REGULATED INDUSTRIES COMMISSION

REGULATION OF ELECTRICITY TRANSMISSION AND DISTRIBUTION

June 01, 2006 to May 31, 2011

FINAL DETERMINATION

(RATES AND MISCELLANEOUS CHARGES)

Determination No. 1, 2006
Regulated Industries Commission

1. Background

1.1. The Regulated Industries Commission (RIC), under Sections 47 and 48 of the Regulated Industries Commission Act No. 26, 1998, is responsible for setting maximum prices and/or principles for determining rates and charges for service providers and services specified in Schedule 1 and 2 of the RIC Act.

1.2. In investigating and setting the tariffs and/or principles for determining rates and charges, the RIC has had regard to a broad range of matters, including the criteria set out in Section 67 (3) and (4) of the RIC Act.

1.3. In accordance with Section 47 and 48 of the RIC Act, the RIC has fixed the maximum rates for the initial year and set a methodology for determining rates and charges for the Trinidad and Tobago Electricity Commission (T&TEC).

2. Application of this Determination

2.1. This Determination sets the maximum tariffs and sets a methodology for determining the maximum prices that T&TEC may charge for its services.

2.2. This Determination commences on June 01, 2006 (commencement date).

2.3. The maximum tariffs in this Determination apply from the commencement date to May 31, 2011 (the regulatory control period).

3. Monitoring

3.1. The RIC will monitor the performance of T&TEC for the purposes of:
- establishing and reporting on the level of compliance by T&TEC with this Determination; and
- preparing a periodic review of pricing policies.

4. Schedules

4.1. Schedules 1-6 (inclusive) and the Tables in those Schedules set out the maximum prices that T&TEC may charge for its services.

5. Definition and Interpretation

5.1. Definitions and interpretation used in this Determination are set out in Schedule 6.

SCHEDULE 1

STATEMENT OF REASONS UNDER SECTION 47 AND 48 OF THE RIC ACT

Under Sections 47 and 48 of the RIC Act, the RIC may set maximum rates, determine the principles for setting maximum rates and charges or both. In this Determination, the RIC has set maximum rates for the year 2006 and has included a methodology for setting the maximum revenue for each year of the regulatory control period.

SCHEDULE 2

TARIFF STRUCTURE AND PRICES FOR 2006

For the first year of the regulatory control period, the RIC has set a tariff structure and prices for each customer class, which are indicated in **Table 1.**

Table 1 – Tariffs for 2006

Rate Class	Customer Charge $	Energy Charge (¢/kWh)	Demand Charge ($/kVA)
Residential (Bi-monthly):			
Up to 400 kWh	6.00	27.00	-
401 - 1000 kWh	6.00	31.00	-
Over 1000 kWh	6.00	34.00	-
Commercial (Bi-monthly):			
Rate B	25.00	38.00	-
Rate B1	Minimum bill of 5000 kWh	58.00	-
Industrial (Monthly):			
Rate D1	-	18.00	48.00
Rate D2	-	20.00	48.00
Rate D3	-	16.50	41.00
Rate D4	-	15.00	38.00
Rate D5	-	14.50	35.00
Rate E1	-	13.00	42.00
Rate E5	-	13.00	38.00
Street Lighting (Annually):			
S1 – 1	792.00	-	-
S1 – 2	528.00	-	-
S1 – 3	384.00	-	-
S1 – 4	348.00	-	-
S2 – 2	420.00	-	-
S2 – 3	324.00	-	-
S2 - 4	264.00	-	-

SCHEDULE 3

REVENUE CAP FOR TRANSMISSION AND DISTRIBUTION SERVICES

Schedule 1 tariffs would be escalated annually by applying the RPI-X formula from June 01, 2007, with no further rebalancing of prices within the regulatory control period without the RIC's approval.

T&TEC to set prices for year t such that the reasonable forecast annual revenue received (ARR_t) from the service complies with the following formula in **Table 2**:

Table 2 - Formula for Establishing Annual Revenue

$$*ARR_t \leq (1 + RPI)(1 - X_t)) \times ARR_{t-1} + U$$

Where:

Year t	X_t
2007	4.4
2008	4.4
2009	4.4
2010	4.4

ARR= Annual Revenue Received from Services.
ARR_{2006} = $1901.03 million.
RPI means the Retail Price Index as determined by the CSO.
U = Unused charge. T&TEC will be permitted to carry over any unused change in charges from one year to the following years.

The RPI will be calculated using the following formula:

$$RPI_t = \frac{\text{RPI June}_{t-1} + \text{RPI Sept}_{t-1} + \text{RPI Dec}_{t-1} + \text{RPI Mar}_{t-1}}{\text{RPI June}_{t-2} + \text{RPI Sept}_{t-2} + \text{RPI Dec}_{t-2} + \text{RPI Mar}_{t-2}}$$

Where:

- Year t is the year for which tariffs are being set
- $Year_{t-1}$ is the previous year
- $Year_{t-2}$ is two years previous.

The overall side constraint is set at (RPI + X) = 7.4%.

SCHEDULE 4
MISCELLANEOUS SERVICES

The following Miscellaneous Services will be regulated by the RIC and the prices for these services are as set out below in **Table 3** for the duration of the regulatory control period.

Table 3 - Miscellaneous Charges

	Charge ($)
• Meter Check at customer's request: - If found in working order - If found defective	 194.00 No charge
• Visit for Non-payment of Account	234.00
• Install meter and reconnect secondaries	194.00
• Reconnect, disconnect and/or change meter	194.00
• Reposition of secondaries	194.00
• Change and/or reposition meter	194.00
• Disconnection for non-payment	118.00
• Reconnection after disconnection for non-payment	118.00

SCHEDULE 5

ANNUAL PRICE APPROVAL PROCESS DURING THE REGULATORY CONTROL PERIOD

The Annual Price Approval Process during the regulatory control period is set out below:

- At least 60 days prior to the beginning of each year of the regulatory control period, T&TEC shall submit proposed tariffs which will apply from the start of each year of the regulatory control period for verification of compliance by the RIC.
- T&TEC shall ensure that its proposed tariffs comply with the established principles.
- T&TEC shall, if requested by the RIC, provide additional information and resubmit or revise its proposed tariffs.
- The RIC shall inform T&TEC in writing whether it has verified T&TEC's proposed tariffs as being compliant with the relevant established principles.
- The proposed tariffs shall be deemed to have been verified as compliant by the end of the 60 days from the date of receiving T&TEC's Annual Tariff Approval Submission.
- T&TEC shall inform customers of the new tariffs at least 14 days before implementation through publication in at least one daily newspaper in circulation in Trinidad and Tobago.
- T&TEC shall not introduce any new tariffs and/or tariff components during the regulatory control period other than those approved by the RIC.

SCHEDULE 6
DEFINITIONS AND INTERPRETATIONS

1. Definitions

In this Determination:

"Annual Revenue Requirement" means a forecast of the annual revenue requirement over a regulatory control period.

"Commencement Date" means June 01, 2006.

"Regulatory Control Period" means the period covered by this Determination, that is, June 01, 2006 to May 31, 2011.

"RPI-X Formula" means a formula of regulation that involves setting price/revenue caps that are measured relative to the RPI.

"Retail Price Index (RPI)" means the general index of retail prices published by the Central Statistical Office (the CSO) of the Government of Trinidad and Tobago.

"Service Providers and Service" means the service providers and services as defined in Schedule 1 and 2 of the RIC Act.

"X-factor" means productivity or general efficiency improvement factor.

2. Interpretation

2.1 General Provisions

In this Determination:

a) Headings are for convenience only and do not affect the interpretation of this Determination.

b) A reference to a law includes all amendments or replacement of that law.

2.2 Explanatory Notes and Clarification

a) Explanatory notes do not form part of this Determination, but in the case of uncertainty may be relied on for interpretation purposes.

b) The RIC may publish a clarification to correct any manifest error in this Determination as if that clarification formed part of this Determination.

2.3 Prices exclusive of VAT

Tariffs or charges specified in this Determination do not include value added tax (VAT).

2.4 Billing Cycle of T&TEC

Nothing in this Determination affects T&TEC's billing cycle.

REGULATION OF ELECTRICITY TRANSMISSION AND DISTRIBUTION

JUNE 01, 2006 – MAY 31, 2011

FINAL DETERMINATION

JUNE 2006

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PREFACE

On November 08, 2004, the Trinidad and Tobago Electricity Commission (T&TEC) submitted to the Regulated Industries Commission (RIC) the prices it proposed to charge for transmission and distribution and other prescribed services for the coming five-year period. The submission also included other more detailed information about the strategies and initiatives that are proposed and the revenue needs of the business.

The RIC is required to assess the proposal in accordance with the provisions of the RIC Act No. 26 of 1998. In particular, the RIC is required to decide whether to approve the proposed prices or alternatively, to specify the prices to apply if it is not satisfied that the proposed prices were calculated or determined in accordance with the Act.

This tariff review coincides with the introduction of a new regulatory framework which is aimed at securing greater efficiency in the provision of electricity services and sets the price controls for five years subject only to annual adjustments to allow for the impact of inflation.

The RIC has completed its assessment of T&TEC's proposal in accordance with the provision of the Act. In conducting its assessment of T&TEC's proposal, the RIC has undertaken extensive consultation on the approach to this review, the key issues and information presented. This report sets out the relevant issues, information and analysis underpinning the RIC's Final Determination regarding the prices to be charged and the price control mechanism for electricity prices provided by T&TEC.

It is hereby stated that the RIC has, in exercising the power conferred by the Regulated Industries Commission Act, No. 26 of 1998, determined the revenue requirement, expected revenue from charges, and the tariffs based thereon, which the Trinidad and Tobago Electricity Commission shall accept and implement, along with related directions, as indicated in this document.

Signed, dated and issued by the Regulated Industries Commission on this day of June 01, 2006.

D. Pantin Chairman	**I. Welch** Deputy Chairman	**W. Rennie** Member
A. McKenzie Member	**K. Ramkissoon** Member	**E. Thompson** Member

EXECUTIVE SUMMARY

1. INTRODUCTION

This is the Regulated Industries Commission's (RIC's) Final Determination on the regulation of Electricity Transmission and Distribution services for the period June 01, 2006 to May 31, 2011.

On November 08, 2004, the Trinidad and Tobago Electricity Commission (T&TEC) submitted to the RIC the prices it proposed to charge for transmission and distribution and other prescribed services for the coming five-year period. The RIC is required to assess the proposal in accordance with the provisions of its Act. In particular, it is required to decide whether to approve the proposed prices or, alternatively, to specify the prices to apply if it is not satisfied that the former were calculated or determined in a manner that was consistent with the Act.

This report has been informed by a public consultation process, which involved interested stakeholders providing written comments to the RIC in response to eleven (11) technical papers that were published in April/May 2005 and a **Draft Determination** that was published on January 18, 2006. Five regional and one national consultations were held throughout the country during February/March 2006 to discuss the Draft Determination. This Final Determination sets out the relevant issues, information and analysis underpinning the RIC's decisions.

2. CONTEXT OF THIS REVIEW

In order to place this Determination in an appropriate context, it is necessary to review the events leading up to its completion. This is the first time that rate setting is being undertaken under the Incentive-based (price cap regulation) approach rather than the traditional Rate of Return methodology. It is also the first time that T&TEC has had its pricing proposals subject to the RIC's independent scrutiny where T&TEC was required to publish its Business Plan setting out detailed proposals on what it proposes to deliver in the future, estimates of the likely costs and the prices that it believes it will need to charge in order to deliver those outcomes.

An important aspect of this review has been to establish a firm foundation for economic regulation in the future. The RIC has established a process that facilitates transparency of information and public consultation and debate before decisions are made. The RIC is independent in its decision-making and hence is able to balance a number of competing interests. This new approach has a number of advantages for customers. It enables them to understand and influence what T&TEC is proposing to deliver and judge whether they will receive value for money. It also provides greater certainty as to the prices they will be charged for the next five years, and enables them to manage their consumption more effectively.

Finally, this rate review is the first general review in fourteen (14) years. The last general rate increase was, in fact, based on prices prevailing in 1990/91, close to 16 years ago. Over this period, the general rate of inflation in the country has increased by 115%. The growth in demand has also outstripped the expectations over this period. Significant new investment and operating expenditure are now required for network maintenance and expansion. Furthermore, almost 70% of T&TEC's costs are not directly under its control as they are governed by contracts with power generators and the National Gas Company (NGC) and have provisions for annual automatic increases. The RIC's task, therefore, has been to seek to compensate for the consequences of extended period to source resources for its operations and at the same time not seeking a rate increase.

Following the release of the Draft Determination by the RIC and the public consultation and debate, the views expressed suggest that consumers are not prepared to risk falling service quality. On the contrary, there is an expectation that service quality will improve and that system reliability and security should be paramount. Both of these come at a price. The increases in price that will flow from this Determination are the product of past decisions and the past level of benefits consumers have received from cross subsidies and not the imposition of an unreasonable penalty at this time.

Nevertheless, the RIC has taken definite measures to ensure that final electricity prices will not rise dramatically and that price impacts for customers are reasonable.

3. OVERALL FRAMEWORK AND APPROACH (Chapters 1 and 2)

The RIC Act supports the use of incentive regulation, using a price cap (RPI-X)[1] approach. The range of possible approaches to the RPI-X form of regulation includes revenue capping and price capping. The RIC released its Consultation Document**, "Setting Price Control: Framework and Approach**" in April 2005 within which its preferred form of regulation of revenue capping for the first regulatory control period was articulated.

The RIC has decided to use a fixed (total) revenue cap that provides an appropriate balance of risk between customers and the service provider and gives incentives for the service provider to reduce costs. The RIC has also applied a "building-block" methodology in determining the revenue requirements of the service provider. This methodology involves determining a total revenue requirement from component costs, as follows:

Total Revenue = Forecast Efficient Operating & Maintenance Costs
+ Asset Value x Rate of Return
+ Depreciation of Assets.

Typically, this entails establishing the costs associated with financing past and future capital expenditure which are recovered over the life of the assets through a rate of return on those assets and an allowance for depreciation. Finally, it is necessary to arrive at efficient levels of operating and maintenance expenditure that will be required to maintain assets and provide the range of services sought by customers. The building-

[1] RPI is the Retail Price Index and X is the general efficiency improvement assumption.

blocks include expected efficiency gains but also provide the incentive for the service provider to improve its performance.

4. OVERVIEW OF FINAL DECISION OUTCOMES

4.1 Review of Performance of T&TEC (Chapter 3)

After review of T&TEC's operational and financial performance from 1995 to 2003, the RIC's judgment is that, overall, the quality of service and the physical performance of the transmission and distribution (T&D) system have improved. Many productivity ratios show improvement. Aggregate operating expenditure, however, has also increased significantly.

Although the relatively high growth in electricity sales resulted in higher revenues, T&TEC's financial performance over the period 1995-2003 was generally weak. For T&TEC, the current tariff regime has failed to generate reasonable returns, which are a pre-requisite for effecting continued improvements in the quality of electricity service and sustaining the electricity sector.

4.2 Demand Forecasts (Chapter 4)

Forecasts of customer numbers, electricity consumption and peak demand are important factors influencing future expenditure and also the prices that need to be charged to recover revenue. In assessing T&TEC's proposal, the RIC has, therefore, sought to determine whether the utility's forecasts and assumptions were reasonable.

The RIC has adjusted T&TEC's electricity consumption and customer numbers forecasts where, based on the RIC's own analysis, it considered these forecasts were not appropriate. Energy consumption is forecast to increase steadily for all customers classes at some 3.7% per annum, while customer numbers are expected to increase for all classes but at lower rates. In the case of peak demand forecasts, the RIC has adopted T&TEC's forecast.

The RIC expects that T&TEC will improve the rigour of its forecasting techniques for future reviews and also obtain independent verification that both the forecasts and forecasting methods are robust and reasonable.

4.3 Operating and Maintenance Expenditure (Chapter 5)

In order to set price limits for T&TEC's transmission and distribution services, the RIC needed to establish forecast revenue requirements for the regulatory control period. These revenue requirements are intended to recover efficient costs of operating the T&D network.

In assessing T&TEC's proposed operating and maintenance expenditure (Opex) forecasts, the RIC utilized a number of techniques for arriving at an efficient level of Opex. Using actual reported costs as a starting point, the RIC assessed the validity of the reasons for any variations from the trend, thereby adjusting for any atypical costs (or savings), removing one-off or exceptional costs, and removing any other costs that should not form part of T&TEC's core business costs.

Whilst the RIC has adjusted a number of T&TEC's expenditure proposals, the forecast Opex seeks to ensure that T&TEC will have sufficient revenue over the regulatory period to deliver the proposed services and meet known regulatory obligations. The RIC has determined $10,352.24 million as T&TEC's Opex costs over the five-year regulatory period. **Table ES.1** summarizes the RIC's allowed Opex for 2006-2010.

Table ES.1 – Summary of Allowed Total Opex, 2006-2010 ($Mn)

	T&TEC Requested	RIC Allowed					
		Total	2006	2007	2008	2009	2010
Conversion Cost	5,450.31	5,271.39	792.66	844.08	1,050.27	1,192.87	1,391.51
Fuel Cost	3,770.40	3,232.00	584.10	609.40	651.00	671.50	716.00
Total T&D	2,037.27	1,848.85	342.34	356.10	369.44	384.62	396.35
Total Operating Costs	**11,257.98**	**10,352.24**	**1,719.10**	**1,809.58**	**2,070.71**	**2,248.99**	**2,503.86**

The RIC has made a number of significant reductions amounting to $905.74 million overall, to T&TEC's Opex proposals for the review period 2006-2010 (or $181 million annually), notably in relation to:

- fuel costs which have been lowered by $538.4 million for the period 2006-2010 (or $108 million annually) largely as a result of allowing only 90% pass-through;
- generation (conversion) costs which have been lowered by $178.9 million for the period 2006-2010 (or $36 million annually) as a result of allowing only 98% pass-through;
- total projected employee costs which have been lowered by $124 million for the period 2006-2010 as a result of an observed anomaly; and
- advertising and marketing/sponsorships amounting to $11 million for the period 2006-2010 which have been disallowed.

Further, the forecasts of transmission and distribution costs have been reduced by $53.3 million for 2006-2010 to ensure that they incorporate productivity gains of at least 2.8% per annum (non-compounding). This is based on the operating efficiency improvements expected over the regulatory period.

4.4 Capital Expenditure (Chapter 6)

To forecast the development of the asset base over the regulatory period, the RIC needs to estimate how much will be invested in new assets over that period. T&TEC proposed a capital programme amounting to $3,285.2 million. In assessing the efficiency of T&TEC's proposed capital expenditure (Capex) forecasts, the RIC had engaged the services of a consultant to assist in this regard. T&TEC was provided an opportunity to comment on the consultant's findings, as well as to present its comments following release of the Draft Determination.

Based on the consultant's findings and T&TEC's comments, the RIC has significantly revised T&TEC's Capex forecasts. As indicated, T&TEC's proposed Capex amounted to $657 million of investment each year and represents more than three times the capital expenditure that T&TEC has undertaken in any of the last six years. The proposed investment, therefore, represented a significant delivery challenge. Moreover, T&TEC did not, in all cases, provide adequate supporting information to justify or explain the likely outcomes that customers would see from these expenditures. The RIC also expected that a number of projects will occur later than proposed in the Capex plan. Finally, the RIC also thinks that the increased overall level of infrastructure activity in the country is likely to put further pressure on T&TEC to complete its capital programme.

Additionally, the RIC identified projects amounting to $1,772.6 million (including the National Street-lighting project and aluminum smelters) which should be fully funded by the Government and should be totally ring-fenced, as these projects are Government initiatives that will cater for the needs of a single customer and/or industry.

As a result, in its Draft Determination, the RIC reduced the overall Capex by $2,286.8 million and accepted investment proposals totaling $998.4 million over the regulatory control period. The RIC, following the release of its Draft Determination received additional comments from T&TEC. The Shareholder (Government) has publicly announced its intention to provide funding for T&TEC to finance, among other initiatives, capital projects amounting to $1,124 million, many of these projects were, in any case, identified for Government funding by the RIC. Consequently, the RIC adjusted the Capex forecasts from $998.4 million to $800 million.

The details of the RIC's allowed capital expenditure are provided in **Table ES.2**.

Table ES.2 – RIC's Allowed Capital Expenditure, 2006-2010 ($Mn)

Project	2006	2007	2008	2009	2010	Total
Transmission	42.0	80.0	80.0	30.0	26.0	258.0
Distribution	65.5	38.8	27.3	72.0	87.7	291.3
Other Network Related Projects	28.0	34.0	32.1	20.3	20.5	134.9
Non-Network Related Projects	17.7	38.6	30.0	15.5	14.0	115.8
Total	**153.2**	**191.4**	**169.4**	**137.8**	**148.2**	**800.0**

The RIC intends to strengthen the incentives for T&TEC to operate efficiently over the regulatory period by applying an efficiency carryover mechanism that rewards the service provider where its actual costs incurred during the regulatory control period are less than those utilized to set price controls. The principles underpinning such a mechanism are discussed in Chapter 8. The mechanism allows T&TEC to retain a share of the gains for five years before they are passed on to customers through lower prices.

4.5 Regulatory Asset Base and Cost of Capital (Chapter 7)

The service provider must be able to finance its operations. The cost of capital (allowed return) when applied to the asset base of the service provider enables it to meet its cost of debt financing and provide a return on investment.

Chapter 7 details the complex issues which go into the determination of the Regulatory Asset Base (RAB), the cost of capital and depreciation.

The RIC has used a value based on historical cost valuation for the determination of the opening RAB for the first regulatory control period. Assets should subsequently be revalued by a "roll-forward" methodology, whereby the RAB is updated by adjusting for efficient new capital expenditure, depreciation, asset disposals and inflation. The RIC's proposed rolled-forward RAB is shown in **Table ES.3**.

Table ES.3 – Calculation of the RAB, 2006-2010 ($'000)

	2006	2007	2008	2009	2010
Opening Value	1,276,291	1,352,230	1,460,549	1,533,651	1,566,345
Capex Additions	153,200	191,400	169,400	137,800	148,200
Less: Depreciation	76,892	82,757	95,687	104,364	113,853
Less: Disposals	369	324	611	742	238
Closing Value	1,352,230	1,460,549	1,533,651	1,566,345	1,600,454

The regulator has a duty to set an appropriate rate of return that allows an efficient utility to properly finance its operations. The regulator must also seek a balance between current and future customers by ensuring that the allowed rate of return is only just high enough to cover the costs of the benefits provided to current customers.

In the private sector or at privatized utilities, a market-based weighted average cost of capital (WACC), that is, debt and equity, is utilized to estimate the cost of capital. This is an approach that is derived from finance theory and widely adopted by regulators. However, in the case of T&TEC, it is not possible to estimate a market-based WACC because T&TEC has no contributed equity capital. Since T&TEC does not pay dividends, all of the surplus generated can be reinvested for the benefit of current and future customers. These retained earnings differ from retained earnings in the private sector in that they are not reinvested with the specific goal of generating increased surpluses in the future.

The RIC has sought to provide a return that is sufficient for T&TEC to fund its activities in a sustainable way. T&TEC currently carries high-cost embedded debt (11.87%) as compared to existing market rates of 6.35% to 6.5% for government-guaranteed debt. In fact, a major part of its debt was negotiated at an effective rate of 13.65% to finance operating deficit. The RIC considers that such imprudent interest costs should not be passed to consumers.

Given all the circumstances, the RIC has used a cost of capital of 8.0%, applied to the regulated asset base, to determine the return on assets T&TEC can reasonably earn over the regulatory control period.

4.6 Quality of Service and Performance Monitoring (Chapters 9 and 13)

In April 2004, the RIC implemented a Guaranteed Standards Scheme as part of the regulatory arrangements. Under this scheme, the service provider is required to make guaranteed payments to consumers who receive service below a certain benchmark. The RIC is satisfied with the level of T&TEC's performance under the scheme. However, the RIC is not satisfied with the number of claims made by affected customers. The RIC has also identified some options for larger customers and T&TEC to pursue in order to support the negotiation of enhanced service quality outcomes for large customers who have needs beyond those likely to be addressed through the current scheme.

In addition to the Guaranteed/Overall Standards Scheme, the RIC, in May 2005, released its Consultation Document, "**Performance Monitoring and Reporting Framework (PMR)**", which requires T&TEC to provide data on a core set of financial, operational and service quality measures on a quarterly and an annual basis. This is expected to be a significant performance driver and a useful tool for performance monitoring.

Based on consumers' concerns, the RIC has also proposed specific performance targets for street-lighting.

The RIC expects that, over the first regulatory control period, T&TEC will provide services at much higher levels than currently being achieved.

Future Reporting

Apart from PMR, the RIC has committed itself to issuing regulatory accounting guidelines six months after the release of this Final Determination. The objective of the guidelines will be to enhance the capacity of the RIC to make performance comparisons from year-to-year and to the initial forecasts underpinning this Determination.

Given the substantial cost increases and stakeholders' focus on network performance, the RIC believes that monitoring T&TEC's performance against the targets underlying the pricing determination is critical.

4.7 Miscellaneous Charges (Chapter 10)

Miscellaneous charges are those charges that are required to be paid by customers for non-routine services but are not included under the price control mechanism used to regulate tariffs. The provision of these services is incidental to the provision of the core service of electricity. The miscellaneous charges represent a relatively small proportion of T&TEC's revenue (less than 2%); however, these fees and charges can be significant for individual users.

Given the lack of supporting information, the RIC is unable to fully support the increases in charges requested by T&TEC. Nevertheless, since miscellaneous charges were last adjusted in 1992, the RIC considers a one-off increase in these charges reasonable to reflect the change in the RPI since 1992, but no further increase will be permitted for the duration of the first control period. The RIC has also concluded that the current list of approved miscellaneous services should be maintained without addition.

4.8 Revenue Requirements and Establishing Controls (Chapters 11 and 12)

Having assessed T&TEC's submission and reached decisions on the various elements of the building blocks, the RIC has arrived at total revenue requirements for T&TEC as set out in **Table ES.4**.

Table ES.4 - Revenue Forecasts, 2006-2010 ($Mn)

	T&TEC REQUESTED	RIC Allowed					
		Total	**2006**	**2007**	**2008**	**2009**	**2010**
Conversion Cost	5,450.31	5,271.38	792.66	844.08	1,050.27	1,192.87	1,391.51
Fuel Cost	3,770.40	3,232.00	584.10	609.40	651.00	671.50	716.00
Transmission and Distribution	2,037.27	1,848.85	342.34	356.10	369.44	384.62	396.35
Depreciation	616.40	473.56	76.90	82.76	95.69	104.36	113.85
Return on Capital	870.60*	601.00	108.20	116.80	122.70	125.30	128.00
Return on Working Capital	-	68.75	10.78	12.20	13.83	14.97	16.97
Unsmoothed Revenue Forecast	**12,744.98**	**11,495.55**	**1,914.98**	**2,021.34**	**2,302.93**	**2,493.62**	**2,762.68**

* T&TEC has included return on working capital in its return on capital figure but the RIC has separated these figures.

The RIC's overall allowed revenue requirement is $1,250.43 million (exclusive of embedded debt), which is lower than T&TEC's proposal over the five-year control period. This difference reflects a number of individual cost decisions, with the following accounting for nearly all of the difference:

- reduction in forecast of operating expenditure of $906 million, including generation costs ($179 million), fuel costs ($538 million);

- reduction in the forecast of capital expenditure; and

- reduction in depreciation charges ($143 million).

Despite the reductions, the RIC's judgment is that the allowed revenues provide the capacity for T&TEC to undertake all the works and the investment to achieve its operational objectives, and also to continue to providing services at improved levels.

Annual Revenue Requirements

While these forecast revenues are the maximum amount of revenue T&TEC is entitled to earn, not all this revenue is to be raised from customers. The RIC has deducted non-tariff revenues, that is, customer capital contributions, revenue from rental of poles, disposal of assets and dividend income from PowerGen. As a result, the RIC has set an aggregate revenue requirement (inclusive of embedded debt) to be raised from customers over the regulatory control period as shown in **Table ES.5**

Table ES.5 – Total Allowed Revenue Requirements, 2006-2010 ($Mn)

	T&TEC REQUESTED	RIC Allowed					
		Total	2006	2007	2008	2009	2010
Unsmoothed Revenue Forecast	**12,744.98**	**11,495.55**	**1,914.98**	**2,021.34**	**2,302.93**	**2,493.62**	**2,762.68**
Less: Revenue from Non-Tariffs*	770.81	770.81	151.66	153.02	154.37	155.76	156.00
Less: Asset Disposals	2.28	2.28	0.37	0.32	0.61	0.74	0.24
Unsmoothed Annual Revenue Requirements	**11,971.89**	**10,722.46**	**1,762.95**	**1,868.00**	**2,147.95**	**2,337.12**	**2,606.44**
Embedded Debt Cost	**-**	**386.60**	**128.89**	**122.92**	**109.71**	**25.08**	**-**
Less: Refinancing of NGC Loan		**6.82**	**3.10**	**2.17**	**1.24**	**0.31**	**-**
Unsmoothed Revenue Requirement	**11,971.89**	**11,102.24**	**1,888.74**	**1,988.75**	**2,256.42**	**2,361.89**	**2,606.44**

*This includes dividend income from PowerGen, capital contributions, pole and transformer rentals etc.

As a broad guide to pricing impacts over the regulatory control period, the implied real and minimal prices are shown in **Table ES.6**. These "prices" (cents/kWh) are calculated by dividing annual revenue requirements by the forecast level of electricity consumption. **This is only a notional price and does not represent differences across and within customer classes.**

Table ES.6 – Implied Average Annual Price Changes, 2006-2010

	2006	**2007**	**2008**	**2009**	**2010**
Annual Revenue Requirement ($Mn)	**1,888.74**	**1,988.75**	**2,256.42**	**2,361.89**	**2,606.44**
% Change	**6.02**	**5.30**	**13.46**	**4.67**	**10.35**
Forecast Consumption (GWh)	7205	7330	7627	7882	8150
Implied **Nominal** Price (¢/kWh)	26.21	27.13	29.58	29.96	31.98
Year-on-Year Percentage Change (%)	**16.61**	**3.49**	**9.03**	**1.28**	**6.74**
Implied **Real** Price (¢/kWh)*	22.55	22.65	23.99	23.58	24.48
Year-on-Year Percentage Change (%)	**13.21**	**0.48**	**5.91**	**(1.73)**	**3.84**

*** Based on 2003 prices.**

Revenue Smoothing

The above annual revenues include a degree of volatility from year to year. To reduce volatility, it has become commonplace for regulators to smooth the revenue requirement over the regulatory control period.

Preferably, the approach to smoothing should leave the service provider no worse off in real terms, though there may be changes in the timing of receipt of revenues. Additionally, in the final year, smoothing should arrive at a revenue requirement that offers the prospect of a smooth transition into the next regulatory period. Finally, the smoothing should, as far as possible, avoid severe price shocks for customers.

Of the two basic smoothing techniques – NPV smoothing and straight-line smoothing - the RIC has opted for net present value (NPV) smoothing and a single X-factor across the regulatory control period. The forecast revenue requirements, in NPV terms, will be equal to smoothed revenue over the entire regulatory period. **Table ES.7** shows the effect of NPV smoothing on annual revenue requirement.

Table ES.7 – NPV Smoothed Annual Revenue Requirements, 2006-2010

	2006	2007	2008	2009	2010
Unsmoothed Revenue Requirement:					
- $Mn.	**1,888.74**	**1,988.75**	**2,256.42**	**2,361.89**	**2,606.44**
% Change	**6.02**	**5.30**	**13.46**	**4.67**	**10.35**
Smoothed Revenue Requirements:					
- $Mn.	1,901.03	2,041.71	2,192.80	2,355.06	2,529.34
% Change	**7.4**	**7.4**	**7.4**	**7.4**	**7.4**

Based on the above calculation, the average revenue will increase by 7.4% (**RPI + 4.4%**[2]**)** per year (**in real terms)** under the NPV smoothing approach. Some customers may see significant price changes on either side of this average. However, the significance of the price change will reflect the past level of benefit some customer classes have enjoyed from cross subsidies. The price increases over the regulatory control period are expected to be matched, in broad terms, by improvements in service quality, in particular, due to the minimum service standards being proposed by the RIC, apart from the guaranteed payments scheme already in existence.

Assessing Financial Viability

To determine whether T&TEC will generate sufficient revenue to remain viable, a financial viability analysis was undertaken. As the focus of an assessment of financial viability is the ability of an entity to meet its cash obligations, the most relevant financial indicators are those that reflect the cash needs of the service provider. However, cash-based financial ratios are mainly used by privatized utilities that are required to maintain strict credit ratings. Complying with all the ratios, therefore, would not only be challenging but may also not be entirely desirable for a State-owned entity funded entirely by customer charges and debt.

[2] In instances where a utility needs to undertake significant capital investment or where its current tariffs do not cover efficient costs, and thus it needs significant price increase, then the RPI-X formulation is modified to become RPI + X. This has been done in a number of countries, the water sector in England and Wales being the first.

Cash-based financial ratios are set out in **Table ES.8** to show T&TEC's financial health over the regulatory control period. It was not possible to increase the proposed revenue requirements to comply fully with all the cash-based financial ratios in every year.

Table ES.8 - Financial Performance, 2006-2010

	2006	2007	2008	2009	2010	"Best Practice" Target
(FFO + Net Interest) / Net Interest (Times)	3.29	3.35	2.72	2.85	2.16	Between 2 to 3
Net Debt / FFO (Times)	4.58	4.33	6.45	6.20	11.22	Between 5 to 7
FFO / Net Debt (Times)	0.22	0.23	0.16	0.16	0.09	Greater than 13
(FFO – Dividends)/Net Capex (%)	73.6	143.1	94.4	127.6	66.4	Minimum 40%
Net Debt / RAB (%)	83.7	81.1	78.5	75.6	76.5	Below 65%

FFO – Funds from operations. **RAB – Regulatory asset base.**

Cost Allocation and Structure of Prices

Having determined the annual revenue requirements, it is necessary to determine the price each consumer category pays for electricity. Cost allocation is the process by which this is achieved. This involves assessment of, among other things, what proportion of total service provider costs is to be recovered from particular customers or classes of customers, and from particular components of a price (for example, fixed and variable charges). The structure of tariffs and the level at which charges are set provide important signals to customers about the costs of providing services and also the incentive to use resources more efficiently.

In formulating the new tariff schedules, the RIC has adopted factors that will encourage efficiency, economical use of the resources, good performance and optimum investments. It has sought to reduce distortions in tariffs so as to lower cross subsidization and has attempted to make tariffs reflective of the underlying costs. **Most importantly, the RIC has been conscious of the need to avoid disruptive and excessive tariff shocks to lower and disadvantaged income groups, in particular,**

and in general, to residential customers. The aim has been to achieve the optimal rate at an appropriate and prudent pace. In particular, in undertaking this first review of prices for the electricity sector after nearly sixteen years, the RIC has sought to enable T&TEC to earn sufficient revenue to efficiently maintain, renew and augment its assets in order to deliver the standards of service expected by its customers and to consider the affordability of the resulting prices and the extent to which any adverse impact on customers' electricity bills (especially low income and vulnerable groups) has been managed effectively.

Table ES.9 shows the RIC's final tariff structure and charges for 2006.

Table ES.9 - RIC's Final Tariffs for 2006

Rate Class	Customer Charge $	Energy Charge (¢/kWh)	Demand Charge ($/kVA)
Residential (Bi-monthly):			
Up to 400 kWh	6.00	27.00	-
401 - 1000 kWh	6.00	31.00	-
Over 1000 kWh	6.00	34.00	-
Commercial (Bi-monthly):			
Rate B	25.00	38.00	-
Rate B1	Minimum bill of 5000 kWh	58.00	-
Industrial (Monthly):			
Rate D1	-	18.00	48.00
Rate D2	-	20.00	48.00
Rate D3	-	16.50	41.00
Rate D4	-	15.00	38.00
Rate D5	-	14.50	35.00
Rate E1	-	13.00	42.00
Rate E5	-	13.00	38.00
Street Lighting (Annually):			
S1 – 1	792.00	-	-
S1 – 2	528.00	-	-
S1 – 3	384.00	-	-
S1 – 4	348.00	-	-
S2 – 2	420.00	-	-
S2 – 3	324.00	-	-
S2 - 4	264.00	-	-

5. FINAL PRICE DETERMINATION

The following is the RIC's Final Determination in respect of electricity transmission and distribution services for the five-year period June 01, 2006 to May 31, 2011:

1. Period of Determination

The provisions below will apply for the five-year period June 01, 2006 to May 31, 2011.

2. Services to be Regulated

The following services will be regulated by the RIC and the prices for these services are as set out below:

(i) Miscellaneous Services

	Charge ($)
• Meter Check at customer's request: - If found in working order - If found defective	 194.00 No charge
• Visit for Non-payment of Account	234.00
• Install meter and reconnect secondaries	194.00
• Reconnect, disconnect and/or change meter	194.00
• Reposition of secondaries	194.00
• Change and/or reposition meter	194.00
• Disconnection for non-payment	118.00
• Reconnection after disconnection for non-payment	118.00

As outlined in the RIC's Social Action Plan and Chapter 9, the service provider will be required to have a Code of Practice to ensure that vulnerable customers are not unduly burdened by these charges.

No further increase will be permitted in the Miscellaneous Services for the duration of the regulatory control period.

(ii) Revenue Cap for Transmission and Distribution Services

- For the first year of the regulatory control period 2006-2010, the RIC has proposed a tariff structure and prices for each customer class, which would be escalated annually by applying the RPI-X formula, with no further rebalancing of prices within the regulatory period without the RIC's approval.

Tariffs for 2006

Rate Class	Customer Charge $	Energy Charge (¢/kWh)	Demand Charge ($/kVA)
Residential (Bi-monthly):			
Up to 400 kWh	6.00	27.00	-
401 - 1000 kWh	6.00	31.00	-
Over 1000 kWh	6.00	34.00	-
Commercial (Bi-monthly):			
Rate B	25.00	38.00	-
Rate B1	Minimum bill of 5000 kWh	58.00	-
Industrial (Monthly):			
Rate D1	-	18.00	48.00
Rate D2	-	20.00	48.00
Rate D3	-	16.50	41.00
Rate D4	-	15.00	38.00
Rate D5	-	14.50	35.00
Rate E1	-	13.00	42.00
Rate E5	-	13.00	38.00
Street Lighting (Annually):			
S1 – 1	792.00	-	-
S1 – 2	528.00	-	-
S1 – 3	384.00	-	-
S1 – 4	348.00	-	-
S2 – 2	420.00	-	-
S2 – 3	324.00	-	-
S2 - 4	264.00	-	-

- T&TEC to set prices for year *t* such that the reasonable forecast annual revenue received from the service (ARR_t) complies with the following formula in **Box 1**:

Box 1: Formula for Establishing Annual Revenue Requirement

$$*ARR_t \leq (1 + RPI)(1 - X_t)) \times ARR_{t-1} + U$$

Where:

Year *t*	$\mathbf{X_t}$
2007	4.4
2008	4.4
2009	4.4
2010	4.4

ARR= Annual Revenue Received from Services.
ARR_{2006} = $1901.03 million.
RPI means the Retail Price Index as determined by the CSO.
U = Unused charge. T&TEC will be permitted to carry over any unused change in charges from one year to the following years.

The RPI will be calculated using the following formula:

$$RPI_t = \frac{\text{RPI June}_{t-1} + \text{RPI Sept}_{t-1} + \text{RPI Dec}_{t-1} + \text{RPI Mar}_{t-1}}{\text{RPI June}_{t-2} + \text{RPI Sept}_{t-2} + \text{RPI Dec}_{t-2} + \text{RPI Mar}_{t-2}}$$

Where:
- Year *t* is the year for which tariffs are being set
- $Year_{t-1}$ is the previous year
- $Year_{t-2}$ is two years previous.

The overall side constraint is set at (RPI + X) = 7.4%.

*** The formula is a slight variation from the standard (1 + RPI – X) formulation. This different version can assist in correcting, to some extent, for differences in forecast and actual RPI having any impact on the operation of the price control mechanism.**

3. **Annual Price Approval Process during the Control Period**

- At least two months prior to the beginning of each year of the regulatory control period, T&TEC must submit proposed tariffs to apply from the start of each year of the regulatory control period for verification of compliance by the RIC.
- T&TEC must ensure that its proposed tariffs comply with the established principles.
- T&TEC must, if requested by the RIC, provide additional information and resubmit or revise its proposed tariffs.
- The RIC must inform T&TEC in writing whether or not it has verified T&TEC's proposed tariffs as compliant with the relevant established principles.
- The proposed tariffs will be deemed to have been verified as compliant by the end of the two months from the date of receiving T&TEC's Annual Tariff Approval Submission.
- T&TEC must inform customers of the new tariffs at least two weeks before implementation through publication in at least one daily newspaper in circulation in Trinidad and Tobago.
- T&TEC is prohibited from introducing new tariffs and/or tariff components during the regulatory control period other than those approved by the RIC.

4. **Trigger Event**

A trigger event will apply only if it imposes a total annualized cost of more than one per cent of revenue.

Impact of RIC's Pricing Determination

The RIC has considered the impact of its pricing decisions on:

- customers, especially those in low-income and disadvantaged groups;
- inflation; and
- the country's competitiveness.

Average Bills

As can be seen from **Table ES.10**, a typical residential customer using 100 kWh should see nominal price increase in his final bill of $2.17 per month (from $13.18 to $15.35). Similarly, residential consumers using 250 kWh, would see their final bill going from $29.94 to $34.91 per month, that is, less than $4.97 per month. It is important to note that customers using up to 250 kWh bi-monthly comprise about 16% (or 50,977 customers) of total customers.

For customers reliant on government pensions, or falling into similar low-income groups, whose monthly income is about $1,150 and who consume about 200 kWh, their total monthly expenditure of $28.50 on electricity will be about 2.5% of their monthly income, well below the internationally accepted target of about 10%.

Table ES.10 – Impact on Bills of Price Increases for Typical Residential Customers, 2006

kWh	No. of Customers	Current		RIC Approved				
		Monthly $	Bi-monthly $	Monthly $	Bi-monthly $	Monthly Increase $	Bi-monthly Increase $	% Increase
100	20,768	13.18	26.35	*15.35	*30.69	2.17	4.34	**16.5**
250	30,209	29.94	59.88	**34.91	**69.83	4.97	9.94	**16.6**
400	43,266	46.70	93.40	**54.15	**108.30	7.45	14.90	**16.0**
600	62,744	69.05	138.10	88.00	176.00	18.95	37.90	**27.4**
800	49,514	91.40	182.80	119.00	238.00	27.60	55.20	**30.2**
1000	34,886	113.75	227.50	150.00	300.00	36.25	72.50	**31.9**
1300	32,181	147.28	294.55	201.00	402.00	53.72	107.44	**36.5**
1600	17,738	180.80	361.60	252.00	504.00	71.20	142.40	**39.4**

* This includes additional subsidy of 7%.

** This includes additional subsidy of 5%.

Similarly, a typical **commercial** customer (**Table ES.11**) using 500 kWh would see nominal price increase in his final bill of $38.85 per month (from $68.65 to $107.50), that is, $9.71 per week.

Table ES.11 - Impact on Bills of Price Increases for Typical B Commercial Customers, 2006

kWh	Current		RIC Approved			
	Monthly $	Bi-monthly $	Monthly $	Bi-monthly $	Monthly Increase $	Bi-monthly Increase $
500	68.65	137.30	107.50	215.00	38.85	70.70
1000	127.30	254.60	202.50	405.00	75.20	150.40
1500	185.95	371.90	297.50	595.00	111.55	223.10
2000	244.60	489.20	392.50	785.00	147.90	295.80
2500	303.25	606.50	487.50	975.00	184.25	368.50

The impact on typical industrial customers is shown in **Table ES. 12.**

Table ES.12 -Impact on Bills of Price Increases for Typical Industrial Customers, 2006

Rate Category	Current	RIC Approved
¢/kWh	23.71	18.00
D1: $KVA	21.75	48.00
Total Bill ($)	**7,188.88**	**9,024.00**
¢/kWh	22.16	20.00
D2: $KVA	21.75	48.00
Total Bill ($)	**90,365.46**	**101,700.00**
¢/kWh	13.86	16.50
D3: $KVA	26.08	41.00
Total Bill ($)	**308,798.96**	**413,896.32**
¢/kWh	13.86	15.00
D4: $KVA	26.08	38.00
Total Bill ($)	**200,021.62**	**247,438.40**
¢/kWh	13.86	14.50
D5: $KVA	26.08	35.00
Total Bill ($)	**659,790.18**	**749,479.51**
¢/kWh	13.10	13.00
E1: $KVA	23.60	42.00
Total Bill ($)	**3,066,467.65**	**3,653,196.56**
¢/kWh	13.10	13.00
E5: $KVA	23.60	38.00
Total Bill ($)	**18,615,010.98**	**21,847,925.40**

Impact on Inflation

Any inflationary impact is likely to be small as the average household electricity bill represents only 3.5% of average monthly national household expenditure, as at August 2005 (i.e. $157.10 of $4,474.49). Therefore, an average additional cost in electricity per month would increase the share of electricity cost on average monthly household expenditure by an estimated 0.03%.

Impact On Country's Competitiveness

The RIC considered the likely impact of increased electricity charges on different sectors of the economy and, consequently, on the competitiveness of these sectors. As **Table ES.13** shows, the contribution of increased costs of electricity would have minimal impact on total operating expenses of different industries in the country.

Table ES.13 - Contribution of Electricity to Total Operating Expenses

Industries	Electricity as % of Total Operating Costs (Before Price Increase) (2002)	Electricity as % of Total Operating Costs (After Price Increase)
Sugar	0.7	0.7
Petroleum and Other Mining	0.8	0.8
Food Processors and Drinks	1.1	1.2
Textiles, Garments, Footwear, Headwear	1.6	1.7
Printing, Publishing, Paper Converter	1.2	1.3
Wood and Related Products	1.4	1.6
Chemicals and Non-metallic Minerals	2.9	3.1
Assembly Type & Related Industries	8.9	9.6
Miscellaneous Manufacturing	2.2	2.4
Electricity and Water	3.0	3.3
Construction and Quarrying	0.1	0.1
Distribution	4.7	5.1
Hotels and Guest Houses	5.2	5.6
Transportation, Communication & Storage	0.5	0.5
Finance, Insurance, Real Estate & Business	1.4	1.4
Central and Local Government	1.0	1.0
Education	3.3	3.6
Personal Services	10.0	10.8
Total for All Industries	**1.6**	**1.7**

Source: Central Statistical Office, 2002

Moving Forward

The RIC's Final Determination on the regulation of the electricity transmission and distribution sector for the period 2006 to 2010 includes a number of responsibilities which the RIC will address during the regulatory period.

Prices reflecting the annual revenue requirements will be approved annually by the RIC in accordance with the provisions of this Determination. The RIC will continue to monitor and report regularly on T&TEC's financial, operational and quality-of-service performance.

A list of **specific directives** for T&TEC is presented in the Table below, as well as, a list of **final decisions**.

SPECIFIC DIRECTIVES

SPECIFIC DIRECTIVES	REMARKS
Chapter 2 • T&TEC is required to inform the RIC on a yearly basis of the balance in the "unders and overs" account. This report will be due within 30 days after the end of every year. If at the end of a year, the balance in the "unders and overs" account deviates from pre-allowed revenue targets, the following will apply: ▪ **Under 5%** - T&TEC must notify the RIC within the stipulated timeframe. ▪ **Over 5%** - T&TEC must notify the RIC but must also provide an action plan to resolve the balance.	2006/Ongoing
Chapter 3 • T&TEC is to ensure that in its next rate review submission, it provides a comprehensive analysis of actual performance vis-à-vis the determinations of the RIC and proposes suitable treatment for any deviations.	
Chapter 4 • In the next regulatory period T&TEC will be required to provide comprehensive demand forecasts that have been independently verified to ensure that their forecasts and forecasting methods are robust and reasonable. Specifically,	

T&TEC must demonstrate that the methodology: ▪ is appropriate for the electricity sector; ▪ reflects the key drivers of peak demand, customer numbers and energy consumption; ▪ has used the most recent information available, in conjunction with historic data, to identify trends in growth; and ▪ has taken into account demand side management.	
Chapter 5	
• T&TEC must ensure that its submission for the next regulatory review period conforms to the RIC's Information Requirements. Failure to do so will result in future submissions being delayed/rejected.	Ongoing
• T&TEC will be required to submit to the RIC annually audited accounting statements based on the Regulatory Accounting Guidelines stipulated by the RIC.	Ongoing/Annual
• T&TEC to put in place systems to collect data on total annual leave per employee (contracted, extended and emergency leave) as well as the additional costs incurred as a result of the relatively high rate of absenteeism on account of sick leave.	2006/Ongoing
• T&TEC to retain a consultant to review its organizational structure with a view to identifying weaknesses.	2006
• T&TEC to appoint a reputable consultant to suggest an appropriate policy on capitalization of salaries and wages.	2006
• T&TEC to put in place systems to identify separately the costs associated with the payment of cess and payments under the guaranteed standards scheme.	2006
• T&TEC to provide the details of internal energy consumption (both in terms of unit sales and amounts) from 2006 onwards.	2006/ongoing
• T&TEC to identify costs of Advertising and Marketing/Sponsorships separately.	2006

• T&TEC to: ▪ submit to the RIC annually its actual expenditure on Repairs and Maintenance; ▪ submit to the RIC quarterly reports on outages by area and reasons for outages; and ▪ repair and maintain pole mounted distribution transformers at a rate of 20% per annum and submit quarterly reports. • T&TEC must insist that every effort be made by PowerGen to reduce the system heat rate to the lower end of the range outlined in the PPA.	2006/ongoing 2006
Chapter 6 • The RIC has identified projects that should be fully funded by Government. These projects should be totally ring-fenced. If and when one of these projects is set to proceed, the RIC would require T&TEC to: ▪ demonstrate that the project will have no negative impact on any other users; ▪ show that accounting arrangements have been established to ensure capital and operating expense classification; and ▪ provide evidence that the associated costs are being fully covered by the Government. • T&TEC to provide a detailed review of the prudence of the capital programme at the end of the first regulatory control period. • T&TEC is required to provide the following information: ▪ an annual report of investment including an explanation of any divergence; ▪ the final costs of all projects completed during the regulatory control period; ▪ a full justification why any project included in the approved Capex programme was not carried out, including the external factors that changed after the forecasts were made; ▪ a full justification that any project completed above the forecast estimate, represented the best value for money; ▪ details of tenders received from all successful and unsuccessful bidders for any project externally contracted but completed above the forecast estimate; and ▪ detailed investigations of any divergence at the end of the price control period, with a correction to ensure that any unacceptable divergence is revenue neutral.	As necessary 2006/ongoing

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The RIC will also require in the future a detailed project-by-project capital expenditure programme with major projects to be audited by a person/consultant nominated by the RIC.
The RIC will require T&TEC to provide documented cogent explanations for Capex underspends. Only if it is satisfied by the justifications given, would the Capex portion of the appropriate portion of the underspend be allowed to roll-forward into the next regulatory period.

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Chapter 8

T&TEC to develop (in conjunction with the RIC) a framework for assessing the economic prudence of loss management investment during the first price control period.
The RIC requires that T&TEC install the appropriate metering/monitoring equipment at strategic locations of its network during the first regulatory period in order to more accurately measure losses in the system.

</td><td>2006</td></tr>
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Chapter 9

T&TEC will be required to:

publish information on the Guaranteed and Overall Standards, at least once per quarter and at least in one daily newspaper widely circulating in Trinidad and Tobago;
provide information, on the standards and how customers can claim compensation, at least twice per year in customers' bills. This requirement to be continued until the end of 2007;
ensure that claim forms are readily available at all T&TEC customer service offices/centres;
adequately display the standards in all T&TEC customer service offices/centres; and
provide to the RIC annual reports on its efforts to promote the standards (including evidence of newspaper advertisements, etc.).

T&TEC will be required to report to the RIC on a number of reliability measures by distribution area:

SAIFI (System Average Interruption Frequency Index) measures the probability that a customer will experience an outage.

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2006/ongoing</td></tr>
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▪ SAIDI (System Average Interruption Duration Index) provides a measure for the average time that customers are interrupted. ▪ CAIDI (Customer Average Interruption Duration Index) is a measure for the average time required restoring service to the average customer per outage ▪ MAIFI (Momentary Average Interruption Frequency Index) is the total number of momentary interruptions (of less than three minutes duration) that a customer could expect, on average, to experience in a year.	
▪ T&TEC must install equipment for monitoring quality of supply at each zone substation and at the far end of one of the distribution feeders supplied from each zone substation to better monitor voltage problems.	2006
• The RIC proposes that prior to setting any targets for voltage surges or voltage sags and harmonic distortions, the following quality of supply data be provided by T&TEC on an annual basis: ▪ Number of over-voltage events, and number of customers receiving over-voltage, due to high voltage injection. ▪ Number of over-voltage events, and number of customers receiving over-voltage, due to lightning. ▪ Number of over and under-voltage events, and number of customers receiving over and under-voltage, due to other causes. ▪ Number of voltage variations – steady state, one minute, 10 seconds.	2006/ongoing
• T&TEC must establish a suitable system to track performance and commence collection of data against the specified customer service parameters listed below: ▪ total number of calls; ▪ number of calls not answered within 30 seconds; ▪ average waiting time before a call is answered; ▪ number of complaints received and resolved by type; and ▪ resolution time (average, minimum and maximum by complaint).	2006
• T&TEC must also ensure that proper systems for recording and reporting information against these parameters are put in place by the end of 2006.	2006/ongoing

• As a minimum, T&TEC must: ▪ repair or replace any reported street light failure within 7 working days; ▪ replace photo-electric cells at least every 8 years or otherwise as required; ▪ clean, inspect for damage and repair luminaries during any re-lamping; ▪ routinely patrol major roads to inspect, replace or repair luminaries at least twice per year; ▪ commence installation within two weeks after payment is received; and ▪ consider implementing a telephone hotline number for customers to report street-lighting problems. Additionally, T&TEC must submit to the RIC annual reports on the above performance targets.	 2006/ongoing
• T&TEC should develop a more customer friendly damaged appliance policy. The policy must state the nature and scope of the investigations T&TEC conducts to arrive at its decision. Additionally, the RIC will establish a Working Group, comprising NGOs, Business Organizations, T&TEC and the RIC, to develop a more comprehensive policy on damaged appliances. There is also the need for T&TEC to have information available in all its offices about exactly what customers need to do in order to make a claim for damaged appliances. In addition, T&TEC should also educate customers about the need for proper surge protection devices for appliances without endorsing a particular brand or type of protective device.	2006/ongoing
• The RIC accepts that large customers may have found it difficult to negotiate service provisions in their connection agreements. Consequently, the RIC will seriously consider measures that facilitate large customers being able to negotiate for service levels above the standard service provided. If these customers and T&TEC agree to specific service levels, then T&TEC will be required to monitor and report to these customers on the measures and at the intervals specified in the agreement.	2006
• T&TEC must not issue two or more consecutive estimated bi-monthly bills; and	

• An estimated bill must be based on the average of the last four billings. The RIC will also encourage T&TEC to consider reorganization of its billing procedures so as to generate bi-monthly bills based on a fixed number of days.	
Chapter 12 • T&TEC must submit proposed prices (rates) at least two months before the beginning of each year of the regulatory control period and the RIC will approve or reject prices within a month of the submission and allow another week to re-submit prices if rejected.	2006/ongoing
Chapter 14 • T&TEC must consider the rationalization of its administration of regulatory requirements. • T&TEC is required to inform the RIC of long-term supply contracts or any other contract likely to affect customer rates or services. Further, T&TEC must ensure that the involvement of and approval by the RIC occurs prior to the execution of any such contracts. • T&TEC is required to publish its procurement procedures and submit same to the RIC. • T&TEC must demonstrate a commitment to the promotion of competition in areas such as the installation of street lighting, metering/meter reading etc. by publicly inviting bids for such works/services.	

FINAL DECISIONS

Chapter 2

The RIC's decisions are:

- to utilize a fixed revenue cap form of regulation in the first regulatory control period.

- to utilize the cost "building-block" approach to setting revenue caps and will incorporate incentives for expected efficiency gains.

- to utilize X as a smoothing device and a single X-factor to reduce the volatility in annual revenues.

- to use RPI as the inflation factor.

- to adopt a five-year regulatory period for this determination.

- not to utilize an error correction factor to automatically adjust revenue forecasts.

- the operation of the "unders and overs" account in the form described and the proposed annual tolerance limits and actions for treatment of variations.

- to include and provide for a within-period adjustment to the revenue cap under strict conditions.

Chapter 3

- The service providers will be required to provide a comprehensive analysis of actual performance vis-à-vis the determination of the RIC and to propose suitable treatment for any deviations.

Chapter 4

- The RIC's decision is to adopt demand forecasts for customer numbers, energy consumption and peak demand as shown in **Tables 4.2, 4.3 and 4.4** in Chapter 4.

- For future price reviews, the service provider will be required to obtain and provide to the RIC, independent verification that its forecasts and forecasting methods are robust and reasonable. The RIC will also ensure that the independent auditor's report is made public.

Chapter 5

The RIC's decisions are:

- to adopt total transmission and distribution expenditure (excluding conversion and fuel costs) as indicated in **Table 5.7** in Chapter 5.

- in the case of unforeseen uncontrollable costs, each event for pass-through be assessed on its merits and on a case-by-case basis.

- to establish a materiality threshold for any potential trigger event at 1 percent of actual annual regulated revenue per event.

- that the use of automatic adjustment clauses be discontinued as these clauses do not generally form part of incentive regulation and have been a source of confusion for customers.

- that Government/T&TEC should seek to re-negotiate more favourable terms in respect of PPA contracts.

- to allow a pass-through of 98% of conversion costs for the first regulatory control period as proposed in **Table 5.14.**

- in order to provide the right incentives and save on fuel costs, there should be only 90% pass-through of fuel costs and the costs for failing to introduce combined cycle plant should not be borne by the consumer and, accordingly, have not been considered in the revenue requirement. Further, in the future, all additional capacity sourced should be through the installation of combined cycle units.

- to adopt fuel costs as proposed in **Table 5.19** in Chapter 5.

- to adopt total operating costs for the first regulatory control period as proposed in **Table 5.20** in Chapter 5.

Chapter 6

The RIC's decisions are:

- to include capital expenditure forecast for T&TEC of $800 million for the first regulatory control period.

- to use regulatory audits to monitor the progress in improving the quality of T&TEC's asset management systems.

- as part of capital expenditure assessment, that T&TEC will be required to present capital forecasts for three scenarios:
  - maintaining the current service quality level;
  - improving service quality aimed at delivering an agreed average level of service; and
  - specific additional commitments aimed at improving the quality of service in specific parts of the network or addressing identified customer requirements and including clearly identified service quality outcomes.

- to include capital expenditure in the regulatory asset base when the asset comes into service.
- to continuously monitor capital expenditure during the regulatory control period.
- to publish details annually of T&TEC's actual capital expenditure against proposed capital expenditures.
- to identify failure to deliver major capital projects against the timelines proposed and seek explanations as to the reasons for such failures.
- to audit the asset management capability and conduct an audit of major capital expenditure as part of the regulatory audit programme.

Chapter 7

The RIC's decisions are:

- to use a value based on historical cost valuation in setting the initial regulatory asset base for the first regulatory control period
- to determine working capital for the first price control period as follows:

$$\textbf{Working Capital} = \textbf{Total Revenue from Sales} \times \frac{\mathbf{57}}{\mathbf{365}}$$

$$\textbf{Less: Operating Costs} \times \frac{\mathbf{30}}{\mathbf{365}}$$

- to apply interest during construction only to those projects that span several years and to not allocate CWIP across asset categories during the roll forward but will remain as a financial entry only.
- to allow contributed assets to be incorporated into the RAB and recognise contributions in the year of receipt as a revenue flow.
- to approve the depreciation profile (based on historical cost on a straight-line basis) and the effective asset life proposal of T&TEC as these lives generally reflected current experience in the utility industry, for this regulatory control period.
- to establish the opening regulatory asset base for the 2006-2010 regulatory period by rolling the regulatory asset base at December 2004 on the basis of the forecast capital expenditure proposed by the RIC.
- not to include a return on equity.
- to ensure T&TEC initiate debt restructuring immediately with a view to negotiating lower interest rates.

- to apply a cost of capital of 8.0% for the first regulatory control period for the purpose of calculating the building-block allowance for the return on capital.

Chapter 8

The RIC's decisions are:

- to implement a rolling carryover mechanism.
- to utilize a P_o adjustment to share out-performance.
- to utilize a mechanism for sharing profits with customers if profits exceed 10% of the total revenue forecasts.
- to have T&TEC maintain an "unders and overs" account in respect of actual revenues versus the forecast revenues. T&TEC to report to the RIC on a yearly basis of the balance in the account.
- to use the following mechanisms, if the balance in the "unders and overs" account deviates:
    - Under 5%, T&TEC must notify the RIC within 30 days after the end of every year.
    - Over 5%, T&TEC must notify but must also provide an action plan to resolve the balance.
- to incorporate the principles in section 8.6 for the calculation of the efficiency carryover amount and the outstanding "unders and overs" account balances to be incorporated into the revenue requirements for the 2011-2015 regulatory control period.
- to adopt the initial level of system losses at 7.9% and set the target for reduction in loss levels for the first regulatory control period at 6.75%.
- to allow T&TEC to keep 90% of the gains if actual system losses fall below 6.75%, the sharing of the gains to occur at the end of the regulatory control period.
- to support the principle of taking into account the value of loss reduction into the asset base when it is rolled forward to encourage investment in the loss reduction equipment.
- to ensure that T&TEC installs the appropriate metering/monitoring equipment at strategic locations of its network during the first regulatory control period.

Chapter 9

The RIC's decisions are:

- not to include a performance incentive mechanism (S-factor) for the first regulatory control period.

- to ensure that T&TEC prepares and submits Codes of Practice for the RIC's approval before the end of the first quarter of 2007 on the following:
  - Provision of Priority Services for Vulnerable Groups;
  - Procedures for Dealing with Customers in Default;
  - Debt Recovery and Disconnection Procedures and Policies;
  - Retroactive Billing Policy;
  - Range and Accessibility of Payment Methods;
  - Handling of Complaints; and
  - Continuous Consumer Education.

- to appoint an independent agency to design and administer a customer satisfaction survey and present its conclusions in a report which will be posted on its website and made available to stakeholders and all interested parties at the beginning of each price control period.

- not to introduce changes to the current scheme at this time. The RIC will review the scheme at the end of three years (i.e. in 2007) for appropriate action/proposals.

- to ensure effective promotion of the current scheme, T&TEC will be required to:
  - publish information on the Guaranteed and Overall Standards, at least once per quarter and at least in one daily newspaper widely circulating in Trinidad and Tobago;

  - provide information, on the standards and how customers can claim compensation, at least twice per year in customers' bills. This requirement to be continued until the end of 2007;

  - ensure that claim forms are readily available at all T&TEC customer service offices/centres;

  - adequately display the standards in all T&TEC customer service offices/centres; and

  - provide to the RIC annual reports on its efforts to promote the standards (including evidence of newspaper advertisements, etc.).

- that the service incentive arrangements for the first price control period should consist of the Guaranteed Payment Scheme and Performance Reporting Requirements.

- to consider the inclusion of the public (street) lighting targets in its Guaranteed Standards Scheme for the second regulatory control period.

- the RIC's decision is to introduce a late payment charge of 1.5% per month on all customers.

- that T&TEC must improve the reliability of service to its largest customer, and failing that, the RIC may consider the introduction of a special regime of interruptible tariffs.

Chapter 10

- The RIC does not intend to provide the flexibility to automatically adjust the list of services or charges during the price control period.

- The RIC will continue to regulate the current set of miscellaneous services.

- The RIC considers a fee-by-fee cap to be reasonable for miscellaneous charges.

- To prevent the proliferation of miscellaneous services, the RIC considers the current list of approved miscellaneous charges to be exhaustive.

- The RIC will exempt pole and transformer rentals from the miscellaneous schedule.

- The RIC's decision is that charges for miscellaneous services can increase by the RPI from 1992 via a once-only adjustment. No further increase will be permitted for the duration of the first control period.

- The RIC requires T&TEC to put systems in place to capture and record the various efficient cost components involved in providing miscellaneous services. These costs are to be verified by an independent party.

- The RIC's decision is that there should be at least one free meter test every 5 years regardless of the result of the test.

- The RIC considers that the service deposit issue needs further investigation, and will establish a Working Group comprising the service provider, NGOs, other consumer interests, and the RIC. This group will develop proposals on service deposit issues and report to the RIC within six months of the establishment of the Working Group.

- The RIC will set up a Working Group comprising the service provider, NGOs, other consumer interests, and the RIC. This group will develop proposals on capital contribution issues and report to the RIC within six months of the establishment of the Working Group.

Chapter 11

The RIC's allowed annual revenue requirements are as follows:

2006 ($Mn)	**2007 ($Mn)**	**2008 ($Mn)**	**2009 ($Mn)**	**2010 ($Mn)**	**TOTAL ($Mn)**
1,888.74	1,988.75	2,256.42	2,361.89	2,606.44	11,102.24

- The RIC's decision is to adopt the NPV smoothing approach as it allows the service provider to recover fully its revenue requirements, as well as minimize price volatility for customers.

Chapter 12

- For the first regulatory period, the RIC intends to accept cost allocation based on the fully distributed cost method. In future, the RIC will require T&TEC to submit marginal cost analysis that could be used for the development of tariffs.
- The RIC intends to incorporate a rebalancing control (side constraint) as part of the first regulatory price control.
- The RIC intends to set the size of the side constraint on the expectation that it would broadly allow the achievement of cost reflective pricing by the end of the first regulatory control period.
- The RIC requires that T&TEC must, at least two months prior to the beginning of each year of the regulatory control period, submit proposed tariffs to apply from the start of each year of the regulatory control period for verification of compliance by the RIC.
- T&TEC must ensure that its proposed tariffs comply with the established principles.
- T&TEC must, if requested by the RIC, provide additional information and resubmit or revise its proposed tariffs.
- The RIC must inform T&TEC in writing whether or not it has verified T&TEC's proposed tariffs as compliant with the relevant established principles.
- The proposed tariffs will be deemed to have been verified as compliant by the end of the two months from the date of receiving T&TEC's Annual Tariff Approval Submission.
- T&TEC must inform customers of the new tariffs at least two weeks before implementation by publishing in at least one daily newspaper in circulation in Trinidad and Tobago and by the use of other media.

- T&TEC is prohibited from introducing new tariffs and/or tariff components during the regulatory control period other than those approved by the RIC.

- The RIC requires T&TEC to implement the following Demand Side Management techniques:
  - strategic conservation by creating a database of energy efficient appliances and products to be recommended for consumer use; and
  - consumer tips for strategic conservation.

- The RIC also intends to incorporate incentives in the regulatory framework for T&TEC to invest in demand management initiatives.

- The RIC requires T&TEC to undertake a study and report to the RIC within 18 months after the release of the Final Determination on the feasibility of implementing time-of-use tariffs for its customers.

Chapter 13

- The RIC will periodically review its Performance Monitoring and Reporting (PMR) Framework. In the meantime, no changes are proposed to the indicators as set out in the **Annex** to Chapter 13.

- The RIC will consider measures over the coming regulatory period that facilitate large customers being able to negotiate for service levels above the standard service provided.

- The RIC will develop and publish the Regulatory Accounting Guidelines within six months of the release of the Final Determination.

RIC'S RESPONSE TO STAKEHOLDER COMMENTS –

A SUMMARY

Stakeholder Comment	RIC's Response
1. Request for extension of the date for submission of comments.	Deadline for submission was extended from January 17, 2006 to May 15, 2006.
2. Issues relevant to tariffs: • Request for reduction of the fixed charge for residential customers.	- Fixed charge for residential customers reduced from $8.00 to $6.00 bi-monthly.
• Request for elimination of Natural Disaster Preparedness Charge.	- RIC decided not to impose a natural disaster preparedness charge on customer billings. **However**, T&TEC is being asked to open an account with funds from Government/T&TEC amounting to $5 million deposited annually over the 5-year period and to stock emergency supplies of critical items for use in the event of a natural disaster.
• Introduce either a flat rate per kWh or a sliding scale rate in which the first few units are charged a higher rate.	- RIC considers its proposed tariff structure to be appropriate.
• Increases will lead to a rippling effect on prices.	- RIC maintains that there will be a marginal impact on the rate of inflation and that, on average, electricity costs of total cost will increase from 1.6% to 1.7%. - RIC will work closely with the Consumer Affairs Division to ensure that consumers are aware of the facts.
• T&TEC should reduce/ eliminate electricity theft in certain areas.	- T&TEC to consider the installation of insulated secondary distribution wires to mitigate against throw-ups. - T&TEC to seek co-operation of the residents in the affected areas.

<table>
<tr><th>Stakeholder Comment</th><th>RIC's Response</th></tr>
<tr><td>• T&TEC has requested increase in Capital Expenditure (Capex). However, the Shareholder (Government) has indicated that it will provide funding for T&TEC to finance some projects.</td><td>- RIC has adjusted its Capex forecast downward from $998.4 million to $800 million, thereby reducing the revenue requirement by $16 million over the 5-year control period.</td></tr>
<tr><td>• Based on actual figures for Opex, T&TEC has requested an increase in Opex (operating expenditure).</td><td>- Opex to be increased for personnel costs but no other adjustments being made to Opex.</td></tr>
<tr><td>• T&TEC has indicated that its debt to NGC has been growing at a monthly rate of approximately $43.5 million since September 2005 and that its liability to NGC as at April 30, 2006 was $389.2 million.</td><td>- The RIC is of the view that the Government should assume responsibility for the accumulated debt to the NGC since September 2005. In fact, the Shareholder (Government) has agreed to give consideration to the provision of funds to assist T&TEC in servicing its debt obligation in the sum of $283 million.</td></tr>
<tr><td>• NGC has requested an increase in the annual escalation factor from 3% to 4% or an increase in the price of gas from US$1.05 to US$1.065/MMBTU with an escalation factor of 3%.</td><td>- RIC considers its proposed annual escalation factor of 3% and the price of natural gas of US$1.05/MMBTU reasonable.</td></tr>
<tr><td>3. Subsidies/Cushioning the Impact:
- Subsidies for lower income groups (i.e. below 400 kWh) and retired persons not sufficient.</td><td>(i) RIC's Tariffs for Residential Customers - 2006:
<table>
<tr><th></th><th>Draft Determination</th><th>Final Determination</th></tr>
<tr><td>Up to 400 kWh</td><td>29 ¢/kWh</td><td>27 ¢/kWh</td></tr>
<tr><td>401-1000 kWh</td><td>32 ¢/kWh</td><td>31 ¢/kWh</td></tr>
<tr><td>Over 1000 kWh</td><td>35 ¢/kWh</td><td>34 ¢/kWh</td></tr>
</table></td></tr>
</table>

<table>
<tr><th>Stakeholder Comment</th><th>RIC’s Response</th></tr>
<tr>
<td>- First year increases too high for residential customers.

- No cross-subsidization.</td>
<td>(ii) RIC’s Discounts for Electricity Consumption:
- Customers between 0-400 kWh get 44.9% discount
- Customers between 401-1000 kWh get 30% discount
- Customers over 1000 kWh get 20.0% discount.

(iii) Fixed Dollar Discount on Customer Charge:
- Customer using less than 400 kWh get a subsidy of $0.53 million
- Total subsidy for customer charge to all residential customers - $1.6 million.

(iv) Total Subsidy to Residential Customers:
<table>
<tr><th></th><th>Draft Determination</th><th>Final Determination</th></tr>
<tr><td>Fuel Cost Subsidy</td><td>$167 million</td><td>$167 million</td></tr>
<tr><td>Total Subsidy</td><td>$209 million</td><td>$224 million</td></tr>
</table>
(v) Low Income Assistance Programme ($5 million):
<table>
<tr><th></th><th>Draft Determination</th><th>Final Determination</th></tr>
<tr><td>Bill Assistance</td><td>Not specified</td><td>7% of Bill for below 100 kWh</td></tr>
<tr><td></td><td>Not specified</td><td>5% of Bill for 101-400 kWh</td></tr>
</table>
(vi) - Cross-subsidization by the industrial customers has been reduced from $215 million in 2005 to $57 million.

- The subsidy to commercial and street-lighting has been eliminated.</td>
</tr>
<tr>
<td>4. Quality of Service Issues:
- Main problem areas of concern to consumers:

▪ Complexity of Bills

▪ Estimated Billing</td>
<td>▪ Bills simplified – only two rate elements (fixed charge and energy charge).

▪ There now has to be three actual readings per year for residential customers and estimated billing has to be based on last four billings (rather than last three actual readings as proposed in the Draft Determination).</td>
</tr>
</table>

Stakeholder Comment	RIC's Response
▪ Damaged Appliance	▪ Establishment of a Working Group comprising key stakeholders to develop damage appliance policy within the first 6 months of the finalization of the Determination.
▪ Voltage Fluctuations	▪ **T&TEC to:** * Repair/maintain/replace 20% of transformers every year. * Service/maintain/repair "On Load Tap Changers" (OLTC) in the distribution substations. * Repair/install capacitor banks at overloaded substations.
▪ Capital Contribution	▪ Establishment of a Working Group comprising key stakeholders to develop proposals on capital contribution issues.
▪ Repairing of Street Lights	**T&TEC to:** ▪ Repair/replace reported street light failure within 7 working days. ▪ Replace photo-electric cells at least every 8 years or as required. ▪ Routinely patrol major roads to inspect; replace or repair luminaries at least twice per year. ▪ Implement a telephone hotline number for customers to report street-lighting problems.
▪ Free meter test requirement is contrary to T&TEC's Act	▪ RIC continues to hold the view that there should be one free meter test every five years and that its proposal is not contrary to T&TEC's Act.
▪ Request by a major customer for compensation for unreliability in supply	▪ T&TEC to improve reliability to this customer by first quarter of 2007. Otherwise, the RIC may consider the introduction of a special regime of interruptible tariffs.
▪ Enforcement of Standards	▪ RIC will immediately establish its "Performance Monitoring and Reporting Framework" (PMR).

Stakeholder Comment	RIC's Response
5. Methodological Issues: • Request to reduce the length of the regulatory control period to three years. • Request to use Total Factor Productivity approach for determining the X-factor vs the Building-Block approach	 • RIC considers a five-year regulatory control period to be appropriate. • RIC considers the Building-Block approach to be appropriate.
6. General: • Restructure the electricity sector. • Regulate the generators.	 • RIC to review the current institutional arrangements in the sector and prepare a paper for public comments. • RIC to formulate performance benchmarks for generators.

CHAPTER I

INTRODUCTION

1.1 ECONOMIC REGULATION UNDER THE RIC ACT 1998

The Regulated Industries Commission (RIC) is the jurisdictional regulator for the approval of electricity and water rates in Trinidad and Tobago.

The Regulated Industries Commission (RIC) Act, No. 26 of 1998, has outlined the contours of a framework for the regulation of electricity, and the water and wastewater sectors. This Act prescribes the setting up of a Board of Commissioners with a mandate *inter alia* to establish the principles and methodologies by which service providers determine rates for services, to promote efficiency, to prescribe and monitor standards for services, to facilitate competition, to ensure fair returns to service providers and to ensure transparency in the performance of its functions.

1.2 LEGAL FRAMEWORK FOR SETTING PRICE CONTROLS

Sections 48 and 67 (2), (3) and (4) of the RIC Act broadly define the role of the RIC in determining tariffs. In seeking to achieve its primary functions for the setting of price controls, the RIC is required to have regard to the following objectives:

- the protection of consumer interest with regard to the price, quality and reliability of services;
- the facilitation of efficiency and economy of operations by service providers;
- the facilitation of competition where competition is possible and desirable;
- the facilitation of the financial viability of service providers;
- the need to ensure that regulatory decision-making has regard to current national environmental policy; and
- the fairness and transparency of the price determination.

Further, in respect of price reviews, under Section 67 of the RIC Act, the Regulations provide that the RIC may:

- prescribe the procedure for the conduct of price reviews;
- prescribe forms of accounts and records to be kept by service providers;
- prescribe sanctions for non-compliance; and
- prescribe any matter or thing that is required by the Act to be prescribed.

Some other salient features of the RIC Act are that:

- the tariffs, as determined by the RIC, shall not be amended or modified more than once in any year;
- the service provider must justify a price review by setting out projected revenues against projected expenditure and reasons for any significant changes thereof; and
- the service provider must set out the results of any actions taken to meet the projections of any preceding review.

1.3 PROCEDURE FOR PRICE CONTROL REVIEW

Section 49 of the RIC Act specifies the procedure to be followed for establishing the principles and methodologies for determining rates and charges for services as follows:

- a written notice to the RIC requesting a review of the principle or rate in such manner and accompanied by such information as specified in Section 49 (2);
- the notice to be published in the Gazette and at least one daily newspaper;
- the RIC shall consult with stakeholders and other parties not later than three months after receipt of the notice;
- the RIC shall notify the service provider in writing where it is of the opinion that a review is not warranted;
- the RIC may determine the matter by modifying the existing principle or establishing a new principle; and
- the period between the date of the notice and a determination by the RIC shall not exceed six months.

1.4 REVIEW PROCESS

By letter dated November 08, 2004, the Trinidad and Tobago Electricity Commission (T&TEC) requested a review of its existing rates and charges.

The staff of the RIC carried out a preliminary scrutiny of the submission and met with T&TEC's officials on November 26, 2004 to discuss identified weaknesses and discrepancies in the submission. Considering the information gaps in the submission, a detailed request was sent to T&TEC on December 2, 2004 for the provision of information for addressing each deficiency. T&TEC was again written to on January 12, 2005 reminding it to submit the requested information along with other clarifications sought by the staff of the RIC in its various letters and meetings. Items requested are listed in **Table 1.1**.

Pending reply on many of the queries and issues raised in **Table 1.1**, the process of analysis and price control determination began.

Having received and reviewed most of the required information and keeping in view its role to promote efficiency and economy in the activities of the electricity industry, the RIC, in order to proceed further in spite of some outstanding informational deficiencies, accepted T&TEC's submission (Notice) at its meeting on February 15, 2005.

By letter dated February 21, 2005, the line Ministry (Ministry of Public Utilities and the Environment) was informed of the acceptance of the notice with a request to Gazette the salient features of the submission in accordance with the RIC Act. The legal notice was gazetted on December 01, 2005.

As provided in the RIC Act, the RIC published the salient features of T&TEC's submission in the Guardian newspaper on June 30, 2005. A summary of the details of T&TEC's submission was made available to the public at the RIC's office and was also placed on its website.

Table 1.1 – T&TEC's Submission and Information Requests

Information/Data Requested	Date of Request
• T&TEC submitted its "Review of Tariffs" Application.	November 08, 2004
• T&TEC's Presentation of Business Plan to the RIC.	November 26, 2004
• RIC's Request for detailed Information from T&TEC on: - Non-controllable costs and Heat Rate - Current and Projected levels of Operating Costs, including: ▪ Cost of service study for 2003 ▪ Detailed explanation of the methodology for allocating costs ▪ Maintenance expenditure by preventive, reactive and active maintenance expenditure ▪ Financial costs including: projected borrowing, interest and charges, bad and doubtful debts etc. ▪ Staffing levels: permanent and temporary employees, crew sizes and types of crews with functions, wages and salaries breakdown and overtime. - Efficiency improvements and strategies for achieving gains - Cost of capital determination and methodology employed - Methodologies and demand forecasts - Capital expenditure breakdown into renewal, growth related, quality enhancement expenditure, and procurement methods.	December 2, 2004
• Data regarding the plant heat rates and computation of level of Total Factor Productivity for the period 1989-2004.	December 13, 2004
• Reminder letter and prioritization of information request to T&TEC, including: - Analysis of Bad Debt - Non-controllable costs - Measurement of system losses - Fixed assets and depreciation rates	January 12, 2005
• Status report and reminder of data request of January 12, 2005	February 11, 2005
• Reminder letter on outstanding data request and new request for data on personnel expenses by business function, accumulated depreciation by asset category, length of transmission and distribution lines, collective bargaining agreements.	April 06, 2005
• Request for information on additional capacity and forecasts of energy purchases.	May 13, 2005

1.5 CONSULTATION PROCESS

The RIC is mandated to follow a transparent procedure in the determination of tariffs, taking into account the view of stakeholders and representatives of consumer interest groups and any other interested parties. The RIC is of the view that as the rates impact on the lives of every member of society, it is important for everyone to be able to participate and have the opportunity to express their opinions on the formulation of recommendations. Therefore, an integral part of the RIC's methodology has been to engage in broad-based consultation with key stakeholders and the general public so as to ensure that the rate review process is meaningful and effective. Public consultation also assists the RIC in identifying and balancing competing interests before arriving at a preferred approach.

Furthermore, the RIC believes that, in making its determinations/decisions, it must publish full and reasonable details of the basis of and rationale for the determinations/decisions including but not limited to the following:

- reasonable details of qualitative and quantitative methodologies applied including any calculations and formulae; and
- options considered and discretions exercised that have a material bearing on the outcome of the determination/decision.

To pursue these objectives, the RIC sought ways to maximize its interaction with stakeholders and all other interested parties and improve the effectiveness of the consultation process.

To facilitate communication between the RIC and stakeholders, the RIC established a dedicated area on its website (**www.ric.org.tt/T&TECReview**) for T&TEC's price review. At this site[1], stakeholders were able to view copies of all consultation documents, any submissions received in response to those papers, updates on the progress of the review, and information on how to participate in the various stages of the review.

[1] Documents are still available on the website.

Generally, in undertaking consultations, the process involves the prior release of consultation documents and hosting public information sessions and discussion forums. In the case of this review, the RIC's consultation process comprised the three stages outlined below.

First, the RIC released its Consultation Document, "**Information Requirements: Business Plan 2004-2008 (November 2004)**", which provided guidance to the service provider on the preparation of its price review submission. The aim of this document was to have the service provider present its submission and other information in a consistent format. This document was placed on the RIC's website for public scrutiny.

Second, the RIC released eleven consultation documents, including a methodology paper, "**Setting Price Control: Framework and Approach (April 2005)**", which presented the RIC's initial thinking on the methodology that would be used to arrive at the service provider's price controls. This was followed by the first consultation which was held in Port-of-Spain on May 10, 2005. Public notices for this consultation were issued in the daily newspapers. Eight open house consultations were also held in different parts of the country to enable the public to express their views. The RIC also engaged a consultant (Kenesjay Systems Limited) to provide advice on the investment programme of T&TEC and on an appropriate asset valuation methodology. Round table discussions on the preliminary views of the consultant's work were also held.

The RIC received approximately 93 objections/comments from the public. The public meetings also provided a forum for participants to ask questions, air their concerns and issues, and obtain clarification on the RIC's processes. The RIC considered all the comments/responses provided by the public and T&TEC in finalizing its **Draft Determination**.

The RIC held a Press Conference on its Draft Determination on January 18, 2006 during which a powerpoint presentation was made and a hard copy of the Executive

Summary and a soft copy of the full document were distributed. The Draft Determination was also placed on the RIC's website (www.ric.org.tt) on the same day.

A supplement summarizing the RIC's Draft Determination was published in the daily press on January 19, 2006 and the public's written comments were expected by February 17, 2006. The RIC appeared on three television stations as well as on radio talk shows. Additionally, the RIC organized five (5) public consultations designed to garner the views of a wide cross section of consumers, as well as give the stakeholders an opportunity to be heard and make representations to the RIC. At these meetings, the RIC elaborated its tariff proposals via a powerpoint presentation and the public was given an opportunity to present suggestions, pose questions and to express concerns. The consultations were held as follows:

- Port-of-Spain - February 06, 2006
- Arima - February 06, 2006
- Chaguanas - February 07, 2006
- San Fernando - February 09, 2006
- Tobago - February 10, 2006

The RIC regards hosting consultations as an important aspect of its mandate to regulate the sectors, to effectively provide the highest quality services at reasonable rates and to ensure the service providers' viability and sustainability. Public participation enhances the RIC's ability to carry out its work in an efficient, transparent and fair manner. However, given the poor attendance at the above-mentioned consultations and in a further attempt to engage the wider community, the RIC also organized a national consultation on March 07, 2006. The response in this instance was more encouraging as one hundred and eleven (111) persons attended, representing a wide cross-section of the society. A number of useful submissions were made. This was followed by the publication of a supplement in the daily newspapers on March 11, 2006 summarizing some of the major issues, such as the new proposed standards, costs to achieve the desired quality of service standards, cushioning the impact of rate increases, calculation of new bills and some other measures for the consideration of the Government. The RIC also responded, in writing, to letters and opinions that appeared in the daily press.

The RIC published its "**Response to the Stakeholder Comments on the Draft Determination**" on June 01, 2006.

The RIC has considered the comments/responses provided by all interested parties in this its Final Determination. The **Annex** lists the organizations/individuals that submitted written comments and attended the consultations.

Box 1.1 provides a summary of the RIC's approach to information collection and decision-making, while **Table 1.2** details the full consultation process of the RIC.

<u>Box 1.1 – RIC's Approach to Information Collection and Decision-Making</u>

The RIC's review included an extensive investigation and public consultation. As part of this review, the RIC:

- released its consultation document, "Information Requirements: Business Plan 2004-2008", which provided guidance to the service provider on the preparation of its price review submission
- required service provider to provide extensive financial and performance data to justify its proposal
- released 10 issues papers for public comment
- held public consultations on the 10 issues papers and invited comments
- engaged a consultant to review service provider's capital expenditure and asset valuation methodology
- held a public meeting on the consultant's draft report
- gave the service provider the opportunity to respond to the findings of the consultant
- released its Draft Determination for public comment detailing the decisions made and the reasons for them, and inviting public submissions
- held public consultations on the Draft Determination
- considered the public submissions received on the Draft Determination
- published and released its Final Determination.

Table 1.2 – Consultation Process

Activity	Timeframe
• **Release of Documents for public comment:**	
- Information Requirements: Business Plan 2004 – 2008	November 2004
- Setting Price Control: Framework and Approach	April 2005
- Review of the State of T&TEC (1995 – 2003)	May 2005
- Receivables Policy for T&TEC	March 2005
- Sharing of Benefits of Efficiency Gains and Efficiency Carryover Mechanisms	June 2005
- Incentive Mechanisms for Managing Transmission and Distribution Losses - Trinidad and Tobago Electricity Commission	May 2005
- The Treatment of Uncontrollable Costs in Incentive Regulation - The Case of the Trinidad and Tobago Electricity Commission	June 2005
- Performance Monitoring and Reporting Framework	May 2005
- Approaches to Determining Regulatory Depreciation Allowances	May 2005
- Benchmarking – Its Applicability to Assessing Costs Efficiency	June 2005
- Performance Indicators for the Trinidad and Tobago Electricity Commission	April 2005
• **Public Consultation, Port-of-Spain**	May 10, 2005
• **Other Stakeholder Meetings and Consultations:**	
- Trinidad and Tobago Chamber of Industry and Commerce	June 06, 2005
- Federation of Independent Trade Unions (FITUN) and NGO's	June 07, 2005
- National Trade Union Centre (NATUC) and the Seamen and Waterfront Workers Trade Union (SWWTU)	June 13, 2005
- South Chamber of Industry and Commerce	June 16, 2005
- Couva/Point Lisas Chamber of Industry and Commerce	
- Greater Chaguanas Chamber of Industry and Commerce	
- Trinidad and Tobago Association of Village Councils	June 25, 2005
- Local Government Corporations/Bodies	July 06, 2005
- Tobago	August 25, 2005
• **Open Discussion** on Asset Valuation Methodologies	June 22, 2005
• **Open Discussion** on T&TEC's Investment Plan.	July 15, 2005
• **Consultation with the Shareholder**	November 21, 2005
• **Release of Draft Determination**	January 18, 2006
• **Stakeholder Meetings/Consultations:**	
- Port of Spain	February 06, 2006
- Arima	February 06, 2006
- Chaguanas	February 07, 2006
- San Fernando	February 09, 2006
- Tobago	February 10, 2006
• **National Consultation**	March 07, 2006
• **Publication/Release of RIC's Response to Stakeholder Comments on Draft Determination**	June 01, 2006
• **Publication/Release of Final Determination**	June 01, 2006

1.6 STRUCTURE OF THIS DOCUMENT

This document outlines the RIC's process for conducting this review, and explains the context of the review and the main issues the RIC has considered in making its final price determination, including how and why it reached its decisions and what those decisions mean for the customers and other stakeholders. The issues covered by each section in this document are as follows:

- Chapter 2 provides an outline of the RIC's regulatory framework and sets out the RIC's proposed methodology on the main regulatory issues;

- Chapter 3 briefly analyses the performance of T&TEC during the period 1999-2003;

- Chapter 4 details the RIC's proposed approach to determining the growth forecasts, including peak demand, customer numbers and energy consumption, for the first control period;

- Chapter 5 assesses issues related to operating and maintenance expenditure, power purchase costs and fuel costs and sets out the RIC's decision regarding the operating expenditure allowances to be applied over the control period;

- Chapter 6 analyses issues related to proposed capital expenditure requirements and the determination of the forecasts of capital expenditure;

- Chapter 7 sets out the manner in which the regulated asset base, forecast depreciation and cost of capital have been calculated by the RIC;

- Chapter 8 sets out the efficiency carryover mechanism and incentives to achieve efficiency gains;

- Chapter 9 discusses consumer and service quality issues;

- Chapter 10 outlines the RIC's proposed approach to issues related to miscellaneous services and other activities;

- Chapter 11 utilizes the building-block components of Chapters 5 to 7 and calculates T&TEC's total regulated revenue requirement;

- Chapter 12 explains how the RIC proposes to translate the revenue requirement into specific tariff proposals and sets out the likely impact of the final decision on consumers;

- Chapter 13 gives directions to T&TEC for compliance monitoring and reporting; and

- Chapter 14 provides concluding remarks and the "way forward" by clearly laying down the vision for the electricity sector.

CHAPTER 2
RIC'S REGULATORY FRAMEWORK

2.1 INTRODUCTION

Having outlined the statutory environment within which the RIC is expected to perform its functions, it is important to discuss the regulatory framework to be used in determining tariffs, and other underlying theoretical issues. This will be done before undertaking an analysis of the various aspects of the Trinidad and Tobago Electricity Commission's (T&TEC's) submission for a price review.

While the regulatory framework under which the RIC is required to operate is new, there is a substantial volume of literature on the theory of regulation and regulatory experiences in other parts of the world. The RIC recognized the importance of this literature in assisting to discharge its functions and arriving at a reasoned stance on the various issues. This chapter is devoted to examining the alternative approaches available for tariff determination and the path the RIC chooses to adopt, keeping in mind the statutory provisions of the RIC Act.

2.2 LEGAL REQUIREMENT

The RIC Act (Sections 6, 47 to 52 and 67) provides for the type of regulation to be of the prospective RPI-X[2] form or some incentive based variant that is consistent with the objectives and principles outlined therein. The Act mandates the RIC to:

- establish the principles and methodologies by which service providers determine rates [Section 6 (1) (h)]; and
- review the principles for determining rates and charges for services every five years (Section 48).

[2] RPI – Retail Price Index and X is the general efficiency improvement assumption.

In setting out principles for determining rates, Sections 6 and 67 of the Act require the RIC to have regard to:

- the funding and ability of the service provider to perform its functions;
- the ability of the consumer to pay rates;
- the results of studies of economy and efficiency;
- the standards of service being offered by the service provider;
- the rate of inflation in the economy for any preceding period as may be considered appropriate; and
- future prospective increases in productivity by the service providers.

The RIC has interpreted these sections as giving clear support for the use of not only incentive regulation, but for the application of a price cap (RPI-X) form of regulation in shaping its approach to future rate reviews.

2.3 METHODS OF REGULATION

As discussed in detail in the RIC's Consultation Document, "**Setting Price Control: Framework and Approach (April 2005)**", there are two dominant methods of price regulation that have been generally utilized internationally; the Rate of Return and Incentive Regulation.

Rate of Return

The Rate of Return (ROR) method sets prices which provide the service provider with the target rate of return on investment and is adjusted up or down over time if the return varies from the set rate of return. As ROR regulation equates prices with costs, it provides relative certainty for cost recovery while limiting the profit level that can be achieved. It also provides a stable environment for attracting investment. However, ROR has a number of serious drawbacks including:

- weak incentives to reduce costs, operate efficiently or increase productivity by linking allowed revenues to costs;
- incentives to exaggerate costs by the operator;

- incentives to over-invest in fixed assets and to incur costs that may not be in the best interest of consumers; and
- limited incentives to develop or introduce new services and to fulfill the needs of consumers.

Incentive Regulation

There is a range of possible approaches to the RPI-X form of regulation, including revenue capping and price capping. In its simplest form, price cap regulation uses an indexing formula to determine the maximum allowable price to recover unavoidable cost increases by a utility but also requires it to lower prices regularly to reflect productivity (X-factor), during a defined period. The X-factor is set at the time of the determination for the duration of the regulatory control period. In the determination of the X-factor, a number of relevant factors are taken into account, such as demand, costs and underlying efficiency.

A basic price cap formula is shown in **Box 2.1**. It demonstrates several key features about the RPI-X form of regulation.

Box 2.1 - Basic Price Control Formula

$$P_t = P_{t-1}[1 + I - X] \pm Z \pm K$$

Where:

P_t = maximum price in year t

P_{t-1} = the maximum price in previous year t-1

I = inflation index

X = productivity or efficiency factor

Z = defined pass-through items or adjustment for unforeseen events

K = adjustments for under or over recovery against previous year's target

A revenue cap is similarly constructed by replacing P with R.

The first characteristic of the RPI-X form of regulation is the limit on the average price (or permitted revenue) of the service provider. This limit is fixed for a defined period. Second, there is the length of the defined period over which the price restraint is to apply. A five-year timeframe is typical, though some controls have been for shorter intervals, especially during periods of transition or change. Third, under a RPI-X regime, the permitted price limit automatically adjusts from one year to the next by an escalation factor. Fourth, is the X-factor which reflects the extent to which the regulated entity is capable of increasing its productivity/efficiency more rapidly than the set target and/or decreasing the input prices less rapidly than included in the forecasts. In reality, the process for determining the X-factor is complex. A fifth feature is that the service provider is generally allowed to retain the benefit of any efficiency savings over and above the projected level during the control period. A sixth important feature is the review process itself. The review is both backward and forward-looking and commences with an assessment of performance against established targets. Finally, the formula can include additional adjustment terms which are applied to the calculation of the price limit.

The central idea behind price cap regulation is to encourage firms to "outperform" pre-determined benchmarks embodied in the price cap regime, and to allow them to retain part or all of the benefit from doing so. It is argued that the regulated firm will have little incentive to devote managerial effort to achieve the gains if it cannot retain some of the benefits. In fact, a price cap regime offers financial rewards to those service providers who continue to improve their efficiency but it applies financial penalties to those who fail to achieve the efficiency improvement benchmarks reflected in the regime. In this way, price cap regulation endeavours to mimic the discipline of a competitive market. Customers ultimately benefit by sharing in the gains that are realized over time.

There are a number of advantages to using incentive regulation:

- it produces financial stability and viability by introducing rating flexibility;

- it provides incentives to minimize costs and allows the attainment of dynamic efficiency;
- it reduces/eliminates the tendency to over invest in fixed assets;
- it reduces the ability to cross-subsidize; and
- it reduces the transaction costs of regulation, especially costs related to regulatory hearings.

In short, incentive regulation helps avoid the pitfalls commonly associated with rate of return regulation and allows service providers to concentrate on minimizing costs which result in savings that are eventually passed on to the customers.

2.4 FORM OF REGULATION

The first element in developing a price control framework involves the establishment of the form of economic regulation that is to be applied to service providers. The form of regulation applied to service providers is one of the most important factors in determining the overall performance of the utility and the level of benefits delivered to customers.

The RIC Act gives clear support for the use of incentive regulation, using a price-cap approach, rather than rate of return regulation. However, various forms of price control fall under the general rubric of the price-cap approach, and are compatible with incentive-based regulation. Within this general requirement, the RIC Act provides no specific guidance and/or restriction as to the exact form of price control that should be used and the scope of the services to be regulated. Consequently, the RIC has flexibility in choosing the form of the price control to be adopted.

Section 6 of the RIC Act sets out the powers and functions of the RIC. Those powers and functions emphasize the importance of ensuring the financial viability of the service providers, the facilitation of competition, where possible, the promotion of efficiency and the protection of the interests of customers. Specifically, the powers and functions are noteworthy to:

- ensure, as far as is reasonably practicable, that the service provided by a service provider operating under prudent and efficient management will be on terms that will allow the service provider to earn sufficient return to finance necessary investment [Section 6 (1) (c)];
- facilitate competition between service providers where competition is possible and desirable [Section 6 (1) (k)];
- prescribe and publish standards for services [Section 6 (1) (e)];
- carry out studies of efficiency and economy of operation, and of performance by service providers [Section 6 (1) (d)]; and
- have regard to maximum efficiency in the use and allocation of resources to ensure as far as is reasonably practicable, that services are reliable and provided at the lowest possible cost [Section 6 (3) (a)].

In assessing different forms of price control, the RIC will have regard to these objectives and, in particular, the extent to which they encourage efficient behaviour by the service providers, the extent to which price controls ensure that total revenues track total costs and, finally, the extent to which the different forms of price control have implications for risk allocation between customers and service providers. Overall, the RIC will ensure that regulation is cost-effective, transparent, accountable, applied consistently and balanced between the interests of consumers and the service providers. Additionally, regulated prices will aim to achieve economic efficiency, revenue sufficiency and equity.

2.5 STRUCTURE OF PRICE CONTROL

Internationally, a number of different structures of price control have been implemented, reflecting the different characteristics of the utilities being regulated. The RIC has a number of choices, including applying the RPI-X to aggregate revenue (a "total revenue" cap), average revenue (an "average revenue" cap) or a weighted average of all prices (a "tariff basket").

Revenue Cap Approach

Under the revenue cap approach, the service provider's gross revenues are limited to a fixed amount for a defined set of services. This fixed amount (cap) is usually subject to an annual adjustment for productivity gains (called the X-factor) and inflationary effects. Periodic readjustments assist in scaling revenues appropriately to changes in the customer base of the regulated firm. Broadly, the revenue cap can be expressed as:

$$R_t = (R_{t-1} + CGA * CUST) * (1 + RPI - X) \pm Z - - - - - (i)$$

$$OR$$

$$R_t = R_{t-1} \left[(1 + (CGA * CUST) + (RPI - X) \right] \pm Z - - - -(ii)$$

Where :

R_t - is the authorized revenue for time t

RPI - is the annual change in retail prices

X - is the reduction in prices imposed by the regulator based on projected productivity gains

Z - is a cost pass-through variable

CUST - is the annual change in the number of customers (or the annual change in output)

CGA - is a customer growth factor which can be expressed in either absolute dollar terms, [equation (i)], or in percentage terms, [equation (ii)].

Revenue caps may be established for different customer groups, for categories of service or for the entire business. An initial revenue cap for a level of service is set according to traditional rate of return procedures (the "building block" approach for assessing required revenue). Thereafter, real revenue is typically reduced each year by the X-factor until the next review. If the service provider can realize efficiency gains greater than the X-factor then it can keep all or some percentage of such gains. If not, the service provider's profit suffers. It is this costs risk and/or opportunity to outperform that provides a regulated firm with significant incentives to operate more efficiently. Revenue caps come in different forms.

- **Pure Revenue Cap**

  Under a **pure** (or **fixed or total**) revenue cap, the firm's revenues are limited to a fixed amount and the cap is subject to annual adjustment for inflationary effects and productivity gains. Fixed revenue caps can be applied at the level of a service basket, service classification or an entire business and they provide discretion to the utility to set charges within the cap. It also provides the service provider with a guaranteed level of income and thus reduces revenue risk.

  This form of cap does not provide incentives to pursue new customers or increase sales once the cap is reached. Although it provides strong incentives to cut costs, there is the potential for sustained profits or losses with the financial benefit/risk to be borne by the service providers. Additionally, there is no causal link formed between costs and revenues and it allows for flexibility in tariffs in order to reflect changing costs.

- **Flexible (Variable) Revenue Caps**

  Flexible revenue caps (i.e. average revenue cap or revenue yield) allow total revenue to vary in line with the change in some underlying variable (the growth in customer base or any other variable). Broadly speaking, this form of regulation imposes a cap on the maximum revenue that a utility is permitted to earn per unit.

  Under this form of control, revenue varies directly with output, and the cap is allowed to vary over different time periods in line with the RPI-X formula. Since the average revenue per unit is constant, there is an incentive to minimize costs and increase output, as there is no limit to the total revenue that a firm can generate. The service provider also has a certain degree of flexibility in setting individual tariffs. This flexibility can apply to both the split between the fixed and variable elements of any one tariff category and to different tariff categories.

Under a revenue cap mechanism, a correction mechanism ("unders and overs" account) is usually used to adjust for forecast errors. A sharing arrangement is also specified and any surplus in the account is returned to customers. The revenue cap can be expressed as follows:

$$R_t = (RPI - X) * R_{t-1} - K_t$$

Where: K_t is a correction factor that adjusts for under and over recovery of revenue.

The main advantages of revenue caps include incentives for cost reduction, investment, and productivity improvements. They may be better suited to networks such as electricity and water transmission and distribution systems which generally exhibit reducing average costs as output increases. Revenue caps also allow a more direct means of passing on the efficiency gains to customers. On the other hand, revenue caps have some important disadvantages. Revenue caps, if not adjusted for customer numbers or output, may provide incentives to restrict sales. Also, when significant growth is expected, revenue caps require accurate estimates of demand.

- **Price Cap Approach**

  Price cap regulation attempts to control price rather than revenue. As in the case of revenue caps, prices are set according to traditional rate of return procedures as the cap applies to particular prices rather than revenue. Price caps could be either in the form of a weighted average price cap (tariff basket) or a series of separate price controls independent of any total revenue requirement. In setting the weighted average price, the weights can be volume (sales) or value (revenue) and the weights may be fixed by reference to the base year or they may reflect actual quantities with a lag, thereby breaking the link between allowed revenue and the volume. This approach allows for more than one charge, a connection as well as a volumetric charge. Generally, under this approach, total revenues will track total costs, thus limiting the financial risks faced by service providers.

Price cap regulation provides a number of advantages. As in the case of revenue caps, it provides incentives for cost reduction and productivity improvements. It provides incentives to satisfy demand as well as protection to individual users of services as it assigns most of the risks to the firm. Among the main disadvantages of price caps are the reduced flexibility to adjust prices to maximize efficiency and the incentives to cut costs through reduced service quality. Additionally, the translation of revenue targets into weighted average price controls is not only complex but subject to errors.

- **Hybrid forms of Control**

  Although hybrid controls come in a variety of forms, they generally contain a fixed revenue component combined with annual revenue drivers, such as customer numbers, sales and length of network system. Therefore, the development of a cost tracking formula is an integral part of setting hybrid controls. A price cap with automatic pass-through of costs is one of the most common forms of hybrid control.

  Another option is to make modifications to the general schemes discussed above or to combine elements from different schemes. The objective of such schemes is to offset the weaknesses of one scheme with the strengths of others.

  The main advantages of hybrid control are: the lowering of disincentive to expand growth in services; the increased incentives to participate in demand management; the moving of revenue closely in line with costs; and the lowering of financial risk of service providers. Overall, hybrid forms of control offer the potential for significant improvements in regulatory effectiveness. The main disadvantages include the potential difficulty of developing an effective cost tracking formula; the potential to less accurately track incremental costs; and the reduction in incentives to maximize efficiency, since under the hybrid form of control the cap is required to be reset each year of the regulatory period.

Choosing an Option

As noted above, each of the options discussed has advantages and disadvantages in terms of meeting regulatory objectives, depending on the situation and context. More importantly, corporate governance, ownership, the form and extent of private sector involvement and the current state of regulatory environment may largely determine which option is optimal. In choosing one option over another, there may also be direct trade-offs which need to be considered. Therefore, the RIC needed to make a judgment about which form of price control is most likely to produce the best overall outcome.

There are six key considerations to take into account when assessing different options:

- Revenue/Income Variations
- Degree of Competition
- Impact of Cost Structure
- Risk Reduction
- Nature of Incentives
- Fair Prices

These considerations are discussed below.

- **Revenue/Income Variations**

  Price cap regulation is more likely to expose a regulated firm to variations in revenue, especially when demand volumes fluctuate. Additionally, when fixed costs constitute a significant portion of a regulated firm's costs (as is generally the case in transmission and distribution networks), price cap regulation can expose the firm to unduly wide variations in net income. Under these circumstances, revenue cap regulation can help avoid/minimize these wide variations in revenue and/or income.

Furthermore, revenue caps make more sense if costs do not vary with volume. With respect to transmission and distribution utilities, the evidence is fairly clear that costs do not vary with volume, making revenue caps the more sensible approach.

- **Degree of Competition**

  In most non-contestable elements of network industries (i.e. transmission and distribution networks) and where the networks are considered to have a strong or dominant ongoing degree of monopoly, a revenue cap approach is generally considered to be more appropriate by most regulators.

- **Impact of Cost Structure**

  Price cap regulation generally aims to de-link the prices of a firm from its own costs. The important question is whether it is totally possible to disregard the firm's actual costs. The form of price regulation should take into account the cost structure of the industry, the substantial fixed costs needs associated with infrastructure repair, rehabilitation, replacement and new capital investment obligations and even some of the variable costs over which the utility has no control such as gas and conversion costs of electricity to T&TEC. These costs need to be considered in light of the firm's stable but flattening per capita demands and revenue as well as the utilities' generally low elasticities of demand for services. In such circumstances, a revenue cap is more likely to ensure that revenues are adequate to cover costs.

- **Risk Reduction**

  A further potential benefit of revenue caps may be that they would reduce the risk which service providers face, since they would be able to recover a fixed amount of revenues each year. Lower risk may translate into a lower cost of capital for a regulated utility.

- **Nature of Incentives**

  One of the most important considerations in assessing different options is the nature of incentives inherent in a particular option. The regulatory approach must not only ensure efficiency gains are achieved but that these gains benefit consumers and are eventually passed on to them. In this respect, a revenue cap (also price cap) with periodic re-determinations based partly on building blocks procedures, can be most effective.

- **Fair Prices**

  The RIC's approach to introducing a new set of regulatory arrangements must, of necessity, be cautious. T&TEC is currently faced with serious revenue shortfalls. By determining a fair and reasonable level of revenue and setting a revenue cap for the initial regulatory period, along with some secondary price controls to limit price shocks to consumers, the RIC would be better able to set a fair price for the services, balancing both the interests of consumers and service providers.

Final Decision

In its Draft Determination, the RIC indicated that it preferred to use a fixed (total) revenue cap in the first regulatory control period, as it provides an appropriate balance of risk between customers and the service provider, and at the same time provides incentives for the service provider to reduce costs. It should provide T&TEC with the operational flexibility it needs to meet its service objectives and, at the same time, it exposes T&TEC to risks it can control. The RIC received no objection to this approach and maintains this position.

The RIC's decision is to utilize a fixed revenue cap form of regulation in the first regulatory control period.

2.6 BUILDING-BLOCK METHODOLOGY FOR DETERMINING REVENUE

The RIC must be satisfied that price/revenue controls comply with the regulatory principles outlined in the RIC Act. Specifically, the RIC Act [Section 67 (2) (3) and (4)] requires price/revenue control to be set so as to:

- allow the recovery of least-cost operating expenditure;
- allow the recovery of replacement capital cost expenditure;
- allow the recovery of return of capital (depreciation) and return on rate base;
- take into account the funding and ability of the service provider to perform its functions;
- take into account the interest of shareholders of the service provider;
- take into account the ability of consumers to pay rates;
- take into account the standard of service being offered by the service provider; and
- provide the service provider with incentives to pursue efficiency improvements and to promote the sustainable use of resources.

The first step in determining price/revenue controls is to establish the **allowable revenue** of the service provider on which to base a price control. The approach is to set the maximum allowable base year revenue requirement for each regulatory control period and to test the forecast revenue requirement to ensure that they allow the regulated firm to remain financially viable. The X-factor determines the amount by which revenues will move up or down over the regulatory control period in real terms.

There are two broad approaches that are commonly used to determine allowable revenue. The first approach (cost-linked) involves linking the service provider's costs to the revenue to be earned or prices to be charged. Therefore, prices will track costs more closely and customers are likely to pay prices near to actual costs of service. The use of this approach has been criticized on the grounds that it requires a high degree of firm-specific information and that it may tend to merge into ROR regulation.

In the second approach (cost-unlinked), the controls are not directly determined by reference to the costs of the service provider, instead they may be set by reference to the prices or costs of utilities elsewhere. In the determination of the level of costs under this approach, a variety of approaches is utilized including; benchmarking, econometric analysis or frontier methods such as Data Envelopment Analysis and Stochastic Frontier Analysis.

As this cost-unlinked approach allows a greater deviation of prices from the specific costs of service providers, the outcome will be generally consistent with the operation of a competitive market. Furthermore, the rate of efficiency improvement is likely to be higher and the benefits derived therefrom will redound to the benefit of customers. However, there are a number of serious concerns with setting price/revenue controls completely independent of the service provider's costs:

- the approaches used to set prices independent of costs require comprehensive data that are generally not available;
- the benchmarking techniques may not adequately reflect the local service providers' costs, especially as they face significant capital expenditure requirements for network replacement, growth and service standards requirements;
- any reliance on the prices or costs of other utilities may not enable the initial prices to be set at levels which are reasonable, especially given that T&TEC is currently experiencing large revenue short-falls in its operations;
- the benchmarking techniques used for the estimation of efficient costs are approximate at best, and involve too many practical problems and as a result total reliance should not be placed on them; and
- the degree of certainty required to encourage efficient new investment may not be provided when prices are set completely independent of the service providers' costs.

In light of the above concerns, it is difficult to conceive of circumstances where external benchmarks could become a complete substitute for service provider-specific costs data.

A starting point for determining revenue requirements and the rate of change in prices would invariably be determined by reference to the service provider's costs. In fact, there are very few examples of the pure application of either approach and there is likely to be significant advantage in combining the two approaches.

Although the RIC Act provides no specific guidance on the exact approach to be used, it embodies a strong presumption that both service provider-specific costs and comparative data should be the main basis for determining the revenue requirements [Sections 67 (2) (3) and (4)]. By setting regulated revenue with reference to the service provider's costs, and adjusting with reference to the costs of similar utilities elsewhere, forward looking revenues can be set which deliver strong incentives for future efficiency improvements.

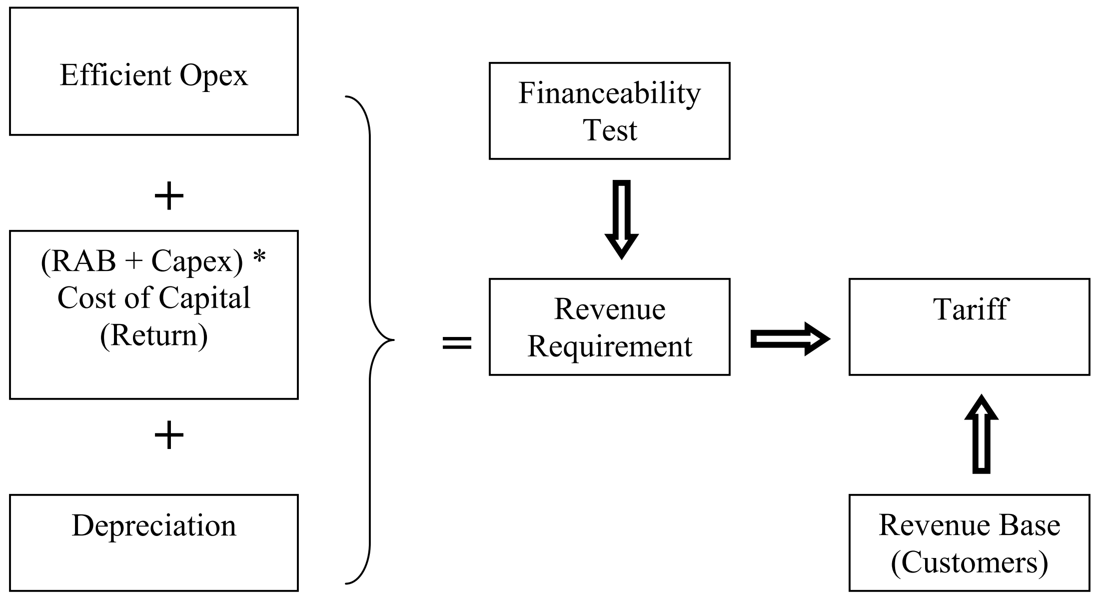
The **cost building-block approach** is the framework typically utilized under a cost-linked approach to the determination of the efficient costs of service providers. The building-block approach determines the expenditure that an efficient service provider would need to incur to provide service over the regulatory period. The building-block approach is consistent with the RIC Act [Section 67(4)] which requires the RIC to have regard to, *inter alia*:

- replacement capital cost expended;
- least-cost operating expenses which may be incurred;
- annual depreciation; and
- return on the rate base.

Consequently, the RIC's legal mandate, regulatory objectives and the industry-specific context make it appropriate to adopt the building-block approach to establish the price controls.

The following chart (**Figure 2.1**) provides an overview of the revenue requirement calculation.

Figure 2.1 - Overview of the Revenue Requirement Calculation



Stakeholder Comments and Final Decision

In response to the Draft Determination, one respondent proposed the use of an unlinked approach (TFP). As noted in the preceding paragraphs and in "**RIC's Response to Stakeholder Comments on the Draft Determination"** document, our reasons for the use of a building-block approach is appropriate for both the establishment of starting prices as well as the form of the X-factor, as it is more likely to be useful and effective during the first regulatory control period and encourage T&TEC to behave efficiently and reveal efficient costs (initially), thereby enabling an efficient level of prices to be determined for the benefit of consumers.

The RIC's decision is to utilize the cost building-block approach to setting revenue caps and will incorporate incentives for expected efficiency gains.

2.7 DETERMINING THE X-FACTOR

As indicated above, the RIC proposes to utilize the building-block approach to setting the revenue cap. The approach typically determines the forward-looking revenue forecasts of the service provider by assessing the following key elements:

- the growth in demand, as changes in demand will impact on both operating and capital expenditures over the regulatory period;
- the efficient operating and maintenance costs;
- forecasts of annual capital expenditure;
- the return of capital (depreciation) to recoup the capital that the service provider has invested in its business over the useful lives of the assets;
- the return on capital reflecting the return on the regulated asset base to achieve a reasonable rate of return given the risks; and
- the scope for efficiency gains.

Each of these key elements is discussed in Chapters 4 to 8.

Once the regulator has set the total revenue requirement applicable to electricity service, it is able to define the relevant RPI-X price control mechanism. The key design issue for this mechanism is the selection of the X-factor. The value of the X-factor is the amount by which tariffs are allowed to escalate relative to the rate of inflation. It is meant to ensure that productivity improvements are passed on to the consumers over time, and to remove any existing above-normal profits and inefficiencies. Since productivity is a primary driver of real price movements, X is often referred to as a productivity or efficiency factor.

In order to determine the X-factor, the regulator needs to make a number of decisions, in addition to determining the building-block costs. These decisions include:

- the form of regulation – the variable to which the RPI-X adjustment factor is applied; and
- the form of the X-factor – the manner in which the X-factor will change across the regulatory control period.

There are two main approaches to setting the value of the X-factor. The **first approach** relates X directly to available average annual inflation adjusted reductions in aggregate costs. Under this approach, X is a proxy for available efficiencies and not strictly a productivity measure. The X is based on a benchmark estimate of the trend for annual rate of productivity (or efficiency). The X-factor can be established by considering the operational history of a service provider or alternatively, by reference to industry or economy-wide benchmarks that are independent of the service provider's costs of production. This then becomes the performance target that the service provider must equal to maintain its profitability. Performance better than the target will mean higher profits during the control period for the service provider and this provides the key incentive properties of the RPI-X form of regulation. Generally, the productivity offset or X-factor takes into account a number of factors, including:

- the ability of the regulated firm to finance its operations;
- the capacity of the firm to lower costs without compromising quality of service;
- the future scope for productivity improvements in the regulated firm relative to productivity growth in the economy;
- a consumer productivity dividend (stretch factor) i.e. a dividend to consumers resulting from streamlining of regulation and increased incentives for efficiency under incentive regulation;
- the competitive adjustment which could be a positive or negative figure; and
- an allowance for a period of adjustment to new rates.

The **second approach** uses X as a smoothing device. Under this approach, expected efficiencies are separately factored into each building-block cost category and the X-factor represents the value which, on average, achieves the resultant real-term change in revenues (or revenue path) that minimizes price shocks. In other words, the net present value of required revenues is fully recovered over the regulatory period through the X-factor, using a smoothing technique. The RIC's rationale for using the building block approach was provided in the Draft Determination. This was based on a number of considerations including: the requirements of the statutory framework; the absence of a prior regulatory review of T&TEC's efficient costs to establish starting point prices; the anomalies and the need to rebalance the existing tariff structures; and to both improve the incentive elements and tackle the information asymmetry problems.

Broadly, there are four alternative approaches to smoothing revenues:

- **Net Present Value approach (NPV)** – where a single X-factor is applied such that the service provider's expected revenue equals its forecast revenue requirement in NPV terms throughout the regulatory control period.

- **NPV approach with P_o adjustment** – where revenue is allowed to move by a fixed amount in year one and then an X-factor is applied to revenue in the remaining years so that, in total, revenue value is maintained in NPV terms;

- **Straight-line smoothing** – where a single X-factor is applied so that prices change smoothly from the first to the last year (ignoring the intervening years) to ensure that the service provider's expected revenue equals its forecast revenue requirement in the final year of the regulatory period; and

- **Hybrid P_o adjustment with straight-line smoothing** – where an initial revenue adjustment is allowed in the first year of the control period to move the expected revenue closer to the forecast revenue requirement. An X-factor is then set to target the service provider's expected revenue equaling its forecast revenue requirement in the final year of the control period (as under the straight-line approach).

Each of these approaches has different implications for:

- revenue recovery;
- price stability (price stability and certainty are important to customers);
- incentives for efficiency; and
- transitional issues going into the next regulatory period.

The precise form of smoothing to be applied by the RIC as well as any pricing implications is discussed in detail in Chapter 12.

The RIC Act imposes a broad requirement outlining what the X-factor should represent. Section 67 (3) (h) states that the RIC will have regard to future prospective increases in productivity by the service provider when setting out principles on which rates charged should be based.

Stakeholder Comments and Final Decision

One respondent to the Draft Determination felt that TFP analysis would be more appropriate. Based on its reasons behind the use of the building-block approach to establish starting prices and to utilize X as a smoothing device, the RIC still considers this approach to be appropriate and useful during the first regulatory control period.

> The RIC's decision is to utilize X as a smoothing device and a single X-factor to reduce the volatility in annual revenues.

2.8 THE INFLATION FACTOR

As noted above, the price cap formula includes an inflation factor, which partially accounts for changes in input costs of the service provider. For example, holding all other variables constant a percentage change of 3% in the inflation factor would allow the service provider to increase its prices by that amount.

In selecting an inflation factor most regulators have regard to the following:

- **Reflectiveness of service provider's costs** – for the inflation factor to be a useful variable, it should (at least partially) reflect changes in the operators' input costs. This is particularly important for a service provider that typically imports/purchases a large proportion of its equipment.

- **Source of the Inflation Factor** – the inflation factor should be available from a credible independent source. This is important if the price cap is to have credibility with all parties involved.
- **Availability on a timely basis** – in order for the price cap formula to be adjusted in timely manner the inflation factor should be available with a lag of 2 to 4 months.
- **Understandability** – there is significant benefit in including an inflation factor that is easily understood not only by all the players in a sector, but by the public at large.
- **Stability** – the values of some statistical indices are subject to revision after their initial release. An inflation factor should be chosen that is not subject to large frequent revisions.
- **Consistency with total factor productivity of the economy** – if an index-based Total Factor Productivity is to be the basis for establishing the X-factor, then the choice of inflation factor will have a direct impact on the way the X-factor is calculated as efficiency gains in the rest of the economy affect the service provider through price indices such as the Retail Price Index (RPI).

In light of the above, the RIC used the RPI for the following reasons:

- it is complied and published by the Central Statistical Office (CSO) of Trinidad and Tobago (a credible source) on a regular basis;
- it is familiar and relatively easy to understand by the public at large; and
- it is likely to reflect T&TEC's controlled input costs as these costs constitute only about 30% of its total costs. The other 70% of T&TEC's costs are conversion and fuel costs and they are being treated as pass-through items.

The RIC's decision is to use RPI as the inflation factor.

2.9 LENGTH OF THE REGULATORY PERIOD

The length of the regulatory period influences the incentives faced by the service provider. The period needs to be long enough for management initiatives to be implemented and to take effect. The period must also be long enough to discourage measures to increase profitability in the short-term at the expense of long-term considerations. The length of the regulatory period generally depends on the level of confidence in costs and productivity improvement forecasts. Efficiency gains made during the regulatory control period are shared by owners and users. Therefore, the longer the owners are able to retain the benefits of increased efficiency through higher profits, the greater the incentives to pursue these initiatives but the longer the customer must wait to share the benefits. A longer period can:

- provide greater incentives to increase efficiency, by allowing service providers to retain gains over a longer period;
- provide a more stable and predictable regulatory environment which may lower business risk and lead to better investment decisions; and
- lead to fewer regulatory reviews thus lowering regulatory costs.

On the other hand, a longer regulatory period can lead to greater exposure to unforeseen cost increases thus leading to financial uncertainty and/or non-viability. Consumers may also be exposed to increased risks if there are implications for the long-term level of prices, apart from delaying the delivery of benefits of efficiency gains.

Requirements of the RIC Act

Section 48 of the RIC Act specifies that the RIC shall review the principles for determining rates and charges every five years or, where the licence issued to the service provider prescribes otherwise, at such shorter interval as it may determine. This requirement appears to suggest that the RIC may adopt a regulatory period shorter than five years, if that were considered to be appropriate.

Stakeholder Comments and Final Decision

One respondent felt that the regulatory period could be shortened to three years. As noted above, although the RIC Act specifies that it shall review the principles for determining rates and charges every five years, it leaves room for adopting a regulatory period shorter than five years. The length of the regulatory period has implications for the incentives for efficiency improvements, the predictability and stability of the regulatory environment, and the effectiveness of the regulation. On the other hand, a long price control period could involve excessive risks that could create disparity between costs and revenues and delayed benefits for consumers from efficiency gains.

In the case of T&TEC, there is one major risk with regard to generation costs as these costs account for nearly 70% of T&TEC's total costs. However, these costs are governed by long-term contracts and the RIC has adequately accounted for such risks under its proposed revenue cap mechanism. The RIC has also proposed the adoption of other mechanisms to reduce risks by including oversight of T&TEC's earnings and a mechanism for sharing earnings above an allowed range. Therefore, risks that unanticipated events will occur and the likely impact of such events are much less significant than they would otherwise be.

Consequently, the RIC remains of the view that a five-year regulatory period is appropriate, as it strikes a balance between providing incentives for improving efficiency, reducing regulatory uncertainty and allowing sufficient time for T&TEC to improve its performance.

The RIC's decision is to adopt a five-year regulatory period for this determination.

2.10 CORRECTION FACTORS AND WITHIN PERIOD ADJUSTMENTS

A regulator's commitment not to revoke a revenue cap during the regulatory period, unless there are exceptional circumstances, allows the service provider to make its decisions without further regulatory involvement. It also benefits consumers by providing greater certainty about future prices.

Requirements of the RIC Act

Although the RIC Act (Section 48) specifies that the RIC shall review the principles for determining rates and charges every five years, Section 49 of the Act provides a mechanism for addressing the possibility of within-period adjustment:

> ***"Notwithstanding Section 48, where it is the opinion of a service provider that there has been such a fundamental change in circumstances as to warrant a review of the principles for determining rates for the service which it provides, it may give written notice to the Commission requesting a review of the principles except that it may not request a review more than once in any year".***

It is quite possible that actual revenue received by a service provider in any year can vary from the forecast. Under a fixed revenue cap, the under or over recovery of revenue needs to be adjusted in subsequent years. The RIC in its Consultation Document, "**Sharing of Benefits of Efficiency Gains and Efficiency Carryover Mechanisms (June 2005)**", proposed the adoption of an "unders and overs" approach. This approach requires the balance of the "unders and overs" account to be assessed after the end of each financial year of the control period. Depending on the size of the variation from the approved revenue cap, certain action will be required by the service provider.

As argued in its consultation document, the RIC does not intend to utilize an error correction factor to automatically adjust revenue forecasts. The RIC is, however, mindful that any within-period adjustments, if absolutely necessary, must be on the strict conditions that:

- the major exogenous and unforeseen events impact significantly upon the returns of the service provider;
- the event is beyond the service provider's control;
- the event was not reasonably able to have been foreseen at the time of the price control process; and
- the benefits of adjustment outweighs the costs of re-opening the revenue calculations.

Furthermore, the RIC believes that, in general, the trigger for initiating a within-period review should come from the service provider as provided in Section 49 of the RIC Act. However, the RIC reserves the right to review the revenue cap within the regulatory period where, in its view, information provided to the RIC is found to have been false or materially misleading, or a material error was made in setting the revenue cap or there is a fundamental restructuring/change in ownership that may materially effect the revenue requirement.

Additionally, as argued in its consultation document, the service provider will be required to maintain an "unders and overs" account in respect of actual revenue versus the forecasts included in the final determination. T&TEC will be required to inform the RIC on a yearly basis of the balance in the "unders and overs" account. This report will be due within 30 days after the end of every year. If at the end of a year, the balance in the "unders and overs" account deviates from pre-allowed revenue targets, the following will apply:

- **Under 5%** - T&TEC must notify the RIC within the stipulated timeframe.
- **Over 5%** - T&TEC must notify the RIC but must also provide an action plan to resolve the balance.

Stakeholder Comments and Final Decision

The RIC received one comment which was in favour of operating an "unders and overs" account and for the revenue cap to include and provide for a within period adjustment under strict conditions.

The RIC's decision is not to utilize an error correction factor to automatically adjust revenue forecasts.

The RIC's decision is to operate the "unders and overs" account in the form described and the proposed annual tolerance limits and actions for treatment of variations. The regulatory framework to include and provide for a within-period adjustment to the revenue cap under strict conditions.

2.11 CONCLUSIONS ON THE REGULATORY FRAMEWORK

The overall objective of the new regulatory framework is to provide service providers with incentives so that they operate in a manner that results in the long-term efficient provision of services. This objective is achieved by ensuring the service providers receive adequate revenue, while at the same time, providing them with sufficient opportunities to increase their returns by achieving efficiency gains but making sure that these gains are not achieved at the expense of a deterioration in service levels.

The RIC was required to resolve various analytical and conceptual issues in arriving at the tariffs to be implemented. The choice between alternative options available was at times difficult to make or the optimal solution was difficult to fully implement immediately, on account of lack of data. In all such cases, the RIC has attempted to arrive at a reasoned solution. In exercising various options, the RIC has been guided by the underlying belief that prudently determined tariffs and related requirements can enhance efficiency in the electricity sector and safeguard the viability of T&TEC, while protecting the interest of the consumer.

The adoption of incentive/price cap regulation using an RPI-X approach provides service providers with the financial rewards for undertaking efficiency improvements that lead to a reduction in expenditure. Indexing prices to inflation and committing not to review the level of X for a fixed period means that service providers have an incentive to benefit from outperforming the expenditure forecasts.

The new regulatory framework also includes an efficiency carryover mechanism which further strengthens the incentives provided by the price cap to reduce costs.

The approach taken to resetting the price controls at the end of each regulatory period and the certainty of that approach are both critical to the strength of the incentives created under this regulatory framework. In resetting the price controls, due consideration is given to sharing of efficiency gains between customers and service providers.

In addition to the RPI-X price control and efficiency carryover mechanism, the RIC has included two quality of service incentive initiatives – guaranteed payments to customers who experience poor quality of service and annual Performance Monitoring and Reporting (PMR). Together these quality of service incentive mechanisms are designed to encourage service providers to achieve cost efficiency gains while continuing to meet or exceed service quality targets.

In short, therefore, the use of price cap regulation supported by guaranteed payments scheme and other service quality measures, and the efficiency carryover mechanism provides effective incentives for efficient expenditure and investment decisions.

CHAPTER 3

REVIEW OF PERFORMANCE OF T&TEC

The functions mandated by the RIC Act include, *inter alia*, prescribing and enforcing standards with respect to the quality, continuity and reliability of service as well as carrying out studies of efficiency and economy of operation and of performance of service providers.

Accordingly, the following sections are devoted to reviewing the actual performance of T&TEC with respect to sales, revenue collection, losses, expenditure control, service and reliability issues.

3.1 INDUSTRY STRUCTURE

The electricity industry was restructured in December 1994, whereby generation was separated from transmission and distribution (T&D). In generation, arrangements were introduced to allow generating capacity to be privately built and owned. In T&D, one government-owned entity, T&TEC, operates the network and has an exclusive right to transmit and distribute electricity from the generator to the end user.

In T&D, where competition is less likely, there exists an imbalance in the relative bargaining position of the providers of the service and users of the service. Consequently, prices can be distorted above economically efficient levels resulting in an adverse impact on economic efficiency. The regulatory regime, under the RIC Act, attempts to correct this market failure by incentive regulation.

The overall aim of the regulatory regime is to control the service provider's ability to charge monopoly prices, but at the same time, provide the service provider with a fair return on its investment and create the correct incentives, through incentive regulation, for the service provider to pursue on-going efficiency gains via cost reductions. This performance review relates only to the transmission and distribution aspect of the sector.

3.2 OVERVIEW OF THE TRANSMISSION & DISTRIBUTION SECTOR

Table 3.1 presents key data for T&TEC.

Table 3.1 - Key Data for T&TEC, 1999-2003

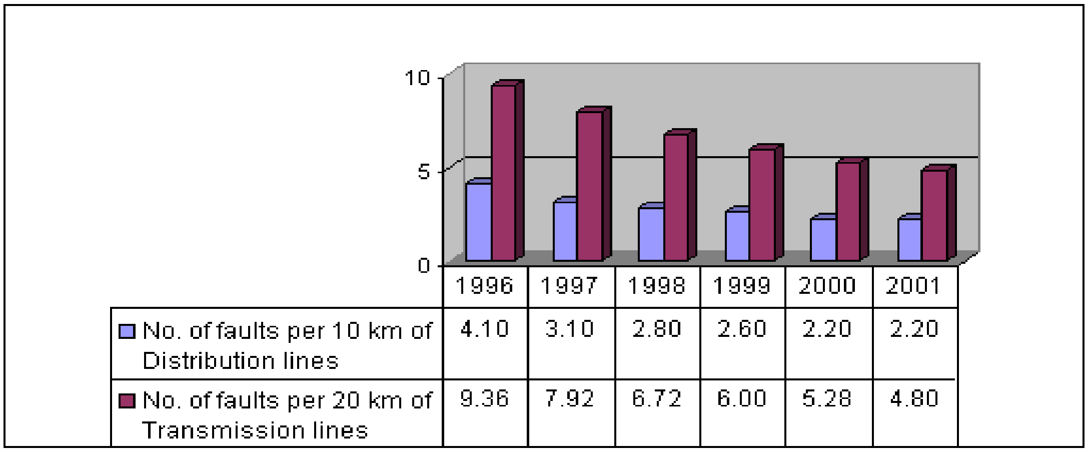
	1999	2000	2001	2002	2003
Total Service Area (sq Km)	5,128	5,128	5,128	5,128	5,128
Total System Length (Km)	12,311	12,311	12,311	12,311	12,311
Maximum Demand (MW)	815	834	876	925	970
Energy Sold (GWh)					
Domestic Customers	1,145	1,251	1,285	1,399	1,542
Commercial Customers	457	475	523	520	581
Industrial Customers	3,270	3,272	3,158	3,707	3,942
Total No. of Employees	2,242	2,174	2,238	2,328	2,335
Customers					
Customers Connected (No)	315,482	316,017	332,920	337,902	348,022
Customer Density (customers per sq Km of area)	58	58	61	62	64
Customer Density (customers per Km of length)	26	26	27	28	28
Customers per employee (No.)	141	145	149	145	149

3.2.1 RELIABILITY OF SUPPLY

Over the period 1999 to 2003, the reliability of supply has consistently improved as illustrated by the following statistics:

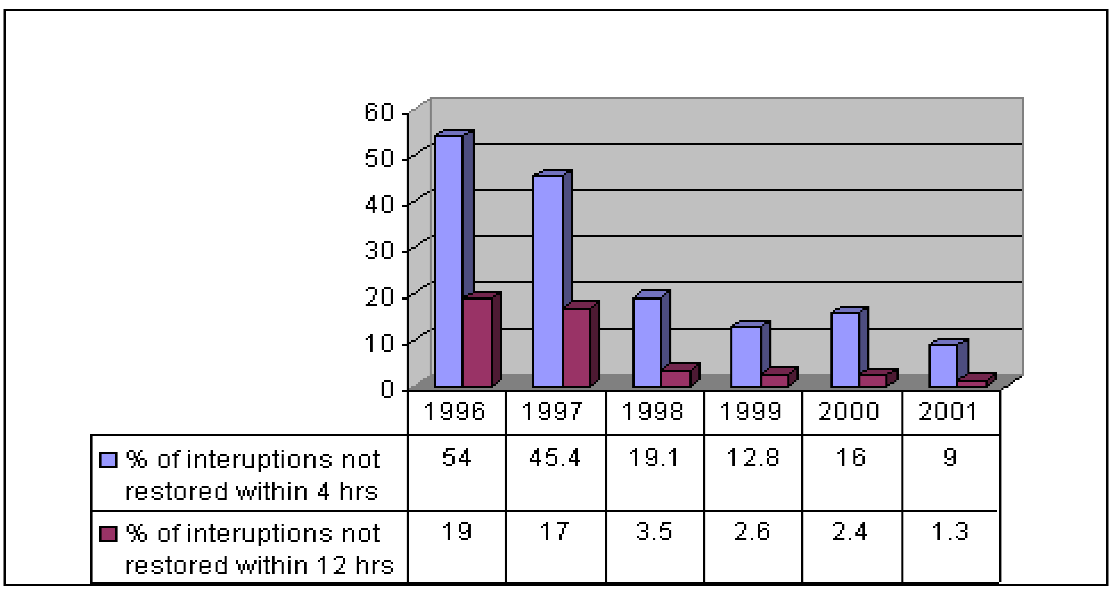
- **Circuit Interruptions (Outages)** – this statistic shows a consistent downward trend in outages per km (**Figure 3.1)**

Figure 3.1 - Number of Transmission & Distribution Circuit Interruptions/Outages, 1996-2001



Outage Restoration Time – this statistic shows a significant improvement in the response time to outages (**Figure 3.2**).

Figure 3.2 – Percentage of Interruptions not restored within Targeted Performance Time, 1996-2001



- **New Connection Back Log** – the new connections backlog has been decreasing over the period (**Table 3.2**).

Table 3.2 - New Connections Backlog by Month for years 1996-2001

NO. OF OUTSTANDING CONNECTIONS												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
1996	279	201	216	249	126	99	123	168	134	132	174	123
1997	131	168	138	119	151	146	105	81	118	118	148	137
1998	129	158	106	82	90	94	99	51	87	125	114	107
1999	145	55	56	64	2	75	68	69	52	46	63	52
2000	17	22	18	1	19	13	31	15	6	12	51	25
2001	5	0	6	11	28	7	14	2	8	12	17	14

- **System Losses** – T&TEC's overall losses compare favourably with most other jurisdictions, although there are variations from year-to-year as observed in **Table 3.3.** Nevertheless, one of the main factors contributing to this overall favourable level of losses is the fact that over 40% of T&TEC's load is located close to the main source of generation. The rest of the T&D system consists of longer lines based on customer loads. This has led to fairly high levels of losses in some regions of the country.

Table 3.3 - System Losses*, 1999-2003

Method	**1999**	**2000**	**2001**	**2002**	**2003**	**Avg.**
1- $\frac{\text{Units Billed}}{\text{Units Purchased}} \times \frac{\text{Collection \$}}{\text{Billing \$}}$	6.3%	7.7%	10.7%	8.0%	6.9%	7.9%

*This method calculates loss as units input into the system and the units for which the payment is collected (i.e. all losses – technical, non-technical and non-realization of payments).

- **Other Indicators** - there are three reliability of supply statistics for T&TEC (**Table 3.4**) that do not fare favourably when compared with international "best practice":
  - average number of times a customer's supply is interrupted per year (SAIFI);

- total number of minutes on average that a customer is without electricity in a year (SAIDI); and
- average duration of interruption per customer (CAIDI).

Table 3.4 – System Reliability Indicators, 2001-2004

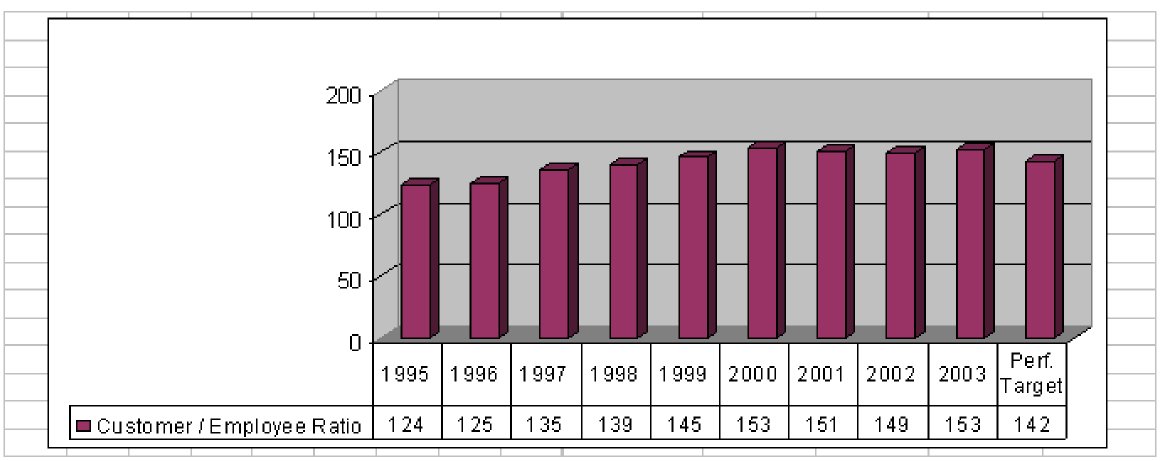
Indicators	2001	2002	2003	2004
SAIFI	9.76	10.56	10.25	9.54
CAIDI (Hours)	1.93	1.73	1.57	1.46
SAIDI (Min./year.)	1128.0	1092.6	963.0	838.2

3.2.2 PRODUCTIVITY TRENDS

Labour Productivity

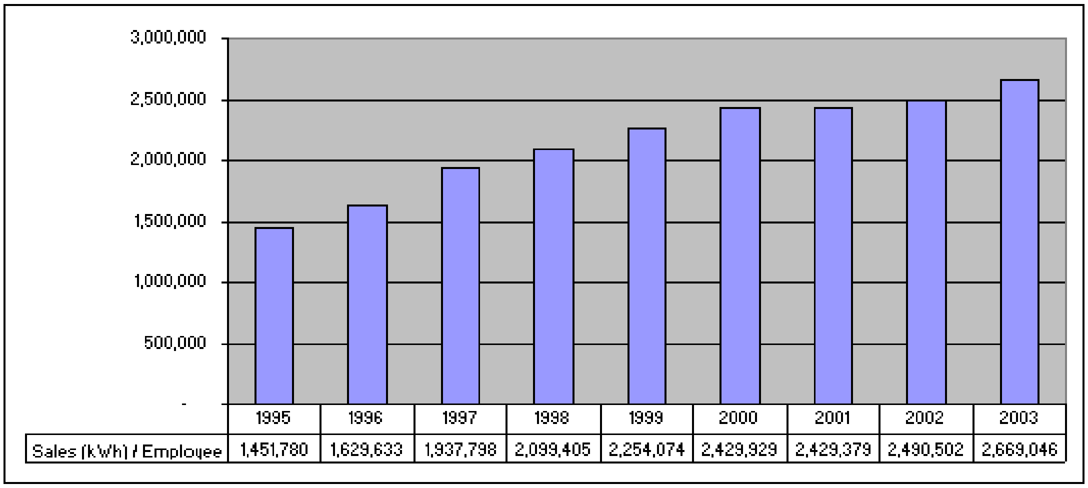
Productivity trends show the level of efficiency of an entity. In the electricity sector, customers per employee and electricity sales per employee are the two most widely used indicators of labour productivity. The customer per employee ratio has improved from 124 customers per employee in 1995 to 153 in 2003 (**Figure 3.3**), an improvement of 23%.

Figure 3.3 - Customer/Employee Ratio, 1995-2003



Similarly, T&TEC's sales per employee ratio has improved from 1.45 million kWh sales per employee in 1995 to 2.67 million in 2003, an increase of 84% (**Figure 3.4**). Therefore, overall, the quality of service and the physical performance of the transmission and distribution system have improved significantly.

Figure 3.4 - Sales (kWh) Per Employee Ratio, 1995-2003



Other Productivity Ratios

Two other productivity ratios also show improving levels of productivity (**Table 3.5**). Real operating cost per MWh sales declined significantly over the period, as there was on average a 4.7% decrease in this statistic. However, on average the ratio of real operating costs per customer showed little change.

Table 3.5 - Operating Performance, 1995-2003

	1995	1996	1997	1998	1999	2000	2001	2002	2003	Average
Real Operating Cost per MWh sales ($/MWh)	256.4	238.63	213.56	201.14	198.66	207.61	191.64	184.36	173.44	-
% Change	-	**(6.9)**	**(10.5)**	**(5.8)**	**(1.2)**	**4.5**	**(7.7)**	**(3.8)**	**(5.9)**	**(4.7)**
Real Operating Cost per customer ($/cust.)	3003.6	3113.9	3064.3	3038.0	3078.7	3294.8	3073.7	3127.1	3171.7	-
% Change	-	**3.7**	**(1.6)**	**(0.9)**	**1.3**	**7.0**	**(6.7)**	**0.2**	**(1.5)**	**0.2**

3.3 FINANCIAL PERFORMANCE

Table 3.6 shows the financial performance of T&TEC between 1995 and 2003. Overall, the measures indicate that T&TEC's financial performance has been weak.

Table 3.6 - Key Financial Indicators, 1995-2003

	1995 $M	1996 $M	1997 $M	1998 $M	1999 $M	2000 $M	2001 $M	2002 $M	2003 $M
Total Revenue	847.6	960.4	1155.9	1218.2	1249.5	1296.1	1351.8	1489.2	1600.7
Operating Expenditure	874.3	972.1	998.1	1068.4	1136.4	1260.9	1308.8	1386.7	1458.2
Depreciation	30.6	31.9	31.2	29.9	31.7	41.8	47.6	52.1	72.7
Net Interest Payments	53.5	48.2	60.7	69.0	30.4	64.5	116.4	107.1	96.8
Total Expenditure	958.4	1052.2	1090.0	1167.3	1198.5	1367.3	1472.9	1583.1	1627.7*
Surplus (Deficit)	(131.9)	(74.2)	65.8	50.9	51.0	(71.1)	(121.1	(93.9)	310.3
Total Assets (Book Value)	1465.1	1338.8	1568.2	1671.9	1825.0	2008.0	2146.6	2364.5	2547.4
Total Liabilities	703.3	642.7	768.8	771.1	866.9	1182.8	1461.7	1767.1	1628.8
of which Net Debt	478.8	417.4	347.4	301.9	458.1	486.3	828.6	819.2	1253.5
Operating Cashflow	15.2	(118.0)	48.6	22.2	(72.8)	36.6	(272.2)	83.6	(502.7)
Capital Expenditure	35.9	39.8	114.8	153.2	243.7	167.7	172.3	135.0	159.9
Accumulated Deficit	(655.4)	(729.6)	(663.8)	(612.8)	(563.1)	(710.5)	(861.6)	(955.5)	(645.2)

Source: T&TEC
* Includes a net decrease in retirement benefit obligations of $337.25 Mn.

The indicators show that:

- T&TEC's total revenue grew from $847.6 million in 1995 to $1600.7 million in 2003, reflecting an increase of 88.9%.
- Total expenditure grew from $958.4 million in 1995 to $1290.4 million in 2003, an increase of 34.6%, peaking in 2002 at 1583.1 million.
- Net debt grew to $1253.5 million in 2003, an increase of 161.8%, over the 1995 figure, while interest and financial charges increased from $53.5 million in 1995 to $96.8 million in 2003, an increase of 80.9%, peaking in 2001 at 116.4 million.

3.4 EXPENDITURE

As revealed above, T&TEC's total costs increased from $958.4 million in 1995 to $1290.4 million (excluding net decrease in retirement benefit obligations) in 2003, an increase of 34.6%. The factors that contributed to this significant increase in expenditure were conversion and fuel costs, which are largely beyond T&TEC's control. The details are shown below (**Tables 3.7, 3.8 and 3.9**):

- Conversion cost rose from $425.4 million in 1995 to $705.4 million in 2003, an increase of 65.8%.
- Fuel and other costs rose from $204.0 million in 1995 to $449.6 million in 2003, an increase of 120.4%.
- In 2003, conversion and fuel and other costs represented 43.3% and 27.6% respectively of total costs.

Table 3.7 - Generation and T&D Costs, 1995-2003

Year	GENERATION			Transmission, Distribution & Administration Costs ($ M)	Depreciation, Interest & Finance and Other Costs ($M)	Total Costs ($ M)
	Conversion ($M)	Fuel and Other Costs ($M)	Total Generation Costs ($ M)			
1995	425.4	204.0	629.4	244.9	84.1	958.4
1996	457.1	222.1	679.2	292.9	80.1	1,052.3
1997	495.4	265.6	761.0	237.2	91.9	1,090.0
1998	538.4	300.2	838.6	229.8	99.0	1,167.3
1999	582.6	314.9	897.5	238.9	62.1	1,198.5
2000	664.4	326.3	990.7	270.2	106.3	1,367.2
2001	675.8	345.5	1,021.3	287.5	164.0	1,472.9
2002	686.7	395.3	1,082.0	304.7	196.4	1,583.1
2003	705.4	449.6	1,155.0	303.2	169.5	1,627.7
CAGR*	**6.52%**	**10.43%**	**7.90%**	**2.71%**	**9.16%**	**6.85%**

*CAGR – Compound Average Growth Rate

Table 3.8 - Total Expenditure, 2003

	TT ($M)	%
Conversion Cost	705.39	43.3
Fuel	442.82	27.2
Other Expenses (generation)	0.04	0.0
Internal Generation	6.78	0.4
Transmission & Distribution (includes maintenance & operations)	190.78	11.7
Administrative & General	108.67	6.7
Depreciation	72.67	4.5
Interest on Loans	83.50	5.1
Interest on Gas	17.71	1.1
Loss / Gain on Exchange	(0.70)	(0.0)
TOTAL	**1,627.66**	**100**

Source: T&TEC, Financial Report December 2002.

Table 3.9 - Transmission & Distribution Expenditure, 1998-2002 ($Mn)

	1998	1999	2000	2001	2002	% Increase 1998 - 2002
Personnel Expenditure	**$ M**	**$ M**	**$ M**	**$ M**	**$ M**	**%**
Overtime	5.65	6.39	6.82	6.58	7.96	40.8
Gross Wages & Salaries	79.60	80.53	74.07	83.59	94.44	18.6
Contribution to Pension Plan	11.97	12.24	12.38	14.08	12.17	1.6
Cost of Medical, Welfare Facilities	3.10	3.58	4.15	5.38	5.20	67.7
Employer's contribution to NIS	1.25	2.48	3.13	5.21	3.84	208.3
Other payments to employees	3.79	5.47	6.67	3.39	3.57	-5.9
Materials	16.00	13.43	12.43	11.53	9.83	-38.6
Maintenance	68.00	61.44	55.55	56.84	58.70	-13.7
Capitalised Personnel Expenditure	8.18	20.15	20.27	18.71	22.14	170.9
Total	**197.55**	**205.72**	**195.48**	**205.32**	**217.85**	**10.3**

Source: T&TEC Finance Department, 2003.

3.5 CAPITAL EXPENDITURE

Table 3.10 reflects the movement in capital expenditure in real terms from 1995 to 2003; the levels vary on a year-to-year basis. The most significant increase in capital expenditure occurred in 1997.

Table 3.10 - Capital Expenditure, 1995-2003

	1995 $M	1996 $M	1997 $M	1998 $M	1999 $M	2000 $M	2001 $M	2002 $M	2003 $M
Capital Expenditure	35.9	39.8	114.8	153.2	243.7	167.7	172.3	135.0	159.9
Retail prices index (base yr: 1995)*	100.0	103.3	107.1	113.1	117.0	121.1	127.9	133.2	138.1
Capital Expenditure in real terms	35.9	38.5	107.2	135.5	208.3	138.5	134.7	101.3	115.8
Percentage Change	-	7.2	178.5	26.4	53.7	-33.5	-2.7	-24.8	14.3

***Source:** Central Statistical Office, General Index of Retail Prices Trinidad and Tobago.

3.6 REVENUE

T&TEC's total sales increased from $754.7 million in 1995 to $1439.5 million in 2003, an increase of 91%. The units sold, however, increased from 3,410 GWh to 6,088 GWh, an increase of 79%, while the unit cost of sales increased by 7% over the same period (**Figures 3.5 and 3.6**).

Figure 3.5 - Light & Power Sales ($Mn), 1995-2003

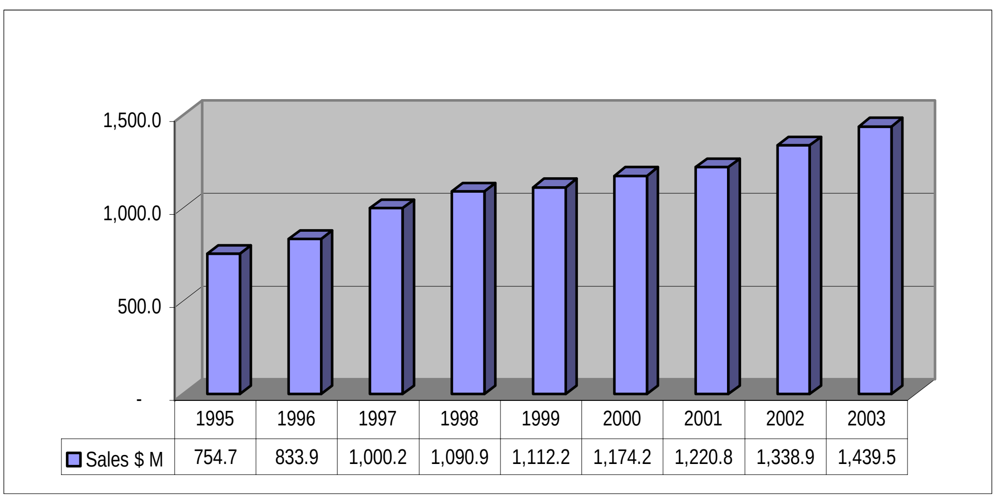
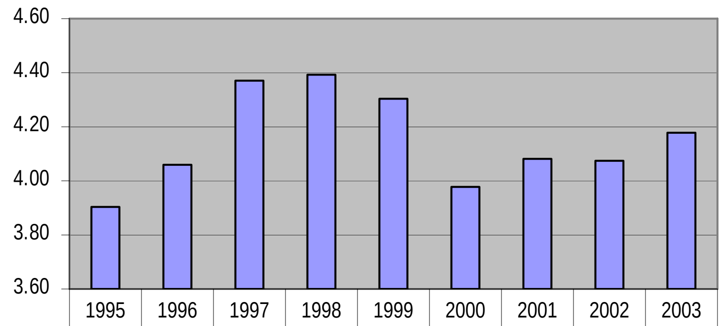


Figure 3.6 - Unit Cost of Sales, 1995-2003



	1995	1996	1997	1998	1999	2000	2001	2002	2003
Unit Cost of Sales (Dollars / kWh)	3.90	4.06	4.37	4.40	4.30	3.98	4.08	4.07	4.18

3.7 BILLING AND COLLECTIONS

One indicator that is usually used to measure the relative efficiency of a utility's commercial practices is the "Collection Period" (i.e. Accounts Receivable in days). Delayed collections can lead to significant cash flow problems. **Table 3.11** reveals consistently high levels of receivables including receivables from Government and Government agencies.

Table 3.11 - Aged Analysis of Receivables as at December 2002 ($'000)

	0 - 30 Days	31 - 60 Days	61 - 120 Days	Over 120 Days
Domestic & General	26,927	12,305	7,954	5,041
Industrial	51,261	30,663	48,892	136,707
Street Lighting	2,170	1,729	2,490	11,353
Total	**80,358**	**44,697**	**59,336**	**153,101**

Of Which:

	0 - 30 Days	31 - 60 Days	61 - 120 Days	Over 120 Days
Government	4,483	2,702	1,661	3,557
Statutory Boards	7,835	7,569	5,336	37,116
State Enterprises	710	102	18	0.457
Total	**13,027**	**10,374**	**7,015**	**40,673**

Source: T&TEC Finance Department, 2003.

3.8 TARIFFS AND SUBSIDIES

For the period 1993-2003, the overall average tariff decreased in real (1995) terms by 22% (**Table 3.12 and Figure 3.7**).

Table 3.12 - Average Tariff – Domestic, General & Industrial, 1993-2003

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Average Tariff (¢/kWh)	19.05	20.13	22.13	21.08	21.97	23.23	22.75	23.53	22.86	23.71	23.64
Retail Price Index*	87.30	95.00	100.00	103.30	107.10	113.10	117.00	121.10	127.90	133.20	138.10
Real Tariff (TT$)	21.82	21.19	22.13	20.41	20.51	20.54	19.44	19.43	17.87	17.80	17.12

*Base Year 1995

*Source: Central Statistical Office, General Index of Retail Prices Trinidad and Tobago.

Figure 3.7 - T&TEC Average Tariff, 1993-2003

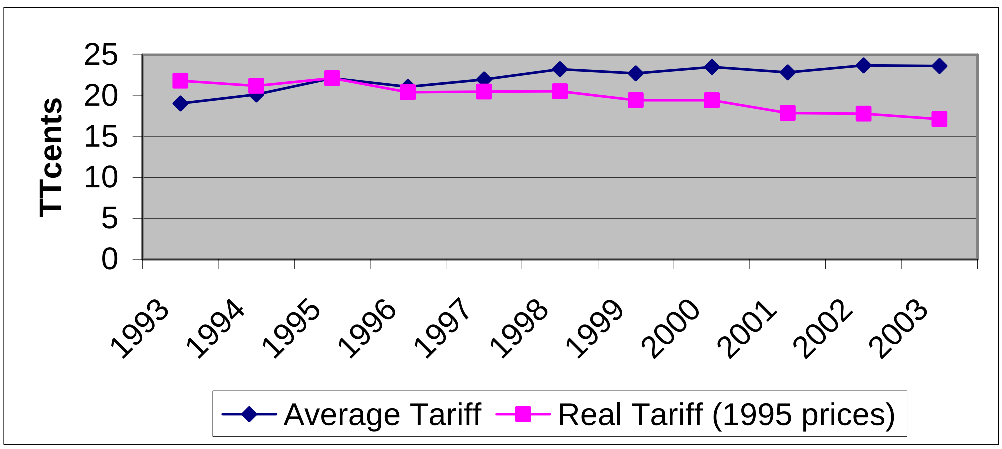


Table 3.13 shows energy sold and revenue collected between 1992–2003 by customer class. Domestic customers share of energy consumption decreased from 27% in 1992 to 25% in 2003, while the share of revenue received from sales to domestic customers decreased from 32% to 24%. For industrial customers, on the other hand, the share of energy consumption increased from 63% in 1992 to 65% in 2003, while the share of revenue received from the sale of electricity increased from 55% to 65%. The tariff in the residential sector has realized a growth of only 2% between 1992–2003, which is below the inflation rate for the period, implying a fall in real tariff for the residential class.

Table 3.13 – Energy Sold (GWh) and Revenue Collected by Customer Class, 1992-2003

Year	Domestic		Commercial		Industrial		*Total	
	GWh Sold	Revenue $ Million	GWh Sold	Revenue $ Million	GWh Sold	Revenue $ Million	GWh Sold	Revenue $ Million
1992	894.6	157.8	342.0	53.7	2,116.2	268.9	3,367.3	490.4
1993	935.9	159.7	334.5	69.0	2,062.3	392.7	3,347.2	637.7
1994	921.2	171.1	343.9	74.8	2,210.5	437.6	3,490.6	702.6
1995	897.2	176.7	319.9	75.9	2,178.1	484.1	3,410.2	754.7
1996	1,002.0	200.5	360.4	82.6	2,565.6	532.5	3,943.7	831.3
1997	1,060.2	228.6	410.3	98.3	2,877.6	615.1	4,363.9	958.9
1998	1,117.9	246.5	432.3	104.3	3,127.4	723.4	4,696.4	1,090.9
1999	1,144.7	247.2	456.6	107.9	3,270.5	737.6	4,889.1	1,112.2
2000	1,250.6	276.1	475.1	113.2	3,271.7	771.5	5,015.4	1,180.3
2001	1,285.0	287.3	522.9	118.6	3,513.1	793.6	5,339.8	1,220.8
2002	1,398.7	310.2	520.2	125.5	3,706.8	881.1	5,646.0	1,338.9
2003	1,541.6	340.2	581.4	136.6	3,942.0	935.3	6,088.1	1,439.5

* Total includes Domestic, Commercial, Industrial and **Street Lighting** figures.

The change in average tariffs across consumption categories that has occurred over the years is observed in **Table 3.14**. In 1992, the average revenue realized from the industrial class was 72% of the average revenue realized from residential consumers. However, this percentage has been increasing steadily since then and it was 108% in 2003. Significantly, the average revenue realization in the residential sector has been lower than average cost of electricity supply for the entire period under consideration.

Table 3.14 - Per Unit Average Revenue by Class, 1992-2003

Year	Residential Revenue / kWh (¢)	Commercial Revenue / kWh (¢)	Industrial Revenue / kWh (¢)	Total Revenue / kWh (¢)
1992	17.64	15.69	12.71	14.56
1993	17.07	20.62	19.04	19.05
1994	18.57	21.75	19.80	20.13
1995	19.69	23.71	22.23	22.13
1996	20.00	22.93	20.75	21.08
1997	21.56	23.96	21.38	21.97
1998	22.05	24.12	23.13	23.23
1999	21.60	23.62	22.55	22.75
2000	22.08	23.83	23.58	23.53
2001	22.36	22.69	22.59	22.86
2002	22.18	24.13	23.77	23.71
2003	22.07	23.49	23.82	23.64

The above analysis suggests that the residential sector enjoyed a substantial cross subsidy in electricity tariff over the review period. An accurate estimation of the subsidy to different classes of customers would require fairly elaborate data, which are not currently available. The RIC is of the view that there should be full transparency in the allocation of a subsidy to different classes of customers. The practice of using the industrial sector to cross-subsidize other sectors cannot be sustained beyond a point.

An attempt was also made to determine other sources of subsidy to the electricity sector, as well as the subsidy between classes. The subsidy to the electricity sector may have come in different forms, such as fuel (natural gas), cost of capital which would have been lower than the going commercial rates etc. As can be observed in **Table 3.15**, there has been a significant element of subsidy provided to all classes of customers from lower fuel prices paid by T&TEC when compared with market prices for fuel. In fact, the average annual subsidy from lower prices amounted to $96 million between 1999-2003. As expected, overall, a significant share (75%) of this subsidy went to the commercial and industrial classes.

Table 3.15 – Share of Fuel Subsidy by Class of Customer, 1999-2003

Year	Total Fuel Subsidy $ M	Total Energy Sold (GWh)	Domestic			Commercial			Industrial		
			GWh Sold	Share of Subsidy (%)	Share of Subsidy $ M	GWh Sold	Share of Subsidy (%)	Share of Subsidy $ M	GWh Sold	Share of Subsidy (%)	Share of Subsidy $ M
1999	52	4,889.1	1,144.7	23	12.2	456.6	9	4.9	3,270.5	67	34.8
2000	82	5,015.4	1,250.6	25	20.4	475.1	9	7.8	3,271.7	65	53.5
2001	83	5,339.8	1,285.0	24	20.0	522.9	10	8.1	3,513.1	66	54.6
2002	92	5,646.0	1,398.7	25	22.8	520.2	9	8.5	3,706.8	66	60.4
2003	171	6,088.1	1,541.6	25	43.3	581.4	10	16.3	3,942.0	65	110.7

Overall, revenue generation has consistently lagged behind cost of electricity supply, although the gap between average cost of electricity supply and average tariff has narrowed from 6 cents per unit to 3.1 cents per unit between 1995-2003. Thus, the current tariff regime has failed to generate reasonable returns for T&TEC, which is a prerequisite for effecting continued improvements in the quality of electricity service and sustaining the electricity sector.

3.9 PERFORMANCE ASSESSMENT IN THE FUTURE

The actual performance of the service provider during the control period may vary from the forecasts/targets set by the regulator. Therefore, a "true-up"[3] of performance is not only essential but fair to all concerned. This being the first price control period, a "true-up" of past performance against forecast performance indicators cannot be undertaken. However, in the future, as part of the RIC's investigation into the appropriate revenue cap to apply to T&TEC for the second regulatory control period, a "true-up" of past performance in the areas of financial, service quality and price outcomes would be an integral part of price control process.

Accordingly, the RIC directs T&TEC to ensure that in its next rate review submission, it provides a comprehensive analysis of actual performance vis-à-vis the determinations of the RIC and propose suitable treatment for any deviations.

The service provider will be required in the future to provide a comprehensive analysis of actual performance vis-à-vis the determination of the RIC and to propose suitable treatment for any deviations.

3.10 CONCLUSIONS

Aggregate operating expenditure during the period 1995-2003 has increased significantly. The major sources of increase have been the fuel and conversion costs which increased by 21% and 66% respectively during the period. Together these costs comprise nearly 70% of total operating expenditure and are largely uncontrollable. Part

[3] Actual performance of the service provider in terms of the RIC's established/prescribed performance indicators.

of the reason for increased expenditure has been the additional energy consumption to meet increasing demand, which grew by 78% during the period. On the other hand, T&TEC's other costs increased by 43% during the same period. T&TEC has indicated that cost increases were due to a number of factors, including:

- increased personnel costs due to pay increases;
- increased network maintenance costs associated with routine maintenance; and
- increased major network and maintenance activities.

In aggregate, capital expenditure over the same period did not increase significantly.

Although the relatively high growth in electricity sales resulted in higher revenues, T&TEC's financial performance over the period has been generally weak.

CHAPTER 4

DEMAND FORECASTS

4.1 IMPORTANCE OF DEMAND FORECASTS

Broadly, the setting of price controls involves the following steps:

(1) Estimation of the likely electricity consumption during the period for which the price control is being established;

(2) Estimation of the efficient costs, inclusive of the reasonable permissible return, likely to be incurred by the service provider in supplying the consumption estimated in (1);

(3) Estimation of the total revenue likely to be recovered by the service provider for the supply of this demand, at the current tariffs; and

(4) Determination of the revised tariffs, to meet the gap (if any) between the results arrived at in (2) (Revenue Requirement) and (3) (expected revenue from current tariffs).

In this chapter, demand forecasts are examined.

Demand forecasts are an important factor underlying the determination of the total revenue requirement, for at least three reasons. In order to propose the prices required to recover the revenue needed to deliver the services over the price control period, a clear view of the future estimates of demand is needed. Demand forecasts are also a key determinant of capital and operating expenditure, as future expenditure requirements are driven partly by expected growth in both peak demand and customer numbers. Finally, growth projections impact on the calculation of the productivity (X-factor) in the weighted average price cap and average revenue control, as this will influence the unit price of services. Therefore, robust estimates of demand are important.

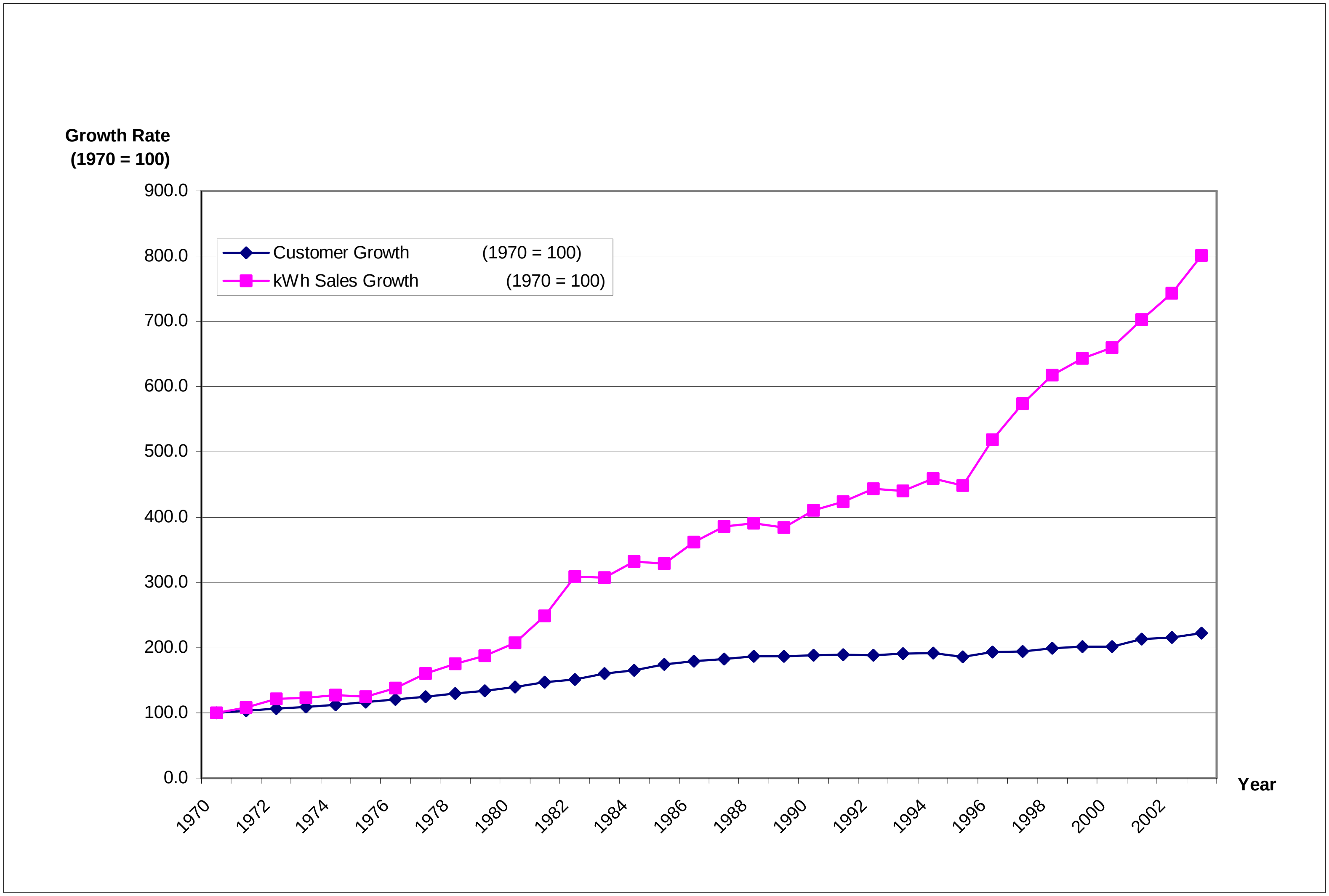
In the electricity sector, demand forecasts are required for electricity consumption, peak demand and customer numbers. For the regulator, the forecast rate of growth in these three measures is of particular concern. Growth in demand affects investment decisions and has on-going consequences for the medium to long-term strategies of service providers. Additionally, where initial prices depend on forecasts of the growth in customer numbers and energy consumed, variations between actuals and forecasts have an impact on the revenue received over the regulatory period. The planning of future capital investment is based on peak demand and consumption forecasts. In the final analysis, therefore, the success of price cap/incentive regulation would depend on the accuracy of the demand estimates underlying the service provider's business plan. In general, accurate demand forecasts tend to result in efficient operations.

A forecast is a quantitative estimate about the likelihood of future events based on past and current information. Forecasts can be short-term, medium or long-term. Short and medium term forecasts are intended to ensure continuity and reliability of supply. Long-term forecasts project several years into the future and their focus tends to be on building adequate capacity for the provision of services.

4.2 FORECASTING PROCESS

For this price review, T&TEC was required to provide in its Business Plan comprehensive demand forecasts, using the forecasting method that it considered most appropriate and reasonable. T&TEC was also requested to provide forecasts for low, medium and high growth scenarios. The main issues for the RIC were to clarify whether T&TEC's forecasts were developed on an appropriate basis and whether the resulting forecasts were robust and reasonable. **Figure 4.1** shows the growth in sales of energy and customers. Overall, the sale of electricity has increased significantly for all classes of customers between 1970 and 2003. While energy sold to the residential class grew by 71.8% between 1970–2003, energy sold to commercial and industrial classes grew by 81.8% and 81.0% respectively.

Figure 4.1 – Growth in Sale of Energy and Customers, 1970-2003



As can be observed from **Table 4.1,** the total sales increased at a compound average growth rate (CAGR) of 5.5% between 1992-2003. Examining the components of overall growth, domestic sales grew at a CAGR of 5.07%, industrial grew by 5.82% and commercial at a CAGR of 4.94% during this period. Interestingly, the Index of Domestic Production (All Industries) registered an average annual growth rate of 8.25% for the same period. As to the share of different classes in total energy consumption, the share of all classes has increased during the period, with the share of the industrial class increasing at a slightly more rapid rate than other classes.

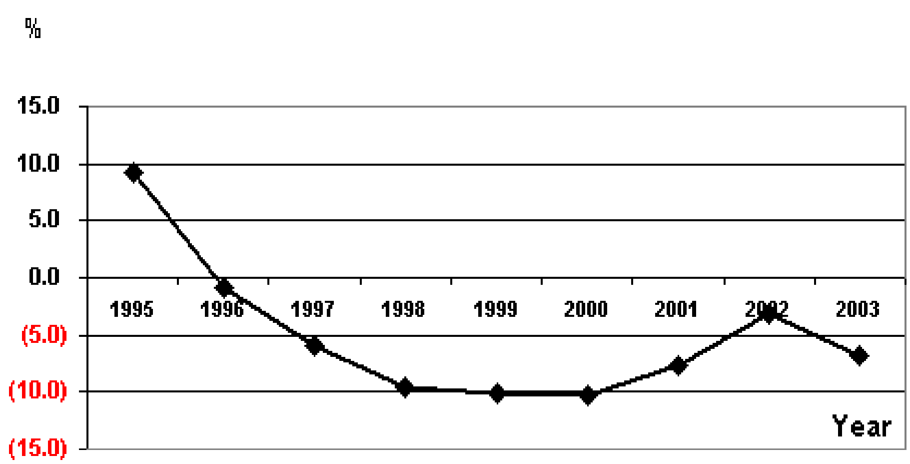
Table 4.1 - Energy Consumption (GWh) by Class, 1992-2003

Year	Domestic		Commercial		Industrial		*Total	
	GWh Sold	Share (%)	GWh Sold	Share (%)	GWh Sold	Share (%)	GWh Sold	Share (%)
1992	894.6	26.6	342.0	10.2	2,116.2	62.8	3,367.3	100
1993	935.9	28.0	334.5	10.0	2,062.3	61.6	3,347.2	100
1994	921.2	26.4	343.9	9.9	2,210.5	63.3	3,490.6	100
1995	897.2	26.3	319.9	9.4	2,178.1	63.9	3,410.2	100
1996	1,002.0	25.4	360.4	9.1	2,565.6	65.1	3,943.7	100
1997	1,060.2	24.3	410.3	9.4	2,877.6	65.9	4,363.9	100
1998	1,117.9	23.8	432.3	9.2	3,127.4	66.6	4,696.4	100
1999	1,144.7	23.4	456.6	9.3	3,270.5	66.9	4,889.1	100
2000	1,250.6	24.9	475.1	9.5	3,271.7	65.2	5,015.4	100
2001	1,285.0	24.1	522.9	9.8	3,513.1	65.8	5,339.8	100
2002	1,398.7	24.8	520.2	9.2	3,706.8	65.7	5,646.0	100
2003	1,541.6	25.3	581.4	9.5	3,942.0	64.7	6,088.1	100
CAGR	**5.07%**		**4.94%**		**5.82%**		**5.53%**	

* Total includes Domestic, Commercial, Industrial and **Street Lighting** figures.

T&TEC's growth in energy consumption over the period 1995-2003 indicates that, in nearly all cases, actual consumption has been much higher than forecast (**Figure 4.2**). On the other hand, a review of growth in customer numbers for the same period indicates that the growth in actual customer numbers has been higher than expected for only three years (**Figure 4.3**). Furthermore, average variations from actual were much higher for energy consumption, moving between 0.9% and 10.4%, whereas for customer numbers average variations were only between 0.5% and 4.5%. Clearly, the energy forecasts are far from robust.

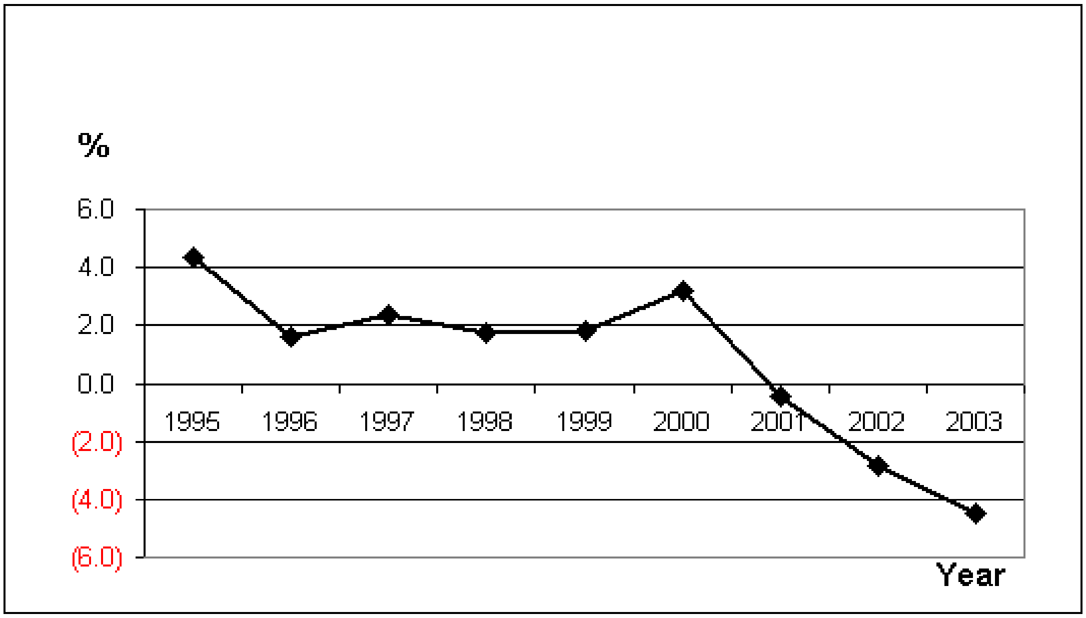
Figure 4.2 - Energy Consumption, Actual vs Forecast, 1995-2003 (T&TEC)



	1995	1996	1997	1998	1999	2000	2001	2002	2003
Forecast (GWh)	3,727	3,909	4,107	4,243	4,396	4,495	4,601	5,473	5,676
Actual (GWh)	3,410	3,944	4,364	4,696	4,889	5,015	4,985	5,647	6,088
Difference (%)	**9.3**	**(0.9)**	**(5.9)**	**(9.7)**	**(10.1)**	**(10.4)**	**(7.7)**	**(3.1)**	**(6.8)**

Chart shows % difference between actual and forecast.

Figure 4.3 – Customer Numbers, Actual vs Forecast, 1995-2003 (T&TEC)



	1995	1996	1997	1998	1999	2000	2001	2002	2003
Forecast (Thousands)	303.8	307.0	311.4	316.3	321.2	326.2	331.4	328.2	332.5
Actual (Thousands)	291.1	302.2	304.1	310.9	315.5	316.0	332.9	337.9	348.0
Difference (%)	**4.4**	**1.6**	**2.4**	**1.7**	**1.8**	**3.2**	**(0.5)**	**(2.9)**	**(4.5)**

*** Chart shows % difference between actual and forecast.**

4.3 FORECASTING APPROACHES

Many different forecasting techniques have been developed and are used by engineers and economists. Despite the existence of varying techniques, forecasting procedures may be broadly classified into one of four categories:

- **Judgmental Approach** – Such an approach uses subjective and qualitative data to forecast outcomes. It inherently relies on experience, intuition, judgment and expert opinion, among other things. This approach is generally used when historical data are not available. Sometimes surveys of a sample of customers are used to estimate demand.

- **Experimental Approach** - This approach is used to conduct a demand experiment on a small group of customers and to extrapolate the results to a larger population. It is better suited to a new product than to one which has accumulated valuable demand data.

- **Relationship/Causal Approach** – This approach attempts to forecast demand by examining and understanding the reason(s) why a consumer uses a product. In essence, some explanatory variables would be used as a basis for forecasting demand. This can be done using econometric models and tends to be better suited to larger scale macro-economic analysis.

- **Time Series Approach** – This approach is fundamentally different to the previous three in that no judgment or expertise or opinion is sought. No causal relationships are examined. By their nature, time series procedures are applied to data that are longitudinal rather than cross-sectional. In essence, the approach assumes that demand occurs over time in patterns that repeat themselves, at least approximately. Based on the trends and pattern that emerge a projection of those is made into the future in the belief that the future will replicate the past.

The methods, which are commonly used to forecast electricity requirements, may be classified into two groups; global and sectoral. In the case of global techniques, two commonly used methods are trend extrapolation and single variable correlation.

4.3.1 Global Methods

Trend Method

Essentially, the trend extrapolation models are deterministic, in that no reference is made to the source or nature of the underlying randomness in the series. These models have been the standard tools of economists forecasting business cycles. They can range from simple linear projections and compound annual growth rates, to more sophisticated variants. Short-term estimates based on these methods are likely to be reasonably accurate.

This method falls under the category of the non-causal models of demand forecasting that do not explain how the values of the variable being projected are determined. The variable to be predicted (energy demand) is expressed as a function of time, rather than relating it to economic, demographic or policy variables. This method is mainly used for short-term projections. Its advantage is its simplicity of use. Its main disadvantage is that it ignores possible interaction of the variable under study with other economic factors such as, income, prices, population growth etc. The simplest extrapolation model is a linear trend model. If one believes that a series Y_t will increase in constant absolute amounts each time, one can predict Y_t in the future by fitting the trend line $Y(t) = \alpha + \beta t$ where t is the time index. The parameters alpha and beta are usually estimated via a simple regression in which Y is the dependent variable and the time index (t) is the independent variable.

Single Variable Method

The single variable correlation method is a more popular approach, which uses an econometric model to relate demand to a variable by a regression technique. In many cases, the variable economic growth (real GDP) has been found to have a strong relationship to electricity demand.

4.3.2 Sectoral Methods

It is generally believed, given the data, that sophisticated econometric models are likely to fare better than simple trend extrapolation methods in developing countries where independent variables such as income, prices, and the size of the manufacturing sector move with less unison. As a result of the inadequacy of the global methods other techniques have been used to forecast demand. Some of these methods are described below.

Usage per Customer

This is a short-term forecasting procedure and may be used in non-electrified areas. It involves two basic steps; (a) an estimation of the rate of potential connections, and (b) the estimation of the Kilowatt-hour (kWh) usage per customer.

The kWh usage for a residential customer can be estimated by an analysis of the number and type of electricity using appliances which households possess, depending on income levels. Such information is usually obtained through household surveys. The consumption levels of commercial and small industrial customers are estimated by using data of existing fuel consumption while in the case of very large customers surveys can be used.

Multifactorial Approach

This approach recognizes that the demand for electricity is not a simple linear relationship but depends on social and economic factors. One of the primary objectives of this method is to understand the underlying factors, which determine a future trend line. It provides better understanding of the past and, therefore, a better base to make predictions, especially of a long-term nature. The quantity of electricity demanded across various consumer categories depends on various explanatory variables like price, income, population, industrial growth, urbanization, price of substitutes etc. To that extent, estimation of future consumption requires the estimation of the relationship between the quantity of electricity demanded and the appropriate explanatory variables, through regression analysis. This estimated relationship could then be used to predict future consumption by inputting the expected future values of the explanatory variables obtained from various primary and secondary sources. This method, however, requires reliable data on a large number of variables, for a significant number of past years, to provide statistically reliable results.

One of the major advantages of this technique is the use of sensitivity analysis to determine the effect on total electricity requirements resulting from changes in parameters. The usefulness of the models for long-term forecasting under this approach has been questioned on the grounds that the estimated coefficients are based on past data, hence, they take no account of new developments. However, they are very useful as they allow management the opportunity of evaluating the impact of alternative policies.

End Use Method

This approach attempts to capture the impact of energy usage patterns of various devices and systems. It focuses on electricity use by major appliances and other machinery or equipment for each class of customer. It takes into consideration trends in appliance saturation, efficiency and equipment choices. It is based on the premise that energy is required for the service that it delivers and not as a final good. For these reasons the forecasts are likely to be more accurate, and the utility is better able to shape consumption decisions. This approach is useful when there is a lack of adequate time series data on trends in consumption and other variables but it requires a high level of detail on each of the end-users. Its disadvantages are: it may lead to mechanical forecasting of demand without adequate regard for behavioural responses of consumers; and it does not pay attention to variations in consumption patterns due to demographic, socio-economic and cultural factors. Its use is limited because of the volume of data required on a continuous basis.

4.3.3 Other Techniques

The above-discussed methods are useful for forecasting electricity demand requirements for classes of customers. In the case of peak demand forecast other techniques are used. Peak demand refers to the simultaneous demand or coincidental demand of all customers on the system occurring at a point in time. The capacity decisions of most electric utilities are based on a forecast of expected peak demand plus an allowance for a reserve margin. There are many techniques available for forecasting loads but three of the more popular are: Artificial Neural Networks; Semiparametric Regression Modeling; and Multi-equation Models.

Artificial Neural Networks (ANN)

Historically, ANN solutions have been popular with electrical engineers. One of the most popular involves using back-propagation algorithms to select parsimonious radial basis function representations of the non-linear periodic daily and weekly effects. Because of its inherent low level of noise relative to non-linear signals, these models produce quality forecast. However, it is not a statistical approach.

Semiparametric Regression Modeling

The statistical equivalent of the ANN solution is to estimate an additive semiparametric regression model, which also results in the estimation of smooth non-linear periodic daily and weekly effects. If properly implemented the forecasts are at least as accurate as those from comparable ANN methods but there are advantages to using a statistical model. First, full predictive distributions of load are available and second, time series models for the residuals can be estimated.

Multi-equation Models

This method has been championed by econometricians working on energy problems. It does not involve estimating a smooth daily or weekly periodic function as in the semiparametric regression model. Instead, each intra-day period is written down as a separate parametric regression but with cross-correlated errors. These models have been widely used and are straightforward to estimate using either Maximum Likelihood or Bayesian methods. One of its advantages is that Time Series models for errors, such as, "vector auto regressions", can also be used.

Apart from the above-mentioned methods a variety of other methods are common. A study by the Trinidad and Tobago Public Utilities Commission (1991), discussed five approaches to forecasting peak electricity demand. These are: Time Series (ARIMA) Models; The Direct Model; The Single Component Indirect Model; The Multi Component Indirect Model; and The End-Use Model. Based on its research and findings the PUC recommended the use of the **Demand Distribution Model**, a component of the **Multicomponent Indirect Model**, which generates projections of energy by customer class, as an acceptable method for forecasting peak demand.

4.4 PREFERRED FORECASTING TECHNIQUES

Using annual data collected from T&TEC and the Central Statistical Office over the period 1970 to 2003, the RIC generated forecasts for customers by class, and kilowatts sales by class. Peak demand forecasts were derived using data from the same sources.

Three techniques were used to forecast customers and energy sales: ARIMA Models; Trending; and Vector Auto Regression (VAR) Models. In the case of the ARIMA model, the results did not closely correspond to observed values over the sample period and the RIC has ruled against using this method even though its test statistics were good. In essence, any method which produces forecasts which do not correspond closely with observed values cannot be relied upon for prediction. This, however, is not necessarily a fault of the technique but largely due to the short time series. Perhaps in the future with better data this method could produce desirable results.

With respect to the VAR forecasts, these tended to correspond more closely to the observed values and evidenced lower variation between the actual and estimated series. However, the confidence intervals for these estimates were fairly wide and increasing. Changing variables and adjusting the lengths of the series did not result in any significant improvement in the intervals. The estimates produced by this technique are not being recommended.

The third technique used was a simple trending approach. The estimates derived from this technique closely approximated the observed sample values and produced average variations from the actual forecasts of between 1.1% and 3.3%. The forecasts produced by this technique are clearly superior to the other techniques used and the level of confidence in the results is acceptable. Thus, the RIC has decided to use the estimates provided by this technique. In fact, the trending approach and the use of judgment, based on the knowledge of the sector, can provide reasonable forecasts (**Tables 4.2 and 4.3**).

<u>Table 4.2 – RIC's Forecast of Customer Numbers</u>

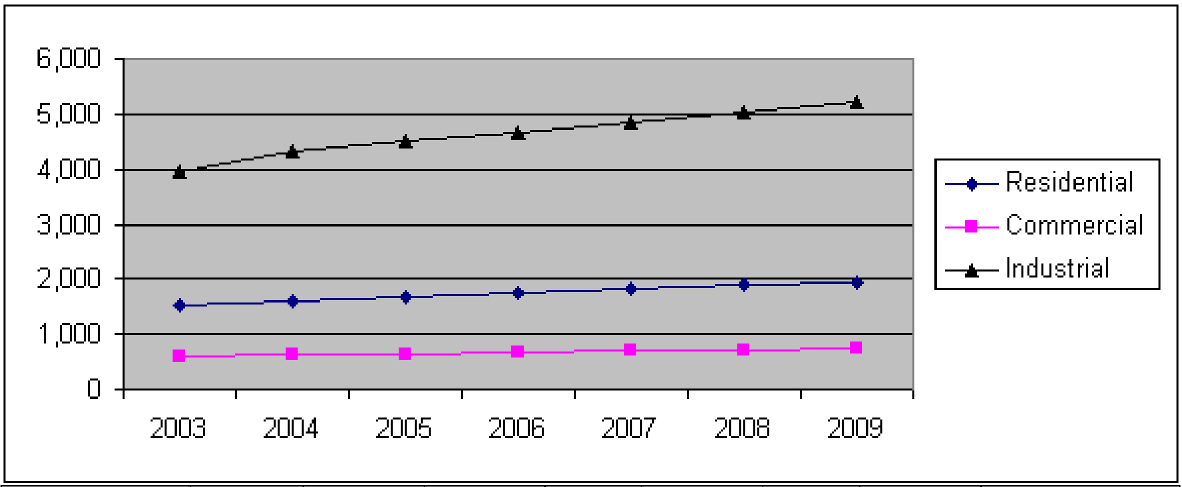
YEAR	RESIDENTIAL			COMMERCIAL			INDUSTRIAL		
	Actual	Forecast	Variance %	Actual	Forecast	Variance %	Actual	Forecast	Variance %
1993	268,676	260,889	-2.9	28,041	26,362	-6.0	1,817	1,754	-3.5
1994	268,988	262,780	-2.3	28,034	26,336	-6.1	1,863	1,783	-4.3
1995	262,309	266,096	1.4	26,354	26,517	0.6	1,840	1,822	-1.0
1996	272,547	271,599	-0.3	27,309	27,130	-0.7	1,874	1,880	0.3
1997	276,180	276,456	0.1	25,625	27,714	8.2	1,905	1,945	2.1
1998	280,151	281,558	0.5	28,378	28,539	0.6	1,989	2,015	1.3
1999	283,613	286,860	1.1	29,418	29,173	-0.8	2,045	2,086	2.0
2000	285,019	292,499	2.6	28,544	29,779	4.3	2,102	2,162	2.8
2001	299,652	299,038	-0.2	30,631	30,613	-0.1	2,235	2,245	0.4
2002	303,901	304,567	0.2	31,281	31,296	0.0	2,338	2,324	-0.6
2003	312,805	310,412	-0.8	32,419	31,988	-1.3	2,409	2,399	-0.4
2004		315,134			32,509			2,490	
2005		321,139			33,314			2,549	
2006		326,773			34,044			2,623	
2007		332,103			34,691			2,693	
2008		337,527			35,331			2,762	
2009		342,889			35,949			2,829	
Average			1.1			2.6			1.7

<u>Table 4.3 – RIC's Forecast of Energy Consumption (kWh)</u>

YEAR	RESIDENTIAL			COMMERCIAL			INDUSTRIAL		
	Actual	Forecast	Variance %	Actual	Forecast	Variance %	Actual	Forecast	Variance %
1993	935,875	865,515	-7.5	334,462	315,148	-5.8	2,062,260	2,079,351	0.8
1994	921,155	884,880	-3.9	343,940	325,925	-5.2	2,210,461	2,206,482	-0.2
1995	897,241	926,869	3.3	319,855	342,778	7.2	2,178,077	2,355,906	8.2
1996	1,002,041	988,297	-1.4	360,403	370,205	2.7	2,565,626	2,554,196	-0.4
1997	1,060,166	1,047,465	-1.2	410,278	396,587	-3.3	2,877,566	2,731,979	-5.1
1998	1,117,945	1,111,085	-0.6	432,262	422,080	-2.4	3,127,392	2,909,431	-7.0
1999	1,144,684	1,179,356	3.0	456,613	449,722	-1.5	3,186,697	3,093,564	-2.9
2000	1,250,643	1,256,767	0.5	475,128	479,441	0.9	3,271,729	3,300,254	0.9
2001	1,285,003	1,336,171	4.0	522,911	512,497	-2.0	3,513,056	3,534,800	0.6
2002	1,398,664	1,429,667	2.2	520,224	544,375	4.6	3,706,752	3,781,323	2.0
2003	1,541,567	1,524,344	-1.1	581,389	585,561	0.7	3,941,961	4,047,592	2.7
2004		1,600,762			620,372			4,320,493	
2005		1,678,409			649,410			4,497,919	
2006		1,747,989			675,738			4,670,711	
2007		1,814,120			700,250			4,841,666	
2008		1,881,795			726,106			5,025,309	
2009		1,949,005			752,704			5,213,109	
Average			2.6			3.3			2.8

Based on the forecasts in **Tables 4.2 and 4.3**, energy consumption is forecast to increase steadily for all customer classes at around 3.7% per annum (**Figure 4.4**). Similarly, customer numbers are expected to increase steadily for all classes but at much lower rates.

Figure 4.4 – Energy Consumption Forecasts, 2003-2009 (GWh)



	2003 Actual ('000)	2004 ('000)	2005 ('000)	2006 ('000)	2007 ('000)	2008 ('000)	2009 ('000)	% Change (CAGR)
Residential	1,542.6	1,601.0	1,678.4	1,748.0	1,814.1	1,882.0	1,949.0	3.07
Commercial	581.4	620.4	649.4	676.0	700.3	726.1	753.0	3.72
Industrial	3,942.0	4,321.0	4,498.0	4,671.0	4,842.0	5,025.0	5,213.1	4.35

CAGR – Compound Average Growth Rate

In the case of Peak Demand forecasts, three methods were utilized; Artificial Neural Networks (ANN), ARIMA models and Trending. The estimates produced by the ANN technique were highly undesirable. The peak demand forecast of the ARIMA and Trending Models were fairly similar, with variation from actual averaging 11.3% and 10.1% respectively. The forecasts values for the period 2005 to 2009 were fairly close and had a similar upward trend. They also proved to be fairly close to, though slightly higher than, T&TEC's projections. Since T&TEC has intimate knowledge of the planning process and the network, the RIC is inclined to adopt the peak demand forecasts of T&TEC (**Table 4.4**).

Table 4.4 – RIC's Forecast of Peak Demand (MW)

YEAR	ACTUAL	FORECAST	VARIANCE (%)
1994	607	630	3.8
1995	665	663	-0.3
1996	710	704	-0.8
1997	746	729	-2.3
1998	806	739	-8.3
1999	815	752	-7.7
2000	834	768	-7.9
2001	876	785	-10.4
2002	925	900	-2.7
2003	970	933	-3.8
2004	1,034	1,013	-2.0
2005		1,062	
2006		1,104	
2007		1,129	
2008		1,153	
2009			
Average			4.6

Source: T&TEC

4.5 CONCLUSION ON DEMAND FORECASTS

The RIC has carefully reviewed the information provided by T&TEC in relation to demand forecasts and its own forecasts utilizing different methods. Moreover, under the form of price control to be adopted by the RIC, the forecasts of energy consumption do not have a direct impact on the proposed price path. Rather, energy forecasts are more important in determining the annual tariff during the regulatory period. Therefore, the RIC accepts the forecasts outlined in **Tables 4.2, 4.3 and 4.4**. The RIC also proposes that, in future, not only will the service providers be required to provide comprehensive demand forecasts but they would be required to provide independent verification that their forecasts and forecasting methods are robust and reasonable. They will be required to demonstrate that the methodology:

- is appropriate for the electricity sector;
- reflects the key drivers of peak demand, customer numbers and energy consumption;
- has used the most recent information available, in conjunction with historic data, to identify trends in growth; and
- has taken into account demand side management.

The RIC's decision is to adopt demand forecasts for customer numbers, energy consumption and peak demand as shown in **Tables 4.2, 4.3 and 4.4.**

For future price reviews, the service provider will be required to obtain and provide to the RIC, independent verification that its forecasts and forecasting methods are robust and reasonable. The RIC will also ensure that the independent auditor's report is made public.

CHAPTER 5

OPERATING AND MAINTENANCE EXPENDITURE

5.1 LEGAL FRAMEWORK

This chapter analyses the operating and maintenance expenditure (Opex) requirements for the 2006-2010 regulatory control period. Section 67 of the RIC Act contains a number of specific requirements that the RIC is required to follow when setting out the principles on which rates chargeable by service providers should be based, as well as a number of specific requirements governing price determinations.

Section 67, sub-sections (3) and (4) mandate that when establishing principles, the RIC must have regard to, *inter alia*:

- the funding and ability of the service provide to perform its functions;
- the ability of consumers to pay rates;
- the results of studies of economy and efficiency; and
- least cost operating expenses which may be considered.

In its Consultation Document, "**Setting Price Control: Framework and Approach (April 2005)"**, the RIC indicated that it intended to use the building-block approach to determine the maximum revenue requirements of the service provider. This approach is consistent with the requirements of Section 67 of the RIC Act. The building-block typically determines the forward-looking revenue forecasts as follows:

- the operating and capital expenditure that an efficient service provider would need over the regulatory control period, as opposed to actual costs;
- depreciation; and
- a return on the initial asset base.

The sum of these elements of the building-block provides the estimate of the efficient cost of delivering the utility services over the regulatory period. In developing the cost build-up, operating costs are a significant factor. In determining the operating costs, the

RIC must balance the needs of the service provider to fund operational activities with the needs of consumers, by ensuring that operating expenditure is at an efficient level.

5.2 OPEX REVIEW PROCESS

Briefly, the expenditure review process involved the following stages:

- **Set up stage** – the preparation of a document, "**Information Requirements: Business Plan 2004-2008 (November 2004)**" by the RIC to provide guidance to T&TEC on the information requirements in the consideration of an application for a price review;
- **Facilitation stage** – where the RIC provided on-going advice to T&TEC to ensure that the data to be submitted was consistent with the requirements of the Business Plan; and
- **Assessment stage** – where the RIC assessed the data to ensure that expenditure reflected the efficient cost of provision of service. The RIC also compared the various elements of cost of supply with the norms applicable to the industry. The RIC has also indicated a multi-period time path of cost/efficiency levels that would be allowed/required in the future. It is intended that this would induce the service provider to take appropriate steps to reach acceptable levels of efficiency in a time bound manner. Surpluses resulting from improvements would be shared between customers and the service provider, and act as an incentive.

Broadly, T&TEC was required to provide details of actual expenditure between 1999-2004 and forecast Opex, together with supporting explanations and information. Opex forecasts requested were for base operating and maintenance costs, costs associated with growth in demand and costs arising from new or changed functions/obligations (step changes).

After its preliminary analysis of the information provided by T&TEC, the RIC identified a range of issues, including deficiencies and inconsistencies in the information, and commenced discussions with T&TEC to improve understanding of its submission. Eliminating the anomalies and aberrations was a long process, as supporting information had to be sourced to ensure that the expenditure forecasts were internally consistent and reconcilable with the information submitted.

The key information/clarifications that have been submitted by T&TEC, after its main submission, included *inter alia*, the following:

- submission of actual information for the year 2004;
- audited accounts for the years 1999-2004;
- revised projected levels of operating costs; including maintenance expenditure, projected borrowing and interest charges, staffing levels, wages and salaries breakdown and overtime;
- details of energy sales and revised costs for the year 2009;
- revised figures for peak demand and additional capacity requirements for the years 2006-2010;
- demand forecasts for energy sales and customer numbers;
- revised investment programme 2006-2010; and
- non-controllable costs and heat rates by plant.

The RIC utilized the revised information/clarifications submitted by T&TEC in its assessment of Opex. The RIC also indicated that this being the first review period, T&TEC was in the process of establishing suitable systems and processes that would enable it to make the information available in the desired format in the future.

However, as indicated in the Draft Determination, the RIC maintains that in the future, the submission is liable to be delayed/rejected if the details are not complete and are not submitted in the formats specified by the RIC.

The RIC was also mindful that at the time of the final determination, T&TEC may have been able to report on its actual expenditure for 2005. This was indeed the case and consequently the RIC has given due consideration to this and has adjusted calculations accordingly.

5.3 ASSESSMENT OF OPERATING AND MAINTENANCE COSTS

5.3.1 General Approach and Issues

T&TEC's costs, like that of all utilities, consist of:

- **Operating Expenditure (Opex)**. These costs cover the day-to-day costs of running the network, and include *inter alia*, repairs and maintenance, salaries and wages, power purchase, fuel costs and overheads.
- **Capital Expenditure**. Capital costs cover spending on assets, the benefits of which would be expected to last for several years, such as plant and machinery, transformers, etc.
- **Returns to Capital Providers**. These are payments that are necessary to reward the providers of debt and equity.

As one of the objectives of regulation of network prices is to provide the service provider with incentives to utilize efficient operating and maintenance practices, the Opex to be included in the calculation of revenue requirement should be based on costs facing an efficient operator taking into account the scale of operations. In arriving at a measure of efficient Opex for T&TEC, the RIC considered T&TEC's forecast Opex relative to its past performance, electric utility standards and the potential for improving efficiency of T&TEC's Opex. The level of service quality to be delivered was also considered.

Regulators have a number of options open to them in assessing efficient levels of expenditure. Under one option, the regulator can build a detailed "bottom-up" forecast of efficient expenditure on a category-by-category basis. Benchmarking information is typically used to assist in defining efficient expenditure levels for each major category. This approach is information intensive and time consuming.

Under a second approach, the regulator takes a broader view of operating expenditure and selects a base year for which it believes base-level expenditure is both efficient and representative (typically the latest year for which actual data are available), then focuses on the level of future changes to this base-level expenditure that may be considered efficient. However, determining a representative year is always problematic.

The RIC has, therefore, assessed the Opex forecasts using a combination of both approaches but generally focusing on many of the major individual cost categories in more detail, particularly where there were significant changes in those items and they represented cost drivers.

There are a number of issues to be considered when determining whether allowed revenues based on cost projections are reasonable:

- **Efficiency**. In order to set a price control formula, regulators typically project a target level of costs during the period of the control. This target level usually includes an estimate of the cost savings and efficiencies that the regulator expects the service provider to make during the price control period. If the service provider outperforms these targets, then typically it retains these benefits for the duration of the control period. If, however, the service provider does not meet these targets, it would make less profit (or even a loss), the cost of which is borne by the service provider. The RIC will not allow customers to fund inefficiencies. However, it should not be expected that there would be overnight changes and thus it may be appropriate to consider a "phased-path" towards higher efficiency.

- **Cost Allocation**. Costs that cannot be attributed to particular services (common and overhead costs) must be allocated to activities. Since there are a number of dimensions to cost allocation, the cost allocation should be reasonable and based on sound regulatory principles.

- **Benchmarking**. One useful source of information to make a reasonable judgment on an "efficient" level of expenditure can be expenditure benchmarking, where T&TEC's proposed expenditure is compared with utilities of similar size elsewhere. However, estimating efficient costs purely on the basis of benchmarking would be challenging given the practical problems of finding good comparators as network companies differ in size, structure and other operating environment factors. This is not to suggest that there will be an all-or-nothing approach, because benchmarking can be used to identify costs that are suitable for further investigation and can indicate where there is scope for efficiency improvements. Other complementary analysis can include an internal analysis of the major cost drivers that underpin T&TEC's expenditure, and analysis of historical trends in forming an overall view of "efficient" expenditure.

- **One-off/Non-recurring Costs.** Some costs in the base year may be considered "one-off" or "non-recurring" and therefore should not be included for a forward-looking price control. However, if a one-off cost is expected to be efficiently incurred during the course of the control period, the RIC might in setting the control amortize its recovery over time to smooth the profile of costs.

- **Advertising and Marketing/Sponsorship Projects**. T&TEC has often undertaken some form of community sponsorship and/or brand marketing. This action is consistent with the behaviour of a responsible corporate citizen. Although socially responsible, a natural monopoly does not have the same need for a strong brand name as private companies. With respect to social responsibility, since the money used is derived from customers, it could be argued that it is inappropriate for customers to fund such projects and that such projects should be provided for out of surpluses or by the Government. Additionally, since some of these costs are one-off, non-recurring costs they should not in any event be included in the base year operating costs.

- **Non-controllable Costs**. Some costs may be genuinely outside the control and influence of T&TEC. Regulators typically allow such costs to be passed through, though the absence of incentives to reduce such costs means that such cost pass-throughs are kept to a minimum.

The remainder of this chapter concentrates on an assessment of T&TEC's Opex over the period 1999-2004, and forecasts over the period 2006-2010. It then goes on to analyze 2004 costs in detail, making adjustments for cost allocations and attributions. These adjustments lead to a base level of maintainable Opex for 2004.

Based on the discussion of the above issues, the RIC has utilized a number of techniques for arriving at an "efficient" level of Opex. These include:

- Assessing the rate of change in actual costs for the period 1999-2004;
- Analyzing actual costs in detail for 2004 as base year;
- Bottom-up analysis, such as cost activity analysis;
- Assessing increases in Opex due to growth forecasts;
- Assessing changes in Opex due to new (or changed) functions and obligations; and
- Top-down analysis, such as comparisons/benchmarking with other utilities.

5.3.2 Transmission and Distribution Expenditure

5.3.2.1 Normalisation of Data

As indicated above, the RIC relied on analysis of actual information for 1999-2004 to forecast Opex requirements for the 2006-2010 control period. With this in mind, the first step was to "normalize" the actual data between 1999-2004 and this was done in consultation with T&TEC. Based on the normalized (adjusted) data, the RIC was more readily able to identify trends based on the actual costs incurred by T&TEC. Briefly, the RIC has made the following adjustments to the Opex reported by T&TEC:

- One-off/non-recurring costs associated with Hurricane Ivan in Grenada and Tobago amounting to $3.66 million were excluded from estimate of 2004 Opex;
- One-off costs with respect to insurance settlement amounting to $4.01 million were also disallowed for 2003; and

- Promotional expenditure with respect to sponsorships and branding was excluded for the years 1999 to 2004.

Based on the adjustment outlined above, **Table 5.1** below presents the T&D Expenditure for the purpose of trend analysis:

Table 5.1 - Proposed Adjustment to T&TEC's T&D Expenditure ($Mn)

	1999	2000	2001	2002	2003	2004
T&TEC's Data	1,198.48	1,366.49	1,472.85	1,546.18	1,638.52	1,750.58
RIC's Adjustments	0.495	0.771	0.426	0.934	6.143	5.488
Normalised Opex	1,197.99	1,365.72	1,472.42	1,545.25	1,632.38	1,745.09

5.3.2.2 T&TEC's Proposed Transmission & Distribution Expenditure

T&TEC has proposed a forecast of Transmission and Distribution (T&D) expenditure amounting to $2,037.3 million over the first regulatory control period, 2006-2010. T&TEC also provided a number of adjustments to its original submission. T&TEC's forecasts, including adjustments, are set out in **Table 5.2**.

Table 5.2 – T&TEC's Projected T&D Expenditure, 2006-2010 ($Mn)*

	2006	2007	2008	2009	2010	Total 2006-2010
Transmission	6.05	7.20	8.31	9.57	10.05	41.18
Distribution	212.18	222.60	233.29	244.64	254.43	1,167.14
Engineering Administration	15.60	15.69	15.92	16.22	16.50	79.93
Administration and General	136.40	140.03	142.88	146.84	149.65	715.80
Internal Generation	6.52	6.58	6.65	6.71	6.76	33.22
Total	**376.75**	**392.10**	**407.05**	**423.98**	**437.39**	**2,037.27**

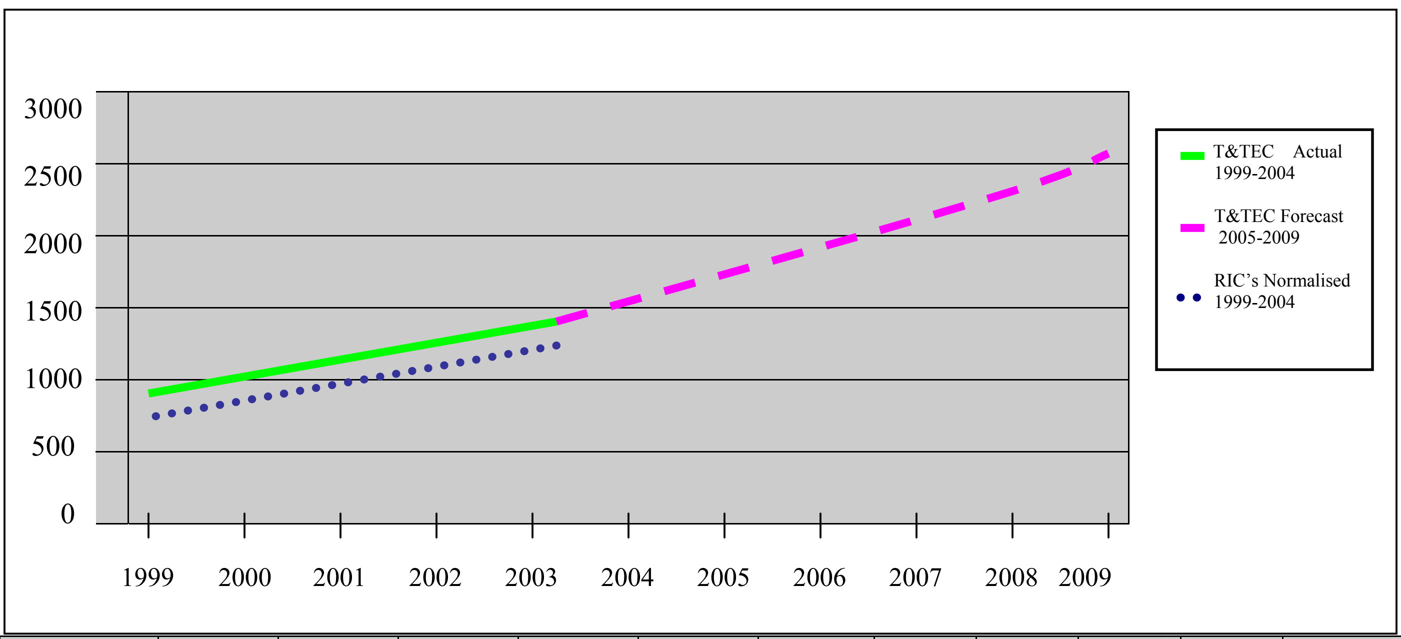
*Conversion costs and Fuel costs are not included.

In terms of the future forecasts, T&TEC has identified the main cost drivers/pressures as:

- increased costs associated with routine maintenance as a result of:
    - the aging of T&TEC's asset base;
    - the adoption of improved asset monitoring practices to meet the RIC's established standards;
    - the need to undertake maintenance deferred from the current period as a result of lack of financial resources;
- major maintenance activities; and
- increases in labour costs.

Figure 5.1 below compares T&TEC's actual T&D costs for 1999-2004 and its proposed T&D costs for 2005-2009.

Figure 5.1 – Actual and Forecast T&D Costs as submitted by T&TEC



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
T&TEC's data	1198.5	1366.5	1472.9	1546.2	1638.5	1750.6	1927.3	2102.1	2369.6	2528.7	2809.8
RIC's Normalised	1198.0	1365.7	1472.4	1545.3	1632.4	1745.1	-	-	-	-	-

The above figures of T&D indicate that T&TEC's costs between 1999-2004 have, on average, increased by 46.1% in nominal terms. On the other hand, T&TEC's forecast T&D costs show that these costs are expected to increase by 45.8% between 2005-2009.

5.3.2.3 RIC's Proposed Efficient Costs

As noted above, the building-block approach requires the RIC to establish an efficient level of Opex for the period 2006-2010. In arriving at its decision, the RIC has taken great care to examine the arguments put forward by T&TEC. Indeed, the RIC has provided comments on detailed and specific aspects of the forecast T&D costs. However, in the final analysis, the RIC is required to arrive at a figure which in aggregate represents the efficient level of costs required to meet T&TEC's obligations given its operating environment.

In undertaking its review, the RIC has made a number of broad observations relating to T&TEC's T&D costs, including the following:

- although T&TEC has identified some areas where it considers operating efficiencies have been made, it did not present any quantitative substantiation of such claims;
- potential savings have not been recognized in T&TEC's forecasts; potential savings could arise from:
  - general productivity gains;
  - savings in operational expenditure as a result of capital investment initiatives;
  - the potential benefits from maintenance activities;
- a number of instances exist where costs are not justified or opportunities where efficiencies can be gained; and
- based on employee to customer ratio, T&TEC is possibly overstaffed, even though this ratio has improved.

In arriving at its proposed T&D costs, the RIC has also made key adjustments to T&TEC's forecasts in a number of areas. These are discussed below.

The RIC believes that advances in technology, improved operational knowledge, and other business practices should lead to sustained cost reductions.

5.3.2.4 Employee Costs

This section analyses T&TEC's payroll and human resource costs. This includes the benchmarking of overtime and sickness rates, an assessment of pay rates, and consideration of the efficiency of T&TEC's organizational shape.

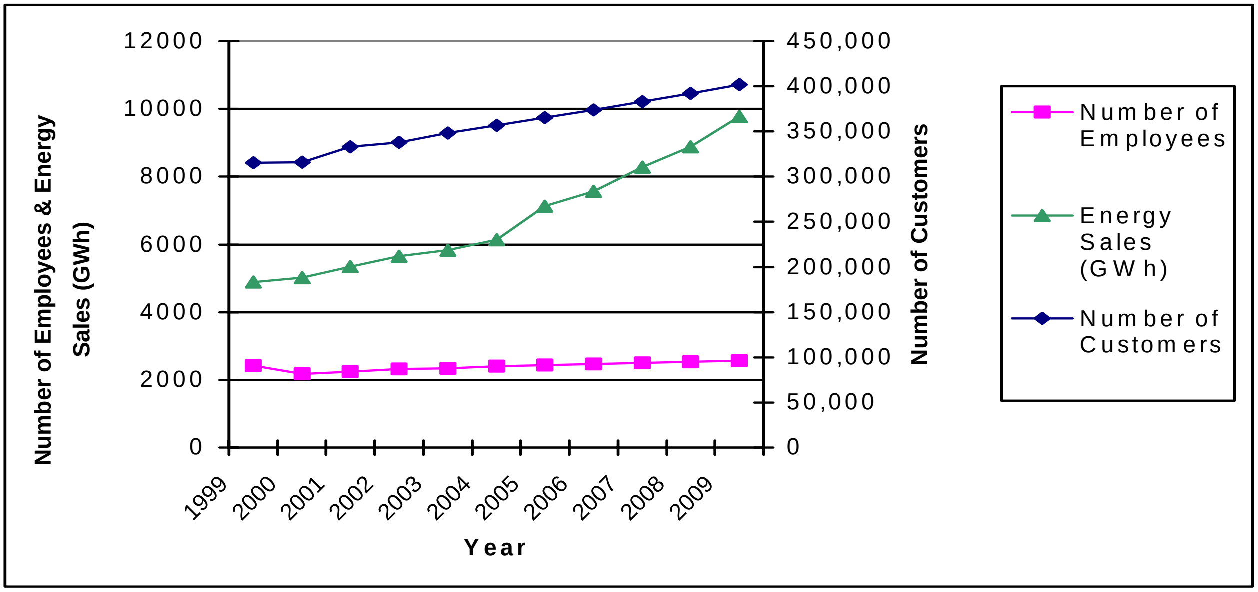
Employee costs account for almost 44% of the total Opex of T&TEC (excluding conversion and fuel costs which are approximately 70% of total expenditure of T&TEC). Employee costs are a function of the level of staffing and salary costs.

Figure 5.2 presents a comparison of annual increases in staff levels, number of customers and sale of energy for the period 1999-2009. From **Figure 5.2,** it can be observed that:

- staff levels increased by 7.9% for the period 1999-2004 and are forecasted to increase by about 5.7% during 2006-2010;
- actual number of customers increased by 13.0% during 1999-2004 and is projected to increase by 10% during the period 2006-2010; and
- actual sales of energy increased by 25.4% and are projected to increase by 37.1% during 2006-2010.

T&TEC has projected its overall employee costs to increase by 21.6% in nominal terms during 2006-2010.

Figure 5.2 - Actual and Forecasts of Staff Levels, Customer Numbers and Energy Sales as submitted by T&TEC, 1999-2009



Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Number of Employees	2242	2174	2238	2328	2335	2399	2432	2466	2501	2536	2571
Number of Customers	315,482	316,017	332,920	337,902	348,022	356,638	365,074	373,935	383,053	392,434	402,086
Energy Sales (GWh)	4889.1	5015.4	5339.8	5646.0	5821.4	6130.8	7134.0	7573.0	8274.0	8882.0	9781.0

Overtime and Absenteeism

It is generally argued that an efficient recurring level of overtime should be around 10% of the total payroll cost. Although T&TEC's overall level of overtime is below 10%, certain departments, especially security, are recording much higher levels (over 20%) of overtime. Similarly, the generally accepted efficiency recurring level of sickness and absenteeism is around 2.5%. The data supplied by T&TEC indicate that total leave (contracted, extended and emergency leave) per employee amounted to approximately 6% of working days per annum. The RIC expects that in the future T&TEC would put systems in place to collect data on an annual basis, as well as information on additional costs incurred as a result of the relatively high rate of absenteeism on account of sick leave.

Rates of Pay

T&TEC's total payroll for 2004 was $247.4 million, with an average annual salary of $103,124 per employee. The average salary per employee is projected to increase to $139,989 by 2010, an increase of 36% over a period of 5 years. In order to encourage the employees to achieve higher levels of performance, the RIC, for the purposes of this first review, accepts the rates of pay at the levels requested by T&TEC. It is not for the RIC to suggest to T&TEC how it should conduct its wage negotiations. Nevertheless, the RIC expects that any bargaining agreement that replaces the existing one will incorporate an expectation of productivity improvements commensurate with sound business practice.

Organizational Structure

A review of T&TEC's organizational structure suggests that its management structure appears to be top heavy and that the shape could be squeezed downwards with a reduced level of management required for certain positions. The RIC's decision is that T&TEC should retain a consultant to review its organizational structure.

Capitalization Policy

T&TEC's policy of capitalization of salaries and wages currently in use is not totally satisfactory. It applies fixed rates to personnel expenditure in order to derive the capitalized personnel expenditure. The fixed capitalization rates have not been reviewed for a long time. The RIC strongly believes that *adhoc* capitalization of expenses based on fixed percentages of investment is far removed from reality and therefore, capitalization should be done on actual rather than on an assumed proportion. Consequently, the RIC's considered position is that T&TEC should appoint a reputable consultant to suggest an appropriate policy on capitalization of salaries and wages.

Stakeholder Comments and Final Decision

In response to the Draft Determination, T&TEC has submitted that its actual expenditure at the end of 2005 was higher than the RIC's allowed expenditure in certain areas, especially in the area of personnel costs and repair and maintenance.

The RIC was mindful that, at the time of the final determination, T&TEC may be in a position to report the actual data for 2005. Therefore, the RIC will give due consideration to the 2005 actuals in determining the Opex for 2006. This is not an uncommon practice to be adopted by regulators. As indicated in its Draft Determination, the RIC analyzed the trend in total personnel expenditure for the period 1999 to 2004. The year-to-year variation in personnel expenditure during that period ranged from –3.7% to 14.2% with a compounded annual growth rate (CAGR) of 8.5%. If T&TEC's actual expenditure for 2005 is included in the analysis, the CAGR is 10.6% for the whole period. The RIC has decided to increase personnel expenditure for 2005 over 2004 by 10.6%. However, the forecast expenditure for the remainder of the control period will be increased only by 5%. This is not only consistent with T&TEC's proposed "rate of change" in personnel expenditure for the period 2007 to 2010 but is consistent with bargaining agreements being negotiated in the economy.

On the basis of additional information provided by T&TEC and further analysis, the RIC has approved the following as employee costs for the years 2006-2010 (**Table 5.3**). Further, the RIC will require T&TEC to initiate the process of separation of accounts.

Table 5.3 – RIC's Allowed Employee Cost, 2006-2010 ($Mn)

	T&TEC Requested	RIC Approved 2006-2010	2004 Actual	2006	2007	2008	2009	2010
Wages	525.58	522.48	85.49	94.55	99.29	104.25	109.46	114.93
Salaries	808.53	670.04	109.64	121.26	127.33	133.69	140.37	147.39
Employee Related Benefit	302.07	319.30	52.26	57.79	60.68	63.71	66.89	70.23
Charged to Revenue	**1636.18**	**1511.82**	**247.39**	**273.61**	**287.30**	**301.65**	**316.72**	**332.54**

5.3.2.5 Administration and General Expenses

T&TEC has estimated the Administration and General (A&G) expenses to be $143.16 million, on average, per annum for the period 2006-2010. This represents an increase of 11.8% per annum above the average annual figure for the period 1999-2004. The primary reason for the increase in A&G expenses is the increase in customer costs, supplies and risk management/insurance costs. A&G costs account for almost 6.2% of the total Opex.

Under the A&G category of expenses, the RIC had concerns in a few areas, namely the Advertising and Marketing, cess payments, payments under the guaranteed scheme and one-off non-recurring costs.

Advertising and Marketing/Sponsorships

As argued earlier, costs relating to building or restoring a brand and sponsorships should not be included in the base year operating costs. Although T&TEC was unable to detail these costs, the RIC, based on discussion with T&TEC, has only allowed 82.5% of these costs for inclusion. The RIC will require T&TEC to put systems in place to identify these costs separately.

One-off non-recurring expenses, where identified, were not considered as these costs should not be included for a forward-looking price control.

Guaranteed Standards Payments/Cess Payments

As discussed in Chapter 9, T&TEC is required to compensate customers for the established guaranteed standards that it is unable to meet. Based on the actual information for the year 2004, a sum of $200,000 per annum has been provided for in the Opex. Similarly, the Cess payments have to be included in the Opex. The RIC will require T&TEC to put systems in place to identify these costs separately.

Own-use Consumption

The electricity charges on account of internal consumption (own-use) by T&TEC can account for a significant proportion of total A&G expenses. However, T&TEC does not accurately measure its consumption for own-use. The RIC will require T&TEC to provide the details of internal energy consumption (both in terms of unit sales and amounts) from 2007 onwards.

Based on the above adjustments, the A&G expenses approved by the RIC for 2006-2010 are shown in **Table 5.4**. The RIC will require T&TEC to initiate the process of separation of accounts.

Table 5.4 – RIC's Allowed Administration and General Expenses, 2006-2010 ($Mn)

	2004 Actual	T&TEC Requested 2006-2010	RIC Approved 2006-2010	2006	2007	2008	2009	2010
Building Maintenance and Services	5.30	34.24	34.24	6.54	6.71	6.83	7.01	7.15
Commercial – Head Office/ Customer Services	10.61	99.04	99.04	18.96	19.41	19.78	20.27	20.62
Security	28.61	82.84	82.84	15.90	16.23	16.48	16.48	17.39
Rates, Taxes, Insurance	1.62	11.57	11.57	2.29	2.31	2.31	2.33	2.33
General Expenses	81.95	488.11	477.26	90.66	93.25	95.31	98.15	99.89
Charged to Revenue	**128.09**	**715.80**	**704.95**	**134.35**	**137.91**	**140.71**	**144.24**	**147.38**

5.3.2.6 Repairs and Maintenance

Repairs and Maintenance (R&M) planned expenses submitted by T&TEC were not fully backed by any concrete plans. The RIC has approved an amount of $398.57 million for the period 2006-2010. The approved R&M expenditure is in keeping with generally accepted benchmarks of 1.5% of gross fixed assets for transmission assets and 2.5% of gross fixed assets for distribution assets.

An adequate expenditure on R&M will lead to enhanced performance of the network system overall, as well as directly impact on the reduction of consumer complaints in the following areas:

- damaged appliances;

- outages; and
- low voltage problems.

The RIC will require T&TEC to:

- submit to the RIC annually its actual expenditure on R&M;
- submit to the RIC quarterly reports on outages by area and reasons for outages; and
- repair and maintain pole mounted distribution transformers at a rate of 20% per annum and submit quarterly reports.

Subsequent to the release of the RIC's Draft Determination, T&TEC indicated that RIC's allowance for Repairs and Maintenance was insufficient. The RIC has carefully considered this request but remains convinced that adequate provision has been made for repairs and maintenance. The approved repairs and maintenance expenses are shown in **Table 5.5.**

Table 5.5 – RIC's Allowed Repairs and Maintenance and Other T&D Expenses, 2006-2010 ($Mn)

	2004 Actual	RIC Approved 2006-2010	2006	2007	2008	2009	2010
Transmission R&M	2.39	41.18	6.05	7.20	8.31	9.57	10.05
Distribution R&M	64.25	357.39	65.02	68.35	71.81	75.44	76.77
Other	144.01	889.69	162.77	169.94	177.41	185.42	194.15
Charged to Revenue	**210.65**	**1,288.25**	**233.83**	**245.49**	**257.53**	**270.43**	**280.97**

5.3.2.7 Step Changes

The RIC had requested T&TEC to identify any new Opex items as a result of new (or changed) functions and obligations. Such requirements are generally referred to as "step changes". The only two items specified by T&TEC were the cess payments and guaranteed standards payments.

Although not a “step change”, growth forecasts are central to the forecasts of expenditure and expected revenue. The growth adjustments reflect the forecasts of cost to be incurred by servicing additional customers. T&TEC did not supply any forecasts of expenditure based on the expected growth in number of customers. The RIC has, however, included growth related expenditure in the forecasts of Opex for the period 2006-2010 based on the marginal cost per customer per annum.

5.3.2.8 Rate of Change

In its Consultation Document, “**Information Requirements: Business Plan 2004-2008 (November 2004)**”, the RIC indicated that it would utilize the “rate of change” as one of the techniques for arriving at an “efficient” level of Opex for the first regulatory control period. The rate of change is the year-to-year change in Opex for a number of factors such as, expected productivity improvements and changes in the price of inputs. Utilities generally oppose the reduction of forecast costs for future “unidentified” efficiencies on the grounds that it is inconsistent with incentive regulation and that it places utilities at significant risks if those implied efficiencies cannot be realized. T&TEC was asked to propose an appropriate rate of change in Opex and to provide information to justify the trend. T&TEC opted to offer no such information.

The main argument for using the “rate of change” method is that it avoids the information asymmetry associated with attempting to establish Opex forecast using more information intensive options. As indicated above, the RIC’s preferred approach to produce the best estimate of costs was to:

- establish a base-level of Opex based on the reported actual Opex results;
- account for any new or changed functions (step changes);
- consider the trend in Opex of past actual Opex; and
- benchmark with external information.

There is sufficient evidence from the UK, Australia and New Zealand of significant productivity gains driven by the initial regulatory restructuring reforms and commercial drivers. In fact, Opex productivity gains grew at an average annual rate of about 8%

over the first regulatory control period in these countries. Additionally, there are a number of regulatory precedents, observed in USA and Europe, where productivity indexing is typically used by regulators.

The RIC has decided to determine the rate of change in Opex that should apply in respect of T&TEC. This rate will be the trend in the rate of change established for the period 1999-2003, on the assumption that the rate of change will continue at least for the first regulatory period. The actual productivity changes in Opex for T&TEC over the 1999-2003 period are seen in **Table 5.6**.

Table 5.6 - Productivity Changes in Opex for T&TEC, 1999-2003 (Real 1995)

	1999	2000	2001	2002	2003	Average
T&TEC Opex (%)	1.2	4.5	(7.7)	(3.8)	(5.9)	2.8

5.3.2.9 Determination of Opex

Based on the discussions of all issues highlighted, a summary comparison between T&TEC's submission and the RIC's approved Opex (excluding generation and fuel costs) forecasts for the period 2006-2010 is shown in **Table 5.7**. The figures reveal that:

- the RIC's overall approved T&D expenditure (excluding conversion and fuel costs) is $188.42 million (or about $38 million annually) lower than T&TEC's submitted forecasts;
- the major reductions are in proposed increases in the area of personnel costs as a result of an observed anomaly in their personnel expenditure projected in Year One;
- the estimated promotional costs amounting to $10.9 million for the period 2006-2010 have been disallowed; and
- the RIC expects T&TEC to achieve efficiency gains amounting to $53.3 million during the period 2006-2010 and these would be passed to the consumers at the beginning of the next regulatory period.

Table 5.7 – RIC's Determination of T&D Expenditure, 2006-2010 ($Mn)

	T&TEC Requested 2006-2010	RIC Approved 2006-2010	2006	2007	2008	2009	2010
Internal Generation	33.22	33.22	6.52	6.58	6.65	6.71	6.76
Transmission Maintenance	41.18	41.18	6.05	7.20	8.31	9.57	10.05
Distribution	1,167.14	1,167.14	212.18	222.60	233.29	244.64	254.43
Engineering Administration	79.93	79.93	15.60	15.69	15.92	16.22	16.50
Administration and General	715.80	715.80	136.40	140.03	142.88	146.84	149.65
Sub-Total	**2,037.27**	**2,037.27**	**376.75**	**392.10**	**407.05**	**423.98**	**437.39**
Less:							
Promotional Costs	-	10.87	2.06	2.12	2.17	2.24	2.28
Personnel Expenses		124.29	22.49	23.62	24.80	26.04	27.34
Total T&D before Efficiency Savings	**2,037.27**	**1902.11**	**352.20**	**366.36**	**380.08**	**395.70**	**407.77**
Less: Efficiency Savings (2.8 % per annum)	-	53.26	9.86	10.26	10.64	11.08	11.42
Total Approved T&D	**2037.27**	**1848.85**	**342.34**	**356.10**	**369.44**	**384.62**	**396.35**

The RIC needed to strike a balance between ensuring the viability of the service provider and protecting the interest of the consumer. Going too far too soon could unduly hurt the service provider while doing too little would be unfair to the consumer and undermine the purpose of regulation. It is the RIC's considered view that the reductions noted in **Table 5.7** above are within the desired balance.

The RIC's decision is to adopt total transmission and distribution expenditure (excluding conversion and fuel costs) as indicated in **Table 5.7.**

5.3.2.10 Efficiency Carryover Mechanism for Opex

In its Consultation Document, "**Sharing of the Benefits of Efficiency Gains and Efficiency Carryover Mechanisms (June 2005)**", the RIC intimated that it will consider the possibility of introducing an efficiency carryover mechanism for Opex. An efficiency carryover mechanism is the means whereby the incentive to make efficiency gains by a service provider is enhanced by permitting it to carry over gains from one regulatory period to the next. Customers benefit from lower prices when efficiency gains are passed to them at the end of the period. The actual mechanism to be adopted for the Opex is discussed in detail in Chapter 8.

5.4 UNCONTROLLABLE COSTS AND COST PASS-THROUGH

5.4.1 Introduction

Cost pass-through provisions are key components of incentive regulation plans that cater for uncontrollable costs, that is, costs over which the actions of the regulated firm have little or no effect. In fact, mechanisms that treat with uncontrollable costs are not unique to incentive regulation and have existed in the form of automatic adjustment clauses that are often included in rate of return regulation. The existing fuel charge and exchange rates adjustments are examples of automatic adjustment clauses.

Uncontrollable costs may arise from **unforeseen events** or they can be known beforehand, that is, they can be **foreseen**. An example of the former can be the passage of new legislation that may impact on the actions of a particular type of firm. The latter can include items such as, fuel costs and power purchase costs. The international experience suggests that three broad categories of costs have been considered for pass-through by different regulators. They are:

- costs due to changes in statutory requirements;
- cost changes due to unforeseen events; and
- cost changes due to non-statutory cost drivers.

Provisions that cater for uncontrollable costs are included because the regulator needs to provide the regulated firms with incentives to reduce costs that are under their control while simultaneously insulating them from losses arising from costs that are outside their control and precluding abnormal profits. In order to cater for foreseen uncontrollable costs, regulators often allow full pass through of these costs in the revenue requirement of the firm. The provision for unforeseen uncontrollable costs is often made within the price cap or revenue cap formula through the inclusion of a Z-factor. Alternatively, they can be dealt with by some other licensing condition.

5.4.2 Degree of Cost Controllability

The degree of controllability involves more than simply categorizing costs as being either fully controllable or fully uncontrollable, since the degree of controllability may depend on the timeframe involved as well as the fact that only some elements of a cost may be controllable. In addition to the degree of controllability, regulators choose to limit pass-throughs to items which constitute a significant portion of a service provider's total costs. However, determining how to allocate costs between categories of controllable and uncontrollable categories is not straightforward. As a first step to ascertaining what should be treated as uncontrollable costs, the degree of controllability for all the major cost categories in the case of T&TEC is examined in **Table 5.8** below.

Table 5.8 - Degree of Controllability For All Major Costs – T&TEC

	Degree of Control	Remarks	Percentage Share of Total Costs
• Generation: - Conversion Costs - Fuel	Very Limited/Nil Very Limited Very Limited	• Sole Buyer • "Take or Pay" contracts • Long term contract	• **70** • 43 • 27
• Transmission Costs	Limited	Limited control on purchases/material costs	• 7
• System Losses	Substantial		
• Labour costs: - Overtime - Salaries & Wages	Some High Some	Depends on what aspect. eg. It may be easier to control overtime expenditure.	• 13
• Material Costs	Some	Mostly imported	
Rent, Rates, Insurance	Very Limited		• 7
• Investment Costs: - Demand - Quality related - Other	Some Limited Some	Set by Regulator	• 1
• Depreciation (Regulatory)	Limited	Regulator influences	• 1
• Required Profit	Limited	Set by Regulator	-

Based on the above analysis, the RIC is proposing to provide for the pass-through of only fuel and conversion costs, which in the case of Trinidad and Tobago are the equivalent of power purchase costs over which T&TEC has little or no control. These costs are subject to long-term contractual agreements. They also represent about 70% of T&TEC's total costs and thus constitute a significant portion of T&TEC's operating costs.

5.4.3 Treatment of Unforeseen Uncontrollable Costs

This section briefly discusses the RIC's rationale for not allowing unforeseen uncontrollable costs as pass-throughs. The RIC's detailed treatment of all issues relating to uncontrollable costs and cost pass-through were the subject matter of its Consultation Document, "**The Treatment of Uncontrollable Costs in Incentive Regulation**", which was released in June 2005.

The purpose of providing a general cost pass-through mechanism is to allow costs associated with major exogenous and unforeseen events beyond the service provider's control to be passed to customers. Therefore, the intention of a pass-through is not to protect the service provider from every unforeseen event that may occur during the regulatory control period. It is quite likely that forecast and actual costs will vary up and down during the regulatory control period but this does not preclude these costs from being recovered in the future.

Consequently, the RIC does not consider it appropriate to pre-qualify certain events as pass-through events when, by definition, they are either unforeseen or uncertain. The RIC prefers that the degree of controllability of all costs be considered and that each event be assessed on its merits and on a case-by-case basis.

Another important issue to be considered in deciding whether a cost pass-through is required is that of the associated costs. Specifically, whether such costs are likely to impact on the service provider's returns in a way that require them to be passed through immediately to customers. Internationally, regulators have adopted the view that for an event to be considered for pass-through, it must be material, with the potential to affect the commercial viability of the service provider. Consequently, most regulators apply a materiality threshold to limit pass-through to events that have a significant impact on costs while, at the same time, avoiding the risk of introducing a cost-plus regulatory regime. Consistent with other jurisdictions, the RIC considers a one percent materiality threshold on a service provider's annual revenue to be reasonable. Based on T&TEC's annual revenue, this would require a trigger event to have an unforeseen impact on its annual revenue requirement of around $18 million before being considered for potential pass-through.

> In the case of unforeseen uncontrollable costs, the RIC's decision is that each event for pass-through be assessed on its merits and on a case-by-case basis.
>
> The RIC's decision is to establish a materiality threshold for any potential trigger event at 1 percent of actual annual regulated revenue per event.

5.4.4 Existing Cost Pass-Through Mechanisms

An automatic adjustment clause is a tariff provision approved in advance by a regulator, in which a change in a pre-selected cost item(s) will automatically permit a change in the price charged to customers. Currently, there are two automatic adjustment clauses (Exchange Rate Adjustment and Fuel Adjustment Clause) applied to base tariffs. These are intended to offset any movement in the T&T currency relative to the US dollar and changes in fuel prices.

These clauses hold some clear advantages for the utility including:

- allowing recovery of increases in costs over which the utility has little or no control;
- reducing the regulatory lag by operating swiftly thereby protecting the utility's financial viability; and

- saving regulatory costs through automatic recovery which implies infrequent rate reviews.

The clauses also have certain drawbacks:

- recovery of increased cost for one item may ignore compensating or offsetting savings for economies realized elsewhere in the business through improved technology, labour productivity, and/or operating efficiency;
- automatic adjustment may reduce the company's incentive for efficient management of operations and/or may discourage hard bargaining for contract negotiations by allowing quick and easy recovery of a particular cost item such as fuel;
- utilities have risks like non-regulated companies. In the competitive market place the latter survives through innovation, efficiency, and good management. To the extent adjustment clauses dampen efficiency and innovation, the public interest is not served; and
- the clauses have raised concerns for consumers. Consumers generally appreciate certainty about prices since it allows them to plan future expenditure. Prices that move from bill to bill may make budgeting decisions difficult. For instance, based on a review of the fuel charge, it has been observed that the annual increase in customer bills has fluctuated markedly from 30% in 1997 to as low as 4% in 1999.

The RIC received support for its decision not to continue with automatic adjustment clauses.

The RIC's decision is that the use of automatic adjustment clauses be discontinued as these clauses do not generally form part of incentive regulation and have been a source of confusion for customers.

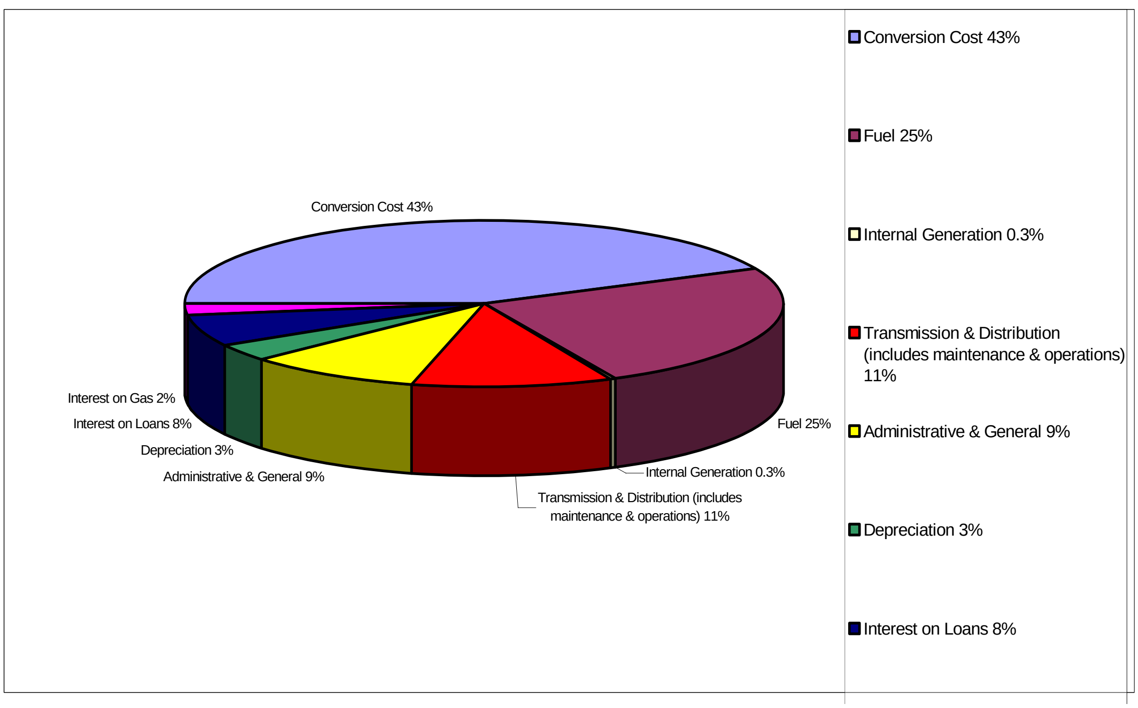
5.4.5 Treatment of Conversion Costs

5.4.5.1 Introduction

In section 5.3 above, the T&D costs of T&TEC were considered. These costs were categorized into employee costs, administrative & general, and repairs & maintenance. It was noted that two of the major cost components of T&TEC are the cost of power (conversion cost) and fuel cost, comprising approximately 70% of T&TEC's total annual costs.

Conversion costs rose by 61.5%, from $425.5 million in 1995 to $686.7 million in 2002. Fuel cost rose by 93.8%, moving from $204 million to $395.3 million over the same period. By 2002, conversion and fuel costs represented 43% and 25% respectively of total costs **(Figure 5.3).** In 2003, conversion cost rose by approximately 3% to reach $705.4 million. Fuel cost for 2003 was $449.6 million (an increase of 13.7% over 2002 costs). The method to be adopted for determining conversion and fuel costs is discussed below.

Figure 5.3 - Total Expenditure, 2002



Power Purchase Agreements (PPAs)

T&TEC has power purchase agreements (PPAs) with two power generating companies. The first is a 15-year contract signed on December 23, 1994 between T&TEC and PowerGen for 819MW. The second is a 30-year contract signed on February 12, 1998 between T&TEC and Trinity Power (formerly InnCOGEN) for 215MW. These contracts expire in 2009 and 2029 respectively.

PowerGen and Trinity Power supply power to T&TEC under various purchasing arrangements. The main characteristics of both contracts are shown in **Table 5.9** below. T&TEC's tariff is fixed but the levels of PPA costs are variable to T&TEC as any changes in costs incurred by the generators are passed through to T&TEC. The fuel cost also is currently passed through directly to customers.

Table 5.9 – Main Characteristics of PPA Contracts

PARAMETER	POWERGEN	TRINITY POWER	COMMENTS
Parties	T&TEC – Buyer/ Purchaser PowerGen – Seller	T&TEC - Buyer Trinity Power - Seller	-
Contract or Effective Date	23 December, 1994	12th February, 1998	-
Term of Contract	15 yrs (put end date)	30 yrs	-
Contracted Capacity	Not greater than 819 MW (719-peak, 100-spinning reserve)	Total gross capacity – 215 MW	-
Option to Extend	Automatic for 3 years, unless either party gives written notice one year before the expiration of the term of contract.	On the written notice provided by either Party, not more than 48 months nor less than 12 months before the expiration of the term.	-
System Heat Rate	The Guaranteed System Heat Rate is set at 14,000 kJ/kWh, as amended from time to time by mutual agreement of the parties based on certain conditions.	The Guaranteed System Heat Rate is not defined in the contract	-
Monthly Capacity Payment	Based on a base capacity rate of US$7.48 per kW per month, the contracted capacity and 95% of the change in US consumer price index (CPI) per annum.	Based on a base capacity rate of US$0.012 per kWh, the declared capacity for the month and 27.5% of the change in US consumer price index	In the case of PowerGen, this payment is calculated by an average calendar month of 30 days and in the case of Trinity Power, because it is calculated on a per kWh basis, T&TEC pays on average for about 730 hours per month
Energy Payment	Base Energy Rate is US$0.00055 per kWh, which escalates by the US CPI.	Base Energy Rate is US$0.00045 per kWh, which escalates by the US CPI.	The contents of this provision are similar in both contracts.
Excess Capacity Payment	Calculated in the same manner and using the same rates as the Monthly Capacity Payment in respect of the Contracted Capacity. However, according to the contract, once Excess Capacity is requested a complex mechanism is activated, which requires a large recurring monthly payment to the end of the current year, whether the capacity is used or not.	Excess Demand is charged on an as-used basis at the base rate.	This payment applies when T&TEC requires the generating companies to provide Capacity in excess of the contracted capacity.
Heat Rate Bonuses and Compensation Amounts	If the annual average heat rate is brought below 13,300 (14000x0.95) kJ/kWh T&TEC pays PowerGen a bonus for saving fuel. Conversely, if the annual heat rate exceeds 14,737 (14000/0.95) kJ/kWh T&TEC charges PowerGen a penalty towards the excess fuel used.	No provision exists.	-
Payment for Unit Start-ups	No provision exists	The Buyer shall pay the Seller $1900.00 for each unit start-up.	-
Sale and Purchase Obligations	Provision has also been made for the spinning reserve levels.	Sale of capacity and energy by the Seller to the Buyer, with the consent of the Minister. No Spinning reserves.	Both PPA's provided for the risk of loss and property with the energy delivered from the Seller to Buyer/Purchaser at the Delivery Point. A noted difference is that in the case of Trinity Power, the consent of the Minister is required.
Fuel Supply Obligations	Clause 4	Clause 8.3	This clause provides for the supply and delivery of Gas by the T&TEC to the Seller free of charge. The clause also provides for the quality of gas, how the gas would be delivered, pressures of gas, etc.

Conversion Costs

Conversion costs vary based on the capacity required and changes in the US consumer price index (CPI). Conversion costs for the period 1999-2004 for both PowerGen and Trinity Power are shown in **Tables 5.10 and 5.11** respectively.

Table 5.10 - Annual Payment and Load Schedule for PowerGen, 1999-2004

Year	Contracted Capacity (MW)	Capacity Payment $	Energy Payment $	Excess Capacity (MW)	Excess Payment $	Total Conversion Cost $	% Change
1999	819	522,730,616	18,777,962	192*	1,785,153	543,293,731	-
2000	819	527,431,395	16,331,354	0	0	543,762,749	0.1
2001	819	537,759,277	17,726,777	0	0	555,486,054	2.0
2002	819	545,679,202	21,284,777	0	0	566,963,979	2.2
2003	819	561,025,756	20,726,724	0	0	581,752,480	2.6
2004	819	665,118,294	21,081,178	60**	3,567,586	689,767,058	18.6

Source: Trinidad and Tobago Electricity Commission
*** This represents 32MW for each of the months from July to December.**
**** This represents 30MW each for November and December 2004.**

Table 5.11 - Annual Payment and Load Schedule for Trinity Power, 1999-2004

Year	Contracted Capacity (MW)	Capacity Payment $	Energy Payment $	Excess Capacity (MW)	Excess Payment $	Total Conversion Cost $	% Change
1999	195	37,962,176	853,853	0	0	38,816,029	-
2000	195	116,691,435	3,657,592	63*	3,375	120,352,402	-
2001	195	116,850,186	3,502,241	0	0	120,352,427	0.0
2002	195	117,377,958	2,317,392	0	0	119,695,350	(0.5)
2003	195	118,930,449	4,593,304	255**	112,685	123,636,438	3.3
2004	195	143,145,644	5,571,179	441***	241,660	148,958,483	60.9

Source: Trinidad and Tobago Electricity Commission
*** These amounts were required at different times on the same day in December.**
**** Individual requests for excess capacity totaling 255MW.**
***** Individual requests for excess capacity totaling 441MW.**

As can be seen, conversion costs consists of the following payments:

- Monthly capacity payment;
- Energy payment; and
- Excess payment.

Capacity Payment

The capacity payment is a monthly payment for capacity by T&TEC to both generators. The payment in each case is a function of the base capacity rate, the contracted capacity and the US consumer price index. The monthly capacity payment is determined as follows:

POWERGEN	TRINITY POWER
MCP = (BCR x CC) x [1 + (CPI x 0.95)] Where: MCP = the monthly capacity payment (expressed in US dollars) BCR = the Base Capacity Rate (being US$7.48 per kW per month) CC = the contracted Capacity (expressed in kW) CPI = the percentage change in the US consumer price index between that published or determined in the month before the effective date of the Contract (base level) and that determined in the month in respect of which the Monthly Capacity Payment is being determined.	**CP_m = $MADC_m$ x HIM_m x BRC x (1 + 0.275 (CPI_m/CPI_o – 1)** Where: CP_m = the Capacity Payment for the $month_m$, expressed in US dollars $MADC_m$ = the Monthly Average Declared Capacity for $month_m$, expressed in kW HIM_m = the number of hours in $month_m$ BCR = the base capacity rate, being US$0.012 per kWh CPI_m = CPI for $month_m$ CPI_o = the CPI for the month of September, 1999

Based on these formulas, there is little scope for reduction of capacity costs at this time. However, there were a few anomalies observed that would impact on the quantum of the monthly capacity payment:

- The base capacity rate is quoted in different units in the two PPAs. In the case of PowerGen, it is US$/kW/month, where month is defined as a calendar month, while for Trinity Power, it is US$/kW/hour for Trinity Power. These payments are monthly, so Trinity Power uses an average month of 30.42 days. This difference in calculation affects T&TEC's cash flow especially in a short month like February when revenue collected is based on 28 days.

- While both formulas have a factor to accommodate changes in the US CPI, one formula incorporates 95% of this change (in the case of PowerGen) while the other only 27.5%. The difference this makes is reflected in **Table 5.12**, which shows the movement in these payment factors from the inception of the PPAs to present.

Table 5.12 - Comparison of Base Capacity Rate Factors* (US$/kW/mth)

Date	PowerGen	Trinity Power
December 1994 (start of Powergen contract)	$7.48	-
September 1999 (start of Trinity Power contract)	$8.35**	$7.88
November 2004	$9.39	$8.17

Source: Trinidad and Tobago Electricity Commission's Engineering Department
*** Base Capacity Rate Factor is the Base Capacity Rate by the change in US CPI.**
**** November 1999 data.**

The above assessment clearly highlights the need for renegotiation of the formula used to calculate the monthly capacity payment, especially in the case of PowerGen. In the case of any new generation contracts, the calculation of a more favourable monthly capacity payment charge must be given top priority. Consumers should never be put at a disadvantage when these contracts are negotiated, as they should not stand the consequences of any unfavourable decisions.

Energy Payment

Once again, T&TEC makes monthly payments to the generating companies for the energy delivered in accordance with specific formulas stipulated in the contract. The formulas are as follows:

POWERGEN	TRINITY POWER
$MEP = (BER \times (1 + CPI)) \times ED$ Where:- MEP = the Monthly Energy Payment (expressed in US dollars) BER = the Base Energy Rate (being US$0.00055 per kWh) CPI = the percentage change (whether of a positive or negative value) in the Consumer Price Index between that published or determined in the month before the relevant month in respect of which the Monthly Energy Payment is being determined, and expressed as a fraction of the base level ED = the Energy Delivered from all the Facilities (expressed in kWh) during the relevant month.	**$EP_m = DE_m \times (BER \times (CPI_m/CPI_o))$** Where:- EP_m = the Energy Payment for the $month_m$, expressed in US dollars. DE_m = the Energy Delivered (expressed in kWh) to the delivery point for each day in $month_m$ BER = the base energy rate, being US$0.00045 per kWh CPI_m = CPI for $month_m$ CPI_o = the CPI for the month of September, 1999

Based on the above formulas, the energy rate factors, as at November 2004, were calculated to be US$0.00070/kWh for PowerGen and US$0.00051/kWh for Trinity Power. As in the case with the capacity payment, the energy rate factor for Trinity Power appears to be much more favourable.

Excess Payment

The excess payment applies when T&TEC requires the generating companies to provide capacity in excess of the contracted capacity. The methods of calculation utilized for generators are shown below.

PowerGen

Excess Payment is calculated in the same manner and using the same rates as the Monthly Capacity Payment in respect of the Contracted Capacity. However, according to the contract, once Excess Capacity is requested a complex mechanism is activated, which once triggered requires a large recurring monthly payment to the end of the current year, whether the capacity is used or not.

Trinity Power

Excess Capacity is charged on an as-used basis at the base rate. Once again, this method is quite economical as an examination of the data for excess capacity and excess payment for 2004 shows a significant difference. The excess capacity from PowerGen was 60MW, which translated to a payment of $3,567,586, while the excess capacity from Trinity Power was 441MW, for a total payment of only $241,660. This significant difference highlights the variation in the method used by each company to calculate the excess payment, and is therefore an area that needs to be closely examined.

International Experience with Cost Pass-throughs

Northern Ireland, only allows 95% of the generating costs to be passed through. The remaining 5% is based on an index of fuel costs – a yardstick introduced to give some incentive for efficient purchase of electricity. A similar approach has been adopted by the regulator of airports in the UK. Security costs are treated as a cost pass-through item, given their external nature. However, to ensure that some sort of incentive is created to keep control over any additional security costs incurred in any year, only 95% of the costs are allowed to be recovered.

The RIC acknowledges that the scope for reducing the cost of conversion is limited given the existing terms of the both PPAs. However, the RIC is not inclined to pass-through 100% of these costs, as no regulator can knowingly allow inefficiencies to be passed on to the consumers in the form of higher rates.

5.4.6 Forecast of Conversion Costs, 2006-2010

Based on the assessment of growth in demand, as well as increases in the US CPI and the additional capacity that is to be added in 2006, **Table 5.13** below shows estimates of capacity and conversion costs for the period 2006-2010. These estimates include additional generation capacity that needs to be installed to meet the growing demand in the country. T&TEC has recently completed negotiations with PowerGen for some of this additional capacity.

Table 5.13 - T&TEC's Forecast for Capacity and Conversion Costs, 2006-2010

Year	Contracted Capacity (MW)	Capacity Payment $	Energy Payment $	Total Conversion Cost $
2006	1,079	779,673,993	30,635,531	810,339,524
2007	1,289	880,091,484	33,683,399	913,774,883
2008	1,452	1,036,936,500	38,251,901	1,075,188,401
2009	1,507	1,180,192,111	42,389,167	1,222,581,278
2010	1,717	1,380,476,366	47,947,467	1,428,423,833

Source: T&TEC's Engineering and Planning Department

5.4.7 Renegotiation of PPAs

The RIC is mindful that although T&TEC is ultimately responsible for power procurement, it responds to government policy initiatives that often impose specific guidelines and timetables. However, despite these constraints, a regulator's responsibility is to provide the regulated firm with incentives to explore options for reducing costs. The RIC is of the view that T&TEC must pursue every avenue in the reduction of costs, including the renegotiation of PPAs, if necessary. In fact, it is incumbent on T&TEC to seek the interest of consumers since it is the majority shareholder in PowerGen.

It is also important for the regulatory body to be involved in the aspect of negotiations that affects its regulatory responsibilities. In particular, long-term supply or other contracts affecting customers' rates or services should require some form of review and approval by the regulator.

Research undertaken by the World Bank has shown that many governments are running into difficulties with independent power producers (IPPs), and IPPs have been the subject of protracted legal, political and economic battles. In some countries, electric utilities have been crippled by payments due to IPPs. Others have questioned the generous terms offered to power producers. Governments are tied into buying the same amount, regardless of fluctuations in demand or alternative sources of supply. Prices are fixed in foreign currencies, regardless of how this might relate to domestic prices or to what utilities are able to charge customers. In the words of the World Bank study[4]:

> "*PPAs can hamper efficiency in system operations and sector liberalization. Even if all the output can be freely dispatched, PPA prices deviate from those provided by a competitive pool …. PPA prices provide no incentive to maximize the availability of base load IPPs in the period when supply costs are highest …. Managers have no incentive to respond to market changes or to improve technological practices …. IPPs are capital intensive and the most flexible cost is labour. Hence, the main 'efficiency gains' we can expect from the IPP over time is downward pressure on wages and numbers employed*".

Despite rigidities, economic reality is forcing IPPs to face up to changing circumstances and to accept more reasonable charges, regardless of the legalities of the PPAs:

- In the **Philippines**, Napocor is discussing terms of restructuring payments with 32 IPPs. One possibility is an arrangement by which some of the payments due from Napocor are delayed until the end of the IPP contract period.
- In **Indonesia**, PLN is re-negotiating its PPA to lower the price of their power. In one case, PLN effectively negotiated the nationalization of a power plant at a price which made the station's output attractive – as well as allowing PLN the flexibility that comes with ownership.
- In **Costa Rica**, in August 2000, the country's Comptroller General declared that clauses relating to rate levels in 15 private sector power generator contracts lacked legal status. Rate levels and adjustments sought to guarantee the profits of private sector companies, and not ensure economic benefit to the country or consumers, as the 1990 law on electric power cogeneration required them to do.

[4] Yves Albony and Reda Bousby, The impact of IPPs in Developing Countries – Out of the Crisis and into the Future, The World Bank, Public Policy for the Private Sector, December, 1998

- In August 2000, the **<u>Croatian</u>** Government insisted on tearing up a PPA contract signed by Enron with a previous government. The contract was considered to be unaffordable. Croatia successfully forced Enron to abandon the original agreement.
- In the **<u>Philippines</u>**, in September 2000, to arrest the financial burden caused by the IPP deals, Energy Secretary Mario Tiaoqui said that his Government will not renew these contracts.

In light of the above discussion, the RIC's decision is that Government/T&TEC should seek to re-negotiate more favourable terms in respect of PPA contracts.

Based on the energy requirement assessment, the conversion costs that will be allowed by the RIC in the revenue requirement are presented in **Table 5.14** below. These costs have been adjusted taking into consideration revised energy forecasts submitted by T&TEC in its comments on the Draft Determination.

<u>Table 5.14 - Forecast and RIC's Allowed Conversion Costs, 2006-2010</u>

	PowerGen Conversion Cost	Trinity Power Conversion Cost	Total Conversion Cost	98% Conversion Cost	RIC's Approved
Year	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
2006	657,516	152,823	810,340	794,133	792,663
2007	759,336	154,439	913,775	895,499	844,078
2008	919,550	155,639	1,075,188	1,053,685	1,050,265
2009	1,065,399	157,182	1,222,581	1,198,130	1,192,871
2010	1,269,720	158,704	1,428,424	1,399,855	1,391,507

The RIC's decision is to allow a pass-through of 98% of conversion costs for the first regulatory control period as proposed in **Table 5.14.**

5.4.8 Treatment of Fuel Costs

Fuel costs are dependent on the unit price paid for the various types of fuel utilized in the generation of electricity and the volume of fuel consumed. The latter, of course, is driven by changes in the demand for electricity. The heat rate also affects the efficiency of the conversion process and impacts on the volume of fuel consumed. There are four types of fuel currently used for power generation. The main fuel used is natural gas, which is responsible for 90% of the power produced; diesel is used to produce 9% of the power; fuel oil and Jet A account for the residual. Under the terms of the PPAs, T&TEC is obliged to pay for the fuel that is converted into electricity by the generators.

Price of Fuel

Natural gas

Based on a Cabinet decision of 1995, the price of natural gas has increased annually by 4%. Natural gas is currently charged at US$0.87/MMBTU. Over the period 1993–2004 fuel prices have increased significantly (**Table 5.15**). In fact, NGC has proposed a price of US$1.05/MMBTU, escalating at 4% per annum for the period 2006-2010. This price was derived as follows:

- Royalty gas[5] (50 – 100 mmcfd) - US$0.00 per MMBTU
- BpTT Tranche 4 (100 mmcfd), escalating at 2.5% per annum - US$0.81 per MMBTU
- Average non-product related gas, escalating at 4.6% per annum - US$1.33 per MMBTU
- Additional incremental volumes, escalating at 4% per annum - US$1.80 per MMBTU

Based on the RIC's assessment, a gas price of US$1.05/MMBTU appears acceptable. However, considering the different volumes of gas acquired at different prices and escalation factors, the RIC considers an escalation factor of 3% to be more reasonable.

[5] This gas has been made available by the Government of Trinidad and Tobago and represents a saving of TT$99 million in 2006 and TT$203 million per year for 2007-2010.

Consequently, and in the absence of further guidance from the Government, the RIC would use a price of US$1.05/MMBTU and an escalation factor of 3% per annum in its calculations.

The RIC recommends that Government consider a number of options in order to reduce the impact of annual increases:

- the negotiation of a long-term gas contract between T&TEC and the National Gas Company. Bearing in the mind the public interest and the substantial natural gas resources of the country, the new contract should be based on a natural gas price that reflects these considerations;
- the linking of increases in the annual price of natural gas to the rate of inflation, with a cap of 3%; and
- the freezing of the price of gas until a new contract is negotiated.

Diesel

Diesel is primarily used in Tobago to operate the diesel generators that serve as a standby system. The price of diesel has remained fairly constant, with the exception of two years when an increase of 25% in 1994 and 2.4% in 1997 were observed. There is little scope for reduction in the price of diesel at this time.

Table 5.15 - Gas and Diesel Prices and Inflation Rates, 1993-2004

Year	Gas Price (US¢/MMBTU)	Increase in Gas Price (%)	Diesel Price (TT$/Litre)	Increase in Diesel Price (%)	Inflation Rate (%)
1993	50.72		1.00		10.8
1994	52.84	4.18%	1.25	25%	8.9
1995	58.95	11.56%	1.25	0%	5.3
1996	61.31	4.00%	1.25	0%	3.3
1997	63.76	4.00%	1.28	2.4%	3.6
1998	66.31	4.00%	1.28	0%	5.6
1999	68.96	4.00%	1.28	0%	3.4
2000	71.72	4.00%	1.28	0%	3.5
2001	74.59	4.00%	1.28	0%	5.6
2002	77.57	4.00%	1.28	0%	4.1
2003	80.67	4.00%	1.28	0%	3.7
2004	83.90	4.00%	1.28	0%	3.6

Volume of Fuel

Natural gas consumption has grown consistently with increasing demand. However, the growth in diesel consumption has been punctuated with some spikes since it is mainly used to keep the standby generators running in Tobago (**Table 5.16**).

Table 5.16 - Gas and Diesel Usage, 1993-2004

Year	Gas Usage (MMBTU)	Diesel Usage (Litre)
1993	51,620,751	158,383
1994	52,548,469	194,293
1995	56,070,537	214,571
1996	58,580,014	805,734
1997	63,032,828	4,977,882
1998	68,339,360	8,470,063
1999	69,184,371	3,578,571
2000	70,537,516	644,064
2001	73,010,119	751,911
2002	80,698,560	750,812
2003	87,198,800	2,098,000
2004	96,473,200	2,631,913

Heat Rate

The system generation heat rate measures the efficiency of the thermal conversion processes of a power generating plant. It can be defined as the thermal energy content of the fuel (kJ) required to produce one kWh of electricity. Lowering the heat rate means improving the efficiency of the conversion process, thereby reducing the volume of fuel consumed and consequently fuel costs.

There is no specific guaranteed system heat rate defined in the Trinity Power PPA, while PowerGen's PPA defines it as 14,000 kJ/kWh. Additionally, in the case of PowerGen, there is a ±5% tolerance limit for which either bonuses or compensatory payments would apply. This effectively creates an acceptable heat rate range of between 13,300 to 14,737 kJ/kWh for PowerGen.

The overall average system heat rate for the period 1991 to 2004, based on an average of all the generating stations, is shown in **Table 5.17.**

Table 5.17 - System Generation Heat Rate, 1991-2004

Year	Overall System Generation Heat Rate (kJ/kWh)	PowerGen (kJ/kWh)				Trinity Power (kJ/kWh)	Tobago (kJ/kWh)
		Average System Net Heat Rate	Port of Spain	Point Lisas	Penal		
1991	14,696	14,697	14,449	17,380	10,866	N/A	12,722
1992	14,423	14,424	14,559	16,535	9,998	N/A	12,118
1993	14,495	14,496	14,222	15,750	11,380	N/A	11,494
1994	13,941	13,941	14,418	15,854	10,590	N/A	13,213
1995	14,274	14,274	15,266	16,047	10,512	N/A	11,667
1996	14,048	14,050	15,320	15,439	10,598	N/A	11,719
1997	14,011	14,017	15,054	15,237	10,647	N/A	11,546
1998	14,122	14,140	14,924	15,433	10,765	N/A	10,428
1999	14,078	14,131	14,939	15,939	9,996	13,334	10,831
2000	13,745	13,941	14,409	16,427	10,098	13,144	11,590
2001	13,764	13,949	14,340	16,222	10,037	13,086	10,845
2002	13,937	14,131	14,908	16,228	10,068	13,307	10,532
2003	14,389	14,686	15,206	16,398	10,565	13,451	10,600
2004	14,433	14,752	14,744	16,557	11,179	13,438	10,711

Over the 14-year period (1991-2004), the heat rate ranged from 13,745 kJ/kWh to 14,696 kJ/kWh. Further examination of the data shows that while no heat rate was specified for Trinity Power, its heat rate figures (13,086 to 13,451 kJ/kWh) were always at the lower end of the range specified for PowerGen. In the case of PowerGen, with the exception of 2004, the average heat rate was always within the range of 13,300 to 14,737 kJ/kWh.

A closer examination of the PowerGen stations shows that there is marked variation in the operational efficiencies. Point Lisas, the station with the highest heat rates, has never really come close to the guaranteed heat rate of 14,000 kJ/kWh, as it has to respond to large daily fluctuations in demand, commonly referred to as spiking, rather than maintaining base load. Therefore, it is unlikely to operate at optimum. Penal's combined cycle plant is currently the most efficient and is largely responsible for keeping the average system net heat rate of all PowerGen's stations within the required range. Despite these difficulties, the RIC is of the firm belief that T&TEC must insist that every effort be made to reduce the system heat rate to the lower end of the range proposed in the PPA with PowerGen. Possibilities for further improvement in the heat rate include:

- improving the availability of the Penal combined cycle plant. This can be done economically by installing a new maintenance-extender kit on the two gas turbines;
- reducing the large spinning reserve (averaged over 200 MW in Dec '04, maximum was over 360 MW);
- commissioning the Load Share control system on the 8 large generating units at the Point Lisas station;
- upgrading the older generators; and
- implementing analytical monitoring tools to change the despatch of the plants to a more energy efficient arrangement.

However, improvements in the heat rate can be made only via contract renegotiations. The contract with PowerGen was amended when the new generating company, Trinity Power, started operations. However, the amendment removed several of the clauses that held PowerGen liable for poor performance, leaving very little incentive for it to improve performance.

The heat rate achieved at Trinity Power is currently about 12,700 kJ/kWh. This can be reduced, but would require capital investment.

As stated above, reducing the heat rate can lead to significant savings through reduction in fuel consumed. In order to examine the possible cost savings from reducing the heat rate, various scenarios were examined. These are summarized in **Table 5.18** below.

Table 5.18 - Summary of Fuel Cost Savings from Heat Rate Reductions

Scenario	Stations	Heat Rate Reduction	Annual Savings (US$)	Savings over Review Period (5 Years) (US$)
1.a)	All Power stations that supply T&TEC	From: 14,433 kJ/kWh To: 13,300 kJ/kWh	6,031,732	30,158,664
1.b)	All Power stations that supply T&TEC	From: 14,433 kJ/kWh To: 12,000 kJ/kWh	12,949,339	64,746,695
2	PowerGen Stations	From: 14,752 kJ/kWh To: 13,300 kJ/kWh	5,872,689	29,363,445
3	Point Lisas Station	From: 16,557 kJ/kWh To: 13,300 kJ/kWh	6,617,013	33,085,068

The annual savings on fuel costs calculated from different scenarios are significant. T&TEC must insist that the power generators, especially PowerGen, reduce their heat rates. The RIC recognizes that there are cost implications to reducing heat rate. However, cost savings in the medium to long term are significant and must be achieved. Additionally, it is estimated that in 2006 additional capacity will be required to cater for normal growth in demand. The RIC firmly believes that a cost-efficient option would be to introduce a combined cycle plant to generate additional capacity. Such a system would effectively lower the heat rate since the exhaust from the combustion turbines drives the steam turbine, thereby significantly reducing the amount of additional natural gas required to generate more power. In fact, based on the under-mentioned assumptions, the RIC has estimated that over a fifteen (15) year period there will be savings of $28.1 million per annum[6]:

[6] Detailed assumption made were as follows:

- Estimated purchase cost – combined cycle US$126 million, simple cycle US$92.4 million (Power Engineers, Idaho, USA).
- Interest rate of 5.381% (6 month Libor + 1.5% country risk).
- Heat Rate for new plant – combined cycle 7500 kJ/kWh, simple cycle 11500 kJ/kWh.
- Capacity factor of 85%.
- Operating and Maintenance costs – combined cycle US$5.88 million per year, simple cycle US$7.14 million per year.

- Capital outlay and other associated costs of combined cycle generation for the additional 208 MW capacity;
- Operating and maintenance costs (excluding fuel costs);
- Fuel purchases from NGC; and
- Heat rate of 12,000 kJ/kWh.

The RIC intends to reduce the fuel cost accordingly while being mindful of the initial cost of installation and system improvements.

In order to provide the right incentives and save on fuel costs, the RIC's decision is that there should be only 90% pass-through of fuel costs and the costs for failing to introduce combined cycle plant should not be borne by the consumer and, accordingly, have not been considered in the revenue requirement. Further, the RIC's decision is that, in the future, all additional capacity sourced should be through the installation of combined cycle units.

5.4.9 Forecast of Fuel Costs, 2006-2010

Based on future energy needs and 90% pass-through, the fuel costs that will be allowed by the RIC in the revenue requirement are presented in **Table 5.19**.

Table 5.19 - Forecast for Fuel Costs, 2006-2010

Year	Annual Gas Cost	Annual Diesel Cost	Total Annual Fuel Cost	90% of Annual Fuel Cost	RIC's Approved (90% of Annual Fuel Cost)
	($Mn.)	($Mn.)	($Mn.)	($Mn.)	($Mn.)
2006	650.2	3.2	653.4	588.0	584.1
2007	681.4	3.8	685.2	616.7	609.4
2008	728.5	32.2	760.7	684.6	651.0
2009	761.2	3.5	764.7	688.3	671.5
2010	827.2	3.3	830.5	747.4	716.0

The RIC's decision is to adopt fuel costs as proposed in **Table 5.19.**

- Fuel price US$0.87/MMBTU with 4% annual escalation.

Stakeholder Comments and Final Decision

Broadly, there were three sets of comments/suggestions on the RIC's Consultation Document, "**The Treatment of Uncontrollable Cost in Incentive Regulation** (**June 2005)**". The first set of comments related to the renegotiation of PPA contracts by including more favourable conditions and the inclusion of the RIC in this process.

The RIC has already proposed a number of measures with respect to renegotiation of PPA contracts and looks forward to a favourable response from the Government.

The second set of comments related to the additional generation capacity being sourced through the installation of combined cycle units rather than simple gas turbines.

The RIC is cognizant of the fact that combined cycle gas turbine technology is considered to be the least cost alternative for the addition of new capacity at this time. Consequently, the RIC has already indicated its intention of only considering the costs for the most efficient method in the calculation of revenue requirements for T&TEC. The RIC believes that customers should not be asked to bear the cost of inefficient decisions.

The final set of comments related to the purchase of gas by the generators and suggestions that the first beneficiaries from the country's natural gas reserves should be the citizens of Trinidad and Tobago.

Once again, the RIC has proposed a number of solutions for the consideration of the Government, as the RIC and T&TEC have to comply with Government's policy on fuel cost. **The Government will determine the final price of natural gas for use in the generation of electricity**.

5.4.10 Uncertain Costs

The Draft Determination and the RIC's paper, **"The Treatment of Uncontrollable Cost in Incentive Regulation"**, classified uncontrollable costs into unforeseen uncontrollable cost and foreseen uncontrollable costs. However, there exists between these two categories instances where a service provider is able to identify a "known" item that can have significant impact on their costs, but the precise level of impact is either difficult to quantify in advance of its implementation or cannot be forecasted with precision until plans are substantially finalized. T&TEC has indicated to the RIC the possibility that in 2009 it may be required to provide capacity of approximately 400 MW to a steel company that may be established in Trinidad and Tobago. The RIC proposes to treat with such an event by way of the trigger event mechanism identified in Section 5.4.3 of this Determination.

5.5 CONCLUSIONS ON TOTAL OPEX

The RIC's judgment is that the forecasts of Opex provided by T&TEC do not reflect efficient cost of service. The RIC has, therefore, prepared its own forecast of reasonable costs sufficient for T&TEC to provide services at higher than current levels. The RIC's forecasts have allowed:

- increased expenditure in the operational areas, where necessary;
- anticipated expenditure to comply with the RIC's guaranteed standards;
- anticipated expenditure for cess payments; and
- increased expenditure levels for repair and maintenance.

However, the RIC has also made a number of significant reductions in the Opex amounting to $905.74 million overall for the period 2006-2010 (or $181 million annually), notably in relation to:

- fuel costs, which have been lowered by $538.4 million for the period 2006-2010 (or $108 million annually);
- generation (conversion) costs, which have been lowered by $178.92 million for the period 2006-2010 (or $36 million annually);

- total projected employee costs have been lowered by $124 million for the period 2006-2010 as a result of an observed anomaly; and
- advertising and marketing/sponsorships expenditure amounting to $11 million for the period 2006-2010 have been disallowed.

The RIC has also included a 2.8% (non-compounding) efficiency factor, based on the operating efficiency improvements expected for the period 2006-2010, thereby reducing the T&D costs by $53.3 million for the period 2006-2010.

The RIC's total operating expenditure is set out in **Table 5.20**. These forecasts are used in the calculation of the total revenue requirement in Chapter 11.

Table 5.20 – Determination of Total Operating Costs, 2006-2010 ($Mn)

	T&TEC Requested 2006-2010	**RIC Approved 2006-2010**	**2006**	**2007**	**2008**	**2009**	**2010**
Conversion Cost	5,450.31	5,271.39	792.66	844.08	1,050.27	1,192.87	1,391.51
Fuel Cost	3,770.40	3,232.00	584.10	609.40	651.00	671.50	716.00
Total T&D	2,037.27	1848.85	342.34	356.10	369.44	384.62	396.35
Total Opex Charged to Revenue	**11,257.98**	**10,352.24**	**1,719.10**	**1,809.58**	**2,070.71**	**2,248.99**	**2,503.86**

The RIC's decision is to adopt total operating costs for the first regulatory control period as proposed in **Table 5.20.**

CHAPTER 6

CAPITAL EXPENDITURE

6.1 INTRODUCTION

Capital Expenditure (Capex) forms an important and integral part of the costs of a transmission and distribution entity and contributes significantly to the final prices that customers pay for their electricity supply. There is also a close link between capital expenditure and quality of supply. Capex is recovered through prices over the life of the asset in the form of a return of these assets (through depreciation). Under the building-block approach, the regulator seeks to provide an appropriate return on efficient investment in the network. This is achieved by including proposed capital expenditure in the projections of the regulatory asset base over the next regulatory period.

It is incumbent on the regulator to ensure that capital expenditure forecasts are reasonable and efficient, and once this has been determined, the regulator must allow the appropriate level of Capex to form part of the revenue requirement of the service provider.

The RIC Act requires the RIC to ensure that the service providers are provided with a sustainable revenue stream that does not reflect monopoly rents or inefficient expenditure and allows the service provider to recover expenditure on renewing and rehabilitating existing assets. The RIC recognizes that a return should be allowed only on the legitimate level of investment that is required to service the scale of operations undertaken by the service provider and must always guard against allowing a return on wastefully applied capital. In establishing Capex requirements for T&TEC, the key issues for the RIC are to ensure that:

- Capex reflects an unbiased requirement that would be undertaken by an efficient service provider;
- there is no evidence of unnecessary or inappropriate Capex;

- the service provider quantifies the reduction in Capex through improved efficiency;
- Capex requirements are consistent with the service provider's demand forecasts, service targets and other obligations; and
- the service provider's Capex forecasts are credible in light of the outturn results.

6.2 CAPEX REVIEW PROCESS

As in the case of Opex, the expenditure review process for Capex contained the same three stages: set up stage, facilitation stage and assessment stage. T&TEC was required to provide details of actual Capex between 1999-2004 and forecasts for 2006-2010, together with supporting explanations and information for:

- demand-driven (or reinforcement) Capex to meet growth in demand;
- non-demand related or replacement Capex to replace assets at the end of their economic lives;
- improvement expenditure to maintain or improve reliability and quality of service through an ability to outperform quality of service standards already set; and
- expenditure for other purposes, including non-network general assets, network control etc.

After its preliminary analysis of the information, the RIC identified a range of issues, including deficiencies and inconsistencies in the information, and commenced discussions with T&TEC to improve its understanding of the submission. Eliminating the anomalies and aberrations was a long process, as supporting information had to be sourced to ensure that the expenditure forecasts were internally consistent and reconcilable with the information submitted, such as: demand forecasts, remaining asset lives, network reliability and quality targets and long-term asset management plans.

The Capex assessment is particularly critical since allowed Capex will be rolled-forward into the asset base. Accordingly, the RIC was committed to ensuring that only efficient and prudent Capex are allowed. The efficient capital expenditure allowance is used as the basis for determining the revenue requirements of the service provider in the building-block methodology. By implication, only efficient capital expenditure earns a rate of return for the regulatory period.

Given the importance of Capex in determining revenue requirement, the RIC engaged a consultant (Kenesjay Systems Limited) to provide independent advice on the efficient amount of capital expenditure required to achieve the service outcomes desired by customers. The consultant's remit was to advise:

> "as to whether the proposed capital expenditure (investment levels) forecasts of T&TEC are reasonable and represent an efficient level of capital expenditure. Where the study identifies that the level of proposed capital expenditure is not reasonable, the consultant is required to identify the appropriate level of expenditure, and provide adequate explanations for the major differences and the level deemed appropriate".

A copy of the consultant's final report can be found on the RIC's website.

6.3 ASSESSMENT OF CAPITAL EXPENDITURE

6.3.1 Broad Approaches and Issues

The overriding concern of the RIC is to ensure that Capex costs are efficient and prudent. In testing these concepts, the RIC needed to understand the key drivers of the capital expenditure and be convinced that the proposed Capex represents an efficient means of meeting the demand and quality of network services. The efficient amount of capital expenditure is assessed by a combination of internal historical benchmarking, benchmarking against similar utilities and expert analysis. An assessment of typical productivity improvements in similar industries is often used as a guide.

The RIC had to be convinced that proposed Capex plans of T&TEC were:

- consistent with its business strategies;
- rigorously developed and data-driven using the best information at the time;

- such that adequate capacity and mechanisms were in place to undertake projects;
- based on efficient procurement mechanisms;
- such that project benefits were clearly known and well articulated so that monitoring of such deliverables would be encouraged by beneficiaries themselves; and
- appropriate to deliver service standards particularly those defined by the Guaranteed Standards.

The RIC's focus on the Capex assessment process has been to ensure that any significant changes in expenditure levels reflect the need to upgrade or invest in new infrastructure to meet the service expectations of customers or that they are linked to clear new obligations and that T&TEC has identified the outputs to be achieved and the associated costs are prudent and efficient. It is understandable that forecast Capex must be influenced by historical Capex performance. Thus, the RIC had requested data on Capex and implementation performance for the preceding five years and had indicated that the past trend in Capex would be used as the starting point for assessing T&TEC's proposals for the 2006-2010 period. The trend captures the actual information that the RIC can rely on as a basis for reviewing 2006-2010 Capex forecasts. Although the historical assessment will consider the data and circumstances that prevailed at the time the Capex decisions were made, the RIC feels that identifying the deviation from the trend in Capex provides a reasonable basis for assessing forecast requirements.

In summary, in the assessment of T&TEC's proposed Capex, the RIC considered whether:

- the proposed Capex trends were related to trends in historical Capex, such that the reasons underpinning any difference could be identified together with any other relevant factors;
- there was evidence of, and consistency with, well developed asset management planning and processes that demonstrated whether forecasts

took account of the planning horizon which extends beyond the five year control period;

- the Capex associated with new functions and obligations clearly reflected additional obligations; and
- the proposed programme of Capex was deliverable over the five year control period.

Additionally, the RIC expected that significant increases in Capex would be substantiated by supporting information on the following cost drivers:

- **for growth-related Capex** – evidence of growth in demand;
- **for Capex on existing infrastructure** – evidence that networking needs to be renewed to ensure continuity in service delivery to meet customers expectations;
- **for Capex on new functions/obligations** – evidence of significant customer preferences; and
- **for corporate and other Capex** – evidence that existing assets were inadequate to meet customer needs.

6.3.2 T&TEC's Proposed Capital Expenditure

T&TEC proposed a capital expenditure programme amounting to $3,285.2 million (in 2004 dollars) over the first regulatory control period broadly divided into transmission and distribution categories, summarized in **Table 6.1.**

Table 6.1 – T&TEC's Forecast Capital Expenditure, 2006-2010

Category	Amount ($Mn.)
Transmission	420.0
Distribution	741.1
Information Technology	92.5
Control & Communication	71.2
Commercial and Metering	47.8
Administration & General	140.0
Street Lighting	732.8
Government Initiated Projects	1,039.8
TOTAL	**3,285.2***

* This figure represents revisions to the original Capex list submitted in T&TEC's Business Plan 2004-2008.

This capital forecast includes revisions made since T&TEC's November 2004 submission. The proposed average annual Capex represents a significant increase on T&TEC's past Capex. Major drivers of the proposed capital expenditure include:

- government economic policy driven projects and street lighting programmes at a total cost of $1772.6 million;
- the upgrade of transmission system at a total cost of $420 million from 2006-2010;and
- rehabilitation and upgrade of the distribution system at a total cost of $1043.2 million over the control period.

In its Business Plan, T&TEC advanced the under-mentioned reasons for the proposed investments. These issues are inextricably linked to the key business issues, which the service provider will attempt to address over the control period:

- catering for anticipated future network growth;
- enhancing the level of customer service;
- achieving a balance in the supply/demand relationship;
- maintaining the network infrastructure and assets and replacing of assets that are approaching the end of their useful life; and
- catering for government initiated projects.

6.3.3 Consultant's Overview

As indicated above, the RIC requested that the Consultant review T&TEC's proposed level of capital expenditure to provide an overall strategic view of whether expenditure levels were reasonable and represent an efficient level of expenditure. In undertaking this review, the Consultant made a number of broad observations on T&TEC's capital programme and other related issues, including that:

- a significant proportion of the capital programme lacked a robust audit trail, and the quality assurance of supporting documents was generally poor; and
- T&TEC lacked an integrated asset management philosophy – overall asset management policies were not succinctly argued and communicated.

6.3.4 Consultant's Proposed Capital Plan

As part of its review, the Consultant was requested to propose an efficient capital expenditure plan. The Consultant's overall view was that T&TEC's capital plan was over ambitious and included some individual projects that were not fully justified or could be deferred or deleted. The major concern of the Consultant was the fairly low implementation over the period 2000-2004, which led to serious questions about T&TEC's ability to implement the proposed plan. T&TEC's inability to implement its capital programme during the years 2000-2004 is clearly depicted in **Table 6.2** below.

Table 6.2 – T&TEC's Planned vs Actual Capital Expenditure, 2000-2004

Year	Budgeted ($'000)	Actual ($'000)	Divergence ($'000)	Divergence (% of Budget)
2000	198,000	168,000	30,000	15%
2001	191,000	172,000	19,000	10%
2002	221,000	135,000	86,000	39%
2003	306,000	160,000	146,000	48%
2004	633,000	133,000	500,000	79%

The Consultant's proposed capital expenditure plan was developed using T&TEC's proposed capital plan after making the following adjustments:

- removing the Automatic Metering project from the capital expenditure programme. The Consultant was of the view that this project could not be justified at this point in time;
- revising the estimates for new customer connections to the system consistent with the project growth rates in demand and number of customers; and
- revising downward the cost of several projects based
    - on lower estimates for projects of a similar nature, and
    - in other cases such revisions were based on T&TEC's previous rate of project implementation.

The Consultant's proposed efficient capital expenditure in respect of those projects examined is presented in **Table 6.3.** It should be pointed out that this examination did not include additional capital expenditure proposals, which T&TEC submitted to the RIC for consideration, after the Consultant completed the exercise. However, these were exclusively projects which the RIC has determined should be funded by Government as explained later in this chapter.

Table 6.3 – Consultant's Recommended Capital Expenditure on Selected Projects

Category	Amount ($Mn.)
Transmission	390.7
Distribution	398.2
Information Technology	63.1
Control & Communication	11.3
Commercial and Metering	6.0
Administration & General	50.7
TOTAL	**920.0**

6.3.5 RIC's Conclusion on Efficient Capital Expenditure

The RIC has found the comments of the Consultant and the responses from T&TEC to be of value in arriving at a conclusion with respect to the proposed capital expenditure over the first regulatory control period. The Consultant has suggested that there is significant room for capital efficiencies, with a number of projects being uncertain or having their potential scope overstated. T&TEC has responded to a number of observations and criticisms and, in particular, has noted difficulties in finalizing the capital expenditure programme on a project-by-project basis "so far in advance".

The RIC accepts that over the regulatory control period, there may be a need to defer some projects and bring forward other projects. Future capital plans should not be seen as being sufficient to cover all potential eventualities but those considered to be likely over the five-year period. Therefore, some latitude in the forward estimates of capital expenditure may be allowed, given the nature of the estimates that are used. The provision in the price path for a capital expenditure programme, which covers all potential developments would leave the utility with very limited exposure to normal commercial risk and would, therefore, require an appropriate adjustment in the cost of capital to reflect that lower than normal risk.

The key issue is whether T&TEC has the resources to deliver the proposed investment programme within the five-year period, especially since major projects often require detailed planning and approvals before they can proceed. In the light of previous expenditure history and the absence of a detailed plan for different projects, the RIC has serious concerns about T&TEC's capability to deliver the level of work proposed, particularly given the increased construction activities in the country and the resulting shortage of skilled resources generally throughout the country.

The RIC has identified projects amounting to $1,772.6 million which should be fully funded by Government, as they would benefit only a target customer and/or industry. Such projects should have no impact on prices faced by network users and thus they have been excluded from T&TEC's Capex building-block. These projects should be totally ring-fenced. At the beginning of the second regulatory control period, the RIC will adjust T&TEC's asset base to account for all government contributions actually received during the first regulatory period. If and when one of these projects is set to proceed, the RIC would require T&TEC to:

- demonstrate that the project will have no negative impact on any other users;
- show that accounting arrangements have been established to ensure capital and operating expense classification; and
- provide evidence that the associated costs are being fully covered by the Government.

The Government has already committed to spending $622 million on street lighting from the Consolidated Fund. This amount was therefore also deducted.

Stakeholder Comments and Final Decision

In light of the above discussion, the RIC has revised the Capex forecasts proposed by T&TEC and had initially proposed a Capex forecast of $998.4 million in its Draft Determination. While significantly lower than T&TEC's forecasts, the RIC believed it had made a sound case for the proposed Capex forecast of $998.4 million over the first regulatory control period. The RIC, following the release of its Draft Determination received additional comments from T&TEC. T&TEC argued, that the RIC has provided insufficient allowance for Capex. However, in May 2006 the shareholder (Government) publicly announced its intention to provide funding for T&TEC to finance, among other initiatives, capital projects amounting to $1,124 million over the period 2006-2008. These projects include:

- Expansion of transmission and sub-transmission infrastructure amounting to $844 million;
- Upgrade and expansion of telecommunications in the sum of $70 million; and
- Advance metering infrastructure system estimated to cost $210 million.

The RIC has noted that several of these projects related to expansion of the transmission and sub-transmission infrastructure were already allowed in the draft determination. It is the responsibility of the regulator to ensure that consumers do not pay twice for the same infrastructure, and consequently, the RIC's previous Capex allowance of $998.4 million has been reduced to $800 million (averaging $160 million per annum) over the regulatory control period as summarized in **Table 6.4** below (**see Tables 6.5, 6.6, 6.7 and 6.8 for details**). This has become necessary since Government will assist in financing major elements of T&TEC's overall capital programme.

Table 6.4 – RIC's Allowed Capital Expenditure, 2006-2010 ($Mn)

Project	Allowed 2006	Allowed 2007	Allowed 2008	Allowed 2009	Allowed 2010	Allowed Total
Transmission	42.0	80.0	80.0	30.0	26.0	258.0
Distribution	65.5	38.8	27.3	72.0	87.7	291.3
Other Network Related Projects	28.0	34.0	32.1	20.3	20.5	134.9
Non-Network Related Projects	17.7	38.6	30.0	15.5	14.0	115.8
Total	**153.2**	**191.4**	**169.4**	**137.8**	**148.2**	**800.0**

The RIC remains committed to ensuring that adequate resources are provided to T&TEC to secure its ability to improve service reliability to all consumers. As such, those projects essential to enhancing the service provider's reliability in supply have been allowed. This ensures that the minimum quality of service standards are achieved and delivered to all consumers.

It should be pointed out that:

- the approved level of Capex compares favourably with the annual average Capex over the last five years. The information on past investment indicates that spending on capital works had been fairly low. If anything, Capex proposed by the RIC is slightly higher than that realized over the course of the last five years;
- the RIC's proposed Capex is based on a different profile of expenditure from that proposed by T&TEC to facilitate a better match with resources. In some instances, the RIC recommended revising the timing of proposed Capex within the five year period (for example, moving the project from year one to year two);
- the RIC has opted for slightly declining expenditure in the later years to reduce the risk of non-completion of projects and avoid "back-ending" investment. Back-ending means customers are denied the earlier improvements for which

they have paid. While it may sometimes be unavoidable for reasons genuinely outside a service provider's control, back-ending investment in a price control period is profitable to a service provider; and

- the RIC has agreed with those increases in expenditure proposed by T&TEC seen to benefit the consumer and/or enhance its operational efficiency.

The RIC's decision is to include capital expenditure forecast for T&TEC of $800 million for the first regulatory control period.

Another issue the RIC considered was whether T&TEC has in place adequate asset management systems to accurately forecast the required future investment. Key elements of good asset management include the establishment of asset data bases, the use of GIS and Supervisory Control and Data Acquisition systems, the establishment of condition assessment and internal performance monitoring, and the development of economic decision-making tools to evaluate whether to renew or rehabilitate assets. The RIC is of the view that T&TEC needs to improve asset management and capital budgeting processes over the regulatory control period.

The RIC's decision is to use regulatory audits to monitor the progress in improving the quality of T&TEC's asset management systems.

Details now follow on the allowed Capex.

Transmission Projects

Capital investments on the transmission network are essential to improving the network's reliability and facilitating the growth demand forecasts. According to the consultant's analysis of T&TEC's cost estimates for transmission projects, the majority of the high voltage sub-stations with associated overhead lines were implemented at final costs below their estimates. Further, the comparisons of transmission project costs with electricity companies in other jurisdictions were found to be reasonable. Thus, the RIC has allowed the full costs of the under-mentioned transmission projects (**Table 6.5**).

Table 6.5 – RIC's Allowed Transmission Projects ($Mn)

Project	Purpose	Request Total	Allowed Total	Remarks
Rehabilitation of Substations at the Transmission Level	Caters for improved network reliability	**129.5**	**129.5**	The programme of substation rehabilitation primarily addresses reliability improvements to the existing network and would involve upgrade of the following substations: Pinto Road; Mt. Hope; Trincity including 66kV OH line: Abattoir; San Juan; Barataria Earth Link; South East Ring 33kV OH line; Champ Fleurs; Bamboo132kV; O'Meara; Five Rivers; and Establishing 33kV Earth Link for Tobago.
Establishment of New Substations and Network Development	Growth	**128.4**	**128.4**	Establishment of New Substations is concerned primarily with boosting supply consistent with demand and growth forecasts. This programme will involve construction and/or expansion of substations at the following locations: Invaders Bay; Macoya; Unicell; San Rafael; Longdenville; Charlieville; Tarouba; Tunapuna; construction of the following overhead lines - Penal/Harmony Hall; Philippine/Penal; Roxborough including 33kV OH line; 66kV to Nitrogen 2000; Pinto Rd/San Rafael 132kV twin circuit line construction; and installation of 132/66kV transformer at Penal.
Total Transmission Projects		**257.9**	**257.9**	

Distribution Projects

The RIC has allowed a reduced amount in respect of the distribution projects necessary for improving the systems network. Upon analysis it was found that many of the project proposals were not adequately documented and therefore the much-needed justification for their full allowance was lacking. In agreement with the consultant, some project requests appeared to be exaggerated and the consultants' recommendation for the appropriate scope and costs were used to revise such projects and subsequently make the appropriate allowance provisions. Further, much of the investment expenditures were heavily front-loaded that is, they were projected to be implemented in the earlier years of the price control period. Hence priority adjustments were made in many instances suggesting that such project commencement dates be postponed to a later start date in the control period (**Table 6.6**).

Table 6.6 – RIC's Allowed Distribution Projects ($Mn)

Project	Purpose	Request Total	Allowed Total	Remarks
Upgrade of Substations at the Distribution Level	Rehabilitation to improve reliability and cater for demand growth	**238.8**	**165.2**	The programme focuses on upgrade works at various substations to improve service delivery at the distribution level and will involve the substations in the following locations: Westmoorings; Barataria; Diego Martin; Abattoir; Port of Spain; Maraval; Corinth; Rio Claro; North Oropouche; Scarborough; Central; Santa Cruz; Barataria/San Juan; Bamboo; St. Augustine; Trincity; Five Rivers; Chaguanas West; Independence Square; Brechin Castle; Pinto Rd. and St. Mary's. Scope of works will include installation of transformers, switchboards, insulators, beakers, underground cables, vacuum units, and fault interrupters. Additionally, provisions have been allowed for general substation upgrades, as and when the need arises. Also a programme of preliminary surveys and investigations would also commence.
Upgrade of Distribution Network	Maintenance of system reliability and caters for demand growth	**126.1**	**126.1**	The programme of upgrade to the distribution network focuses on installation and replacement of underground cables and overhead lines. These works are targeted for the following areas: L'Anse Formi/Charlotteville; Barataria/San Juan; Port of Spain; Trincity; Carenage; Couva; Fyzabad/Brighton; Caura/Maracas; Mantra; and Piarco. Also included is a provision to facilitate line repairs and extensions throughout all distribution areas, should the need arise. Additionally, provision has been allowed for line clearing primarily for new projects and recommencement of hotline repair work.
Total Distribution Projects		**364.9**	**291.3**	

Other Network Related Projects

Many of the under-mentioned listed projects are important in the drive to modernize the operations of T&TEC. To this end these investments are essential to achieving the necessary efficiencies during the first price control period. Accordingly, out of a total request of $153.0 million, the sum of $134.9 million is allowed for the period 2006-2010 as efficient and prudent investment geared towards enhancing the operational efficiency of the service provider (**Table 6.7**).

Table 6.7– RIC's Allowed Other Network Related Projects ($Mn)

Project	Purpose	Requested Total	Allowed Total	Remarks
Pole Replacement Programme	Reliability improvement	**80**	**80**	This programme caters for pole replacement (concrete, metal, wood) throughout all distribution regions.
Improvement to Network Systems	To meet quality of service standards; improve reliability and cater for demand growth	**61**	**45.5**	This project involves general improvement works throughout the distribution network to correct voltage; cater for new customer connections and upgrade customers' meters.
Strengthening of Controls & Communications Systems	Operational efficiency	**2.7**	**2.7**	Improvements to the communications and controls systems will involve replacing obsolete RTUs and installation of a backup system at the control room.
Enhancement of Metering Systems	Improves Operational Efficiency	**9.3**	**6.7**	This project involves the replacement of electro-mechanical meters; replacement of Solkor relays; and upgrade of substations protection and control systems.
Total Other Network Related		**153.0**	**134.9**	

Non-Network Related Projects

Of the total request of $226 million for non-networked related projects, the RIC has allowed $115.8 million to be invested over the price control period. Upon investigation and analysis, many of the proposed projects in this category were adjusted either in terms of timing (implementation) or reduced to reflect more realistic cost estimates. These findings were also consistent with the consultant's view (**Table 6.8**).

Table 6.8 – RIC's Allowed Non-Network Related Projects ($Mn)

Project	Purpose	Request Total	Allowed Total	Remarks
Strengthening of Administrative Services	Operational Efficiency	**168**	**80**	The proposed scope of works include: refurbishment of Head Office, Welfare Block and Dow Village Warehouse; construction of a new northern-area building and office building; procurement of vehicles and pole lifting equipment; and implementation of load monitoring and research programme.
Upgrade of Information Technology Systems	Improved operational efficiency	**53.5**	**31.3**	This project involves the procurement of state of the art IT equipment and software aimed at improving operational efficiencies in several areas including: meter reading; billing; customer information; human resource and document management; and plant maintenance management.
Establishment of Customer Call Centres	Operational Efficiency	**4.5**	**4.5**	Project caters for the upgrading and establishment of strategically located customer call centres.
Total Non-Network Related		**226**	**115.8**	
Total of all Projects Considered		**1197.7**	**800.0**	

T&TEC's capital projects, which were not allowed, are shown in the <u>Annex</u> to this chapter.

In light of the proposed Capex programme, it is expected that by the end of the first regulatory control period, T&TEC's network would be delivering a significantly higher level of service than at present. However, in accepting this programme, the RIC is still concerned about T&TEC's ability to implement and complete the projects on time and the estimated costs for some of the projects. Given these concerns and the fact that this is the first price control period, the RIC would require a relatively detailed review of the prudence of the capital programme at the end of the first regulatory control period. Additionally, the RIC will impose a relatively rigorous and continuous review of the capital expenditure programme during the price control period.

The annual monitoring of Capex is to provide checks and balances and to act as an early warning mechanism for all underperformance, in an attempt to ensure that the quality and levels of services promised to customers are being delivered.

Additionally, reporting on key outputs, workload and investment should provide a good measure of progress against planned efficiency targets. A monitoring programme will enable the RIC to observe any major changes in actual expenditure from the plan, the reasons for these changes and the ability to identify genuine capital efficiencies as they occur rather than wait until the next control period. T&TEC can also benefit from this type of arrangement, as it should be easier for T&TEC to demonstrate efficiency gains.

Among other things, this will involve T&TEC being required to provide the following information:

- an annual report of investment including an explanation of any divergence;
- the final costs of all projects completed during the regulatory control period;
- a full justification why any project included in the approved Capex programme was not carried out, including the external factors that changed after the forecasts were made;
- a full justification that any project completed above the forecast estimate, represented the best value for money;

- details of tenders received from all successful and unsuccessful tenderers for any project externally contracted but completed above the forecast estimate; and
- detailed investigations of any divergence at the end of the price control period, with a correction to ensure that any unacceptable divergence is revenue neutral.

The RIC will also require, in the future, a detailed project-by-project capital expenditure programme with major projects to be audited by a consultant approved by the RIC. Additionally, the RIC will publish details annually of T&TEC's actual expenditure against proposed expenditure in its performance reports.

As part of capital expenditure assessment, T&TEC will be required to present capital forecasts for three scenarios:

- maintaining the current service quality level;
- improving service quality aimed at delivering an agreed average level of service; and
- specific additional commitments aimed at improving the quality of service in specific parts of the network or addressing identified customer requirements and including clearly identified service quality outcomes.

The RIC's adjustments to the total value of the forecast capital expenditure programme do not prevent T&TEC from spending money on any specific investment activity during the regulatory control period. The forward capital expenditure estimates provide a context for the price path over the regulatory control period. However, it is the actual prudent capital expenditure that is ultimately rolled into the regulatory asset base and carried forward for the life of the asset.

6.4 OTHER CAPITAL EXPENDITURE RELATED ISSUES

6.4.1 Efficiency Carryover Mechanism for Capex

In its Consultation Document, "**Sharing of the Benefits of Efficiency Gains and Efficiency Carryover Mechanism (June 2005)**", the RIC put forward the view that it will consider the possibility of introducing an efficiency carryover mechanism for Capex. An efficiency carryover mechanism is the means whereby the incentive to make efficiency gains by a service provider is enhanced by permitting it to carry over gains from one regulatory period to the next. Customers benefit in lower prices when efficiency gains are passed to them at the end of the period. The actual mechanism to be adopted for the Capex is discussed in detail in Chapter 8.

6.4.2 Timing of Inclusion of Capex in Asset Base

Broadly, there are two options for the inclusion of capital expenditure in the regulatory asset base (RAB). Some regulators include capital expenditure in the RAB at the time it is incurred. However, a large number of regulators include capital investments and the capitalized interest costs associated with the project in the RAB when the asset comes into service. The advantage of the second option is that service providers have an incentive to complete projects on a timely basis, ensuring that customers do not pay for incomplete projects.

The RIC's decision is to include capital expenditure in the regulatory asset base when the asset comes into service.

6.4.3 Treatment of Divergences between Expected and Out-Turn Capex

It is important to consider how Capex overspend and underspend will be treated during the price control period. Overspend and underspend create divergences between forecast capital expenditure and outturn (or actual) capital expenditure incurred during the period of review. Therefore, investments may exceed or fall below the capital expenditure allowances set by the regulator in its determination.

The divergences are generally captured under efficiency carryover mechanisms[7]. A service provider gains efficiencies when it out-performs the pre-set productivity factor (X-factor). In such circumstances, the regulator would implement mechanisms to share

[7] For a full exposition of RIC's approach to dealing with this concept, see Consultation Document – Sharing of Efficiency Gains and Efficiency Carryover Mechanisms.

a portion of this profit with customers who must ultimately benefit from improved efficiencies, usually in the form of lower prices.

RIC's Approach

Overspend will be considered and allowed particularly in cases where the estimates were grossly inaccurate, or capital input prices may have risen unexpectedly. Where overspend is a result of gross inaccuracy, the regulator must be assured that the service provider is not culpable simply by knowingly trying to get the Capex item allowed in the first place by undervaluing the scope of works to be undertaken. Where the overspend result from unforeseen but necessary Capex, such items stand a better chance of being allowed by the regulator.

Similarly, instances of Capex underspend will be examined to verify the reasons for such a divergence. The objective here is to ensure that a service provider's inefficiencies are not passed to consumers and that consumers are not made to experience the negative effects of poor implementation performance and the resultant substandard service levels. Reasons for underspend include protracted delays in procurement mechanism, underestimates of project scope and durations and poor project management. The RIC will require T&TEC to provide documented cogent explanations for Capex underspend and if satisfied by the justification given, the Capex portion of the appropriate portion of the underspend would be allowed to roll-forward and be added to the next year's previously agreed upon Capex programme.

Divergences that arise during the regulatory control period can be accounted for in a special account each year. This account will be reconciled at the end of the price control period, at which time further consideration will be given to the treatment of overspend and underspend when rolling-forward the RAB into the successive control period.

6.4.4 Rolling-forward of Prudent Capital into the RAB

Once the prudence of actual Capex in the previous regulatory control period has been determined, how it is rolled in the regulatory asset base (RAB) becomes important.

There are a number of alternative approaches and each one has a different set of implications for achieving capital efficiencies.

One option is to roll into the RAB all of the prudent Capex from the previous regulatory control period, irrespective of whether it is above the efficient forecast from the previous price determination. This means that, to the extent there are prudent increases (decreases) above (below) the forecast Capex, losses (gains) are borne by the service provider until the next regulatory period. At the next control period, the RAB will be adjusted accordingly and earn a rate of return for the remainder of the asset's life. This approach may distort the incentives to seek capital efficiency in the later years of the control period.

A second option is to roll forward prudent Capex only up to the forecast level identified at the previous price control. This would mean that any overspend would be borne by the service provider for the entire life of the asset. However, any efficiency gains over and above the expected level assumed at the previous control period would be kept by the service provider for the duration of the control period. This approach is likely to deter a service provider from investing in unforeseen capital needs and this can ultimately affect service delivery to customers.

A third option (a variant of the second) allows all efficient Capex to be rolled into the RAB, irrespective of the actual Capex allowed for in the current price determination. This approach eliminates the need to undertake a "prudence review" of actual Capex but the service provider bears the losses and retains the benefits from over and under investment for the duration of the asset's life. This approach also increases the risk for the service provider of unforeseen capital needs.

The final approach involves the introduction of a five-year rolling Capex, whereby the actual prudent Capex is rolled progressively into the RAB according to the year it was commissioned in the previous period. This approach ensures that the efficiency incentives are evenly spread in all years of the price control period. Regardless of which years the service provider underspend or overspend on its Capex, the benefits and losses will be borne by the service provider for five years.

The RIC has considered alternative approaches to rolling actual Capex into the RAB and the implications for incentives, as well as the fact that it proposes to introduce a capital efficiency carryover mechanism. On balance, the RIC favours the first approach to the rolling forward of Capex into the RAB.

The RIC intends to continuously monitor capital expenditure during the regulatory control period. The RIC will publish details annually of T&TEC's actual capital expenditure against proposed capital expenditures. The RIC will identify failure to deliver major capital projects against the timelines proposed and seek explanations as to the reasons for such failures. The RIC will audit the asset management capability and conduct an audit of major capital expenditure as part of the regulatory audit programme.

ANNEX

T&TEC CAPEX NOT ALLOWED 2006-2010 ($Mn)

The following **table (Parts 1 & 2)** lists all the projects for which funding, in the amount of $2087.5 million, was requested by T&TEC but was not allowed by the RIC. In each case a reason is offered as to why these capital expenditures were not allowed for the first price control period.

Part 1 - Government Policy Driven Projects

Project	Purpose	Request Total	Proposed Total	Remarks
Street Lighting				
Street lighting – South bypass	Community	7.0	0	This project is not allowed since street lighting activities are funded by government.
Street lighting - Lady Young Rd & Priority bus route	Community service	4.0	0	- do -
Street lighting upgrades	Community	15.8	0	- do -
Street lighting, Roosevelt Hwy. and Priority bus route	Community	35.0	0	- do -
Street Lighting. Restore UG circuits. Hochoy Hwy.	Community	1.0	0	- do -
National Streetlighting programme		550	0	The funds have already been allocated by government.
Rural Electrification Programme	EU funded	14	0	Programme already funded by EU.
Streetlighting and electrification		120	0	This project is not allowed since government already funds street lighting activities.
Upgrade network and establish substations to supply ANSA-Terra, Nu-Iron and Methanol 5000		23.6	0	This project was not allowed since it will benefit only a target customer group.
Extend the 132kV system to the South and establish the Reform, Union Estate and Chatam 132kV substations.		591.6	0	- do -
Extend the transmission network to Wallerfield and Establish the Wallerfield 132KV substation and upgrade the Pinto Road 66Kv substation		110.6	0	This project was not allowed since it's a government initiative that would benefit only a target customer group.
Provide safe, more reliable and environment friendly transmission and distribution system		300.0	0	This project was not allowed because it was not justified.
Total Government Policy Driven Projects		**1772.0**	**0**	

Part 2 - T&TEC Specific Projects

Project	Purpose	Request Total	Proposed Total	Remarks
Transmission				
Establishment of New Gateway – Bamboo to POS	Reliability	162.1	0	The project will now be undertaken with funding from Government.
Total Transmission		**162.1**		
Distribution				
HV/LV line extensions	Growth	21.4	0	Project included and allowed elsewhere.
Upgrade Port of Spain 6.6kV underground network	Quality	40.0	0	Utility corridor and undergrounding activities are being driven by government and the costs of such activities could be shared among other service providers.
Undergrounding residential systems	Reliability	11.6	0	- do -
Underground switch- and fuse-gear	Reliability	9.9	0	- do -
Establish UG cable utility corridor	Reliability	1.0	0	- do -
Automatic meter reading - remote data acquisition	Efficiency upgrade	86.0	0	Consultant indicated that this project is not economically and financially sustainable at this time.
Total Distribution		**169.9**	**0.0**	
Information Technology				
Financial Software	Upgrade to Version 8.4	6.7	0	Project cost exaggerated.
Online Cash Receipt System	Efficiency improvement	3.0	0	Project already established.
Time Clocks for Payroll System	Replacing mechanical clocks	1.7	0	Project lacks proper justification at this time.
Software Licences		15.0	0	This is an Opex item rather than Capex.
Automatic Metering & Communication	Improve meter reading efficiency	11.0	0	Consultant indicated that this project is not economically and financially sustainable at this time.
Disaster Recovery (This is related to the Automatic Meter Reading Project)	Automated recovery plan	1.0	0	- do -
Computer Kiosks	Computer access to workers in field	0.6	0	Project lacks proper justification at this time.
Total IT		**39.0**	**0**	

Part 2 - T&TEC Specific Projects

Project	Purpose	Request Total	Proposed Total	Remarks
Communications				
Upgrade microwave equipment	Technology upgrade	31.0	0	This project was not adequately supported by proper documentation and justification.
Install fibreoptic cables – North; East; Central; South; & Tobago	Technology upgrade	12.4	0	- do -
South Trinidad Communications	Upgrade	1.0	0	- do -
Install Mobile Trunking radio	Technology upgrade	20.0	0	- do -
Install Voice Trunking radio	Technology upgrade	0.5	0	- do -
Total Communications		**68.5**	**0**	
Metering				
Automated Distribution	Quality Enhancement	33.8	0	Funding for this project will be provided by Government.
Test van	Mobile test laboratory	2.0	0	Project not justified.
Automatic meter reading – Industrial	Productivity	5.5	0	There is a need for this project to be better researched.
Automatic meter reading – Commercial	Productivity	25.0	0	- do-
Total Metering		**32.5**	**0**	
Commercial				
Electronic Bill Presentment and Payment (Scheme)		3.0	**0**	Project already established.
Total Commercial		**3.0**	**0**	
Admin. & General				
3-phased Backup Generator		2.0	0	Project accorded a low priority.
Total Admin. & General		**2.0**	**0**	
Total T&TEC Specific Projects		**314.9**	**0**	
Total of All Projects Not Allowed (Part 1 & 2)		**2283.4**	**0**	

CHAPTER 7

REGULATORY ASSET BASE AND COST OF CAPITAL

7.1 INTRODUCTION

One of the primary objectives of regulation is to ensure that the service provider is able to finance its operations. In fact, Section 6 (1) clearly sets out one of the functions of the RIC as to:

> "*ensure, as far as reasonably practicable, that the service provider operating under prudent and efficient management will be on terms that will allow the service provider to earn sufficient return to finance necessary investment*".

Shareholders and creditors will require a return on the capital which they invest. The cost of capital is the cost to the service provider of meeting the required return. The cost of capital is determined in the financial markets. The cost of capital (allowed return) when applied to the asset base should enable the service provider to meet its cost of debt financing and provide a return on investment.

Given the capital-intensive nature of transmission and distribution networks, capital related costs, return on capital and return of capital (depreciation), can form the largest component of the revenue requirement. The recovery of the annual costs of financing investments in long-term assets is achieved in two ways:

- the return of capital (depreciation) enables the recovery of the invested capital; and
- the return on the regulatory asset base enables the recovery of the costs related to the providers of equity and debt.

7.2 REGULATORY ASSET BASE

7.2.1 Introduction

To estimate both the return on capital and return of capital (depreciation) components, the RIC must first establish an opening value of the regulatory asset base (RAB), that is, the investment base (Rate Base) upon which a service provider is allowed to earn a fair return. Section 67 (3) mandates the RIC to have regard to, *inter alia*:

- annual depreciation; and
- return on the rate base.

In defining the rate base, the RIC Act states that the Rate Base means the sum value of:

(a) plant used and useful in providing a service;

(b) construction work-in-progress directly related to providing a service;

(c) an allowance for working capital to meet current expenses and contingencies; and

(d) average annual interest charged in respect of construction work in progress, less accumulated depreciation.

The Rate Base is the value on which the service provider can expect to earn a return (return on capital). The Rate Base is also the value that is returned to the asset owners over the economic life of the assets (depreciation). This value directly impacts on the tariffs consumers pay. Any under-valuation or over-valuation can lead to losses or undue surpluses for the service provider.

7.2.2 Qualifying Criteria for Assets

All the assets included in the rate base should be used in the transmission and distribution of electricity. All other assets should be excluded. The transmission and distribution sector is a capital intensive one. Thus, one would expect that property, transmission and distribution network substations, would be significant assets. However, the retail aspect of the service provider's business does not have a significant asset base.

The criteria for qualifying assets should be:

- Fixed assets must be long-term in nature and must be "used and useful". Other assets that are not in a "used and usable" form will, therefore, be excluded from the asset base.

- Used and useful means that assets should be in a condition that makes it possible to satisfy demand in the short-term.

7.2.3 Determining an Initial Regulatory Asset Base (RAB)

The task of setting an initial regulatory asset value for the assets employed by a service provider in providing services involves determining a notional cost associated with the existing assets for the purpose of reflecting this cost in prices that the business is allowed to charge. While a service provider may have asset values established for accounting purposes (i.e. written down book values), these asset values are not necessarily the appropriate basis for the valuation of assets for regulatory purposes.

The regulatory asset values are initially set with regard to a range of considerations, and then changed over time in a manner consistent with ensuring that prices reflect an opportunity for the service provider to recover a return on initial RAB and subsequent capital expenditure. Capital expenditure undertaken after the initial valuation is either at cost, or at a deemed efficient cost.

There is, however, no one particular method for determining what the RAB should be when first considering the setting of tariffs. Economic theory suggests that the RAB should lie between the value of the assets in their "next best use", which could be very low for assets involved in the transmission and distribution of electricity, and the value that reflects the cost structure of a hypothetically efficient new entrant, which could be very high. An additional guide is that the RAB should be at least a value that is consistent with the service provider remaining in a financially viable position that generates sufficient revenue to be able to finance current operations and investment in growth.

Asset valuation often becomes one of the most difficult and controversial aspects of price setting. The numerous, conceptually consistent methods for valuing assets which are available, and are widely used in differing circumstances, can produce widely diverging results. It may often be preferable to confine oneself to using a single, if somewhat imperfect methodology, than to be continuously adjusting the method over time because changes may have significant price impacts and would contribute to regulatory uncertainty.

7.2.4 Asset Valuation Methodologies

The range of asset valuation methodologies commonly applied are generally grouped into two categories: **revenue-based** and **cost-based**. The most commonly used methodologies are:

- Historical Cost (variations include original cost);
- Replacement Cost (variations include inflation-indexed);
- Optimised Deprival Valuation; and
- Depreciated Optimised Replacement Cost.

Historical Cost

An historical cost value generally refers to a value derived as the actual cost of assets less depreciation and is often referred to as a depreciated actual cost (DAC). Different methodological approaches may be taken to determine a DAC value. Original cost less depreciation is the easiest measure to understand and the most widely used internationally. This method of valuation is generally viewed as being fair because the utility earns a return on the capital it spent on purchasing the asset. The method is simple and easy to administer because most of the required information can be found in the accounting books of the utility.

The main drawback of this method is that the price signals to consumers may be distorted. This is caused by a difference between the original depreciated book value and the economic value of the asset. This method understates the value of assets during periods of high inflation and overstates the value during periods of significant technological advancements. Three options on valuation can be adopted:

- retaining valuation at historic cost. This approach is in the consumers' best interest in terms of prices, but problems could arise if the valuation and the cash flows implied from this are insufficient;
- retaining historic cost valuation of the current asset base, but to incentivise new investments by indexing them into the future to protect their value

against inflation. This will result in prices increasing to consumers in real terms; and

- starting from the historical cost valuation, but indexing both this value and future investment. This would increase prices still further.

Replacement/Current Cost Valuation

Current/replacement cost is determined by finding current market prices for assets, that is, the price one would pay in the current period for the same asset. A replacement cost valuation is usually conducted taking into account available current technologies, and also determining the cost that would be incurred in constructing new assets using modern technology to provide the same "service potential" as the existing assets. A valuation made in this way is commonly termed an "optimized replacement cost", and is most suited for industries where technological changes pose a serious concern.

A significant drawback of the replacement/current cost methodology is that it may not succeed in sending efficient price signals. The second drawback is that its practical implementation is very complex. Ideally, it requires a complete and accurate asset register and considerable effort by experts in the field of utility costs for proper value determination. The third drawback is that it might increase the regulatory risk, as the asset value is usually the result of negotiations between the utility and the regulators.

Optimal Deprival Valuation

A general definition of deprival value is the value of an asset to the owner considered in terms of the loss that would be incurred if deprived of the asset. It is the lesser of the net present value of the income to be generated by the asset or the depreciated optimised replacement (DORC) value of the asset. When defined in this way, it is also referred to as an optimised deprival value (ODV).

There are two common problems in determining ODV. First, for regulated infrastructure assets, the future prices of services provided by these assets will be regulated and determined from the RAB. There is an obvious circularity in the asset valuation at a deprival value and the dependence of the deprival value on prices that would be determined from the value. Second, it may be difficult to determine an economic value for a set of assets where there is no clearly identifiable revenue stream for those assets.

Some regulators have even used a more pragmatic approach to determining the initial RAB by first considering the level of revenue that would be appropriate for the entity, and then back-calculating the asset value given forecasts of Opex, depreciation and a rate of return.

As can be seen, each of the methodologies has advantages and disadvantages. The determination of an appropriate initial RAB is, therefore, of necessity a pragmatic decision, with the most appropriate valuation determined by consideration of the unique circumstances of the regulated business and the outcomes of the valuation.

Depreciated Optimised Replacement Cost (DORC)

The DORC is derived by the scaling down of an estimated optimized replacement cost of an asset to reflect the lower value of the existing (old) asset relative to a new asset. The DORC is a complex methodology and is determined by:

- taking the utility's assets and optimizing them from an engineering perspective;
- determining the replacement cost of these using the Modern Equivalent Asset (MEA) value; and
- depreciating the assets based on their age.

Although this methodology takes into account inflation and technological changes, it suffers from many drawbacks, as the level of complexity and data requirements are extremely high.

7.2.5 Conclusion on Regulatory Asset Base

In setting the initial RAB for the first regulatory control period, the RIC has to consider what is the most appropriate value to use for the investment in an asset that has not been undertaken within normal economic and business considerations.

Options available to the RIC are:

- to treat all the investment to date as sunk costs and thus, value it at zero because the investment has already been undertaken with direct funding support from Government. However, to treat the asset as having no value does not seem appropriate. Clearly, the assets have some value in the provision of service and need to be recognized in the setting of price controls;
- to adopt a depreciated historical value assessment of the asset base because it is simple to apply and is fair, since the service provider earns a return on the capital it spent in purchasing the asset; and
- to adopt some form of current cost replacement approach (including DORC, ODV, etc.) which reflect the "cost" that would be incurred by a new entrant seeking to establish electricity business.

While arguments can be made for the use of different methods of valuation, the RIC, under its Act, is restricted to using a value based on historical cost valuation for the first price control period. This will provide a degree of regulatory certainty for T&TEC going forward.

For the purpose of determining the opening asset valuation for the second regulatory control period, the RIC has two options:

- to roll forward the value determined based on historical cost valuation and include all prudent capital expenditure over the first regulatory period, and deduct the regulatory depreciation which would be returned to the service provider over the first control period; or
- to revalue the asset base using one of the main valuation methodologies before the start of the second regulatory control period. The potential triggers for a revaluation of the RAB are likely to include:
    - change of ownership of assets; and
    - major advances in technology.

Stakeholder Comments and Final Decision

In a written response to the Draft Determination, one respondent expressed concern about the accuracy of the RAB and its impact on revenue requirement. The RIC has discussed this issue in great detail and is satisfied that the Fixed Asset Register of T&TEC provides an accurate account of T&TEC's fixed assets in use. As such, the Fixed Asset Register provided by T&TEC will be used by the RIC to determine the initial value of the RAB.

In setting the initial regulatory asset base for the first regulatory control period, the RIC's decision is to use a value based on historical cost valuation.

7.3 WORKING CAPITAL

The rate base, as defined in the RIC Act, also includes an allowance for working capital. A working capital requirement arises from the cash flow timing differences in respect of operating costs where cash operating payments may be required to be made before cash receipts are recovered.

The issue for the RIC is the need for T&TEC to be compensated for such cash flow differences. Working capital represents only a minor element of the total revenue requirement for T&TEC. While there is no standard approach to the issue of working capital, many regulators continue to provide for working capital. They argue that working capital is universally accepted as a necessary and efficient cost incurred by businesses as part of their ordinary activities. It is analogous to a return on capital invested and is calculated based on a simplified payment cycle, making assumptions about the timing of cash flows. However, there are other regulators who hold the view that the calculation of revenue forecasts under the building-block approach tends to overstate the cost of financing capital expenditure since the implicit assumption under this approach is that revenues are received at the end of the year rather than at regular intervals throughout the year.

The RIC accepts that there may be cash flow timing differences in respect of operating cash since cash operating payments may be required to be made before cash income is received thus creating a working capital requirement. However, the RIC is of the view that any allowance for working capital must be considered from a holistic perspective and that the timing of all the forecast cash flow needs to be considered.

However, given the conditions imposed by the RIC Act, the RIC proposes to make an allowance for working capital only for the first regulatory control period. The allowance is being made on the assumption that it takes 57 days[8] between the supply of electricity and the receipt of payment by T&TEC and that T&TEC has 30 days in which to pay, after receipt of goods and services of an operational nature. Total annual revenue from electricity sales is, thus, factored down by 57/365 and annual operating costs are similarly factored down by 30/365. The calculated working capital is added to the asset base.

> The RIC's decision is to determine working capital for the first price control period as follows:
>
> $$\textbf{Working Capital} = \textbf{Total Revenue from Sales} \times \frac{\textbf{57}}{\textbf{365}}$$
>
> $$\textbf{Less: Operating Costs} \times \frac{\textbf{30}}{\textbf{365}}$$

7.4 CONSTRUCTION WORK IN PROGRESS

Construction work in progress (CWIP) and average annual interest charged in respect of CWIP are two other components of the rate base. CWIP represents the assets that are partly constructed but not yet placed in service. On the completion of these works, the relevant amount can be transferred into the RAB. However, there are two options for treating the time at which assets are reflected in the RAB:

- at the time the service provider incurs expenditure on the asset; and
- at the time when the asset enters into service.

[8] 57 days is a weighted average. Rates A and B are billed bi-monthly while industrial customers are billed monthly by T&TEC and customers are given about 15 days to pay.

The first option would imply including CWIP but the second would exclude this. However, the financing costs (interest) incurred prior to the asset being entered into service need to be provided for with respect to the second option. These two options should have an identical financial effect on the entity. As indicated earlier, most regulators include capital investments in the RAB when the asset comes into service, thereby ensuring that customers do not pay for incomplete projects.

The RIC has decided that interest during construction should apply only to those projects that span several years and CWIP will not be allocated across asset categories during the roll forward but will remain as a financial entry only.

7.5 CONTRIBUTED ASSETS

In certain circumstances, T&TEC receives capital contributions as part of its customer connection arrangements. It also receives 'service deposits' from customers. Since such capital is cost-free to T&TEC, then it is reasonable that it should not earn a return on the components of the rate base that this capital supports. However, these assets need to be recognized as part of the service provider's asset base, as the responsibility for management of these assets remains with the service provider.

The RIC's decision is to allow contributed assets to be incorporated into the RAB and to recognise contributions in the year of receipt as a revenue flow.

7.6 REGULATORY DEPRECIATION

As depreciation is one of the components of the forward-looking revenue requirements under the building-block approach, it provides a source of cash flow to the service provider. Therefore, the allowance made for depreciation effectively determines the amount of capital investment that will be returned to the service provider. The determination of the depreciation to be incorporated in the revenue requirement depends on the opening value of the RAB and on the rate at which invested capital is returned. Therefore, the application of depreciation policy must give confidence to service providers that depreciation charges will be sufficient to cover return of capital. As depreciation can account for a significant proportion of the total costs and hence of prices customers pay for electricity, the RIC will pay close attention to the opening value of the RAB and the rate of depreciation.

The central issue is the pattern of recovery and period over which the invested capital should be returned to the service provider. In its Consultation Document, "**Approaches to Determining Regulatory Depreciation Allowances (May 2005)**", the RIC dealt with these and other issues in detail and had indicated its initial thinking on some of the issues.

Depreciation charge for T&TEC has been assessed on the basis of the fixed assets register, provided by T&TEC. The class of assets and the specific depreciation rates used are shown in **Table 7.1** below. A comparison of these asset lives with international norms suggests that the asset lives of most assets of T&TEC are close to the international levels. For comparison and benchmarking purposes, many regulators often assess depreciation on the basis of weighted average depreciation rates. The weighted average depreciation rate of 5.27% for transmission assets and 7.84% for distribution assets is generally used. Using these benchmark data, the depreciation charge computed for T&TEC was well within targets.

Table 7.1 - Class of Assets and Depreciation Rates
Average Depreciation Rate Comparison for T&TEC and Jamaica

Class of Assets	Depreciation Rate (%)		Standard Useful Life (Years)	
	T&TEC	Jamaica	T&TEC	Jamaica
Land - Leasehold	2.0	2.0	50	50
Buildings	3.33	2.0	30	50
Generating Assets:				
- Steam Production Plant	-	4.0	-	25
- Hydraulic Production Plant	-	2.86	-	35
- Diesel Generators	5.0	4.0	20	25
- Gas Turbine	-	4.17	-	24
Transmission Assets:		**4**		**25**
- Control gear/Switchgear	4.0		25	
- Transformers	4.0		25	
Distribution Assets:				
- Overhead Mains	3.33	3.33	30	30
- Underground Mains	2.5	3.33	40	30
- Submarine Cables	6.67	-	15	-
- Meters	6.67	3.33	15	30
Other:				
- Street lights	5.0	3.33	20	30
- Test Equipment	6.67	4.0	15	25
- Supervisory Control System	4.0	4.0	25	25
- Electronic Equipment	10.0	4.0	10	25
- Communication Equipment	20.0	6.65	5	15
- Computer Equipment	16.67	5.0	6	20
- Furniture & Office Equipment	10.0	5	10	20
- Automobiles	25.0	14.3	4	7

Source: T&TEC and JPS Limited, Jamaica

The depreciation profile only affects the timing of cash flows, rather than their present value. Therefore, if the rate of depreciation were to be increased, revenue and prices would be higher in the short-term, but would be lower than otherwise in the future. As the rate of regulatory depreciation only affects the timing of the cash flows – and the value of those cash flows – the RIC will provide T&TEC with a degree of flexibility in this review and the RIC does not intend to standardize depreciation profiles and economic life for particular asset classes.

Stakeholder Comments and Final Decision

In general, submissions to the RIC's Consultation Document, "**Approaches to Determining Regulatory Depreciation Allowances (May 2005)**", supported the RIC's approach to the use of the straight-line method, computed on the historic cost of assets. There was also support for determining depreciation rates and asset life in accordance with international standards for comparable/similar assets subject to similar usage and other conditions.

The discussion of alternative depreciation profiles highlights the need for flexibility, as there is no single depreciation method, which is always the most appropriate. Having considered the advantages and disadvantages of different methods, the RIC has decided to use the straight-line method computed upon the historic cost of assets for the first price control period.

For the purpose of first regulatory control period, the RIC's decision is to approve the depreciation profile (based on historical cost on a straight-line basis) and the effective asset life proposal of T&TEC as these lives generally reflected current experience in the utility industry.

7.7 DETERMINATION OF THE RATE BASE

The RIC's allowed initial regulatory asset base, consistent with its Act, is presented in **Table 7.2** below.

Table 7.2 – RIC's Allowed Asset Base for Test Year (2004)

ITEMS	T&TEC Requested ($'000)	RIC Allowed ($'000)
Original Cost of Fixed Assets	1,869,570	1,869,570
Working Capital	105,117	*
Capital Work in Progress	96,114	*
Less: Accumulated Depreciation	593,279	593,279
Net Regulatory Asset Base (RAB)	**1,447,522**	**1,276,291**

* The RIC has allowed return on working capital and interest for CWIP separately in the calculation of revenue requirement.

7.8 ROLLING FORWARD OF ASSET BASE

Having set the opening asset value, the RIC is required to determine how this base will be rolled forward over the regulatory control period. In contrast to the setting of an initial RAB, economic theory provides sufficient guidance for the revaluation of assets over time. That guidance is that the method of revaluation must provide investors with expectations of making a reasonable return on new investment and the return of that capital over time. That is, the revaluation method must be consistent with providing incentives for investment. This is considered to be best achieved by a "roll-forward" methodology, whereby the RAB is updated between price control periods by adjustment for new Capex, depreciation, asset disposals and the rate of indexation required to maintain the real value of the asset base. That is:

Opening RAB + Forecast Inflation + Forecast Capex - Forecast Depreciation - Asset Disposals

Although for the larger projects explicit allowance can be made for changes to the asset base, the expenditure during the roll-forward period is not allocated to specific asset categories so that there is no update of the asset count. The RIC's rolled-forward RAB is shown in **Table 7.3**.

Table 7.3 – RIC's Determined Rolled Forward RAB, 2006-2010 ($'000)

	2006	2007	2008	2009	2010
Opening Value	1,276,291	1,352,230	1,460,549	1,533,651	1,566,345
Capex Additions	153,200	191,400	169,400	137,800	148,200
Less: Depreciation	76,892	82,757	95,687	104,364	113,853
Less: Disposals	369	324	611	742	238
Closing Value	1,352,230	1,460,549	1,533,651	1,566,345	1,600,454

The RIC's decision is to establish the opening regulatory asset base for the 2006-2010 regulatory period by rolling the regulatory asset base at December 2004 on the basis of the forecast capital expenditure proposed by the RIC.

7.9 COST OF CAPITAL

7.9.1 Introduction

Price cap regulation involves setting maximum prices at levels judged sufficient by the regulator to enable an "economic and efficient" regulated business to earn the allowed cost of capital. The price control mechanism in effect sets future cash flows of an "economic and efficient" regulated business such that it can expect to earn the allowed cost of capital on the RAB. Given the capital-intensive nature of the sector, changes in the cost of capital can have a significant effect on the allowed revenue. The allowed return when applied to the service provider's RAB should enable the service provider to meet its cost of capital and therefore finance its operations. The cost of capital is, therefore, a very significant element in the determination of price controls as it is applied not only to marginal investment, but to the entire RAB. The cost of capital is not intended to provide a floor on return. Actual returns could potentially fall (or increase) as a result of under or outperformance of assumptions underpinning the revenue requirements.

The estimation of the cost of capital is not a mechanical process, in part because it concerns market perceptions about the future and full information is generally not known about the investor's expected return and the current and expected market conditions. Although modern finance theory provides useful tools, there are many judgments and assumptions to be made. Nonetheless, the regulator has a duty to set an appropriate rate of return that allows an efficient utility to properly finance its functions. Therefore, the RIC considered a range of issues critical to the determination of the cost of capital, among them being:

- the method for determining the cost of capital;
- the relevant input values; and
- the appropriate level of gearing.

7.9.2 Weighted Average Cost of Capital

The RIC's objective was to ensure that it set a rate of return for T&TEC so that it can finance its efficient operations. The Weighted Average Cost of Capital (WACC) method is the most commonly used technique for determining the allowed return, and most regulators use it in the electricity sector for tariff setting. The formula for assessing the WACC is shown below.

$$\mathbf{WACC = [(K_d \times D) + (K_e (1- D)]}$$

Where:

K_d = cost of debt

D = debt

K_e = cost of equity

In order to calculate WACC, the regulator has to decide on an appropriate rate of return for both debt and equity and assign an appropriate market value to the debt and equity. The calculation is further complicated by both taxation (if any) and inflation.

Capital Structure

The first issue the regulator has to determine is an appropriate capital structure (debt/equity ratio) in order to set an allowed weighted average cost of capital. There is no consensus on the optimum mix of debt and equity. In a monopoly situation, where the regulator has a duty to ensure that the service provider can finance its activities, high levels of gearing (debt/equity) may be considered "efficient" in terms of capital structure. In setting a price control, the regulator must assess what an efficient policy is rather than the actual policy that the service provider has adopted. This argument also applies to the level of gearing. Many regulators consider 60% to 70% to be the range for efficient gearing (debt/equity).

There are two ways that the RIC can deal with the gearing issue. One is for the RIC to identify an optimal ratio and establish the cost of capital on that deemed combination of debt and equity. The other is to use T&TEC's current gearing level to compute the WACC. In 2003, T&TEC's accounts showed that 56% of its capital was financed by debt and 44% by equity[9].

[9] There are two ways that a regulator can measure the level of debt and equity:

- By using the market value of debt and equity; and
- By using the RAB as a proxy for the market value of the service provider. The difference between the RAB and the level of debt issued by the service provider is, therefore, the level of equity.

Cost of Debt

There are a number of ways to approach the recovery of interest costs. One obvious option is to use T&TEC's actual cost of long-term debt. With this option, the calculation of the risk free rate and risk premium etc., are avoided. The major drawbacks are that it is a backward-looking assessment of the rates at which the service provider has been able to borrow money and the past may not be a good guide to the future. It is also likely to blunt incentives for T&TEC to source and manage its capital as efficiently as possible. Another option is to use long-term Government bonds as a proxy for the cost of debt. Finally, a third option is to use the incremental cost of new debt financing where the risk-free rate plus T&TEC's risk premium etc., need to be calculated.

Based on audited accounts for the year ending December 31, 2003, the cost of T&TEC's embedded debt was calculated to be 11.87% (**Table 7.4**)

Table 7.4 - T&TEC's Long-Term Debt Obligations as at December 31, 2003

Source	Amount ($'000)
Debt Capital	**1,190,310**
12.25% Fixed Rate Bonds (2021)	693,680
Floating Rate Bonds (2011)	93,073
8.75% Fixed Rate Loan (2009)	403,557

The high cost of T&TEC's embedded debt is mainly due to a $500 million bond issue, which was raised in 2001, at an interest rate of 12.25%. The terms and conditions of this debt allowed for a moratorium on interest and principal for a period of three years, giving an effective interest rate of 12.31% (2005) over the remaining tenor of the bond. Further, in respect of refinancing, the relative loan agreement states:

> "*the issuer shall not be entitled at any time prior to the maturity date to prepay the amount due under the Bond*".

Cost of Equity

The cost of equity is the return sought by investors to compensate them for the variability of their bottom line profits. It includes both business risk arising from the variability of operating cash flows and the financial risk from the variability of residual cash flows after servicing interest payments. The cost of equity cannot easily be observed in the market. Regulators, therefore, use several methods to estimate an appropriate cost of equity, among them are the following:

- the Capital Asset Pricing Model (CAPM);
- the Dividend Growth Model;
- the Price/Earning Ratio; and
- the Arbitrage Pricing Theory.

Except in the case of CAPM, the other methods require information on the firm's share price or its dividend beforehand. Therefore, their application is not possible in the case of T&TEC as it has no such information. Also, because most of them rely on input variables for which independently collated data do not exist over a sufficiently long period, they are likely to prove impractical and of dubious robustness. The CAPM is the only likely candidate as it uses the risk-free rate, the market risk premium and the beta of the stock to estimate the return on equity. Even here, all the values cannot be calculated with certainty but have to be estimated using historical returns or comparative data from other utilities. In functional form, the method is defined as follows:

$$R_e = R_f + B_e \text{ x } (R_m - R_f)$$

Where:

R_e = return on the equity of the firm

R_f = risk-free rate

B_e = is a measure of the correlation between an asset's risk and that of the overall market

R_m = rate of return

In effect, the CAPM formula says that the return on equity for a particular business is the difference between the market return and the risk-free rate. The margin (and hence the B_e) reflects how risky the business is, compared with the rest of the market.

The Risk-Free Rate

Consensus exists among regulators for the use of average yields on the long-term government bonds as a proxy for the risk-free rate. However, there is a wide spectrum of differences as to whether it should be average yield over a year or over a five-year period to smooth fluctuations that occur over shorter periods.

Expected Market Return

The market risk premium is what the investors expect to earn over and above the risk free rate of return. One of the criticisms leveled against the CAPM is the difficulty of measuring the market portfolio and for this reason the market generally uses the all-share index quoted on its Securities Exchange as a proxy for calculating the expected market return.

The Beta Coefficient

Beta is calculated as a measure of the entity's risk profile (uncertainty) in comparison to the market as a whole. Beta measures the risk that cannot be diversified even in a well-balanced or diversified portfolio. A beta of 1 means that the entity's risk is the same as the market risk. A beta of 0.7 means that the entity is 30% less risky than the market as a whole. Regulated entities are inherently less risky than non-regulated, as their returns are set by regulators and their prices paid for by their captive customers. Generally accepted betas in the electricity T&D sector range between 0.3 and 0.4.

Return on Turnover

Given the estimation issues discussed above, some regulators tend to use a return on turnover rather than a return on a regulatory value based on assets. This approach has been used by the U.K. regulator, Ofgem, for gas supply activities and the electricity retail supply business. Ofgem has used 1.5% return on turnover in both cases.

One advantage of this approach is that as the return is directly related to turnover, it might provide an incentive to grow volumes in an innovative way. It is also relatively transparent. However, a return on turnover may suffer from the drawback that it is not directly related to capital invested and may be seen as subjective. There may also be an issue if this approach provides an incentive to overestimate future costs to achieve higher allowed revenues, since Opex and Capex would receive a rate of return.

Experience from several countries reveal that the cost of capital has been determined using WACC and CAPM, which evaluate the cost of capital based on market/stock market performance. Although it may seem feasible to estimate a WACC for T&TEC, issues arise because T&TEC does not have debt or equity that is publicly traded. The RIC is, therefore, unable to establish a market-based measure of equity or debt for T&TEC in the same way that one would for a private utility. Consequently, the RIC has to consider a range of factors, including determinations made by other regulators. The tendency in many countries in recent years has been for a cost of capital of between 6% to 8% as the basis on which price controls were set (**Table 7.5**).

Table 7.5 - Comparative Cost of Capital Calculations

Regulator	Ofgem UK 1999	Ofwat UK 1999	Ofreg N. Ireland 2001	Competition Commission UK 1996	Jamaica 2004
Basis of Estimation	Real pre-tax	Real post-tax	Real pre-tax	Real pre-tax	Real post-tax
Risk-free rate (%)	2.25-2.75	2.5-3.0	2.5-3.25	3.5-3.8	-
Equity risk premium (%)	3.25-3.75	3.0-4.0	3.25-4.0	4.0-5.0	-
Equity beta	1.0	0.7-0.8	0.7	0.7-0.9	0.87
Debt premium	1.85-1.7	1.5-2.0	1.01-1.41	0.3-0.8	-
Gearing	Optimal 50%	Optimal 50%	73% - 90%	Estimated 30%	Actual 44%
WACC	6.0-6.9	4.6-6.2	3.84-6.65	6.4-8.3	12%

7.9.3 Possible Approaches for T&TEC

An issue that arises in applying WACC/CAPM to T&TEC is whether to use an estimate of its true WACC (i.e. as a Government-owned entity) or to use a private sector surrogate. The standard practice amongst many regulators is to adopt benchmark assumptions about financing arrangements, rather than to use the entity's actual position. This allows regulated businesses to benefit from innovation (and more efficient) financing decisions, while protecting customers against any inefficient financing decisions. It also improves the comparability across the utilities/sectors. Similarly, the practice is to adopt a benchmark for the cost of debt rather than the entity's actual costs. The benchmark cost of debt, it is argued, should reflect the latest market evidence available on the borrowing costs of an efficiently financed business.

However, this raises the question of embedded debt cost which may exceed prevailing market rates. For instance, T&TEC's embedded cost of debt is about 11.87% as compared to existing market rates of 6.35% to 6.5% for government guaranteed debt (**Table 7.6**). Maintaining high cost debt that is actually higher than the prevailing market rates would result in customers paying prices over time that are inefficiently high. This would be inconsistent with the RIC Act which requires that prices reflect efficient costs. It may also reduce the incentives for an entity to efficiently manage its debt portfolio.

Table 7.6 – T&TEC's Embedded Debt Profile, 2005-2009 ($'000)

		2005	2006	2007	2008	2009
8.75 Fixed Rate Loan - 2009 Initial Amount $400 Mn	Principal	75,278	112,917	112,917	112,917	37,639
	Interest	25,601	32,934	23,054	13,174	3,293
	Sub-Total	100,879	145,851	135,971	126,091	40,932
12.25% Fixed Rate Bonds – 2011	Principal	43,304	43,304	43,304	43,304	43,304
	Interest	87,528	82,223	76,919	71,614	66,309
	Sub-Total	130,832	125,527	120,223	114,918	109,613
Floating Bond Rate – 2011 (amount $93 Mn)	Principal	14,257	13,122	11,987	11,590	11,152
	Interest	6,961	5,642	4,481	3,372	2,321
	Sub-Total	21,218	18,764	16,468	14,962	13,473
Grand Total		**252,929**	**290,142**	**272,662**	**255,971**	**164,018**

Accordingly, the RIC considers that the combination of a forward-looking cost of capital and an allowance for embedded fixed rate debt provides a more reasonable approach. Therefore, in order to take account of the higher cost of embedded debt faced by T&TEC, the RIC has included an allowance to reflect T&TEC's embedded fixed rated debt. A cost of capital of 8% for new investment has been assumed[10] and an embedded debt allowance for the years 2006 – 2010 would be included as a separate line item in the revenue requirement calculations. This proposed approach will address the historic legacy of debt and, at the same time, would be broadly neutral with respect to incentives.

This brings to the fore another important issue which has been of concern to regulators, and it is whether consumers should be required to provide a state-owned utility with a return on equity financing. Since T&TEC is not required to earn a return to compensate the investor for undertaking risk by investing in it, the cost of capital to T&TEC should be limited to only the cost of debt. Furthermore, as was indicated above, it is generally felt among regulators that return on capital should be a current or forward-looking concept and not merely based on historical experience.

The RIC's overall objective in setting an appropriate rate of return for T&TEC would be to allow a return that is sufficient for T&TEC to fund its activities in a sustainable way and that at the same time, is only just high enough to cover the costs of the benefits provided to customers.

Given the above issues, the RIC confirms the view it expressed in the Draft Determination that T&TEC should refinance its existing debt, such that the resultant debt service payments reflect current market rates. The RIC strongly believes that imprudent interest costs should not be passed to consumers.

Stakeholder Comments and Final Decision

T&TEC, in response to the Draft Determination, has indicated that its debt to NGC has been growing at a monthly rate of approximately $43.5 million since September 2005 and that its liability to NGC as at April 30, 2006 was $389.2 million.

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[10] This is based on three considerations. First, the shareholder (Government) has indicated its unwillingness to provide government guarantee for T&TEC. Second, T&TEC has indicated that its bankers would be willing to lend at 2% to 2.5% below the prime rate without a government guarantee. The prime rate as at December 2005 stood at 9.75% and projected to increase in the future. However, the weighted average lending rate of commercial banks was approximately 8.76% as at December 2005.

T&TEC's current severe financial difficulties are the result of inadequate surpluses from operations. Cash problems have been building-up over time and should not be expected to disappear within a year or two. In fact, the difficulties now being experienced by T&TEC are the result of successive governments' approach to tariffs. Consumers must pay a fair price for the service but should not be asked to directly contribute to bad decisions of governments or the management. The RIC believes, therefore, that the accumulated debt to the NGC since September 2005, should be assumed by the Government. In fact, the shareholder (Government) has agreed to give consideration to the provision of funds to assist T&TEC in servicing its debt obligation in the sum of $283 million.

The RIC's decision is not to include a return to the shareholder (Government).

T&TEC should initiate debt restructuring immediately with a view to negotiating lower interest rates.

The RIC's decision is that for the purposes of calculating the building-block allowance for the return on capital, a cost of capital of 8% will be applied for the first regulatory control period.

CHAPTER 8

EFFICIENCY CARRYOVER

8.1 INTRODUCTION

One of the key elements of incentive based/price cap regulation is the incentive for the service provider to achieve on-going efficiency improvements. One way to encourage on-going efficiency improvements is to permit the service provider to retain some share of gains achieved for a fixed period of time.

In its Consultation Document, "**Sharing of Benefits of Efficiency Gains and Efficiency Carryover Mechanisms (June 2005)**", the RIC indicated its intention to introduce some mechanism to provide service providers with a continuous incentive to achieve efficiency gains. By indicating its intention before the implementation of the price control, it will provide some certainty to the service provider in respect of any carryover of efficiencies from the first regulatory period to the next. Therefore, any mechanism introduced in the first regulatory period will only have practical implications in the next regulatory period.

The above-mentioned document also raised various questions and issues relating to the proposed structure of the efficiency carryover mechanism. The RIC had argued that under incentive regulation, the regulated entity has an incentive to improve its efficiency within a regulatory period, as allowed revenues/prices within the period are not linked directly to actual costs of the entity. In the absence of an efficiency carryover mechanism, the entity has a stronger incentive to achieve efficiencies in the earlier part of the control period than it does in the latter part of the control period. The benefits achieved towards the end of the control period would be kept only for a shorter period if the regulator sought to pass these benefits to consumers, through lower prices, at the next price control period. Therefore, the service provider is likely to delay making efficiency gains in the later years of the price control period.

The efficiency carryover mechanism removes this timing incentive by allowing the service provider to keep any efficiencies for a specified period of time, regardless of when those efficiencies are generated.

This chapter specifies the design of the efficiency carryover mechanism that the RIC intends to introduce for the first regulatory control period. The RIC wishes to state categorically that a reduction in costs is not an efficiency improvement if it is achieved by not delivering the outputs, by delivering them late or at the expense of a deterioration in service to customers.

8.2 DESIGN OF THE EFFICIENCY CARRYOVER MECHANISM

In order to provide a clear and stable regulatory framework within which T&TEC can make future expenditure decisions, the RIC sets out in detail the efficiency carryover mechanism it intends to apply in relation to efficiency gains (or losses) made in the coming regulatory period. This includes both a description of how gains and losses will be assessed in practice and how these gains (or losses) will then be carried forward.

8.2.1 Management Induced Versus External Efficiency Gains

The efficiency gains (savings) could arise as a result of specific management initiatives or as a result of factors external to the firm. Therefore, it is possible to treat efficiency savings achieved by management differently from those achieved due to exogenous factors.

In practice this is likely to be difficult. Additionally, the costs of information gathering and analysis may outweigh the benefits of sophisticated analysis. Indeed, attempts to distinguish between different gains could be viewed as intrusive and high-handed, as well as complex and damaging to incentives. Therefore, the RIC will not differentiate between management induced and external efficiencies.

However, the RIC is inclined to apply the following rules of thumb:

- **Variations in revenue as a result of variation in demand forecasts** - Gains arising therefrom may be considered to be windfall gains (or losses) and may be taken into account when the carryover mechanism is calculated in the next regulatory period.
- **With respect to variations in costs arising from substantial changes (above or below forecasted levels) in the cost of fuel or conversion costs** - Gains arising therefrom may be considered to be windfall gains (or losses) and may be taken into account when the carryover mechanism is calculated in the next regulatory period.

Additionally, the RIC maintains its position not to use an in-built adjustment mechanism to adjust prior year forecasts to take into account differences in demand or scope of obligations.

8.2.2 Length of Retention Period

In the RIC's June 2005 consultation document, it was proposed that efficiency gains from underspending capital or operating expenditure should be retained for five years from the year in which the gains were made, regardless of when the gains were made, to ensure equal incentive to make gains in each year of the period.

The RIC is of the view that the rationale to support this proposal remains sound for the following reasons:

- a balance needs to be struck between incentives for out-performance and passing the benefits of such out-performance too quickly back to customers;
- the length of the retention period has implications for the sharing ratio;
- a five-year retention period will provide the appropriate and required balance of providing incentives to T&TEC to achieve efficiencies while at the same time passing benefits in a timely manner to customers; and
- a five-year period provides practical benefits, matching the five-year regulatory period.

8.2.3 Sharing Ratio

Under the efficiency carryover mechanism, the benefits are shared between customers and the service provider over different periods of time. Service providers derive benefits over the specified period set by the regulator. Customers, on the other hand, derive benefits in the form of lower prices. There is no single ‘right’ answer to the question of the optimal sharing ratio. A 50:50 sharing of gains between customers and service providers can only be considered fair if one assumes a linear relationship i.e. incentives to make gains increase in proportion with the share of gains retained. Moreover, a 50:50 sharing of gains may mean that the service provider would keep gains for more than one regulatory period.

However, the sharing ratio essentially compares the present value of the benefits that flow to customers and service providers. Based on the assumption that service providers keep the benefits for five years and the customers for an infinite period in the form of lower prices, the implied sharing ratio of gains between service providers and customers is about 30:70.

8.2.4 Measuring Efficiency Gains

The RIC indicated in its consultation document that the efficiency carryover mechanism will apply to operating and maintenance expenditure and capital expenditure. As a general rule, an efficiency gain will be defined as the difference between the forecast expenditure established by the RIC for operating and maintenance expenditure (Opex) and capital expenditure (Capex) at the outset of the regulatory review period, and the actual capital and operating expenditure outcomes over the regulatory period. However, consistent with the practice in other regulatory jurisdictions, the RIC reserves the right to revise these expectations when the efficiency carryover mechanism is calculated through the process commonly referred to as “logging up or down” to reflect non-trivial changes in requirements or failures to deliver specified output on time (shortfalls).

8.2.5 Operating Expenditure Efficiency Carryover

The RIC will use the incremental approach, as explained in our consultation document when calculating efficiency gains or losses for operating expenditure. Under this approach, only the additional improvements in efficiency in a given year are captured, over and above the improvements that have been achieved through initiatives in previous years.

Therefore, the incremental approach will only reward efficiency savings made by the entity that are permanent savings. Any one-off savings achieved by the service provider may be treated as an efficiency gain in one year, but this would be offset by an efficiency loss in the following year since the savings would not be sustained. If the incremental approach was not adopted for operating and maintenance expenditure, the customers would not receive any part of the efficiency gains, as the service provider would keep the full value of any temporary underspend in perpetuity.

8.2.6 Capital Expenditure Efficiency Carryover

As indicated in the RIC's consultation document, the treatment of efficiency gain (loss) will be different for capital expenditure as compared to operating expenditure. This is due primarily to the project-based nature of such capital expenditure. Thus, capital gains efficiency will be computed by comparing actual expenditure to the forecasted level of expenditure for that year, multiplied by the regulatory weighted average cost of capital (WACC). In the consultation document, the RIC further noted that some regulators included a provision for depreciation in the calculation of the efficiency carryover amount based on a standard mix of asset lives. The RIC intends to apply an allowance for depreciation when calculating the carryover amount. The allowance for depreciation would then be calculated as follows:

- The difference in actual capital expenditure divided by a weighted average asset life (to be determined by the RIC). This gives the depreciation adjustment for one year. The annual adjustment is then multiplied by the number of years remaining until the end of the price setting period and then allowed in the final determination.

8.2.7 Symmetrical Treatment of Gains and Losses

In its consultation document, the RIC proposed that gains and losses should be treated symmetrically, so as to avoid perverse incentives. Efficiency losses cannot be disregarded from the calculation of an efficiency carryover mechanism since such losses could distort the incentive for T&TEC to achieve efficiency gains in each year of a regulatory period.

8.2.8 Treatment of Negative Carryover

Given the symmetrical treatment of gains and losses, there are two issues which need to be dealt with (although they are related):

- the treatment of negative carryover; and
- whether or not gains (losses) under capital and operating expenditure should be combined or treated separately.

First, the RIC does not intend to treat the efficiency carryover mechanism for operating and capital expenditure separately. That is, gains (losses) under operating and capital expenditure will be combined. Thus, a negative carryover in operating expenditure can be offset against gains in respect of capital expenditure and *vice versa*.

Second, a negative carryover in one year will be offset by a positive carryover from another year in the regulatory period. Where the negative carryover does not exceed the amount it is offsetting, it will not result in a reduction in the service provider's revenues below the revenue requirement determined for the regulatory period. Rather it means that the service provider does not receive as much additional revenue via the efficiency carryover amount. Consequently, there is no threat to the service provider's financial viability.

However, if the efficiency carryover amount results in a negative carryover overall for the full regulatory period, it will imply a reduction in the allowed revenue requirement. In such an instance, the RIC will apply a zero-floor mechanism, that is, the carryover will be set to zero. Any alternative action that could threaten the financial viability of the service provider becomes a relevant consideration.

8.2.9 Choice of Mechanism

There are two basic efficiency carryover mechanisms:

- **the Rolling Carryover Mechanism** – where efficiency gains (losses) are carried over for a specified number of years following the year in which they occurred.
- **the Glide Path Mechanism** - where gains (losses) are calculated by comparing actual expenditure achieved in the last year of the regulatory period with the forecast expenditure for that year. The forecasts of expenditure for the next regulatory period are based on the actual expenditure for the last year of the previous regulatory period. The gains achieved in the first regulatory period are then phased out over the subsequent period at a decreasing rate per year.

The RIC favours the arrangement whereby the efficiency gains from underspending on capital or operating expenditure should be retained for five years from the year in which the gains were made, regardless of when the gains were made. This would ensure an equal incentive to make gains in each year of the control period. This is achieved under the rolling carryover mechanism.

The glide path mechanism does not provide an equal incentive to make gains in each year of the control period as the gains made are glided out over the whole of the subsequent period.

The RIC will implement a rolling carryover mechanism.

8.2.10 Efficiency Gains in the Last Year of the Regulatory Period

Under incentive regulation, the price formula is reset periodically (usually every five years). However, at the time the formula is reset for the next control period, the actual expenditure for the final year of the current period is generally not known. The RIC intends to apply a pragmatic solution as follows:

- **Operating expenditure** – actual operating expenditure in the last year of the regulatory period (i.e. 2006-2010) will be assumed to be equal to expenditure in the previous year multiplied by the change in efficiency embodied in the original expenditure forecasts between those years.
- **Capital expenditure** – actual capital expenditure in the last year of the regulatory period (i.e. 2006-2010) will be assumed to be equal to the forecasted level.

8.2.11 Rolling or Smoothed Adjustments

Under the fixed term or rolling carryover mechanism prices are unlikely to follow a smooth path. The RIC, therefore, reserves the right to "smooth" the path of prices. The calculation to achieve this is straightforward and can be based on calculating the smooth stream of payments that has the same present value as the sequence of rolling payments.

An illustration of how the efficiency carryover mechanism will work in practice is presented in **Table 8.1** below.

Table 8.1 – Efficiency Carryover Mechanism – An Illustration

Operating and Maintenance Expenditure	**$**									
YEAR	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Benchmark Forecast for Operating Expenditure and Maintenance (Initial regulatory assumption)	100	100	100	100	100					
Logging up or down (Adjustments to reflect non-trivial changes in requirements)	-	-	-	-	-					
Shortfalls (Failures to deliver specified outputs on time)	-	-	-	-	-					
Actual Expenditure	80	80	70	80	80					
Less atypical and exceptional costs	-	-	-	-	-					
Under-spend (Over-spend)	20	20	30	20	20					
Incremental Efficiency Gain (loss)	20	0	10	-10	0					
Efficiency Carryover										
-Year 1	-	20	20	20	20	20				
-Year 2	-	-	0	0	0	0	0			
-Year 3	-	-	-	10	10	10	10	10		
-Year 4	-	-	-	-	-10	-10	-10	-10	-10	
-Year 5	-	-	-	-	-	0	0	0	0	0
O&M Efficiency Carry-over to be added to Target Revenue						**20**	**0**	**0**	**-10**	**0**

Capital Expenditure	**$**									
YEAR	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Benchmark Forecast for Capital Expenditure	200	200	200	200	200					
Revised Regulatory Expectation	-	-	-	-	-					
Actual Expenditure	180	200	200	200	200					
Depreciation Adjustment										
Under-spend (Over-spend)	20	0	0	0	0					
Incremental Efficiency Gain (loss) **(Assuming a WACC of 10% for simplicity)**	**2**	**0**	**0**	**0**	**0**					
Efficiency Carryover										
-Year 1	**-**	**2**	**2**	**2**	**2**	**2**				
-Year 2	-	-	0	0	0	0	0			
-Year 3	-	-	-	0	0	0	0	0		
-Year 4	-	-	-	-	0	0	0	0	0	
-Year 5	-	-	-	-	-	0	0	0	0	0
Capex Efficiency Carryover to be added to Target Revenue	**2**	**2**	**2**	**2**	**2**	**2**	**0**	**0**	**0**	**0**
Annual Efficiency Carryover to be added to Target						**22**	**0**	**0**	**-10**	**0**
Net Overall Efficiency Carryover amount to be added to Target Revenue						**12**				

8.3 SHARING OF BENEFITS

In its consultation document, the RIC had discussed, in detail, two broad options for sharing the benefits of out-performance of the X-factor with customers as follows:

- One-off Reductions (P_o Adjustment) – where gains in excess of those stipulated by the X-factor in the current period are passed directly on to customers in the development of new price controls.
- Phased Option – here gains are passed to customers over a period of years. This approach is referred to as a glide path. A variation of this approach is 'gains maintenance'.

The RIC has decided to utilize a P_o Adjustment to share out-performance. However, the RIC did not rule out the possibility of utilizing a combination of P_o Adjustment and a phased adjustment if it was necessary to limit the rate of change in prices to consumers or to consider the cash flow impact on the service provider. In fact, the one-off reduction (P_o Adjustment) drew favourable support from all those who commented on the consultation document. While the RIC is of the view that consumers should share as quickly as possible from gains in excess of those embodied in the X-factor, a hybrid approach, that is, a combination of P_o Adjustment and the phased option, may be necessary to ensure that the service provider has the maximum incentives to cut costs throughout the regulatory period while at the same time ensuring that customers also benefit. The RIC will ensure that, as far as possible, customers benefit from gains as quickly as possible.

The RIC's decision is to utilize a P_o Adjustment to share out-performance. However, the RIC reserves the right to use a combination of P_o Adjustment and phased adjustment if it feels that this is necessary.

8.4 REVENUE/PROFIT SHARING

In its consultation document, the RIC noted the possibility of earning excessive profits as one by-product of a revenue cap and the RIC proposed the use of a profit sharing mechanism to curb excessive profits if such a situation emerged during the regulatory control period. The RIC is aware that such a mechanism can dampen the incentives to cut costs. To counteract such an eventuality, the RIC has proposed the use of an efficiency carryover mechanism:

- to ensure that T&TEC has incentives to pursue efficiency savings throughout the regulatory period, which in turn reduces future prices to customers; and
- to reduce the incentive that might otherwise exist to defer the pursuit of efficiency gains immediately before the review of price controls, by providing a more consistent incentive to achieve costs reductions in every year of the regulatory period.

The RIC is aware that a profit sharing mechanism, if improperly implemented, can dampen the effects of the carryover mechanism. Therefore, the RIC will utilize a profit sharing mechanism only as a side constraint to ensure that customers benefit from excessive gains in the quickest period possible. The mechanism will only be utilized if profits exceed 10% of total revenue. If this occurs, the RIC will also determine the appropriate sharing ratio.

The RIC's decision is to utilize a mechanism for sharing profits with customers if profits exceed 10% of the total revenue forecasts.

8.5 CORRECTION FACTORS AND "UNDERS AND OVERS" ACCOUNT

As noted in its consultation document, the RIC does not intend to utilize an error correction factor to automatically adjust revenue forecasts. However, the service provider will be required to maintain an "unders and overs" account in respect of actual revenue versus the forecasts included in the final determination. This is merely a notional account.

T&TEC will be required to inform the RIC on a yearly basis of the balance in the "unders and overs" account. This report will be due within 30 days after the end of every year. If at the end of a year, the balance in the "unders and overs" account deviates from pre-allowed revenue targets, the following will apply:

- Under 5%, T&TEC must notify the RIC within the stipulated timeframe.
- Over 5%, T&TEC must notify the RIC but must also provide an action plan to resolve the balance.

The RIC intends to have T&TEC maintain an "unders and overs" account in respect of actual revenues versus the forecast revenues. T&TEC to report to the RIC on a yearly basis of the balance in the account.

If the balance in the "unders and overs" account deviates, the RIC intends to use the following mechanisms:

- Under 5%, T&TEC must notify the RIC within 30 days after the end of every year.
- Over 5%, T&TEC must notify but must also provide an action plan to resolve the balance.

Stakeholder Comments and Final Decision

Overall, the RIC's approach to efficiency carryover mechanism was endorsed by one respondent but two issues were also raised. It was suggested that 100% gains outside the control of the service provider should be passed to customers and that profit sharing should apply only to the gains arising from the service provider's own efforts. The RIC's view is that it is possible to treat efficiency savings achieved by management differently from those achieved due to exogenous factors. However, the RIC also noted that, in practice, this is likely to be difficult. Additionally, the cost of information gathering and analysis may outweigh the benefits of sophisticated analysis. Therefore, the RIC's thinking is not to differentiate between gains arising from the service providers own efforts and those outside the control of the service provider.

The second issue related to the passing of gains. It was suggested that the distribution of gains made during a regulatory period should be made at the beginning of the next regulatory period by means of a credit note. The RIC is not in favour of the credit note, as it would totally dampen the incentives built into the system of incentive regulation. If all the gains are to be shared at the beginning of each regulatory period, there will be no incentive for the service provider to make any gains towards the end of the regulatory period. The regulator has to strike a balance between sharing benefits and maintaining the incentive in the system. Therefore, the RIC favours that gains should be retained for five years from the year in which they were made.

8.6 CALCULATION OF THE EFFICIENCY CARRYOVER FOR 2006-2010 PERIOD

To assist the service provider in preparing its submission, the method for computing the efficiency carryover amount generated during the 2006-2010 regulatory control period should be included in the revenue requirement in the 2011 period and must incorporate the following principles:

- the efficiency carryover mechanism to be applied to the difference between forecast and outturn expenditure with regard to Opex and Capex costs only;
- an efficiency gain (loss) in Opex in any year to be calculated as the reduction (increase) in the level of Opex compared to the forecast for that year;
- an efficiency gain (loss) in Capex to be calculated as the WACC multiplied by the reduction (increase) in Capex against the Capex forecast;
- any efficiency gains(losses) to be retained by the service provider for five years after the year in which the gains (losses) are made; regardless of when the efficiency gain is made;
- there be no reopening of original Opex and Capex forecasts except where applicable under Section 49 of the RIC Act;
- efficiency gains and losses to be treated symmetrically;
- there be no negative carryover in any year. Where the carryover is negative, the efficiency carryover to be set to zero for that year, and the implied negative value be used to offset any positive gain in the following year;

- implied negative values to be carried over and accrued each year until the end of the regulatory period. Any accrued negative carryover amount at the end of the regulatory control period must be taken into account in setting the forecast for the following regulatory control period; and
- the efficiency gain (loss) for the last year of the regulatory period to be assumed as zero.

As indicated, the reason for including an efficiency carryover mechanism in the building-block approach is to provide the utility with a strong incentive to reveal its efficient level of costs, because it is directly rewarded for outperforming the expenditure forecasts established at the beginning of the regulatory control period. This inferential approach can also reduce the need for reliance on external benchmarking to assess the efficiency of costs forecasts.

The RIC's decision is to incorporate the principles in section 8.6 for the calculation of the efficiency carryover amount and the outstanding "unders and overs" account balances to be incorporated into the revenue requirements for the 2011-2015 regulatory control period.

8.7 INCENTIVE MECHANISM FOR MANAGING SYSTEM LOSSES

8.7.1 Importance of Incentives for Reducing Losses

Given the system specific issues of T&TEC's network, the RIC in its Consultation Document "**Incentive Mechanisms for Managing Transmission and Distribution Losses (May 2005)**", identified three major categories of inputs that it proposed to treat with in the design of an efficiency carryover mechanism:

- operating expenditure;
- capital expenditure; and
- system losses.

The measurement and incentive mechanism for managing system losses are discussed in this section. The cost to customers, of losses in the transmission and distribution system, is significant. Currently, T&TEC does not have effective financial incentives to optimize the level of losses, and so reduce the overall cost to customers. As a minimum, the RIC intends to establish an incentive mechanism to reduce losses, establish benchmarks for losses for the first regulatory control period, and to monitor and publicly report on the actual losses recorded.

8.7.2 System Losses

Losses are generally divided into technical and commercial losses. **Technical losses** refer to losses related to physical plant. In the electricity utility, most of the technical losses result from losses in the delivery system. Such losses are generally referred to as line losses and are a natural part of transmitting and distributing electricity. These losses occur as voltages are stepped down to levels useful to customers. As such, line losses are greater for customers taking electricity at lower voltage levels.

Problems arise when the line losses go beyond levels that are considered to be acceptable or reasonable under proper utility operating practices. The typical treatment of technical losses in rates involves customers being charged for only a reasonable amount of technical losses pre-set by the regulator. This level is set so as not to jeopardize the reliability or safety of the network.

Commercial losses come from a variety of sources, all of which have in common that energy was delivered but no revenue was collected. Theft, meter tampering, meter reader fraud etc., are examples of commercial losses. Since commercial losses originate for various reasons, a single approach for mitigating them may not suffice. Certainly, the utility has some control over the mitigation of commercial losses; but even with its best efforts, some commercial losses would still continue. The typical rate treatment can be to simply place the utility totally at risk for a failure to recover these losses.

8.7.3 Cost and Calculation of System Losses

All losses are currently incorporated into the tariffs and, as such, losses translate into higher prices for all consumers, as the service provider must purchase greater quantities of electricity than actually consumed. It is important therefore, that the service provider receives appropriate incentives to manage these losses and optimize the level of losses in the most efficient and effective way. The RIC, cognizant of this fact, is proposing an incentive mechanism that should encourage T&TEC to minimise those losses thereby eventually reducing the cost of electricity to consumers. In fact, efforts to mitigate these losses have to become an integral part of overall solutions in tariff and pricing policies.

Transmission and distribution system losses are generally defined as a percentage of the difference between total energy input to the network and sales to all customers. Other jurisdictions have defined total losses as total energy purchased minus the sum of the total annual sales of energy and own usage. Furthermore, there are other jurisdictions that calculate losses as the difference between the units input and units realized (units billed and collected). These methods lump all technical and non-technical losses together.

The RIC is of the view that the clearest measure of overall efficiency of the network is the difference between units input into the system and the units for which the payment is collected. As a result, the RIC will use the formula below to calculate the total system losses for T&TEC, since it takes into account the revenue collected by the service provider.

$$\textbf{Total System Losses} = 1 - \left\{ \frac{\textbf{Energy Units Billed}}{\textbf{Energy Units Purchased}} \times \frac{\textbf{Collection in \$}}{\textbf{Billing in \$}} \right\}$$

Based on the above method, transmission and distribution system losses for T&TEC averaged 7.9% over the period 1999-2003 and reduction of these losses will constitute a fairly significant source of efficiency gain. In fact, the average cost per kWh of energy was estimated to be about TT$0.1275 for the period 1999 to 2003. Using this figure, the average value of total system losses is approximately TT$52.7 million per year. In 2002, when losses of 8.0% were recorded, a 0.5% reduction in total system losses would have saved T&TEC $3.7 million.

Given that loss levels tend to be system specific, the overall loss level of T&TEC compares favourably with most other jurisdictions. However, in the case of T&TEC, about 40% of its load is located close to the main source of generation (Point Lisas). T&TEC's overall system losses are, therefore, impacted positively by this. The rest of the T&D system consists of longer lines based on the locations of customer loads and, as a consequence, there is much scope for the reduction of system losses.

Stakeholder Comments and Final Decision

The comments received in response to the RIC's Consultation Document, "**Incentive Mechanisms for Managing Transmission and Distribution Losses (May 2005)**", were general in nature, with the exception of two comments. One respondent suggested that the appropriate level of losses for T&TEC should be less than 6% in line with countries like Finland and Netherlands. Reducing losses from fairly low levels takes a lot of resources and time. From the current level of losses of around 7.9%, the RIC has set a system loss target for T&TEC of 6.75% for the first regulatory control period. The RIC is of the view that this level of losses compares very favourably with most developed countries, where the average level is around 7%.

The second issue of concern to some respondents was that of measuring technical and non-technical losses separately. The RIC prefers not to distinguish between different types of losses when setting a loss reduction target. T&TEC needs to develop more accurate measurement strategies before any difference in the treatment of various kinds of losses can be implemented. At the overall proposed target level of losses, it may even turn out to be a useless exercise to separately measure technical and non-technical losses.

8.7.4 Incentive Mechanism and Level of Sharing

In its consultation document, the RIC had discussed different incentive options as well as advantages and disadvantages of output- and input-based incentive mechanisms, where incentives are provided for investment in loss reducing equipment. Because the disadvantages of input-based mechanisms outweigh the advantages, the RIC is inclined to utilize an output-based mechanism for this first regulatory period and the RIC favours the following option:

> Prescribing a target system loss level at the beginning of the regulatory control period, such that, any improvement would constitute an incentive. Based on T&TEC's current performance, it is proposed that the target for the first regulatory control period be 6.75%.

Given that this is the first period under this new form of regulation, the RIC proposes that T&TEC be allowed to keep 90% of the gains if the actual system loss falls below the proposed targeted level of 6.75%.

The RIC's decision is to adopt the initial level of system losses at 7.9% and set the target for reduction in loss levels for the first regulatory control period at 6.75%. Further, the RIC's decision is that T&TEC be allowed to keep 90% of the gains if actual system losses fall below 6.75%, the sharing of the gains to occur at the end of the regulatory control period.

Additionally, it was pointed out in the consultation document, that in certain circumstances the net present value of losses saved by capital expenditure can be significantly less than the capital expenditure. However, the service provider may not be willing to invest in the appropriate level of loss management equipment unless there is a regulatory mechanism to require such investment.

Consequently, the RIC will be willing to support the principle that the value of loss reductions should be taken into account when the asset base is rolled forward. The RIC, therefore, proposes to work with T&TEC to develop a framework for assessing the economic prudence of loss management investment during the first price control period.

The RIC supports the principle of taking into account the value of loss reduction into the asset base when it is rolled forward to encourage investment in the loss reduction equipment.

A correct assessment of system losses is dependent on appropriate and accurate measurement. This will also be useful for distinguishing between technical and non-technical losses. At present, limited measurement takes place on T&TEC's system. In determining the appropriate strategies for reducing system losses, an accurate degree of measurement is required. Consequently, the RIC requires the service provider to install the appropriate metering/monitoring equipment at strategic locations of its network during the first regulatory period.

The RIC requires T&TEC to install the appropriate metering/monitoring equipment at strategic locations of its network during the first regulatory control period.

CHAPTER 9

CONSUMER AND QUALITY OF SERVICE ISSUES

The price, reliability and the quality of electricity supply are perhaps the most important aspects of electricity services to consumers. The need to maintain or improve service quality is one of the key cost drivers of operating and capital expenditure. To ensure that any reductions in expenditure are not due to deterioration in service, regulators have recognized the importance of clearly specifying service targets and providing adequate incentives to achieve those targets.

The emphasis on quality is not misplaced. Beyond the obvious benefits to consumers, quality of service has a broader impact on the economy. Poor voltage, frequent interruptions and frequency digressions damage industrial plant and equipment. Disruptions to residential and commercial users may lead to expensive repairs, replacement or investment in protective measures, and incur opportunity costs. Improvement in quality will enhance productivity in all sectors of the economy, help attract new investment, especially high technology investments, and provide better living and working conditions for users. As a result, an important feature of this price review process is to clearly establish the level of performance and the quality of service standards.

In fact, in April 2004, the RIC introduced a system of incentives to encourage T&TEC to improve its service quality. The incentive scheme is discussed below.

9.1 RATIONALE AND LEGAL FRAMEWORK

The RIC Act mandates the RIC to establish standards for services. Sections 6 (e), (f) and (g) of the RIC Act require the RIC, *inter alia*, to:

- prescribe and publish in the Gazette and in at least one daily newspaper circulating in Trinidad and Tobago, standards for services;
- monitor service providers and conduct checks to determine their compliance with the standards; and

- impose such sanctions as it may prescribe for non-compliance with the standards.

Under all forms of regulation of monopolies (and more so under incentive regulation), there is the risk that firms may increase profits by lowering the quality of service. Most regulators, therefore, include measures directed at regulating service standards in the regulatory regimes to ensure that reductions in expenditure are, in fact, due to efficiencies and not at the expense of lower service standards. The measures may take the form of financial penalties/incentives and/or obligations contained in a licence or legislation.

An important feature of this price review process is to clearly establish the level of quality of service standards.

9.2 BROAD MECHANISMS FOR REGULATING SERVICE

There are at least three (3) broad mechanisms that exist for regulating service standards. None of these approaches precludes the use of any other option, and the best approach may well be a combination of the following options:

- **Comparative (Performance) Reporting** – One method of providing incentives for service providers to improve the level of service is to establish a regime aimed at disclosing information about their performance, thereby increasing the accountability and transparency of service providers. Under the comparative benchmarking and reporting option, the service provider is required to report its performance against a specified set of measures. While comparative reporting may not appear to be a strong option for encouraging improved performance, this approach encourages service providers to maintain and improve service quality to a level that is more in line with customers expectations by exposing them to critical assessment. It is a relatively straight forward approach and is arguably a pre-requisite for other forms of incentive. This approach generally uses trend analysis of service providers' performance, although benchmarking of performance with other utilities has been commonly conducted. The RIC is committed to implementing an annual monitoring and reporting framework covering the service and financial performance of service providers, as monitoring of service performance will operate as a more overt customer protection measure.

- **Financial Incentives for Service Performance –** Another method of providing incentives to improve service performance is the linking of actual service performance to prices. There are two approaches:

  (i) ***Guaranteed Payments*** – Under this approach, the service provider is required to make guaranteed payments to customers who receive service below a certain benchmark. Currently, this is one of the most common approaches used by regulators to control service standards. The standards are divided into guaranteed and overall standards.

  Guaranteed standards set service levels that must be met in the provision of service to each individual consumer. Failure to meet guaranteed standards requires a specified payment to be made to the affected customer. **Overall standards** cover areas of service that affect all or a large group of customers and, therefore, compensatory payments are not feasible. However, even in such circumstances, it is desirable for the firm to provide service at a predetermined minimum quality. Under this approach, the primary purpose is to provide an incentive to improve key aspects of service rather than to provide some form of compensation.

  The RIC Act specifies the establishment of service standards and the imposition of sanctions for non-compliance. In fact, the process used by the RIC for establishing guaranteed and overall standards has already been implemented in the electricity sector as of April 2004.

(ii) ***Performance Incentive Mechanism (S-Factor)*** - Some regulators have included a service standards incentive mechanism in the price control equation, "S-factor", which provides an incentive for the firm to increase service levels by collecting additional revenue where the service provider exceeds predetermined service quality targets. Such a mechanism establishes a linkage between the price level and performance indicators, out-performance is rewarded through a higher price, while failure to achieve standards results in a lower price. Although this approach provides incentives to achieve or exceed the service targets and standards, an "S-factor" incentive regime has practical difficulties, including:

- the exact form of the S-factor and the availability of data to support it;
- the appropriate measures of performance indicators to be included;
- the level of revenue that should be put at risk; and
- the treatment of the impact of external events on service.

The RIC currently has very little information regarding which service indicators would be appropriate to include in an S-factor and believes that until it has considered all these issues, it may be inappropriate to include a performance incentive mechanism in the regulatory regime. The RIC will, therefore, develop the reporting information required for an S-factor and embark on trial monitoring during the first control period. The results will be reviewed before confirming its introduction as part of the adjustment mechanism for the second regulatory control period.

Legal Compensation and/or Application of Statutory Penalties – Under this approach, service providers face incentives from the possibility of awards of compensation by the courts or the application of statutory penalties by the regulator. This approach carries high transaction costs but can be an effective incentive of last resort.

The RIC's decision is not to include a performance incentive mechanism (S-factor) for the first regulatory control period.

9.3 RIC'S MAJOR INITIATIVES FOR SERVICE QUALITY

Apart from the guaranteed scheme already in place, the RIC plans to undertake three major initiatives aimed at improving the quality of service customers receive from T&TEC:

- The introduction of Codes of Practice, which are essentially a set of guiding principles that T&TEC should consistently use in dealing with specific consumer issues. They are designed to improve the delivery of the service provider's social obligations. Under this initiative, T&TEC would be required to prepare and submit Codes of Practice for RIC's approval on the following:
  - Provision of Priority Services for Vulnerable Groups;
  - Procedures for Dealing with Customers in Default;
  - Debt Recovery and Disconnection Procedures and Policies;
  - Retroactive Billing Policy;
  - Range and Accessibility of Payment Methods;
  - Handling of Complaints; and
  - Continuous Consumer Education.
- Benchmarking and monitoring quality of supply, which involves quantitative measures to be monitored on a regular basis; and
- Customer Satisfaction Survey, which involves a qualitative survey conducted at the beginning of each price control period.

Qualitative Survey

The RIC has decided that Customer Satisfaction Surveys will be carried out by an independent organization at least twice over the price control period.

The aim of this survey will be to:

- elicit consumers' views on the quality of service and identify their concerns;
- gauge the awareness of consumers knowledge of their rights, the performance standards and of the service provider's procedures for handling complaints; and
- obtain feedback for improvement in any specific aspect of quality of supply and customer service.

The survey will help to bring out several aspects of performance and service that are not easy to capture through quantitative means. For instance, the survey can help assess if consumers receive bills regularly, if they receive notice before disconnection, whether payment locations are convenient, if the service provider's staff is courteous and helpful, and so on. The RIC is conscious that the responses will be subjective but it believes the benefits will far outweigh such concerns. A detailed questionnaire will be utilized to solicit responses on a set of issues. For future repeats of this survey, the RIC will endeavour to use the same questionnaire so that consumer satisfaction can be tracked over a long period of time based on the same parameters.

T&TEC would be required to prepare and submit Codes of Practice for the RIC's approval before the end of the first quarter of 2007 on the following:

- Provision of Priority Services for Vulnerable Groups;
- Procedures for Dealing with Customers in Default;
- Debt Recovery and Disconnection Procedures and Policies;
- Retroactive Billing Policy;
- Range and Accessibility of Payment Methods;
- Handling of Complaints; and
- Continuous Consumer Education.

The RIC will appoint an independent consultant to design and administer a customer satisfaction survey and present its conclusions in a report which will be posted on its website and made available to stakeholders and all interested parties.

9.4 OVERVIEW OF THE EXISTING ARRANGEMENT

The current arrangement of Guaranteed and Overall Standards has been in place since April 2004. It was developed in consultation with the service provider, consumer groups, other stakeholders and interested parties, and will be reviewed in 2007. The Scheme consists of six Guaranteed Standards and nine Overall Standards. The Guaranteed Standards carry compensatory payments in the event of non-compliance. The compliance rate for billing punctuality (OES 2) for the period April 2004 to March 2005 and the compliance rate for provision of estimates (GES 6) for the period April 2004 to March 2005 are presented in **Figures 9.1 and 9.2.** The performance of T&TEC with respect to these standards and compensatory payments are presented in **Tables 9.1 and 9.2** below.

In accordance with the requirements, T&TEC submits quarterly/annual reports on the compliance of these standards. T&TEC has been capturing all the data regarding the standards in a systematic manner to allow for the generation of reports. A brief summary of the first annual report is presented below.

Figure 9.1 – Compliance Rate for Billing Punctuality (OES 2) for the period April 2004 to March 2005

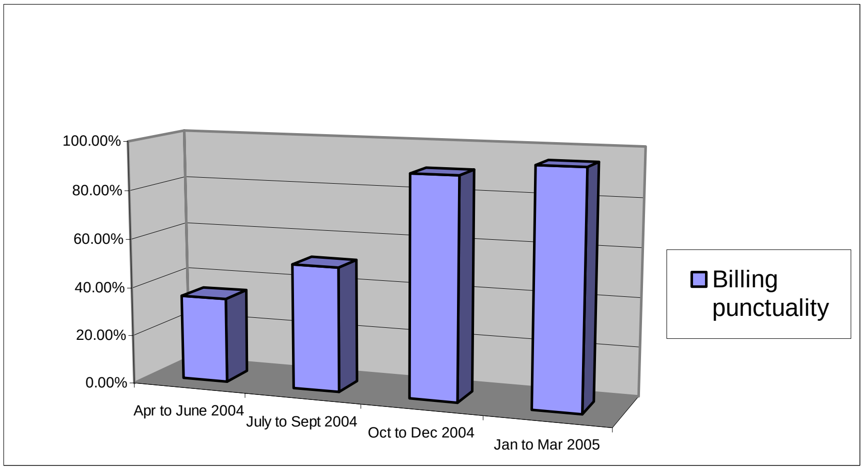

Figure 9.2 – Compliance Rate for Provision of Estimates (GES 6) for the period April 2004 to March 2005

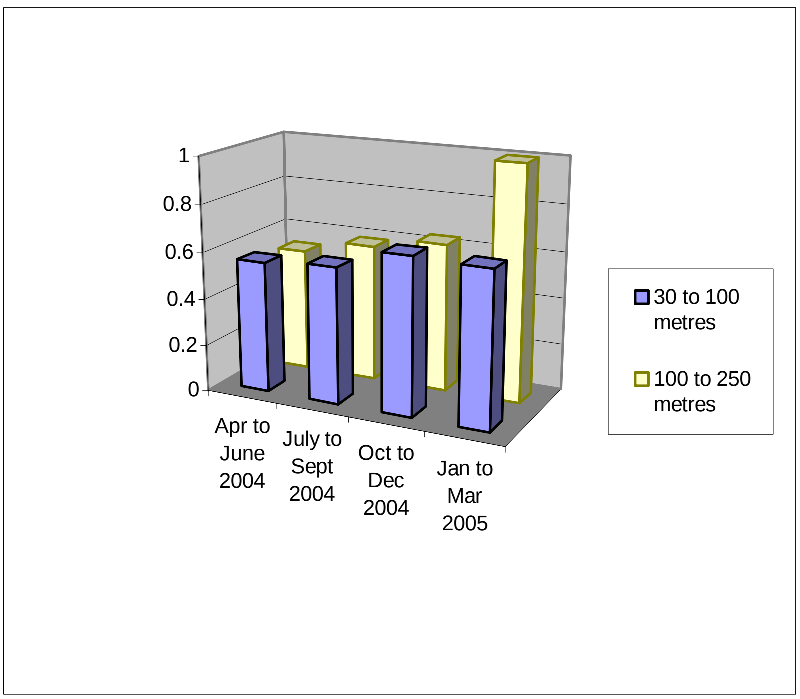

Table 9.1 - Performance Review of the Guaranteed Standards, April 2004 to March 2005

Code	Service Description	Performance Measure	Required Performance Units	Compliance Rate: Apr to June 2004	July to Sept 2004	Oct to Dec 2004	Jan to Mar 2005
GES1	Response and restoration time after unplanned (forced) outages on the distribution system.	Time for restoration of supply to affected customers	Within 12 hours For each further 12 hr period	99.0%	99.2%	98.7%	99.7%
GES2	Billing Punctuality (new customers)	Time for first bill to be mailed after service connection: (a) Residential	65 days	99.2%	100%	100%	96.9%
		(b) Non-Residential	35 days	75.0%	100%	93.7%	75.0%
GES3	Reconnection after payment of overdue amounts or agreement on payment schedule	Time to restore supply after payment is made (All customers)	Within 24 hours	100%	99.3%	98.5%	98.8%
GES4	Making and keeping appointments	Where required, appointments will be made on a morning or afternoon basis	Failure to give 24 hours notice of inability to keep the appointment	100%	100%	100%	100%
GES5	Compensatory payment	(i) Time to credit compensatory payment after non-compliance	Within 35 working days	100%	100%	100%	100%
		(ii) Time to complete investigation, determine liability and make payment after receiving a claim.	Within 35 working days	100%	100%	100%	100%
GES6	Connection to supply:	Service drop and meter to be installed:					
	30 to 100 metres	(a) Provision of estimate (subject to all documents being provided)	Within 5 working days.	56.0%	58.2%	66.9%	65.9%
	30 to 100 metres	(b) Complete construction (after payment is made)	Within 15 working days.	93.4%	77.1%	65.3%	84.5%
	100 to 250 metres	(a) Provision of estimate (subject to all documents being provided)	Within 7 working days.	52.9%	58.8%	63.5%	100%
	100 to 250 metres	(b) Complete construction (after payment is made)	Within 20 working days.	85.3%	58.8%	82.4%	83.3%

Table 9.2 - Performance Review of the Overall Standards, April 2004 to March 2005

Code	Service Description	Required Performance Units	Compliance Rate: Apr to June 2004	July to Sept 2004	Oct to Dec 2004	Jan to Mar 2005
OES1	Line faults repaired within a specified period (for line faults that result in customers being affected)	100% within 48 hours	100%	100%	100%	100%
OES2	Billing punctuality	98% of all bills to be mailed within ten (10) working days after meter reading or estimation	35.0%	51.0%	90.0%	95.0%
OES3	Frequency of meter testing	10% of industrial customers' meters tested for accuracy annually.	14.0%			ARF
OES4	Frequency of meter reading	(a) 90% of industrial meters should be read every month	96.0%			ARF
		(b) 90% of residential and commercial meters read according to schedule	92.0%			ARF
OES5	System revenue losses (difference between energy received and energy for which revenue is derived)	7.5 % losses of total energy delivered to customers	100%			100%
OES6	Response to customer queries/requests (written) (a) Time to respond after receipt of queries.	Within 5 working days	23.0%	48.0%	64.0%	61.7%
	(b) Time to complete investigation and to communicate final position	Within 15 working days of inquiry	74.0%	54.0%	17.0%	19.1%
	(c) Time to complete investigation and communicate final position if third party is involved (e.g. insurance claim.)	Within 30 working days after third party actions completed	N/a	N/a	N/a	N/a

ARF – Annual Reporting Frequency.

			Compliance Rate			
Code	**Service Description**	**Required Performance Units**	**Apr to June 2004**	**July to Sept 2004**	**Oct to Dec 2004**	**Jan to Mar 2005**
OES7	Number of complaints to TTEC by type: (a) Billing queries	(a) 500 telephone and/or written complaints per 10,000 customers per annum	100%			ARF
	(b) Voltage Fluctuations/Damage	(b) 300 telephone and/or written complaints per 10,000 customers per annum	100%			ARF
	(c) Street Lights/ Poles/Disconnections/Other	(c) 1000 telephone and/or written complaints per 10,000 customers per annum	100%			ARF
OES8	Prior Notice of planned outages	At least 72 hours (3 days) advance notice of planned outages 100% of the time	88.0%	55.0%	86.0%	93.4%
OES9	Correction of Low/ High Voltage complaints	All voltage complaints to be responded to within 24 hours	95.0%	98.0%	99.0%	99.8%
		and rectified within 15 working days	87.0%	87.0%	91.0%	99.1%

ARF - Annual Reporting Frequency
N/a - Not Applicable

Table 9.3 - Number of Breaches Under the Guaranteed Standards (9 months of 2004)

Standard	Requests/ Customers affected	Breaches	% Breach
1. Response and Restoration to Supply	2,032,035	20,575	1.01
2. Billing Punctuality	341	22	6.4
3. Reconnection after Payment of Overdue Amount/ Agreement	14,480	129	0.9
4. Making and Keeping Appointments	0	0	0
5. Time to credit Compensatory Payment	0	0	0
6. Connection to Supply	538	320	59.4
TOTAL	**2,047,394**	**21,046**	**1.03**

With regard to compensatory payments, only two claims amounting to $60.00 were made, out of 21,046 breaches with a value of approximately $640,000 as compensation for breach of the standards.

In light of the above assessment of the existing scheme, the RIC will not introduce changes at this time. The RIC will review the scheme at the end of three years (i.e. in 2007) for appropriate action/proposals.

To ensure effective promotion of the current scheme, T&TEC will be required to:

- publish information on the Guaranteed and Overall Standards, at least once per quarter and at least in one daily newspaper widely circulating in Trinidad and Tobago;
- provide information, on the standards and how customers can claim compensation, at least twice per year in customers' bills. This requirement to be continued until the end of 2007;
- ensure that claim forms are readily available at all T&TEC customer service offices/centres;
- adequately display the standards in all T&TEC customer service offices/centres; and
- provide to the RIC annual reports on its efforts to promote the standards (including evidence of newspaper advertisements, etc.).

9.5 MEASURES OF SERVICE

In addition to the guaranteed/overall standards scheme, T&TEC will be required to report to the RIC on a number of other service measures. These measures are generally classified as reliability measures, quality of supply measures and customer service measures. By monitoring and publicly reporting on these measures, the RIC provides an incentive to the service provider to maintain and improve its service levels.

9.5.1 Reliability Measures

The reliability measures are considered to be the most important aspect of network quality as they lie at the heart of the network service. Network reliability is a measure of the ability of the network to continuously meet the demand from customers. This aspect can be divided into two components. The first relates to guaranteeing sufficient capacity in the long-term and the second one relates to ensuring that the customers do not experience interruptions in the supply of electricity. Network reliability is characterized by the number and duration of interruptions experienced by customers. Several indicators are used to evaluate the reliability of the distribution network. The most common measures at the system level are the so-called SAIFI, SAIDI, CAIDI and MAIFI indicators which measure reliability over a pre-defined period, usually over one year.

- SAIFI (System Average Interruption Frequency Index) measures the probability that a customer will experience an outage. It is calculated by dividing the number of customer interruptions by the total number of customers served. The number of customer interruptions is the total number of interrupted customers for each outage.

- SAIDI (System Average Interruption Duration Index) provides a measure of the average time that customers are interrupted. It is calculated by dividing the total number of interruption durations by the total number of customers. The customer interruption duration is defined as the aggregate time that all customers were interrupted.

- CAIDI (Customer Average Interruption Duration Index) is a measure of the average time required for restoring service to the average customer per outage. It is calculated by dividing the total interruption durations by the total number of outages.

- MAIFI (Momentary Average Interruption Frequency Index) is the total number of momentary interruptions (of less than three minutes duration) that a customer could expect, on average, to experience in a year.

9.5.2 Quality of Supply Measures

The quality of electricity supply deals with the characteristics of the supply delivered to customers' premises, specifically voltage surges or voltage sags and harmonic distortions. In fact, one of the main concerns of consumers, in many areas of Trinidad and Tobago, is voltage fluctuations. In order for T&TEC to better monitor voltage problems, it has to install monitoring equipment at each zone substation and at the far end of one of the distribution feeders supplied from each zone substation.

Prior to setting any targets, the RIC will require that the following quality of supply data be provided on an annual basis:

- Number of over-voltage events, and number of customers receiving over-voltage, due to high voltage injection.
- Number of over-voltage events, and number of customers receiving over-voltage, due to lightning.
- Number of over and under-voltage events, and number of customers receiving over and under-voltage, due to other causes.
- Number of voltage variations – steady state, one minute, 10 seconds.

9.5.3 Customer Service Measures

Customer service measures relate to the service provider's performance in meeting customer requirements such as responding to queries, meeting timelines etc. T&TEC

will be required to establish a suitable system to track performance against the specified customer service parameters listed below:

- total number of calls;
- number of calls not answered within 30 seconds;
- average waiting time before a call is answered;
- number of complaints received and resolved by type; and
- resolution time (average, minimum and maximum) by complaint type.

The RIC requires T&TEC to commence the collection of data on all of the above measures. This will help establish a baseline in a reasonable period of time. Based on this, it will review the performance improvement against the identified parameters and set targets in the second price control period.

The RIC will monitor and publicly report on these measures. As part of T&TEC's second price control proposals, T&TEC will be required to propose targets for the second regulatory period. Only at the end of the first control period and after the RIC's assessment, as well as with the consultation of the consumers and other stakeholders, will targets for these measures be established for inclusion in the second price control period.

The RIC also requires the service provider to ensure that proper systems for recording and reporting information against these parameters are put in place by the end of 2006.

Service Incentive Mechanisms

In defining appropriate performance targets, it is important to consider the nature of incentives that service providers will face in order to achieve service standards during the price control period.

As indicated above, the service incentive mechanisms consist of the following elements:

- Performance Reporting Requirements;

- The Service Incentive Scheme (or S-Factor Scheme). Under this scheme, a service provider's allowed revenue is increased (decreased) based on its performance in relation to performance targets; and
- The Guaranteed Payment Scheme. Under this scheme, payments are made to customers where the performance received by them is below a specific threshold.

The RIC has already implemented the Guaranteed Payment Scheme and Performance Reporting requirements.

The RIC's decision is that the service incentive arrangements for the first price control period should consist of the Guaranteed Payment Scheme and Performance Reporting Requirements.

9.6 PUBLIC (STREET) LIGHTING

One of the contentious issues raised by consumers and Regional Corporations is the tardiness of T&TEC in repairing and installing streetlights. Additionally, consumers were concerned that street lighting was inadequate and requests for additional lights were not being satisfied.

With respect to additional lighting, the RIC is satisfied with the existing arrangement under which the Regional Corporations are responsible for the payment of street lighting bills, and as such, they must have the responsibility for determining where new lights are to be installed.

However, the RIC is of the view that T&TEC has full responsibility for:

- the monitoring of the condition and performance of public lighting assets; and

- the development and implementation plans for the operation, maintenance, refurbishment, replacement, repair and installation of the public lighting assets.

As a consequence of this responsibility, T&TEC's plans must include performance targets. As a minimum, T&TEC must:

- repair or replace any reported street light failure within 7 working days;
- replace photo-electric cells at least every 8 years or otherwise as required;
- clean, inspect for damage and repair luminaries during any re-lamping;
- routinely patrol major roads to inspect, replace or repair luminaries at least twice per year;
- commence installation within two weeks after payment is received; and
- consider implementing a telephone hotline number for customers to report street-lighting problems.

Additionally, T&TEC must submit to the RIC annual reports on the above performance targets. Based on the performance, the RIC may consider the inclusion of these targets in its Guaranteed Standards Scheme.

The RIC will consider the inclusion of the above public (street) lighting targets in its Guaranteed Standards Scheme for the second regulatory control period.

Other Service Quality Initiatives

The RIC has proposed the implementation of a number of additional quality of service standards including measures related to the frequently complained issues, such as complexity of bills, estimated billing, and the need to reduce voltage fluctuations.

Disruptions in Service

Several consumers have complained about the poor quality of service. They mentioned that there were frequent unscheduled power outages and voltage fluctuations which resulted in production loss and damage to equipment. While consumers accepted that the reliability of the service has improved, there were concerns about the lack of notification by T&TEC for planned outages. They were also concerned about the timely restoration of service and the quality of the supply directly after an outage.

The RIC has already proposed a number of service quality measures to be constantly monitored. In fact, the RIC's allowed Capex to upgrade the network has recognized this need. The RIC requires T&TEC to:

- repair and install capacitor banks at overloaded sub-stations;
- maintain balance load on feeders and transformers; and
- construct (under the Capex programme) new 33-11 KV substations and bifurcate LT lines for better load planning.

Voltage Quality and Damaged Appliances

The single most contentious issue raised was the quality of the voltage supplied by T&TEC and the resultant damage to equipment. Customers also contended that the process for seeking redress for damaged appliances was complex and lengthy. Overall, customers were of the view that T&TEC should guarantee a certain quality of voltage and therefore any fluctuation which leads to damages, should incur some liability on the part of T&TEC.

The RIC is well aware of the concerns regarding voltage fluctuations and customers' dissatisfaction with T&TEC's handling of damaged appliance cases. It also recognizes that the issue is complex and as such will deal with the matter at different levels. The RIC has already, under its Guaranteed Standards Scheme, set time limits within which T&TEC will complete its investigations and communicate its position to the customer.

T&TEC should also develop a more customer friendly damaged appliance policy. This would allow customers to benefit from more objective consideration for any damage suffered due to operational incidents over which T&TEC should reasonably be expected to have control. The policy must state the nature and scope of the investigations T&TEC conducts to arrive at its decision.

In this regard, the RIC will establish a Working Group, comprising NGOs, Business Organizations, T&TEC and the RIC, to develop a more comprehensive policy on damaged appliances. There is also the need for T&TEC to have information available in all its offices about exactly what customers need to do in order to make a claim for damaged appliances. In addition, T&TEC should also educate customers about the need for proper surge protection devices for appliances without endorsing a particular brand or type of protective device.

Billing and Receivables

The billing and, especially, receivables issues generated a lot of public comment during the RIC's consultation process. Two areas dominated the comments. The first issue raised was the margin between the provision for bad debt and the actual debt, and the suggestion was to reduce it to the level of actual bad debt.

The RIC plans to allow 2% as provision for bad debt, in keeping with industry best practice and has requested T&TEC to properly document its policy and procedures on writing off bad debt.

The second issue concerns receivables, especially of government/local government bodies, as public sector customers account for a significant portion of receivables. In fact, improvements in collection of billed amounts from Government were stressed by many participants.

Given the seriousness of the issue, the RIC has proposed a number of measures, including:

- **the re-introduction of the Reserve Vote System** – this system makes specific, separately identified allocations for utility bill payments. These funds will be "reserved" under a separate line item in each Ministry's Vote and can only be used for the payment of bills;
- **a late payment charge** of 1.5% per month levied on all customers (including government); and
- **other collection measures**, such as opening of cash collection centres for longer hours, making locations for bill payment more accessible to customers.

The RIC's decision is to introduce a late payment charge of 1.5% per month on all customers.

Simplification of Bills

Many customers expressed their concern as to the number of charges/services included in their bills. They indicated that as a result they were unable to easily understand their electricity bills and there was also some confusion as to the breakdown of various components.

The RIC understands customers' concerns which are mainly due to the volatility of the fuel charge and to some extent the foreign exchange charge which influence the bills rendered by T&TEC. However, the RIC has decided to eliminate fuel and exchange rate clauses and as a consequence the bills in the future would be simple with just two charges – a fixed charge and a charge based on kWh usage.

Estimated Billing

The matter of estimated billing was also of concern to some customers, as well as the method of estimation.

The RIC is well aware of the concerns of customers, as estimated billing has been a constant source of concern to them for sometime now. Unless Automatic Meter

Reading is implemented, it may be difficult to phase out estimated billing completely. In fact, most utilities in the world strive for between 3 to 4 actual reads in a year. There is another factor that leads to variations in kWh consumption in the bi-monthly billing which often goes undetected by consumers and it is the variability associated with the "number of days" in the billing cycle. In keeping with the 'best practice' in the utility industry, the RIC requires that:

- T&TEC must not issue two or more consecutive estimated bi-monthly bills; and
- An estimated bill must be based on the average of the last four billings.

The RIC will also encourage T&TEC to consider, if possible, reorganization of its billing procedures so as to generate bi-monthly bills based on a fixed number of days.

Electricity Supply to the Steel Company

The single largest consumer of electricity in the country (Mittal Steel) suffers a much lower reliability in the supply of electricity compared with the rest of the country. This is so because in an event of distribution and production problems, including shortage of power or any other emergency situation, its load is reduced thereby ensuring that the rest of the country continues to benefit from a good and higher reliability.

Consequently, this consumer has requested to be compensated for this unreliability in power supply as this loss of supply results in significant production losses. In monetary terms, it could represent a loss of $520,000.00 for loss of supply for 25 hours.

Given the size and nature of the steelworks operation, the supply to this consumer is deliberately interrupted by T&TEC in order to provide the rest of the country with reliable supply. However, on many occasions, the nature of steel operation is itself the cause of a drop in frequency which then triggers an automatic load shed. Maintaining a stable frequency is, therefore, difficult. The 30 MW static watt compensator, which is part of the plant design to minimize these effects, has not been functioning properly. The reinstatement cost of this compensator is very high and neither party is willing to finance it alone. Additionally, T&TEC's contract with Mittal Steel is for 150 MW but

Mittal Steel wants its contracted capacity to be increased to 240 MW. This can only be accommodated after the new generation capacity has been installed by T&TEC. The additional capacity is expected to be installed by the first quarter of 2007.

The RIC has carefully considered the situation and recommends that both parties continue to meet to discuss and resolve operational problems. To seek to remedy this situation by penalizing one party at this time might be unfair. The reliability is likely to improve substantially when the new capacity is commissioned in the first quarter of 2007. However, if this situation continues thereafter, the RIC may consider the introduction of a special regime of interruptible tariffs.

The RIC directs that T&TEC must improve the reliability of service to its largest customer, and failing that, the RIC may consider the introduction of a special regime of interruptible tariffs.

CHAPTER 10

MISCELLANEOUS CHARGES

10.1 INTRODUCTION

Miscellaneous Charges are fees charged for non-routine services that are not included under the price control mechanism used to regulate tariffs. The provision of miscellaneous services is incidental to T&TEC's core service of providing electricity. In regulating such charges, the regulator usually attempts to protect consumers by making these charges as cost reflective as possible.

The charges are applied for services such as, meter installation, reposition of meters, service deposit and meter testing which are related to the distribution of electricity. The RIC's concern about miscellaneous charges is derived from complaints reported to its Customer Service Department. Although miscellaneous charges do not collectively account for a significant proportion of T&TEC's total revenue, those charges can have an impact on individual customers, particularly those in low-income groups.

This chapter discusses the issues relating to some of the important services and makes proposals for dealing with miscellaneous services.

10.2 CURRENT MISCELLANEOUS CHARGES

The current charges for miscellaneous services were established by the Public Utilities Commission in 1992. The allowable charges and their maximum levels were fixed on a fee-by-fee basis (**Table 10.1**). Apart from the charges shown in **Table 10.1**, T&TEC also collects revenue from pole and transformer rentals.

Table 10.1 – Miscellaneous Charges

Miscellaneous Charge	2006 T&TEC's Requested ($)	Current Maximum Allowable ($)
Meter Check at customer's request: - If found in working order - If found defective	 No charge	 120.00 No charge
Visit for non-payment of Account	343.00	145.00
Install meter and reconnect secondaries	384.23	120.00
Reconnect; disconnect and/or change meter	331.88	120.00
Reposition of secondaries	196.80	120.00
Change and/or reposition meter	326.96	120.00
Disconnection for non-payment	331.88	73.00
Reconnection after disconnection for non-payment	331.88	72.00
Service deposit (1)	-	95.00

As can be seen from **Table 10.2**, T&TEC earns, on average, at least $25.8 million of its revenue from miscellaneous charges annually. This represents about 1.8% of T&TEC's revenue.

Table 10.2 - T&TEC's Revenue from Miscellaneous Charges, 1999-2003

Charge	1999 $	2000 $	2001 $	2002 $	2003 $
Meter Check at customer request (if found in working order)	26,615	40,800	31,344	30,480	29,050
Visit for non-payment of Account					
Install Meter and Reconnect Secondaries	36	11,940	112,061	64,338	59,862
Reconnect, Disconnect and/or change meter	120	68,929	189,910	271,801	383,062
Repositioning of Secondaries	6,104	600	27,599	12,286	17,677
Change and/or repositioning of Meter	651,377	469,046	474,901	433,671	503,784
Disconnection for non-payment					
Reconnection after disconnection for non-payment	3,281,477	2,205,860	3,062,149	2,422,402	2,650,259
Service Deposit	2,652,426	2,334,271	3,492,294	1,966,645	2,823,473
Pole Rentals*	19,699,496	5,512,799	12,808,964	30,027,790	20,385,895
Transformer Rentals*	1,829,356	2,085,408	2,086,057	1,970,764	2,027,966
TOTAL	**28,147,007**	**12,729,653**	**22,285,279**	**37,200,177**	**28,881,028**

* Revenue from Transformer and Pole Rentals does not fall under Miscellaneous Charges.

Note: (1) This is a refundable deposit and not a Miscellaneous Charge.

10.3 LIST OF SERVICES AND COST RECOVERY

There are two broad areas of concern expressed by T&TEC with respect to miscellaneous services:

(i) non-flexibility of the current arrangement – that is, there is no automatic mechanism to adjust the list of services, especially if the system does not allow for new charges to be introduced without the involvement of the regulator; and

(ii) fee structure – that is, the current fee structure does not provide flexibility for upward adjustment to current charges to reflect changes in the underlying cost of delivering these services.

Consequently, T&TEC has made two broad proposals with respect to a flexible regime for miscellaneous charges:

- a procedure to be agreed upon for the introduction of new services as the need arises: and
- the introduction of a price adjustment mechanism which can be utilized to allow for cost increases over the course of the regulatory control period.

An automatic mechanism to adjust the list of services and charges during the price control period would require the RIC to introduce a service where the service is not already the subject of a determination. Under its Act, the RIC is required to conduct an investigation, report and determine the charge for the service. A determination must either establish maximum rates/prices, or decide on the methodology for setting maximum prices. In conducting its investigation and before arriving at a decision, the RIC is required to consult with all stakeholders. This consultation process assumes that either the service exists or is separately identified before determination is made.

Consequently, it is difficult for the RIC to determine a maximum price for a service whose nature and scope are not known at the time of the determination.

Further, the RIC would wish to consult the public on setting a price/rate for a service between determinations. However, given the size and scale of miscellaneous fee income relative to total income of the service provider, it would be impractical to hold consultations purely for the introduction of miscellaneous service during the price control period.

Based on the requirements imposed by the RIC Act, it does not seem possible to provide the flexibility sought by T&TEC to automatically adjust the list of services or charges during the price control period. This decision is further reinforced by the impracticality of engaging in a separate determination during the price control period, given the size and scale of income from miscellaneous charges relative to the total revenue of T&TEC.

The RIC does not intend to provide the flexibility to automatically adjust the list of services or charges during the price control period.

Another issue highlighted by the service provider is the failure to provide a mechanism for adjusting current charges to reflect annual changes in the underlying cost of delivering miscellaneous services. T&TEC has claimed that its actual cost of providing of these services is now approximately 250% more than the maximum allowable charges (**Table 10.1**).

Any proper analysis of the "true cost" of delivering miscellaneous services would require detailed and disaggregated cost analyses of the various operational and administrative activities to deliver a particular service. This information would then facilitate an appropriate cost allocation methodology to support the respective charges. T&TEC has not provided such detailed information. Furthermore, it would be extremely difficult to identify and allocate costs pertaining specifically to miscellaneous service delivery.

There are three broad approaches commonly used to allocate costs:

- Fully Distributed Cost Allocation method;
- Marginal Cost method; and
- Avoidable Cost method.

Fully Distributed Cost Allocation method, where the total cost (direct and indirect costs) of the miscellaneous service is assigned in accordance with a predetermined allocation policy. Under this method, common cost is allocated based on some physical measure of utilization. T&TEC does not have a specialized administrative unit dedicated to miscellaneous services. Therefore, cost allocation under this method is inappropriate. Furthermore, as the provision of miscellaneous services is incidental to the provision of a total service, this method of allocating costs may also be inappropriate. This method is likely to allocate a higher proportion of costs to miscellaneous services than is appropriate.

Marginal Cost (MC) refers to the change in total costs arising from providing an additional unit of service. The difficulty in measuring MC resides in problems of determining the appropriate unit of service output and the timeframe to which costs should be applied. As all costs are variable in the long run, they may be considered marginal, therefore substantial costs may be viewed as fixed in the short term and excluded from marginal cost calculations.

Avoidable Cost (AC), this method estimates costs which would be avoided if a particular service was not provided. Thus, AC is the marginal costs of varying output over a range rather than a varying single unit. It is clear that T&TEC's current system of information is unlikely to support MC or AC methods of allocating costs.

Given the complexities involved in identifying costs, the RIC prefers to rely on its own judgment. The RIC also believes the actual cost of miscellaneous services may, fully or substantially, already be incorporated in "total Opex".

Despite the difficulties inherent in accurately quantifying cost recovery, setting miscellaneous charges at a "reasonable" level will provide proper signals which will ensure that customers do not exploit the services.

Given the lack of supporting information, the RIC is unable to support the requested increases in charges by T&TEC. Nevertheless, the RIC is aware that miscellaneous charges were last adjusted in 1992. The RIC considers that a one-off increase in these charges will reasonably reflect the change in the RPI since 1992. The new maximum allowable charges for these services are indicated in **Table 10.3** below. The RIC will require T&TEC to put systems in place to capture and record the various efficient cost components involved in providing miscellaneous services. These costs are to be verified by an independent party. This information would form the basis for reviewing miscellaneous charges for the next review period.

Table 10.3 - New Miscellaneous Charges

Miscellaneous Charges	Current Allowable ($)	T&TEC Requested ($)	RIC's Draft Determination ($)
Meter Check at customer's request:			
- If found in working order	120.00		194.00
- If found defective	No charge	No charge	No charge
Visit for non-payment of Account	145.00	343.00	234.00
Install meter and reconnect secondaries	120.00	384.23	194.00
Reconnect; disconnect and/or change meter	120.00	331.88	194.00
Reposition of secondaries	120.00	196.80	194.00
Change and/or reposition meter	120.00	326.96	194.00
Disconnection for non-payment	73.00	331.88	118.00
Reconnection after disconnection for non-payment	72.00	331.88	118.00

As indicated previously, T&TEC receives payments from pole and transformer rentals. These are generally considered non-distribution services. As such, it is not generally subject to regulation. However, regulated assets are used to provide this service. The more common method of dealing with such an issue is by adjusting the revenue requirement to account for this income.

The RIC will continue to regulate the current set of miscellaneous services.

The RIC considers a fee-by-fee cap to be reasonable for miscellaneous charges.

To prevent the proliferation of miscellaneous services, the RIC considers the current list of approved miscellaneous charges to be exhaustive.

The RIC will exempt pole and transformer rentals from the miscellaneous charges schedule.

The RIC's decision is that charges for miscellaneous services can increase by the RPI from 1992 via a once-only adjustment. No further increase will be permitted for the duration of the first control period.

The RIC requires T&TEC to put systems in place to capture and record the various efficient cost components involved in providing miscellaneous services. These costs are to be verified by an independent party.

10.4 TREATMENT OF MISCELLANEOUS SERVICES

Apart from the cost recovery and other issues associated with miscellaneous charges, some aspects of specific miscellaneous charges require further consideration. This is primarily because of the significant difference in the way they are treated in Trinidad and Tobago when compared to other jurisdictions. Two such services are discussed:

- Meter Testing; and
- Service Deposit.

Meter Check (Tests)

T&TEC is mandated under the quality of service standards to conduct functional tests on no less than 10% of the revenue meters for Industrial customers in accordance with Overall Standard #3 (OES 3). Although no such standard exists for commercial and domestic customers, T&TEC checks such meters at its discretion or at the request of the customer. Any meter found registering within a range of plus or minus two percent either fast or slow is considered as registering accurately. When T&TEC checks a meter at the customer's request and it is found to be defective, there is no charge and the meter is changed. However, when the meter is checked at the customer's request and is found to be in good order, the customer is required to pay.

In the US and many other jurisdictions, the electricity companies test the meter, at the request of the customer, once within each calendar year at no charge to the customer. Each subsequent test, within the year, in which the meter is found to be registering accurately, results in the cost of such test being borne by the customer.

Stakeholder Comments and Final Decision

In response to the RIC's draft decision that there should be one free meter test every five years, T&TEC argued that any requirement for a free meter test may be contrary to Section 58 (3) of its Act, while one stakeholder favoured two free meter tests in the five-year period. Although Section 58 (3) of T&TEC's Act talks about payment for a meter test when the meter is checked at the customer's request and is found to be in good order, Section 58 (1) mandates T&TEC to keep meters in proper order at its own expense. Therefore, the RIC is simply enforcing a requirement that is adequately covered in T&TEC's Act for the maintenance of meters in proper order. More importantly, the RIC is establishing a service standard to encourage T&TEC to improve its service quality and is therefore, well within its mandate to do so. Consequently, the RIC continues to hold the view that there should be at least one free meter test every five years regardless of the result of the test.

The RIC's decision is that there should be at least one free meter test every 5 years regardless of the result of the test.

Service Deposit

A service deposit/security deposit (SD) is required to safeguard the recovery of dues for electricity supplied to consumers. The main rationale of the SD is the need to minimize the risk of financial loss associated with bad debts arising from customers. Utilities and regulators worldwide consider the application of a SD as a fair and reasonable approach.

SD constitutes a charge and legally comes under the ambit of the RIC Act. The Act defines rate as including every rate, fare, toll, charge, rental or other compensation or payment whatsoever for services. Therefore, the RIC Act is sufficiently inclusive to provide the legal basis for regulating SD. Consequently, there should be clearly specified and consistent terms under which SD is required, used and refunded. In Trinidad and Tobago, the SD is a one-off payment and it does not attract interest. There are two main areas of concern raised by consumers; the structure and value of the SD, and the payment of interest.

There are many conventions that are used by utility companies in other international jurisdictions to determine the value of the SD, including:

- not exceeding one month's estimated consumption;
- one month's estimated consumption on the condition that if a customer defaults in payment of his/her bills more than once in any financial year,

or two consecutive months spread over two financial years, the utility company would be free to have the SD increased so as to be equal to the bill for two months' estimated consumption. Nevertheless, the utility company would be entitled to request an increased amount of SD only once in any financial year from such consumers;

- estimated monthly average cost of the annual consumption by such customer plus thirty percent;
- not exceeding two months estimated consumption; and
- large SD is required where there is a high risk of non-payment, but the SD is refunded over a period not exceeding 15 years.

Similarly, there are different requirements/circumstances under which deposits are imposed by different utilities. In fact, many regulators have imposed conditions where SD may not be required unless one or more of the following applies:

- the customer is known to have left a previous supply address without settling an outstanding payment;
- the customer has been responsible for the illegal use of electricity;
- the customer is new and refuses to produce acceptable identification; and
- the customer does not have a satisfactory credit rating.

Regardless of the different requirements for the imposition and the payment amounts for the SD, many utilities pay interest on the SD at a rate and on terms approved by regulators. Different regulators have set different rates and terms for the payment of interest. As indicated above, the SD in Trinidad and Tobago does not attract any interest.

The RIC is not totally convinced that a sufficient case has been made for the payment of interest. T&TEC has to make large cash outlays to arrange for the supply of electricity to consumers, who consume electricity on credit of varying periodicity, depending on the consumer category. Hence, this security is justified, and is in the nature of an advance consumption deposit aimed at continually offsetting amounts owed by the consumer to ensure payment. Furthermore, this deposit is not similar to a savings deposit or fixed deposit but is essentially a running current account. Additionally, the nature of the relationship between the supplier and the customer is not one of debtor and creditor. In light of the above, the RIC is reluctant to pronounce on the merits of the case for interest payment. However, the RIC is open to suggestions and intends to establish a Working Group to develop proposals on the issues associated with the service deposit.

The RIC considers that the service deposit issue needs further investigation, and will establish a Working Group comprising the service provider, NGOs, other consumer groups, and the RIC. This group will develop proposals on service deposit issues and report to the RIC within six months of the establishment of the Working Group.

10.5 CAPITAL CONTRIBUTION

A Capital Contribution (CC) is a network cost which is an advance lump sum payment to facilitate infrastructure works for an electricity supply. It is the customer's contribution to the capital cost of new network development.

Where a customer is not close to the existing network, or the network is already fully used and new capacity is required, the cost of extending the network may be high. Under these circumstances, a customer is required to pay all or part of the capital cost, which may act as a significant barrier to obtaining a connection. Alternatively, if a large proportion of the costs is recovered through tariffs rather than through a CC, the customer being connected enjoys a significant benefit at the expense of other customers on the system. Masking these costs can lead to inefficient network investments. Consequently, both customers and service providers raise concerns regarding the impact/effect of capital contributions.

A number of key elements characterize T&TEC's current capital contribution system:

- Customers are responsible for the direct cost of all non-shared assets required for their connections downstream from the point of connection (i.e. the nearest point on the network capable of supporting the customer load). These costs include labour and materials (lines, poles, insulators, transformers etc.) that are dedicated to that customer or group of customers.
- There is no scheme for reimbursing customers for assets they have funded if these assets are subsequently shared.
- The CC is non-refundable and is aptly termed Non-Refundable Capital Contribution (NRCC).
- T&TEC calculates the NRCC requirement as follows:

  NRCC = 70% of Total Cost (TC) minus projected revenue (PR) for 3 years.

  If PR is ≥ 70% of TC, no NRCC is required.

There are a number of issues in respect of capital contributions and these may be grouped into the following areas:

- definition of a connection point;
- definition of shared assets;
- funding of connection works; and
- asset ownership.

Additionally, the charging methodology raises equity issues, in particular it encourages parties seeking connections to delay in the hope that someone else will fund the necessary infrastructure, upon which they would be able to "free ride".

Capital contribution issues are complex and far-reaching and need further investigation. However, in the interim, an applicant for a connection may be required to make a capital contribution towards the extension of connection equipment or network system assets only if the service provider can demonstrate that extension is not commercially viable without such a capital contribution.

> The RIC will set up a Working Group comprising the service provider, NGOs, other consumer interests, and the RIC. This group will develop proposals on capital contribution issues and report to the RIC within six months of the establishment of the Working Group.

CHAPTER 11

REVENUE REQUIREMENT

11.1 INTRODUCTION

Setting price controls involves two main steps:

- determining revenue requirements for the service provider, based on a given level of service quality to be provided over the control period; and
- designing a tariff structure such that the expected revenue is equal to the forecast total revenue requirement.

The forecast revenue is the sum of the return on capital, the return of capital (depreciation) and the Opex. These components were discussed in Chapters 5, 6 and 7.

This chapter brings together these individual building-block components in order to estimate the revenue requirements for the regulatory control period. In light of the fact that a certain proportion of the revenue of the service provider comes from sources other than the regulated tariffs (e.g. capital contributions made by customers), adjustments are made to establish the revenue forecasts of the service provider. Any variations from those forecasts, whether favourable or unfavourable, will redound to the benefit or will be borne by the service provider. It is also to be noted that external benchmarks were used to complement the RIC's analysis of the building-block components to establish the forward-looking forecasts upon which the price controls are based.

11.2 REVENUE REQUIREMENT MODEL

The functional form of the model utilized by the RIC for estimating the revenue forecasts is shown below:

$$\mathbf{Rev._{Max} = WACC * (RAB + Capex) + D + Opex_{TD} + PP + F}$$

Where:

$Rev._{Max}$ = Maximum Revenue

WACC = Weight Average Cost of Capital

RAB = Regulatory Asset Base

Capex = Capital Expenditure

D = Depreciation

$Opex_{TD}$ = Operating and Maintenance expenditure for transmission and distribution (including internal generation)

PP = Purchased Power (conversion costs)

F = Fuel Costs

To the above maximum revenue, any necessary positive or negative revenue adjustments are made to arrive at the annual revenue requirement (ARR) forecasts upon which the price controls are based. These adjustments are for the non-tariff revenues the service provider makes and all other adjustments the regulator makes in its determination of the service provider's revenue needs.

11.3 ANNUAL REVENUE REQUIREMENT

In establishing the annual revenue requirements for the regulatory control period, the RIC utilized a cost of capital of 8%, a regulatory asset base of $1,276.29 million, and straight-line depreciation (discussed in Chapter 7), operating and maintenance expenditure requirements, and conversion and fuel costs (discussed in Chapter 5), and capital expenditure (discussed in Chapter 6).

In arriving at the annual revenue requirement of T&TEC, the RIC deducted amounts reflecting forecast capital contributions over the regulatory control period. The RIC will include all contributed assets in the regulatory asset base and will make an equal and offsetting reduction to the service provider's revenue in the year of acquisition. This method leaves the service provider no better or worse off, and it also avoids the problems of tracking contributed assets separately.

A similar adjustment was also made for the shared assets (e.g. rental of poles). While not impacting on the forecasts of revenue during the first price control period, the revenue adjustment would also be made based on the service provider's "under and overs" account in future. Revenue adjustments can also be expected for items such as disposal of assets, change in asset lives etc.

A significant revenue adjustment item for this price control period is the dividends received by T&TEC from its investment in PowerGen. The shareholding in PowerGen was derived from the sale of the generating assets from T&TEC to PowerGen in December 1994. Consideration for the generating assets was in the form of majority ownership (51% shareholding). The taxpayers paid for the assets in question since T&TEC received subventions from Government. As a result of this, the RIC has determined that any returns from these assets should be returned to the rate-paying base.

Having assessed and reached decisions on the various cost components, as detailed in the previous chapters, the RIC has used the cost building blocks set out in **Table 11.1** to determine revenue forecasts and the associated annual revenue requirements for the first regulatory control period.

Table 11.1 - Revenue Forecasts and Annual Revenue Requirements, 2006-2010 ($Mn)

	T&TEC REQUESTED	RIC APPROVED	2006	2007	2008	2009	2010
Conversion Cost	5,450.31	5,271.38	792.66	844.08	1,050.27	1,192.87	1,391.51
Fuel Cost	3,770.40	3,232.00	584.10	609.40	651.00	671.50	716.00
T&D Cost	2,037.27	1,848.85	342.34	356.10	369.44	384.62	396.35
Depreciation	616.40	473.56	76.90	82.76	95.69	104.36	113.85
Return on Capital	870.60*	601.00	108.20	116.80	122.70	125.30	128.00
Return on Working Capital	-	68.75	10.78	12.20	13.83	14.97	16.97
Unsmoothed Revenue Forecast	**12,744.98**	**11,495.55**	**1,914.98**	**2,021.34**	**2,302.93**	**2,493.62**	**2,762.68**
Less: Revenue from Non-Tariffs**	770.81	770.81	151.66	153.02	154.37	155.76	156.00
Less: Asset Disposals	2.28	2.28	0.37	0.32	0.61	0.74	0.24
Unsmoothed Annual Revenue Requirements	**11,971.89**	**10,722.46**	**1,762.95**	**1,868.00**	**2,147.95**	**2,337.12**	**2,606.44**
Embedded Debt Cost	**-**	**386.60**	**128.89**	**122.92**	**109.71**	**25.08**	**-**
Less: Refinancing of NGC Loan		**6.82**	**3.10**	**2.17**	**1.24**	**0.31**	**-**
Unsmoothed Revenue Requirement	**11,971.89**	**11,102.24**	**1,888.74**	**1,988.75**	**2,256.42**	**2,361.89**	**2,606.44**

* This includes return on working capital as T&TEC did not reflect it separately.
**This includes dividends, capital contributions, pole and transformer rentals etc.

The RIC's overall approved revenue requirement is $1,250.43 million (exclusive of embedded debt), lower than T&TEC's proposal over the five years of this regulatory control period. This difference reflects a number of individual cost decisions, with the following accounting for nearly all of the difference:

- reduction in forecast of operating expenditure of $905.74 million, including generation costs ($178.92 million), fuel costs ($538.4 million);

- reduction in the forecast of capital expenditure; and
- reduction in depreciation charges ($142.84 million).

The RIC considers the total revenue requirement, as proposed in **Table 11.1**, to be sufficient for T&TEC to meet the expenditure required for the effective exercise of its core functions, as well as meeting the milestones for customer service improvements.

The RIC's allowed annual revenue requirements are as follows:

2006 ($Mn)	2007 ($Mn)	2008 ($Mn)	2009 ($Mn)	2010 ($Mn)	TOTAL ($Mn)
1,888.74	1,988.75	2,256.42	2,361.89	2,606.44	11,102.24

11.4 IMPLIED AVERAGE PRICE CHANGES

As a broad guide to pricing impacts over the control period, the implied real and nominal price increases are shown in **Table 11.2** below. These "prices" (¢/kWh) are calculated by dividing the annual revenue requirements by the forecast level of electricity consumption. This is a notional price only and does not represent differences across and within customer classes.

Table 11.2 - Implied Average Annual Price Changes, 2006-2010

	2006	2007	2008	2009	2010
Annual Revenue Requirement ($Mn)	**1,888.74**	**1,988.75**	**2,256.42**	**2,361.89**	**2,606.44**
% Change	**6.02**	**5.30**	**13.46**	**4.67**	**10.35**
Forecast Consumption (GWh)	7,205	7,330	7,627	7,882	8,150
Implied **Nominal** Price (¢/kWh)	26.21	27.13	29.58	29.96	31.98
Year-on-Year Percentage Change (%)	**16.61**	**3.49**	**9.03**	**1.28**	**6.74**
Implied **Real** Price (¢/kWh)*	22.55	22.65	23.99	23.58	24.48
Year-on-Year Percentage Change (%)	**13.21**	**0.48**	**5.91**	**(1.73)**	**3.84**

*** Based on 2003 prices.**

11.5 REVENUE SMOOTHING AND CALCULATION OF THE X-FACTOR

11.5.1 Introduction

The data in **Table 11.2** reveal that there is an increase of 6.02% in T&TEC's annual revenue requirement in the first year of the regulatory control period. This first year increase is followed by further increases of 5.30%, 13.46%, 4.67% and 10.35% for 2007, 2008, 2009 and 2010 respectively.

Having determined these revenue requirements for each year, the RIC needed to calculate the amount by which T&TEC's revenue can rise or fall in each year of the regulatory control period to generate the calculated revenue requirements. It must be noted that the actual revenue of T&TEC for each year will depend on actual growth in sales of electricity and cost reductions and so may be more or less than forecast revenue requirements. Under the RPI-X form of regulation, the regulator determines the X-factor. The X-factor is the real change in revenue or prices each year.

In order to determine this X-factor, the regulator needs to make a number of decisions, including:

- the form of regulation – the variable to which the RPI-X adjustment factor is applied; and
- the form of the X-factor – the manner in which the X-factor will change across the regulatory control period.

11.5.2 Form of the X-Factor and Smoothing

It was noted in Chapter 2 that the RIC decided to utilize a "total revenue" cap form of regulation for the first regulatory control period. This section provides the RIC's rationale on the approach to be used to calculate the X-factor for each year.

The X-factor could be a constant value over the course of the regulatory control period or a different value each year, or there could be an initial adjustment (commonly referred to as a P_o adjustment) followed by a different X-factor in subsequent years. If the X-factor is to be the same for each year, the regulator needs to decide how the total revenue requirement is to be "smoothed" over the regulatory control period in order to allow for the use of a stable X-factor.

In fact, in order to reduce volatility in annual revenues and resulting prices to customers, it has become common practice for regulators to smooth the revenue requirements over the regulatory control period.

In considering any revenue smoothing, the RIC has to consider the conflicting objectives. In particular, the objectives in the RIC Act specifically require that the service provider is able to earn sufficient return to finance necessary investment (that is, a sufficient return over the regulatory period and not necessarily in any given year), while having regard to the ability of consumers to pay rates.

In Chapter 2, it was pointed out that there are four broad approaches for calculating the amount by which revenue needs to change to deliver the forecast revenue requirements to the service provider over the regulatory period. In deciding which approach to use, a number of different implications need to be considered, including; price stability, revenue recovery, incentives for efficiency and transitional issues going into the next regulatory period. In fact, a price-cap plan must begin from a fair starting point. The fair starting point must provide the utility with a reasonable opportunity to recover its just and reasonable cost of doing business, including cost of capital

There are two commonly used methods for calculating a constant X-factor – straight-line smoothing and net present value (NPV) smoothing. The information requirements for both methods are similar and they are calculated in a similar fashion. Straight-line smoothing solves for the level of X so that the revenue requirement in the last year equals the smoothed revenue in the last year of the regulatory period. Here, the service provider's revenue requirements during the intervening years may be higher or lower than the forecast revenue requirements. NPV smoothing solves for the level of X so that the NPV of forecast revenue requirements equals the NPV of the smoothed revenue where average revenue grows by RPI-X every year. In other words, the NPV smoothing balances costs and revenues over the entire regulatory period and not just in the last year as in the case of straight-line smoothing. The equating of expected revenue and forecast revenue requirements in NPV terms takes account of any timing differences in receipts and costs. For example, if a service provider is expected to earn more revenue than the forecast revenue requirement in the early years of the control period, then under this approach, the potential interest it can earn on the difference is effectively deducted from the forecast revenue requirement in later years. There is a much simpler and theoretically sound method, "Average Growth Rate Smoothing" which can also be utilized to meet the stated criteria of price stability, revenue recovery and transitional issues.

This section provides a brief evaluation of the outcome of each method against the above-mentioned criteria. Ideally, any smoothing approach should leave the service provider no worse off in real terms. To be fully consistent with the principles of incentive regulation, the revenue expected over the forthcoming regulatory control period should equate with the unsmoothed revenue requirements in NPV terms over the same period. It should also provide price stability and sustainability over the regulatory period and arrive at a revenue requirement in the final year that offers a prospect of a smooth transition into the next regulatory control period. These objectives may not always be met. A comparison of outcomes under these methods is presented in **Table 11.3**.

Table 11.3 – Comparison of Outcomes of Smoothing

	NPV Smoothing	Straight-line Smoothing	Average Growth Rate Smoothing
Constant X-Factor	**7.4%**	**8.0%**	**7.7%**
Level of Revenue Recovery ($Mn) (Unsmoothed)			
2006 – 1,888.74	1,901.03	1,916.08	1,876.58
2007 – 1,988.75	2,041.71	2,074.16	2,021.08
2008 – 2,256.42	2,192.80	2,245.28	2,176.70
2009 – 2,361.89	2,355.06	2,430.52	2,344.31
2010 – 2,606.44	2,529.34	2,631.04	2,524.82
Total 11,102.24	**11,019.94**	**11,199.72**	**10,943.49**
Revenue Recovery Over 5 Years	**Full in NPV terms**	**Over by $97.48 Mn.**	**Less by $159 Mn.**
Final Year Revenue Recovery	**Under by $77 Mn.**	**Over by $25 Mn.**	**Under by $82 Mn.**

The results show that the NPV method would require revenues/prices to go up by the smallest amount as the X-factor is 7.4% for each year of the control period. In the case of straight-line and average growth rates methods, the value of the X-factor is much higher (between 8.0% to 7.7%), thereby imposing a sustained larger price increases across the entire regulatory control period on all customers. Furthermore, straight-line smoothing is forecast to over recover revenue by $97.48 million over the regulatory control period, whereas there will be under recovery of $159 million in the case of average growth rate smoothing.

Additionally, all methods fail to meet one of the criteria of arriving at a revenue requirement in the final year that offers the prospect of a smooth transition into the next regulatory control period. However, the RIC believes that this is unlikely to impose a serious problem as it is expected that T&TEC's performance will improve over the control period and there will be efficiency gains towards the end of the first regulatory control period.

In short, the NPV smoothing provides a more reasonable and acceptable balance of the interests of all stakeholders. In light of these arguments, the RIC utilized the NPV smoothing approach which satisfies most of the above criteria and, by achieving an equivalent NPV to the unsmoothed revenues, is economically sound.

The effect of NPV smoothing of T&TEC's annual revenue requirements to eliminate year-to-year volatility while still returning the same amount of revenue (in NPV terms) over the regulatory control period is detailed in **Table 11.4**.

Table 11.4 – NPV Smoothed Annual Revenue Requirements, 2006-2010

	2006	2007	2008	2009	2010
Unsmoothed Revenue Requirement:					
- $Mn.	**1,888.74**	**1,988.75**	**2,256.42**	**2,361.89**	**2,606.44**
% Change	**6.02**	**5.30**	**13.46**	**4.67**	**10.35**
Smoothed Revenue Requirements:					
- $Mn.	1,901.03	2,041.71	2,192.80	2,355.06	2,529.34
% Change	**7.4**	**7.4**	**7.4**	**7.4**	**7.4**

Based on the above calculation, the average revenue will increase by 7.4% (**RPI + 4.4 percent)** per year (in real terms) under the NPV smoothing approach. Within this average revenue outcome, there will potentially be price changes on either side of this average for some customers. The price increases over the regulatory control period are expected to be matched, in broad terms, by improvements in service quality, in particular due to the minimum service standards being proposed by the RIC, apart from the Guaranteed Payments Scheme already in existence.

The RIC's decision is to adopt the NPV smoothing approach as it allows the service provider to recover fully its revenue requirements, as well as minimize price volatility for customers.

11.6 ASSESSING FINANCIAL VIABILITY

11.6.1 Importance of Financial Viability Analysis

Having calculated the maximum allowable revenue, it is necessary to determine whether the service provider will generate sufficient revenue to remain a financially viable stand-alone entity. In this section the financial viability analysis is undertaken.

The cost of capital is the minimum rate of return that investors require on their investment, given the risk profile of such investment. Therefore, from a theoretical stand point, an efficiently financed company might be expected to be able to attract sufficient funds to finance its functions, given an appropriate rate of return on both equity and debt, determined without reference to explicit tests of cash-based ratios.

However, capital investment programmes may be "lumply" and a large Capex programme might leave a company with temporarily low interest cover ratios. Consequently, regulators often use financial indicators and tests to adjust allowed returns.

The major objective of the financial indicators is to monitor the ability of the service provider to attract equity capital in future and its ability to raise and service debt. The first of these will be satisfied if the returns to equity investors included in the forecast revenues by the regulator are within the range that equity investors expect in current financial market conditions. The second centres on the credit worthiness of the regulated business. This objective will be met if the cash flows implied by the regulated revenues would continue to sustain a commercially satisfactory credit rating.

The results of the financial analysis can also be utilized as a "check" on the proposed initial regulatory asset base. For instance, if the service provider's initial RAB (Regulatory Asset Base) provides a level of financial performance that is high in comparison to other utilities, this could indicate that the initial RAB and associated revenue requirements are high. The central principle of financial viability analysis is that revenue requirements should allow the service provider a reasonable revenue to cover its operating costs, depreciation and provide a reasonable return on the service provider's capital base.

Requirements of the RIC Act

One of the key components of the new regulatory framework under the RIC Act is that prices for services will bear a formal relationship to costs, as Section 6 (1) (c) of the RIC Act requires that services provided will be on terms that will allow the service provider to earn sufficient return to finance necessary investment. More specifically, Section 67 (4) states that the Commission shall have regard to the following:

- replacement capital cost expended;
- least-cost operating expenses which may be incurred;
- annual depreciation; and
- return on the rate base.

11.6.2 Indicators of Financial Viability

As the focus of an assessment of financial viability is the ability of an entity to meet its cash obligations, the most relevant financial indicators are those that reflect the cash needs of the service provider. The financial indicators that reflect accounting identities, such as provisions and accruals are influenced by the entity's accounting policies. As such, they are likely to provide a misleading impression of the actual needs of the service provider.

In fact, cash-based financial ratios are used by privatized utilities which are required to maintain strict credit ratings. Complying with all the ratios would not only be challenging but may not be totally desirable for a state-owned entity which is funded entirely by customer charges and debt. The RIC expects T&TEC to be broadly compliant in future, with the target value for these ratios.

The cash flow based indicators generally measure the ability of service provider to service its debt burden. The trend of such financial indicators, considered as a package, is generally more important than the absolute figures for any particular indicator in any particular year.

A range of financial indicators can be used to assess the sustainability of revenue streams. However, the cash-based financial indicators that both regulators and rating agencies most commonly use for assessing the strength of cash flows are shown in **Table 11.5** below.

Table 11.5 - Proposed Main Financial Indicators for Assessing Financial Viability

Indicator	Description	Formula	Target
Funds Flow Interest Cover (Times)	Measures the level of protection the entity has to meet its interest obligations after meeting its cash operating expenses.	(FFO[11]+ Net Interest) / Net Interest	Between 2 to 3
Debt Payback Period (Years)	Measures the length of time that the entity could retire its debt if it devoted all cash flow (after meeting cash operating expenses).	Net Debt / FFO	Between 5 to 7
Funds Flow / Net Debt (Times)	Inverse of net debt payback and provides a measure of the extent to which serviceability of debt is improving/declining.	FFO / Net Debt	Greater than 13
Internal Financing Ratio (%)	Measures the extent to which an entity has cash remaining to finance prudent capital expenditure after dividends (if any).	(FFO – Dividends) / Net Capital Expenditure	Minimum 40
Debt as a proportion of the RAB (%)	Measures the debt component in regulatory capital structure.	Net Debt / RAB	Below 65

Based on a cost of capital of 8.0% (discussed in Chapter 7), **Table 11.6** below sets out the financial ratios for T&TEC. The revenue requirements have been set to allow T&TEC to maintain both an adequate level and trend of critical financial indicators, as well as ensuring that T&TEC is able to earn, on average, a return at least equal to the

[11] FFO is funds from operations and is approximately equal to the accounting definition of net cash flow from operating activities, less the sources of non-recurrent revenue – i.e., revenue from customer capital contributions and the proceeds from disposals.

assessed (8.0%) cost of capital. Despite being allowed an adequate return on capital, there may be variations in the cash based indicators from year to year due to the relative amount of debt at the beginning of the regulatory control period as well as its type (for example, fixed or floating rate), maturity and cost.

Table 11.6 - Key Financial Performance Ratios for T&TEC, 2006-2010

	2006	2007	2008	2009	2010	"Best Practice" Target
(FFO + Net Interest) / Net Interest (Times)	3.29	3.35	2.72	2.85	2.16	Between 2 to 3
Net Debt / FFO (Times)	4.58	4.33	6.45	6.20	11.22	Between 5 to 7
FFO / Net Debt (Times)	0.22	0.23	0.16	0.16	0.09	Greater than 13
(FFO – Dividends)/Net Capex (%)	73.6	143.1	94.4	127.6	66.4	Minimum 40%
Net Debt / RAB (%)	83.7	81.1	78.5	75.6	76.5	Below 65%

Given T&TEC's current financial position and the fact that the cash-based ratios are mainly used by privatized utilities whose shares are traded on the stock markets, the ratios set out in **Table 11.6** show that T&TEC's financial position is comfortable when considered as a package over the length of the regulatory control period. Even though all of the cash-based financial ratios do not fully comply with target ratios in each year, one of the more important ratios (i.e. debt to RAB) improves over the control period.

Some regulators use a rule of thumb to assess financial viability of a network. A commonly used rule of thumb is that a well-run electricity company should be financially viable if its distribution margin (i.e., the difference between its average tariff to its customers and the average price that it pays for power purchases) is at least over 3 cents per kWh. **Table 11.7** shows the distribution margin for the period 2006-2010. It shows that T&TEC has a comfortable distribution margin per kWh.

Table 11.7 – Distribution Margin Per kWh for T&TEC, 2006-2010

	2006	2007	2008	2009	2010
Average Price of Power to T&TEC (¢/kWh)	20.10	20.39	22.98	24.27	26.47
Average Tariff to Customers (¢/kWh)	29.61	29.87	32.41	32.63	34.55
Distribution Margin (¢/kWh)	9.51	9.48	9.43	8.36	8.08

11.7 RIC'S PROPOSALS FOR SHAREHOLDER'S CONSIDERATION

As part of the consultation process and in the light of the fact that T&TEC was last permitted a general rate increase in 1992 and a further increase for industrial customers in 1997 and given that the RIC's determination will move T&TEC to a full cost recovery mode within the first five year rate review period, the RIC had put forward a number of proposals for the shareholder's (Government) consideration. These were as follows:

i. that Government assume responsibility for the NGC 8.75%, loan in the sum of $403 million taken in 2003 with final payment due in 2009. This measure will reduce T&TEC's revenue requirement by $449 million over the review period;

ii. that Government assume responsibility for the $500 million, 12.25%, 2021 Bond Issue which matures in 2021. This measure will reduce T&TEC's revenue requirement by $470 million over the review period;

iii. that Government assume responsibility for both loans at (i) and (ii) above to give a resultant reduction in revenue requirement of $919 million over the review period;

iv. that Government assume responsibility for T&TEC's embedded cost amounting to $387 million;

v. that T&TEC should enter into a long-term natural gas contract with NGC at the current price of US$0.87/MMBTU with an escalation of no more than 4% per annum;

vi. that the Reserve Vote system be reintroduced whereby funds are specifically allocated to Ministries/public sector bodies for the payment of utility bills only. As an interim measure, an interest free loan to T&TEC to compensate for outstanding electricity rates owed by Government Ministries/Agencies be considered; and

vii. that Government renegotiate the existing power purchase agreements with the involvement of the RIC in the light of several clear inadequacies in these agreements in particular the heat rate, where the RIC has estimated that if the current heat rate trends persist over the coming five years, there will be a cost of $578 million more than is efficient and hence not justifiable. In fact, the RIC has already taken this into account by a 2% reduction in the conversion costs and a 10% reduction in the fuel costs proposed by T&TEC. However, unless there is a renegotiation of the contracts, T&TEC may still be required to meet these costs on the grounds that they arise out of existing power purchase agreements with PowerGen and Trinity Power. This proposal for renegotiation is not unique. In fact, other countries have successfully engaged in such renegotiations in recent years including Costa Rica, Indonesia, the Philippines and Croatia.

Additionally, the shareholder can also decide, inter alia, to subsidize tariffs to customers or a class of customers to avoid the need for large tariff increases provided it compensates the service provider to the extent of subsidy granted. The whole issue of subsidization, however, raises a number of issues for the regulator, including:

- the mechanism for the payment of subsidy;
- the total amount of the subsidy to be provided and the length of the period over which the subsidy will be available; and

- whether there should be a government guarantee to ensure that the subsidy would actually be paid as promised. This is important because in the event of non-receipt of subsidy, the regulator should be able to resort to the Full Cost Tariffs to ensure the service provider's operations remain unaffected.

The RIC in its Draft Determination had indicated that the acceptance of some or all of the above proposals by the shareholder would be acknowledged and taken into consideration in the calculation of the RIC's final tariff proposals.

In response to the Draft Determination, the shareholder (Government) has indicated that "it is not in support of a general price subsidy, even by way of the removal of Value Added Tax on electricity, as it provides a greater subsidy to consumers who have higher electricity usage and are by definition less in need of the subsidy". Further, it stated that the RIC should not use the subsidy, if any, to determine the price cap as there are a number of options open to the shareholder to provide relief to low income earners, one of them being the Hardship Relief Programme. Additionally, the shareholder has stated that it has agreed to give consideration to the provision of funds to assist T&TEC in servicing its debt obligations in the sum of $283 million.

CHAPTER 12

ESTABLISHING PRICE CONTROLS

12.1 INTRODUCTION

Tariff setting is an important tool for making the electricity sector self-sufficient. It is useful for improving efficiency, enhancing the quality of service and providing the shareholders with the confidence to introduce new technology and management techniques. In meeting these objectives, the RIC has to balance the interests of consumers and the service provider, and also ensure that this process is undertaken in a fair, impartial and transparent manner. This requires fair allocation of costs among customer classes according to the burden they impose on the network. There also has to be a reasonable degree of price stability so that large price fluctuations are avoided from year to year. The special needs of the customers who may not be able to afford full cost cannot be overlooked.

The previous Chapter 11 illustrated the impact on average price levels arising from the proposed annual revenue requirements. This chapter sets out the issues relating to the design and structure of tariffs, and presents an indication of the likely impacts of the different proposals.

12.2 PRICING METHODOLOGIES AND TARIFF DESIGN

After the total revenue requirements of the service provider are determined, it is necessary to determine the price each consumer category should pay for electricity. This is accomplished by the process of cost allocation which involves the following three steps. First, the total costs of the service provider are calculated. These costs represent the total revenue the service provider is allowed to recover from customers. These revenues determine the overall level of rates. The second step assigns responsibility by customer class for total costs based on share of costs. A third step is developing what is called a rate design. A rate design establishes a set of prices charged to each consumer class for varying levels of consumption.

12.2.1 Cost Allocation

Cost allocation, therefore, refers to the setting of prices for particular customers or classes of customers that recover the costs of the service provider. It includes the determination of a proportion of the total costs of the service provider that is recovered from particular customers or classes of customers, and from particular components of a price (for example, fixed and variable charges) that a customer or class of customers pays for the service.

Cost allocation normally involves assigning costs by utility function (e.g. generation, transmission, distribution), rate components (e.g. energy, demand, customer), costing periods (e.g. peak, off-peak, non-time differentiated), and consumer classes (residential, commercial, industrial).

With regard to rate components, separate demand, energy and customer charges may be imposed on customers. Demand charges reflect the cost of meeting maximum demand; these costs may include the cost of capital and other fixed expenses associated with generating plants, transmission lines, substations, and part of the distribution system. Energy charges reflect the costs associated with the amount of kilowatt hours consumed, while customer charges incorporate the cost to the utility of a customer having access to its system.

In a general sense, the allocation of costs and the setting of prices by the regulator may be accomplished in one of two ways:

- an explicit allocation of costs or share of costs to customer classes and to particular components of a price structure; or
- a determination of prices for customer classes and components of a price structure according to a range of commercial or other considerations and subject to a constraint that the prices set should not recover more than the total cost of the service provider. Under this approach, the service provider is generally subject to either the price or revenue cap form of price control and it has significant flexibility in the setting of prices subject to maximum

changes in prices from year to year. This approach involves determining a path for reference tariffs, rather than a tariff structure, that is forecast to deliver a revenue stream.

Whatever approach is taken, the resulting prices should meet the requirements of economic efficiency[12] and equity. There are at least three approaches to cost allocation.

Equity and Social Rate Making

Generally accepted social/equity considerations require that costs recovered from each customer cover at least the avoidable cost of providing the service, and that common costs be allocated such that each user bears a "fair" share of these common costs.

However, under the social rate-making approach, social policy determines the final levels of revenue from each class and there is little relationship between the costs a customer imposes on the network and the price the customers pay. The inefficiencies inherent in this method are significant.

Marginal Cost-based Tariffs

The most economic allocation of a service provider's revenue requirement can be achieved through the use of marginal costs as the basis for class revenue developments. This is done by determining what the revenue realization would be if marginal costs were charged as prices to each class and then comparing the total to the revenue requirement of the utility. Almost certainly, the two totals will differ, as marginal cost pricing under conditions of natural monopoly, leads to the marginal price being less than the average price. This causes the service provider to incur a loss thereby violating

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[12] Economic efficiency can be defined as an outcome whereby it is difficult to reallocate resources between uses, or to change production techniques in order to make consumers as a group better off. Economic theory distinguishes between three components of economic efficiency:

- allocative efficiency – which means that the right mix of goods and services is being produced;
- productive efficiency (or X efficiency) – which means that the mix of goods and services is being produced at the lowest cost; and
- dynamic efficiency – which means that the right mix of goods and services continues to be produced for the lowest cost over time.

the requirements for achieving allocative and dynamic efficiency. In addition, the utility may also fail to attract investment. Solutions have been suggested to address this issue:

- provide revenue on a per customer basis that is lower than the stand alone cost of providing the service; and
- provide revenue on a per customer basis that is higher than the avoidable cost of providing the service.

Setting prices within these bounds (generally referred to as upper and lower bounds for efficient prices) implies an allocation of the joint or overhead costs of service provision across customers. As a general proposition, this efficiency goal would be met if the recovery of joint or overhead costs is derived from those customers with more inelastic demand for the service over the relevant price range (i.e. second-best or Ramsey pricing rule). A strict adoption of this rule would make prices high for consumers whose use of electricity constitutes a necessity and these are usually the low-income groups.

Fully Distributed Cost Models for Cost Allocation

Under this method, revenue responsibility is assigned using the results of a cost study based on the historic, embedded costs of the utility. Generally, this method allocates costs by:

- attributing them to a particular class of customers; and for costs that are of a common or shared nature, allocating those by cost-allocation rules/factors. These factors can be based on the contributions of the classes to the total demand, the kWh purchased by each class as a percentage of total sales, the number of customers in the class as well as many other factors and combinations thereof.

This is the most common method used for cost allocation. Cost of service plays a pivotal role in the process of rate making and determining tariffs for different categories of consumers. The service provider is required to undertake separate studies on each category to ascertain the shapes of the load curves of individual consumer categories and their consumption patterns. The distribution of joint costs of transmission and distribution are allocated to each category of consumers based on three allocation factors: energy, demand and customer charges. Among the three factors, contribution to peak demand has a decisive influence on the cost-to-serve of a category. The full unit energy (kWh) cost to-serve is the total cost weighted by the allocation factors and divided by the net units consumed (net of losses).

The advantage of this method is that the data are typically recorded in the books of the service provider. The main disadvantage is that tariffs based on this method reflect the average historic costs of supply, which tend to be different from the economic costs. As a result, consumers may make distorted decisions about the level of electricity consumption. The other disadvantage is that regulators must make certain assumptions in deciding which allocation factors should be used in allocating the overall costs to functions and individual consumer classes.

Notwithstanding these limitations, this method offers valuable information requiring judgment by analysts and regulators. The method certainly does not produce precise results but the pertinent question is whether other methods are better. Currently the answer seems to be that there are no better methods.

12.2.2 T&TEC's Cost Allocation Methodology

T&TEC uses the Fully Distributed Cost Method for undertaking a cost of service study. The costs directly associated with a customer class are assigned to that class and the remaining costs are then apportioned based on three steps:

- **Functionalization** – assignment based on functional categories, e.g. generation, transmission and distribution.
- **Classification** – assignment by energy usage, peak demand and number of customers within the functional categories.
- **Allocation** – assignment to customer groupings or classes after the costs have been functionalized and classified.

After functionalization, it is necessary to decide whether the predominant criteria should be employed. Under this method, if an account is predominantly (51-100%) energy related (or demand related) it is classified as energy (or demand) costs. Accordingly, the costs of the network are divided into customer costs, energy (volumetric) and demand (capacity) costs. However, allocation of demand cost is a complex issue and there are three methods for allocating demand costs:

- **Coincident System Peak Responsibility Method** – here the entire capital costs are imputed to those services that are rendered at the time of system peak.
- **Non-coincidental Demand Method** – this method apportions capacity entirely on the basis of kilowatts of load rather than on the basis of kilowatt-hours of energy in proportion to the maximum demands of the different classes even though these demands may not coincide with the system peak.
- **Average and Excess Demand Method** – this method apportions costs based on two criteria, namely the average demand and the excess demand of the class. The average demand cost represents the cost of plant and other "capital type" expenses required to serve the system's average demand. This cost is divided among customer classes in proportion to their average demand. The excess system demand cost represents the additional costs to serve demand in excess of the average. These costs are divided such that those customer classes which have a high excess demand in relation to their average demand, bear the larger share. The average and excess demand method is widely used by utilities, including T&TEC, and is arguably the fairest method of allocating demand costs.

Based on the fully distributed cost model, revenue allocation for each class of customers is presented in **Table 12.1**.

Table 12.1 – Revenue Allocation by Class of Customer

	2006	2007	2008	2009	2010
Residential (36.5%) $Mn	**693.88**	**745.22**	**800.37**	**859.60**	**923.21**
Customers (No.)	321,139	326,773	332,103	337,527	342,889
Consumption (kWh '000)	1,771,667	1,806,029	1,880,944	1,943,129	2,006,918
Commercial (16.2%) $Mn	**307.97**	**330.76**	**355.23**	**381.52**	**409.75**
Customers (No.)	33,314	34,044	34,691	35,330	35,949
Consumption (kWh '000)	685,493	698,175	726,044	749,772	775,070
Industrial (45.8%) $Mn	**870.67**	**935.10**	**1,004.30**	**1,078.62**	**1,158.44**
Customers (No.)	2,549	2,623	2,693	2,762	2,829
Consumption (kWh '000)	4,747,839	4,825,796	5,020,012	5,189,099	5,365,012
Street Lighting (1.5%) $Mn	**28.52**	**30.63**	**32.89**	**35.33**	**37.94**
Total Revenue Requirement ($Mn)	**1,901.03**	**2,041.71**	**2,192.80**	**2,355.06**	**2529.34**

For the first regulatory control period, the RIC intends to accept cost allocation based on the fully distributed cost method. In future, the RIC will require T&TEC to submit marginal cost analysis that could be used for the development of tariffs.

12.3 OBJECTIVES OF A TARIFF STRUCTURE AND KEY ISSUES

The prime tariff issue is the structure of electricity prices and the resultant impact/implications for both service provider and customers in terms of:

- equity and fairness for customers;
- incentives for efficient use of electricity;
- the link between prices and costs and, therefore, economic efficiency;
- revenue risks and volatility for the service provider;
- the level of revenue raised from fixed charges relative to volumetric charges, including step increases in volumetric charges; and
- the impact on the environment.

The objectives of tariff structure generally include:

- **simplicity** – the tariff structure should be easy to understand. It is only with this understanding that customers will respond appropriately to the price signal given by the structure;
- **social equity** – the tariff structure should be consistent with the social needs of the society. One interpretation[13] of this is that the price of electricity for essential use should not be excessive, and excessiveness is defined in terms of the maximum bill that an individual pays as a percentage of his income;
- **cost recovery** – the prices should fully recover the costs of an efficiently operated business (including an adequate return on investment) but not over-recover costs;
- **economic efficiency** – the tariff structure should encourage productive, allocative and dynamic efficiency, including the optimal use of scarce resources; and
- **other objectives** – the tariff structure should be consistent with meeting government objectives.

Requirements of the RIC Act

The RIC's functions relating to rates and tariffs determination are outlined mainly in Sections 6, 47-52 and 67 of the Act. Specifically, Section 67 provides that the RIC may specify through Regulations, the terms and conditions for the determination of revenues and rates and shall be guided, among other things, by the following:

- funding and ability of the service provider to perform its functions;
- ability of consumers to pay rates;
- quality and reliability of service, in accordance with appropriate standards;
- factors that would encourage maximum efficiency and economical use of resources; and
- national environmental policy.

[13] Another meaning of affordability is the condition under which consumers are able to pay for utility services without foregoing the purchases of other goods and services that are essential to their livelihood.

All the above requirements of the Act are related to the pricing structure. While the RPI-X formula provides the broad framework within which individual tariffs are set, it is the structure of these tariffs that has a more direct impact on consumers and consumption patterns. Thus, tariff structure is fundamental and equally important to, or more important than, the change in average tariff. In accordance with its mandate, the RIC has decided to establish a well-defined framework within which T&TEC must set tariffs and translate the RPI-X price direction into final prices paid by consumers.

Apart from the above objectives specified by the RIC Act, there are other principles which provide signposts for pricing. These require that:

- prices should lie on or between the upper and lower bounds of incremental cost and stand-alone cost for economically efficient prices; and
- prices should signal efficient economic costs of service provision by having regard to the level of available capacity, and should also signal the impact of additional usage on future investment costs.

To meet these pricing principles it needs to be demonstrated that:

- the proposed prices do not involve cross-subsidies (i.e. the prices fall within the upper and lower bounds); and
- the structure of prices (that is, the balance of fixed, demand and energy components) is consistent with economic pricing principles.

No single set of prices can equally satisfy the objectives that have been discussed above. There are always trade-offs between the objectives. Prices have a broader function than signaling economic costs. They are also required to recover the revenue necessary for financial viability and to allocate sunk network costs among customers.

Subsidies and Phasing-in of Tariffs

The above discussion on the objectives of tariff structure clearly raises the issue of subsidies. The current levels of tariff contain a large degree of cross-subsidy, with residential and commercial categories of consumers paying well below the economic cost of supply. These subsidies, of course, have not been confined to benefiting only those who were targeted for the purpose, that is, the lower income groups.

The efficiency criterion requires that tariffs should be cost-based without any cross-subsidization. Cross-subsidization takes place when one consumer group pays a part or all of the cost imposed on the system by another consumer group. Low and subsidized tariffs lead to inefficiently high demand for power, which puts pressure on the system capacity and the quality of service. In fact, cross-subsidization can lead to serious problems for the utility and the country, and these problems generally tend to intensify over time. The adverse consequences of cross-subsidization have several components. First, cross-subsidies are economically inefficient as they provide wrong signals to consumers on the amount of service they should consume. In setting tariffs, economic efficiency should be an important consideration as it takes into account the aggregate costs and benefits of a society.

Second, cross-subsidies are unfair to some members of society. Third, cross-subsidies can impact adversely on the environment. This can include the emission of certain greenhouse gases. Finally, cross-subsidies implemented over a long period of time are likely to lead to shortages and deterioration of service quality as a result of inadequate new capacity and under-maintenance of existing capacity.

Eliminating or reducing cross-subsidies should constitute an important strategy in allowing utilities to increase their revenues and operate their networks efficiently. There are a number of options for reducing cross-subsidies. First, it can be achieved by the "phasing-in" of tariff increases to soften the impact of large rate increases. However, it is generally believed that "phasing-in" of tariff should be undertaken according to a set schedule that is relatively short, for example, often two to three years, but never more than five years. While rate "phase-ins" might make rate increases gradual, ultimately, they result in higher rates and lead to intergenerational equity issues. Second, the reduction of cross-subsidies can be achieved by price re-balancing, that is, the prices for individual categories of customers may vary, in terms of percentage, to mitigate price distortions across consumer groupings. For example, prices can be higher for those classes of customers that have been historically the beneficiaries of cross-subsidies. Finally, lower income groups can be targeted for lower prices through life-line rates[14] and/or by providing income support payments through the governmental budgeting process, as significant increases in tariffs over a short period of time can unduly burden these groups. The cost of tariff relief should be recovered in a manner that does not create additional inefficiencies in the sector. Raising funds through a general tax system imposes lower costs on the society than creating a sector-specific tax system. A financially viable sector would be more efficient, productive and reliable, thereby benefiting consumers. On the other hand, regardless of when and how subsidies are delivered, consumers will ultimately pay for the subsidies either in the form of higher taxes or in reduced government services.

Stakeholder Comments and Final Decision

Broadly, there were two sets of comments. Some of the stakeholders argued that the proposed subsidies were not enough for lower income groups and that there should be special consideration for retired persons. On the other hand, there were other stakeholders who opposed the prevailing and any continuation of cross-subsidies and stated that subsidy to any category of consumers must be limited to the extent that it is borne by the State.

The Government of Trinidad and Tobago has historically provided electricity to the population at below-market prices. As part of the rationalization process, the major issue faced by the RIC, therefore, is how to address the impact of the higher prices on low-income households. The current levels of electricity tariffs contain a large degree of cross-subsidy, with industrial customers paying well above the economic cost of supply, cross-subsidizing other customers to the tune of $215 million in 2005. Many of these industrial consumers operate in an increasingly competitive environment, typically being subject to national and international competition.

[14] A means-tested cross-subsidy produces less inefficiencies than a broad-based cross-subsidy in achieving the same objective of making utility service more affordable to low-income groups.

While not denying the logic for subsidizing or cross-subsidizing the cost of electricity to economically disadvantaged consumers on social considerations, the RIC recognizes the inappropriateness of unwarranted and excessive cross subsidies. However, the RIC is of the view that these imperfections cannot be done away completely in one-go. Therefore, the RIC has reduced these imperfections as the starting point in a progress time bound transformation to distortion free tariff structure, where the tariffs across consumer categories will increasingly reflect the underlying cost of supply. While full discussion as to how the RIC addressed the subsidy issues appears above, its main proposals are summarized hereunder.

First, the adjustment to what would be the desired level of rates is being implemented over the coming five years. Second, correcting the imbalance in the rate differentials between the subsidizing and subsidized categories of consumers is being effected by significantly reducing the amount of subsidy provided to residential customers by industrial customers (i.e. only $57 million for the first year of the regulatory control period) and eliminating subsidy to commercial and street lighting customers. This will bring the proposed rates closer to the cost of supply for all classes. The RIC's proposal on the possibility of introducing time-of-use rates in the future is another element of bringing rates closer to cost-reflectiveness. Third, rates have been structured to provide a subsidy for all residential customers but, in particular, for those consuming the least electricity on the assumption that this coincides with lower income groups. The main rationale being that electricity ought to be made available to every citizen in a modern society because of its potential impact on education, standard of living and quality of life generally.

12.4 TARIFF RE-BALANCING AND SIDE CONSTRAINTS

As indicated above, the RIC is required to consider a number of factors in arriving at its price control decisions, including the impact on consumers and economic efficiency. It is, therefore, common for regulatory arrangements to include a "rebalancing control" or "side constraints" which means setting limits to the extent of annual price increases to customers. In the absence of side constraints, individual customers could face significant price movements from year to year. An example may be to impose a price constraint on the first block of consumption to limit the price increase to the lower income consumers to an affordable level.

Although the side constraints provide price stability for customers, they are likely to have adverse effects in terms of the ability of the regulated firm to fully recover its revenue requirement.

Stakeholder Comments and Final Decision

In general, written submissions supported the use of side constraints, noting the benefits of price stability, especially for lower income groups. T&TEC also supported the use of side constraints for lower income groups on the ground that it will provide protection to this group from significant price changes. However, T&TEC proposed that there be no side constraints for other customers to allow greater flexibility in setting prices to reflect costs.

The RIC recognizes that side constraints can ensure that end users are protected from price shocks. The RIC has a number of options for applying side constraints, including:

- applying them to all customers or just certain customer groups;
- applying them at the individual customer level or at a customer group level; and
- specifying the constraints either as a maximum real-term percentage change, as a maximum nominal percentage change, or as a maximum dollar amount change.

The RIC has carefully considered the issues and has decided to specify the side constraint as a maximum real-term percentage change.

Decision

The RIC's decision is to incorporate a rebalancing control (side constraint) as part of the first regulatory price control and to set the size of the side constraint on the expectation that it would broadly allow the achievement of cost reflective pricing by the end of the first regulatory control period.

12.5 PROCESS FOR ANNUAL TARIFF APPROVAL

An integral part of establishing the initial tariff structure and the annual revenue requirements is the process for annual tariff approval for T&TEC. This section discusses a number of matters that need to be addressed for adjusting prices within the regulatory control period.

An important feature of incentive regulation is that once the pricing principle/formula is established, the regulator does not adjust the pricing principle/formula within the regulatory control period to reflect any changes between the actual and forecast revenue requirements. The service providers have to manage any differences between forecast costs, determined by the regulator, and actual costs during the regulatory control period. To the extent that costs differ, the service provider retains the benefits or bears the loss. This is one of the central tenets of incentive-based regulation and provides service providers with an incentive to efficiently control their costs. An efficiency carryover mechanism (discussed in Chapter 8) provides further incentives to improve efficiency.

The price control mechanism/formula sets out how prices will be adjusted annually to meet the forecast revenue requirements over the regulatory control period. At a minimum, the prices in each year of the regulatory control period will need to be adjusted by the rate of inflation and the X-factor. There may also be a case for adjusting prices where an unforeseen event that is outside the control of the service provider, impacts significantly on its costs during the regulatory control period. The RIC has proposed a mechanism in Chapter 5 to cater for such events.

Requirements of the RIC Act

Section 6 (1) (h) and (i) of the RIC Act states that:

> *The Commission may have and exercise such functions, powers and duties as are imposed on it by this Act and in particular –*
>
> - *establish the principles and methodologies by which service providers determine rates for services*

- *monitor rates charged by service providers to ensure compliance with the principles established.*

To ensure compliance with the established principles, the RIC will require T&TEC to submit proposed prices at least two months before the beginning of each year of the regulatory control period and the RIC will approve or reject prices within a month of the submission and allow another week to re-submit prices if rejected.

It will be the responsibility of the service provider to demonstrate compliance with the established pricing principles and any other requirements of the RIC's Final Determination. The document to be known as **"Annual Tariff Approval Submission",** must include the calculation method and other necessary information for understanding the objectives and rationale of the tariffs to be implemented. The RIC would strongly encourage the service provider to consult with customers regarding tariff changes during the regulatory control period.

Once approved by the RIC, the service provider must inform its customers of the new tariffs at least two weeks before implementation by publishing in at least one daily newspaper in circulation in Trinidad and Tobago and by the use of other media.

The RIC requires that T&TEC must, at least two months prior to the beginning of each year of the regulatory control period, submit proposed tariffs to apply from the start of each year of the regulatory control period for verification of compliance by the RIC.

T&TEC must ensure that its proposed tariffs comply with the established principles.

T&TEC must, if requested by the RIC, provide additional information and resubmit or revise its proposed tariffs.

The RIC must inform T&TEC in writing whether or not it has verified T&TEC's proposed tariffs as compliant with the relevant established principles.

The proposed tariffs will be deemed to have been verified as compliant by the end of the two months from the date of receiving T&TEC's Annual Tariff Approval Submission.

T&TEC must inform customers of the new tariffs at least two weeks before implementation by publishing in at least one daily newspaper in circulation in Trinidad and Tobago and by the use of other media.

T&TEC is prohibited from introducing new tariffs and/or tariff components during the regulatory control period other than those approved by the RIC.

12.6 OTHER TARIFF ISSUES

As part of its pricing submission, T&TEC has proposed a number of changes to the current tariff structure. In addition, the RIC has given consideration to a number of tariff issues raised as part of its consultation papers and process, including:

- the merits of demand side management; and
- the merits of time-of-use pricing.

12.6.1 Demand Side Management

During the RIC's consultation process, a number of participants presented arguments in favour of demand side management to lessen the impact of increasing peak demand problems.

Demand management usually refers to the smoothing of demand over a period of time (a day, week, month, or year) but can also extend to matters of energy conservation. In fact, demand side management (DSM) generally refers to measures or programmes undertaken by a utility that are designed to influence the level or timing of customers' demand for energy. This is done in order to optimize the use of available supply resources, thus allowing suppliers to defer the purchase of additional generating capacity.

DSM programmes aim to achieve three broad objectives:

- **Energy conservation**, that is, the reduction of overall consumption of electricity by reducing its use in lighting, cooling, cooking, etc.;
- **Energy Efficiency**, that is, encouraging customers to use energy more efficiently through the use of energy-efficient lighting, appliances, etc.; and
- **Load Management**, that is, providing incentives to use electricity during off-peak periods, thereby reducing the quantum of additional capacity required to serve customers during periods of peak demand.

The consideration of the following price-related and non-price-related techniques can assist in demand management.

Price Related DSM Techniques

- **Rate Restructuring**

  Cost reflective tariffs have been generally used as one of the techniques for DSM as consumers become more concerned about their use of electricity. However, this argument assumes an elastic demand for electricity.

- **Load Shifting**

  Large Industrial Customers can be given incentives to reduce their loads (via time-of-use tariffs) at times of peak demand. As at September 2004, T&TEC had 29 large industrial customers which accounted for approximately 40% of the daily load. A change in the load profiles for these 29 customers could delay the need for additional capacity. Time-of-use tariffs are discussed in greater detail below.

<u>Non-Price Related DSM Techniques</u>

- **Strategic Conservation**

  Energy efficient appliances save energy, cost less to run and are environmentally friendly. The use of these appliances should be encouraged.

- **Consumer Tips**

  A comprehensive plan should be devised, which would outline the approach to educating the public about energy conservation techniques. Listed below are some examples of strategic conservation techniques:

  - avoid leaving appliances on standby;
  - replace regular light bulbs with energy savings ones;
  - fill an electronic kettle with just enough water for required needs;
  - set water heater thermostat at 60°C/140°F as hot water does not need to be scalding; and
  - encourage industrial customers to use three phase instead of single phase machinery and encourage them to employ power factor correction techniques.

DSM options can be a cost-effective way of relieving network capacity constraints and can improve capital efficiency with a flow of benefits to customers in the form of lower costs. However, DSM raises issues which extend beyond the immediate role of the regulator and requires action by several players – government, service provider, regulator and customers. Nevertheless, the RIC believes that DSM is a sensible means for managing the growth in peak demand. The RIC can help guide the establishment of efficient prices which would assist in demand management. The RIC can also take action to support network driven demand management by, among other things:

- incorporating incentives in the regulatory framework for T&TEC to invest in loss reduction initiatives by allowing T&TEC to include into its asset base prudent expenditure on loss management equipment; and
- giving rebates in the calculation of revenue requirement for load reduction initiatives.

The RIC requires T&TEC to implement the following Demand Side Management techniques:

- strategic conservation by creating a database of energy efficient appliances and products to be recommended for consumer use; and
- consumer tips for strategic conservation.

The RIC's decision is to incorporate incentives in the regulatory framework for T&TEC to invest in demand reduction initiatives.

12.6.2 Time-of-Use Tariffs

The system peak demand is the main determinant of the capacity that T&TEC requires to serve its customers. Investing in additional capacity to meet an unconstrained peak demand would entail significant capital investment. It is the fixed cost associated with this system capacity that is captured in the demand charge. Therefore, the charge arising from demand during the system peak should be higher than those applicable at other times. Similarly, fuel cost per kWh generated during the off-peak is lower than it is during the peak. This is so because in the generating process, plants with the lower variable cost (base load plants) are loaded first and those with higher variable cost (peaking plants) are reserved for peak load hour. As a result, the price of electricity can vary significantly depending on the time of day the service is used. To capture these differences, the utilities offer, what is called, time-of-use (TOU) tariffs. These "pricing signals", if powerful enough, will induce customers to modify their pattern of consumption, consciously curtailing consumption during peak hours thereby reducing the system maximum demand.

Prices for electricity that reflect differences in cost as much as possible are usually more efficient. The RIC believes that effective cost-based electricity pricing would involve TOU tariffs and they should be encouraged. TOU tariffs can provide customers with additional choices for avoiding the costs of using the network by offering a greater differentiation of tariffs to match a broader range of possible alternative consumption patterns during the day. TOU tariffs are often attractive to manufacturers that operate processes with low start-up and shut down costs or that can be suspended for limited periods without incurring great cost. Residential TOU tariffs can also be used as an incentive to increase the overall sale of electricity during off-peak periods.

However, the RIC recognizes that meter costs are high and can outweigh Time-of-Use (TOU) benefits for a residential customer. Residential customers may also prefer simpler bills to the more complex under TOU tariffs. Against this background, the RIC has decided that T&TEC should undertake a study to determine its ability to develop TOU tariffs for its customers.

The RIC requires T&TEC to undertake a study and report to the RIC within 18 months after the release of the Final Determination on the feasibility of implementing time-of-use tariffs for its customers.

12.7 RIC'S TARIFF PROPOSALS

12.7.1 Overview

As discussed in Chapter 11, the RIC has opted to adopt NPV smoothing and a single X-factor across the regulatory control period. This raises an issue for regulators as to who should ideally translate the final revenue requirement determined by the regulator into individual tariffs to ensure equity and fair allocation of costs to the various customer classes.

Typically the incentive regulatory frameworks do not specify the end use rates to be applicable. Instead the framework specifies a transparent and formulaic mechanism for revenue requirement and rate determination. Therefore, some regulators choose to leave the responsibility for the development of final prices with service providers on the grounds that they have a better understanding of their costs and customers. Others feel that tariff structure is too critical to be left totally to the discretion of the service provider, especially where competing objectives need to be resolved.

The RIC considers that ensuring appropriate translation of forecast revenues into customer prices is an important function of the regulator, particularly from the customer's perspective. In fact, the RIC will be acting in contravention of its Act if it fails to establish a well-defined framework. The tariff structure is fundamental to this framework. Additionally, the RIC is concerned by the unanticipated price shock that can occur if the service provider aims to achieve full cost reflectivity within the shortest possible time, thereby leading to significant price increases for some customer classes. The service provider has to be operating at reasonably accepted levels of efficiency, with prevailing pricing structures fairly close to underlying costs, and commercial considerations governing service providers' actions, before it would be prudent to give them the autonomy and freedom to determine tariff structures within the confines of the price/revenue caps.

The average cost of supply and the average revenue per unit at current tariff levels for different categories of consumers are presented in **Table 12.2** below. It can be seen that in the residential customer category, an increase of 44% and in the commercial category, an increase of 19.2% would be required to reach the average cost of supply. For street lighting, the tariff would have to be raised by 3.7% to reach the average cost of supply. Even in the case of street lighting, it is clear that industrial customers are subsidizing the Government/local government bodies.

Table 12.2 – Per Unit Cost of Supply vs Per Unit Revenue, 2003

	Domestic	Commercial	Industrial				Street Lighting
	Rate A	Rate B	Rate D1	Rate D2	Rate D3	Rate E	
Revenue – ¢/kWh	22.07	23.49	32.13	28.55	21.33	18.98	**102.33**
Cost – ¢/kWh	39.43	29.18	30.46	27.89	19.51	18.30	106.25
% Difference	(44.0)	(19.15)	5.5	2.40	9.3	3.7	(3.7)

In formulating the new tariff schedules, the RIC has adhered to its mandate to adopt factors that will encourage efficiency, economical use of the resources, good performance and optimum investments. It has taken into consideration the need to reduce distortions in tariffs so as to lower cross subsidization and has attempted to make tariffs reflective of the underlying costs. The RIC recognizes the impact of good tariff design in promoting efficient consumption since poorly designed tariffs can result in wasteful consumption of electricity. More importantly, the RIC has been conscious of the need to avoid disruptive and excessive tariff shocks to lower and disadvantaged income groups, in particular, to the residential consumer category, and expects to achieve the optimal level at an appropriate and prudent pace. Furthermore, the RIC has set targets in all areas of T&TEC's operations and has provided an incentive structure in case the efficiency gains are beyond the targets set. The RIC is confident that the tariff structure proposed will provide the impetus for T&TEC to greatly improve its performance and its financial viability.

12.7.2 Main Features of Proposed Tariff Schedules

Currently, T&TEC's existing tariff comprises four standard rate classes:

- Rate A (Residential customers)
- Rate B (Commercial customers)
- Rate D (Industrial customers) – of which there are four sub-categories – D1, D2, D3 & E
- Rate S (Street lighting) – this is further sub-divided into S1, S2 and S3.

Customers in all rate classes incur at least two of the under-mentioned charges:

- **Customer Charge** – designed to recover investment and costs incurred by the service provider to serve the consumer. These costs have to be incurred whether or not the consumer actually uses electricity. The costs relate to metering, billing and collecting;
- **Demand Charge** – designed to recover investment and expenses incurred by the service provider to serve expected load;
- **Energy Charge** – designed to recover costs that vary with the number of units supplied.

In addition to the above charges, a fuel charge is shown separately and it varies with the cost of fuel and the number of kWh supplied to the customer. For residential and commercial customers, the demand charge is effectively rolled into the energy charge, thereby resulting in only two charges for these customers – the customer (fixed) and energy charge. **Table 12.3** shows the current T&TEC's electricity rates.

Table 12.3 – Summary of Current Electricity Rates

Class	Residential	Commercial	Industrial		Heavy Industrial	
	A	B	D1	D2	D3	E
Frequency of Billings	Every 2 months	Every 2 months	Monthly	Monthly	Monthly	Monthly
FIXED CHARGES Customer Charge	$4.00	$20.00	Not Applicable	Not Applicable	Not Applicable	Not Applicable
USAGE CHARGES **1. ENERGY**						
Base Energy Rate per kWh	0.150000	0.165000	0.167500	0.152000	0.069000	0.061400
Fuel Charge (July 2005) per kWh	0.051432	0.051432	0.051158	0.051158	0.051158	0.051158
Exchange Rate (July 2005 Adjustment per kWh	0.02203	0.02203	0.02203	0.02203	0.02203	0.02203
Total Energy Charge Rate	**$0.223462**	**$0.238462**	**$0.240688**	**$0.225188**	**$0.142188**	**$0.134588**
2. DEMAND						
Maximum Demand Charge per kVA per month	Not Applicable	Not Applicable	$21.75	$21.75	$26.08	$23.60
MINIMUM BILL	$10.00	$58.00	**Equivalent to Demand Charge for 75% of Customer's Reserve Capacity	**Equivalent to Demand Charge for 75% of Customer's Reserve Capacity	**Equivalent to Demand Charge for 75% of Customer's Reserve Capacity	**Equivalent to Demand Charge for 75% of Customer's Reserve Capacity

** Industrial customers are required to specify the planned Maximum Demand of their plant in kVA (the Reserve Capacity) when requesting a supply.

T&TEC has made proposals for rationalization of rate classes, introduction of special tariffs and for realignment of tariffs towards cost reflectiveness. The new proposals are examined below.

Residential (Rate A)

T&TEC, in its submission, has proposed to adjust its existing Rate A tariff structure by including a three-tiered inclining block tariff per billing period, as follows:

- First block, 0-500 kWh;
- Second block, 501-1500 kWh; and
- Third block above 1500 kWh.

Block tariffs are tariffs that differ across some threshold consumption level. In the case of an inclining block tariff structure, additional amounts of energy consumed above a specified minimum level attract a higher tariff rate. The case for an inclining tariff structure is generally made on economic efficiency grounds. T&TEC has provided little justification and rationale for the proposed number of consumption blocks.

In setting block levels, the need to consider the consumption profiles (and also demand elasticity) is important. T&TEC's customer consumption profiles show that 28% of the customers consume less than 400 kWh, 38% less than 500 kWh, 73% less than 1000 kWh and 87% of the customers less than 1500 kWh, bi-monthly. In setting consumption levels for the first and subsequent blocks, one needs to have a good understanding of customer's discretionary and non-discretionary electricity use. If the first block is set too high, it is unlikely to effectively target discretionary use.

T&TEC's proposed tariff structure consists of a lifeline block (i.e. up to 500 kWh) within the residential structure which allows for all residential customers to enjoy lower rates regardless of total consumption. Although the RIC is quite aware of the use of lifeline blocks to assist lower income groups, to its knowledge, there are no data to suggest that 500 kWh is the most appropriate amount, especially in light of the fact that about 38% (or 122,454) of the customers consume less than 500 kWh bi-monthly. The size of the initial block appears high if the objective is to target lower income groups for subsidy, and will not target non-discretionary consumption, neither will it provide effective electricity conservation signals. Similarly, by establishing the second block, up to 1500 kWh, it means that 87% of the customers would fall below this amount. Once again, defeating the purpose of establishing an inclining block structure.

The ease of understanding the tariff structure is an important factor in deciding on the number of consumption blocks to include in an inclining block tariff. The fewer blocks there are, the more readily customers will be able to understand the tariff and make appropriate electricity consumption decisions. A tariff structure consisting of two or three blocks is likely to be easily understood by customers.

Another important issue relates to the time period over which consumption is measured. An inclining block usage charge measured over a two-month period, as proposed by T&TEC, will send more frequent price signals about the cost of electricity. Therefore, electricity conservation signals are reinforced every time a customer receives a bill.

Commercial (Rate B and B1)

The commercial class has been divided by T&TEC into Rate B and B1 by introducing a new rate tariff, Rate B1. The Rate B supply voltage options have been expanded to include the 6.6 kV and 12 kV voltage levels. The new Rate B1 will cater for commercial and small industrial customers with demands in the range 50 kVA to 350 kVA and nominally low load factors (0.30 or less).

Industrial (Rates D5 and E5)

In the case of the industrial class, customer groups have been amended to offer greater supply voltage options and customers are categorized into different rate classes on the basis of their demand profiles and the voltage level at which they are connected to T&TEC's system. A customer's maximum kVA demand will be the primary basis for assignment to a particular rate class.

Stakeholder Comments and Final Decision

One consumer expressed the view that either a flat rate per kWh or a sliding scale rate in which the first few units are charged at a higher rate than the remainder be introduced.

The general objectives of economic regulation inform the rate design process. More specifically, the objective of a tariff structure (rate design) is to set economically efficient and fair prices, while simultaneously allowing the service provider an opportunity to recover efficient costs of providing service. However, the reconciliation of the need to cover legitimate costs with the desire to set economically efficient prices, and then to meet other objectives of regulation requires much judgment and trade-offs. Faced with these issues, regulators use different tariff structures to suit different objectives and legislative requirements.

There are a number of approaches which can be used to design individual prices, which include:

- Fully Distributed Cost based pricing;
- Marginal/Incremental costs pricing;
- Ramsey pricing;
- Linear (or uniform or flat rate) prices;
- Multi-part prices; and
- Non-linear (or non-uniform) prices.

As indicated above, the challenge is to design tariffs that promote efficiency and address other economic concerns, while balancing distributional concerns. Consequently, only the pricing methods that lend themselves to these concerns are briefly discussed below i.e. multi-part prices and non-linear prices.

Multi-part prices – the simplest form of this method is the two-part tariff, where customers pay an access fee (or fixed charge) plus a usage fee. However, multi-part prices can be tailored to suit many other circumstances. A two-part tariff made up of a customer charge (fixed charge) and an energy charge that is equivalent to **marginal cost** incorporates efficiency and distribution considerations but fails to meet the revenue sufficiency and conservation objectives.

Non-linear prices – there are two basic types of non-linear tariff structures – inclining block tariffs and declining block tariffs. The **Declining Block tariff** methods imply that successive blocks at higher levels of consumption are charged at progressively decreasing levels. These are generally advocated on the basis that larger consumers are cheaper to serve than smaller ones because costs decline with increasing volume. However, the declining block structure is unlikely to meet other objectives of regulation.

Under the **Inclining Block tariff** a low rate is charged for an initial block of consumption, referred to as the life-line block, and progressively higher rates are then charged for successive blocks. Lowering the price of the first block means that larger users would pay relatively more for electricity, thereby increasing incentives for conservation while still providing a modest price for small users.

The RIC supports an inclining stepped tariff structure as it is likely to discourage wasteful consumption at higher levels of consumption, send better signals and provide incentives for sustainable use of electricity, while at the same time catering for the needs of the lower consumers of electricity. In designing an inclining block structure, one needs to consider a number of issues, including:

- the level of usage at which the first block and subsequent blocks should be set;
- the price relativities between blocks; and
- the number of blocks to be considered.

The RIC's proposed structure for residential customers consists of:

- a fixed charge;
- a variable component for the first 400 kWh consumed;
- a variable component for the next 600 kWh consumed; and
- a variable component for consumption thereafter.

The fixed component is consistent with the fixed costs of providing electricity and the variable components which broadly coincide with lower, middle and high income groups in the society, are likely to provide efficient price signals, promote efficient demand management, as well as promote better economic use of resources.

The RIC will continuously focus its attention on aligning the rates for all categories of consumers with the cost of supply over a timeframe through phased reduction of subsidies and will be examining, under its Social Action Plan, other options for addressing affordability and broader hardship issues more effectively. This may involve examining how T&TEC's policies and practices currently deal with customers who are generally unable to pay their bill, especially old age pensioners and disadvantaged groups. It will also include requirements for T&TEC to assist customers who have payment difficulties, and provide flexible payment plans where appropriate.

In determining the tariffs for various consumer categories, the RIC has carried out a rationalization of the tariff categories. The increases proposed vary across consumer categories. The lowest increase has been proposed for lower income groups. With respect to low-income groups, the RIC's three main proposals for reducing the impact of increased prices are:

(a) **Discount Plan/Tariff Mechanism:** A life line tariff system which allows the households to pay at a lower rate for a certain monthly consumption level. In fact, the discount varies with customer's usage:

- customers using up to 400 kWh bi-monthly will pay 27 cents per kWh, true cost being 39 cents, i.e. **a discount of 44.9%**;
- customers using 401 – 1000 kWh will pay 31 cents, i.e. **a discount of 29.7%**; and
- customers using over 1000 kWh will pay 34 cents, i.e. **a discount of 19.1%**.

- **Fixed dollar discount on customer charge** – a subsidy of $0.53 million for customers using less then 400 kWh (or total subsidy to residential class of $1.6 million).

- **Fuel Cost Subsidy** - $27 million for customers using less than 400 kWh bi-monthly (i.e. overall subsidy for residential class of $167 million).

In total, residential customers will benefit from overall subsidies worth $224 million.

(b) **Low Income Assistance Programme:** T&TEC will establish a special fund of $5 million to cater for the special needs of those who may still experience difficulty in paying their bills. This fund will be available for customers who have been identified as being in need and whose usage falls below 400 kWh bi-monthly. T&TEC will maintain a register of customers in need and the fund will be used for:

- customer bill assistance (that is, a maximum of 7% and 5% of customer's bill for customers using less than 100 kWh and between 101 to 400 kWh respectively);
- appliance repair assistance; and
- arrears forgiveness.

Other measures under the low income assistance programme to include:

- waiving of interest payments on outstanding accounts;
- protection from service termination (some forms of non-payment are not to be tolerated i.e. illegal tampering of meters); and
- extended payment arrangements i.e. the option of arranging alternative payment schedules and deferring payments.

(c) **Energy Efficiency Programme:** This is to reduce or manage energy consumption and education is an important component of efficiency programme to control bills by wise usage.

Various stakeholders also contended that the RIC's proposed fixed charge was high and that the lower-income groups would face a disproportionately high cost in their total electricity bills.

The main rationale for levying a fixed charge is to recover part of the fixed costs incurred by the utility to serve the consumer. These costs have to be incurred whether or not the consumer actually uses electricity. The fixed charge includes such costs as those related to metering, billing, collecting and providing information service and is based on customers served. Such a tariff structure provides incentives to improve supply and recover some minimum costs.

Overall, the RIC has held the view that cost-reflectiveness and economic price signalling (economic efficiency) principles must be a key part of the rate setting exercise. The question of equity/social objectives should be dealt with by targeted subsidies. However, affordability and the amount of the total bill are key issues in tariff design. The regulator must, therefore, balance these competing objectives. Economic principles dictate that a greater portion of the customer's bill must come from consumption charge. Based on the RIC's tariff proposals, the fixed charge is 22% of total bill for consumers using 100 kWh and 10% for customers using 250 kWh, in comparison with some other utilities where this charge is as high as 40%.

The RIC, in light of the stakeholder comments and after further consideration, proposes to lower the fixed charge for residential customers from the proposed $8.00 bi-monthly to $6.00 bi-monthly.

Table 12.4 shows the RIC's proposed tariff structure and charges for 2006.

Table 12.4 – RIC's Proposed Tariffs for 2006

Rate Class	Customer Charge $	Energy Charge (¢/kWh)	Demand Charge ($/kVA)
Residential (Bi-monthly):			
Up to 400 kWh	6.00	27.00	-
401 - 1000 kWh	6.00	31.00	-
Over 1000 kWh	6.00	34.00	-
Commercial (Bi-monthly):			
Rate B	25.00	38.00	-
Rate B1	Minimum bill of 5000 kWh	58.00	-
Industrial (Monthly):			
Rate D1	-	18.00	48.00
Rate D2	-	20.00	48.00
Rate D3	-	16.50	41.00
Rate D4	-	15.00	38.00
Rate D5	-	14.50	35.00
Rate E1	-	13.00	42.00
Rate E5	-	13.00	38.00
Street Lighting (Annually):			
S1 – 1	792.00	-	-
S1 – 2	528.00	-	-
S1 – 3	384.00	-	-
S1 – 4	348.00	-	-
S2 – 2	420.00	-	-
S2 – 3	324.00	-	-
S2 - 4	264.00	-	-

12.7.3 Impact of RIC's Proposed Pricing Decision

In this section, the RIC considers the impact of its pricing decision on customers, especially the low income and disadvantaged groups, inflation, and the country's competitiveness. In introducing the changes indicated above, the RIC has been conscious of the need to select an optimal pace, to avoid excessive revenue risk exposure to T&TEC, and rate shock to the consumer. The efficiency improvement factor imposed on T&TEC in the form of mandating savings through adoption of efficiency improvement requirements is also aimed at transformation in the desired direction. A provision for sharing gains from productivity improvements in excess of the X percent requirement between consumers and T&TEC has also been spelt out.

The RIC's analysis of the impacts has concentrated on the overall effect on customers' total bills. It has looked at how the increased bills compare with the past prices of services. It has also looked at how the size of a bill varies with usage.

Impact on Customers

The impact on individual customers will depend on a number of factors, of which the proposed price path adjustment is just one. Social outcomes would be particularly influenced by changes to the tariff structure, the low usage (life-line) charge, etc, as changes in these have the potential to impact individual bills significantly.

In general, relative increases in the customer (fixed) charge will create a greater percentage change in bills for small consumers, compared to relative increases in the volumetric charge.

As can be seen from **Table 12.5**, a typical **residential** customer using 100 kWh would incur a nominal price increase in his final bill of $2.17 per month (from $13.18 to $15.35). Similarly, the final bill for a residential customer using 250 kWh will increase from $29.94 to $34.91 per month, that is, $4.97 per month. It is important to note that customers using up to 250 kWh bi-monthly comprise about 16% (or 50,977 customers) of T&TEC's total customer base.

For customers reliant on government pensions, or falling into similar low-income groups, whose monthly income is about $1,150 and consume about 200 kWh, their total monthly expenditure of $28.50 on electricity will be about 2.5% of their monthly income, well below the internationally accepted target of about 10%.

Table 12.5 – Impact on Bills of Price Increases for Typical Residential Customers, 2006

kWh	No. of Customers	Current		RIC Approved				
		Monthly $	Bi-monthly $	Monthly $	Bi-monthly $	Monthly Increase $	Bi-monthly Increase $	% Increase
100	20,768	13.18	26.35	*15.35	*30.69	2.17	4.34	**16.5**
250	30,209	29.94	59.88	**34.91	**69.83	4.97	9.94	**16.6**
400	43,266	46.70	93.40	**54.15	**108.30	7.45	14.90	**16.0**
600	62,744	69.05	138.10	88.00	176.00	18.95	37.90	**27.4**
800	49,514	91.40	182.80	119.00	238.00	27.60	55.20	**30.2**
1000	34,886	113.75	227.50	150.00	300.00	36.25	72.50	**31.9**
1300	32,181	147.28	294.55	201.00	402.00	53.72	107.44	**36.5**
1600	17,738	180.80	361.60	252.00	504.00	71.20	142.40	**39.4**

* This includes additional subsidy of 7%.
** This includes additional subsidy of 5%.

The impact of the RIC's decisions on commercial and industrial customers will generally vary depending on their level of usage. Because commercial and industrial customers are much more diverse in terms of their usage patterns than residential customers, it is difficult to draw general conclusions about the impact of this decision on these customers. A typical **commercial** customer (**Table 12.6**) using 500 kWh would face a nominal price increase in his final bill of $38.85 per month. **Table 12.7** examines the impact on industrial customers.

Table 12.6 – Impact on Bills of Price Increases for Typical B Commercial Customers, 2006

kWh	Current		RIC Approved			
	Monthly $	Bi-monthly $	Monthly $	Bi-monthly $	Increase $	
					Monthly	Bi-monthly
500	68.65	137.30	107.50	215.00	38.85	70.70
1000	127.30	254.60	202.50	405.00	75.20	150.40
1500	185.95	371.90	297.50	595.00	111.55	223.10
2000	244.60	489.20	392.50	785.00	147.90	295.80
2500	303.25	606.50	487.50	975.00	184.25	368.50

Table 12.7 – Impact on Bills of Price Increases for Typical Industrial Customers, 2006

Rate Category	Current	RIC Approved
¢/kWh	23.71	18.00
D1: $KVA	21.75	48.00
Total Bill ($)	**7,188.88**	**9,024.00**
¢/kWh	22.16	20.00
D2: $KVA	21.75	48.00
Total Bill ($)	**90,365.46**	**101,700.00**
¢/kWh	13.86	16.50
D3: $KVA	26.08	41.00
Total Bill ($)	**308,798.96**	**413,896.32**
¢/kWh	13.86	15.00
D4: $KVA	26.08	38.00
Total Bill ($)	**20 0,021.62**	**247,438.40**
¢/kWh	13.86	14.50
D5: $KVA	26.08	35.00
Total Bill ($)	**659,790.18**	**749,479.51**
¢/kWh	13.10	13.00
E1: $KVA	23.60	42.00
Total Bill ($)	**3,066,467.65**	**3,653,196.56**
¢/kWh	13.10	13.00
E5: $KVA	23.60	38.00
Total Bill ($)	**18,615,010.98**	**21,847,925.40**

Impact on Inflation

The RIC has also considered the inflationary impact of its proposals. Any inflationary impact is likely to be small as the average household electricity bill represents only 3.5% of average monthly household expenditure as at August 2005 (i.e. $157.10 of $4,474.49). Therefore, an average additional cost in electricity per month would increase the share of electricity cost on monthly average household expenditure by an estimated 0.03%.

Impact on Country's Competitiveness

The RIC considered the likely impact of increased electricity charges on different sectors of the economy and, consequently, on competitiveness of these sectors. As **Table 12.8** shows, the contribution of increased costs of electricity would have a minimal impact on total operating expenses of different industries in the country, given the small share of electricity costs in total operating costs. The RIC estimates, based on figures obtained from the Central Statistical Office, that, on average, electricity constitutes 1.6% of the production costs of a firm in Trinidad and Tobago. With the increase in electricity rates, this is expected to increase to 1.7%. This is not to deny that some sectors/firms may experience higher increases but, on the other hand, some are expected to see lower increases than the average increase.

Table 12.8 – Contribution of Electricity to Total Operating Expenses of Industries, 2002-2006

Industries	Electricity as % of Total Operating Costs (Before Price Increase)	Electricity as % of Total Operating Costs (After Price Increase)
Sugar	0.7	0.7
Petroleum and Other Mining	0.8	0.8
Food Processors and Drinks	1.1	1.2
Textiles, Garments, Footwear, Headwear	1.6	1.7
Printing, Publishing, Paper Converter	1.2	1.3
Wood and Related Products	1.4	1.6
Chemicals and Non-metallic Minerals	2.9	3.1
Assembly Type & Related Industries	8.9	9.6
Miscellaneous Manufacturing	2.2	2.4
Electricity and Water	3.0	3.3
Construction and Quarrying	0.1	0.1
Distribution	4.7	5.1
Hotels and Guest Houses	5.2	5.6
Transportation, Communication & Storage	0.5	0.5
Finance, Insurance, Real Estate & Business	1.4	1.4
Central and Local Government	1.0	1.0
Education	3.3	3.6
Personal Services	10.0	10.8
Total for All Industries	**1.6**	**1.7**

Source: Central Statistical Office, 2002

The RIC also compared a total bill of a typical industrial customer in Trinidad and Tobago with customers in some of the other Caribbean countries (**Table 12.9**). As can be seen from the table, a typical industrial customer in Trinidad and Tobago has the lowest total bill.

Table 12.9 – Bills of a Typical Industrial Consumer (using 275 KVA & 100,000 kWh) in different Caribbean Countries, 2002

Country	Bill Amount ($US)
Dominica	26,566.31
St. Lucia	22,010.38
Curacao	21,956.87
Guyana	20,977.12
Grenada	19,013.58
Antigua	17,712.20
Belize	17,682.50
St. Vincent	17,468.00
Barbados	16,469.70
Jamaica	11,129.17
Bahamas	10,283.05
Trinidad and Tobago (2006)	**4,952.38**

12.8 NATURAL DISASTER PREPAREDNESS FUND

The RIC was mindful of the devastating effects that natural disasters can have on the electricity transmission and distribution network. Accordingly, the RIC, in its Draft Determination, proposed a disaster recovery plan for the first price control period. This initiative would have allowed T&TEC to charge each customer a flat fee of $1.00 per billing for residential customers, $5.00 per billing for commercial customers and $90.00 per billing for industrial customers for the sole purpose of natural disaster preparedness.

However, there was much debate on the issue and many stakeholders, including the shareholder, questioned the RIC's authority to impose such a charge.

The RIC's rationale behind its proposal is briefly outlined hereunder. The RIC argued that there are numerous factors over which the utility has little or no control, for example, hurricanes which can have a significant adverse impact on the costs of a utility's operations. However, such material non-recurring costs may not be part of operating costs in a typical year.

Where a service provider has incurred extra costs in any year because of particular weather conditions, those costs are part of the money spent to maintain a service to customers and therefore are legitimate costs and exclusion of these occasional costs would not recognize normal business risk. These "one-off" costs are usually excluded in assessing future base costs and the scope for future efficiency savings. Regulators often allow such costs to be passed as a direct part of the tariff or, more often, as a surcharge. In many regulatory environments, it is common practice to include a pass-through provision to be applied in the event of "unforeseen external events", including (but not limited to) events that threaten the security of supply by terrorism and/or natural disasters which have a material impact on costs. In some cases, the magnitude of a natural disaster create implications that extend beyond cost and price issues. In such a case, all aspects of a price determination may need to be reopened to reflect the new circumstances.

Utilities generally do not carry enough insurance to cover these additional expenses because the cost of such insurance is very high. Indeed the cost to the customer of increased insurance cover can be significantly higher than the proposed charge.

The establishment of the National Disaster Preparedness Charge is a forward thinking preventative initiative, which would avoid the need for the RIC to undertake interim price review during the price control period similar to the recent experiences of other jurisdictions like Jamaica and Miami, USA. There are many advantages of such a charge:

- they preserve a common rate for both existing and new customers;
- they reduce the need for an increase in rates at a time of disaster; and

- because funds are readily available, they enable the utility to respond quickly.

The RIC now understands that the Government has allocated funds for T&TEC for natural disaster purposes. However, the RIC is unaware of how these funds are to be released or exactly for what purpose or under what conditions are they to be used. Therefore, the RIC, after careful consideration, has decided not to impose a natural disaster preparedness charge on customer billings but mandates T&TEC to open a Natural Disaster Preparedness Account with funds from Government/T&TEC amounting to $5 million deposited annually over the review period and to stock emergency supplies of some critical items such as poles, transformers, cables, back-up generators, etc. for use in the event of a natural disaster.

12.9 FINAL PRICE DETERMINATION

The following is the RIC's Final Determination in respect of electricity transmission and distribution services for the five-year period June 01, 2006 to May 31, 2011:

1. Period of Determination

The provisions below will apply for the five-year period June 01, 2006 to May 31, 2011.

2. Services to be Regulated

The following services will be regulated by the RIC and the prices for these services will be subject to formulas and other arrangements as set out below:

(i) Miscellaneous Services

	Charge ($)
• Meter Check at customer's request: - If found in working order - If found defective	 194.00 No charge
• Visit for Non-payment of Account	234.00
• Install meter and reconnect secondaries	194.00
• Reconnect, disconnect and/or change meter	194.00
• Reposition of secondaries	194.00
• Change and/or reposition meter	194.00
• Disconnection for non-payment	118.00
• Reconnection after disconnection for non-payment	118.00

As outlined in the RIC's Social Action Plan and Chapter 9, the service provider will be required to have a Code of Practice to ensure that vulnerable customers are not unduly burdened by these charges.

No further increase will be permitted in the Miscellaneous Services for the duration of the regulatory control period.

(ii) Revenue Cap for Transmission and Distribution Services:

- For the first year of the regulatory control period 2006-2010, the RIC has proposed a tariff structure and prices for each customer class, which would be escalated annually by applying the RPI-X formula, with no further rebalancing of prices within the regulatory period without the approval of the RIC.

Tariffs for 2006

Rate Class	Customer Charge $	Energy Charge (¢/kWh)	Demand Charge ($/kVA)
Residential (Bi-monthly):			
Up to 400 kWh	6.00	27.00	-
401 - 1000 kWh	6.00	31.00	-
Over 1000 kWh	6.00	34.00	-
Commercial (Bi-monthly):			
Rate B	25.00	38.00	-
Rate B1	Minimum bill of 5000 kWh	58.00	-
Industrial (Monthly):			
Rate D1	-	18.00	48.00
Rate D2	-	20.00	48.00
Rate D3	-	16.50	41.00
Rate D4	-	15.00	38.00
Rate D5	-	14.50	35.00
Rate E1	-	13.00	42.00
Rate E5	-	13.00	38.00
Street Lighting (Annually):			
S1 – 1	792.00	-	-
S1 – 2	528.00	-	-
S1 – 3	384.00	-	-
S1 – 4	348.00	-	-
S2 – 2	420.00	-	-
S2 – 3	324.00	-	-
S2 - 4	264.00	-	-

- T&TEC to set prices for year *t* such that the reasonable forecast annual revenue received from the service (ARR_t) complies with the following formula in **Box 12.1**:

Box 12.1 - Formula for Establishing Annual Revenue Requirement

$$^*ARR_t \leq (1 + RPI)\,(1 - X_t))\ \text{x}\ ARR_{t-1} + U$$

Where:

Year *t*	X_t
2007	4.4
2008	4.4
2009	4.4
2010	4.4

ARR= Annual Revenue Received from Services.
ARR_{2006} = $1901.03 million.
RPI means the Retail Price Index as determined by the CSO.
U = Unused charge. T&TEC will be permitted to carry over any unused change in charges from one year to the following years.

The RPI will be calculated using the following formula:

$$RPI_t === \frac{RPI\ June_{t-1} + RPI\ Sept_{t-1} + RPI\ Dec_{t-1} + RPI\ Mar_{t-1}}{RPI\ June_{t-2} + RPI\ Sept_{t-2} + RPI\ Dec_{t-2} + RPI\ Mar_{t-2}}$$

Where:

- Year *t* is the year for which tariffs are being set
- $Year_{t-1}$ is the previous year
- $Year_{t-2}$ is two years previous.

The overall side constraint is set at (RPI + X) = 7.4%.

3. Side Constraint

The overall side constraint is set at (RPI + X) = 7.4%.

*** The formula is a slight variation from the standard (1 + RPI – X) formulation. This different version can assist in correcting, to some extent, for differences in forecast and actual RPI having any impact on the operation of the price control mechanism.**

4. Annual Price Approval Process during the Control Period

- At least two months prior to the beginning of each year of the regulatory control period, T&TEC must submit proposed tariffs to apply from the start of each year of the regulatory control period for verification of compliance by the RIC.
- T&TEC must ensure that its proposed tariffs comply with the established principles.
- T&TEC must, if requested by the RIC, provide additional information and resubmit or revise its proposed tariffs
- The RIC must inform T&TEC in writing whether or not it has verified T&TEC's proposed tariffs as compliant with the relevant established principles.
- The proposed tariffs will be deemed to have been verified as compliant by the end of the two months from the date of receiving T&TEC's Annual Tariff Approval Submission.
- T&TEC must inform customers of the new tariffs at least two weeks before implementation through publication in at least one daily newspaper in circulation in Trinidad and Tobago.
- T&TEC is prohibited from introducing new tariffs and/or tariff components during the regulatory control period other than those approved by the RIC.

5. Trigger Event

The trigger event will apply only if it imposes a total annualized cost of more than 1% of revenue.

CHAPTER 13

COMPLIANCE MONITORING AND REPORTING

13.1 PERFORMANCE MONITORING AND REPORTING

The basic function of the RIC as a regulator is to regulate the service providers in a manner so as to promote efficiency and economy in the activities of the utility providers under its jurisdiction. Section 6 of the RIC Act empowers the RIC to establish and enforce standards with respect to quality, continuity and reliability of service. To achieve these objectives, the RIC will focus its compliance efforts on monitoring the performance of the service provider. This will involve the gathering of sufficient information from the service provider to ensure compliance with certain decisions of the first Determination and other relevant decisions of the RIC as required by the Act.

In fact, the RIC has an on-going responsibility to ensure that the service provider complies with its determination. The directions are for the general improvement of the service provider and, if complied with, will result in significant gains in the form of increased efficiencies and overall development of the electricity sector.

In June 2005, the RIC released its Consultation Document, "**Performance Monitoring and Reporting Framework (PMR) (May 2005)**", which requires the service provider to provide data on a core set of financial, operational and service quality measures on a quarterly and annual basis. It was argued that the PMR will be a significant performance driver and a useful tool for:

- informing customers and other interest groups about the level of service they receive;
- providing information and data for developing regulatory standards when required and for on-going assessment of compliance with such standards;
- informing the decision-making processes of regulators; and

- identifying baseline performance of service providers as well as comparing relative performance with other utilities.

The RIC has established a Guaranteed Standards Payment Scheme with specific service quality levels for T&TEC to achieve and report on during the first regulatory control period. However, as argued in Chapter 9, the RIC acknowledged its inability to develop a service quality incentive scheme at this time due partly to the lack of available and comparable service quality data. The PMR and other proposed measures will enable the RIC to monitor the standards of service provided by the service provider and to assess whether, in the absence of an incentive scheme, the level and quality of service are at least maintained throughout the regulatory period. In addition, PMR and other data can create pressure to improve performance by allowing customers, the media and stakeholders to critically assess the service provider's performance.

13.2 COMMENTS IN RESPONSE TO THE RIC'S PMR DOCUMENT

Generally, all comments supported the need for reporting and monitoring of the proposed indicators. Many suggested that the RIC should require more detailed reporting of network performance, particularly in relation to voltage dips and surges and momentary interruptions to supply, as these were serious problems faced by consumers.

Comments from organizations expressed concerns that the proposed standards did not place sufficient emphasis on measures relevant to large customers, including those with continuous processes or sensitive loads. The RIC is of the view that the reporting needs of large customers are sufficiently specialized and thus make them difficult to accommodate within a system-wide framework. The RIC would prefer to see customer-specific measures reported by the service provider to customers with a continuous process and/or sensitive load which accounts for over 46% of the total load. These arrangements should ideally form part of a large customer's connection agreement.

The RIC accepts that large customers may have found it difficult to negotiate specific service standards in their connection agreements. Consequently, the RIC will seriously consider measures that facilitate large customers being able to negotiate for service levels above the standard service provided. If these customers and T&TEC agree to specific service levels, then T&TEC will be required to monitor and report to these customers on the measures and at the intervals specified in the agreement.

One respondent raised concern about the verification of the reliability measures. The PMR document has proposed the utilization of an independent audit of all service quality measures and public disclosure of the results of those audits.

Apart from the above concerns, many respondents suggested that the RIC consider reporting performance indicators quarterly, that performance indicators include employee safety and other safety indicators and that performance indicators in relation to generation must also be established and monitored regularly. These are reasonable and worthwhile suggestions and will be seriously considered by the RIC.

The RIC will periodically review its Performance Monitoring and Reporting (PMR) Framework. In the meantime, no changes are proposed to the indicators as set out in the **Annex** to this chapter.

The RIC will consider measures over the coming regulatory period that facilitate large customers being able to negotiate for service levels above the standard service provided.

13.3 REGULATORY ACCOUNTING GUIDELINES

The regulatory accounts are a critical information source for the RIC in ensuring compliance with its decisions, in assessing implementation of the RIC Act and for informing customers and other stakeholders of the performance of the service provider.

All business activities are required to comply with a range of reporting requirements for specific purposes. The regulatory accounts are required for specific regulatory purposes. There are differing purposes for statutory accounts and regulatory accounts.

Furthermore, as already noted in Chapter 5, the current documentation and information did not provide a totally satisfactory framework for a workable regulatory reporting environment. Of particular concern was the failure of accounting information to allow for the measurement of performance consistently over a number of years – a prime purpose of the regulatory accounts – or to consistently explain variations from year-to-year. The RIC's review of T&TEC's information also highlighted difficulties associated with the consistency of T&TEC's accounting information from year-to-year, particularly with respect to T&TEC's operating and maintenance cost categories. Amongst other things, this made it difficult to place T&TEC's proposed Opex forecasts in a meaningful historical context. The current statutory accounting system also made it very difficult for the RIC to assess the merits of T&TEC's claim that it made efficiency gains during the last number of years.

The RIC is convinced of the importance of establishing a regulatory accounting and reporting framework for a core set of financial and service quality reporting requirements for T&TEC. The RIC considers that, to be effective, regulatory accounting guidelines need to be consistent with the requirements of best practice reporting standards. The key attributes of best practice reporting are generally recognized to be:

- relevance – where the information reported has the capacity to make a difference in its informational or accountability role;
- consistency – where the information reported allows comparison to be made for the same organization over periods of time;
- comparability – where the information reported enables valid comparisons to be made between different utilities; and

- reliability – where the information reported corresponds with the actual underlying transactions, is capable of independent verification and is free from error and bias.

Requirements of the RIC Act

The RIC Act (Sections 57, 58 and 59) requires service providers to submit any information and Annual Reports to the RIC at such time and in such form as the RIC may require.

In light of the above, the RIC will develop and finalise the Regulatory Accounting Guidelines. The information provided to the RIC pursuant to these guidelines will enable the RIC to:

- measure actual performance against forecast;
- inform future price determinations;
- ensure the correct allocation of revenue and costs between customer classes;
- publish information on the performance of the service provider;
- improve the level of transparency in regulatory processes; and
- generally give effect to the objectives of the RIC as stated in its Act.

To ensure that the information obtained pursuant to these guidelines is relevant, the RIC will amend the guidelines, as necessary, from time to time to meet the changing needs of the RIC and to reflect evolving regulatory practice and experience.

The RIC will consult with the service provider and all other interested parties before finalizing the guidelines.

The RIC will develop and publish the Regulatory Accounting Guidelines within six months of the release of the Final Determination.

13.4 DIRECTIONS TO T&TEC FOR COMPLIANCE

The basic function of the RIC, as a regulator, is to regulate the electricity sector in a manner that promotes efficiency and economy, and financial viability and sustainability. The RIC is also empowered to establish and enforce standards with respect to quality, continuity and reliability of services. The RIC has, therefore, issued various directives in this **Determination** to T&TEC to achieve the above objectives. The under-mentioned directives will result in significant gains in the form of increased efficiency and overall development of the sector.

T&TEC will be required to submit a completed Action Plan to implement all the directions of the RIC contained in this Determination, within six (6) months of its release.

The RIC is confident that T&TEC will make the desired headway in implementing the directives.

SPECIFIC DIRECTIVES	REMARKS
Chapter 2 • T&TEC is required to inform the RIC on a yearly basis of the balance in the "unders and overs" account. This report will be due within 30 days after the end of every year. If at the end of a year, the balance in the "unders and overs" account deviates from pre-allowed revenue targets, the following will apply: ▪ **Under 5%** - T&TEC must notify the RIC within the stipulated timeframe. ▪ **Over 5%** - T&TEC must notify the RIC but must also provide an action plan to resolve the balance.	2006/Ongoing
Chapter 3 • T&TEC is to ensure that in its next rate review submission, it provides a comprehensive analysis of actual performance vis-à-vis the determinations of the RIC and proposes suitable treatment for any deviations.	

Chapter 4 • In the next regulatory period T&TEC will be required to provide comprehensive demand forecasts that have been independently verified to ensure that their forecasts and forecasting methods are robust and reasonable. Specifically, T&TEC must demonstrate that the methodology: ▪ is appropriate for the electricity sector; ▪ reflects the key drivers of peak demand, customer numbers and energy consumption; ▪ has used the most recent information available, in conjunction with historic data, to identify trends in growth; and ▪ has taken into account demand side management.	
Chapter 5	
• T&TEC must ensure that its submission for the next regulatory review period conforms to the RIC's Information Requirements. Failure to do so will result in future submissions being delayed/rejected.	Ongoing/annual
• T&TEC will be required to submit to the RIC annually audited accounting statements based on the Regulatory Accounting Guidelines stipulated by the RIC.	Ongoing/Annual
• T&TEC to put in place systems to collect data on total annual leave per employee (contracted, extended and emergency leave) as well as the additional costs incurred as a result of the relatively high rate of absenteeism on account of sick leave.	2006
• T&TEC to retain a consultant to review its organizational structure with a view to identifying weaknesses.	2006
• T&TEC to appoint a reputable consultant to suggest an appropriate policy on capitalization of salaries and wages.	2006
• T&TEC to put in place systems to identify separately the costs associated with the payment of cess and payments under the guaranteed standards scheme.	2006
• T&TEC to provide the details of internal energy consumption (both in terms of unit sales and amounts) from 2006 onwards.	2006/ongoing
• T&TEC to identify costs of Advertising and Marketing/Sponsorships separately.	2006

• T&TEC to:
  ▪ submit to the RIC annually its actual expenditure on Repairs and Maintenance;
  ▪ submit to the RIC quarterly reports on outages by area and reasons for outages; and
  ▪ repair and maintain pole mounted distribution transformers at a rate of 20% per annum and submit quarterly reports.
 	
• T&TEC must insist that every effort be made by PowerGen to reduce the system heat rate to the lower end of the range outlined in the PPA.
	2006/ongoing
	
	2006

Chapter 6
• The RIC has identified projects that should be fully funded by Government. These projects should be totally ring-fenced. If and when one of these projects is set to proceed, the RIC would require T&TEC to:
  ▪ demonstrate that the project will have no negative impact on any other users;
  ▪ show that accounting arrangements have been established to ensure capital and operating expense classification; and
  ▪ provide evidence that the associated costs are being fully covered by the Government.
 	
• T&TEC to provide a detailed review of the prudence of the capital programme at the end of the first regulatory control period.
 	
• T&TEC is required to provide the following information:
  ▪ annual reporting of investment including an explanation of any divergence;
  ▪ the final costs of all projects completed during the regulatory control period on an on-going basis.;
  ▪ a full justification why any project included in the approved Capex programme was not carried out, including the external factors that changed after the schedules were made;
  ▪ a full justification that any project completed above the forecast estimate, represented the best value for money;
  ▪ details of tenders received from all successful and unsuccessful bidders for any project externally contracted but completed above the forecast estimate; and
  ▪ detailed investigations of any divergence at the end of the price control period, with a correction to ensure that any unacceptable divergence is revenue neutral.
	As necessary
	
	2006/ongoing

• The RIC will also require in the future a detailed project-by-project capital expenditure programme with major projects to be audited by a person/consultant nominated by the RIC. • The RIC would require T&TEC to provide documented cogent explanations for Capex underspends. Only if it is satisfied by the justifications given, would the Capex portion of the appropriate portion of the underspend be allowed to roll-forward into the next regulatory period.	
Chapter 8 • T&TEC to develop (in conjunction with the RIC) a framework for assessing the economic prudence of loss management investment during the first price control period. • The RIC requires that T&TEC install the appropriate metering/monitoring equipment at strategic locations of its network during the first regulatory period in order to more accurately measure losses in the system.	 2006
Chapter 9 • T&TEC will be required to: ▪ publish information on the guaranteed and overall standards at least once per quarter, and at least in one daily newspaper widely circulating in Trinidad and Tobago; ▪ provide information, on the standards and how customers can claim for compensation, at least twice per year include in customers bills. This requirement to be continued until the end of 2007; ▪ ensure that claim forms are readily available at all T&TEC customer service offices/centres; ▪ adequately display the standards in all T&TEC customer service offices/centres; and ▪ provide to the RIC annual reports on its efforts to promote the standards (including evidence of newspaper advertisements, etc.) • T&TEC will be required to report to the RIC on a number of reliability measures by distribution area: ▪ SAIFI (System Average Interruption Frequency Index) measures the probability that a customer will experience an outage.	 2006/ongoing 2006/ongoing

▪ SAIDI (System Average Interruption Duration Index) provides a measure for the average time that customers are interrupted. ▪ CAIDI (Customer Average Interruption Duration Index) is a measure for the average time required restoring service to the average customer per outage. ▪ MAIFI (Momentary Average Interruption Frequency Index) is the total number of momentary interruptions (of less than three minute duration) that a customer could expect, on average, to experience in a year.	
• T&TEC must install equipment for monitoring quality of supply at each zone substation and at the far end of one of the distribution feeder supplied from each zone substation to better monitor voltage problems.	2006
• The RIC proposes that prior to setting any targets for voltage surges or voltage sags and harmonic distortions, the following quality of supply data be provided by T&TEC on an annual basis: ▪ Number of over-voltage events, and number of customers receiving over-voltage, due to high voltage injection. ▪ Number of over-voltage events, and number of customers receiving over-voltage, due to lightning. ▪ Number of over and under-voltage events, and number of customers receiving over and under-voltage, due to other causes. ▪ Number of voltage variations – steady state, one minute, 10 seconds.	2006/ongoing
• T&TEC must establish a suitable system to track performance and commence collection of data against the specified customer service parameters listed below: ▪ total number of calls; ▪ number of calls not answered within 30 seconds; ▪ average waiting time before a call is answered; ▪ number of complaints received and resolved by type; and ▪ resolution time (average, minimum and maximum by complaint).	2006
• T&TEC must also ensure that proper systems for recording and reporting information against these parameters are put in place by the end of 2006.	2006/ongoing

• As a minimum, T&TEC must: ▪ repair or replace any reported street light failure within 7 working days; ▪ replace photo-electric cells at least every 8 years or otherwise as required; ▪ clean, inspect for damage and repair luminaries during any re-lamping; ▪ routinely patrol major roads to inspect, replace or repair luminaries at least twice per year; ▪ commence installation within two weeks after payment is received; and ▪ consider implementing a telephone hotline number for customers to report street-lighting problems. Additionally, T&TEC must submit to the RIC annual reports on the above performance targets.	2006/ongoing
• T&TEC should develop a more customer friendly damaged appliance policy. The policy must state the nature and scope of the investigations T&TEC conducts to arrive at its decision. Additionally, the RIC will establish a Working Group, comprising NGOs, Business Organizations, T&TEC and the RIC, to develop a more comprehensive policy on damaged appliances. There is also the need for T&TEC to have information available in all its offices about exactly what customers need to do in order to make a claim for damaged appliances. In addition, T&TEC should also educate customers about the need for proper surge protection devices for appliances without endorsing a particular brand or type of protective device.	2006/ongoing
• The RIC accepts that large customers may have found it difficult to negotiate service provisions in their connection agreements. Consequently, the RIC will seriously consider measures that facilitate large customers being able to negotiate for service levels above the standard service provided. If these customers and T&TEC agree to specific service levels, then T&TEC will be required to monitor and report to these customers on the measures and at the intervals specified in the agreement.	2006
• T&TEC must not issue two or more consecutive estimated bi-monthly bills; and	

• An estimated bill must be based on the average of the last four billings. The RIC will also encourage T&TEC to consider reorganization of its billing procedures so as to generate bi-monthly bills based on a fixed number of days.	
Chapter 12 • T&TEC must submit proposed prices (rates) at least two months before the beginning of each year of the regulatory control period and the RIC will approve or reject prices within a month of the submission and allow another week to re-submit prices if rejected.	2006/ongoing
Chapter 14 • T&TEC must consider the rationalisation of its administration of regulatory requirements. • T&TEC is required to inform the RIC of long-term supply contracts or any other contract likely to affect customer rates or services. Further, T&TEC must ensure that the involvement of and approval by the RIC occurs prior to the execution of any such contracts. • T&TEC is required to publish its procurement procedures and submit same to the RIC. • T&TEC must demonstrate a commitment to the promotion of competition in areas such as the installation of street lighting, metering/meter reading etc. by publicly inviting bids for such works/services.	

ANNEX

PERFORMANCE INDICATORS FOR T&TEC

Item	Category	Indicator	Definition	Units	Reporting Period
1.0	**Aggregate Data**				
1.1		Number of electricity customers by class and area	T&TEC's customer data		Yearly
1.2		kWh sales by area	T&TEC's customer data		Semi Annually
1.3		kWh purchased	The basic unit of electric demand, equal to 1,000 watt-hours.	kWh	Monthly
1.4		Total System Losses	$1-\left(\frac{[\text{Energy Units Billed}]}{[\text{Energy Units Purchased}]} x \frac{[\text{Collection in \$}]}{[\text{Billing in \$}]}\right)$	MWh	Semi Annually
1.5		Number of connections and disconnections			Yearly
1.6		Peak demand	The maximum load during a specified period of time	MW	Semi Annually
1.7		Electricity coverage (i.e. Access to electricity)	$\frac{[\text{No. of customers (T\&TEC stats)}]}{[\text{No. of households in T\&T}]}$ x 100	%	Quarterly & Yearly
2.0	**Financial**				
2.1		Maintenance cost per MWh Sold	$\frac{\left[\begin{array}{l}\text{Total annual maintenance costs} \\ \text{(excluding capital cost)}\end{array}\right]}{[\text{MWh sold}]}$	$/MWh	Yearly
2.2		Cost of fuel per kWh	$\frac{[\text{Total costs of fuel}]}{[\text{kWh generated}]}$	$/kWh	Quarterly & Yearly
2.3		Cost of fuel (sales)		$	Quarterly & Yearly
2.4		Revenue per kWh	$\frac{[\text{Total revenue from sales}]}{[\text{Total no. of kWh sold}]}$	$/kWh	Yearly

Item	Category	Indicator	Definition	Units	Reporting Period
2.5		Internal manpower costs	Annual internal manpower costs / annual running costs x 100.	%	Yearly
2.6		Energy costs ratio	Annual energy costs / annual running costs x 100.	%	Yearly
2.7		Depreciation costs ratio	Annual depreciation costs / annual capital costs x 100.	%	Yearly
2.8		Net interest costs ratio	(Interest expenses costs – interest income) / annual capital costs x 100.	%	Yearly
2.9		Sales revenues	(Sales revenues / annual revenues) x 100	%	Yearly
2.10		Total cost coverage ratio	Annual revenues / annual costs.		Yearly
2.11		Delay in accounts receivable	Year-end account receivable / annual sales revenues x 12.	months equivalent	Yearly
2.12		Investment ratio	Annual investments subject to depreciation / annual depreciation x 100.	%	Yearly
2.13		Debt service coverage ratio	Profit before interest and tax / (Interest + capital repayments) x 100	%	Yearly
2.14		Operating ratio	$\frac{\left[\begin{array}{l}\text{Operating costs}\\ \text{(including depreciation and interest)}\end{array}\right]}{[\text{Operating revenue}]}$		Yearly
2.15		Working ratio	$\frac{\left[\begin{array}{l}\text{Operating costs}\\ \text{(excluding depreciation and interest)}\end{array}\right]}{[\text{Operating revenue}]}$		Yearly
2.16		Return on net fixed assets	Net operating income / net fix assets x 100.	%	Yearly
2.17		Return on equity	Profit after interest and tax / shareholders' equity x 100.	%	Yearly
2.18		Operating cost per customer	$\frac{[\text{Total operating costs}]}{[\text{Total no. of customers}]}$	$/cust.	Yearly

Item	Category	Indicator	Definition	Units	Reporting Period
2.19		Operating revenue per kWh	$\frac{[\text{Total operating revenue}]}{[\text{Total no. of KWh sold}]}$	$/kWh	Yearly
2.20		Current ratio	$\frac{[\text{Current assets}]}{[\text{Current liabilities}]}$		Yearly
2.21		Quick Ratio	$\frac{[\text{Current assets - stock}]}{[\text{Current liabilities}]}$		Yearly
2.22		Return on capital employed	$\frac{[\text{Profit before interest and tax}]}{[\text{Capital employed}]} x100$	%	Yearly
2.23		Gearing	$\frac{[\text{Interest bearing debt}]}{[\text{Interest bearing debt + equity}]}$		Yearly
2.24		Creditors Payments	$\frac{[\text{Creditors}]}{[\text{Credit purchases}]} x12$	Monthly equivalent	Yearly
2.25		Total revenue	Operating revenue and other revenue for the period	$	Yearly
2.26		Total expenditure	Operating expenses plus other expenses (Operating Expenses includes Generation, Transmission and Distribution, Administration and General, and Depreciation)	$	Yearly
2.27		Operating profit	Revenue from the organization's regular activities, less costs, and expenses and before income deduction	$	Yearly
2.28		Asset turnover	$\frac{[\text{Sales}]}{[\text{Capital employed}]}$		Yearly
2.29		Interest Cover	$\frac{[\text{Profit before interest and tax}]}{[\text{Interest}]}$		Yearly
2.30		Long term debt	Debt liabilities due in excess of one year	$	Yearly

Item	Category	Indicator	Definition	Units	Reporting Period
3.0	**Network Reliability**				
3.1		System average interruption frequency index (SAIFI) (Average number of sustained interruptions per customer)	Total number of reported customer interruptions greater than 1 minute duration / total number of customers served	Interruptions per year	Yearly
3.2		System average interruption duration index (SAIDI) (Average minutes off supply per customer)	Sum of each outage duration in minutes times the number of customers / total number of customers served	Minutes	Yearly
3.3		Customer average interruption duration index (CAIDI) (Average interruption duration)	$\frac{[SAIDI]}{[SAIFI]}$	Minutes	Yearly
3.4		Number of faults per 10km of distribution lines		No.	Yearly
3.5		Number of faults per 20km of transmission lines		No.	Yearly
3.6		Number of transmission and distribution circuit trip outs by voltage level		No.	Yearly
3.7		Interruptions restored within 3 hours and 5 hours		No.	Yearly
3.8		Supply interruptions per 100 connected customers		No.	Yearly
3.9		Number of complaints on voltage levels per 100 connected customers		No.	Yearly
3.10		Number of faults assigned to modifications at substations		No.	Yearly

Item	**Category**	**Indicator**	**Definition**	**Units**	**Reporting Period**
3.11		Disaggregation of causes for interruptions of supply: 1. Maintenance 2. New construction 3. User connection 4. Faults		No.	Yearly
3.12		Average response time to interruptions		Minutes	Yearly
4.0	**Affordability and other Economic Data**				
4.1		Sales per employee (kWh)	$\frac{[\text{Total kWh sales}]}{[\text{Number of employees}]}$	KWh/emp.	Yearly
4.2		Sales per employee ($)	$\frac{[\text{Total revenue form sales}]}{[\text{Number of employees}]}$	$/emp,	Yearly
4.3		Customers per employee	$\frac{[\text{Total no of customers}]}{[\text{Total number of employees}]}$	Cust./Emp.	Yearly
4.4		Low/High voltage complaints by area		No.	Quarterly and Yearly
4.5		Consumption per capita (kWh)	$\frac{[\text{Total kWh sales}]}{[\text{Total population}]}$	kWh/person	Yearly
4.6		Tariff for electricity services by category			Yearly
4.7		Restrictions for non payment of bills		No.	Yearly
4.8		Average consumption by class		kWh	Yearly
4.9		Average electricity bill by class		kWh	Yearly
4.10		Percentage of Customers with installment plans		%	Yearly

Item	Category	Indicator	Definition	Units	Reporting Period
5.0	**Customer Responsiveness and Service**				
5.1		Calls to emergency phone Line (% answered in 30 sec.)		%	Quarterly and Yearly
5.2		Written complaints not responded to within 5 working days		No.	Quarterly and Yearly
5.3		Complaints received (per 100 customers)		No.	Quarterly and Yearly
5.4		Complaints by major type	Reporting on the major areas of complaint	No.	Quarterly and Yearly
5.5		Complaints resolved by type		No.	Quarterly and Yearly
6.0	**Operational Indicators**				
6.1		Operator effectiveness Training requirements (Per generation unit)	$\frac{\left[\text{MWh lost due to operator caused outage}\right]}{\left[\text{MWh generated}\right]} \times 100$	%	Quarterly and Yearly
6.2		Performance of generation unit when most needed (Per generation unit)	$\frac{\left[\text{Output (MW) at each monthly peak}\right]}{\left[\text{Name plate rating}\right]}$	No.	Quarterly and Yearly
6.3		Spinning Reserves Availability Indicates how well the system responds to load increases	$\frac{\left[\text{Spinning reserves at each monthly peak}\right]}{\left[\text{System peak load}\right]} \times 100$	%	Quarterly and Yearly
6.4		Generator Performance under Peak Load	$\frac{\left[\text{The generator unit output (MW) at each monthly system load peak}\right]}{\left[\text{The unit's name plate rating}\right]}$		Quarterly and Yearly
6.5		Capacity Factor	$\frac{\left[\text{Annual electricity produced (MWh)}\right]}{\left[\text{Installed capacity (MW) x 8760 (period in hours)}\right]} \times 100$	%	Yearly

Item	Category	Indicator	Definition	Units	Reporting Period
6.6		Load Factor When the capacity factor is approximately the same as the load factor, this is an indication that installed capacity matches demand.	$\frac{[\text{Annual electricity produced (MWh)}]}{\left[\begin{array}{l}\text{Maxium load (MW) x}\\ \text{8760 (period in hours)}\end{array}\right]} \times 100$	%	Yearly
6.7		Monthly System Peak Load Demand Indicates if monthly system peak loads are being met	$\frac{\left[\begin{array}{l}\text{Available capacity (MW) at}\\ \text{each monthly peak}\end{array}\right]}{[\text{System peak load}]} \times 100$	%	Quarterly and Yearly
6.8		Generation Unavailability This indicates the generation capacity short fall due to forced or planned outages	$\frac{\left[\begin{array}{l}\text{Unavailable capacity (MW)}\\ \text{at each monthly peak}\end{array}\right]}{[\text{System peak load}]} \times 100$	%	Quarterly and Yearly
6.9		Forced outage rate at monthly peak (per generator)	$\frac{[\text{unit rating (MW)} \times \text{outage hours (hrs)}]}{[\text{installed capacity (MW)} \times \text{period (hrs)}]}$		Quarterly and Yearly
6.10		Availability Factor Measures the availability of each unit after partial or full outages (both planned and forced) have been allocated Indicates whether sufficient capacity is available in the total system	$\frac{\left[\begin{array}{l}\text{Total hours of operation}\\ \text{of plant during the period}\end{array}\right]}{[\text{Total length of period (hours)}]} \times 100$ o Ratio of available to installed capacity	%	Quarterly and Yearly
6.11		Output Factor (per unit) Measures the extent to which each unit capability is used	$\frac{[\text{MWh generated in period}]}{\left[\begin{array}{l}\text{Site rating on unit (MW) x}\\ \text{hours in period connected to system}\end{array}\right]} \times 100$	%	Quarterly and Yearly

Item	**Category**	**Indicator**	**Definition**	**Units**	**Reporting Period**
6.12		Realization of monthly system loads	$\frac{[\text{Available capacity (MW)}]}{[\text{System peak load at each monthly peak}]} \times 100$	%	Quarterly and Yearly
6.13		Inadequate generation capacity due to a forced or planned outages	$\frac{[\text{Unavailable capacity (MW)}]}{\begin{bmatrix}\text{System peak load at} \\ \text{each monthly peak}\end{bmatrix}} \times 100$	%	Quarterly and Yearly
6.14		Average Heat Rate (per unit) Measures the amount of energy needed to produce one kWh of electrical output. The smaller the heat rate the greater the efficiency	$\frac{[\text{Total Energy content of fuel burned}]}{[\text{Net kWh generated by unit}]}$	kJ/kWh	Quarterly & yearly

CHAPTER 14

CONCLUDING REMARKS AND THE WAY FORWARD

This is the first time that a service provider's pricing proposal, in this case T&TEC, has been subjected to the RIC's independent scrutiny. It is also the first time that the RIC has undertaken an exercise of this nature using the incentive-based approach to regulation. Under this approach, the service provider was required to publish its Business Plan setting out detailed proposals on future deliverables, estimates of the likely costs and the prices it will need to charge in order to achieve those outcomes.

This new approach has a number of advantages for stakeholders. In particular, it enables them to understand and influence what the service provider is proposing to deliver and judge for themselves whether they receive value for money. It also provides greater certainty about the prices that they will be charged for the next five years and enables them to manage their own usage more effectively.

There are also a number of benefits to an independent regulatory body such as the RIC, undertaking this role:

- There are well established procedures and processes that facilitate the transparency of information and effective public consultation and debates about key issues before decisions about prices are made; and
- It is independent in its decision-making and hence is able to balance a number of competing interests.

An important aspect of this first review has been to establish a firm foundation for economic regulation. The process that the RIC has undertaken has provided valuable lessons for the RIC as well as stakeholders based on feedback received.

It is apparent that the demands of the new regulatory environment will be very different to those which existed under the previous regime. The same applies in relation to information requirements. In particular, under the new regulatory framework superior baseline data availability is absolutely vital. In certain instances, therefore, the information quality has to improve significantly. However, the intensity of regulation will automatically reduce as and when quality information is available on all essential parameters. The effectiveness of regulatory intervention will also improve if the data environment improves, benefiting both the utility and consumers.

The measurement and analysis systems that need to be implemented must perform the tasks as a matter of routine. In many cases, recording and exchange of data need to be undertaken on-line between the utility and the RIC to facilitate their efficient transfer. The RIC recognizes that intensive efforts are necessary to make this a reality, since it would entail not only the establishment of IT systems, but also, in several instances, automation of basic information that is fed into the systems. In this regard, T&TEC must consider the rationalisation of its administration of regulatory requirements.

The RIC has also drawn attention to the inability of T&TEC to collect a significant portion of its revenue. Important contributors to the shortfall in collection are the Ministries and other State agencies. If Government Agencies/Ministries fail to pay, then it would be difficult to caution others. The RIC has proposed a number of measures to reduce receivables. The RIC hopes that the Government would issue strict instructions to Government Ministries/Agencies to remit payments to the service provider.

The RIC would also like to highlight certain other specific issues. The need to ensure institutional capability in the utility to meet and exceed the sector goals is critical. Operating in a monopoly environment with little commercial accountability can dull the inherent skills and capabilities of personnel in the organization. Human resources are key to the efficient functioning of the utility and sustainability of its operations. There has to be a continuous effort to improve the quality of human resources through training, performance evaluation and rewards for achieving organizational goals.

Two areas need special attention. First, an important lacuna in the working of T&TEC has been, to some extent, the lack of attention and commitment to training. In this regard, it is noted that T&TEC has not yet implemented a system to capture or identify training needs for the staff in various departments. T&TEC has one training centre but has not been able to fully capitalize on this asset to provide reasonable benefits to the organization. T&TEC should initiate a comprehensive training programme which should be drawn from the analysis of the Performance Management System that is currently in place. Hot-line repair and maintenance should be part of the overall training programme. Additionally, the RIC would like T&TEC to finalize a well-defined policy for upgrading training skills during 2006.

Second, T&TEC currently has no incentive programmes in place to motivate staff to excel and surpass annual set targets. Modern organizations have put different programmes in place to increase productivity and improve revenue. Similar programmes can be employed by T&TEC and they should be communicated to all employees in the context of meeting and surpassing goals and objectives for the creation of a sustainable organization that is capable of facing the challenges of the fast evolving future environment. Unless the process of capacity building is fully in place, and autonomy is provided to managers for operating on commercial lines, T&TEC may not be able to face future challenges.

There are opportunities to further build on the arrangements put in place as part of this review and to strengthen the incentives to improve the service provider's performance over time. This can occur by the RIC continuing to refine its regulatory approach as well as by Government examining opportunities to strengthen corporate governance arrangements for the sector that reinforce and complement the incentives created by this regulatory framework.

Safeguarding the interests of the marginal customers also needs to be an essential part of the on-going sector development. In view of the current wide divergence between costs and tariffs, the achievement of cost reflective tariffs especially for the residential class should be a medium-term goal, even though, the RIC Act requires the reduction and eventual elimination of cross-subsidization. Under these circumstances, continuation of some subsidies especially to the lower income group appears unavoidable. However, it is equally important to target the subsidies to ensure that they reach the most deserving.

Universal service obligation is another aspect which needs to be given full recognition in the development of the electricity sector.

An empowered process of independent regulation can provide much greater transparency and ensure professionalism in the functioning of the utility sector. Independent regulation is an important factor in bringing about improvements in the efficiency of the sector. In this regard, the RIC believes that certain essential aspects are required to make the regulatory process, and indeed the sector, successful, thereby benefitting the consumers. The RIC strongly believes that the speedy creation of a structure that responds to regulatory inducements should be the immediate objective of any reform process.

It is important for the regulatory body to be involved in that aspect of the process that affects its regulatory responsibilities. In particular, long-term supply contracts or other contracts affecting customer rates or services require some form of review and approval by the regulatory body before implementation. Consequently, T&TEC is required to inform the RIC of long-term supply contracts or any other contract likely to affect customer rates or services. Further, T&TEC must ensure that the involvement of and approval by the RIC occurs prior to the execution of any such contracts.

The RIC, in accordance with its legal mandate, would also be paying due attention to many other relevant issues, including the procurement procedures, outsourcing and the promotion of competition in the areas of installation of street lighting, metering/meter reading, etc. T&TEC is required to publish its procurement procedures and submit same to the RIC. T&TEC must also demonstrate a commitment to the promotion of competition in areas such as the installation of street lighting, metering/meter reading, etc. by publicly inviting bids for such works/services.

There is an urgent need to reform the utility for it to function as a public commercial enterprise rather than as a public administrative body. The RIC firmly believes that better governance is vital if the overall performance of T&TEC is to improve.

In this respect, the RIC takes this opportunity to briefly highlight some aspects of corporate governance arrangements that can be put in place for the benefit of the sector:

- there should be well-defined responsibilities for the State as owner, the Board and the senior management, ensuring that accountability of each party is rigorous and transparent;
- there should be high quality, independent, commercially experienced non-executive Board members who will bring openness and objectivity but also be able to question and advise senior management when necessary about the different aspects of the operations; and
- there should be transparent and appropriate incentives and penalties for staff to ensure that the right calibre of professionals are attracted to the sector. Senior management should be able to earn bonuses which should be published in advance and should be independently measurable and verifiable.

Currently, electricity transmission and distribution activities in Trinidad and Tobago are entirely State-owned. Generally, this makes the utility less responsive to change thus making effective regulation a challenge. As infrastructure services are consumed widely and are often considered essential, the State has had a long tradition of holding prices below their economic costs. The deficits so created have generally led to deterioration of assets through inadequate maintenance. Therefore, there is an urgent need to reform the utility for it to function on commercial principles. The RIC will prepare a paper that elaborates its ideas for sector reform. The document would be put out for public consultation.

The RIC is confident that T&TEC will rise to the challenge and look at proposed initiatives afresh with the aim of carrying out genuine improvements in service and efficiency. The electricity sector is critical in the development of any economy, and the state of the power sector is often an accurate reflection of the state of the economy. It is for T&TEC to take note of this important social and economic responsibility and take necessary measures to propel the sector ahead.

SUMMARY OF RIC'S FINAL DECISIONS

Chapter 2

- The RIC's decision is to utilize a fixed revenue cap form of regulation in the first regulatory control period.

- The RIC's decision is to utilize the cost "building-block" approach to setting revenue caps and will incorporate incentives for expected efficiency gains.

- The RIC's decision is to utilize X as a smoothing device and a single X-factor to reduce the volatility in annual revenues.

- The RIC's decision is to use RPI as the inflation factor.

- The RIC's decision is to adopt a five-year regulatory period for this determination

- The RIC's decision is not to utilize an error correction factor to automatically adjust revenue forecasts.

- The RIC's decision is to operate an "unders and overs" account in the form described and the proposed annual tolerance limits and actions for treatment of variations.

- The regulatory framework to include and provide for a within-period adjustment to the revenue cap under strict conditions.

Chapter 3

- The service providers will be required in the future to provide a comprehensive analysis of actual performance vis-à-vis the determination of the RIC and to propose suitable treatment for any deviations.

Chapter 4

- The RIC's decision is to adopt demand forecasts for customer numbers, energy consumption and peak demand as shown in **Tables 4.2, 4.3 and 4.4** in Chapter 4.

- For future price reviews, the service provider will be required to obtain and provide to the RIC, independent verification that its forecasts and forecasting methods are robust and reasonable. The RIC will also ensure that the independent auditor's report is made public.

Chapter 5

- The RIC's decision is to adopt total transmission and distribution expenditure (excluding conversion and fuel costs) as indicated in **Table 5.7** in Chapter 5.

- In the case of unforeseen uncontrollable costs, the RIC's decision is that each event for pass-through be assessed on its merits and on a case-by-case basis.

- The RIC's decision is to establish a materiality threshold for any potential trigger event at 1 percent of actual annual regulated revenue per event.

- The RIC's decision is that the use of automatic adjustment clauses be discontinued as these clauses do not generally form part of incentive regulation and have been a source of confusion for customers.

- In light of the above discussion, the RIC's decision is that Government/T&TEC should seek to re-negotiate more favourable terms in respect of PPA contracts.

- The RIC's decision is to allow a pass-through of 98% of conversion costs for the first regulatory control period as proposed in **Table 5.14.**

- In order to provide the right incentives and save on fuel costs, the RIC's decision is that there should be only 90% pass-through of fuel costs and the costs for failing to introduce combined cycle plant should not be borne by the consumer and, accordingly, have not been considered in the revenue requirement. Further, in the future, all additional capacity sourced should be through the installation of combined cycle units.

- The RIC's decision is to adopt fuel costs as proposed in **Table 5.19** in Chapter 5.

- The RIC's decision is to adopt total operating costs for the first regulatory control period as proposed in **Table 5.20** in Chapter 5.

Chapter 6

- The RIC's decision is to include capital expenditure forecast for T&TEC of $800 million for the first regulatory control period.

- The RIC's decision is to use regulatory audits to monitor the progress in improving the quality of T&TEC's asset management systems.

- As part of capital expenditure assessment, T&TEC will be required to present capital forecasts for three scenarios:
  - maintaining the current service quality level;
  - improving service quality aimed at delivering an agreed average level of service; and
  - specific additional commitments aimed at improving the quality of service in specific parts of the network or addressing identified customer requirements and including clearly identified service quality outcomes.

- The RIC's decision is to include capital expenditure in the regulatory asset base when the asset comes into service.

- The RIC intends to continuously monitor capital expenditure during the regulatory control period.

- The RIC will publish details annually of T&TEC's actual capital expenditure against proposed capital expenditures.

- The RIC will identify failure to deliver major capital projects against the timelines proposed and seek explanations as to the reasons for such failures.

- The RIC will audit the asset management capability and conduct an audit of major capital expenditure as part of the regulatory audit programme.

Chapter 7

- In setting the initial regulatory asset base for the first regulatory control period, the RIC's decision is to use a value based on historical cost valuation.

- The RIC's decision is to determine working capital for the first price control period as follows:

$$\textbf{Working Capital} = \textbf{Total Revenue from Sales} \times \frac{\textbf{57}}{\textbf{365}}$$

$$\textbf{Less: Operating Costs} \times \frac{\textbf{30}}{\textbf{365}}$$

- The RIC has decided that interest during construction should apply only to those projects that span several years and CWIP will not be allocated across asset categories during the roll forward but will remain as a financial entry only.

- The RIC's decision is to allow contributed assets to be incorporated into the RAB and recognise contributions in the year of receipt as a revenue flow.

- For the purpose of this regulatory control period, the RIC's decision is to approve the depreciation profile (based on historical cost on a straight-line basis) and the effective asset life proposal of T&TEC as these lives generally reflected current experience in the utility industry.

- The RIC's decision is to establish the opening regulatory asset base for the 2006-2010 regulatory period by rolling the regulatory asset base at December 2004 on the basis of the forecast capital expenditure proposed by the RIC.

- The RIC's decision is not to include a return on equity.

- T&TEC should initiate debt restructuring immediately with a view to negotiating lower interest rates.

- The RIC's decision is that for the purposes of calculating the building-block allowance for the return on capital, a cost of capital of 8% will be applied for the first regulatory control period.

Chapter 8

- The RIC intends to implement a rolling carryover mechanism.

- The RIC's decision is to utilize a P_o adjustment to share out-performance.

- The RIC's decision is to utilize a mechanism for sharing profits with customers if profits exceed 10% of the total revenue forecasts.

- The RIC intends to have T&TEC maintain an "unders and overs" account in respect of actual revenues versus the forecast revenues. T&TEC to report to the RIC on a yearly basis of the balance in the account.

- If the balance in the "unders and overs" account deviates, the RIC intends to use the following mechanisms:

  - Under 5%, T&TEC must notify the RIC within 30 days after the end of every year.

  - Over 5%, T&TEC must notify but must also provide an action plan to resolve the balance.

- The RIC's decision is to incorporate the principles in section 8.6 for the calculation of the efficiency carryover amount and the outstanding "unders and overs" account balances to be incorporated in to the revenue requirements for the 2011-2015 regulatory control period.

- The RIC's decision is to adopt the initial level of system losses at 7.9% and set the target for reduction in loss levels for the first regulatory control period at 6.75%.

- The RIC's decision is that T&TEC be allowed to keep 90% of the gains if actual system losses fall below 6.75%, the sharing of the gains to occur at the end of the regulatory control period.

- The RIC supports the principle of taking into account the value of loss reduction into the asset base when it is rolled forward to encourage investment in the loss reduction equipment.

- The RIC requires T&TEC to install the appropriate metering/monitoring equipment at strategic locations of its network during the first regulatory control period.

Chapter 9

- The RIC's decision is not to include a performance incentive mechanism (S-factor) for the first regulatory control period.

- T&TEC would be required to prepare and submit Codes of Practice for the RIC's approval before the end of the first quarter of 2007 on the following:
  - Provision of Priority Services for Vulnerable Groups;
  - Procedures for Dealing with Customers in Default;
  - Debt Recovery and Disconnection Procedures and Policies;
  - Retroactive Billing Policy;
  - Range and Accessibility of Payment Methods;
  - Handling of Complaints; and
  - Continuous Consumer Education.

- The RIC will appoint an independent agency to design and administer a customer satisfaction survey and present its conclusions in a report which will be posted on its website and made available to stakeholders and all interested parties at the beginning of each price control period.

- In light of the above assessment of the existing scheme, the RIC will not introduce changes to the current scheme at this time. The RIC will review the scheme at the end of three years (i.e. in 2007) for appropriate action/proposals.

- However, to ensure effective promotion of the current scheme, T&TEC will be required to:
  - publish information on the Guaranteed and Overall Standards, at least once per quarter and at least in one daily newspaper widely circulating in Trinidad and Tobago;
  - provide information, on the standards and how customers can claim compensation, at least twice per year in customers' bills. This requirement to be continued until the end of 2007;
  - ensure that claim forms are readily available at all T&TEC customer service offices/centers;
  - adequately display the standards in all T&TEC customer service offices/centres; and
  - provide to the RIC annual reports on its efforts to promote the standards (including evidence of newspaper advertisements, etc.)
- The RIC's conclusion is that the service incentive arrangements for the first price control period should consist of the Guaranteed Payment Scheme and Performance Reporting Requirements.
- The RIC will consider the inclusion of the above public (street) lighting targets in its Guaranteed Standards Scheme for the second regulatory control period.
- The RIC's decision is to introduce a late payment charge of 1.5% per month on all customers.
- That T&TEC must improve the reliability of service to its largest customer, and failing that, the RIC may consider the introduction of a special regime of interruptible tariffs.

Chapter 10

- The RIC does not intend to provide the flexibility to automatically adjust the list of services or charges during the price control period.
- The RIC will continue to regulate the current set of miscellaneous services.
- The RIC considers a fee-by-fee cap to be reasonable for miscellaneous charges.
- To prevent the proliferation of miscellaneous services, the RIC considers the current list of approved miscellaneous charges to be exhaustive.
- The RIC will exempt pole and transformer rentals from the miscellaneous schedule.

- The RIC's decision is that charges for miscellaneous services can increase by the RPI from 1992 via a once-only adjustment. No further increase will be permitted for the duration of the first control period.

- The RIC requires T&TEC to put systems in place to capture and record the various efficient cost components involved in providing miscellaneous services. These costs are to be verified by an independent party.

- The RIC's decision is that there should be at least one free meter test every 5 years regardless of the result of the test.

- The RIC considers that the service deposit issue needs further investigation, and will establish a Working Group comprising the service provider, NGOs, other consumer interests, and the RIC. This group will develop proposals on service deposit issues and report to the RIC within six months of the establishment of the Working Group.

- The RIC will set up a Working Group comprising the service provider, NGOs, other consumer interests, and the RIC. This group will develop proposals on capital contribution issues and report to the RIC within six months of the establishment of the Working Group.

Chapter 11

The RIC's allowed annual revenue requirements are as follows:

2006 ($Mn)	**2007 ($Mn)**	**2008 ($Mn)**	**2009 ($Mn)**	**2010 ($Mn)**	**TOTAL ($Mn)**
1,888.74	1,988.75	2,256.42	2,361.89	2,606.44	11,102.24

- The RIC's decision is to adopt the NPV smoothing approach as it allows the service provider to recover almost fully its revenue requirements, as well as minimize price volatility for customers.

Chapter 12

- For the first regulatory period, the RIC intends to accept cost allocation based on the fully distributed cost method. In future, the RIC will require T&TEC to submit marginal cost analysis that could be used for the development of tariffs.

- The RIC intends to incorporate a rebalancing control (side constraint) as part of the first regulatory price control.

- The RIC intends to set the size of the side constraint on the expectation that it would broadly allow the achievement of cost reflective pricing by the end of the first regulatory control period.

- The RIC requires that T&TEC must, at least two months prior to the beginning of each year of the regulatory control period, submit proposed tariffs to apply from the start of each year of the regulatory control period for verification of compliance by the RIC.

- T&TEC must ensure that its proposed tariffs comply with the established principles.

- T&TEC must, if requested by the RIC, provide additional information and resubmit or revise its proposed tariffs.

- The RIC must provide T&TEC in writing whether or not it has verified T&TEC's proposed tariffs as compliant with the relevant established principles.

- The proposed tariffs will be deemed to have been verified as compliant by the end of the two months from the date of receiving T&TEC's Annual Tariff Approval Submission.

- T&TEC must inform customers of the new tariffs at least two weeks before implementation by publishing in at least one daily newspaper in circulation in Trinidad and Tobago and by the use of other media.

- T&TEC is prohibited from introducing new tariffs and/or tariff components during the regulatory control period other than those approved by the RIC.

- The RIC requires T&TEC to implement the following Demand Side Management techniques:
  - strategic conservation by creating a database of energy efficient appliances and products to be recommended for consumer use; and
  - consumer tips for strategic conservation.

- The RIC also intends to incorporate incentives in the regulatory framework for T&TEC to invest in demand management initiatives.

- The RIC requires T&TEC to undertake a study and report to the RIC within 18 months after the release of the Final Determination on the feasibility of implementing time-of-use tariffs for its customers.

Chapter 13

- The RIC will periodically review its Performance Monitoring and Reporting (PMR) Framework. In the meantime, no changes are proposed to the indicators as set out in the **Annex** to Chapter 13.

- The RIC will consider measures over the coming regulatory period that facilitate large customers being able to negotiate for service levels above the standard service provided.

- The RIC will develop and publish the Regulatory Accounting Guidelines within six months of the release of the Final Determination.

APPENDIX

LIST OF STAKEHOLDERS WHO SUBMITTED WRITTEN RESPONSES

NAME OF PERSON/ORGANIZATION	NAME OF PERSON/ORGANIZATION
1. Government of the Republic of Trinidad and Tobago	14. Aziz Khan
2. Trinidad & Tobago Chamber of Industry & Commerce/ Trinidad and Tobago Manufacturers Association	15. Jessamy Pillai
3. Couva/Point Lisas Chamber of Commerce	16. Gookool Samuel
4. Trinidad & Tobago Electricity Commission (T&TEC)	17. Concerned Citizen ('Fed Up')
5. Water and Sewerage Authority	18. Betty Huggins
6. Mittal Steel Point Lisas Limited	19. Carlton Gibbs
7. Charles DeMatas	20. Concerned Citizen
8. Emru D. Millette	21. Asana Gumansingh
9. Senator Mary K. King	22. Furness Trinidad Ltd
10. Trinidad and Tobago Association of Retired Persons (TTARP)	23. Nirupa Sonja Nandram
11. Anton Daniel	24. Hercial Vitalis
12. Francis & Jill Williams-Smith	25. Keith Boodoo
13. Daniel Singh	26. Name withheld on request

LIST OF STAKEHOLDERS WHO ATTENDED REGIONAL CONSULTATIONS

FEBRUARY 6 – 10, 2006

DATE & VENUE	NAME OF STAKEHOLDERS		
February 6, 2006 Old Fire Station, Abercromby Street, Port-of-Spain	1. Oswald Downes 2. Emru Millette 3. Douglas P. Munro 4. Carl Drayton 5. James Chang Kit 6. Brian Ngfatt 7. Anthony Wahid 8. Jacqui Harris 9. Patrick Rambert 10. Glen Cyrille 11. Israiell Ali 12. Delores Charles 13. Ursula Felix Nesbitt 14. Rodney Latchman 15. Ronald De Silva	16. Mumtaz Ali 17. Harold McLean 18. Courtehay Legendre 19. Stephen Martel 20. Abdul-Rahman Aquil 21. Larry Western 22. Juanita Charles 23. Irvin Thompson 24. Charles DeMatas 25. Asha Javeed 26. Kamta Kulraj 27. Meera Singh 28. Kerwin Awai 29. Colleen Licorish 30. Patsy Peters	31. Courtenay Mark 32. Curtis Rahim 33. Jennifer Allen 34. Wendell Mayers 35. Renwick Mathura 36. Charles Davis 37. Hazel Brown 38. Lloyd Awai 39. Dennis James 40. Malisa Neptune 41. Ricardo Herbert 42. Trinidad & Tobago Manufacturers Association (TTMA) 43. Ministry of Public Utilities and the Environment
February 6, 2006 Arima Town Hall, Sozano Street, Arima	1. Nigel Charles 2. Vishnu Seetaram 3. Felix Alleyne 4. Kathy Irish 5. Marilyn Moore	6. Alan Richardson 7. Wendell Mayers 8. Annette James 9. Zainool Mohammed 10. Shawn Solomon 11. Nizam Baksh	12. Chrisalston Belle 13. Wendy Lee Yuen 14. Jackie Gaskin 15. Jennifer McCollin 16. Ministry of Public Utilities and the Environment
February 7, 2006 Chaguanas Senior Comprehensive School, Helen Street, Lange Park, Montrose Chaguanas	1. Stephen Kangal 2. Kanhai Kangal 3. Latta Jahoor 4. Kelvin Ramsook 5. Johann Rackal 6. Ramesh Ramoutar 7. Maimoon Ali	8. John Tang Yew 9. Theodore Lamblin 10. Richard Ramcharan 11. Michael Bedasie 12. Lydia Baah 13. Thelma Valfre 14. Wendell Mayers 15. Nadine Jeffrey	16. Shazard Mohammed 17. Raj Bhaggan Wegner 18. Michael Jordon-Elcock 19. E. Ramjass 20. Conrad Pierre 21. Tim Ramkin 22. Ministry of Public Utilities and the Environment
February 9, 2006 San Fernando City Corporation, City Hall, Harris Promenade, San Fernando	1. Andrew Joseph 2. Eric Lewis 3. Angela Lashley-Mendoza 4. Stephen Martel	5. Narine Charran 6. Simon Bhagwandeen 7. C. Baptiste 8. David Abdullah 9. Aldwin Beddoe	10. K. Mootoo 11. Keith Boodoo 12. Glen Jemmott 13. Ministry of Public Utilities and the Environment

DATE & VENUE	NAME OF STAKEHOLDERS		
February 10, 2006 Fairfield Complex, Tobago	1. Curtis Hamylin 2. Hollis McCardy 3. Aivenna Yorke 4. Kaman Akili 5. Sheryl Jemmott 6. K. Phillips 7. Gwendolyn Clinton-Sealy	8. Victoria K. Baid 9. Selby Levin 10. Liz 11. Diane Rampadarath 12. Janet Bovell 13. Sheila Williams 14. Charles Inniss	15. Janice Baito 16. Avril Edwards 17. Alvin Gray 18. Adanne Guy 19. Agnes Carrington 20. Ministry of Public Utilities and the Environment
March 7, 2006 Crowne Plaza, Port-of-Spain	1. David Abdullah 2. Andrew Aleong 3. Azim Ali 4. Israiell Ali 5. Sayad Ali 6. Wilbert Archie 7. Marie Baptiste 8. Judy Beckles 9. Neil Beekhee 10. Roland Bernard 11. Savitri Bessessar 12. Yvette Bobb-Morris 13. Keith Boodoo 14. Dereck Boyce 15. Petra Bridgemohan 16. Hazel Brown 17. Catherine Castello-Green 18. Meryll Cezair-Lau 19. Kurtis Chase 20. Dereck Coa 21. Violet Currie 22. Edward Dansica 23. Karen DeGannes 24. Desmond Diaz 25. Michelle Durham-Kissoon 26. Shinelle Edwards 27. Lester Forde 28. Agnita Francis 29. Sati Gajadhar Inniss 30. Jacqueline Gaskin 31. Carlton Gibbs 32. Hudson Grazette	33. Patrick Hall 34. Max Herbert 35. Kathy Ann Holder 36. Peter Huggins 37. Kenrick James 38. Janine John 39. Andy Johnson 40. Amberlene Joseph 41. Ancil Joseph 42. Mathyr Joseph 43. Stephen Kangal 44. Brian Knight 45. Brian La Fond 46. Dehenley Leander 47. Selwyn Liddelow 48. Colleen Lodge 49. Lynette Mahabir 50. Vashti Mahabir 51. Stephen Martrel 52. Wendell Mayers 53. David Maynard 54. Ann Mc Carthy 55. Joseph Mendes 56. Lynette Mendoza 57. Carl Merrick 58. Emru Millette 59. G. Mohammed 60. Haseed Mohammed 61. Shaheed Mohammed 62. Kenny Mootoo 63. Nanika Morain 64. Joycelyn Morang	65. Douglas P. Munro 66. V. Nanan 67. Sampson Nanton 68. David Neehall 69. Earl Nesbitt 70. Henry Nicholas 71. Halima Omadally 72. Irma Ou Young 73. Althea Pascall-Nicholas 74. Michael Peters 75. Patsy Peters 76. Frances Peterson 77. Colin Ramesar 78. Driselle Ramjohn 79. Gangaram Ramlogan 80. Rajendra Ramlochan 81. Kevin Ramnarine 82. Trevor Ramsaran 83. Michael Ramsingh 84. Sam Razak 85. David Renwick 86. Seebaran Santokee 87. Kamine Sarran 88. Lynette Serrette 89. Helen Simpson 90. Balkaran Singh 91. Menee Singh 92. Zahina Singh 93. Shelly Slater 94. Andrew Small 95. Rudy Sookhan 96. Kenrick Sooknarine

DATE & VENUE	NAME OF STAKEHOLDERS		
March 7, 2006 Crowne Plaza, Port-of-Spain (Continued)	97. Lynette Stephenson 98. Harrilal Sudama 99. Bridget Telfer 100. Clair Terry 101. Irwin Thompson	102. Thomas Verasammy 103. Hercial Vitalis 104. Merle Waldron 105. Errol O. C. Webb 106. Rudolph Weekes	107. Philmore Williams 108. Terrance Williams 109. Patricia Wiltshire 110. Kenneth Young Jr. 111. Param Maharaj 112. Ministry of Public Utilities and the Environment

Glossary of Terms and Definitions

Building Block Approach	The approach to deriving forecast revenue requirements that is the sum of a return on the regulatory asset base including net new investment (return on assets), a return of the regulatory assets base (depreciation) and efficient operating, maintenance and administrative costs.
Business Plan	The submission that sets out the service provider's views of the rates/price limits requested for the duration of the regulatory control period and its reasons for them.
Capex	Capital Expenditure/works of the service provider.
Combined Cycle	An electric generating technology in which electricity and process steam is produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating plant.
Comparative Analysis (Benchmarking)	The use of a number of different utilities' performance in a given area to assess relative performance of an individual utility.
Cost of Capital	The minimum return that providers of capital require to induce them to invest.
Cost-Reflection Pricing	Where charges are based on the cost of the service provider of actually providing that service to a customer.
Cost Pass-Through	Component of incentive regulation that caters for uncontrollable costs. (*See Uncontrollable Cost).*
Cross-Subsidy	The subsidization of a particular customer group by another group.

Demand	The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts (kW), megawatts (MW), or gigawatts (GW), at a given instant or averaged over any designated interval of time. Demand should not be confused with Load or Energy.
Demand Charge	A fee based on the peak amount of electricity used during the billing cycle.
Demand Related Tariffs	Tariffs that are structured so that they encourage the efficient use of a product/service by those whose demands impose additional costs of supply.
Demand Side Management (DSM)	Programs to influence the amount or timing of customers' energy use.
Depreciation/ Return of Capital	A measure of the consumption, use or wearing out of an asset over the period of its useful economic life.
Economic Life	The economic life of an asset is the period for which an asset remains useful.
Economies of Scale	Economies or savings resulting from the use, management of production of goods in large quantities. A lower cost per unit of output is achieved than would have been the case if smaller quantities were produced.
Energy Conservation	Using less energy, either by greater energy efficiency or by decreasing the types of applications requiring electricity or natural gas to operate.
Energy Efficiency	Using less energy (electricity and/or natural gas) to perform the same function at the same level of quality. Programs designed to use energy more efficiently - doing the same with less.
Equity Finance	The risk-sharing part of a company's (utility) capital. Usually referred to as ordinary share capital.
Financial Indicators	Certain financial ratios (such as gearing, interest cover and dividend c over) used to measure the financial performance of a company.
Gearing	A service provider's net debt expressed as a percentage of its total capital.

GWh	Gigawatt Hours, which is the equivalent of 1,000,000 Watt hours.
Inclining Block Tariffs	A tariff structure where the incremental unit price increases as the level of consumption increases.
Indexation	The policy of connecting prices, costs, wages etc. to rises in the general price level, retail prices or other measures of prices (inflation).
Interim Determination	A condition that allows the regulator to make, in any year during the regulatory control period adjustments to the price limits for certain relevant changes of circumstances, provided these are material.
Investment Programme	A schedule of planned investment (network and non-network related) to be undertaken to provide continuing services to customers.
Independent Power Producer (IPP)	A private entity that operates a generation facility and sells power to electric utilities for resale to retail customers.
Kilowatt (kW)	This is a measure of demand for power.
Kilowatt-hour (kWh)	A measure of consumption. It is the amount of electricity that is used over some period of time, typically a one-month period for billing purposes. Customers are charged a rate per kWh of electricity used.
kV	Kilovolt, which is the equivalent of 1,000 volts.
Load	An end use device or customer that receives power from an energy delivery system. Load should not be confused with Demand, which is the measure of power that a load receives or requires. (See Demand).
Logging Up and Down	An adjustment that takes place at the end of the regulatory control period to reflect differences in cost from the original determination.
Marginal Cost	The cost to the utility of providing the next (marginal) kilowatt-hour of electricity, irrespective of sunk costs.
MVA	Megavolt Ampere, which is the equivalent of 1,000,000 volt amperes.

MWh	Megawatt-hour; the unit of energy equal to that expended in one hour at a rate of one million watts.
Net Present Value	The economic value of a project, at today's prices, calculated by netting off its discounted cash flow from revenues and costs over its full life.
Nominal Terms	Values expressed in the year of occurrence, but ignoring changes in the purchasing power of money.
Opex	Operating Expenditure (comprising day-to-day running costs).
P_0 adjustment	A permanent percentage reduction in prices as a result of efficiency gains that have been achieved by the utility.
Peak Load or Peak Demand	The electric load that corresponds to a maximum level of electric demand within a specified time period.
Rate of Return	The annual income and capital growth from an investment, expressed as a percentage of the original investment.
Real Terms	The value of money expressed in constant dollar terms.
Regulatory Asset Base (RAB)	The value of the regulated business' assets used to derive forecast revenue requirement under the building block approach. The RAB is used for regulatory price setting purpose only and is different to the value that the utility may adopt for accounting purposes. The RAB is updated for new capital expenditure, depreciation and disposals.
Regulatory Control Period/ Regulatory Period/ Control Period/ Price Control Period	The period covered by a price determination made by the regulator.
Retail Price Index (RPI)	The general index of retail prices published by the Central Statistical Office (the CSO).
Revenue Requirement	A forecast of the revenue required over a regulatory control period.

RPI-X Regulation	A form of regulation that involves setting price caps that are measured relative to the RPI.
Sunk Cost	In economics, a sunk cost is a cost that has already been incurred, and therefore cannot be avoided by any strategy going forward.
Time-of-Use (TOU) Rates	The pricing of electricity based on the estimated cost of electricity during a particular time block. Time-of-use rates are usually divided into three or four time blocks per twenty-four hour period (on-peak, mid-peak, off-peak and sometimes super off-peak) and by times of the year. Real-time pricing differs from TOU rates in that it is based on actual (as opposed to forecasted) prices that may fluctuate many times a day and are weather-sensitive, rather than varying with a fixed schedule.
Transmission Network	The system that carries the electricity over long distances at high voltage from the generation plant to the distribution substation, where the electricity is "stepped down" (the voltage is reduced) for distribution to residential, commercial and industrial customers.
Unbundling	Disaggregating electric utility service into its basic components and offering each component separately for sale with separate rates for each component. For example, generation, transmission and distribution could be unbundled and offered as discrete services.
Uncontrollable Costs	Costs over which the actions of the service provider have little or no effect.
Universal Service	Electric service sufficient for basic needs made available to all members of the populations, regardless of income.
Weighted Average Cost of Capital (WACC)	The average of cost of debt and cost of equity capital, weighted according to the balance of debt and equity which finances the utility's assets.
X-Factor	Productivity or general efficiency improvement factor.