may make an application for determination of tariff for new transmission system including communication system or element thereof as the case may be in accordance with the Procedure Regulations, in respect of the transmission system or elements thereof anticipated to be commissioned **within 180 days from the date of filing of the petition.***

(3) *In case of an existing generating station or transmission system including communication system or element thereof, the application shall be made not later than 180 days from the date of notification of these regulations **based on admitted capital cost including any additional capital expenditure already admitted up to 31.3.2014 (either based on actual or projected additional capital expenditure) and estimated additional capital expenditure** for the respective years of the tariff period 2014-15 to 2018-19.*

(4) *The generating company or the transmission licensee, as the case may be, shall make*

an application as per **Annexure-I** of these regulations, for determination of tariff **based on capital expenditure incurred duly certified by the auditors or projected to be incurred up to the date of commercial operation** and additional capital expenditure incurred duly certified by the auditors or projected to be incurred during the tariff period of the generating station or the transmission system as the case may be:

Provided that the petition shall contain **details of underlying assumptions for the projected capital cost and additional capital expenditure**, wherever applicable.

(5) If the petition is inadequate in any respect as required under **Annexure-I** of these regulations, the application shall be returned to the generating company or transmission licensee as the case may be, for resubmission of the petition within one month after rectifying the deficiencies as may be pointed out by the staff of the Commission.

(6) If the information furnished in the petition is in accordance with the regulations and is adequate for carrying out prudence check of the claims made, the Commission shall consider the suggestions and objections, if any, received from the respondents within one month from the date of filing of the petition and any other person including the consumers or consumer associations. The Commission shall issue the tariff order after hearing the petitioner, the respondents and any other person specifically permitted by the Commission.

(7) In case of the new projects, the generating company or the transmission licensee, as the case may be, **may be allowed tariff by the Commission based on the projected capital expenditure from the anticipated COD in accordance with Regulation 6 of these regulations:**

Provided that :

- (i) **the Commission may grant tariff upto 90% of the annual fixed charges claimed in respect of the transmission system or element thereof** based on the management certificate regarding the capital cost for the purpose of inclusion in the POC charges in accordance with the CERC (Sharing of Inter State Transmission charges and losses), Regulation, 2010 as amended from time to time:
- (ii) **if the date of commercial operation is delayed beyond 180 days from the date of issue of tariff order in terms of clause (6) of this regulation, the tariff granted shall be deemed to have been withdrawn** and the generating company or the transmission licensee shall be required to file a fresh application for determination of tariff after the date of commercial operation of the project:
- (iii) **where the capital cost considered in tariff by the Commission on the basis of projected capital cost as on COD or the projected additional capital expenditure exceeds the actual capital cost incurred on year to year basis by more than 5%, the generating company or the transmission licensee shall refund to the beneficiaries or the long term transmission customers /DICs as the case may be, the excess tariff recovered corresponding to excess capital cost, as approved by the Commission alongwith interest at 1.20 times of the bank rate as**

prevalent on 1st April of respective year:

- (iv) *where the capital cost considered in tariff by the Commission on the basis of projected capital cost as on COD or the projected additional capital expenditure falls short of the actual capital cost incurred on year to year basis by more than 5%, the generating company or the transmission licensee shall be entitled to recover from the beneficiaries or the long term transmission customers /DICs as the case may be, the shortfall in tariff corresponding to reduction in capital cost, as approved by the Commission alongwith interest at 0.80 times of bank rate as prevalent on 1st April of respective year." (emphasis added)*

Thus, the CERC Tariff Regulations, 2014 clearly specify that the generating company may make an application for determination of tariff for new generating stations or units within 180 days of the anticipated date of commercial operation. Further, to ensure that the time span between issue of the Order on approval of provisional tariff and achievement of COD does not exceed 180 days, the CERC Tariff Regulations specify that if the date of commercial operation is delayed beyond 180 days from the date of issue of Tariff Order, the provisional tariff granted shall be deemed to have been withdrawn and the generating company shall be required to file a fresh application for determination of tariff after the date of commercial operation of the project.

The GERC MYT Regulations, 2011 specify that the Petition for approval of provisional tariff has to be filed strictly on the basis of audited capital expenditure on or before the date of filing the Petition, and not based on projected capital expenditure as on date of COD. It is a fact that preparation and filing of the Petition, as well as audit of capital expenditure are time consuming activities. Also, the major portion of the assets gets capitalised in the last year before the COD. In view of such facts, based on the provisions of the current GERC MYT Regulations, the capital cost in the Petition for provisional tariff may be significantly lower than actual capital expenditure as on COD. Hence, there would be more certainty and minimum retrospective adjustments if the filing of Petition for provisional tariff is allowed based on the projected capital expenditure. Therefore, it is proposed that the new generating stations be allowed to file the Petition for provisional tariff based on the projected capital expenditure.

Further, the CERC Tariff Regulations, 2014 specify that a generating company or transmission licensee can file the Petition for approval of provisional tariff based on the basis of projected capital expenditure. The recovery of the difference between the

provisionally approved tariff and final tariff, as a result of difference between the provisionally approved capital cost and actual capital cost, is clearly specified in the CERC Tariff Regulations. Further, for discouraging the generating companies or transmission licensees from projecting higher capital expenditure, the interest applicable to the recovery of such difference has been specified at a higher rate in case the actual capital expenditure is lower than the approved projected capital expenditure, as compared to the interest rate applicable in case where the actual capital expenditure exceeds the provisionally approved capital expenditure.

It is proposed to adopt the same approach in the revised GERC MYT Regulations, with the following modifications:

- a) "Where the tariff is being determined for Stage or Generating Unit of a Generating Station, the Generating Company shall adopt a reasonable basis for allocation of capital cost relating to common facilities and allocation of joint and common costs across all Stages or Generating Units, as the case may be:

Provided that the Generation Company shall maintain an allocation statement providing the basis for allocation of such costs, which shall be duly audited and certified by the statutory auditors and submit such audited and certified statement to the Commission along with the application for determination of tariff.

- b) In the case of an existing Generating Station, the application for determination of generation tariff shall be made not later than one hundred and eighty days from the date of notification of these Regulations, based on the approved capital cost including any additional capital expenditure already approved up to March 31, 2016, based either on actual or on projected additional capital expenditure and estimated additional capital expenditure for the ensuing financial years.
- c) In the case of existing projects, the Commission may allow the Generation Company, the tariff based on the approved capital cost as on the April 1, 2016 and projected additional capital expenditure for the ensuing financial years:
- d) Provided that the Generation Company shall continue to bill the beneficiaries at the tariff approved by the Commission and applicable as on March 31, 2016 for the period starting from April 1, 2016 till approval of tariff by the Commission in accordance with these Regulations.

- e) The Generation Company shall file the application for determination of provisional tariff for new Generating Station, one hundred and eighty days prior to the anticipated date of commercial operation of Generating Unit or Stage or Generating Station as a whole, as the case may be.
- f) The Generation Company shall make an application for determination of tariff based on capital expenditure incurred or projected to be incurred up to the date of commercial operation and additional capital expenditure incurred, duly certified by the statutory auditors:
Provided that the application shall contain details of underlying assumptions for the projected capital cost and additional capital cost, wherever applicable.
- g) In the case of new projects, the Generation Company may be allowed provisional tariff by the Commission from the anticipated date of commercial operation, based on the projected capital expenditure.
- h) If the date of commercial operation is delayed beyond one hundred and eighty days from the date of issue of tariff order, the tariff granted shall be deemed to have been withdrawn and the Generation Company shall be required to file after the date of commercial operation of the project, a fresh application for determination of tariff.
- i) The Generation Company shall file the application for determination of final tariff for new Generating Station within one hundred and eighty days from the date of commercial operation of Generating Unit or Stage or Generating Station as a whole, as the case may be, based on the audited capital expenditure and capitalisation as on the date of commercial operation.
- j) Truing up of the capital cost for the new Generating Station shall be done by the Commission based on prudence check of the audited capital expenditure and capitalisation as on the date of commercial operation.
- k) Where the actual capital cost incurred on year to year basis is lesser than the capital cost approved for determination of tariff by the Commission on the basis of the projected capital cost as on the date of commercial operation or on the basis of the projected additional capital cost, by five percent or more, the Generation Company shall refund to the beneficiaries as approved by the Commission, the excess tariff realised corresponding to excess capital cost, along with interest at 1.20 times of the Base Rate of State Bank of India plus three hundred and fifty basis

points, as prevalent on the first day of April of the respective financial year.

- 1) Where the actual capital cost incurred on year to year basis is higher than the capital cost approved for determination of tariff by the Commission on the basis of the projected capital cost as on the date of commercial operation or on the basis of the projected additional capital cost, by five percent or more, the Generation Company shall, subject to the approval of the Commission, be entitled to recover from the beneficiaries the shortfall in tariff corresponding to such decrease in capital cost along with interest at 0.80 times of the Base Rate of State Bank of India plus three hundred and fifty basis points, as prevalent on the first day of April of the respective financial year.

4.2.2 Renovation and Modernisation

As regards Renovation and Modernisation, the National Electricity Policy of Government of India stipulates as under:

*“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.”(emphasis added)

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.” (emphasis added)

The expected ‘useful’ life of power plants has historically been considered as 25 years for thermal (coal/gas/liquid fuel) generating stations and 35 years for hydel generating 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, six (6) numbers of Units of Dhuvaran oil based thermal power station (TPS) owned by GSECL have already outlived their initial rated ‘useful’ life and have been retired. Further, many of the Units of the thermal power stations owned by GSECL are in operation for more than 25 years. Further, as regards hydro power stations, all the four (4) Units of Ukai HEP owned by GSECL have outlived their ‘useful’ life of 35 years. In view of the same, it is very important to discuss the principles regarding Renovation & Modernisation beyond the original useful life.

As the plant approaches the end of its 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 a well maintained old plant, just enhanced repair and maintenance may be adequate to maintain the performance and efficiency.

The decision for Renovation & Modernisation has to be primarily based on comprehensive techno-economic considerations, after carrying out the required

Residual Life Assessment (RLA) study and cost-benefit analysis. Accordingly, the GERC Tariff Regulations, 2011 specifies that the Generating Company is required to come up with a detailed proposal for in-principle approval along with a DPR, giving complete scope, justification, cost-benefit analysis, estimated life extension, financial package, phasing of expenditure, schedule of completion reference price level, estimated completion cost, record of consultation with beneficiaries, etc. 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. The Regulation 51.6 specifies as reproduced below regarding the Renovation and Modernisation:

“51.6 Renovation & Modernisation:

(i) The Generating Company, for meeting the expenditure on Renovation and Modernization for the purpose of extension of life beyond the useful life of the generating station or a unit thereof, shall file 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, financial package, phasing of expenditure, schedule of completion, reference price level, estimated completion cost, record of consultation with beneficiaries and any other information considered to be relevant by the Generating Company:

Provided that in case of coal-based/lignite fired thermal generating station, the Generating Company, may, at its discretion, avail of a ‘special allowance’ in accordance with the norms specified in Clause (iv), as compensation for meeting the requirement of expenses including Renovation and Modernisation beyond the useful life of the generating station or a unit thereof, and in such an event, revision of the capital cost shall not be considered and the applicable operational norms shall not be relaxed but the special allowance shall be included in the Annual Fixed Cost: Provided also that such option shall not be available for a generating station or Unit for which Renovation and Modernization has been undertaken and the expenditure has been admitted by the Commission before the date of effectiveness of these Regulations.

(ii) Where the Generating Company files an application for approval of its proposal for Renovation and Modernisation, the approval shall be granted after due consideration of reasonableness of the cost estimates, schedule of completion, use of efficient technology, cost-benefit analysis, and such other factors as may be considered relevant by the Commission.

(iii) Any expenditure incurred or projected to be incurred and admitted by the Commission after prudence check based on the estimates of Renovation and

Modernization expenditure and life extension, and after deducting the accumulated depreciation and corresponding equity contribution, already recovered from the original project cost, shall be considered for determination of tariff.

(iv) A Generating Company, on opting for the alternative in the first proviso to clause (i) of this Regulation, for a coal-based/lignite fired thermal generating station, shall be allowed special allowance @ Rs. 5 lakh/MW/year in FY 2011-12 and thereafter escalated @ 5.72 % every year during the Control Period, Unit-wise from the next financial year from the respective date of the completion of useful life with reference to the date of commercial operation of the respective unit of generating station:

Provided that in respect of a Unit in commercial operation for more than 25 years as on 1.4.2011, this allowance shall be admissible from FY 2011-12."

Hence, Regulation 51.6 of the GERC Tariff Regulations, 2011 provides the following two options 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 can file 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, financial package, phasing of expenditure, schedule of completion, reference price level, estimated completion cost, record of consultation with beneficiaries and any other information considered to be relevant by the Generating Company. 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.

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. As per the existing Regulations, in this option, the Generating Companies, in case of thermal generating stations, had an option to 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.

CERC Tariff Regulations, 2014 specifies as reproduced below, in this regard:

“15. Renovation and Modernisation: (1) *The generating company or the transmission licensee, as the case may be, for meeting the expenditure on renovation and modernization (R&M) for the purpose of extension of life beyond the originally recognised useful life for the purpose of tariff of the generating station or a unit thereof or the transmission system or an element 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, financial package, phasing of expenditure, schedule of completion, reference price level, estimated completion cost including foreign exchange component, if any, and any other information considered to be relevant by the generating company or the transmission licensee.*

(2) *Where the generating company or the transmission licensee, as the case may be, makes an application for approval of its proposal for renovation and modernisation, the approval shall be granted after due consideration of reasonableness of the cost estimates, financing plan, schedule of completion, interest during construction, use of efficient technology, cost-benefit analysis, and such other factors as may be considered relevant by the Commission.*

(3) *In case of gas/ liquid fuel based open/ combined cycle thermal generating station, any expenditure which has become necessary for renovation of gas turbines/steam turbine after 25 years of operation from its COD and an expenditure necessary due to obsolesce or non-availability of spares for efficient operation of the stations shall be allowed :*

Provided that any expenditure included in the R&M on consumables and cost of components and spares which is generally covered in the O&M expenses during the major overhaul of gas turbine shall be suitably deducted after due prudence from the R&M expenditure to be allowed.

(4) *Any expenditure incurred or projected to be incurred and admitted by the Commission after prudence check based on the estimates of renovation and modernization expenditure and life extension, and after deducting the accumulated depreciation already recovered from the original project cost, shall form the basis for determination of tariff.*

16. Special Allowance for Coal-based/Lignite fired Thermal Generating station: (1) *In case of coal-based/lignite fired thermal generating station, the*

generating company, instead of availing R&M may opt to avail a 'special allowance' in accordance with the norms specified in this regulation, as compensation for meeting the requirement of expenses including renovation and modernisation beyond the useful life of the generating station or a unit thereof, and in such an event, revision of the capital cost shall not be allowed and the applicable operational norms shall not be relaxed but the special allowance shall be included in the annual fixed cost:

Provided that such option shall not be available for a generating station or unit for which renovation and modernization has been undertaken and the expenditure has been admitted by the Commission before commencement of these regulations, or for a generating station or unit which is in a depleted condition or operating under relaxed operational and performance norms.

(2) The Special Allowance shall be @ Rs. 7.5 lakh/MW/year for the year 2014-15 and thereafter escalated @ 6.35% every year during the tariff period 2014-15 to 2018-19, unitwise from the next financial year from the respective date of the completion of useful life with reference to the date of commercial operation of the respective unit of generating station:

Provided that in respect of a unit in commercial operation for more than 25 years as on 1.4.2014, this allowance shall be admissible from the year 2014-15:

Provided further that the special allowance for the generating stations, which, in its discretion, has already availed of a 'special allowance' in accordance with the norms specified in clause (4) of regulations 10 of Central Electricity Regulatory Commission (Terms and Conditions of Tariff Determination) Regulations, 2009, shall be allowed Special Allowance by escalating the special allowance allowed for the year 2013-14 @ 6.35% every year during the tariff period 2014-15 to 2018-19.

(3) In the event of granting special allowance by the Commission, the expenditure incurred or utilized from special allowance shall be maintained separately by the generating station and details of same shall be made available to the Commission as and when directed to furnish details of such expenditure."

Hence, the provision of allowing the generating station with aforementioned two options with regard to Renovation and Modernisation are suggested to be continued, which are in line with the provisions of the CERC Tariff Regulations, 2014. However, there is a need to review the allowable amount as special allowance and allowable escalation rate on the same. In this regard, as per CERC Tariff Regulations, 2014 the special allowance is @ Rs. 7.5 lakh/MW/year for the year 2014-15 and thereafter escalated @ 6.35% every year during the tariff period 2014-15 to 2018-19.

Thus, the provisions of GERC MYT Regulations, 2011 are appropriate and are in line with the CERC Tariff Regulations, 2014. Hence, it is suggested that the same provisions be continued in the new GERC MYT Regulations, with incorporation of the above suggested modification relating to allowable amount as special allowance and allowable escalation rate for the same.

The following clauses are proposed in the MYT Regulations for the third Control Period, in this regard:

- a) "In case of gas/ liquid fuel based open/combined cycle thermal generating station, any expenditure which has become necessary for renovation of gas turbines/steam turbine after 25 years of operation from its COD and an expenditure necessary due to obsolescence or non-availability of spares for efficient operation of the stations shall be allowed:

Provided that any expenditure included in the R&M on consumables and cost of components and spares which is generally covered in the O&M expenses during the major overhaul of gas turbine shall be suitably deducted after due prudence from the R&M expenditure to be allowed.

- b) Any expenditure incurred or projected to be incurred and admitted by the Commission after prudence check based on the estimates of renovation and modernization expenditure and life extension, and after deducting the accumulated depreciation already recovered from the original project cost, shall form the basis for determination of tariff.

- c) In case of coal-based/lignite fired thermal generating station, the Generating Company, may, at its discretion, avail of a 'special allowance' in accordance with the norms specified in Clause (iv), as compensation for meeting the requirement of expenses including Renovation and Modernisation beyond the useful life of the generating station or a unit thereof, and in such an event, revision of the capital cost shall not be allowed and the applicable operational norms shall not be relaxed but the special allowance shall be included in the Annual Fixed Cost:

Provided that such option shall not be available for a generating station or Unit for which Renovation and Modernization has been undertaken and the expenditure has been admitted by the Commission before the date of effectiveness of these Regulations, or for a generating station or unit which is in a depleted condition or operating under relaxed operational and performance norms.

- d) The Special Allowance shall be @ Rs. 7.5 lakh/MW/year for the year 2016-17 and thereafter escalated @ 5.72% every year during the Control Period, unit-

wise from the next financial year from the respective date of the completion of useful life with reference to the date of commercial operation of the respective unit of generating station:

Provided that in respect of a unit in commercial operation for more than 25 years as on 1.4.2016, this allowance shall be admissible from the year 2016-17:

Provided further that the special allowance for the generating station, which, in its discretion, has already availed of a 'special allowance' in accordance with the norms specified in clause (iv) of Regulations 51.6 of Gujarat Electricity Regulatory Commission (Multi Year Tariff) Regulations, 2011, shall be allowed Special Allowance by escalating the special allowance allowed for the year 2015-16 @ 5.72% every year during the Control Period.

- e) In the event of granting special allowance by the Commission, the expenditure incurred or utilized from special allowance shall be maintained separately by the generating station and details of same shall be made available to the Commission as and when directed to furnish details of such expenditure."

4.2.3 Rebate/Discount on prompt payment of bills

The rebate/discount allowed to the distribution licensees by the Generating Companies for prompt payment of bills amounts to a reduction in the revenue of the Generating Company. However, the Generating Company saves on working capital interest as a consequence, where one month's receivables are considered on a normative basis.

Regulation 43 of the GERC MYT Regulations, 2011 regarding rebate is as reproduced below:

"43. Rebate

43.1 For payment of bills of generation tariff or transmission charges through Letter of Credit or otherwise, within 7 days of presentation of bills, by the Generating Company or the Transmission Licensee, as the case may be, a rebate of 2% on billed amount, excluding the taxes, cess, duties, etc., shall be allowed. Where payments are made subsequently through opening of Letter of Credit or otherwise, but within a period of one month of presentation of bills by the Generating Company or the Transmission Licensee, as the case may be, a rebate of 1% on billed amount, excluding the taxes, cess, duties, etc., shall be allowed."

Thus, the GERC MYT Regulations, 2011 specify that the Generating Company shall allow a rebate of 2% in case the payment through Letter of Credit has been paid by the beneficiary within 7 days of presentation of bills. If the payment against the bills is done after 7 days but within one month of presentation of bills, a rebate of 1% shall be allowed. The CERC Tariff Regulations, 2014 specifies as reproduced below, with regard to rebate on prompt payment:

“44. Rebate

(1) For payment of bills of the generating company and the transmission licensee through letter of credit on presentation or through NEFT/RTGS within a period of 2 days of presentation of bills by the generating company or the transmission licensee, a rebate of 2% shall be allowed.

(2) Where payments are made on any day after 2 days and within a period of 30 days of presentation of bills by the generating company or the transmission licensee, a rebate of 1% shall be allowed.”

Further, as per the GERC MYT Regulations, 2011, two-thirds of the efficiency gains on account of over-achievement in the controllable factors, which include working capital requirement, are allowed to be retained by the generating company. Regulation 25 of the GERC MYT Regulations, 2011 is reproduced below:

“25 Mechanism for sharing of gains or losses on account of controllable factors

25.1 The approved aggregate gain to the Generating Company or Transmission Licensee or Distribution Licensee on account of controllable factors shall be dealt with in the following manner:

(a) One-third of the amount of such gain shall be passed on as a rebate in tariffs over such period as may be stipulated in the Order of the Commission under Regulation 22.6;

(b) The balance amount, which will amount to two-thirds of such gain, may be utilised at the discretion of the Generating Company or Transmission Licensee or Distribution Licensee.

25.2 The approved aggregate loss to the Generating Company or Transmission Licensee or Distribution Licensee on account of controllable factors shall be dealt with in the following manner:

(a) One-third of the amount of such loss may be passed on as an additional charge in tariffs over such period as may be stipulated in the Order of the Commission under Regulation 22.6; and

(b) The balance amount of loss, which will amount to two-thirds of such loss, shall be absorbed by the Generating Company or Transmission Licensee or Distribution Licensee."

Since, 2/3rd of the efficiency gains on account of interest on working capital are allowed to be retained by the generating company, it is not appropriate to allow such rebate/discount on prompt payment as a separate expense item in the ARR.

4.3 Thermal Generating Stations

4.3.1 Treatment of Infirm Power

The power generated prior to commercial operation of the Unit of a generating station is treated as infirm power.

The GERC MYT Regulations, 2011 specifies as under, as regards the treatment of infirm power:

"52 Sale of Infirm Power

52.1 The tariff for sale of infirm power from a thermal generating station to the Distribution Licensee shall be equivalent to the actual fuel cost, including the secondary fuel cost, as the case may be, incurred during that period subject to prudence check:

Provided that any revenue other than the recovery of fuel cost earned by the Generating Company from sale of infirm power shall be used for reduction in capital cost and shall not be treated as revenue."

Hence, in GERC MYT Regulations, 2011, the price of infirm power is allowable at variable cost to recover actual fuel cost, including secondary fuel. Further, the excess revenue from sale of infirm power above the fuel cost is to be adjusted in the capital cost.

CERC Tariff Regulations, 2014 specifies as under as regards the treatment of infirm power:

"18. Sale of Infirm Power: Supply of infirm power shall be accounted as deviation and shall be paid for from the regional deviation settlement fund

accounts in accordance with the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related matters) Regulations, 2014, as amended from time to time or any subsequent re-enactment thereof:

Provided that any revenue earned by the generating company from supply of infirm power after accounting for the fuel expenses shall be applied in adjusting the capital cost accordingly."

Thus, CERC Tariff Regulations, 2014 has linked the rate of the infirm power to the deviation settlement mechanism, wherein the price of energy is determined based on the prevailing grid frequency.

The objective behind linking of rate for infirm power with grid frequency is better grid stability. 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. 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. In view of the above, it is suggested that the present mechanism with regard to the sale of infirm power be continued.

Further, for sale of infirm power from hydro power plants, it is proposed that the tariff for sale of infirm power shall be equivalent to the energy charge rate for the first financial year, and the revenue recovered from sale of infirm power shall be deducted from the capital cost.

4.3.2 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

recover the fuel costs for the primary and secondary fuel consumption at normative parameters.

The GERC Tariff Regulations, 2014 has specified the following elements as a part of the Annual Fixed Cost:

- (a) Depreciation
- (b) Operation & Maintenance expenses
- (c) Return on Equity
- (d) Interest and Finance Charges on Loan Capital
- (e) Interest on Working Capital

Minus

- (f) Non-Tariff Income:

The CERC Tariff Regulations, 2014 has specified 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;

It may be observed that CERC has removed cost of secondary fuel oil from the components of fixed cost, which had been considered as part of fixed cost in the earlier Tariff Regulations. 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 appropriate not to consider the cost of secondary fuel oil as part of fixed cost and it may be considered as a part of the variable cost as per the existing practice in Regulations of GERC and CERC.

Further, a generating company can earn non-tariff income under several heads. The Regulation 53 of the GERC MYT Regulations, 2011 specifies several heads of non-tariff income of a generating company. In view of such provisions regarding non-tariff income, the current provision of including non-tariff income as part of the AFC may be continued.

The notification S.O. 2804 (E) of the Ministry of Environment and Forests dated November 3, 2009, stipulates that:

“The amount collected from sale of fly ash and fly ash based products by coal and/or lignite based thermal power stations or their subsidiary or sister concern unit, as applicable should be kept in a separate account head and shall be utilized only for development of infrastructure or facilities, promotion and facilitation activities for use of fly ash until 100 percent fly ash utilization level is achieved; thereafter as long as 100% fly ash utilization levels are maintained, the thermal power station would be free to utilize the amount collected for other development programmes also and in case, there is reduction in the fly ash utilization levels in the subsequent year(s), the use of financial return from fly ash shall get restricted to development of infrastructure or facilities and promotion or facilitation activities for fly ash utilization until 100 percent ash utilization level is again achieved and maintained.”

It is clear from the above notification that the earnings from the sale of fly ash have to be used only for the development of infrastructure or facilities related to fly ash. However, since the income from sale of fly ash is being considered as Non-Tariff Income, the generating companies shall be allowed additional capital expenditure, as and when needed, for development of infrastructure or facilities related to use of fly ash.

Further, as mentioned earlier, the GERC MYT Regulations, 2011 specifies that 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. Such provisions in the GERC MYT Regulations, 2011 are proposed to be continued as elaborated earlier. Therefore, in view of the same, it is proposed to include ‘special allowance in lieu of Renovation & Modernisation, wherever applicable’ as an element comprising AFC.

4.3.3 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 as well as other SERCs. In GERC MYT Regulations, 2011, the recovery of Fixed Cost is linked to the actual Availability of the stations, as reproduced below:

“59 Computation and Payment of Annual Fixed Charges and Energy Charges for Thermal Generating Stations

A. Annual Fixed Charges:

59.1 *The total Annual Fixed Charges shall be computed based on the norms specified under these Regulations and recovered on monthly basis under capacity charge. The total capacity charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share / allocation in the capacity of the generating station.*

59.2 *The capacity charge (inclusive of incentive) payable to a thermal generating station for a calendar month shall be calculated in accordance with the following formulae:*

(a) *Generating stations in commercial operation for less than ten (10) years on 1st April of the financial year :*

$AFC \times (NDM/NDY) \times (0.5 + 0.5 \times PAFM/NAPAF)$ (in Rupees);

Provided further 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:

$AFC \times (0.5 + 35/NAPAF) \times (PAFY/70)$ (in Rupees).

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

$AFC \times (NDM/NDY) \times (PAFM/NAPAF)$ (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
 ...”

The CERC Tariff Regulations, 2014 also provides for recovery of the fixed cost on the basis of actual plant availability vis-a-vis normative plant availability, as reproduced below:

“30. Computation and Payment of Capacity Charge and Energy Charge for Thermal Generating Stations:

(1) The fixed cost of a thermal generating station shall be computed on annual basis, based on norms specified under these regulations, and recovered on monthly basis under capacity charge. The total capacity charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share / allocation in the capacity of the generating station.

(2) The capacity charge payable to a thermal generating station for a calendar month shall be calculated in accordance with the following formulae:

$$CC_1 = (AFC/12) (PAF_1 / NAPAF) \text{ subject to ceiling of } (AFC/12)$$

$$CC_2 = ((AFC/6) (PAF_2 / NAPAF) \text{ subject to ceiling of } (AFC/6)) - CC_1$$

$$CC_3 = ((AFC/4) (PAF_3 / NAPAF) \text{ subject to ceiling of } (AFC/4)) - (CC_1 + CC_2)$$

$$CC_4 = ((AFC/3) (PAF_4 / NAPAF) \text{ subject to ceiling of } (AFC/3)) - (CC_1 + CC_2 + CC_3)$$

$$CC_5 = ((AFC \times 5/12) (PAF_5 / NAPAF) \text{ subject to ceiling of } (AFC \times 5/12)) - (CC_1 + CC_2 + CC_3 + CC_4)$$

$$CC_6 = ((AFC/2) (PAF_6 / NAPAF) \text{ subject to ceiling of } (AFC/2)) - (CC_1 + CC_2 + CC_3 + CC_4 + CC_5)$$

$$CC_7 = ((AFC \times 7/12) (PAF_7 / NAPAF) \text{ subject to ceiling of } (AFC \times 7/12)) - (CC_1 + CC_2 + CC_3 + CC_4 + CC_5 + CC_6)$$

$$CC_8 = ((AFC \times 2/3) (PAF_8 / NAPAF) \text{ subject to ceiling of } (AFC \times 2/3)) - (CC_1 + CC_2 + CC_3 + CC_4 + CC_5 + CC_6 + CC_7)$$

$$CC_9 = ((AFC \times 3/4) (PAF_9 / NAPAF) \text{ subject to ceiling of } (AFC \times 3/4)) - (CC_1+CC_2+CC_3 +CC_4 + CC_5 + CC_6 + CC_7+ CC_8)$$

$$CC_{10} = ((AFC \times 5/6) (PAF_{10} / NAPAF) \text{ subject to ceiling of } (AFC \times 5/6)) - (CC_1+ CC_2+ CC_3 +CC_4 + CC_5 +CC_6 + CC_7 + CC_8 + CC_9)$$

$$CC_{11} = ((AFC \times 11/12) (PAF_{11} / NAPAF) \text{ subject to ceiling of } (AFC \times 11/12)) - (CC_1+ CC_2+ CC_3 +CC_4 + CC_5 + CC_6 + CC_7 +CC_8 +CC_9+CC_{10})$$

$$CC_{12} = ((AFC) (PAFY / NAPAF) \text{ subject to ceiling of } (AFC)) - (CC_1+CC_2 +CC_3+CC_4 +CC_5+CC_6+CC_7+CC_8+CC_9+CC_{10}+CC_{11})$$

Provided that in case of generating station or unit thereof or transmission system or an element thereof, as the case may be, under shutdown due to Renovation and Modernisation, the generating company or the transmission licensee shall be allowed to recover part of AFC which shall include O&M expenses and interest on loan only.

Where,

AFC Annual fixed cost specified for the year, in Rupees.

NAPAF = Normative annual plant availability factor in percentage.

PAFN = Percent Plant availability factor achieved upto the end of the nth month.

PAFY = Percent Plant availability factor achieved during the Year

CC₁, CC₂, CC₃, CC₄, CC₅, CC₆, CC₇, CC₈, CC₉, CC₁₀, CC₁₁ and CC₁₂ are the Capacity Charges of 1st, 2nd, 3rd, 4th, 5th, 6th, 7th, 8th, 9th, 10th, 11th and 12th months respectively.

..."

Thus, the CERC has done away with the distinction between stations in commercial operation for less than ten (10) years and stations in commercial operation for more than ten (10) years, as on 1st April of the financial year.

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 as certified by Gujarat State Load Despatch Centre (SLDC) for all the days during that period expressed as a percentage of the installed capacity of the generating station minus normative auxiliary consumption as specified in these Regulations, and shall be computed in accordance with the following formula...”

...

‘Declared Capacity’ means

- a. *For a thermal generating station 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;”*

Regulation 59 of the GERC MYT Regulations, 2011 specifies computation of Availability as reproduced below:

“...

59.3 *The PAFM and PAFY shall be computed in accordance with the following formula:*

$$\text{PAFM or PAFY} = 10000 \times \frac{\sum_{i=1}^N \text{DC}_i}{\{ N \times \text{IC} \times (100 - \text{AUX}) \}} \%$$

Where,

AUX = Normative auxiliary energy consumption in percentage;

DC_i = Average declared capacity (in ex-bus MW), subject to Regulation 59.4 below, for the ith day of the period, i.e., the month or the year as the case may be, as certified by the concerned load dispatch centre after the day is over;

IC = Installed Capacity (in MW) of the generating station;

N = Number of days during the period i.e. the month or the year as the case may be.

Note: DC_i and IC shall exclude the capacity of generating units not declared under commercial operation. In case of a change in IC during the concerned period, its average value shall be taken.”

The computation of Availability specified in Regulation 59.3 of the GERC MYT Regulations, 2011 is in line with the computation of Availability specified in Regulation 30(3) of the CERC Tariff Regulations, 2014.

In view of shortage of coal and uncertainty of assured coal supply on sustained basis experienced by the generating stations, the normative availability for recovery of fixed charges has been specified at 83% in CERC Tariff Regulations, 2014, for three years from 01.04.2014, subject to review. Accordingly, the provision regarding availability in case of fuel shortage has not been included in CERC Tariff Regulations, 2014. Since, it is proposed to adopt the CERC approach, as discussed below, in the new GERC MYT Regulations, it is proposed to delete the current provisions regarding the availability in case of fuel shortage with respect to delivering higher MW during peak hours.

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. However, this may be disadvantageous to the Distribution Licensee as it has to pay the fixed cost irrespective of the actual drawal. However, in principle, fixed cost recovery should not be linked to generation, and only variable cost recovery should be linked to the generation.

Accordingly, it is proposed to continue with the existing practice of fixed cost recovery based on the normative plant availability with modification in the existing Regulation in accordance with the CERC Tariff Regulations, 2014. 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 shall be on pro-rata basis.

As regards the normative availability for full recovery of fixed charges, the GERC MYT Regulations, 2011 specifies the Normative Annual Plant Availability Factor (NAPAF) for full recovery of fixed charges as 85%, for new plants. It is suggested that the normative availability for recovery of fixed costs may be continued as 85%, for new plants. However, 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. In view of the same, CERC Tariff Regulations, 2014, has also specified lower availability norm for some of the Units/Stations, while for other Generating Stations, CERC has

specified the Availability norm of 85% for thermal generating stations. However, in view of shortage of coal and uncertainty of assured coal supply on sustained basis experienced by the generating stations, the NAPAF for recovery of fixed charges has been specified at 83% by CERC, for three years from 01.04.2014, subject to review, as reproduced below:

“36. The norms of operation as given hereunder shall apply to thermal generating stations:

(A) Normative Annual Plant Availability Factor (NAPAF)

(a) All thermal generating stations, except those covered under clauses (b), (c), (d), & (e) - 85%

Provided that in view of shortage of coal and uncertainty of assured coal supply on sustained basis experienced by the generating stations, the NAPAF for recovery of fixed charges shall be 83% till the same is reviewed.

The above provision shall be reviewed based on actual feedback after 3 years from 01.04.2014.

...

(e) Lignite fired Generating Stations using Circulatory Fluidized Bed Combustion (CFBC) Technology and Generating stations based on coal rejects

- 1. First Three years from COD – 75%*
 - 2. For next year after completion of three years of COD – 80%*
- ...”*

Considering the vintage effect, for full recovery of fixed charges, GERC also in GERC MYT Regulations, 2011, has specified lower NAPAF for the older generating stations of GSECL, whereas for all the other thermal generating stations, the NAPAF has been fixed as 85%. In this regard, the Regulation 54.1 of the GERC MYT Regulations, 2011 specifies as under:

“54.1 Normative Annual Plant Availability Factor for recovery of full Capacity (Fixed) charges for thermal generating stations:

(a) Normative Annual Plant Availability Factor for full recovery of annual fixed charges shall be 85 per cent for all thermal generating stations, except those covered under clause (b);

(b) Normative Annual Plant Availability Factor for full recovery of annual fixed charges for the following stations shall be:

Table 1: Normative Annual Plant Availability Factor for GSECL Generating Stations under Regulation 54.1 (b)

<i>Station Name</i>	<i>Target Availability (%)</i>
<i>Ukai TPS (Unit 1-5)</i>	75
<i>Gandhinagar TPS (Unit 1-4)</i>	79
<i>Sikka TPS</i>	75
<i>Kutch Lignite (Unit 1-3)</i>	75
<i>Kutch Lignite (Unit 4)</i>	80

Provided that the Commission may revise the norms for Availability for the above mentioned Generating Stations in case of Renovation & Modernisation undertaken by the Generating Station."

In line with the approach followed by CERC, it is proposed to specify the normative availability as 85% for all plants, except the plants where lower availability norms are specified, as discussed below. Further, the proviso introduced by CERC relating to lower target availability of 83% till the same is reviewed, is proposed to be introduced in the new GERC MYT Regulations with a slight modification as under:

"Provided that in case of shortage of coal and uncertainty of assured coal supply on sustained basis, the NAPAF for recovery of fixed charges shall be 83% till the coal supply position improves, which shall be reviewed annually."

As regards the normative availability for generating Unit/Stations, which are not able to achieve 85% availability, it is proposed to formulate targets based on the analysis of actual plant availability achieved by these generating stations in the previous years.

Vide its MYT Order dated April 11, 2011, the Commission stipulated normative availability for the generating stations of GSECL for the second Control Period based on the provisions of the GERC MYT Regulations, 2011. For the thermal generating stations of TPL-G, the Commission determined higher target availability for the second Control Period, in the MYT Order dated September 9, 2011, and reviewed the same in the Mid-Term Review Order dated April 29, 2014. However, full recovery of fixed cost is being allowed by the Commission to TPL-G stations based on the normative availability stipulated in the GERC MYT Regulations, 2011. The actual plant availability achieved by the thermal generating stations vis-a-vis the normative availability of the thermal generating stations for the second Control Period, is given in the following Table:

Table 4-3: Actual and normative plant availability of thermal generating stations

Generating Stations	Normative Availability for full recovery of fixed charges for Control Period FY12-FY16 (%)	Actual availability (%)			Average of actual plant availability for three years from FY 12 to FY 14
		FY 12	FY 13	FY 14	
GSECL Stations					
Ukai (1-5)	75.00	78.96	81.57	80.43	80.32
Gandhinagar (1-4)	79.00	81.87	82.83	87.62	84.11
Gandhinagar - 5*	80.00	89.90	97.51	82.95	90.12
Wanakbori 1-6 TPS	85.00	84.66	82.76	91.48	86.30
Wanakbori 7 TPS*	80.00	88.85	99.97	89.60	92.81
Sikka TPS	75.00	74.43	77.47	87.21	79.70
KLTPS 1-3	75.00	60.49	72.13	75.81	69.48
KLTPS 4	80.00	49.78	57.30	59.72	55.60
Duvaran (Gas 1)*	80.00	84.30	90.23	98.51	91.01
Duvaran (Gas 2)	85.00	58.45	89.98	96.34	81.59
Utran (Gas)*	80.00	95.96	85.08	99.99	93.68
Utran Extension*	80.00	94.49	87.51	99.69	93.90
Ukai 6**	85.00			49.27	49.27
Dhuvaran CCPP#3**	85.00				
Sikka (3-4)**	85.00				
TPL-G Stations					
C Station	85.00	93.11	86.06	85.89	88.35
D Station	85.00	94.22	90.33	94.65	93.07
E Station	85.00	94.27	87.67	60.53	80.82
F Station	85.00	96.60	62.21	86.86	81.89
Vatva Gas Station	85.00	98.01	14.29	100	70.77

* PPA based stations – normative availabilities for these Generating Stations were stipulated by the Commission in the MYT Order dated April 11, 2011

** New generating stations, which were not covered in GERC MYT Regulations, 2011 or in MYT Order. For these stations, the approved normative plant availability has been taken from the Tariff Orders subsequent to the MYT Order.

As regards Ukai (1-5) station, the Commission had fixed normative availability at 75% for the Control Period FY 2011-12 to FY 2015-16. Though 4 Units of the plant

have been in operation for around 35 to 38 years, it is observed that the station has achieved actual average availability of 80.32% in the three years from FY 2011-12 to FY 2013-14. The station has achieved 78.96% and 81.57% availability in FY 2011-12 and FY 2012-13 respectively, which is significantly higher than the normative availability of 75.00% approved by the Commission for full recovery of fixed charges. In view of the same, it is proposed that the normative availability for Ukai (1-5) be increased to 80.00% for the next Control Period for full recovery of fixed charges, since, the same is still lower than the normative availability of 85% for other plants.

The availability of the Gandhinagar (1-4) station has been 81.87%, 82.83% and 87.62% for FY 2011-12, FY 2012-13 and FY 2013-14 which signifies the capability of the station to consistently achieve availability of 81% every year, as compared to the existing norm of 79%. Hence, for full recovery of fixed charges, the availability of Gandhinagar (1-4) may be specified as 84% for the next Control Period for full recovery of fixed charges, since, the same is still lower than the normative availability of 85% for other plants.

Wanakbori (1-6) TPS has achieved availability of 84.66%, 82.76% and 91.48% for FY 2011-12, FY 2012-13 and FY 2013-14 respectively. Thus, the actual average availability of the plant has been 86.30% against the availability of 85% approved by the Commission, which is more than the normative availability of 85%. Hence, it is proposed to specify the normative availability for Wanakbori (1-6) TPS for full recovery of fixed costs as 85% .

Sikka (1-2) TPS has achieved availability of 74.43%, 77.47% and 87.21% for FY 2011-12, FY 2012-13 and FY 2013-14 , respectively, and thus, the average availability of the Station has been 79.70% for the three years as against normative availability of 75% approved by the Commission for full recovery of fixed charges for the station for the Control Period from FY 2011-12 to FY 2015-16. The Station has also been showing improving trend in the availability. Unit - 1 of the plant has been in operation for 26 years, while Unit -2 has been in operation for 21 years. As per the submissions of GSECL during regulatory process, in the past, vacuum problems due to low tide and insufficient cooling water flow on account of silting of CW intake channel has been noted at Sikka (1-2) TPS. However, the de-silting work was done at the plant in recent years. In view of the above, the normative availability for full recovery of fixed charges for the station may be revised to 80% for full recovery of fixed cost for the Sikka (1-2) TPS.

The availabilities of KLTPS (1-3) and KLTPS 4 have remained consistently lower than the normative availability of 75% and 80%, respectively, specified by the Commission for the second Control Period. The average availabilities achieved by KLTPS (1-3) and KLTPS 4 in three years from FY 2011-12 to FY 2013-14 have been only 69.48% and 55.60%, respectively. According to submissions of GSECL during regulatory process, KLTPS (1-3) has faced problems related to high vibration of turbines and damage in ESP path, whereas KLTPS 4 has been in operation only since year 2009, and has faced several problems during the stabilisation period. However, the consistent under-performance with regard to availability should not be allowed for any station. Further, with regard to KLTPS 4, the station would have completed more than 6 years in operation on the date of effectiveness of the new GERC MYT Regulations. Therefore, it is suggested that no further relaxation be given to these Generating Stations in target availability for full recovery of fixed charges and the normative availability specified for these stations for the second Control Period be continued.

As regards Dhuvaran Gas-2, the target availability for the station for second Control Period was 85%. As per the submissions of GSECL during regulatory process, in FY 2011-12, the scheduled outage of 15 days was extended to 134 days due to damage to compressor rotor, and therefore, the plant had achieved the availability of only 58.45% in FY 2011-12. However, in FY 2012-13 and FY 2013-14, the plant has achieved availability of 89.98% and 96.34% respectively. Further, the plant has been in operation since year 2007, and therefore, is in its efficient performance years. Hence, it is suggested that the target availability for the Dhuvaran Gas-2 station may be retained at 85%.

The average availability of four Units, namely Station C, Station D, Station E and Station F, of the Sabarmati Station of TPL-G has been 88.35%, 93.07%, 80.82% and 81.89% respectively, over the three years from FY 2011-12 to FY 2013-14. The average availability of the C and D stations have been above the normative availability of 85% specified for the second Control Period. Station F underwent up-rating and renovation in FY 2012-13, and hence, the availability of the station was 62.21% in FY 2012-13. In view of the above, the normative availability for full recovery of fixed cost may be specified as 85% for all the Units of the Sabarmati Station of TPL-G. The Vatva Gas Station of TPL-G has been retired in FY 2014-15.

For the new generating stations, and stations that have been commissioned during the second Control Period, the normative availability for recovery of fixed cost may be stipulated as 85% in line with the provisions of GERC MYT Regulations, 2011.

Further, for the PPA based stations, the normative availability shall be governed by the provisions of PPA.

In view of the above, it is suggested that the Normative Annual Plant Availability Factor for the thermal Generating Stations for recovery of full capacity (fixed) charges for the next Control Period may be specified as mentioned below:

- a) Normative Annual Plant Availability Factor for full recovery of annual fixed charges shall be 85 per cent for all thermal generating stations, except those covered under clause (b):

Provided that in case of shortage of coal and uncertainty of assured coal supply on sustained basis, the NAPAF for recovery of fixed charges shall be 83% till the coal supply position improves, which shall be reviewed annually.

- b) Normative Annual Plant Availability Factor for full recovery of annual fixed charges for the following stations shall be:

Station Name	Target Availability (%)
Ukai TPS (Unit 1-5)	80
Gandhinagar TPS (Unit 1-4)	84
Wanakbori 1-6 TPS	85
Sikka (1-2) TPS	80
Kutch Lignite (Unit 1-3)	75
Kutch Lignite (Unit 4)	80

Provided that the Commission may revise the norms for Availability for the above mentioned Generating Stations in case of Renovation & Modernisation undertaken by the Generating Station.

4.3.4 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 analysis of approved normative operational norms for the generating stations vis-a-vis the actual operational norms achieved by the generating stations in the previous years.

4.3.5 Norms for New Generating Unit/Stations to be commissioned after the date of effectiveness of the new GERC MYT Regulations, 2015

4.3.5.1 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 to be in accordance with the norms specified by CERC in CERC Tariff Regulations 2014, for various technologies and Unit sizes as well as considering the technological advances and improvement, with manufacturers' committing design heat rates as under:

a) Coal-based and lignite-fired Thermal Generating Stations = 1.045 X Design Heat Rate (kcal/kWh)

Where the Design Heat Rate of a generating unit means the unit heat rate guaranteed by the supplier at conditions of 100% 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/cm ²)	150	170	170	247
SHT/RHT (°C)	535/535	537/537	537/565	565/593
Type of BFP	Electrical Driven	Turbine Driven	Turbine Driven	Turbine driven
Max Turbine Cycle Heat rate (kcal/kWh)	1955	1950	1935	1850
Min. Boiler Efficiency				
Sub-Bituminous Indian Coal	0.86	0.86	0.86	0.86
Bituminous Imported Coal	0.89	0.89	0.89	0.89

Max Design Unit Heat Rate (kcal/kWh)				
Sub-Bituminous Indian Coal	2273	2267	2250	2151
Bituminous Imported Coal	2197	2191	2174	2078

Provided further that 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:

Provided also that where unit heat rate has not been guaranteed but turbine cycle heat rate and boiler efficiency are guaranteed separately by the same supplier or different suppliers, the unit design heat rate shall be arrived at by using guaranteed turbine cycle heat rate and boiler efficiency:

Provided also that where the boiler efficiency is below 86% for Sub-bituminous Indian coal and 89% for bituminous imported coal, the same shall be considered as 86% and 89% respectively for Sub-bituminous Indian coal and bituminous imported coal for computation of station heat rate:

Provided also that maximum turbine cycle heat rate shall be adjusted for type of dry cooling system:

Note: In respect of generating units where the boiler feed pumps are electrically operated, the maximum design unit heat rate shall be 40 kcal/kWh lower than the maximum design unit heat rate specified above with turbine driven BFP.

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.

4.3.5.2 Auxiliary Energy Consumption

GERC MYT Regulations, 2011 specify separate auxiliary energy consumption norms for new and existing coal/lignite based generating stations, whereas for gas turbine/combined cycle generating stations, common norms of auxiliary energy consumption are specified in the GERC MYT Regulations, 2011. CERC, in CERC Tariff Regulations, 2014, has specified common norms for all new as well as existing thermal generating stations and only for particular Generating Stations that are unable to achieve the auxiliary energy consumption as per the common stipulations, separate norms for auxiliary energy consumption have been specified by CERC.

For new generating Unit/Stations to be commissioned after the date of effectiveness of the GERC MYT Regulations, 2016, the auxiliary consumption norm is proposed to be in accordance with the norms specified in CERC Tariff Regulations, 2014 for various technologies and Unit sizes as under:

(a) Coal based generating stations:

	With Natural Draft cooling tower or without cooling tower
(i) 200 MW Series	8.5%
(ii) 300/330/350/500 and above	
Steam driven boiler feed pumps	5.25%
Electrically driven boiler feed pumps	7.75%

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

Provided also that Additional Auxiliary Energy Consumption as follows may be allowed for plants with Dry Cooling Systems:

Type of Dry Cooling System	(% of gross generation)
Direct cooling air cooled condensers with mechanical draft fans	1%
Indirect cooling system employing jet condensers with pressure recovery turbine and natural draft tower	0.5%

(b) Gas Turbine / Combine Cycle generating stations:

(i)	Combined Cycle	8.5%
(ii)	Open Cycle	5.25%

(c) Lignite-fired thermal generating stations:

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.

(d) Generating Stations based on coal rejects: 10%

4.3.5.3 Transit Loss

It is proposed that 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 Tariff Regulations, 2014 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%

Provided that in case of pit head stations if coal or lignite is procured from sources other than the pit head mines which is transported to the station through rail, transit loss of 0.8% shall be applicable:

Provided further that in case of imported coal, the transit and handling losses shall be 0.2%.

4.3.5.4 Secondary Fuel Oil Consumption

The GERC MYT Regulations, 2011 specify separate Secondary Fuel Oil Consumption norms for new generating stations. However, CERC, in CERC Tariff Regulations, 2014, has adopted the approach of specifying common norms for new and existing generating stations.

For new Generating Unit/Stations to be commissioned after the date of effectiveness of the GERC MYT Regulations, the secondary fuel oil consumption norm is proposed in accordance with the norms specified in CERC Tariff Regulations, 2014 as under:

(i) Coal-based generating stations:	0.50 ml/kWh
(ii) Lignite-Fired generating stations except stations based on CFBC technology:	2.0 ml/kWh
(iii) Lignite-Fired generating stations based on CFBC technology:	1.00 ml/kWh
(iv) Generating Stations based on coal rejects:	2.0 ml/kWh

4.3.6 Norms for Existing Generating Unit/Stations - Existing before the date of effectiveness of GERC MYT Regulations, 2011 (April 1, 2011)

The Commission, in the GERC MYT Regulations, 2011 has specified the trajectory for various performance parameters for the existing generating Unit/Stations of GSECL and TPL. Taking into account the norms for Generating Stations specified in the GERC Tariff Regulations, 2011, the Commission, vide its Orders dated April 11, 2011 and September 6, 2011, for GSECL and TPL-G respectively, specified the trajectory for operational norms for the Generating Stations for the Control Period from FY 2011-12 to FY 2015-16. In the Mid-Term-Review Order for TPL-G, GERC had revised the normative performance parameters for TPL-G for the remaining years of the Control Period, i.e., FY 2014-15 and FY 2015-16.

The trajectory for performance parameters for the next Control Period is proposed on the basis of assessment of actual performance of the generating stations in past few

years, and accordingly, the operational norms for the years of next Control Period may be specified considering the achievability and efficiency.

4.3.6.1 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 MYT Regulations, 2011, the Commission has specified the following norms for the Gross Station Heat Rate:

“54.2 Gross Station Heat Rate – For existing Generating Stations:

a) *Thermal Generating Stations of Gujarat State Electricity Generation Company Limited (GSECL):*

Table 2: Station Heat Rate for GSECL Stations for the Control Period

(in kcal/kWh)

<i>Stations</i>	<i>FY 2011-12</i>	<i>FY 2012-13</i>	<i>FY 2013-14</i>	<i>FY 2014-15</i>	<i>FY 2015-16</i>
<i>Ukai TPS (Unit 1-5)</i>	2770	2765	2760	2755	2750
<i>Gandhinagar TPS (Unit 1-4)</i>	2782	2782	2782	2782	2782
<i>Wanakbori TPS (Unit 1-6)</i>	2625	2625	2625	2625	2625
<i>Sikka TPS</i>	3040	3035	3030	3025	3020
<i>Kutch Lignite TPS (Unit 1-3)</i>	3300	3300	3300	3300	3300
<i>Kutch Lignite TPS (Unit 4)</i>	3000	3000	3000	3000	3000
<i>Dhuvaran CCPP-2</i>	1950	1950	1950	1950	1950

Provided that the Commission may revise the norms for the heat rate for the above mentioned Generating Stations in case of Renovation & Modernisation undertaken by the Generating Station;

b) *Thermal Generating Units of Torrent Power Limited - Generation Business (TPL-G):*

Table 3: SHR for TPL-G generating stations for the Control Period

(in kcal/kWh)

Stations	FY 2011-12	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16
<i>Sabarmati 'C'</i>	3150	3150	3150	3150	3150
<i>Sabarmati 'D'</i>	2450	2450	2450	2450	2450
<i>Sabarmati 'E & F'</i>	2725	2725	2725	2725	2725
<i>Vatva CCPP</i>	2165	2165	2165	2165	2165

Provided that the Commission may revise the norms for the heat rate for the above mentioned Generating Stations in case of Renovation & Modernisation undertaken by the Generating Station;"

CERC, in its CERC Tariff Regulations, 2014 has considered the technology, configuration, and operating level of different power plants for fixing heat rates for thermal 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 SHR 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."

Hence, the Station Heat Rate for the existing stations for the next Control Period is proposed to be determined based on assessment of actual past performance of Generating Stations, as discussed below.

GSECL

Based on the normative SHR specified in the GERC MYT Regulations, 2011, the Commission, in its MYT Order dated April 11, 2011, for the Control Period from FY 2011-12 to FY 2015-16 had set the trajectory for the SHR for GSECL's Generating Stations. For the PPA based Generating Stations, the normative SHR for the second Control Period was stipulated based on the provisions of the PPA. The relevant extracts of the MYT Order dated April 11, 2011 are reproduced below:

"Commission's Analysis

In the case of PPA governed stations, the SHR is approved based on the conditions in the respective PPAs.

In the case of other stations the heat rate is approved as per the GERC (MYT) Regulations, 2011 as stated earlier.

The SHR approved by the Commission for all the stations for the control period FY 2011-12 to FY 2015-16, are given in Table 6.10 below:

Table 6.10 : Approved Station Heat Rates for the control period FY 2011-12 to FY 2015-16

(Kcal/kWh)						
S.N	Power station	2011-12	2012-13	2013-14	2014-15	2015-16
1	Ukai (1-5)	2770	2765	2760	2755	2750
2	Gandhinagar (1-4)	2782	2782	2782	2782	2782
3	Gandhinagar - 5*	2460	2460	2460	2460	2460
4	Wanakbori 1-6 TPS	2625	2625	2625	2625	2625
5	Wanakbori 7 TPS*	2460	2460	2460	2460	2460
6	Sikka TPS	3040	3035	3030	3025	3020
7	KLTPS 1-3	3300	3300	3300	3300	3300

8	KLTPS 4	3000	3000	3000	3000	3000
9	Duvaran (Gas 1)*	1950	1950	1950	1950	1950
10	Duvaran (Gas 2)	1950	1950	1950	1950	1950
11	Utran (Gas)*	2150	2150	2150	2150	2150
12	Utran Extension*	1850	1850	1850	1850	1850

* PPA governed stations

”

The actual SHR of the GSECL stations from FY 2011-12 to FY 2013-14 vis-a-vis the normative SHR approved by the Commission for the second Control Period is as shown in the following Table:

Table 4-4: Normative and actual SHR of GSECL thermal generating stations (kcal/kWh)

Generating Stations	Normative SHR for second Control Period					Actual SHR			Average of actual SHR for three years from FY12 to FY14
	FY12	FY13	FY14	FY15	FY16	FY12	FY13	FY14	
Ukai (1-5)	2770	2765	2760	2755	2750	2764	2741	2741	2749
Gandhinagar (1-4)	2782	2782	2782	2782	2782	2718	2708	2610	2679
Gandhinagar - 5*	2460	2460	2460	2460	2460	2476	2535	2496	2502
Wanakbori 1-6 TPS	2625	2625	2625	2625	2625	2626	2642	2673	2647
Wanakbori 7 TPS*	2460	2460	2460	2460	2460	2435	2455	2476	2455
Sikka TPS	3040	3035	3030	3025	3020	3014	3002	3009	3008
KLTPS 1-3	3300	3300	3300	3300	3300	3593	3303	3231	3376
KLTPS 4	3000	3000	3000	3000	3000	3297	3022	3012	3110
Dhuvaran (Gas 1)*	1950	1950	1950	1950	1950	1953	1972	2094	2006
Dhuvaran (Gas 2)	1950	1950	1950	1950	1950	1928	1955	2007	1963
Utran (Gas)*	2150	2150	2150	2150	2150	2218	2276		2247
Utran Extension*	1850	1850	1850	1850	1850	1705	1828	2264	1932

* PPA governed stations

It is observed that some of the stations have achieved better SHR than the normative SHR approved by the Commission for the second Control Period, while in case of some other Generating Stations; the actual SHR has been higher than the same approved by the Commission. Further, there are some Generating Stations, whose actual SHR has been very close to the normative SHR stipulated by the Commission.

As regards Ukai (1-5) TPS, the Commission had approved normative SHR of 2770 kcal/kWh for FY 2011-12 and for the subsequent years of the second Control Period, the Commission had approved SHR considering improvement of 5 kcal/kWh every year. It is observed that the actual SHR for Ukai (1-5) TPS for FY 2011-12, FY 2012-13 and FY 2013-14 was 2764 kcal/kWh, 2741 kcal/kWh and 2741 kcal/kWh respectively. Hence, the average SHR achieved by the station in the said three years is 2749 kcal/kWh, which is lower than the normative SHR stipulated by the Commission. In view of the above, it is suggested that the normative SHR for the next Control Period may be specified same as the normative SHR for FY 2015-16 approved by the Commission, for Ukai (1-5) TPS, i.e., 2750 kcal/kWh.

The Gandhinagar (1-4) TPS has achieved actual SHR of 2718 kcal/kWh, 2708 kcal/kWh and 2610 kcal/kWh in FY 2011-12, FY 2012-13 and FY 2013-14 respectively, as against normative SHR of 2782 kcal/kWh approved by the Commission for the second Control Period. Thus, the actual average SHR for Gandhinagar (1-4) TPS for three years from FY 2011-12 to FY 2013-14 was 2679 kcal/kWh, which is much lower than the normative SHR of 2782 kcal/kWh approved by the Commission for the years of second Control Period. It is suggested that for the next Control Period, the normative SHR for the Gandhinagar (1-4) TPS may be specified as 2679 kcal/kWh, which is the average SHR achieved by the Station for the three years from FY 2011-12 to FY 2013-14.

The Wanakbori (1-6) TPS has achieved actual SHR of 2626 kcal/kWh, 2642 kcal/kWh and 2673 kcal/kWh in, FY 2011-12, FY 2012-13 and FY 2013-14 respectively. Thus, the station has achieved average SHR of 2647 kcal/kWh in the said three years, which is marginally higher than the normative SHR of 2625 kcal/kWh approved by the Commission for the second Control Period. In view of the above, and considering some improvement in the SHR for the next Control Period, it is suggested that the normative SHR specified by the Commission for the Wanakbori (1-6) TPS for the second Control Period may be continued for the years of next Control Period.

As regards Sikka (1-2) TPS, the Commission had approved normative SHR of 3040 kcal/kWh for FY 2011-12 and for the subsequent years of the second Control Period, the Commission had specified the SHR considering improvement of 5 kcal/kWh every year. It is observed that the actual SHR for Sikka (1-2) TPS for FY 2011-12, FY 2012-13 and FY 2013-14 was, 3014 kcal/kWh, 3002 kcal/kWh and 3009 kcal/kWh respectively. Thus, the station has achieved average actual SHR of 3008 kcal/kWh in the said three years. It is observed that the actual SHR of the Sikka (1-2) TPS has

consistently remained better than the normative SHR specified by the Commission, however the SHR is still on the higher side and needs to be reduced. In view of the above, it is suggested that for the next Control Period, the SHR for the Sikka (1-2) TPS may be specified as 3008 kcal/kWh for FY 2016-17, with further improvement of 5 kcal/kWh every year till FY 2020-21.

The KLTPS (1-3) has achieved actual SHR of, 3593 kcal/kWh, 3303 kcal/kWh and 3231 kcal/kWh in FY 2011-12, FY 2012-13 and FY 2013-14 respectively. Thus, the station has achieved average SHR of 3376 kcal/kWh in the said three years, which is significantly higher than the normative SHR of 3300 kcal/kWh approved by the Commission for the second Control Period. In FY 2011-12, the high SHR was attributed to bottom ash channel problems, lignite feeding problems due to wet lignite as well as load restricted to 50-55 MW in Unit 3 as blades of two stages of turbines were shaved off. As none of the aforementioned problems persisted in FY 2012-13, the station achieved SHR of 3303 kcal/kWh, which is almost equal to normative SHR of 3300 kcal/kWh specified by the Commission for the years of second Control Period and in FY 2013-14 the SHR improved to 3231 kcal/kWh. In view of the above, it is suggested that for the next Control Period, the stipulation of normative SHR of 3231 kcal/kWh achieved by the station in FY 2013-14 may be continued.

The KLTPS 4 has achieved actual SHR of 3297 kcal/kWh, 3022 kcal/kWh and 3012 kcal/kWh in, FY 2011-12, FY 2012-13 and FY 2013-14 respectively. Thus, the station has achieved average SHR of 3110 kcal/kWh in the said three years, which is significantly higher than the normative SHR of 3000 kcal/kWh approved by the Commission for the second Control Period. However, over the years from FY 2011-12 to FY 2013-14, significant improvement in the SHR of the station is observed. The SHR of 3022 kcal/kWh and 3012 kcal/kWh achieved by the station in FY 2012-13 and FY 2013-14 is only marginally higher than the normative SHR of 3000 kcal/kWh specified by the Commission for the station for the years of the second Control Period. In view of the same, it is suggested that for the next Control Period, the stipulation of normative SHR of 3000 kcal/kWh approved by the Commission for the second Control Period may be continued.

As regards Dhuvaran (Gas-2) TPS, the actual SHR has been 1928 kcal/kWh, 1955 kcal/kWh and 2007 kcal/kWh in FY 2011-12, FY 2012-13 and FY 2013-14 respectively. SHR is constantly increasing year on year. Thus, the station has achieved actual average SHR of 1963 kcal/kWh for the said three years, which is higher than the normative SHR of 1950 kcal/kWh specified by the Commission for

the second Control Period. Further, the Dhuvaran (Gas-2) station was commissioned in the year 2007, and therefore, is comparatively new. Therefore, efficient operation can be expected from the station in the next Control Period. In view of the same, it is suggested that for the next Control Period, the normative SHR for the Dhuvaran (Gas-2) TPS can be specified as 1950 kcal/kWh, as approved by the Commission for the second Control Period.

For all the new Generating Stations like Ukai Unit-6, Dhuvaran CCPP-3 and Sikka Unit 3 & 4 for which the actual SHR data is not available, it is proposed to specify norms same as approved in the Order in Case No 1460 of 2014 for FY 2015-16.

In view of the above, the normative SHR for the thermal Generating Stations of GSECL, not governed by PPAs, for the next Control Period, are suggested as shown in the following Table:

Table 4-5: Proposed SHR for the GSECL Stations for next Control Period (kcal/kWh)

Stations	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	FY 2020-21
Ukai TPS (Unit 1-5)	2750	2750	2750	2750	2750
Gandhinagar TPS (Unit 1-4)	2679	2679	2679	2679	2679
Wanakbori TPS (Unit 1-6)	2625	2625	2625	2625	2625
Sikka TPS (Unit 1-2)	3008	3003	2998	2993	2988
Kutch Lignite TPS (Unit 1-3)	3231	3231	3231	3231	3231
Kutch Lignite TPS (Unit 4)	3000	3000	3000	3000	3000
Dhuvaran CCPP-2	1950	1950	1950	1950	1950
Dhuvaran CCPP-3	1850	1850	1850	1850	1850
Ukai 6	2385	2385	2385	2385	2385
Sikka 3 & 4	2398	2398	2398	2398	2398

TPL-G

The Commission, in its MYT Order dated September 6, 2011, for TPL-G, for the Control Period from FY 2011-12 to FY 2015-16 had set the trajectory for the SHR as reproduced below:

“6.1.2.4 Station Heat Rate (SHR)

Petitioner’s submission

The TPL has projected the SHR of different stations for the control period of FY 2011-12 to FY 2015-16, as given in the table below:

Table 6.9: Projected Station Heat Rate for the control period FY 2011-12 to FY 2015-16

(Kcal/kWh)

Sl. No.	Stations	FY 2011-12	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16
1.	C Station	3150	3150	3150	-	-
2.	D Station	2450	2450	2450	2450	2450
3.	E Station	2725	2590	2455	2455	2455
4.	F Station	2705	2668	2455	2455	2455
5.	Vatva Gas Station	2165	2165	2165	2165	2165

In its petition TPL has submitted on the proposed SHR as follows:

- The SHR for all the stations is proposed at the levels approved by the Commission in its order in case No. 988/2010 dated 31st March, 2010, duly taking into consideration the anticipated improvements in the performance of E&F stations after the Renovation and Modernization works.
- The TPL would approach the Commission for appropriate adjustment in SHR for various stations on the basis of the lower PLF on their respective SHR.

Commission’s Analysis

The Commission has analyzed the submission made by the TPL.

The SHR proposed for the stations C & D and Vatva (CCPP) are in accordance with those permitted levels as per the GERC (MYT) Regulations, 2011. For E&F stations, however, TPL proposed better SHR 2725 to 2455 Kcal/kWh in the case of E station and 2705 to 2455 Kcal/kWh in the case of F station against 2725 Kcal/kWh for all the years of the control period FY 2011-12 to FY 2015-16 as per GERC (MYT) Regulations, 2011.

Clause 4.1 of MYT Regulations, 2011 provides that:

“For removal of doubts, it is clarified that the norms of operation specified under these Regulations are the ceiling norms and this shall not preclude the Generating Company or the Transmission Licensee or the Distribution Licensee, as the case may be, and the beneficiaries from agreeing to improved norms of operation and in case the

improved norms are agreed to, such improved norms shall be applicable for determination of tariff."

In view of the above, the Commission approves the SHR for different stations including the E & F stations for the control period for FY 2011-12 to FY 2015-16 as projected by TPL and are as given in the table below:

Table 6.10: Approved Station Heat Rate for TPL-G (APP) for the control period FY 2011-12 to FY 2015-16

(Kcal/kWh)

Sl. No.	Stations	FY 2011-12	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16
1.	C Station	3150	3150	3150	-	-
2.	D Station	2450	2450	2450	2450	2450
3.	E Station	2725	2590	2455	2455	2455
4.	F Station	2705	2668	2455	2455	2455
5.	Vatva Gas Station	2165	2165	2165	2165	2165

The Commission is of the view that there is no need for review of the SHR approved, at a later date, as submitted by TPL."

For all the other stations, the Commission had approved SHR for all five years of the second Control Period based on the GERC MYT Regulations, 2011. On April 29, 2014, the Commission issued Mid-Term Review Order for TPL-G. In the said Mid-Term Review Order, the Commission considered the submission of TPL-G that 'C Station' would be in operation during the balance of the second Control Period and Vatva Gas Station would retire from FY 2014-15 onwards. In the said Mid-Term Review Order, the Commission approved normative SHR of 3150 kcal/kWh for FY 2014-15 and FY 2015-16, where as no normative SHR was stipulated for Vatva Gas Station considering its retirement from FY 2014-15 onwards. For the remaining three stations of TPL-G, namely, 'D' Station, 'E' Station and 'F' Station, the Commission approved the same normative SHR for FY 2014-15 and FY 2015-16 as approved in the MYT Order dated September 6, 2011 as mentioned above. The relevant extract of the Mid-Term Review Order for TPL-G dated April 29, 2014 is reproduced below:

"Commission's Analysis

The projected SHRs for different Stations are as approved in the MYT Order for FYs 2014-15 and 2015-16 for D, E and F stations. In the case of C-Station, the projected

SHR is approved as per MYT Order. It is, however, proposed to retire Vatva Gas Station, This proposal has been accepted by the Commission.

In view of the position explained above, the Commission approves the SHRs, proposed by TPL, for Mid-term Review of Business Plan, as given in the Table below:

Table 4.9: Approved Station Heat Rate (SHR) for the Purpose Mid-term Review for FY 2014-15 and FY 2015-16

Sl. No.	Particulars	FY 2014-15	FY 2015-16
1	C-Station	3150	3150
2	D-Station	2450	2450
3	E-Station	2455	2455
4	F-Station	2455	2455
5	Vatva Gas Station	-	-

Truing up of the SHR will be undertaken in accordance with the Regulations.”

The comparison of actual SHR of the Generating Stations of TPL-G in FY 2011-12, FY 2012-13 and FY 2013-14 vis-a-vis normative SHR approved by the Commission is as shown in the following Table:

Table 4-6: Normative and actual SHR of TPL-G stations (kcal/kWh)

Generating Stations	Normative SHR for second Control Period					Actual SHR			Average of actual SHR for three years from FY12 to FY14
	FY12	FY13	FY14	FY15	FY16	FY12	FY13	FY14	
C Station	3150	3150	3150	3150	3150	3124	3130	3154	3136
D Station	2450	2450	2450	2450	2450	2422	2420	2447	2430
E Station	2725	2590	2455	2455	2455	2701	2724	2542	2656
F Station	2705	2668	2455	2455	2455	2686	2698	2440	2608
Vatva Gas Station	2165	2165	2165	-	-	2149	2321		2235

The C Station of TPL-G’s Sabarmati plant has achieved actual SHR of 3124 kcal/kWh, 3130 kcal/kWh and 3154 kcal/kWh in FY 2011-12, FY 2012-13 and FY 2013-14, respectively. Thus, the C Station has achieved actual average SHR of 3136 kcal/kWh in the said three years, which is marginally lower than the normative SHR of 3150 kcal/kWh for the second Control Period. In view of the same, it is proposed

to specify the normative SHR for C Station same as the average SHR achieved in the second Control Period, i.e., 3136 kcal/kWh.

The D Station of TPL-G's Sabarmati plant has achieved actual SHR of 2422 kcal/kWh, 2420 kcal/kWh and 2447 kcal/kWh in FY 2011-12, FY 2012-13 and FY 2013-14 respectively. Thus, the D Station has achieved actual average SHR of 2430 kcal/kWh in the said three years, which is marginally lower than the normative SHR of 2450 kcal/kWh for the second Control Period. In view of the same it is suggested that for the next Control Period, the normative SHR for D Station may be stipulated same as the SHR specified in the second Control Period i.e., 2450 kcal/kWh.

As regards SHR of E Station, the Commission had approved normative SHR of 2725 kcal/kWh for the five years of the second Control Period in the GERC MYT Regulations, 2011. However, during the regulatory process of the MYT Tariff Order for TPL-G for the second Control Period, TPL-G, in its Petition had proposed 2725 kcal/kWh, 2590 kcal/kWh, 2455 kcal/kWh, 2455 kcal/kWh and 2455 kcal/kWh as normative SHR for the five years of the second Control Period. Since the normative SHR for the second Control Period proposed by TPL-G for E Station were stricter than the normative SHR in GERC MYT Regulations, 2011, the Commission had approved the same SHR as proposed by TPL-D as normative SHR for the second Control Period for E Station. However, from the actual performance of E Station, it is observed that the E Station has not been able to achieve improvement in the SHR proposed by TPL-G as mentioned above. The E Station of the TPL-G's Sabarmati plant has achieved actual SHR of 2701 kcal/kWh, 2724 kcal/kWh and 2542 kcal/kWh in FY 2011-12, FY 2012-13 and FY 2013-14, respectively. Hence, E Station has achieved actual average SHR of 2656 kcal/kWh in the said three years, which is better than the normative SHR of 2725 kcal/kWh specified in the GERC MYT Regulations, 2011. During the regulatory process of the Order for truing up for FY 2012-13, TPL-G submitted that the improvement in SHR was not achieved due to deferred up-rating and modernisation activities for the E Station from FY 2012-13 to FY 2013-14. Further, during the regulatory process of the Mid-Term Review Order for second Control Period, TPL-G had proposed 2455 kcal/kWh as normative SHR for FY 2014-15 and FY 2015-16 for E Station, i.e., same as approved in the MYT Order. In view of the abovementioned facts, it is suggested that the SHR of 2455 kcal/kWh may be specified for E Station for the next Control Period, which is same as proposed by TPL-G for FY 2014-15 and FY 2015-16 during the regulatory process for Mid-Term Review Order, considering completion of the up rating and modernisation activities of the E Station.

As regards SHR of F Station, the Commission had approved normative SHR of 2725 kcal/kWh for the five years of the second Control Period in the GERC MYT Regulations, 2011. However, during the regulatory process of the MYT Tariff Order for TPL-G for the second Control Period, TPL-G, in its Petition had proposed 2705 kcal/kWh, 2668 kcal/kWh, 2455 kcal/kWh, 2455 kcal/kWh and 2455 kcal/kWh as normative SHR for the five years of the second Control Period. Since the normative SHR for the second Control Period proposed by TPL-G for F Station were stricter than the normative SHR in GERC MYT Regulations, 2011, the Commission had approved the same SHR as proposed by TPL-D as normative SHR for the second Control Period for F Station. However, from the actual performance of E Station, it is observed that the F Station has not been able to achieve improvement in the SHR proposed by TPL-G as mentioned above. The F Station of the TPL-G's Sabarmati plant has achieved actual SHR of 2686 kcal/kWh, 2698 kcal/kWh and 2440 kcal/kWh in FY 2011-12, FY 2012-13 and FY 2013-14, respectively. Hence, F Station has achieved actual average SHR of 2608 kcal/kWh in the said three years, which is better than the normative SHR of 2725 kcal/kWh specified in the GERC MYT Regulations, 2011. During the regulatory process of the Order for truing up for FY 2012-13, TPL-G submitted that the improvement in SHR of F Station was not achieved, since, the plant shutdown was delayed and the Unit was re-synchronised with the grid after completion of up rating and modernisation in FY 2013-14. Further, during the regulatory process of the Mid-Term Review Order for second Control Period, TPL-G had proposed 2455 kcal/kWh as normative SHR for FY 2014-15 and FY 2015-16 for F Station, i.e., same as approved in the MYT Order. In view of the above, it is suggested that the SHR of 2455 kcal/kWh may be specified for F Station for the next Control Period, which is same as proposed by TPL-G for FY 2014-15 and FY 2015-16 during the regulatory process for Mid-Term Review Order, considering completion of the up rating and modernisation activities of the F Station.

The Vatva Gas Station has been retired in FY 2014-15. Hence, the SHR for this Generating Station have not been proposed.

In view of the above, the proposed SHR for the TPL-G Stations for the next Control Period is shown in the following Table:

Table 4-7: Proposed SHR for TPL-G thermal generating stations for next Control Period (kcal/kWh)

Generating Stations	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	FY 2020-21
C Station	3136	3136	3136	3136	3136

Generating Stations	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	FY 2020-21
D Station	2450	2450	2450	2450	2450
E Station	2455	2455	2455	2455	2455
F Station	2455	2455	2455	2455	2455

4.3.6.2 Auxiliary Energy Consumption

The norms of auxiliary energy consumption specified in the GERC MYT Regulations, 2011 are reproduced hereunder:

"54.6 Auxiliary Energy Consumption:

(a) Existing generating stations of GSECL:

Table 7: Auxiliary Consumption for GSECL Stations for the Control Period:

Stations	2011-12 (%)	2012-13 (%)	2013-14 (%)	2014-15 (%)	2015-16 (%)
Ukai TPS (Unit 1-5)	9.00	9.00	9.00	9.00	9.00
Gandhinagar TPS (Unit 1-4)	10.00	10.00	10.00	10.00	10.00
Wanakbori TPS (Unit 1-6)	9.00	9.00	9.00	9.00	9.00
Sikka TPS	11.00	11.00	11.00	11.00	11.00
Kutch Lignite TPS (Unit 1-4)	12.00	12.00	12.00	12.00	12.00

(b) Existing generating stations of TPL-G:

Table 8: Auxiliary Energy consumption for TPL-G Station for the Control Period

Stations	2011-12 (%)	2012-13 (%)	2013-14 (%)	2014-15 (%)	2015-16 (%)
Sabarmati 'C'	9.50%	9.50%	9.50%	9.50%	9.50%
Sabarmati 'D'	9.00%	9.00%	9.00%	9.00%	9.00%
Sabarmati 'E'	9.00%	9.00%	9.00%	9.00%	9.00%
Sabarmati 'F'	9.00%	9.00%	9.00%	9.00%	9.00%

Provided further that for the thermal generating stations with induced draft cooling towers, the norms shall be higher by 0.50%, as compared to the above norms.

(d) Gas Turbine/Combined Cycle generating stations (Existing and New):

(i) Combined cycle : 3.00%;

(ii) Open cycle : 1.00%.

...”

As mentioned earlier, GERC MYT Regulations, 2011 specify separate Auxiliary Energy Consumption norms for new and existing coal / lignite based Generating Stations, whereas for gas turbine/combined cycle Generating Stations, common norms of auxiliary energy consumption are specified in the GERC MYT Regulations, 2011. CERC, in CERC Tariff Regulations, 2014, has adopted the approach of specifying common norms for all new and existing thermal generating stations and only for particular Generating Stations that are unable to achieve the auxiliary energy consumption as per the common norms, separate norms for auxiliary energy consumption have been specified by CERC.

It is suggested that for existing Generating Stations whose tariff determination is in the purview of GERC, the norms for auxiliary consumption may be determined based on the analysis of actual auxiliary energy consumption of the Generating Stations in the past few years.

Coal/Lignite based thermal Generating Stations

Based on the GERC MYT Regulations, 2011, the Commission had approved auxiliary energy consumption for the Generating Stations of GSECL and TPL-G for second Control Period in their respective MYT Orders dated April 11, 2011 and September 6, 2011, respectively. Further, in the Mid-Term Review Order for TPL-G dated April 29, 2014, the Commission reviewed the normative auxiliary energy consumption for the Generating Stations of TPL-G for FY 2014-15 and FY 2015-16. The actual auxiliary energy consumption achieved by the coal/lignite based thermal Generating Stations vis-a-vis the normative auxiliary energy consumption stipulated for the second Control Period are as shown in the following Table:

Table 4-8: Normative and actual auxiliary energy consumption for coal/lignite based thermal generating stations

Generating Stations	Normative auxiliary energy consumption for the Second	Actual auxiliary energy consumption (%)	Average of actual auxiliary energy consumption for three years from

	Control Period (%)				FY12 to FY14 (%)
		FY12	FY13	FY14	
GSECL Stations					
Ukai (1-5)	9.00	9.34	9.22	9.75	9.44
Gandhinagar (1-4)	10.00	10.39	11.08	12.96	11.48
Wanakbori 1-6 TPS	9.00	8.85	9.17	9.53	9.18
Sikka TPS	11.00	12.85	12.58	12.54	12.66
KLTPS 1-3	12.00	14.65	13.22	12.68	13.52
KLTPS 4	12.00	21.21	19.48	19.90	20.20
Dhuvaran Gas (Unit 2)	3.00	4.51	4.35	6.99	5.28
TPL-G Stations					
C Station	9.50	10.01	9.80	10.44	10.08
D Station	9.00	8.86	8.91	8.99	8.92
E Station	9.00	8.88	9.30	9.32	9.17
F Station	9.00	9.78	9.83	8.98	9.53

* PPA based stations

For new generating stations, the approved auxiliary energy consumption are taken from the Tariff Orders for respective years as these stations are not covered in the MYT Order.

As against the normative auxiliary energy consumption of 9%, the Ukai (1-5) TPS has achieved 9.34%, 9.22% and 9.75% in FY 2011-12, FY 2012-13 and FY 2013-14, respectively. Thus, the average auxiliary energy consumption for Ukai (1-5) TPS was 9.44%. It is observed that the plant has achieved auxiliary energy consumption of 9.34% and 9.22% in FY 2011-12 and FY 2012-13, which is only marginally higher than the normative auxiliary energy consumption of 9.00% approved for second Control Period. In view of the same, the normative auxiliary energy consumption of 9.00% approved in the second Control Period, may be continued in the next Control Period for Ukai (1-5) TPS.

As regards Gandhinagar (1-4) TPS, the station has achieved average auxiliary energy consumption of 11.48% in the three years from FY 2011-12 to FY 2013-14, by achieving auxiliary energy consumption of 10.39%, 11.08% and 12.96% in FY 2011-12, FY 2012-13 and FY 2013-14, respectively. The average auxiliary energy consumption of the station for the said three years is higher than the normative auxiliary energy consumption of 10% approved for the second Control Period. With the view to impose better efficiency, the current norm of 10% auxiliary energy consumption may be continued for the Gandhinagar (1-4) TPS.

For all the three years under consideration, the actual auxiliary energy consumption of Wanakbori (1-6) TPS has remained very close to the normative auxiliary energy consumption of 9% specified for the second Control Period. Hence, the same norm may be continued for the next Control Period.

Sikka (1-2) TPS has achieved auxiliary energy consumption of 12.85%, 12.58% and 12.54% for FY 2011-12, FY 2012-13 and FY 2013-14, respectively, and hence, the average auxiliary energy consumption of the Station has been 12.66% for the said three years as against normative auxiliary energy consumption of 11.00% approved for the second Control Period. According to the submissions of GSECL during regulatory process, in the past, vacuum problems due to low tide and insufficient cooling water flow on account of silting of CW intake channel has been noted. However, the de-silting work was done at the plant in recent years. Further, the normative auxiliary energy consumption of the station is already high at 11% for the second Control Period. Hence, it is suggested that the normative auxiliary energy consumption for Sikka (1-2) TPS may not be relaxed further and may be specified at the existing normative levels, i.e., 11%.

KLTPS (1-3) has achieved normative auxiliary energy consumption of 14.65%, 13.22% and 12.68% in FY 2011-12, FY 2012-13 and FY 2013-14, respectively, as against the normative auxiliary energy consumption of 12.00% for the second Control Period. According to the submissions of GSECL in the regulatory process, the higher than normative PLF in the plant has been on account of following problems:

- (i) Forced outages due to bottom ash channel problems
- (ii) Lignite feeding problems due to wet lignite and excessive rain
- (iii) Load restricted to 50-55 MW in unit no.3 as blades of 2 stages of turbine are shaved off.

The aforementioned problems are not persistent, and also, the inefficient operation of the plant cannot be allowed by relaxation of the norms. Hence, the norms for auxiliary energy consumption may not be relaxed further. Also, with better O&M practices, the problems mentioned in (i) and (iii) above may be avoided. Therefore, it is suggested that the normative auxiliary energy consumption for KLTPS (1-3) may not be relaxed further as the current norm of 12.00% is already on the higher side. Accordingly, the normative auxiliary energy consumption for the KLTPS (1-3) for the

next Control Period may be specified as 12.00%, i.e., same as stipulated in GERC MYT Regulations, 2011 for second Control Period.

KLTPS 4 has seen very high auxiliary energy consumption of 21.21%, 19.48% and 19.90% FY 2011-12, FY 2012-13 and FY 2013-14, respectively. Thus, the plant has achieved average auxiliary energy consumption of 20.20% in the said three years, which is much higher than the normative auxiliary energy consumption of 12.00% specified for the second Control Period. However, the current normative auxiliary energy consumption of 12% specified in the GERC MYT Regulations, 2011 is already very high and the same may not be relaxed further. Thus, it is suggested that the normative auxiliary energy consumption of 12% for the KLTPS-4 specified in the GERC MYT Regulations, 2011 may be continued in the next Control Period.

For the recently commissioned coal/lignite based thermal Generating Stations of GSECL, namely, Ukai-6 and Sikka (3-4), the actual data of auxiliary energy consumption is not available for analysis. For these stations, the norms of operation are proposed to be specified based on the approved auxiliary consumption for FY 2015-16, i.e., 6.00% and 9.00% for Ukai 6 and Sikka Unit 3 & 4, respectively..

The D-Station, E-Station and F-station of TPL-G have seen actual average auxiliary consumption for the three years from FY 2011-12 to FY 2013-14 very close to the normative level of 9% except for C-Station. The actual average auxiliary consumption for the three years from FY 2011-12 to FY 2013-14 works out to be 10.08% and which is higher than the normative auxiliary consumption of 9.50%. It is observed that the existing norm for C-Station is already higher and further no relaxation can be provided. In view of the same it is proposed to continue with the existing norm of 9.50% for C-Station. Further, it is suggested that the normative auxiliary energy consumption of 9% specified for D, E & F Units of Sabarmati Station may be continued for the next Control Period. The remaining two stations, namely, C-Station of Sabarmati Plant and Vatva Gas Stations are not expected to be operational in the next Control Period.

In view of the above, the normative auxiliary energy consumption for coal/lignite based thermal generating stations not governed by the PPAs for the next Control Period may be specified as shown in the following Table:

Table 4-9: Proposed normative auxiliary energy consumption for coal/lignite based thermal generating stations for next Control Period

Generating Stations	Normative auxiliary energy consumption (%)
GSECL Stations	
Ukai (1-5)	9.00
Gandhinagar (1-4)	10.00
Wanakbori 1-6 TPS	9.00
Sikka (1-2) TPS	11.00
KLTPS 1-3	12.00
KLTPS 4	12.00
Ukai 6	6.00
Sikka (3-4)	9.00
TPL-G stations	
C Station	9.50
D Station	9.00
E Station	9.00
F Station	9.00

For new coal based Generating stations, it is proposed to adopt the norms specified in CERC Tariff Regulations, 2014, as under:

Auxiliary Energy Consumption	With Natural Draft cooling tower or without cooling tower
(i) 200 MW series	8.50%
(ii) 250/330/350/500 MW & above	
Steam driven boiler feed pumps	5.25%
Electrically driven boiler feed pumps	7.75%

Provided further that for the thermal generating stations with induced draft cooling towers, the norms shall be further increased by 0.50%, as compared to the above norms.

It is proposed to continue with the same norms for new lignite-fired thermal generating stations as specified in GERC MYT Regulations, 2011:

- (i) All generating stations with below 200 MW sets: 12%;
- (ii) All generating stations with 200 MW sets and above: 0.50% percentage point more than that allowed for coal based generating stations under Table above:

Provided that for the lignite fired stations using CFBC technology, the auxiliary energy consumption norms shall be 1.50 percentage point more than the auxiliary energy consumption norms of coal based generating stations as specified above.

Gas Turbine/Combined Cycle generating stations:

Actual auxiliary energy consumption for the gas turbine/combined cycle thermal generating stations vis-a-vis normative auxiliary energy consumption specified for the second Control Period are as shown in the following Table:

Table 4-10: Normative and actual auxiliary energy consumption for gas based thermal generating stations

Generating Stations	Normative for the Second Control Period (%)	Actual (%)			Average of actual AUX for three years from FY12 to FY14 (%)
		FY12	FY13	FY14	
GSECL Stations					
Dhuvaran (Gas 1)*	3.00	5.59	5.90	14.70	8.73
Dhuvaran (Gas 2)	3.00	4.51	4.35	6.99	5.28
Utran (Gas)*	4.00	5.90	6.73	0.00	4.21
Utran Extension*	3.00	2.36	3.40	59.67	21.81
Dhuvaran CCPP#3#	3.00				
TPL-G Stations					
Vatva Gas Station	3.00	3.04	5.30		4.17

* PPA based stations

For new generating stations, the approved auxiliary energy consumption are taken from the Tariff Orders for respective years as these stations are not covered in the MYT Order.

Vatva Gas Station of TPL-G is retired from FY 2014-15 onwards, whereas Dhuvaran (Gas 1), Utran and Utran extension are PPA based stations whose normative parameters shall be governed by the terms of PPA. Hence, there are only two gas turbine/combined cycle generating stations, namely, Dhuvaran (Gas 2) and Dhuvaran CCPP#3, whose tariff determination is within the purview of GERC.

In GERC MYT Regulations, 2011, common norms for auxiliary energy consumption were specified for existing and new gas turbine/combined cycle generating stations. Such approach is in line with the CERC Tariff Regulations, 2014. However, the norms for the new Stations are improved norms and the existing Stations may find it difficult to achieve these norms. Hence, it is proposed to adopt the existing norm for

existing gas turbine/combined cycle generating stations and specify the improved norms for new gas turbine/combined cycle generating stations, as under:

Gas Turbine/Combined Cycle generating stations

Existing generating stations

- (i) Combined cycle : 3.00%;
- (ii) Open cycle : 1.00%.

New generating stations

- (i) Combined cycle : 2.50%;
- (ii) Open cycle : 1.00%.

Provided that for generating stations having Gas Booster, 1% additional auxiliary consumption shall be allowed.

4.3.6.3 Secondary Fuel Oil Consumption

The norms of secondary fuel oil consumption specified in the GERC MYT Regulations, 2011 are reproduced hereunder:

“54.4 Secondary fuel oil consumption:

For Existing Stations:

a) Secondary fuel oil consumption (SFC) for all thermal generating Units/Stations, except those covered under clause (b) and clause (c) shall be as under:

- i. Coal-based generating stations: 1.00 ml/kWh;*
- ii. Lignite-Fired generating stations except stations based on CFBC technology: 2.00 ml/kWh;*
- iii. Lignite-Fired generating stations based on CFBC technology: 1.25 ml/kWh;*

b) SFC norm for following GSECL stations, shall be as under:

Table 5: SFC for GSECL generating stations under Regulation 54.4 (b) for the Control Period

<i>Stations</i>	<i>2011-12 (ml/kWh)</i>	<i>2012-13 (ml/kWh)</i>	<i>2013-14 (ml/kWh)</i>	<i>2014-15 (ml/kWh)</i>	<i>2015-16 (ml/kWh)</i>
<i>Ukai TPS (Unit 1-5)</i>	2.00	2.00	2.00	2.00	2.00
<i>Gandhinagar TPS (Unit 1-4)</i>	1.50	1.50	1.50	1.50	1.50
<i>Sikka TPS</i>	4.00	4.00	4.00	4.00	4.00
<i>Kutch Lignite TPS (Unit 1-4)</i>	3.00	3.00	3.00	3.00	3.00

c) SFC norm for following TPL-G station, shall be as under:

Table 6: SFC for the Control Period for TPL-G Stations

<i>Stations</i>	<i>2011-12 (ml/kWh)</i>	<i>2012-13 (ml/kWh)</i>	<i>2013-14 (ml/kWh)</i>	<i>2014-15 (ml/kWh)</i>	<i>2015-16 (ml/kWh)</i>
<i>Sabarmati 'C'</i>	2.00	2.00	2.00	2.00	2.00

Provided that the Commission may revise the norms for the secondary fuel oil consumption for the above mentioned Generating Stations in case of Renovation & Modernisation undertaken by the Generating Station.

For New Generating Stations:

- 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.*

Thus, GERC MYT Regulations, 2011 specify separate secondary fuel oil consumption norms for new and existing coal / lignite based Generating Stations. CERC, in CERC Tariff Regulations, 2014, has specified common norms of secondary fuel oil consumption of 0.5 ml/kWh for all new and existing coal/lignite based thermal generating stations. For some particular stations that are unable to achieve the aforementioned secondary fuel oil consumption, plant-wise relaxed norms are specified.

It is suggested that for existing Generating Stations whose tariff determination is in the purview of GERC, the norms for secondary fuel oil consumption may be

determined based on the analysis of secondary fuel oil consumption of the Generating Stations in the past few years.

Based on the GERC MYT Regulations, 2011, the Commission had approved the secondary fuel oil consumption for the Generating Stations of GSECL and TPL-G for the second Control Period in their MYT Orders dated April 11, 2011 and September 6, 2011, respectively. Further, in the Mid-Term Review Order for TPL-G dated April 29, 2014, the Commission reviewed the normative secondary fuel oil consumption for the Generating Stations of TPL-G for FY 2014-15 and FY 2015-16. The actual secondary fuel oil consumption achieved by the coal/lignite based thermal Generating Stations vis-a-vis the normative secondary fuel oil consumption specified for the second Control Period are as shown in the following Table:

Table 4-11: Normative and actual secondary fuel oil consumption

Generating Stations	Normative secondary fuel oil consumption for the Second Control Period (%)	Actual (%)			Average for actual of three years from FY12 to FY14 (%)
		FY12	FY13	FY14	
GSECL Stations					
Ukai (1-5)	2.00	1.16	1.08	0.95	1.06
Gandhinagar (1-4)	1.50	1.21	1.56	1.68	1.48
Gandhinagar - 5*	3.50	0.40	0.30	0.79	0.50
Wanakbori 1-6 TPS	1.00	0.61	0.84	1.43	0.96
Wanakbori 7 TPS*	3.50	0.42	0.03	0.57	0.34
Sikka TPS	4.00	3.57	2.43	3.22	3.07
KLTPS 1-3	3.00	6.06	4.89	2.67	4.54
KLTPS 4	3.00	3.69	3.35	2.52	3.19
Ukai 6#	1.00			4.45	4.45
Sikka (3-4) #	1.00				
TPL-G Stations					
C Station	2.00	2.20	1.16	2.01	1.79
D Station	1.00	0.47	0.36	0.99	0.61
E Station	1.00	0.35	0.44	1.16	0.65
F Station	1.00	0.45	0.44	0.91	0.60

* PPA based stations

For new generating stations, the approved secondary fuel oil consumption are taken from the Tariff Orders for respective years as these stations are not covered in the MYT Order.

In case of Ukai (1-5) TPS, the average secondary fuel oil consumption in the three years from FY 2011-12 to FY 2013-14 has been 1.06 ml/kWh, which is better than normative secondary fuel oil consumption specified for the second Control Period.

In FY 2011-12, secondary fuel oil consumption was 1.16 ml/kWh, however, in the following two years, the secondary fuel oil consumption for Ukai (1-5) TPS has been lower at 1.08 ml/kWh and 0.95 ml/kWh, respectively. In view of the same, it is suggested that the current norm of secondary fuel oil consumption of 2.00 ml/kWh for the second Control Period may be reduced to 1.0 ml/kWh for the next Control Period, since, CERC has reduced the norm to 0.5 ml/kWh for existing and new plants.

The secondary fuel oil consumption of the Gandhinagar (1-4) TPS has been 1.21 ml/kWh, 1.56 ml/kWh and 1.68 ml/kWh for FY 2011-12, FY 2012-13 and FY 2013-14, respectively, with an average secondary fuel oil consumption of 1.48 ml/kWh as compared to the normative secondary fuel oil consumption of 1.50 ml/kWh for the second Control Period specified for the Station. In view of the same, the current norm may be continued for the next Control Period.

The secondary fuel oil consumption of the Wanakbori (1-6) TPS has been 0.61 ml/kWh, 0.84 ml/kWh and 1.43 ml/kWh for FY 2011-12, FY 2012-13 and FY 2013-14, respectively. The average secondary fuel oil consumption for FY 2011-12 to FY 2013-14 works out to be 0.96 ml/kWh, which is better than normative secondary fuel oil consumption. However, considering the fact that the current norm of secondary fuel oil consumption of 1.00 ml/kWh for the station is already lower than the norm for other Generating Stations, and in view of the age of the plant, it is suggested that the current norm of 1.00 ml/kWh of secondary fuel oil consumption for the Wanakbori (1-6) TPS may be continued for the next Control Period.

The secondary fuel oil consumption of the Sikka (1-2) TPS has been 3.57 ml/kWh, 2.43 ml/kWh and 3.22 ml/kWh for FY 2011-12, FY 2012-13 and FY 2013-14, respectively. Thus, the average secondary fuel oil consumption of the station has been 3.07 ml/kWh as compared to the normative secondary fuel oil consumption of 4.00 ml/kWh for the second Control Period specified for the Station. Further, as mentioned earlier, the problem of lower vacuum has been rectified. The current norm of 4.00 ml/kWh secondary fuel oil consumption is also very high compared to the normative secondary fuel oil consumption for the other Generating Stations specified by GERC. In view of the above, it is suggested that the normative

secondary fuel oil consumption for Sikka (1-2) TPS may be specified as 3.00 ml/kWh for the next Control Period.

Because of the problems of forced outages and operation at partial load, the secondary fuel oil consumption of the KLTPS (1-3) has been 6.06 ml/kWh, 4.89 ml/kWh and 2.67 ml/kWh for FY 2011-12, FY 2012-13 and FY 2013-14, respectively, Further, majority of the problems faced by the station are avoidable with better O&M practises, and cannot be considered as persistent problems. Further, the inefficient operation of the plant cannot be allowed by relaxation of the norms and hence, it is suggested that the current norm of secondary fuel oil consumption of KLTPS (1-3) for the station may not be relaxed further and the same may be continued for the next Control Period.

The secondary fuel oil consumption of the KLTPS 4 been 3.69 ml/kWh, 3.35 ml/kWh and 2.52 ml/kWh for FY 2011-12, FY 2012-13 and FY 2013-14, respectively, as against the normative secondary fuel oil consumption of 3.00 ml/kWh for the station for the second Control Period. Though the average secondary fuel oil consumption of the station for the aforementioned three years, i.e., 3.19 ml/kWh has been high compared to the normative secondary fuel oil consumption of 3.00 ml/kWh for the second Control Period, the station has shown improving trend. In view of the same, it is suggested that the current norm of secondary fuel oil consumption of 3.00 ml/kWh for the KLTPS 4 may be continued for the next Control Period.

For the recently commissioned coal/lignite based thermal Generating Stations of GSECL, namely, Ukai-6 and Sikka (3-4) TPS, the actual data of secondary fuel oil consumption is not available for analysis. For these stations, the norms of operation may be specified same as approved in the Order in Case No. 1460 of 2014 for FY 2015-16. Accordingly, normative secondary fuel oil consumption of 1.00 ml/kWh may be specified for these Generating Stations for the next Control Period.

For the D-Station, E-Station and F-station of TPL-G, the average actual secondary fuel oil consumption in all three years, viz., FY 2011-12, FY 2012-13 and FY 2013-14 is significantly lower than the normative secondary fuel oil consumption of 1.00 ml/kWh specified for the second Control Period. However, the current normative secondary fuel oil consumption for these stations is already among the lowest specified by GERC. In view of the same, the low secondary fuel oil consumption achieved by these stations may be attributed to efficient operation and maintenance. In view of the above, the current normative secondary fuel oil consumption for these

stations may not be reduced further, and may be continued for the next Control Period. Further for C-Station it is proposed to specify the norm same as approved in the Mid Term Review of Business Plan Order for FY 2015-16 i.e. 2.00 ml/kwh.

In view of the above, the normative Secondary fuel Oil consumption for the next Control Period for coal/lignite based thermal generating stations not governed by the PPAs, may be specified as shown in the following Table:

Table 4-12: Proposed normative secondary fuel oil consumption for the next Control Period

Generating Stations	Secondary fuel oil consumption (%)
GSECL Stations	
Ukai (1-5)	1.00
Gandhinagar (1-4)	1.50
Wanakbori 1-6 TPS	1.00
Sikka TPS	3.00
KLTPS 1-3	3.00
KLTPS 4	3.00
Ukai 6	1.00
Sikka (3-4)	1.00
TPL-G stations	
C Station	2.00
D Station	1.00
E Station	1.00
F Station	1.00

4.3.6.4 Transit and handling losses

Transit and handling losses are very common in coal transportation, and 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 MYT Regulations, 2011, are as under:

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

(a) Coal or lignite-based Generating Stations, other than those covered under Clause (b):

- i. Pit head generating stations : 0.20%;
- ii. Non-pit head generating stations : 0.80%;

(b) Coal-based Generating Stations for TPL-G Stations:

Table 10: Transit Loss for TPL-G Stations for the Control Period

Stations	Transit Loss (%)				
	FY 2011-12	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16
TPL-G	1.40	1.20	1.00	0.90	0.80

Thus, the Commission, in GERC MYT Regulations, 2011 had specified transit loss of 0.2% and 0.8% pit-head and non-pithead generating stations, respectively, with the exception of stations of TPL-G. For TPL-G, the Commission had specified transit loss reduction trajectory in GERC MYT Regulations, 2011, from 1.40% in FY 2011-12 to 0.80% in FY 2015-16. CERC, in CERC Tariff Regulations, 2014 has also specified the transit loss of 0.2% and 0.8% pit-head and non-pithead generating stations, respectively.

Based on the GERC MYT Regulations, 2011, the Commission had approved transit and handling losses for the Generating Stations of GSECL and TPL-G for second Control Period in their respective MYT Orders dated April 11, 2011 and September 6, 2011. Further, in the Mid-Term Review Order for TPL-G dated April 29, 2014, the Commission reviewed the normative transit and handling losses for the Generating Stations of TPL-G for FY 2014-15 and FY 2015-16. The actual transit and handling losses of the coal/lignite based thermal Generating Stations vis-a-vis the normative transit and handling losses specified for the second Control Period are as shown in the following Table:

The actual transit and handling losses of coal for the domestic coal based Generating Stations of GSECL and TPL-G, vis-a-vis the normative transit and handling losses specified in GERC MYT Regulations, 2011 are as shown in the following Table:

Table 4-13: Normative and actual transit and handling losses

Generating Stations	Normative transit and handling losses for second Control Period (%)					Actual transit and handling losses (%)			Average of actual transit and handling losses for three years from FY12 to FY14 (%)
	FY 12	FY13	FY14	FY15	FY16	FY12	FY13	FY14	
GSECL Stations									
Ukai (1-5)	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
Gandhinagar (1-4)	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
Gandhinagar - 5*	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
Wanakbori 1-6 TPS	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
Wanakbori 7 TPS*	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
Sikka TPS	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
KLTPS 1-3	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
KLTPS 4	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Ukai 6#			0.80	0.80					
TPL-G Stations									
C Station	1.40	1.20	1.00	0.90	0.80	2.43	1.99	1.61	2.01
D Station	1.40	1.20	1.00	0.90	0.80	2.43	1.99	1.61	2.01
E Station	1.40	1.20	1.00	0.90	0.80	2.43	1.99	1.61	2.01
F Station	1.40	1.20	1.00	0.90	0.80	2.43	1.99	1.61	2.01

* PPA based stations

For new generating stations, the approved secondary fuel oil consumption are taken from the Tariff Orders for respective years as these stations are not covered in the MYT Order.

As regards the transit and handling losses for GSECL stations, it appears that the actual transit and handling losses being submitted by GSECL in its Tariff Petitions are not actual transit losses, but normative losses since, the actual transit and handling losses submitted by GSECL are exactly equal to the normative transit and handling losses.

It is proposed to adopt the same norm as specified in CERC Tariff Regulations, 2014, as under:

"Coal or lignite-based Generating Stations:

- i. Pit head generating stations : 0.20%;

ii. Non-pit head generating stations : 0.80%;

Provided that in case of pit head stations if coal or lignite is procured from sources other than the pit head mines which is transported to the station through rail, transit loss of 0.8% shall be applicable:

Provided further that in case of imported coal, the transit and handling losses shall be 0.2%."

As regards the transit and handling losses for TPL-G, it is observed that considering the high transit and handling losses of TPL-G in the past, the Commission, in GERC MYT Regulations, 2011 had relaxed the norms of transit and handling losses for TPL-G and had set trajectory of reduction of the same from 1.40% in FY 2011-12 to 0.80% in FY 2015-16. However, the actual transit and handling losses of TPL-G are 2.43%, 1.99% and 1.61% for FY 2011-12, FY 2012-13 and FY 2013-14 respectively. In its Tariff Petitions, TPL-G has repeatedly submitted that the transit and handling losses are high due to various uncontrollable factors and it has been unable to reduce the same to the extent specified in the GERC MYT Regulations, 2011 despite efforts made by it. The Commission has already granted adequate time for transit loss reduction to TPL-G, and from the current level of actual transit and handling losses. In view of the above, it is proposed to continue with the norm specified for FY 2015-16, i.e., 0.80% for the third Control Period.

For the pit-head stations, the normative transit and handling losses may continued to be specified as 0.20%, i.e., same as specified in CERC Tariff Regulations, 2014.

As regards the norms of transit and handling losses for stations using imported coal, the GERC MYT Regulations, 2011 do not include any mention of the same. However, in the Order dated March 30, 2013, the Commission had observed as reproduced below:

"The transit loss is to be considered only in the case of indigenous coal, washed coal and Lignite, but not on imported coal as mentioned in the MYT Order dated 11th April, 2011"

CERC, in CERC Tariff Regulations, 2014 has specified normative transit and handling losses of 0.20% for imported coal. Since, there shall always be some loss of coal in transportation and handling, it is suggested that the normative transit and handling losses of 0.20% may be specified for imported coal, for the next Control

Period as in CERC Tariff Regulations, 2014. Further, it may also be specified that the transit loss shall not be applicable if coal is procured on delivery basis.

4.3.7 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. Before deciding on the approach for O&M expenses, it is important to analyse the components of O&M expenses.

a. Employee Expenses

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) Expenses

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. Both options have their merits and de-merits. If the O&M expenses are specified in a consolidated manner, the utility has the flexibility to manage its

expenditure through own resources (which will increase the employee expenses) or through outsourcing (which will increase the A&G expenses), as appropriate. However, under this dispensation, the variation in the individual heads of employee expenses, A&G expenses, and Repair & Maintenance expenses are difficult to track, and there are occasions when the Commission may wish to consider these separately, due to specific treatment to be given for pay revision, etc. Traditionally, for generation business, the O&M expenses are specified in a consolidated manner, either as a percentage of the GFA or in terms of Rs. lakh/MW of capacity. GERC has been specifying consolidated O&M expenses for the generation business, which is in line with the approach adopted by CERC in the CERC Tariff Regulations, 2014. Hence, it is suggested that for the generation business, the approach for the specifying the consolidated O&M expenses be continued. In this regard, it is also worth noticing that since, the Commission has been approving the O&M expenses on consolidated basis, plant-wise actual data of all three components of O&M expenses; viz., employee expenses, R&M Expenses and A&G expenses is not available for several of the previous years.

GERC MYT Regulations, 2011 has been specifying different norms for O&M Expenses for the new and existing Generating Stations. CERC, in CERC Tariff Regulations, 2014 has adopted the approach of specifying common norms for O&M Expenses for the new as well as existing thermal Generating Stations.

O&M expenses for new thermal Generating Stations

GERC MYT Regulations, 2011, specifies the normative O&M expenses for the new thermal Generating Stations as reproduced below:

“56. New Generating Stations

a) For coal based generating Units/Stations:

Table 11: O&M Expense Norms of New Coal based Generating Stations for the Control Period

Rs. Lakh/MW

<i>Particulars</i>	<i>O&M Expense Norms</i>
<i>FY 2011-12</i>	<i>14.53</i>
<i>FY 2012-13</i>	<i>15.36</i>
<i>FY 2013-14</i>	<i>16.24</i>

FY 2014-15	17.17
FY 2015-16	18.15

Provided that the above norms shall be multiplied by the following factors for the additional Units whose COD occurs on or after 1.4.2011 in the same Station:

Additional 4 th & 5 th Units	: 0.90
Additional 6 th & more Units	: 0.85

b) For lignite based generating stations:

Table 12: O&M Expense Norms of New Lignite based Generating Stations for the Control Period

Rs. Lakh/MW

Particulars	O&M Expense Norms
FY 2011-12	21.63
FY 2012-13	22.87
FY 2013-14	24.18
FY 2014-15	25.56
FY 2015-16	27.02

c) Gas Turbine/Combined Cycle generating stations:

Table 13: O&M Expense Norms of New Gas Turbine/Combined Cycle generating stations for the Control Period

Rs. Lakh/MW

Year	Gas Turbine/ Combined Cycle generating stations
FY 2011-12	16.54
FY 2012-13	17.49
FY 2013-14	18.49
FY 2014-15	19.55
FY 2015-16	20.67

“

CERC Tariff Regulations, 2014 specifies the norms of O&M expenses for thermal Generating Stations as reproduced below:

“ 29. Operation and Maintenance Expenses:

(1) Normative Operation and Maintenance expenses of thermal generating stations shall be as follows:

(a) Coal based and lignite fired (including those based on Circulating Fluidised Bed Combustion (CFBC) technology) generating stations, other than the generating stations/units referred to in clauses (b) and (d):

(in Rs Lakh/MW)

Year	200/210/250 MW Sets	300/330/350 MW Sets	500 MW Sets	600 MW Sets and above
FY 2014-15	23.90	19.95	16.00	14.40
FY 2015-16	25.40	21.21	17.01	15.31
FY 2016-17	27.00	22.54	18.08	16.27
FY 2017-18	28.70	23.96	19.22	17.30
FY 2018-19	30.51	25.47	20.43	18.38

Provided that the norms shall be multiplied by the following factors for arriving at norms of O&M expenses for additional units in respective unit sizes for the units whose COD occurs on or after 1.4.2014 in the same station:

200/210/250 MW	Additional 5 th & 6 th units	0.90
	Additional 7 th & more units	0.85
300/330/350 MW	Additional 4 th & 5 th units	0.90
	Additional 6 th & more units	0.85
300/330/350 MW	Additional 3 rd & 4 th units	0.90
	Additional 5 th & above units	0.85

...

(c) Open Cycle Gas Turbine/Combined Cycle generating stations:

(in Rs Lakh/MW)

Year	Gas Turbine/ Combined Cycle generating stations other than	Small gas turbine power generating stations	Agartala GPS	Advance F Class Machines

	<i>small gas turbine power generating stations</i>				
2014-15	14.67	33.43	41.32	26.55	
2015-16	15.59	35.70	44.14	28.36	
2016-17	16.57	38.13	47.14	30.29	
2017-18	17.61	40.73	50.35	32.35	
2018-19	18.72	43.50	53.78	34.56	

...

(e) *Generating Stations based on coal rejects:*

<i>Year</i>	<i>O&M Expenses (in Rs Lakh/MW)</i>
2014-15	29.10
2015-16	30.94
2016-17	32.88
2017-18	34.95
2018-19	37.15

(2) *The Water Charges and capital spares for thermal generating stations shall be allowed separately:*

Provided that water charges shall be allowed based on water consumption depending upon type of plant, type of cooling water system etc., subject to prudence check. The details regarding the same shall be furnished along with the petition:

Provided that the generating station shall submit the details of year wise actual capital spares consumed at the time of truing up with appropriate justification for incurring the same and substantiating that the same is not funded through compensatory allowance or special allowance or claimed as a part of additional capitalisation or consumption of stores and spares and renovation and modernization."

it is suggested that for the new Generating Stations achieving COD after the effectiveness of the new GERC MYT Regulations, and the existing Generating Stations which have been in operation for less than three (3) years as on March 31, 2016, the normative O&M expenses for FY 2016-17 to FY 2020-21 may be specified by

escalating the norms of O&M expenses for FY 2015-16 with the escalation factor of 5.72%, as shown in the Tables below:

(a) New Coal based Thermal Generating Stations:

Table 4-14: Proposed normative O&M Expense for new coal based generating stations for the next Control Period (Rs. Lakh/MW)

Year	O&M Expense Norms
FY 2016-17	19.19
FY 2017-18	20.29
FY 2018-19	21.45
FY 2019-20	22.67
FY 2020-21	23.97

Provided that the norms shall be multiplied by the following factors for arriving at norms of O&M expenses for additional units for the units whose COD occurs on or after effectiveness of the new GERC MYT Regulations:

Additional 4 th & 5 th units	0.90
Additional 6 th & more units	0.85

(b) New Lignite based Thermal Generating Stations

Table 4-15: Proposed normative O&M Expense for new Lignite based generating stations for the next Control Period (Rs. Lakh/MW)

Year	O&M Expense Norms
FY 2016-17	28.57
FY 2017-18	30.20
FY 2018-19	31.93
FY 2019-20	33.75
FY 2020-21	35.68

(c) New Open Cycle Gas Turbine/Combined Cycle Generating Stations:

Table 4-16: Proposed normative O&M Expense for new Open Cycle Gas Turbine/Combined Cycle generating stations (Rs. Lakh/MW)

Year	Gas Turbine/Combined Cycle generating stations other than small gas turbine power generating stations	Small gas turbine power generating stations	Advance F Class Machines
FY 2016-17	21.85	37.74	29.98
FY 2017-18	23.10	39.90	31.70
FY 2018-19	24.42	42.18	33.51
FY 2019-20	25.82	44.60	35.43
FY 2020-21	27.30	47.15	37.45

(d) New Generating Stations based on coal rejects:

Table 4-17: proposed normative O&M expenses for new generating stations based on coal rejects (Rs. Lakh/MW)

Year	O&M Expenses
FY 2016-17	32.88
FY 2017-18	34.95
FY 2018-19	37.15
FY 2019-20	39.48
FY 2020-21	41.97

O&M expenses for existing thermal Generating Stations

Regulation 55 of the GERC MYT Regulations, 2011 specifies as reproduced below:

“55 Operation and Maintenance expenses for thermal Generating Stations

55.1 Existing Generating Stations

a) The Operation and Maintenance expenses excluding water charges and including insurance, shall be derived on the basis of the average of the actual Operation and Maintenance expenses excluding water charges and including insurance 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 excluding water charges and including insurance shall be considered as operation and maintenance expenses excluding water charges and including insurance for the financial year ended March 31, 2009 and shall be escalated at the escalation factor of 4 % to arrive at operation and maintenance expenses excluding water charges and including insurance for FY 2011-12.*

c) *The O&M expenses excluding water charges and including insurance for each subsequent year will be determined by escalating the base expenses determined above for FY 2011-12, at the escalation factor of 5.72 % to arrive at permissible O&M expenses excluding water charges and including insurance for each year of the Control Period:*

Provided that water charges shall be allowed separately as per actuals, subject to prudence check.

Provided further that in case an existing generating station has been in operation for less than three (3) years as on the date of effectiveness of these Regulations, the O&M Expenses shall be as specified by Regulation 56 for New Generating Stations."

Thus, as regards the O&M expenses for the existing Generating Stations, the GERC MYT Regulations, 2011 specify principles rather than the norms.

In its Judgment dated May 30, 2014, in Appeal Nos. 147, 148 and 150 of 2013 of Torrent Power Limited, the APTEL has ruled as under:

"23. According to the Appellant, the variation in O&M expenses on account of change in law and higher rate of inflation and expenses are not included in the base expenses but have been necessitated and actually incurred during the year. Further, this issue has been decided in favour of the Appellant in the judgment dated 28.11.2013 passed by this Tribunal in Appeal no. 190 of 2011.

24. According to the State Commission, Operation and Maintenance expenses are allowed on normative basis as per Regulations 98.6 of the MYT Regulations. There is no scope for truing up or considering the actual expenses incurred as uncontrollable and allowing the same in the Tariff. As has been held by the Tribunal in Appeal no. 190 of 2011, the very concept of allowing the O&M on normative basis is that actual expenses are of no relevance thereafter and any variation on the normative O&M expenses is to the account of the Appellant unless there is a specific consequence for such variation provided for in the Regulations itself. Thus, according

to the State Commission this issue is covered against the Appellant in Appeal no. 190 of 2011. 25. Let us examine the findings of the Tribunal in Appeal no. 190 of 2011.

“39. It cannot be disputed that the norms with regard to Operation & Maintenance Expenses is covered under Regulation 98.6 of the MYT Regulations of the State Commission. In terms of this Regulation 98.6, the determination of the O&M expenses for 3 years ending 31st March, 2010 subject to prudence check and escalated at the rate of 4% to arrive at the O&M expenses for the year 2011-12. The O&M expenses for the further period after 2011-12 are to be escalated at the rate of 5.72%.

40. The determination of O & M expenses under the Regulations of the State Commission is on normative basis. **The very concept of allowing the O & M on normative basis is that the actual expenses is of no relevance thereafter and any variation on the normative O & M expenses is to the account of the Appellant unless there is a specific consequence for such variation provided for in the Regulations itself.**

41. The State Commission has determined the O&M expenses strictly in terms of Regulation 98.6. It is not the case of the Appellant that the normative O&M calculated by the State Commission is not in accordance with Regulation 98.6. So, the main controversy revolves around the normative O&M expenses.

44. The reading of the above findings by the State Commission would make it clear that while determining Operation and Maintenance Expenses under Regulation 98.6, the State Commission failed to consider one time pay revision expenses and major overhaul expenses for computing normative O&M expenses for the 2nd control period.

45. In fact, the State Commission has accepted that increase in employee's cost due pay revision is uncontrollable. On this ground, the State Commission had allowed Rs 65.19 Cr towards employees' cost including pay revision costs of Rs 10.59 Cr for FY 2009-10. However, for the purpose of computing normative cost for 2nd Control period, Commission has considered Rs 54.6 Cr (65.19 - 10.59) as actual employees costs for FY 2009-10. This approach may not be correct.

46. With reference to one time major overhauling costs, the Appellant had indicated in its petition that it had deferred the major overhaul, which

was scheduled for FY 2009-10 to FY 2010-11. Therefore, the actual R&M expenditure during FY 2009-10 was reduced by Rs 6.74 Cr on account of deferment of major overhaul. The State Commission had approved the reduced actual R&M expenditure.

47. *The above aspect would clearly establish that major overhaul was part of approved O&M expenditure for FY 2009-10. But for its deferment to FY 2010-11, the Appellant would have spent this amount on major overhaul and claimed as part of actual R&M expenditure for FY 2009-10. In that event, the State Commission would have considered the same for arriving the normative O&M expenses for the 2nd control period for the 2 to FY 2015-16.*

48. *This aspect is required to be considered by the State Commission and pass the necessary orders in the light of the above observations. On this issue, we remand the matter to the State Commission for fresh consideration. This point is answered accordingly."*

26. *Thus, the Tribunal has held that the O&M expenses have been allowed on normative basis and the variation in O&M expenses have to be on account of the Appellant unless there is a specific consequence for such variation provided for in the Regulations. However, the Tribunal held that same uncontrollable expenditure which the State Commission failed to consider for computing the normative O&M expenses were required to be reconsidered.*

27. *Let us now examine the variation in O&M expenses claimed by the Appellant.*

28. *The Appellant had stated in the Petition that base O&M expenses were arrived at considering escalation factor of 4% for 3 years on average of actual normalized O&M expenses of FYs 2007-08, 2008-09 and 2009-10. However the actual weighted average inflation rate (considering 60% and 40% weight to WPI and CPI respectively) is 7.54%, 9.96% and 8.86% for FY 2009-10, FY 2010-11 and FY 2011-12 respectively, Further, wage revision has been carried out under Section 12 (3) of the Industrial "Disputes Act, 1947. The variation in R&M and A&G expenses have been on account of higher rate of inflation. The security expenses have increased due to increase in minimum wage revision and vehicle running expenses have increased due to inflation. Certain expenses like loss on sale of assets and repairs of EHV transformers were not part of the base level expenses.*

29. We find that the State Commission in terms of Regulation 23.2(h) of the MYT Regulations, 2011 has considered the entire variation in O&M expenses as controllable.

30. Let us now examine the MYT Regulations, 2011.

31. Regulation 23.1 specifies the uncontrollable factors. Regulation 23.1 is reproduced below:

“23.1 For the purpose of these Regulations, the term comprise of the following factors, which were beyond the control of the applicant, and could not be mitigated by the applicant:

(a) Force Majeure events;

(b) Change in law, judicial pronouncements and Orders of the Central Government, State Government or Commission;

(c) Variation in the price of fuel and/ or price of power purchase according to the FPPPA formula approved by the Commission from time to time;

(d) Variation in the number or mix of consumers or quantities of electricity supplied to consumers:

Provided that where there is more than one Distribution Licensee within the area of supply of the applicant, 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, on account of migration from one Distribution Licensee to another, shall be attributable to controllable factors:

Provided further that if 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;

(e) Transmission Loss;

(f) Variation in market interest rates;

(g) Taxes and Statutory levies;

(h) Taxes on Income:

Provided that where the applicant or any interested or affected party believes, for any variable not specified above, that there is a material variation or expected variation in performance for any financial year on account of uncontrollable factors, such applicant or interested or affected party may apply to the Commission for inclusion of such variable at the Commission's discretion, under this Regulation for such financial year."

32. Regulation 23.2(h) specifies that variation in Operation and Maintenance expenses are controllable.

33. Thus, the Appellant can claim variation in Operation & Maintenance only to the extent it is covered under the uncontrollable factors specified under Regulation 23.1.

34. The Appellant has stated that one of the reasons for the variation in O&M expenses is due to higher inflation rate based on weighted average of WPI and CPI with weight of 60 and 40 respectively for FYs 2009-10, 2010-11 and 2011-12 is more than 4%. We find that the Regulation 98.6 for O&M expenses provides that O&M expenses shall be derived on the basis of the actual O&M expenses for 3 years ending 31.3.2010. The average of such O&M expenses shall be considered as O&M expenses for FY 2008-09 and shall be escalated at escalation factor of 4% to arrive at the O&M expenses of FY 2011-12. The O&M expenses for subsequent years will be determined by escalating the base expenses determined for FY 2011-12 at the escalation rate of 5.72%. The Regulations specify fixed escalation factors to arrive at the base year O&M expenses and thereafter for determination of O&M expenses for the subsequent years. There is no provision for true up of escalation factor for 3 year period ending 31.3.2010 and escalation factor of 4% used to arrive at O&M expenses of FY 2011-12. The escalation factor for determining the O&M expenses for subsequent year of the control period from the base year O&M expenses of FY 2011-12 is also fixed at 5.72%. However, under the proviso to Regulation 23.1, if an applicant believes that there is material variation in performance for any financial year on account of uncontrollable factors then such applicant may apply to the Commission for inclusion of such variable and the State Commission at its discretion will consider the same.

35. We find that the Appellant has not provided evidence to establish that the factors responsible for variation in O&M expenses are covered under Regulation 23.1

and has also not provided material to establish its claim that these factors have affected material variation in its performance on account of such uncontrollable factor.

36. We, therefore, decide this issue against the Appellant." (*Emphasis added*)

Existing Stations of GSECL

The Commission, in its MYT Order dated April 11, 2011, had approved the plant wise O&M expenses based on the principles specified in the GERC MYT Regulations, 2011 for all the stations not governed by PPA. For the PPA governed stations, the normative O&M expenses were determined based on the provisions of PPA.

The normative and actual O&M expenses for the existing thermal generating stations, which have been in operation for more than three (3) years, is as shown in the following Table:

Table 4-18: Normative and actual O&M expenses for thermal generating stations of GSECL (Rs. Crore)

S.N	Power stations	Normative					Actual		
		FY12	FY13	FY14	FY15	FY16	FY12	FY13	FY14
1	Ukai (1-5)	128.87	136.24	144.04	152.28	160.99	134.24	129.47	163.67
2	Gandhinagar (1-4)	91.27	96.49	102.01	107.85	114.02	96.55	85.57	94.46
3	Gandhinagar - 5*	25.00	26.00	27.00	28.00	29.00	24.55	13.48	23.10
4	Wanakbori 1-6 TPS	131.88	139.42	147.39	155.83	164.74	145.50	145.40	154.27
5	Wanakbori 7 TPS*	25.00	26.00	27.00	28.00	29.00	13.97	2.97	14.88
6	Sikka TPS	46.23	48.88	51.67	54.63	57.75	48.80	56.12	56.93
7	KLTPS 1-3	72.47	76.62	81.00	85.63	90.53	53.90	62.06	89.89
8	KLTPS 4	16.22	17.15	18.14	19.17	20.27	19.39	20.95	5.72
9	Duvaran (Gas 1)*	20.00	16.00	15.00	21.00	18.00	23.77	25.21	20.86
10	Duvaran (Gas 2)	17.85	18.87	19.95	21.09	22.30	24.30	24.51	20.85
11	Utran (Gas)*	13.00	13.00	14.00	14.00	15.00	25.87	39.34	21.73
12	Utran Extension*	45.00	46.00	48.00	49.00	51.00	81.84	51.09	40.66
	Total (GSECL)	632.79	660.67	695.20	736.48	772.61	692.67	656.19	707.02

*PPA based stations

It is observed that for most of the Generating Stations of GSECL, which are not based on PPA, the actual O&M expenses are higher than the normative O&M expenses. For

arriving at the normative O&M expenses for the first year of the Control Period, the Commission, in GERC MYT Regulations, 2011 has considered escalation factor of 4% on the O&M expenses of the base year. In the new GERC MYT Regulations, the escalation factor of 5.72% is proposed for thermal generating stations for arriving at the normative O&M expenses of the first year of the Control Period, i.e., FY 2016-17, and subsequent years.

Existing Stations of TPL-G

The Commission, in its MYT Order dated September 6, 2011, had approved consolidated O&M expenses for TPL-G based on the principles specified in the GERC MYT Regulations, 2011 as shown in the following Table:

Table 4-19: Normative O&M expenses for second Control Period for thermal generating stations of TPL-G as per MYT Order dated September 6, 2011 (Rs. crore)

Particulars	FY 2011-12	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16
O&M expenses	132.26	139.82	147.82	156.28	165.20

In the Mid-Term-Review of second Control Period for TPL-G in the Order dated April 29, 2014, based on the analysis of actual O&M expenses for TPL-G in the previous years, the normative O&M expenses for TPL-G for FY 2014-15 and FY 2015-16 have been revised to Rs. 134.19 crore and Rs. 141.86 crore, respectively. In the said Order, the Commission has stated as reproduced below:

“Commission’s Analysis

The Commission has examined the O&M expenses incurred by TPL (G) during FY 2012-13. The Commission has approved the O&M expenses, based on the audited accounts for FY 2012-13. GERC (MYT) Regulations, 2011, specified the escalation of O&M expenses at 5.72% per annum for FY 2012-13 onwards. The Commission, accordingly, approves the O&M expenses, with 5.72% escalation per annum in the MTR for FYs 2014-15 and 2015-16, over the actual O&M expenses approved in the Truing up for FY 2012-13.

Table 4.27: O&M Expenses Approved in the Mid-term Review For FY 2014-15 and FY 2015-16

(Rs. Crore)

Sl. No.	Particulars	Projected in the MTR		Approved in the MTR	
		2014-15	2015-16	2014-15	2015-16
1.	O&M expenses	153.78	161.75	134.19	141.86

”

The normative and actual O&M expenses of TPL-G are as shown in the following Table:

Table 4-20: Normative O&M expenses for second Control Period for thermal generating stations of TPL-G (Rs. crore)

S.N.	Particular	Normative					Actual		
		FY12	FY13	FY14	FY15	FY16	FY12	FY13	FY14
1	O&M expenses	132.26	139.82	147.82	134.19	141.86	133.17	120.06	129.12

The actual O&M expense for TPL-G for FY 2011-12 were very close to the normative O&M expense for FY 2011-12 approved by the Commission. However, for FY 2012-13, the actual O&M expense for TPL-G was significantly lower than the normative O&M expense approved by the Commission. In view of the same, the Commission had reduced the normative O&M expenses for TPL-G for FY 2014-15 and FY 2015-16 in the Mid-Term-Review Order dated April 29, 2014.

In the said Mid-Term-Review Order dated April 29, 2014, the Commission had also observed the fact of retirement of Vatva Gas Station. The relevant extracts of the Order are reproduced below:

“4.5 Operational Performance Parameters

In the case of Sabarmati C station and Vatva Gas station, TPL-G (APP) has submitted as follows:

***Vatva CCPP:** It has completed 23 years in operation, as against its estimated life of 25 years. Due to non-allocation of domestic gas by the Government and higher cost of RLNG/ Spot Gas, the Vatva CCPP has been kept in wet preservation mode. Hence, due consideration needs to be given to the following factors:*

- *The station is nearing completion of its life in the next two years. Therefore, the continuation of the existing generating station necessitates major capital expenditure for extending its life.*

- *The SHR of this old generating station is higher than that of the new gas generating plants equipped with advanced technology. Further, the price of domestic gas is likely to increase and therefore, the implication of difference in SHR is likely to increase further.*
- *The terms of the existing gas agreements expire on 31.03.2014. The renewal of the gas agreement requires the commitment for Take/ Pay at new gas price, along with Ship/ Pay for gas transportation for the next five years. Considering the financial implications of above factors, it is proposed to retire the Vatva Generation facilities.*

“Commission’s Analysis

In view of the circumstances explained by TPL-G (APP), the Commission considers the submission that C-Station would be in operation during the balance of the MYT period and Vatva Station will be retired.”

Thus, in the same Order, the Commission has considered the fact that the Vatva Gas Station will be retired from FY 2014-15 onwards. In view of the fact that the Commission has reduced the normative O&M expenses for TPL-G for FY 2014-15 and FY 2015-16 in view of the actual O&M expenses of TPL-G in FY 2012-13, and in the same Order the Commission has also considered the fact of retirement of Vatva Gas Station. Actual O&M expense for FY 2011-12 to FY 2013-14 considered for the purpose of determination of O&M expense for third control period is excluding Vatva station O&M expense.

In the new GERC MYT Regulations, the escalation factor of 5.72% is proposed for thermal generating stations for arriving at the normative O&M expenses of the first year of the Control Period, i.e., FY 2016-17, and subsequent years.

Accordingly, the principles for determining the O&M expenses for Generation Companies, is proposed as under:

- a) "The Operation and Maintenance expenses excluding water charges and including insurance, shall be derived on the basis of the average of the actual Operation and Maintenance expenses excluding water charges and including insurance for the three (3) years ending March 31, 2015, subject to prudence check by the Commission.
- b) The average of such operation and maintenance expenses excluding water charges and including insurance shall be considered as operation and

maintenance expenses excluding water charges and including insurance for the financial year ended March 31, 2014 and shall be escalated year on year at the escalation factor of 5.72% to arrive at operation and maintenance expenses excluding water charges and including insurance for subsequent years up to FY 2020-21:

Provided that water charges shall be allowed separately as per actuals, subject to prudence check:

Provided further that in case an existing generating station has been in operation for less than three (3) years as on the date of effectiveness of these Regulations, the O&M Expenses shall be allowed as specified under Regulation 55 for New Generating Stations."

4.3.8 Incentive Mechanism

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 linked with increase in PLF
- Paise/unit linked to actual/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) linked with increase in PLF, the incentive will vary for each Generating Station based on capital cost and means of finance 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.

The existing GERC Tariff Regulations provides for incentive mechanism linked to the Availability of the generating stations. The Regulation 59 (A) of the GERC MYT Regulations, 2011 regarding computation of annual fixed charges is reproduced below:

"59 Computation and Payment of Annual Fixed Charges and Energy Charges for Thermal Generating Stations

A. Annual Fixed Charges:

59.1 The total Annual Fixed Charges shall be computed based on the norms specified under these Regulations and recovered on monthly basis under capacity charge. The total capacity charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share / allocation in the capacity of the generating station.

59.2 The capacity charge (inclusive of incentive) payable to a thermal generating station for a calendar month shall be calculated in accordance with the following formulae:

(a) Generating stations in commercial operation for less than ten (10) years on 1st April of the financial year :

$AFC \times (NDM/NDY) \times (0.5 + 0.5 \times PAFM/NAPAF)$ (in Rupees);

Provided further 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:

$AFC \times (0.5 + 35/NAPAF) \times (PAFY/70)$ (in Rupees).

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

$AFC \times (NDM/NDY) \times (PAFM/NAPAF)$ (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

..."

Thus, as per the GERC MYT Regulations, 2011, the annual fixed charges are linked with the Availability of the plant and are fully recoverable at normative plant availability for the year. Any availability in excess of the normative availability will result in incentive in the form of over recovery of annual fixed charges in proportion to the plant availability.

Incentive in terms of paise/kWh beyond the normative PLF has been a mechanism widely adopted by the various SERCs due to simplicity in implementation, and the fact that it ensures uniform incentive to all generating stations. In CERC Tariff Regulations, 2009, the incentive was linked to the availability of the Station. However, CERC has also switched over to this mechanism for incentivising the thermal Generating Stations in CERC Tariff Regulations, 2014.

Regulation 30 (4) of the CERC Tariff Regulations, 2014 specifies, as reproduced below:

“(4) Incentive to a generating station or unit thereof shall be payable at a flat rate of 50 paise/kWh for ex-bus scheduled energy corresponding to scheduled generation in excess of ex-bus energy corresponding to Normative Annual Plant Load Factor (NAPLF) as specified in regulation 36 (B).”

Hence, CERC Tariff Regulations, 2014 has specified incentive for Generating Stations at a flat rate of 50 paise/kWh for ex-bus scheduled energy corresponding to scheduled generating in excess of ex-bus energy corresponding to Normative Annual Plant Load Factor (NAPLF). In Regulation 30 of the CERC Tariff Regulations, 2014, as reproduced in the earlier para of this Report, in computation of fixed charges, the recovery of fixed charges is capped at AFC for the Generating Station for the year, and hence, there is no incentive in the form of over-recovery of fixed charges in case higher than normative Availability is achieved by a Generating Station.

A generator should be incentivised for actual/scheduled generation rather than availability to generate, as for distribution licensees, the 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. In view of such facts, CERC has switched over to the incentive mechanism linked to PLF from its earlier approach of incentivising the Generating Stations for achieving higher than target availability.

In view of the above, it is proposed to modify the current mechanism of incentivising the Generating Stations for achieving higher than normative availability and adopt the mechanism of allowing Incentive to a generating station at a flat rate of 50 paise/kwh for ex-bus scheduled energy corresponding to scheduled generation in excess of ex-bus energy corresponding to Normative Annual Plant Load Factor (NAPLF) in accordance with CERC Tariff Regulations, 2014. Accordingly, for

removing the linkage of incentive with availability of the Generating Stations, the recovery of fixed charges has been capped at AFC for the year.

As regards the NAPLF for the purpose of incentive, the Commission did not specify the same in the GERC MYT Regulations, 2011 as in the mechanism of allowing incentive on normative availability adopted by GERC, the normative PLF has no significance. However, under the mechanism of allowing incentive for generation in excess of energy corresponding to the NAPLF, the norms for normative PLF have to be specified.

The CERC Tariff Regulations has specified norms for NAPLF for incentive as reproduced below:

"36. The norms of operation as given hereunder shall apply to thermal generating stations:

...

(B) Normative Annual Plant Load Factor (NAPLF) for Incentive

(a) All thermal generating stations, except those covered under clauses (b), (c) - 85%

..."

Thus, CERC has approved NAPLF of 85% for thermal Generating Stations for allowing incentive to thermal generating stations. The target PLF stipulation for incentive purpose should be set considering the vintage of plants and planned maintenance schedules. Also, the actual PLF achieved by the Generating Stations should also be kept in mind while determining the NAPLF for the purpose of incentive.

As mentioned earlier, since the Commission has followed the mechanism of linking incentive with the plant availability in the GERC MYT Regulations, 2011, the Commission did not specify the NAPLF in the GERC MYT Regulations, 2011. However, for the purpose of projecting total generation for determination of tariff, the Commission had approved trajectory for the Generating Stations of GSECL and TPL-G in their respective MYT Orders dated April 11, 2011 and September 6, 2011. Further, in the Mid-Term Review Order for TPL-G dated April 29, 2014, the Commission revised the target PLF for the Generating Stations of TPL-G for FY 2014-15 and FY 2015-16. The actual PLF achieved by the thermal Generating Stations vis-a-

vis the target PLF approved by the Commission in MYT/MTR Orders are as shown in the following Table:

Table 4-21: Approved and actual PLF for thermal generating stations

Generating Stations	Approved for determination of Tariff (%)					Actual PLF (%)			Average of actual PLF for three years from FY12 to FY14 (%)
	FY12	FY13	FY14	FY15	FY16	FY12	FY13	FY14	
GSECL Stations									
Ukai (1-5)	75.00	75.00	75.00	75.00	75.00	75.23	72.14	48.35	65.24
Gandhinagar (1-4)	79.00	79.00	79.00	79.00	79.00	66.86	40.52	12.19	39.86
Gandhinagar - 5*	85.00	85.00	85.00	85.00	85.00	87.35	88.02	66.28	80.55
Wanakbori 1-6 TPS	85.00	85.00	85.00	85.00	85.00	78.77	67.40	35.93	60.70
Wanakbori 7 TPS*	85.00	85.00	85.00	85.00	85.00	84.72	86.51	57.26	76.16
Sikka TPS	68.00	68.00	71.00	71.00	71.00	46.34	37.17	28.56	37.36
KLTPS 1-3	66.00	75.00	75.00	75.00	75.00	61.67	72.34	76.10	70.04
KLTPS 4	75.00	75.00	75.00	75.00	75.00	54.41	60.94	57.27	57.54
Duvaran (Gas 1)*	80.00	80.00	80.00	80.00	80.00	59.19	38.89	4.80	34.29
Duvaran (Gas 2)	80.00	80.00	77.00	80.00	80.00	46.00	49.39	16.18	37.19
Utran (Gas)*	80.00	80.00	80.00	80.00	80.00	47.37	32.81		26.73
Utran Extension*	80.00	80.00	80.00	80.00	80.00	73.74	17.27	0.25	30.42
Ukai 6#			85.00	85.00				38.68	38.68
Dhuvaran CCPP#3#			85.00	85.00					
Sikka (3-4) #				85.00					
TPL-G Stations									
C Station	78.54	80.18	78.19	87.62	69.35	76.39	86.06	74.80	79.08
D Station	83.59	85.41	79.88	81.03	75.12	85.13	90.33	87.51	87.66
E Station	80.74	64.25	81.33	91.54	76.13	84.75	87.67	54.58	75.67
F Station	82.97	65.77	82.62	91.03	78.56	87.01	62.21	81.27	76.83
Vatva Gas Station	88.56	81.88	76.48	-	-	52.08	14.29		33.19

* PPA based stations

For new generating stations, the approved PLF are taken from the Tariff Orders for respective years as these stations are not covered in the MYT Order.

From the above data of actual PLF of the generating Stations vis-a-vis the PLF approved by the Commission, is observed that for most of the Generating Stations not governed by PPA, the actual PLF has been very low. Among the Generating Stations not governed by PPA, none of the GSECL stations has achieved average PLF of more than 70.00%. Stations of TPL-G have achieved comparatively higher PLF.

In view of the actual PLF achieved by the generating stations as mentioned above, the NAPLF of 85% as specified by CERC in CERC Tariff Regulations, 2014 would be unachievable for most of the stations. Hence, for the purpose of incentive, it is suggested that the NAPLF of 85% for all except GSECL stations may be specified by for the next Control Period for all the thermal Generating Stations.

NAPLF for GSECL Stations have been specified as under:

Station	Target PLF (%)
Ukai TPS (Unit 1- 5)	80
Gandhinagar TPS (Unit 1- 4)	85
Wanakbori TPS (Unit 1-6)	85
Sikka TPS	80
Kutch Lignite (Unit 1-3)	80
Kutch Lignite (Unit 4)	80

For ex-bus generation in excess of generation corresponding to the normative NAPLF, incentive of 50 paise/kWh may be allowed to Generating Stations.

It is suggested that the Plant Load Factor may be defined as it is defined in the CERC Tariff Regulations, 2014 as reproduced below:

“Plant Load Factor”, in relation to thermal generating station or unit for a given period means the total sent out energy corresponding to actual generation during the period, expressed as a percentage of sent out energy corresponding to installed capacity in that period and shall be computed in accordance with the following formula:

$$PLF = \frac{10000 \times \sum_{i=1}^N SG_i}{\{ N \times IC \times (100 - AUX_n) \}} \%$$

where,

IC=Installed Capacity of the generating station in MW,

SG_i = Scheduled Generation in MW for the ⁱth time block of the period,

N = number of time blocks during the period, and

AUXn = Normative Auxiliary Consumption as a percentage of gross energy generation

4.3.9 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.

In this regard, the GERC MYT Regulations, 2011 specifies as reproduced below:

“59.8 Landed Cost of fuel:

The landed cost of fuel shall include price of fuel corresponding to the grade/quality/calorific value of fuel inclusive of royalty, taxes and duties as applicable, transportation cost by rail/road/gas pipe line 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 fuel dispatched by the fuel supply company during the month as specified in these Regulations.”

The aforementioned norm of GERC MYT Regulations, 2011 is in line with the CERC Tariff Regulations, 2014 and the same is suggested to be continued.

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 recent three to six 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.

The GERC MYT Regulations, 2011 is silent on the issue of how the cost of fuel may be determined for determination of Tariff. In this regard, the CERC Tariff Regulations, 2014 stipulates as reproduced below:

“23. Landed Fuel Cost for Tariff Determination: The landed fuel cost of primary fuel and secondary fuel for tariff determination shall be based on actual weighted average cost of primary fuel and secondary fuel of the three preceding months, and in the absence of landed costs for the three preceding months, latest procurement price of primary fuel and secondary fuel for the generating station, before the start of the tariff

period for existing stations and immediately preceding three months in case of new generating stations shall be taken into account.”

It is suggested that the aforementioned stipulation of CERC Tariff Regulations, 2014 regarding landed cost fuel for tariff determination may be included in the new GERC MYT Regulations.

4.4 Hydro Generating Stations

4.4.1 Components of Tariff and Recovery of Costs

The existing GERC Tariff Regulations, 2011 specify two-part tariff for sale of electricity from a hydro power generating station comprising of Capacity Charges and Primary Energy Charges. 50% of the total Annual Fixed Charges are recoverable by means of capacity charges, while the remaining 50% of the Annual Fixed Charges are recoverable by means of Energy Charges. In this regard, the Regulation 60.1 of the GERC MYT Regulations, 2011 is reproduced hereunder:

“60.1 The Annual Fixed Charges of a Hydro Generating Station shall be computed on annual basis, based on norms specified under these Regulations, and recovered on monthly basis under capacity charge (inclusive of incentive) and Energy Charge, which shall be payable by the beneficiaries in proportion to their respective share in the capacity of the generating station.”

Such provisions of the GERC MYT Regulations, 2011 are in line with the CERC Tariff Regulations, 2014, and are suggested to be continued.

Capacity Charge (Including incentive/disincentive)

According to the provisions of the GERC MYT Regulations, 2011, the Capacity Charges are linked with the Availability, and are fully recoverable at Availability of 80%. Achievement of availability above or below normative Availability shall result into proportionate over or under recovery of the capacity charges respectively, and hence, would become incentive or disincentive. The provisions of the GERC MYT Regulations, 2011 regarding the Capacity Charge of the hydro generating stations are as reproduced below:

“60.2 The capacity charge (inclusive of incentive) payable to a hydro generating station for a calendar month shall be:

$AFC \times 0.5 \times NDM / NDY \times (PAFM / NAPAF)$ (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.

60.3 The PAFM shall be computed in accordance with the following formula :

$$PAFM = 10000 \times \sum_{i=1}^N DC_i / \{ N \times IC \times (100 - AUX) \} \%$$

Where;

AUX = Normative auxiliary energy consumption in percentage;

DC_i = Declared capacity (in ex-bus MW) for the *i*th day of the month which the station can deliver for at least three (3) hours; as certified by the Gujarat State Load Despatch Centre after the day is over.

IC = Installed capacity (in MW) of the complete generating station;

N = Number of days in the month."

The provisions of regarding Capacity Charge of hydro generating stations are in line with the provisions of CERC Tariff Regulations, 2014 and are proposed to be continued.

Energy Charge

As regards rate of Energy Charges, GERC MYT Regulations, 2011 specifies as reproduced below:

"60.4 The Energy Charge shall be payable by every beneficiary for the total energy supplied to the beneficiary 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 { Energy (ex-bus)} for the month in kWh

60.5 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:

$$ECR = AFC \times 0.5 \times 10 / \{ DE \times (100 - AUX) \};$$

Where;

DE = Annual Design Energy specified for the hydro generating station, in MWh, subject to the provision in Regulation 60.6 below.

60.6 In case actual total energy generated by a Hydro Generating Station during a year is less than the Design Energy for reasons beyond the control of the Generating Company, the following treatment shall be applied on a rolling basis:

(i) in case the energy shortfall occurs within ten years from the date of commercial operation of a generating station, the ECR for the year following the year of energy shortfall shall be computed based on the formula specified in these Regulations with the modification that the DE for the year shall be considered as equal to the actual energy generated during the year of the shortfall, till the Energy Charge shortfall of the previous year has been made up, after which normal ECR shall be applicable;

(ii) in case the energy shortfall occurs after ten years from the date of commercial operation of a generating station, the following shall apply:

Suppose the specified annual Design Energy (DE) for the station is DE MWh, and the actual energy generated during the relevant (first) and the following (second) financial years are A1 and A2 MWh, respectively, A1 being less than DE. Then, the Design Energy to be considered in the formula in these Regulations for calculating the ECR for the third financial year shall be moderated as (A1 + A2 - DE) MWh, subject to a maximum of DE MWh and a minimum of A1 MWh;

(iii) Actual energy generated (e.g., A1, A2) shall be arrived at by multiplying the net metered energy sent out from the station by 100 / (100 - AUX).

60.7 In case the Energy Charge Rate (ECR) for a hydro generating station, as computed in Regulation 60.5 above, exceeds eighty paise per kWh, and the actual saleable energy in a year exceeds { DE x (100 - AUX) / 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 the 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.

60.8 The Gujarat State Load Despatch Centre shall finalise the schedules for the hydro generating stations, in consultation with the beneficiaries, for optimal utilization of all the energy declared to be available, which shall be scheduled for all beneficiaries in proportion to their respective allocations in the generating station."

The aforementioned provisions of GERC MYT Regulations, 2011 regarding the energy charge of the hydro generating stations are in line with the provisions of the CERC Tariff Regulations, 2014, except for some minor differences. The relevant provisions of the CERC Tariff Regulations, 2014 are as reproduced below:

*"(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):

$$ECR = AFC \times 0.5 \times 10 / \{ DE \times (100 - AUX) \times (100 - FEHS) \}$$

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 42.

(6) In case the actual total energy generated by a hydro generating station during a year is less than the design energy for reasons beyond the control of the generating station, the following treatment shall be applied on a rolling basis on an application filed by the generating company:

(a) In case the energy shortfall occurs within ten years from the date of commercial operation of a generating station, the ECR for the year following the year of energy shortfall shall be computed based on the formula specified in clause (5) with the modification that the DE for the year shall be considered as equal to the actual energy generated during the year of the shortfall, till the energy charge shortfall of the previous year has been made up, after which normal ECR shall be applicable:

Provided that in case actual generation from a hydro generating station is less than the design energy for a continuous period of 4 years on account of hydrology factor, the generating station shall approach CEA with relevant hydrology data for revision of design energy of the station.

(b) In case the energy shortfall occurs after ten years from the date of commercial operation of a generating station, the following shall apply.

Explanation : Suppose the specified annual design energy for the station is DE MWh, and the actual energy generated during the concerned (first) and the following (second) financial years is A1 and A2 MWh respectively, A1 being less than DE. Then, the design energy to be considered in the formula in clause (5) of these regulations for calculating the ECR for the third financial year shall be moderated as $(A1 + A2 - DE)$ MWh, subject to a maximum of DE MWh and a minimum of A1 MWh.

(c) Actual energy generated (e.g. A1, A2) shall be arrived at by multiplying the net metered energy sent out from the station by $100 / (100 - AUX)$.

(7) In case the energy charge rate (ECR) for a hydro generating station, computed as per clause (5) of this regulation exceeds **ninety paise per kWh**, and the actual saleable energy in a year exceeds $\{ DE \times (100 - AUX) \times (100 - FEHS) / 10000 \}$ MWh, the Energy charge for the energy in excess of the above shall be billed at **ninety 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 ninety paise per kWh after the energy charge shortfall of the previous year has been made up..."(Emphasis Added)

Thus, CERC Tariff Regulations, 2014 also considers allocation of free energy for the home State in the formulae of Energy charge and Energy Charge Rate, which is not relevant in the case of State-owned hydro stations in Gujarat.

CERC Tariff Regulations, 2014 provides that in case the actual generation from a hydro generating station is less than the design energy for a continuous 4 years in the first 10 years from the COD on account of hydrology factor, the generating station shall approach CEA with relevant hydrology data for revision of design energy of the station. The Commission may decide whether such provision may be included in the new GERC MYT Regulations.

Further, in GERC MYT Regulations, 2011, Energy Charge Rate (ECR) of a hydro generating station is capped at 80 paise/kWh in case the actual saleable energy in a year exceeds $\{DE \times (100-AUX) \times 10000\}$ MWh. As per CERC Tariff Regulations, 2014 Energy Charge Rate (ECR) of a hydro generating station is capped at 90 paise/kWh in case the actual saleable energy in a year exceeds $\{DE \times (100-AUX) \times (100-FEHS)/10000\}$ MWh. Hence, it is proposed to increase such cap on Energy Charge Rate to 90 paise/kWh from the present provision of 80 paise/kWh.

Thus, the current provisions regarding the Energy Charge are suggested to be continued in the new GERC MYT Regulations.

4.4.2 Norms of Operation

The norms of operation for hydro generating stations shall include the norms for Normative Annual Plant Availability Factor (NAPAF), auxiliary energy consumption and transformation loss.

4.4.2.1 Normative Annual Plant Availability Factor (NAPAF)

New Hydro Generating Stations:

The GERC MYT Regulations, 2011 specifies the NAPAF for the new hydro generating stations as reproduced below:

“57.2 The norms of operation for other hydro generating stations for recovery of annual fixed charges, shall be as under:

Table 15: Normative Annual Plant Availability Factor for new Hydro Generating Stations

Particulars	Normative Annual Plant Availability Factor
<i>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</i>	90%
<i>Storage and Pondage type plants with head variation between FRL and MDDL of more than 8%, where plant availability is not affected by silt</i>	<i>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</i>
<i>Pondage type plants where plant availability is significantly affected by silt</i>	85%
<i>Run-of-river type plants</i>	<i>To be determined plant-wise, based on 10-day design energy data, moderated by past experience where available/relevant</i>

It is suggested that the NAPAF for new hydro generating stations may be specified as specified in the CERC Tariff Regulations, 2014 as shown below:

- (1) The following Normative annual plant availability factor (NAPAF) shall apply to hydro generating station:

- (a) 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%
 - (b) In case of storage and pondage type plants with head variation between full reservoir level and minimum draw down level is more than 8% and when plant availability is not affected by silt, the month wise peaking capability as provided by the project authorities in the DPR (approved by CEA or the State Government) shall form basis of fixation of NAPAF.
 - (c) Pondage type plants where plant availability is significantly affected by silt: 85%
 - (d) Run-of-river type plants: NAPAF to be determined plant-wise, based on 10-day design energy data, moderated by past experience where available/relevant.
- (2) 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.
- (3) In case of Pumped storage hydro generating stations, the quantum of electricity required for pumping water from down-stream reservoir to up-stream reservoir shall be arranged by the beneficiaries duly taking into account the transmission and distribution losses, etc., up to the bus bar of the generating station. In return, beneficiaries shall be entitled to equivalent energy of 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir from the generating station during peak hours and the generating station shall be under obligation to supply such quantum of electricity during peak hours:

Provided that in the event of the beneficiaries failing to supply the desired level of energy during off-peak hours, there will be pro-rata reduction in their energy entitlement from the station during peak hours.

Existing Hydro Generating Stations:

For the existing hydro generating stations, namely, Ukai Hydro Station and Kadana Hydro Station, the NAPAF has been specified as 80% in GERC MYT Regulations, 2011. The CERC Tariff Regulations, 2014 stipulates same norms of NAPAF for existing and new hydro generating stations.

In its MYT Order dated April 11, 2011, the Commission had approved NAPAF for the existing hydro generating stations based GERC MYT Regulations, 2011. The normative and actual availability of the hydro generating stations is as shown in the following Table:

Table 4-22: Normative and actual availability of hydro generating stations

Generating Stations	NAPAF for second Control Period (%)	Actual availability (%)			Average of actual plant availability for three years from FY 11 to FY 13 (%)
		FY 12	FY 13	FY 14	
Ukai Hydro	80.00	89.49	87.56	94.10	90.38
Kadana Hydro	80.00	88.68	70.82	82.52	80.67

From the actual availability of the hydro generating stations, it is observed that the average actual availability of both these stations in the three years from FY 2011-12 to FY 2013-14 is significantly higher than the normative availability specified for the second Control Period. The actual average availability for the said three years for the Ukai Hydro Station and Kadana Hydro Station has been 89.55% and 86.15%, respectively. Ukai Hydro Station has achieved availability more than NAPAF in all three years, whereas the Kadana Hydro Station fell short in FY 2012-13 when it achieved availability of 70.82% as against the NAPAF of 80%. Though the average availability of these stations has been higher than NAPAF, it is observed that GSECL has mentioned in its Petition for truing up for FY 2012-13 that operation of these stations depend on the instruction of the Irrigation Department of Government of Gujarat.

In view of the above, the current norm of NAPAF of 80% for the existing hydro stations is proposed to be continued for the next Control Period.

4.4.2.2 Auxiliary energy consumption and transformation loss

New Hydro Generating Stations:

The GERC MYT Regulations, 2011 specifies the normative auxiliary energy consumption for the new hydro generating stations as reproduced below:

“57.3 Auxiliary Energy Consumption:

(a) Surface hydro electric power generating stations:

- i. With rotating exciters mounted on the generator shaft: 0.70%;
- ii. With static excitation system: 1.00%;

(b) *Underground hydro generating station:*

- i. With rotating exciters mounted on the generator shaft: 0.90%;
- ii. With static excitation system: 1.20%. “

The aforementioned norms for auxiliary energy consumption of the hydro generating stations specified in GERC MYT Regulations, 2011 are in line with the norms specified by CERC Tariff Regulations, 2014 and the same are proposed to be continued.

The Regulation 57.4 of the GERC MYT Regulations, 2011 specifies that 0.50% of the energy generated shall be considered as transmission loss in conversion of energy from generation voltage to transmission voltage. The CERC Tariff Regulations, 2014 does not specify such separate norms regarding the transformation loss of the hydro generating stations. Hence, it is proposed to remove such norm for the transformation losses as the same is already included in the norm for auxiliary consumption specified by CERC.

Existing Hydro Generating Stations

The CERC, in CERC Tariff Regulations, 2014 has specified common norms for existing as well as new hydro generating stations. In GERC MYT Regulations, 2011, the normative auxiliary energy consumption, including transformation losses, specified for Ukai Hydro Station and Kadana Hydro Station is 0.70% and 1.19% respectively. The Commission, in its MYT Order dated April 11, 2011 had specified the normative auxiliary energy consumption for the two hydro generating stations based on the GERC MYT Regulations, 2011. The actual auxiliary energy consumption of the hydro generating stations vis-a-vis the normative auxiliary energy consumption for the second Control Period is shown in the following Table:

Table 4-23: Normative and actual auxiliary energy consumption for the hydro generating stations

Generating Stations	Normative auxiliary energy consumption, including transformation loss for second Control Period	Actual auxiliary energy consumption (%)			Average of actual auxiliary energy consumption for three years from FY 12 to FY 14 (%)
		FY 12	FY 13	FY 14	

	(%)				
Ukai Hydro	0.70	0.55	0.58	0.58	0.57
Kadana Hydro	1.19	1.02	1.13	1.92	1.36

As regards Ukai Hydro Station, the average actual auxiliary consumption (including transformation loss, for the three years from FY 2011-12 to FY 2013-14 has been 0.57%. In view of the same, the normative auxiliary energy consumption including transformation loss for Ukai Hydro Station for the next Control Period may be specified as 0.6%.

The Kadana Hydro Station achieved actual auxiliary energy consumption (including transformation loss) of 1.02%, 1.13% and 1.92% in FY 2011-12, FY 2012-13 and FY 2013-14 respectively, and hence, the average actual auxiliary energy consumption of the station for the said three years is 1.36%, which is higher than the normative auxiliary energy consumption of 1.19% specified for the second Control Period. However, there is no justification for the higher auxiliary consumption for Kadana hydro station, and hence, it is proposed that the normative auxiliary energy consumption including transformation loss for the station may be revised to 1.0% for the next Control Period.

4.4.3 Operation and Maintenance expenses

New hydro generating stations

The current norm for the O&M expenses for the new hydro generating stations specified in GERC MYT Regulations, 2011, is as reproduced below:

“58.2 For New Stations:

- (1) O&M expenses for the first year of operation will be 2% of the original project cost (excluding cost of rehabilitation and resettlement works).*
- (2) The O&M expenses for each subsequent year will be determined by escalating the base expenses determined above, at the escalation factor of 5.72%.”*

With regard to the O&M expenses for the new hydro generating stations, it is suggested that the existing O&M expenses norm may be continued.

Existing hydro generating stations:

As mentioned earlier, GERC has been specifying consolidated O&M expenses for the generation business. This approach is in line with the approach adopted by CERC in the CERC Tariff Regulations, 2014. Hence, it is suggested that for the generation business, the approach for specifying the consolidated O&M expenses be continued.

The norms for O&M expenses in the GERC MYT Regulations, 2011 for the existing hydro generating stations is as reproduced below:

“58 Operation and Maintenance Expenses for Hydro Generating Stations

58.1 For Existing Stations:

- 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 at the escalation factor of 4 % to arrive at operation and maintenance expenses for FY 2011-12.*
- c) *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 of 5.72% to arrive at permissible O&M expenses for each year of the Control Period.”*

Hence, as regards the O&M expenses for the existing hydro Generating Stations, the GERC MYT Regulations, 2011 specifies principles rather than the norms.

The Commission, in its MYT Order dated April 11, 2011 had approved the plant wise O&M expenses based on the principles set in the GERC MYT Regulations, 2011. The normative and actual O&M expenses for the existing hydro generating stations are as shown in the following Table:

Table 4-24: Normative and Actual O&M expenses for the hydro generating stations

S.N	Power stations	Normative					Actual		
		FY12	FY13	FY14	FY15	FY16	FY12	FY13	FY14
1	Ukai Hydro	11.48	12.14	12.83	13.56	14.34	12.63	11.29	9.26
2	Kadana Hydro	13.20	13.96	14.75	15.60	16.49	15.09	16.51	16.87

It is observed that the O&M expenses for Ukai hydro generating station for FY 2011-12 is Rs. 12.63 crore, which is higher than the normative O&M expense of Rs. 11.48 crore for FY 2011-12. However, for FY 2012-13 and FY 2013-14, the actual O&M expense for Ukai hydro station is lower than the normative O&M expense for the year. In case of Kadana Hydro generating station, the actual O&M expenses for FY 2011-12, FY 2012-13 and FY 2013-14 have been Rs. 15.09 crore, Rs. 17.43 crore and 18.59 Crore respectively, which are significantly higher than the normative O&M expense of Rs. 13.20 crore, Rs. 13.96 crore and 14.75 Crore for the respective years.

It is suggested that the normative O&M expenses for the next Control Period be determined after modifying the existing escalation rate of the existing principle to 5.72% from 4%.

The suggested clauses are 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, 2015, 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, 2014 and shall be escalated at the escalation factor of 5.72% to arrive at operation and maintenance expenses for subsequent years up to FY 2020-21."

4.4.4 Treatment of Infirm Power

GERC MYT Regulations, 2011 does not include any provision regarding treatment of infirm power generated by hydro generating stations. As mentioned earlier, CERC Tariff Regulations, 2014 has linked the rate of the infirm power to the deviation settlement mechanism, wherein the price of energy is determined based on the prevailing grid frequency. However, due to certain disadvantages such as de-linking of the tariff with cost, uncertainty of price of power sold as infirm power, and possibility of artificial increase in the price when the cost of generation is far lower

than the prevailing UI rate, it is suggested that the price of infirm power may not be linked to the grid frequency.

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. In view of the above it is proposed to add one additional clause in the draft Regulation under the heading "Sale of Infirm Power" which says:

"The tariff for sale of infirm power from a hydro-electric generating station to the Distribution Licensee shall be equivalent to the energy charge rate for the first financial year and revenue recovered from sale of infirm power shall be deducted from the capital cost."

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

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

Gujarat Energy Transmission Corporation Limited (GETCO) was set up in May 1999 and is registered under the Companies Act, 1956. The Company was promoted by erstwhile Gujarat Electricity Board (GEB) as its wholly owned subsidiary as a part of unbundling of the Power Sector. 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, hereinafter referred as 'GETCO'.

The Energy and Petrochemical Department, Government of Gujarat vide its Notification Ref: GHU-2004, 31-GEB-1104-2946-K dated the May 29, 2004 under Section 39 of the Electricity Act, 2003 (36 of 2003) and in supersession of Govt. Notification, Energy and Petrochemical Department No:GHU-99-5-GEB-1198-6329-K dated January 25, 1999 has notified 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.

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 centers within the State.

5.2 Key issues in Transmission for the next Control Period

As discussed in the Preliminary Analysis Report, the key issues in respect of formulation of Tariff Regulations for the Transmission business for the next Control Period can be categorised into four broad categories, as under:

A] Guidance of Regulations notified by CERC and amendments thereof

- As the SERCs are required to be guided by the Tariff Regulations notified by the CERC, the new/modified definitions, norms, principles, etc., as specified in the CERC (Terms and Conditions of Tariff) Regulations, 2014 notified in

February 2014, need to be analyzed and suitably incorporated in the GERC MYT Regulations for the next Control Period.

- CERC has amended the CERC (Sharing of Inter State Transmission Charges and Losses) Regulations, 2010 from time to time; these amendments along with other developments if any, have to be considered and addressed appropriately, while formulating the Regulations for the next Control Period.

B] Incorporation of various APTEL / HC / SC Judgments

- Relevant Judgments of APTEL/High Court/Supreme Court are also needed to be suitably incorporated/addressed, while formulating the Tariff Regulations for the next Control Period.

C] SLDC Budget

- Various implications and benefits need to be studied for taking a decision on whether the SLDC Fees & Charges Regulations need to be merged with the GERC MYT Regulations, or should continue to operate independently.

D] Regulating performance of transmission licensees

- The operating norms and O&M norms for GETCO have to be reset based on the actual performance vis-a-vis the specified norms over the past four years. We have studied the data and information forwarded by the Commission in this regard and have proposed appropriate revised operational norms as well as O&M norms for the next Control Period.

All the above issues have been appropriately addressed in the subsequent sections.

5.3 Regulatory Developments at State and Central level

As regards the sharing of charges for intra-State transmission network, Regulation 74 of the GERC MYT Regulations, 2011, specifies as under:

“74 Sharing of charges for intra-State Transmission Network

74.1 Determination of Monthly Transmission Tariff (MTT):

74.1.1 The aggregate of the yearly revenue requirement for all Transmission Licensees, less the deductions, as approved by the Commission over the Control Period, shall form the "Total Transmission Cost" (TTC) of the Intra-State transmission system, to be recovered from the Long term and Medium term Transmission System Users (TSUs) for the respective year of the Control Period, in accordance with the following Formula:

$$TTC(t) = \sum_{i=1}^n (ARR_i - NT_i - O_i) - STR_{(t-2)}$$

Where,

TTC (t) = Total Transmission Cost of year (t) of the Control Period

n = Number of Transmission Licensee(s)

ARR_i = Aggregate Revenue Requirement approved by the Commission for *i*th Transmission Licensee for the yearly period (t) of the Control Period

NT_i = Approved level of non-tariff income for *i*th Transmission Licensee for the yearly period (t) of the Control Period.

O_i = Approved level of income from other business of the *i*th Transmission Licensee for the yearly period (t) of the Control Period

STR(t-2) = Revenue from short term open access charges earned during previous yearly period (t-2):

Provided that the revenue from short-term open access charges for each yearly period (t) of Control Period shall be taken to be same as that prevalent during the yearly period one year before the commencement of the Control Period. However, the adjustments due to variation in actual revenue from short term open access charges shall be undertaken during annual truing up:

Provided further that ARR of the Transmission Licensee in case of competitively bid transmission projects shall be Transmission Service Charge (TSC) for relevant yearly period as adopted by the Commission in accordance with Section 63 of the Act.

74.1.2 The Total Transmission Cost (TTC) as determined by the Commission as per Regulation 74.1.1 above, shall be shared by all long-term and medium-term open access customers on monthly basis (including existing Distribution Licensees) in the ratio of their allotted capacities, in accordance with the following formula:

Monthly Transmission Tariff (MTT) = $TTC / (ACs \times 12)$ (in Rs./MW/month);

Where;

TTC = Total Transmission Cost determined by the Commission for the transmission system for the relevant year (in Rs), and

ACs = sum of capacities allocated to all long-term and medium-term open access customers in MW.

Provided that Monthly Transmission Tariff shall also be shared by a Generating Company if power from such Generating Company is sold to a consumer outside the State of Gujarat, to the extent of capacity contracted outside the State:

Provided further that the transmission tariff payable by any long-term or medium-term open access customer utilizing the transmission system for part of a month shall be determined as under:

Transmission Tariff = $TTC / (ACs \times 8760)$ (in Rs./MWh);

Where;

TTC = Total Transmission Cost determined by the Commission for the transmission system for the relevant year (in Rs), and MYT Regulations 2011 Page 73 of 92

ACs = sum of capacities allocated to all long-term and medium-term open access customers in MW. "

In this regard, Regulations 3 and 43 of the CERC (Terms and Conditions of Tariff) Regulations, 2014, specifies as under:

"3. Definitions and Interpretations.-In these regulations, unless the context otherwise requires-

..... (57) 'Sharing Regulations' means Central Electricity Regulatory Commission (Sharing of Transmission Charges and Losses in inter-State Transmission System) Regulations, 2010 as amended from time to time;"

"43. Sharing of Transmission Charges:

(1) The sharing of transmission charges shall be governed by the Sharing Regulations.

(2) The charges determined in this regulation in relation to communication system forming part of transmission system shall be shared by the beneficiaries or long term transmission customers in accordance with the Sharing Regulations:

Provided that charges determined in this regulation in relation to communication system other than central transmission system shall be shared by the beneficiaries in proportion to the capital cost belonging to respective beneficiaries."

As reproduced above, the Central Electricity Regulatory Commission has notified Regulations on pricing methodology for inter-State transmission, to make it in line with the requirements of National Electricity Policy and Tariff Policy. The salient features of the CERC (Sharing of Inter State Transmission Charges and Losses) Regulations, 2010 and amendments thereof are given below:

- a) Based on the yearly Transmission Charges of ISTS Transmission Licensees and transmission losses in the ISTS network, the Implementing Agency shall compute the Point of Connection charges and Loss Allocation Factors for all DICs:
 - i. Using load-flow based methods; and
 - ii. Based on the Point of Connection charging method;
- b) The Point of Connection (PoC) methodology is based on a hybrid method, which brings together the strengths of both the Marginal Participation and the Average Participation Method;
- c) The sharing of ISTS transmission charges between designated ISTS customers shall be computed for an application period and shall be determined in advance and shall be subject to periodic true-up as specified subsequently in the Regulations;
- d) The sharing of ISTS transmission charges shall be based on the technical and commercial information provided by various designated ISTS customers, ISTS Transmission Licensees, and any other relevant entity, including the NLDC, RLDCs and SLDCs, to the Implementing Agency;
- e) The mechanism for sharing of ISTS charges shall ensure that:-
 - The yearly Transmission Charge of the ISTS Licensees are fully and exactly recovered; and
 - Any adjustment towards yearly Transmission Charge on account of change in commissioning schedule of elements of the power system and change in factors constituting the transmission charge, approved by the Commission, e.g., FERV, Changes in interest rates shall be fully and exactly recovered, etc., as specified subsequently in the Regulations;
- f) The Point of Connection transmission charges shall be computed in terms of Rupees per Mega Watt per month and transmission charges for short-term open access transactions shall be in terms of Rupees per Mega Watt hour and shall be applicable for the duration of short-term open access approved by the RLDC/NLDC.

- g) The applicable transmission losses for the ISTS shall be declared in advance and shall not be revised retrospectively.

This method was introduced to address the problems in the application of the regional Postage Stamp method, which required all the users of a system in a region to pay same price/MW of allotted transmission capacity. However, due to increasing short-term transactions over the grid, allotment of power plant capacities of one region to the beneficiaries in the other regions, etc., the grid and its usage is getting more and more complex every day. Some of the main triggers are change in the configuration of ISTS, changing nature of use of transmission system by various other users and problem of pancaking, etc.

In this regard, the implementation of the distance sensitive approach in the State of Gujarat would require the following aspects to be addressed:

- a) Whether the system data for implementation of POC charge method is available in the State.
- b) Careful evaluation of implications for various distribution companies (DISCOMs) on account of power flow from source (generating stations) to various regions.
- c) The POC method is yet to be fully implemented by CERC, and a hybrid approach is presently in force.

Hence, at this stage, considering the fact that the Postage Stamp approach is simple, easy to understand and implement, and is also a time tested approach, it may be preferable to continue with the uniform Postage Stamp approach across the State of Gujarat. Accordingly, the following clauses are proposed for determination of Transmission Charges:

"Determination of Transmission Charges

- (i) The transmission charges for access to and use of the transmission system of the Transmission Licensee shall comprise of the following:-
 - a) transmission system access charges; and
 - b) transmission charges.
- (ii) The annual transmission charges shall be determined by the Commission in such a way that the aggregate revenue requirement of the Transmission Licensee for the financial year as approved by the Commission is recovered.

- (iii) The annual transmission charges of the Transmission Licensee shall be determined by the Commission on the basis of an application made by the Transmission Licensee, for the determination of tariff, in accordance with Chapter 2 of these Regulations."

Further, the existing system of pooling of the ARR of the Transmission Licensees is not required, as there is only one Transmission Licensee in the State, i.e., GETCO, and the methodology for Sharing of charges for intra-State Transmission Network needs to be simplified. Further, the mechanism for sharing of Transmission Charges by long-term, medium-term, and short-term users, and group collective transactions (Exchange) needs to be specified.

Accordingly, it is proposed to adopt the following methodology for Sharing of charges for intra-State Transmission Network:

- a) The Aggregate Revenue Requirement of the Transmission Licensee, as approved by the Commission, shall be shared by all long-term users and medium-term users of the transmission system on monthly basis in the ratio of their respective contracted transmission capacities to the total contracted transmission capacity, in accordance with the following formula:-

$$ATC_n = (\text{Transmission ARR} \times CC_n \div SCC) \div 12$$

Where,-

ATC_n = annual transmission charges payable by the nth long-term user or medium-term user of the transmission system;

Transmission ARR = Aggregate Revenue Requirement of the Transmission Licensee, determined in accordance with Regulation 69 of these Regulations;

CC_n = capacity contracted in MW by the nth long-term user or medium-term user of the transmission system;

SCC = sum of capacities contracted in MW by all long-term users and medium-term users of the transmission system;

Provided that the ATC_n shall be payable on monthly basis by each long-term user or medium-term user of the transmission system and shall be collected by the State Transmission Utility (STU).

- b) The short-term users of the transmission system shall pay transmission charges on Rs/MW/day basis, in accordance with the following formula:-

$$TC \text{ (Rs/MW/day)} = (\text{Transmission ARR} \div \text{SCC}) \div 365,$$

Where,-

TC (Rs/MW/day) = transmission charges payable by the short-term user of the transmission system;

Transmission ARR = Aggregate Revenue Requirement of the Transmission Licensee, determined in accordance with Regulation 69 of these Regulations;

SCC = sum of capacities contracted in MW by all long-term users and medium-term users of the transmission system:

- c) For short-term collective transactions through power exchanges, Transmission Charges shall be denominated in Rs/kWh terms, in accordance with the following formula:-

$$TC \text{ (Rs/kWh)} = \text{Transmission ARR} \div \text{Total units wheeled},$$

Where,-

TC (Rs/kWh) = Transmission Charges payable in the case of short-term collective transactions through power exchanges;

Transmission ARR = Aggregate Revenue Requirement of the Transmission Licensee, determined in accordance with Regulation 69 of these Regulations;

Total units wheeled = total energy units wheeled through the transmission system, which shall be equal to the total energy input into the intra-State transmission system during the financial year.

- d) The revenue from short-term open access charges for each yearly period (t) of Control Period shall be taken to be same as that prevalent during the yearly period one year before the commencement of the Control Period. However, the adjustments due to variation in actual revenue from short-term open access charges shall be undertaken during annual truing up.
- e) The consequential impact of any Government of India scheme for waiver/reduction of transmission charges for any entity/ies, on the transmission charges payable by the other entities, shall be addressed through separate Orders to be issued by the Commission from time to time.

5.5 *Regulating Transmission Licensees & Performance Standards*

5.5.1 Availability Norms for Incentive

In line with the CERC approach, the Availability norms for earning incentive have been specified slightly higher than the Availability norm for ensuring full recovery of fixed charges. Certain other provisions have also been introduced, in accordance with the CERC Tariff Regulations, 2014, as under:

- (i) For Incentive consideration:
 - (a) AC system : 98.5 per cent;
 - (b) HVDC bi-pole links and HVDC back-to-back stations : 96 per cent;

Provided that for new HVDC stations, Target Availability shall be considered as 95% for first three years of operations for the purpose of incentive:

Provided further that no incentive shall be payable for availability beyond 99.75%:

Provided also that for AC system, two trippings per year shall be allowed, and after two trippings in a year, additional 12 hours outage shall be considered in addition to the actual outage:

Provided also that in case of outage of a transmission element affecting evacuation of power from a generating station, outage hour shall be multiplied by a factor of 2.

5.5.2 Regulating Operating Performance: O&M Norms

In GERC (MYT) Regulations, 2011, the O&M norms have been specified as reproduced below:

“71.5 Operation and Maintenance expenses:

71.5.1 Existing Transmission Licensee:

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

Particulars	FY 2011-12	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16
O&M Expenses/Bay	5.76	6.09	6.44	6.81	7.19
O&M Expenses/ ckt km	0.49	0.52	0.55	0.58	0.61

71.5.2 For New Transmission Licensee:

For the New transmission licensees, the year-wise O&M norms shall be determined on case to case basis:

Provided that the same shall not be applicable to those new projects, which are awarded on a competitive bidding basis. "

The CERC (Terms and Conditions of Tariff) Regulations, 2014 has specified the norms for O&M expenses for Transmission Licensees handling inter-State transmission of power, wherein voltage-wise norms as well as separate norms for line assets and substation assets have been specified, as reproduced below:

"29. Operation and Maintenance Expenses:

..... **(3) Transmission system**

(a) The following normative operation and maintenance expenses shall be admissible for the transmission system:

Norms for sub-stations (in Rs Lakh per bay)	2014-15	2015-16	2016-17	2017-18	2018-19
765 kV	84.42	87.22	90.12	93.11	96.2
400 kV	60.3	62.3	64.37	66.51	68.71
220 kV	42.21	43.61	45.06	46.55	48.1
132 kV and below	30.15	31.15	32.18	33.25	34.36
400 kV Gas Insulated Substation	51.54	53.25	55.02	56.84	58.73
Norms for AC and HVDC lines (in Rs Lakh per km)					
Single Circuit (Bundled Conductor with six or more sub-conductors)	0.707	0.731	0.755	0.78	0.806
Single Circuit (Bundled Conductor with four sub-conductors)	0.606	0.627	0.647	0.669	0.691
Single Circuit (Twin & Triple Conductor)	0.404	0.418	0.432	0.446	0.461
Single Circuit (Single Conductor)	0.202	0.209	0.216	0.223	0.23
Double Circuit (Bundled conductor with four or more sub-conductors)	1.062	1.097	1.133	1.171	1.21
Double Circuit (Twin & Triple Conductor)	0.707	0.731	0.755	0.78	0.806
Double Circuit (Single Conductor)	0.303	0.313	0.324	0.334	0.346

<i>Multi Circuit (Bundled conductor with four or more sub-conductors)</i>	1.863	1.925	1.989	2.055	2.123
<i>Multi Circuit (Twin & Triple Conductor)</i>	1.24	1.282	1.324	1.368	1.413
Norms for HVDC Stations					
<i>HVDC Back-to-back stations (Rs. Lakh per 500 MW)</i>	578	627	679	736	797
<i>Rihand-Dadri HVDC bi-pole scheme (Rs. Lakh)</i>	1511	1637	1774	1922	2082
<i>Talcher-Kolar HVDC bi-pole scheme (Rs. Lakh)</i>	1173	1271	1378	1493	1617
<i>Balia-Bhiwadi HVDC bi-pole scheme (Rs. Lakh)</i>	1537	1666	1805	1955	2119

Provided that operation and maintenance expenses for new HVDC bi-pole scheme for a particular year shall be allowed pro-rata on the basis of normative rate of operation and maintenance expense for 2000 MW, Talcher-Kolar HVDC bi-pole scheme for the respective year:

Provided further that the O&M expenses norms for HVDC bi-pole line shall be considered as Single Circuit quad AC line.

(b) The total allowable operation and maintenance expenses for the transmission system shall be calculated by multiplying the number of bays and kms of line length with the applicable norms for the operation and maintenance expenses per bay and per km respectively.

(c) The operation and maintenance expenses of communication system forming part of inter-state transmission system shall be derived on the basis of the actual O&M expenses for the period of 2008-09 to 2012-13 based on audited accounts excluding abnormal variations if any after prudence check by the Commission. The normalized O&M expenses after prudence check, for the years 2008-09 to 2012-13 shall be escalated at the rate of 3.02% for computing base year expenses for FY 2012-13 and 2013-14 and at the rate of 3.32% for escalation from 2014-15 onwards."

It may be noted that the normative O&M expenses allowed by CERC for PGCIL are much higher than that specified by SERCs, which may be on account of the fact that the PGCIL network comprises largely of 400 kV and 220 kV transmission system, whereas the voltages at State level are primarily 66 kV and 220 kV with a smaller share of 132 kV and 400 kV lines. Further, the CERC norms have been specified after taking into account the prudently incurred O&M expenses incurred by PGCIL. As long as similar treatment of specifying the O&M norms based on the prudently incurred O&M expenses is followed, the State Transmission Utilities will not be at any disadvantage and

will be able to recover the prudently incurred O&M expenses incurred by them.

In view of the above, for the next Control Period, the O&M norms for the transmission business are proposed to be specified, based on past trends to derive O&M expenses per bay and per ckt km. 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 O&M expenses on per bay and per km basis, respectively. GETCO's operations are mainly at the voltage levels of 66 kV and 220 kV, though GETCO also has 400 kV and 132 kV transmission systems. However, the break-up of O&M expenses incurred across different voltages is not available; hence, it is not proposed to specify voltage-level O&M norms.

5.3.1.3 Norms for O&M expenditure for intra-State Transmission Licensee(s) for third Control Period

For determination of O&M norms, O&M expenses are needed to be allocated amongst substation bays and ckt-km in some ratio depending on ratio of gross fixed asset (GFA) for substations and transmission lines, and manpower required to cater to bays and lines. While determining the O&M norms, the total O&M expenses have to be allocated in some ratio between transmission bays and transmission lines, based on which, the normative O&M expense per circuit-km and O&M expense per bay has to be calculated. In this regard, the CERC in the CERC (Terms and Conditions of Tariff) Regulations, 2014 for the Control Period from FY 2014-15 to FY 2018-19, has considered the ratio between substations and transmission lines as 75:25. Similarly, the ratio has been considered as 70:30 in Rajasthan and Maharashtra, whereas in Kerala, the ratio has been considered as 60:40. For determining the O&M norms for the next Control Period, we have considered the ratio for allocation of O&M expenses between transmission bays and transmission lines as 70:30, which is in concurrence with the approach adopted for the previous Control Period. The appropriate ratio to be considered, i.e., 75:25, 70:30 or 60:40, shall be finalised in consultation with the Commission.

For deriving the O&M norms for the next Control Period, we have compared the actual O&M expense incurred by GETCO with the normative O&M expenses allowed by the Commission over the years at the time of truing up, as shown in the Table below:

Table 5-1: Actual O&M Expenses Vs Normative O&M Expenses of GETCO

Particulars	FY 2011-12	FY 2012-13	FY 2013-14
Actual O&M Expenses	705.34	812.55	894.66
Normative O&M Expenses based on actual number of bays & ckt. km	702.74	792.53	899.47

Source: True-Up Orders for GETCO for, FY 2011-12, FY 2012-13 and FY 2013-14

From the above comparison, it is seen that the normative O&M expenses based on the norms specified in the MYT Regulations, 2011 are very close to the actual O&M expenses incurred by the Licensee. In this regard, for recovery of O&M expenses, the Commission has specified the norms for the entire Control Period which is based on certain percentage of YoY escalation. It is also pertinent to note that the network parameters, viz., transmission line length and bays also grow at a certain percentage, (i.e., YoY growth of around 6.5% for FY 2011-12 to FY 2012-13 for GETCO). The above impact should also be considered while specifying the O&M norms for the next Control Period, as the escalated norms for a particular year are applied on the actual network parameter for that year at the time of truing up. Thus, while determining the O&M expense for the Control Period, the impact of annual growth of the network parameters as well as the escalation approved by the Commission should be considered, which cumulatively adds to the allowance of O&M expense. The same could also be observed from the above table, which shows that the O&M expense allowed by the Commission for FY 2012-13 is around 12-13% higher than that allowed for FY 2011-12.

Hence, the norms specified by the Commission for FY 2015-16 in the GERC MYT Regulations, 2011, have been considered as base year norms. Further, escalation rate of 5.72% (as specified by Central Electricity Regulatory Commission in its CERC (Terms and Conditions of Tariff) Regulations, 2009), has been applied to determine the norms for FY 2016-17 and subsequent years. In addition to this it is proposed to include a proviso that the Transmission Licensee shall submit the certification from the Chief Electrical Engineer for the number of bays and circuit kilometres of transmission line added during the year at the time of truing up.

Table 5-2: O&M expenses norms for FY 2016-17 to FY 2020-21 for transmission utilities

Particulars	(Rs.crore)				
	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	FY 2020-21
O&M Expenses/Bay	7.60	8.04	8.50	8.98	9.50

O&M Expenses/Ckt. Km	0.64	0.68	0.72	0.76	0.81
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6 Norms and Principles for determination of Revenue Requirement and Tariff for SLDC

6.1 SLDC Budget

The State Load Dispatch Centre is the apex body to ensure integrated operation of the power system in the State of Gujarat. It is the strategic functional unit of GETCO, for discharging various functions specified under Section 32 of the Electricity Act, 2003.

In exercise of the powers conferred under Section 181 of the Electricity Act, 2003 and all powers enabling it in that behalf, the Commission notified the GERC (Levy And Collection of Fees and Charges by SLDC) Regulations, 2005. The said Regulation specifies that all the expenses incurred by the SLDC shall be accounted separately and shall be recovered from the Generating Companies and Licensees through charges. Further, as per the existing Regulations, the SLDC charges comprise of only fixed cost components and there is no associated variable charge, as under:

- (a) Interest on loan capital;
- (b) Depreciation
- (c) Operation and maintenance expenses;
- (d) Interest on working capital.
- (e) Overheads and General & administration
- (f) Return on Equity;

It is proposed to merge the Regulations for determination of SLDC fees and charges with the GERC MYT Regulations, 2015, so that a single consolidated Regulation will exist in the State, for determination of tariff for all the Licensees as well as for determination of fees and charges of the SLDC. Hence, the various provisions of the GERC (Levy and Collection of Fees and Charges by SLDC) Regulations, 2005 have been incorporated with suitable modifications in the MYT Regulations for the next Control Period, as proposed below, and the aspects such as Interest on Working Capital, which falls under Financial Principles, have been discussed while discussing IWC for all Businesses:

6.2 *Applicability*

The Regulations contained in this Chapter shall apply to determination of fees and charges to be levied by the SLDC.

6.3 *Application for Connection to Grid*

- a) These Regulations shall apply to determination of fees and charges to be levied by the SLDC.
- b) Generating Companies and Licensees requiring long-term access to the Grid shall submit an application to the SLDC in the specified format at least one month before the proposed date of connection to the State Grid, along with Fees stipulated by the Commission from time to time.
- c) The existing Licensees and Generating Companies shall register themselves with SLDC by filing an application along with the above-mentioned Fees.
- d) The SLDC, after scrutinising the application and after being satisfied of the completeness and correctness of the information furnished in the application, shall register the application in SLDC records duly intimating the applicant regarding the acceptance of the same.

6.4 *Capital Investment Plan*

- 6.4.1 The SLDC shall submit a detailed capital investment plan, financing plan and physical targets for each year to the Commission for approval, as a part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period.
- 6.4.2 The SLDC shall submit the Capital Investment Plan as specified in Chapter-2 of these Regulations.

6.5 Levy and Collection of Charges from Generating Companies and Licensees

- 6.5.1 All expenses incurred by the SLDC shall be accounted separately.
- 6.5.2 Expenses incurred by the SLDC in the discharge of its functions as specified in Section 32 of the Electricity Act shall be recovered from the Generating Companies and Licensees through Charges.
- 6.5.3 The Charges to be recovered from Generating Companies and Licensees shall be determined taking into account the following expenses:
- a) Operation & Maintenance expenses
 - b) Depreciation
 - c) Interest and finance charges
 - d) Interest on working capital
 - e) Return on Equity
- minus
- Non-Tariff Income

Provided that Depreciation, Interest and Finance Charges, and Return on Equity for the SLDC shall be allowed in accordance with the provisions specified in Chapter 3 of these Regulations:

Provided further that prior period income/expenses shall be allowed by the Commission at the time of truing up based on audited accounts, on a case to case basis, subject to prudence check.

6.6 Operation and Maintenance expenses

- 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, 2015, 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, 2014 and shall be escalated at the escalation factor of 5.72% to arrive at operation and maintenance expenses for subsequent years up to FY 2020-21.

6.7 Non-Tariff Income

- 6.7.1 The amount of Non-Tariff Income relating to the SLDC as approved by the Commission shall be deducted from the Aggregate Revenue Requirement in determining the Charges of the SLDC:

Provided that the SLDC shall submit full details of its forecast of Non-Tariff Income to the Commission in such form as may be stipulated by the Commission from time to time.

- 6.7.2 The indicative list of various heads that shall be considered under Non-Tariff Income is as under:
 - a) Income from rent on land or buildings;
 - b) Income from sale of scrap;
 - c) Interest on advances to suppliers/contractors;
 - d) Rental from staff quarters;
 - e) Rental from contractors;
 - f) Income from hire charges from contractors and others;
 - g) Scheduling and System Operation Charges
 - h) Miscellaneous receipts;
 - i) Excess found on physical verification;

- j) Interest on investments, fixed and call deposits and bank balances;
- k) Prior period income.

Provided that the interest earned from investments made out of Return on Equity of the SLDC shall not be included in Non-Tariff Income.

6.8 Determination of SLDC Fees and Charges

- 6.8.1 Upon the Commission being satisfied that all the information and clarification sought for by it have been produced and that sufficient opportunity has been afforded to all the parties concerned, the Commission shall pass appropriate orders on the estimated expenses and determine the Fees and Charges recoverable from the Generating Companies, the Licensees and MTOA beneficiaries.
- 6.8.2 The Fees and Charges so determined by the Commission shall be valid till the approval of next revision.
- 6.8.3 The SLDC Fees and Charges shall be determined by the Commission on the basis of application made by SLDC, for determination Fees and Charges, in accordance with Chapter 2 of these Regulations..
- 6.8.4 Open access users of the Grid shall pay such scheduling and system operation Charges as may be stipulated by the Commission.

6.9 Billing and Collection of SLDC Charges

6.9.1 The SLDC shall furnish necessary monthly bills on the Generating Companies, Licensees and MTOA beneficiaries for each billing month within seven days after the last day of the preceding month, on the basis of the following formula:

$$\text{SLDC Charges payable for a month} = (\text{SC}/12) * (\text{ACi}/\text{SACi})$$

where,

SC = Approved SLDC Aggregate Revenue Requirement for the year;

ACi = Actual Capacity of the respective Generating Companies / Licensees / MTOA beneficiaries for the month 'i';

SACi = Sum of Actual Capacity of the Generating Companies, Licensees and MTOA beneficiaries for the month 'i'.

6.9.2 The Generating Companies, the Licensees and MTOA beneficiaries shall make payment to the SLDC of the amounts due within fifteen (15) days of the date of receipt of the bill.

6.9.3 If the payment is not made within the due date, a penal interest at the rate of two hundred and fifty basis points above the State Bank of India's Base Rate shall be payable on the unpaid amounts.

6.9.4 Generating Companies, the Licensee and MTOA beneficiaries shall arrange payment of the Charges on a priority basis over all other payments except statutory payments.

6.10 Application for Connection to Grid

6.10.1 Generating Companies, Licensees and other beneficiaries requiring access to the Grid shall submit an application to the SLDC in accordance with the Gujarat Electricity Regulatory Commission (Terms and Conditions of Intra-State Open Access) Regulations, 2011, as amended from time to time, along with Fees stipulated by the Commission in the yearly tariff orders.

6.10.2 The SLDC, after scrutinising the application and after being satisfied of the completeness and correctness of the information furnished in the application, shall register the application in SLDC records duly intimating the applicant regarding the acceptance of the same.

6.11 LDC Development Fund

The Commission may permit SLDC to create and maintain a separate development fund for such purposes and from such sources of income, as the Commission may consider appropriate, on a Petition filed by SLDC, once SLDC is formed as a separate independent Company

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

7.1 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, the 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 State Distribution Licensees, following distribution licensees (as per the Commission's record) are present in the State:

- a. Torrent Power Ltd. - Ahmedabad Distribution (TPL-D(A))
- b. Torrent Power Ltd.- Surat Distribution (TPL-D(S))
- c. MPSEZ Utilities Private Ltd. (MUPL)
- d. Kandla Port Trust (KPT)
- e. Aspen Infrastructures Ltd. (AIL)

7.2 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. The GERC MYT Regulations, 2011, specify the various components of the ARR of the Wire business, and for the third Control Period it is not proposed to make any modification to the same.

7.3 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**. The distribution loss targets approved by the Commission and the estimated loss levels of the State distribution Utility over the years in the State of Gujarat are as shown in the Table below:

Table 7-1: Distribution loss targets approved by the Commission vis-a-vis estimated loss levels of distribution utilities

Utility	FY 2011-12			FY 2012-13			FY 2013-14		
	Approved in MYT Order	Actual	True-up	Approved	Actual	True-up	Approved	Actual	True-up
PGVCL	29.00%	27.87%	29.00%	27.00%	29.90%	27.00%	25.50%	23.20%	25.50%
DGVCL	12.35%	10.24%	12.35%	12.00%	11.56%	12.00%	11.75%	9.03%	11.75%
UGVCL	13.50%	9.81%	13.50%	13.00%	14.50%	13.00%	12.50%	6.54%	12.50%
MGVCL	12.75%	12.18%	12.75%	12.50%	12.89%	12.50%	12.25%	12.41%	12.25%
TPL-D(A)	8.50%	7.53%	7.53%	8.50%	7.25%	7.25%	8.50%	7.27%	7.27%
TPL-D(S)	5.15%	4.64%	4.64%	5.15%	4.20%	4.20%	5.15%	4.33%	4.33%
TEL-D	3.00%	-	-	3.00%	0.91%	0.91%	3.00%	0.81%	0.81%
MUPL	8.00%	3.69%	3.69%	7.75%	3.88%	3.88%	7.50%	4.06%	4.06%
KPT	9.00%	-	-	8.75%	#	#	8.50%	#	#

Utility	FY 2011-12			FY 2012-13			FY 2013-14		
	Approved in MYT Order	Actual	True-up	Approved	Actual	True-up	Approved	Actual	True-up
ASPEN	-	-	-	-	-	-	3.30%	4.27%	4.27%

The Commission has not done truing up for KPT for FY 2012-13 and FY 2013-14, as KPT has not submitted the audited accounts for FY 2012-13 and FY 2013-14.

In addition to the above, there is also a loss in revenue collected due to non-realisation of billed 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 drawback 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 stipulated 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%. 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, with the trajectory of distribution loss being stipulated in the Orders rather than being specified in the Regulations.**

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

Section 62 of the EA 2003 requires the 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 continue with the emphasis 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.

From the study of the provisions regarding allocation of costs between Wires Business and Retail Supply Business by various SERCs in their Tariff Regulations, it

is observed that no scientific or uniform methodology for such allocation is being adopted yet. The following approaches are being adopted:

- (i) Allocation Matrix or detailed head-wise principles of allocation are specified by the SERC in the Regulations.
- (ii) Broad principles of allocation of costs are specified in the Regulations, based on which the Commission determines the ratios of allocation of costs.
- (iii) The Allocation Matrix is prepared by the Distribution Licensees and submitted to the SERC for approval.

The GERC MYT Regulations, 2011, also specify that the distribution licensees should submit separate accounts as well as ARR for Wheeling Business and Retail Supply Business. We understand that none of the DISCOMs have complied with this clause of the Regulations, till date. In case the separate accounts are not available, it is necessary to have an allocation matrix for apportioning the ARR of the distribution business between the Wires business and Supply business.

The GERC MYT Regulations, 2011 specifies the following allocation matrix in cases where the Distribution Licensee is not able to submit the audited and certified separate accounts for Distribution Wires Business and Retail Supply Business:

Table 7-2: 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	0%	100%
Income Tax	90%	10%
Transmission Charges intra-State	0%	100%
Contribution to contingency reserves, if any	100%	0%
Return on Equity	90%	10%
Non-Tariff Income	10%	90%

It is proposed to continue with the same allocation matrix with slight modification for the third Control Period.

7.5 Operation & Maintenance Expenses – Norms 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.”

In its existing GERC Tariff Regulations, the Commission has specified that the O&M expenses for distribution licensees shall be approved based on the past performance, with certain escalation factor. It is proposed to continue with the existing principle for O&M expense given in GERC MYT Regulations, 2011.

7.6 Wheeling Charge Determination

The wheeling charges of the Distribution Licensee are to 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.

In this context, the APTEL in Judgment dated July 3, 2012 ruled as under:

- “70. Thus, in accordance with the statutory regulations, the State Commission is required to specify the wheeling charges in Rs/unit and fixed/demand charges in any combination so as to ensure the recovery of the wheeling cost from the wheeling consumers and not to burden the other retail consumers in accordance with the provisions of the Electricity Act, 2003.*
- 71. Thus, the principle of recovery of wheeling charges has already been laid down by this Tribunal and accepted by the State Commission in the Regulations. Therefore, it would be appropriate to direct the State Commission to determine the wheeling charges as a combination of fixed/demand charges in Rs. Per KW and variable charges in accordance with the regulatory provisions specifying the methodology to recover the wheeling charges. Accordingly directed.*
- 72. The Appellant is also directed to co-operate with State Commission by furnishing required particulars to the State Commission to enable it to determine the wheeling charges in the light of the findings of this Tribunal and to pass an order in accordance with the law. Thus, this issue is decided in favour of the Appellant.”(emphasis added)*

For determining wheeling costs at HT (11 kV) level and at LT (400 V) level, separation of asset base between HT and LT voltage levels is necessary. However, in the absence of data regarding assets pertaining to different voltage classes, the allocation matrix may be used for determination of wheeling charges. It is proposed to continue with the existing principle for O&M expense given in GERC MYT Regulations, 2011

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

The GERC MYT Regulations, 2011, specify the various components of the ARR of the Retail Supply business, and it is not proposed to make any major modification to the same, apart from the modification discussed in the General and Financial Chapters earlier in this Report.

8.1 Operation & Maintenance Expenses – Norms for Supply 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.”

In its existing GERC Tariff Regulations, the Commission has specified that the O&M expenses for distribution licensees shall be approved based on the past performance, with certain escalation factor. It is proposed to continue with the existing principle for O&M expense given in GERC MYT Regulations, 2011.

8.2 Tariff Philosophy

The GERC MYT Regulations, 2011, do not specify the overall tariff philosophy. It is proposed to adopt the following Clauses for determination of retail supply tariff:

- a) “The Commission may categorize consumers on the basis of their load factor, power factor, voltage, total consumption of electricity during any specified period or the time at which the supply is required or the geographical position of any area, the nature of supply and the purpose for which the supply is required.
- b) The retail supply tariff for different consumer categories shall be determined on the basis of the average cost of supply, computed as the ratio of the aggregate revenue requirement of the Distribution Licensee

for the financial year calculated in accordance with Regulation 88.1 to the total sales of the Distribution Licensee for the respective financial year.

- c) The Commission shall endeavour to reduce gradually the cross-subsidy between consumer categories with respect to the average cost of supply in accordance with the provisions of the Act.
- d) While determining the tariff the Commission may also keep in view the cost of supply at different voltage levels and the need to minimise tariff shock to any category of consumers.”

8.3 Bad Debts written off

A slight change has been proposed in the existing regulation for Bad Debts written off as shown below:

“The Commission may allow bad debts written off as a pass through in the Aggregate Revenue Requirement, based on the trend of write off of bad debts in the previous years, subject to prudence check:

Provided that the Commission shall true up the bad debts written off in the Aggregate Revenue Requirement, based on the actual write off of bad debts excluding DPC waived off, if any, during the year, subject to prudence check:

Provided further that if subsequent to the write off of a particular bad debt, revenue is realised from such bad debt, the same shall be included as an uncontrollable item under the Non-Tariff Income of the year in which such revenue is realised. “