REGULATED
INDUSTRIES
COMMISSION

REGULATION OF ELECTRICITY TRANSMISSION AND DISTRIBUTION 2023 – 2027

DRAFT DETERMINATION

January 2023

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Glossary of Terms and Definitions

Annual Investment Return	The report to be submitted by the service provider which details its performance on capital projects against allowed capital expenditure projects.
Annual Revenue Requirement	The annual revenue that is required to meet expenses.
Automated Metering Infrastructure (AMI)	Metering technology that comprises several elements used for billing and other customer centric functions, for example outage management.
Benchmarking	The comparison of the performance of various utilities, providing similar services, in a specific area/field (financial / technical / operational).
British Thermal Units (BTU)	The amount of heat required to increase the temperature of one pound of water by one degree Fahrenheit, at a constant pressure of one atmosphere.
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.
Customer Average Interruption Duration Index (CAIDI)	It represents the average time required to restore service. It is calculated by dividing the total interruption durations by the total number of outages.
Capex	The money spent to buy, maintain, or improve the service provider's fixed assets, such as buildings, vehicles, equipment, or land.

Cost of Capital	The minimum return that providers of capital require to induce them to invest.
Cost Pass-Through	Component of incentive regulation that caters for uncontrollable costs. (See Uncontrollable Cost)
Cross-Subsidy	The subsidisation 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 at a given instant or averaged over any designated interval of time. Generally expressed in kilowatts (kW), megawatts (MW), or gigawatts (GW).
Demand Charge	A fee based on the peak amount of electricity used during the billing cycle.
Demand Side Management (DSM)	Programs to influence the amount or timing of customers' energy use.
Depreciation	A measure of the consumption, use or wearing out of an asset over the period of its useful economic life. It is also referred to as Return of Capital.
Discounted Cash Flow	A method used to value investment by adjusting the estimated future cash flows, for the time value of money. It is utilized in Net Present Value analysis.
Economic Life	The economic life of an asset is the period for which an asset remains useful.
Efficiency Carryover Mechanism	A mechanism that provides the service provider with a continuous incentive to achieve efficiency gains.
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. Programmes designed to use

	energy more efficiently by doing the same with less.
Financial Indicators	Financial ratios (such as gearing, interest cover and dividend cover) used to measure the financial performance of a company.
Gearing	A service provider's net debt expressed as a percentage of its total capital.
Gigawatt hours (GWh)	A measure of consumption that is equivalent to 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 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.
Kilojoule (KJ)	A joule is a measure of work or energy in the International System of Units. A kilojoule is 1,000 joules.
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.
Kilovolt (kV)	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. A distinction is often made between Short Run Marginal Cost (SRMC) is the change in total cost when an additional unit of output is produced and at least one cost input remains fixed. Long Run Marginal cost (LRMC) is the change in total cost when an additional unit of output is produced and all input costs are variable.
Megawatt-hour (MWh)	The unit of energy equal to that expended in one hour at a rate of one million watts.
Net Present Value (NPV)	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 period.

Performance Indicators Report	The annual report published by the RIC that assesses T&TEC performance using targets originally established in PRE1.
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/s	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.
System Average Interruption Duration Index (SAIDI)	It indicates the total duration of interruption for the average customer during a predefined period. It is commonly measured in minutes or hours of interruption. It is calculated by dividing the total number of interruption durations by the total number of customers.
System Average Interruption Frequency Index (SAIFI)	It indicates how often the average customer experiences a sustained interruption over a predefined period. It is calculated by dividing the number of customer interruptions by the total number of customers served.

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.
Supervisory Control and Data Acquisition (SCADA)	A category of software applications for controlling industrial processes, which requires the gathering of data in real time from remote locations to control equipment.
Time-of-Use (TOU) Rates	The pricing of electricity based on the estimated cost of electricity during a particular time block.
Transformer	A device for reducing or increasing the voltage of an alternating current.
Transmission Network	The network used for transmission of high voltage electricity through high voltage overhead power lines, transformers and other high voltage equipment and installations, from the point of receipt from the electricity producers or interconnection electricity lines to the point of delivery.
Trigger Event	A materiality threshold to limit cost pass-throughs to events that have a significant impact on the service provider's costs, while avoiding the risk of introducing a cost-plus regulation regime. A one percent materiality threshold is considered to be reasonable and is typically used.
Uncontrollable Costs	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.
Unders and Overs account	A notional account that is used to track the actual revenues of the service provider against forecast revenues at the end of each financial year of the control period.
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	This can either be used as an efficiency factor or as a smoothing factor.

EXECUTIVE SUMMARY

INTRODUCTION

The Regulated Industries Commission (RIC) is responsible for regulating the Water and Wastewater Sector and the Electricity Sector in Trinidad and Tobago. This Price Review, for the control period 2023-2027, concerns the Trinidad and Tobago Electricity Commission (T&TEC), the sole electricity transmission and distribution operator, and follows almost 11 years after PRE1. In the intervening years, the financial circumstances of T&TEC deteriorated to the extent that it was unable to meet its commitments. Therefore, the completion of this review and the implementation of new rates should have a positive effect on the overall operations of T&TEC, thereby leading to improved services to customers.

T&TEC is a "natural monopoly", which if left unregulated may be inefficient and impose tariffs that are too high. The RIC's mandate is not only to protect the interest of consumers, but also to ensure that T&TEC can fulfill its obligations and deliver reliable and safe electricity services. Its responsibilities include establishing methodologies and principles by which revenues and tariffs are set to recover from its customers its operational costs and investment needs to ensure that it can maintain and improve the quality of service.

THE CONTEXT OF THE REVIEW

The RIC is required to take account of a wide range of factors, in making its decisions, to ensure that it achieves a balance between the needs and interests of different stakeholders affected by these decisions. The review of rates and charges for T&TEC is occurring at a challenging time. On the one hand, the world faces the daunting task of mitigating the effects of climate change, while on the other hand the global economy is struggling to cope with high energy prices and supply chain disruptions. In respect of worsening climate issues, the responsibility devolves to all citizens to demonstrate awareness that conservation of electricity is one factor which can assist in reversing this trend. As regards the global economy, it had started to emerge from the recessionary impact caused by the pandemic (COVID-19), only to be set back by the Russia/Ukraine War.

In virtually all countries the poor have become poorer, and the middle class is struggling to maintain the status quo. Trinidad and Tobago, as a net exporter of energy products, has been better placed to cushion some of these impacts. According to the Review of the Economy 2022 “the country has been learning to live with the COVID-19 virus, the Trinidad and Tobago economy is now on a path to recovery and growth, amidst concerted efforts towards rebuilding what was detracted by the pandemic.” However, media reports in Trinidad and Tobago paint a different picture. There are frequent reports of citizens complaining about increased food prices and their inability to meet their monthly household needs. These are the major circumstances that the RIC has had to navigate while conducting its review. Among its main responsibilities, the RIC must ensure the affordability of electricity prices, and provide T&TEC with the funding necessary to provide reliable and quality services to the public. The unenviable challenge for the regulator is how to set prices that would allow T&TEC to provide reliable services and still make these services affordable to citizens.

The purpose of the Review is to determine an appropriate level of allowed revenue for T&TEC, and the level and structure of tariffs that will be paid by customers. In setting the allowed revenue and tariffs, the RIC’s objectives are to ensure that:

- the service provider operating under prudent and efficient management can earn sufficient return to finance necessary investment. In doing so, the RIC wants to ensure that the service provider’s planned investments are necessary and provide value for money for customers;
- the interests of customers are protected, in the short and long-term, by ensuring that services are reliable and provided at the lowest possible cost; and
- appropriate incentives are provided for the service provider to improve its efficiency where possible, and that most of the savings that result from efficiency gains are passed through to customers.

This Draft Determination puts forward the RIC’s proposed decisions on T&TEC’s revenue and incentives for the second control period (2023-2027), to be known as PRE2. T&TEC’s costs and performance over the first control period, PRE1 (2006-2011) are also examined to assess these against this regulatory settlement.

THE PROCESS

The publication of this Draft Determination follows a lengthy period of engagement with the public and the service provider during which twenty (20) papers were released/published for public comment. The engagement involved the assessment/analysis of multiple submissions by the service provider on both its historic and forecast costs, numerous meetings with the service provider to clarify its submissions, site visits, and the benchmarking of the service provider's costs and performance against other utilities. The RIC also engaged the shareholder, the Government of Trinidad and Tobago (GORTT) on key matters.

THE FRAMEWORK

Section 48 of its Act Chapter 54:73 mandates that reviews be conducted every five (5) years or where the licence issued to the service provider prescribes otherwise, at such shorter intervals as it may determine. The five-year control period ensures that customers are protected, while offering the service provider a clear and stable environment to make the necessary investments to ensure a modern and efficient network and high levels of service.[1]

As with PRE1, the RIC has adopted an incentive-based model to determine the service provider's allowed revenue. This approach ensures that the service provider can, through efficient operation, earn a fair return on capital and meet its operating costs. The service provider's costs and revenues are taken as fixed for a five-year period. If the service provider spends more than it is allowed, it bears the cost but if it spends less than what it is allowed, through improvements in efficiencies, it can keep the surplus made in any one year for a period of five years as a means of incentivising efficiency. Customers benefit over time by the progressive decrease in costs allowed at subsequent price reviews.

The RIC sets operating expenditure (Opex) and capital expenditure (Capex) based on the plans submitted by the service provider, and through a combination of assessment of specific underlying costs of the service provider and benchmarking. The service provider is required to manage its Opex and Capex within the allowed levels. The RIC monitors expenditure and conducts a review at the end of the control period to ensure that costs were efficiently incurred,

[1] Some regulators have begun to employ longer price controls, for example, the Office of Gas and Electricity Markets (Ofgem) has moved to an eight-year regulatory period.

and the Capex was necessary and prudent. The review of both Opex and Capex takes into account windfall gains and losses.

REVIEW OF COSTS AND PERFORMANCE DURING PRE1

The RIC compared the performance and expenditure incurred by T&TEC during PRE1, 2006-2011, against the levels approved by the RIC for that period. In general, T&TEC's Opex exceeded what was allowed by the RIC in all but the final year of the control period. Overall, T&TEC's outturn[2] surpassed the RIC's allowed Opex by 5.6%, in nominal terms. T&TEC's proposed Opex for the first control period was $11,258 million and the RIC's approved Opex allowance was $10,353 million. In essence, T&TEC was given an efficiency challenge to reduce expenditure by $906 million in PRE1, but the actual Opex outturn was $11,030 million.

With respect to Capex, T&TEC spent far more than the amount allowed on its Capex programme. The RIC approved a total of $800 million to be spent on 107 identified projects over the entire control period. During the period, T&TEC spent approximately $1,944.04 million, of which $738.60 million was spent on Government projects which were ring-fenced (not included in the RIC's approved Capex) and $1,205.44 million was spent completing 69 RIC approved projects. In fact, T&TEC's expenditure addressed 64% of the RIC's approved projects and was $405.44 million more than the quantum that the RIC allowed.

The increased level of expenditure on Capex maintenance and network renewal projects during PRE1, coupled with T&TEC's response to many of the incentive mechanisms put in place by the RIC, led to an improvement in the quality of supply that customers received. Overall, there was a general improvement in the reliability of T&TEC's network, particularly in the latter three years of the control period, as evidenced by improved SAIFI, SAIDI and CAIDI metrics[3] (table ES1 below). Overall, as can be observed in table ES1 below, there was a general improvement in the reliability of T&TEC's network, as values for SAIFI, SAIDI and CAIDI were less than at the beginning of the control period.

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[2] Outturn is the actual expenditure incurred by the Service Provider.

[3] **SAIFI** (System Average Interruption Frequency Index) indicates how often the average customer experiences a sustained interruption over a predefined period.

SAIDI (System Average Interruption Duration Index) indicates the total duration of interruption for the average customer during a predefined period.

CAIDI (Customer Average Interruption Duration Index) represents the average time required to restore service.

Table ES1: Network Reliability Indicators 2006–2011

Indicator	2006	2007	2008	2009	2010	2011	*NAU
SAIFI (number)	9.93	10.1	6.94	5.5	6.61	5.68	1.1
SAIDI (minutes)	996	1020	603	487	563	486	90
CAIDI (minutes)	100	100	93	87	85	86	82

***Median values for North American Utilities (NAU) according to IEEE Standard 1366-1998. These were included as the nearest available comparators.**

The RIC proposes to continue with most of its existing incentive mechanisms for the forthcoming five-year period. Additional incentive mechanisms have also been included such as a Direct Revenue Adjustment to improve service to customers that experience a reduced level of service ("worst-served customers"). Under this mechanism the RIC proposes a target of no more than three (3) interruptions per month in any area of the country to improve service to worst-served customers over PRE2. The total incentive payment to T&TEC for this mechanism will be capped at $7.5 million during the relevant year, and the total penalty for this mechanism will be capped at $10 million during the relevant year.

APPROVED REVENUE FOR 2023-2027

The revenue approved by the RIC for recovery through tariffs during the 2023-2027 period is shown in table ES2 below. The approved revenue is determined after the RIC makes adjustments for efficiencies to ensure that only efficient costs are recovered through tariffs.

The RIC's approved revenue requirement, exclusive of NGC debt, is $2,818.02 million lower than T&TEC's proposal over the five-year regulatory control period. This difference reflects a number of decisions including:

- reduction in forecast of operating expenditure ($1,512.12 million);
- reduction in generation costs ($181.26 million);
- reduction in fuel costs ($528.22 million); and
- reduction in depreciation charges ($444.74 million).

Table ES2: Requested & RIC's Approved Revenue Requirements, 2023–2027 ($Mn)

	T&TEC REQUESTED	RIC APPROVED	2023	2024	2025	2026	2027
Conversion Cost	9,492.37	9,311.11	1,764.99	1,788.45	1,896.88	1,917.48	1,943.31
Fuel Cost	10,564.19	10,035.97	1,752.22	1,859.74	2,023.37	2,139.51	2,261.13
T&D Cost	6,620.61	5,108.49	1,005.40	1,043.21	1,038.00	1,022.40	999.48
Depreciation	1,844.44	1,399.70	279.27	279.02	280.55	280.03	280.83
Return on Capital	1,466.88	1,447.90	282.97	287.35	290.00	291.82	295.76
Return on Working Capital	140.33	12.63	1.53	1.54	1.56	3.99	4.01
Less: Revenue from Non-Tariffs*	1,000.00	1,005.00	201.00	201.00	201.00	201.00	201.00
Unsmoothed Revenue Requirement before NGC Debt	**29,128.82**	**26,310.80**	**4,885.38**	**5,058.31**	**5,329.36**	**5,454.23**	**5,583.52**
Add: NGC Debt	-	1,157.42	-	-	-	578.71	578.71
Unsmoothed Revenue Requirement	**29,128.82**	**27,468.22**	**4,885.38**	**5,058.31**	**5,329.36**	**6,032.94**	**6,162.23**

*This includes dividend income from Powergen, capital contribution, pole and transformer rentals.

The RIC has made provision for the repayment of NGC debt of $3,832.5Mn accrued up to August 2022. The RIC is proposing that this debt can be repaid over a 10-year period with a moratorium of three years commencing from 2023. The decision to provide a moratorium is intended to lessen the impact of this debt on starting tariffs. Consequently, the RIC has included $1,157.42 million in this review period, which covers a portion of the outstanding sum payable to the NGC for natural gas purchased over the period 2019-2022.

Table ES3 below shows the net capital expenditure (Capex) approved by the RIC for the 2023-2027 period.

Table ES3: Requested and Approved Capex, 2023–2027 ($Mn)

	T&TEC Requested	RIC Approved
Transmission – Refurbishment and Replacement	272.2	212.0
Transmission & Sub-transmission – Development	98.0	32.4
Distribution	596.9	526.4
Street Lighting	57.9	54.6
Other Network Related	27.0	26.2
Non-Network Related	1,186.7	825.7
Total	**2,238.7**	**1,677.3**

Source: T&TEC and RIC computations

The RIC's allowed Capex for PRE2 is $1,677.3 million, which is $561.4 million, or 25% less than that requested by T&TEC. The difference reflects a number of decisions, including:

- reduction of Capex for projects that were deemed not to be prudent[4] ;
- exclusion or ring-fencing of projects to be funded by Government;
- revaluation of expenditure on projects that were too loosely defined, and lacking supporting information and project detail;
- adjustment for expenditure on projects with similar scopes of works/materials but with inconsistencies in costing; and
- exclusion of expenditure for projects whose duration extended beyond the second control period, and inclusion of only the costs associated with the parts of the project works which will terminate within the control period.

The Capex outturn will be reviewed at the end of PRE2, and only efficient and necessary Capex will be added to the regulatory asset base (RAB). The RIC has also included mechanisms not only to incentivise the timely delivery of Capex but also to provide incentives to discourage "gaming" (and reward honesty in Capex forecasting).

In addition to the above reductions in Opex and Capex, the RIC also requires that the service provider deliver additional efficiency savings of 2% annually (non-cumulative), the benefits of which will be passed on to customers within the 2023-2027 period. These efficiency savings

[4] Prudency establishes whether the decision to invest is wise, given the particular and specific circumstances at the time.

amount to $104.25 million, and will be determined by the service provider as they have not been specified by the RIC.

Capital expenditure which is deemed to be prudent and efficient, over the regulatory control period, is added to the regulatory asset base (RAB), and this results in higher depreciation charges and capital costs. The RIC's approved depreciation charge is $1,399.70 million for the second control period, which compares to T&TEC's request of $1,844.44 million. The difference is primarily due to the lower capital expenditure allowance by the RIC.

The RIC recognises that the service provider will have to access the capital market to fund its Capex programme and is aware of the importance of providing regulatory certainty. Equally important is the adaptation of the regulatory model to changing circumstances, particularly in times of uncertainty. The RIC has allowed a return on capital to remunerate debt based on a forward-looking rate and has approved a return on capital of 5.1% which when applied to the RAB equates to an allowance of $1,447.90 over the 2023-2027 period. The RIC believes that its decision to allow the return on capital of 5.1% will support strong credit quality and efficient funding of the investment programme in the short to medium term.

The RIC's decisions for PRE2 provide significant incentives for T&TEC to encourage improvements in operational efficiency. However, there is also the potential reward to the service provider of retaining any efficiency savings beyond those required by the RIC for a rolling five-year period.

DRAFT PRICE DETERMINATION

The Draft Determination in respect of electricity transmission and distribution services will apply for the five-year period 2023 to 2027:

1. **Tariffs for Transmission and Distribution Services**

   For the first year of the regulatory control period 2023-2027, the RIC has proposed a tariff structure and prices for each customer class (see table ES4), which would be escalated annually by applying the RPI-X formula.

Table ES4: Tariffs for 2023

Rate Class		Energy Charge ($/kWh)	Customer Charge ($)	Demand Charge ($/KVA)
Residential (Monthly) kWh Range			7.50	NA
0	200	0.28		
201	700	0.40		
701	1400	0.54		
>1400		0.68		
Commercial (Monthly)				NA
B1*		0.62	35.00	
B2**		0.67	35.00	
High Density (Monthly)				
C1		0.6269	50.00	93.00
C2		0.5858	50.00	93.00
C3		0.5487	50.00	93.00
C4		0.5114	50.00	93.00
Industrial (Monthly)				
D1		0.3453	50.00	86.75
D2		0.3859	50.00	88.50
D3		0.3418	50.00	79.37
D4		0.2877	50.00	68.90
D5		0.2756	50.00	63.74
E1		0.3305	100.00	96.90
E2		0.3305	100.00	95.74
E3		0.3305	100.00	93.63
E4		0.3305	100.00	92.30
E5		0.3305	100.00	91.33
Public Lighting (Monthly)				
Street Lights		82.50		
Traffic Lights		71.50		
Recreation Grounds		306.50		

***B1 (formerly B) customer**
**** B2 (formerly B1) customers have a minimum monthly bill of 5000kWh.**

2. Regulated Miscellaneous Services

The following miscellaneous services are already regulated by the RIC and the prices for these services in year 1 of PRE2 are set out in table ES5 below:

Table ES5: Regulated Miscellaneous Services and Charges from 2023

Miscellaneous Service	RIC's Proposed Charge ($)
Meter Check at customer's request:	
- If found in working order	246.00
- If found defective	No charge
Visit for non-payment of account	297.00
Install meter and reconnect secondaries	246.00
Reconnect, disconnect and/or change meter	246.00
Reposition of secondaries	246.00
Change and/or reposition meter	246.00
Disconnection for non-payment	297.00
Reconnection after disconnection for non-payment	150.00

T&TEC will be required to submit a detailed breakdown of the typical costs to provide the miscellaneous services, that are on the current list, by the end of the second year of PRE2. At the same time, T&TEC must submit a customer impact analysis that shows the impact of any changes on vulnerable/low-income groups. The information will be assessed to determine whether new charges for miscellaneous services are to be applied from the mid-point of PRE2.

3. New Regulated Charges

The RIC has decided that HV isolation, temporary supply and transformer rentals should be regulated going forward. In the interim therefore, **T&TEC will continue to apply the charges that were set for these services as shown in table ES6. Transformer rental services are to continue at existing rates.**

Table ES6: New Regulated Charges

New Miscellaneous Service*	Interim (2023) Charges TT$
HV isolation during normal working hours	4,689.36
HV isolation during weekends and public holidays	16,300.44
Direct single phase temporary supply	3,024.7
Direct three phase temporary supply	5,718.41
Temporary Supply (URD) "Stick in meter"	2,131.44

***Transformer rentals to continue at existing rates**

By the end of the second year of PRE2, **T&TEC will be required to submit a detailed breakdown of the typical costs to provide HV isolation, temporary supply, and transformer rental services.** This information will form the basis upon which the RIC may determine new charges to be applied by the mid-point of PRE2.

Overall Impact of proposed Tariffs

The RIC has assessed the impact of its first-year rates for PRE2 on the three main customer categories (residential, commercial and industrial). The impact on individual customers (within these three broad categories) will be dependent on their actual monthly consumption. Notwithstanding, some of the overall impacts are as follows:

- **Residential customers** at the lower consumption levels (for example, 200 kWh per month) will see an increase of 15% and receive a bill of $63.50 monthly. Residential customers whose average consumption is 627kWh per month, for instance, will receive a bill of $234.30 per month or an 18% increase when compared on a two-month basis. Since the residential tariff structure is an inclining block, it should be noted that the percentage increases in monthly bills can vary for customers whose consumption fall within the higher tiers. For instance, consumers who are currently using 3000kWh bi-monthly will experience a 36% increase over a two-month period, while those using 4000kWh bi-monthly will see a 49% increase.

- **Commercial (B1) customers** will see an increase in their bills in the range of 50%-60%. Commercial customers whose average consumption is 1,361 kWh per month, for instance, will see an increase of 51% and receive a bill of $878.82 per month. **Commercial (B2) customers** will experience an increase in their monthly bills of approximately 10%-11%.

- **Industrial customers** depending on their particular class, will experience an increase ranging between 72% and 126%.

- **Impact on household expenditure and welfare** – in establishing these rates, the RIC remained within the United Nations guidelines on the percentage of income that should be spent on utilities. In each case, the RIC has attempted to set rates which would not exceed the international guidelines regarding the percentage of income that should be spent on utilities.

- **Impact on Country's Competitiveness** – despite the proposed increases, and on the assumption that electricity costs have been averaged to represent 1.5% of total costs across industries, the expectation is that the increased costs of electricity would not have a major impact on total operating expenses of different industries in the country.

- **Financial Impact on the Service Provider** – the tariff increases will deliver two major outcomes for T&TEC: a healthy and sustainable financial outcome, and a specified capital works programme. The proposed tariffs also meet the financial viability criteria, as required under the RIC Act.

4. Tariff Implementation 2024-2027

Tariff structure

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

Box ES 1: Formula for Establishing Annual Revenue Requirement

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

Where:

Year *t*	**X_t**
2023	2.7%
2024	2.7%
2025	2.7%
2026	2.7%
2027	2.7%

ARR= Annual Revenue Received from Services.

ARR_{2023} = $5,078.29 million.

RPI means the Retail Price Index and has been fixed for the purpose of the RIC's calculation at 1.1% per year.

X = The efficiency factor

U = Unused charge. T&TEC will be permitted to carry over any unused change in charges from one year to the following years.

The overall side constraint is set at (RPI + X) = 3.80%.

*** 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.**

Side Constraint

The overall side constraint is set at (RPI + X) = 3.8%.

5. Tariff Implementation

T&TEC's Board must write to the RIC if for any reason a decision is taken not to charge the maximum determined price, providing reasons for its decision. Further, T&TEC must report on an annual basis on the implementation of the tariffs. In this regard, a written report must also be provided on whether the RIC's recommendations/directives that are made in its pricing policy reviews have been implemented, and reasons must be given for any non-implementation thereof.

6. Annual Price Approval Process during the Control Period

- At least three 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 RIC's 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 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 three 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.

7. Trigger Event

The trigger event will apply only if a situation imposes a total annualised cost of more than 1% of revenue.

Directives and Decisions

Apart from the new tariffs and charges which are being proposed for PRE2, the RIC will mandate T&TEC to comply with the undermentioned directives. The RIC will assess T&TEC's compliance with directives as a basis for determining whether to approve annual increases.

A. Meter Checks

T&TEC is required to provide a free meter check every four (4) years instead of every five (5) years.

B. Service Deposits (SD)

For residential and commercial customers requesting a new account, T&TEC can increase the SD from the existing $95.00, to the value of one month's average bill for customers within the respective class based on an average monthly kWh consumption of 627kWh for residential customers and 1,361 kWh for commercial customers. This SD is to be retained by T&TEC for one year (12 months), and thereafter returned to the customer. T&TEC and RIC to discuss how this will be implemented.

For industrial customers requesting a new account, T&TEC can increase the SD to the value of one month's average bill (the higher of 75% reserve capacity or minimum kVA consumption). This SD can be retained by T&TEC for one year (12 months), and thereafter returned to the customer. T&TEC and RIC to discuss how this will be implemented.

C. Time of Use Tariffs (TOU)

T&TEC is required to undertake and complete a comprehensive study on the feasibility of the implementation of TOU rates 24 months after the start of PRE2 and provide the RIC with a report on its findings for further discussion and agreement on implementation.

D. Electric Vehicles

At present, individual EV owners can charge at home subject to the applicable charges for residential customers.

i. Upgrade to Local Network

Where upgrades to the local network are required to facilitate EV charging on a commercial basis or for a private fleet of EVs (more than 2 EVs), the costs associated with same will conform to the principles outlined in the RIC's Capital Contribution Policy (2022).

ii. Installation of a Separate Meter

Where customers own a private fleet of EVs (more than 2 EVs), a separate meter should be installed, and the costs associated with same be borne by the customer.

iii. Public EV charging

Customers (commercial or industrial) who wish to offer public EV charging will have the relevant rate (and its components) applied to them, inclusive of any demand charge. Therefore, all non-residential charging stations are to be billed at commercial (which do not carry a demand charge) or higher rates depending on the rating category applicable to that customer.

E. Operating and Performance Efficiency

i. Payments to NGC

The RIC strongly recommends that T&TEC remains current in settling its debt related to gas usage. Therefore, the following measures will apply:

- T&TEC should promptly provide the RIC with a quarterly report, including details related to the status of payment to NGC and provide details of its intention to cure any breaches in its payment to NGC; and
- Should T&TEC be unable to cure its breaches, the RIC will, after discussions with T&TEC, make a decision as to whether or not it will make adjustments to T&TEC allowed expenditure for this line item.

ii. Payroll costs

- T&TEC is required to submit a detailed report to the RIC, within 18 months of the publication of the Final Determination for PRE2, indicating what steps had been taken and the initiatives it proposes to improve efficiency with respect to the size and composition of its transmission and distribution (T&D) crews. T&TEC must also outline the changes to be made, in the future, regarding the composition of its crews for typical construction and maintenance jobs of the utility.

iii. Service/Maintenance

The RIC will require **T&TEC to submit its actual cost in this expenditure category annually.**

iv. Prescriptive Annual Targets

T&TEC will be required to share with the RIC evidence of its initiatives to improve efficiency. T&TEC will be required to undertake a study of Opex cost efficiency and present the report to the RIC within 30 months of the publication of the final determination. Some of the areas that should be included in the study are:

- unit cost of faults per km;
- unit cost of tree cutting; and
- non-network Opex cost per unit.

v. Reporting Framework for Opex

During its review of Opex the RIC experienced some challenges attributable to the lack of clear separation of some cost items by activity and the need for Opex costs to be broken down into individual costs/activity. To address these issues and as part of its efforts to ensure that T&TEC improves the quality and reliability of its Regulatory Accounts (RAGs), **the RIC will be collaborating with T&TEC to establish a more comprehensive reporting framework for Opex costs.**

F. Capital Expenditure

Capex Reporting Framework

To improve the monitoring and reporting on projects to the RIC the following will apply:

- Implementation of a system of regular engagement with T&TEC to monitor Capex projects and ensure that Capex spend is in line with the RIC's allowances.

- Establishment of a semi-annual reporting framework in which T&TEC will be required to submit Capex reports which are suitable for public release. Specifically, these reports must include information on the status of projects; particular attention is to be paid to timing and cost variances. The format of these reports will be determined by the RIC inclusive of the level of granularity.
- Provision of detailed data on **each project** annually (to be called **Annual Investment Return**). The information to be submitted in the Return will include:
  - forecast and actual project spend for the year;
  - explanations of financial variances; and
  - physical progress of the project against defined milestones.

  The Annual Investment Return is to be supported by the submission of quarterly returns to facilitate ongoing monitoring of T&TEC's Capex.
- Establishment of fixed dates by which T&TEC must meet and achieve Capex-related Directives.
- Conduct of a mid-term review of Capex at the RIC's discretion.
- Implementation of a Capex Safety Net – this allows for the review of the Capex allowance where the Capex underspend/overspend in any given year of the control period, is greater than 20% of the allowed Capex.
- Employment of Public Disclosure of Non-Compliance and/or Public Register notices on the RIC's website. Through these notices, the RIC will publish the occurrences and the manner in which T&TEC has not complied with any targets set for its achievement, inclusive of allowed capital investment projects.

To ensure that tariff revenue will not be used for purposes other than those specified in PRE2, the RIC proposes that the Board of T&TEC provide self-certification assurances, in writing, for projects listed under the heading "Use of Tariff Revenues". This will provide a documented commitment (certification assurances) by T&TEC's Board to fulfil regulatory mandates,

and to desist from using tariff revenues for activities not approved by the RIC.

Capex Forecasts in Subsequent Price Reviews

To improve the quality of Capex submissions and to treat with the issues that had arisen in PRE1, or may arise in future, relating to **T&TEC's execution of the allowed capital programme, the RIC may require:**

- The use of a self-assurance process, the details of which must be submitted by T&TEC to the RIC at the time of a submission of a Business Plan, in which there is an assurance by T&TEC's Board that Capex projections accurately reflect the underlying information base. This is an internal process which does not necessarily entail external scrutiny or assurance.
- The employment of a "Reporter" (independent consultant/engineer) to interrogate T&TEC's Capex plan, and whose findings will be considered in the RIC's assessment of the service provider's proposals. The service provider will pay the Reporter's costs, but the Reporter is approved by the RIC and will be responsible to the RIC.
- The development and submission of detailed Asset Management Plans, alongside longer-term capital investment plans, with a view to assess how T&TEC's proposed Capex relates to, and corresponds with, same. The RIC may also require the service provider to include in its business plan a review of "unit cost" trends, where possible.
- The continuation of detailed *ex-post* efficiency reviews of T&TEC's performance with respect to capital expenditures.

G. Incentive and Performance Monitoring

Performance Indicator Report

The RIC will continue to monitor the performance indicators and quality of service standards introduced in PRE1 and to publish T&TEC's performance accordingly in the RIC's Performance Indicator Report. As

such, T&TEC will be required to provide information to the RIC as required for the preparation of the Report.

Reliability Improvements

Reliability improvements must be a central operational issue for T&TEC. The utility should undertake various measures to maintain and improve reliability, which can include:

- instituting monthly management meetings in each area;
- a change of practice whereby outages are planned for half a day instead of a whole day, where possible and feasible;
- greater utilisation of live line working techniques alongside strict adherence to highest levels of safety practices; and
- setting performance targets for each area, and increasing supervisory and operational staff awareness of the real financial cost of customer interruptions and lost service hours.

The RIC requires T&TEC to report semi-annually on its efforts in this area.

Improving service to worst-served customers

T&TEC must undertake appropriate measures to reduce the level of outages experienced by customers in worst served areas. T&TEC will be required to meet a target of no more than three (3) interruptions per month, in any area of the country, to improve service to worst served customers over PRE2. The RIC will implement the Direct Revenue Adjustment mechanism for the "Number of Customer Interruptions per month" (Interruptions Incentive Scheme) to ensure that this target is met. **The total incentive payment to T&TEC for this mechanism will be capped at $7.5 million during the relevant year and the total penalty for this mechanism will be capped at $10 million during the relevant year.** The RIC will make an annual adjustment to T&TEC's allowed revenue prior to setting/approving T&TEC's tariffs for each subsequent year. The mechanism will commence from the start of the third year of the control period, thereby giving enough time for

T&TEC to put systems in place (inclusive of an appropriate system to facilitate the submission of quarterly reports to the RIC).

Customer Service and Responsiveness

- The RIC has initiated the process of establishing the appropriate call centre metrics for T&TEC. The RIC considers the key performance indicators (KPIs) listed below, which fall under Service Responsiveness to be of critical importance*:*
    - *Service level* – This metric commonly defines X amount of output in Y amount of time. It is often used as a good indicator of customer service quality.
    - *Average handle time* – one of the most commonly measured metrics. It indicates the length of time an agent spends working on a task and, therefore, cannot deal with a new work item.
    - *Average speed of answer* – a metric that shows the amount of time it takes for an agent to answer a typical call once it has been routed to the contact centre, that is, from the ring tone up until the time an agent answers the call.
    - *Call Abandonment Rate* – the percentage of inbound phone calls that are abandoned by customers before speaking to an agent. The rate is usually a reasonable gauge of the customer service experience.

  Once the KPIs are established **T&TEC will be required to report quarterly to the RIC on its performance and thereafter the RIC will publish T&TEC's performance periodically.** The project of establishing Call Centre Metrics for T&TEC is anticipated to be completed in 2023 and is expected to be implemented in the second year of PRE2.

- **T&TEC will also be required to undertake a Customer Satisfaction Survey, commencing from the third year of PRE2.** This survey must be administered by a third party but commissioned by the service provider, and should cover four areas: voltage complaints; unplanned outages; planned outages and new connections. These attributes will be used as a means of getting customer feedback on how the issue was dealt with, rather than the nature of the issue itself. A random sample of customers who dealt with the service provider in the previous six (6) months should be interviewed and the survey conducted annually. **A copy of the survey report is to be submitted to the RIC.**

System Losses

- The application of an incentive mechanism for managing the total system losses will be retained for PRE2;
- An annual reduction target, instead of a target to be achieved over the full regulatory period, is more practical and would encourage compliance with the set target. **T&TEC will incur a penalty of $10 million for failure to achieve the annual reduction target in any given year;**
- The incentive mechanism for PRE2 will be implemented with the following features:

  - Calculate **Total System Losses** as: $\mathbf{1 -} \left\{ \frac{\underline{\textbf{Energy Units Billed}}}{\textbf{Energy Units Purchased}} \right\}$

  - Set the base value of total system losses for the next regulatory control period as the average monthly value computed over the year preceding the commencement of the period, and set a target for an annual reduction in loss levels for the control period of 0.25%, towards an overall target of 6.75% for the period;
  - Allow T&TEC to keep 90% of the gains if total system losses fall below the target set for that year, and share the gains at the end of the regulatory control period. However, given the current uncertainty about the measurement of losses, no incentive payment will be made until the data has been verified to be accurate;
  - Require T&TEC to include in the capital expenditure programme, projects which entail:

    - The installation of appropriate metering/monitoring equipment at strategic locations of its network; and
    - Network modification to reduce the level of total system losses, which include but are not limited to shortening the lengths of long distribution lines and the installation of capacitors on feeders. The execution of these projects is to be given high priority during PRE2;
- Take into account the value of loss reduction equipment in the asset base when it is rolled forward to encourage investment in loss reduction equipment. The full cost incurred would be incorporated into the asset base if the annual target for actual total system losses is achieved, and the cost will be prorated for the partial achievement of the target. However, if the total system losses increase above the initial and successive values calculated by the RIC, T&TEC will be penalised by not having the value of installed loss reduction equipment included in the asset base, and a directive will be issued to institute loss reduction measures at no cost to customers in the following control period; and
- **T&TEC must report annually to the RIC on all the proposed initiatives taken to reduce losses beyond the investment in its capital programme**.

Guaranteed Payments

The RIC will continue to utilise the Guaranteed Standards Scheme. The current scheme, which was revised in 2021, includes a new overall standard which targets reliability indicators and modifies the guaranteed standards related to voltage irregularities and new connections of supply. **T&TEC must continue to comply with the range of reporting requirements under this Scheme.**

Performance Reporting:

T&TEC must employ an independent auditor to review its data collection and dissemination process, and to verify that the data and computations used to derive the values of the indicators are both valid and reliable. The

auditor should be hired, and the report submitted by the third year of PRE2. The RIC will also ensure that the independent auditor's report is made public.

T&TEC must provide updates on performance indicators within the electricity bills of customers once annually. T&TEC will be required to include information on specific "traffic signal" indicators as shown in Table ES7 below:

Table ES7: List of Major Performance "Traffic Signal" Indicators

INDICATOR	What it Measures
Total System Losses (Transmission & Distribution)	The amount of electrical energy that is lost in the system
Current Ratio	Financial Health – Liquidity
System Average Interruption Frequency Index (SAIFI)	Reliability
Customers per Employee Ratio	Operational Efficiency of the company
Written Complaints Response Rate	Customer Responsiveness

H. Conservation

T&TEC should implement major initiatives for reducing households and businesses energy consumption. These initiatives can include:

- providing reasonably priced energy assessments, power saver kits and advice; and
- rebates to small businesses/households installing small-scale solar photovoltaic (PV) systems.

I. Service Provider Support Programme

T&TEC must be proactive and assist customers who may be experiencing financial hardship before their situation reaches a crisis stage by:

- offering preventative measures such as payment plans; and
- assisting them in accessing the Government-sponsored support.

Additionally, the following measures to assist low-income groups should include:

- waiving of interest payments on outstanding accounts;
- protection from service termination (some forms of non-payment are not to be tolerated, such as illegal tampering of meters); and
- extended payment arrangements, such as the option of arranging alternative payment schedules and paying bills in smaller installments (this is to be agreed between the customer and service provider).

J. Energy Efficiency Programme

Reducing consumption can mitigate the impact of rising electricity costs. One way of achieving this is through customer education which is an important component of an efficiency programme. T&TEC will be required to continue and intensify its efforts in this regard, and report bi-annually on its efforts in this area.

K. Regulatory Accounting Guidelines

T&TEC must continue to submit regulatory accounts in the manner specified by the RIC. In an effort to assist T&TEC, the RIC has agreed to align the reporting requirement for financial information to T&TEC's statutory year-end accounts.

The RIC also proposes to publish relevant regulatory accounts and proposes to place such regulatory accounts (including information on other indicators) on its website and make hard copies available on request. The RIC may also publish a condensed version of the regulatory accounts in a newspaper.

Finally, T&TEC must maintain reporting arrangements which provide information that can be verified. In this regard, **T&TEC will be required to provide a responsibility statement signed and dated by the Chief Executive Officer confirming that the information is true and properly reflects its activities.**

Furthermore, the RIC may require, from time to time, an independent assurance (audit) on information submitted. The required scope of any audit or other form of independent assurance will be specified by the RIC. The audit must be undertaken by an independent expert nominated and paid for by the service provider but approved by the RIC.

1 INTRODUCTION

1.1 BACKGROUND

The Regulated Industries Commission (RIC) is charged with the legal responsibility and authority for conducting periodic reviews to set the maximum rates and charges for the electricity, and water and wastewater sectors for each regulatory control period. A regulatory control period is defined as the period between price reviews during which time the price regulation methodology utilised in setting tariffs is held constant. Sections 6, 47, 48 and 67 of the RIC Act, Chapter 54:73, specify the price regulation framework to be observed by the RIC when setting prices.

The price regulation for the first regulatory control period for the Trinidad and Tobago Electricity Commission (T&TEC), which spanned June 1, 2006 to May 31, 2011 (PRE1), was based on the sections identified immediately above. The Price Review for PRE1 was the first time that T&TEC's pricing proposal was subject to the RIC's independent scrutiny. Prior to PRE1, the last general tariff increase was implemented in 1992, under the Public Utilities Commission. The price of electricity which prevailed prior to the RIC's Determination did not fully cover the cost to serve customers, thereby raising serious concerns about the financial viability and sustainability of T&TEC. Underpricing was beginning to result in poor service and reduced incentives to expand the network. PRE1 established a firm foundation for the economic regulation of the sector. The revenue control set in 2006 was intended to support the financial viability and meet the new investment requirements of the service provider while at the same time incentivise efficiency improvements at T&TEC.

Generally, the first revenue control was successful, and T&TEC responded to many of the PRE1 incentive mechanisms by increasing the quality of its service to customers. The transmission and distribution network was extended and reinforced to accommodate rising demand and new connections. Despite this, the RIC had concerns with respect to the non-delivery of its allowed capital programme and T&TEC's failure to reduce operating costs in some areas. Additionally, T&TEC did not meet all the performance targets set by the RIC. These targets were meant to incentivise improvements and, though challenging, were considered to be achievable.

This Draft Determination outlines the RIC's initial decision on the rates and charges that customers will pay and the revenue that T&TEC will be allowed to recover from its customers. This second review and the price regulation methodology to apply from 2023 will be known as the second Regulation of Electricity Transmission and Distribution (PRE2). The rationale for the RIC's decision is explained in detail in the remainder of this document.

1.2 CONTEXT AND OBJECTIVES OF THE SECOND REVIEW

It is important to understand the context for this review, especially the legal requirements the RIC must comply with in conducting price reviews. Section 48 of the RIC Act, in particular, mandates that the RIC reviews the principles for determining rates and charges for services every five years. In accordance with this responsibility, the RIC is conducting this review to determine the appropriate revenues and prices for T&TEC for the period 2023-2027. The RIC is also required to take account of a wide range of factors in making its decisions, and to achieve a balance between the needs and interests of different stakeholders affected by these decisions.

The review of rates and charges for T&TEC is occurring at a very challenging time. On the one hand, the world faces the daunting task of mitigating the effects of climate change, while on the other hand the global economy is struggling to cope with high energy prices and supply chain disruptions. In respect of worsening climate issues, the responsibility devolves on all citizens to demonstrate awareness that conservation of electricity is one factor which can assist in reversing this trend. As regards the global economy, it had started to emerge from the recessionary impact caused by the pandemic (COVID-19) only to be setback by the Russia/Ukraine War.

In virtually all countries, the poor have become poorer and the middle class is struggling to Maintain the *status quo*. Trinidad and Tobago, as a net exporter of energy products, has been better placed to cushion some of the impacts discussed above. According to the Review of the Economy 2022 "the country has been learning to live with the COVID-19 virus, the Trinidad and Tobago economy is now on a path to recovery and growth, amidst concerted efforts towards rebuilding what was detracted by the pandemic." However, media reports paint a different story. There are frequent reports of citizens complaining about increased food prices and their inability to meet their monthly household needs. These are the major circumstances that the

Regulated Industries Commission (RIC) has had to navigate while conducting its review. Among its main responsibilities the RIC must ensure that electricity prices are affordable, and that T&TEC has the funding necessary to provide reliable and quality services to the public. The unenviable challenge for the regulator is how to set prices that would allow T&TEC to provide reliable services and still make these services affordable to citizens.

This Price Review for the control period 2023-2027, follows almost 11 years after PRE1. In the intervening years the financial circumstances of T&TEC deteriorated to the extent that they were unable to meet their commitments. Therefore, the completion of this review and the implementation of the new rates should have a positive effect on the overall operations of T&TEC, thereby leading to improved services to customers.

The purpose of the Review is to determine an appropriate level of allowed revenue for T&TEC and the level and structure of tariffs that will be paid by customers for PRE2. In setting the allowed revenue for PRE2 and starting tariffs for 2023, the RIC's objectives are to ensure that:

- the service provider operating under prudent and efficient management can earn sufficient return to finance necessary investment. In doing so, the RIC wants to ensure that the service provider's planned investments are necessary and provide value for money for customers;
- the interests of customers are protected, in the short and long term, by ensuring that services are reliable and provided at the lowest possible cost; and
- appropriate incentives are provided for the service provider to improve its efficiency where possible, and that most of these savings that result from efficiency gains are passed through to customers.

1.3 REVIEW AND CONSULTATION PROCESS

The RIC reviewed its price regulation methodology and all other issues considered in PRE1, with a view to modifying the methodology and/or specific elements, as appropriate, prior to the commencement of PRE2. When reviewing the principles for determining rates and charges for services, Section 6(2) of the Act requires the RIC … **"to consult with service providers and representatives of consumer interest groups and any other parties it considers as having**

an interest in the matters before it." The RIC is, therefore, required to incorporate public consultation and promote wide-ranging discussion of the issues by all stakeholders when establishing the principles and methodologies to be used in regulating prices in PRE2.

The RIC utilises a transparent process for setting tariffs that involves a considerable degree of consultation with all stakeholders. The process involves the release of written papers inviting responses to specific questions or more general views about the material presented. To this end, the RIC published twenty (20) documents, listed in Box 1.1, for comments from the citizenry. These papers were also distributed to organisations and individuals with an interest in consultation. The views and suggestions garnered in response to our consultation were analysed and used as part of the decision-making process.

Stakeholders will be afforded the opportunity to provide comments on the Draft Determination and to engage with the RIC at public consultations. The RIC will consider all comments and respond where necessary if we have not accepted specific comments or suggestions. Where we find merit in any suggestion from stakeholders, the RIC will consider altering its position based on those comments/suggestions. The Final Determination will be published thereafter.

To facilitate communication between the RIC and stakeholders, the RIC established a dedicated area on its website for the T&TEC's price review. At this site[5], stakeholders were able to view copies of all consultative 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.

The high-level steps associated with this review are as follows:

- **Step 1 – Preparation of the paper, "Information Requirements: Business Plan 2021-2026"**
- **Step 2 – Submission and Analysis of Business Plan**
- **Step 3 – Formal Review Process**

[5] Documents are still accessible on the website: www.ric.org.tt

Step 1 - The RIC **released and posted** on its website for public scrutiny, its Consultative Document, "**Information Requirements: Business Plan 2021–2026"** in December 2020**.** The document provided guidance to the service provider on the preparation of its price review submission so that the submission and any other information requested would be provided in a consistent format.

The **Information Requirements: Business Plan** details the information requirements needed to conduct a price review. In its submission, the service provider must:

- specify its strategy for the future.
- submit its proposed objectives, expenditure needs, financing requirements and implications for bills, etc.
- explain and justify its strategy, associated assumptions and its priorities.

Step 2 – Submission and Analysis of Business Plan

T&TEC submitted its Draft Business Plan on November 26, 2021. After reviewing the document, the RIC had several meetings with T&TEC to gain further understanding of some proposed strategies and projects. Following these meetings, additional data and information were provided and a Final Business Plan was submitted on June 24, 2022. The RIC takes seriously its role to obtain T&TEC's justification for its costs through the provision of sufficiently comprehensive information.

The RIC looks forward to working in a collaborative and open manner with T&TEC such that, delays and the late provision of all relevant and necessary information will be avoided in the future.

Step 3 – Formal Review Process

Concomitant with the release of the **"Information Requirements: Business Plan 2021–2026"** document the RIC released its document **"Framework and Approach: Second Regulatory Control Period.** That document outlined the RIC's overall process and approach to the price review, the work plan, the major issues that the review will consider and the issues that will have to be resolved in implementing the tariffs. Thereafter, the RIC released a series of Consultative and Information Papers. This was followed by the preparation and **release of the Draft Determination which explains the rationale for its proposed decisions**. Prior to the release of the Draft Determination, and in accordance with, Section 6 (2) of the RIC Act, the RIC communicated with T&TEC's shareholder, the Government of Trinidad and Tobago which is a key stakeholder whose public policy decisions must be followed by the RIC and T&TEC. After the release of the Draft Determination, the RIC will engage in public consultations, following which the RIC will formulate recommendations where there is an opportunity to review funding, subsidies and incentives, for Government consideration.

The RIC will hold regional consultations throughout the country, on the Draft Determination. The RIC will consider all public submissions/comments and will respond to them. Finally, the RIC will publish and release its **Final Determination** three months after the release of the Draft Determination (**Box 1.1 briefly highlights the RIC's review process**).

Box 1.1: RIC's Review Process

1. Released the paper, "Information Requirements: Business Plan 2021-2026, requiring T&TEC to provide a submission detailing its pricing proposal together with financial and performance data on the future capital and operating expenditure necessary to maintain customer service levels.
2. Released a consultative paper "Framework and Approach: Second Regulatory Control Period", which outlined the RIC's overall process and approach to the price review, the work plan, the major issues that the review will consider and the issues that will have to be resolved in implementing tariffs.
3. Released the following Consultative and Information papers for public comments:
    - Stakeholder Involvement in Regulatory Decision-Making
    - Review of the Status of the Trinidad and Tobago Electricity Commission
    - Establishing an Appropriate Form of Price Control
    - Determining the Length of the Regulatory Control Period
    - The Treatment of Input Price Inflation in Price Control Reviews
    - Annual Price Adjustments – Are they a necessary feature of Incentive Regulation?
    - Po Adjustment - Passing Cost Savings to Customers

- Treatment of Pension Costs for Regulatory Decision-Making
- Approach to Setting Operating Expenditure
- Review of the Approach to Capital Investments
- Embedding Financial Viability and Sustainability
- Performance Monitoring and Reporting
- Addressing the Affordability of Regulatory Prices
- Regulating Quality of Service
- Incentive Mechanism for Managing System Losses
- Principles of Rate Design and Tariff Structures
- Importance of Conducting Timely Price Reviews
- Improving Transparency and Accountability in the Electricity and Water Sectors.

4. Input from Shareholder (Government) on various issues.

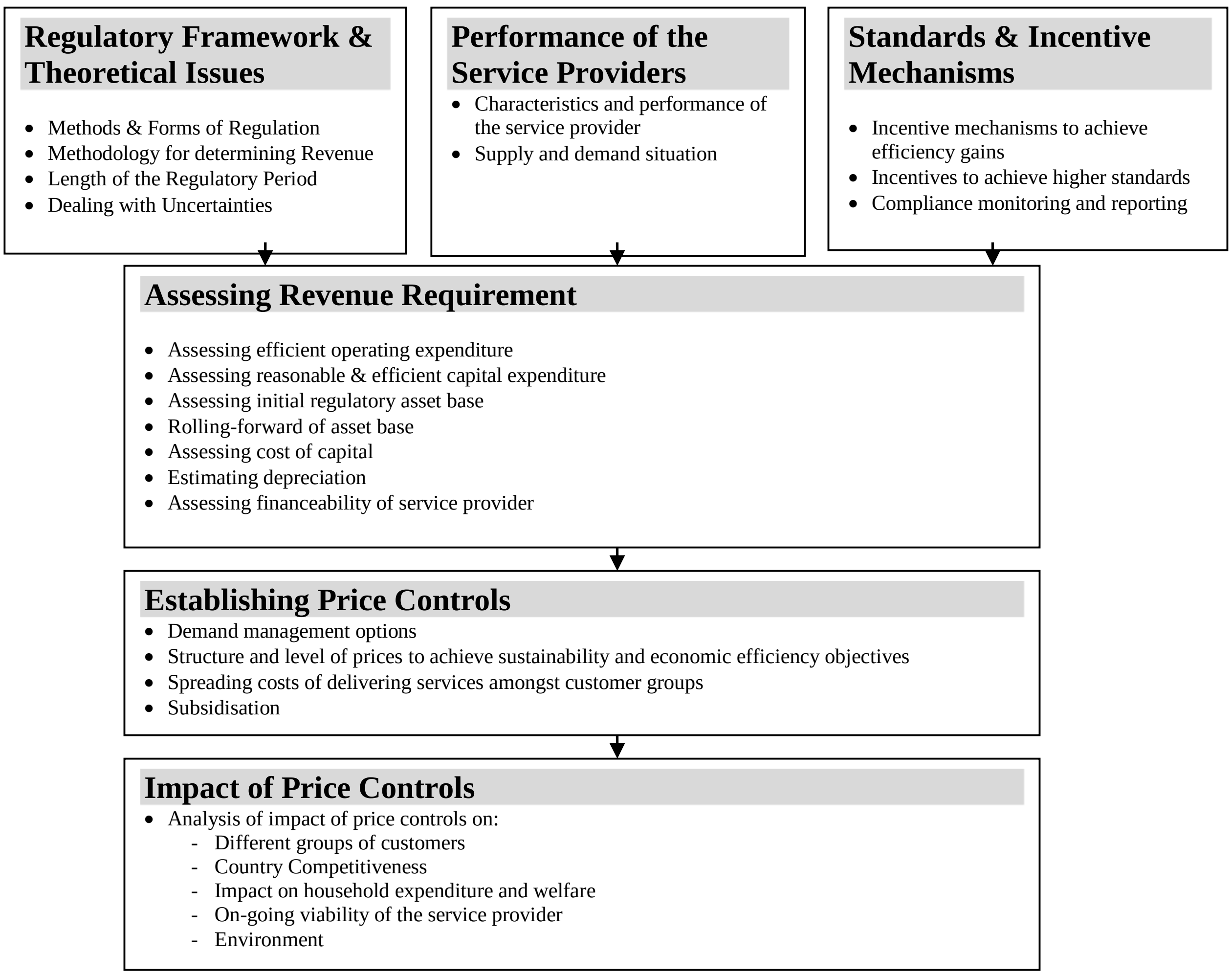
5. Released the Draft Determination for public comment. The draft decisions made and the reasons for them are provided within the document, and the public is invited to make submissions. The RIC plans to hold public consultations on the Draft Determination.

   Three months after, the RIC will publish its Final Determination.

1.4 RIC’S ANALYTICAL APPROACH TO SETTING PRICE LIMITS

There are numerous complex and conflicting requirements that must be considered, when determining price limits for the control period. The analytical steps followed by the RIC are detailed in **Figure 1.1** below.

Figure 1.1: RIC’s Analytical Approach for Setting Price Limits



1.5 STRUCTURE OF THE DOCUMENT

The remainder of this document is structured as follows:

- **Chapter 2** details the RIC's tariff setting approach, including the legal requirements, structure of the price control, approach to determining revenue requirements, and dealing with uncertainty;
- **Chapter 3** provides information on how the service provider's Regulatory Asset Base (RAB) has been derived for PRE2;
- **Chapter 4** provides information on the cost of capital for application to the RAB over PRE2;
- **Chapter 5** provides data on the forecasts of Electricity Demand and Customer Numbers;
- **Chapter 6** provides an overview of the historical performance of the service provider in the areas of finance and operations since PRE1;
- **Chapter 7** outlines a review of T&TEC's historical operational expenditure and performance during PRE1, and T&TEC's forecast operational expenditure for PRE2 and the RIC decisions on the revenue required for operating expenditure;
- **Chapter 8** outlines a review of T&TEC's historical capital expenditure during PRE1, T&TEC's forecast capital expenditure for PRE2 and the decisions on the revenue required for capital expenditure;
- **Chapter 9** provides information on incentives and performance monitoring for PRE2;
- **Chapter 10** provides information on miscellaneous services and charging principles;
- **Chapter 11** provides information on how the decisions outlined within the previous chapters feed into the allowances for a return on assets, depreciation and the revenue that would be collected each year during PRE2, including the forecast of energy sales the RIC used in calculating tariffs;
- **Chapter 12** provides information on tariffs for PRE2 and on the manner in which T&TEC collects its revenue from its customers, as well as discusses the implications of the RIC's decisions on stakeholders; and
- **Chapter 13** provides concluding remarks.

2 RIC'S TARIFF SETTING APPROACH

2.1 INTRODUCTION

Regulation plays an important role in protecting customers' interests and promoting efficiency. Because T&TEC is the monopoly provider of transmission and distribution services in the electricity sector, regulation acts as a proxy for competition. PRE2 establishes the overall regulatory framework, including the financial framework within which T&TEC can operate, and provides the incentives for it to deliver and outperform the RIC's determination.

In this chapter some of the key elements of the RIC's regulatory process are discussed. Many of these elements are similar to those employed by other well-established regulators. The first issue considered in setting price controls for PRE2 was the price/tariff-setting approach that the RIC would utilise. The price/tariff-setting approach broadly comprises the rules and methodologies a regulator employs to determine, monitor and adjust prices over the control period. The RIC reviewed the decisions included in its determination for PRE1 as its starting point and augmented this approach for PRE2 to reflect any changes in the RIC's thinking and/or developments in the regulatory environment. The main elements considered include:

- the legal requirements/mandate under the Act;
- the overall structure of the price control;
- the length of the control period;
- the method for determining revenue requirements;
- a mechanism to provide enhanced incentives to pursue efficiency gains during the control period;
- the setting of rules for updating the revenue control for observable but unpredictable factors (e.g. inflation);
- the setting of adjustment rules that explain how the revenue control may be adjusted during the control period or at the next review period in the light of unforeseen events (e.g. if costs begin to differ materially from set forecasts); and
- the reporting requirements for the service provider.

The sections below and other chapters of this document set out the RIC's position on each of the above elements.

2.2 LEGAL REQUIREMENT

The RIC must take account of a wide range of factors in making its decisions in order to achieve a balance between the competing needs and interests of different parties affected by those decisions. The RIC has three overarching functions/responsibilities as contained in its Act:

- **Financial Viability and Sustainability of the Service Providers** – that is, to ensure that the service providers can carry out and finance their operations and that they have sufficient revenue to afford them an opportunity to earn a reasonable return on their used and useful assets;
- **Economic Efficiency** – that is, to encourage greater efficiency in the use and supply of services; and
- **Protect Customer Interests** – that is, to ensure that there is equity and fairness, and that lower income and vulnerable groups are protected, that the social impact of decisions is considered, and that the quality and reliability of the services are maintained.

The RIC achieves the above objectives through undertaking price reviews. At the conclusion of a price review, the RIC sets price limits on rates which allow the service providers to deliver, at the lowest overall reasonable cost, the expected quality of service and other customer service objectives. The RIC aims to ensure that customers receive the best possible value for money.

The RIC scrutinises all costs (i.e. capital and operating), to ensure that they represent the lowest reasonable overall costs before translating them into tariffs. Efficiency is an important element in determining the lowest reasonable costs and comparisons are made, where possible, with other utilities[6] to gauge what are efficient capital costs and what level of operating cost efficiencies the service provider can achieve. It is important, in assessing the scope of efficiency

[6] This includes identifying and utilising key unit cost and productivity indicators where such information is available.

to consider not only the level of costs, but also the levels of service that are expected to be achieved.

The principles of rate design the RIC broadly adheres to are that:

- customers pay their fair share for the services they receive;
- the tariffs, in general, should be broadly cost reflective;
- the maximum tariffs are affordable, stable and increase by no more than inflation; and
- tariffs should remain harmonised across the country.

Section 6 and 67 of the RIC Act requires 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 periods as may be considered appropriate; and
- future prospective increases in productivity by the service providers.

The RIC uses judgement in determining how to balance these competing interests as its Act does not specify how the RIC is to take account of these factors or provide guidance on which factors should prevail. Hence, the RIC understands the need to ensure that prices are, as far as possible, cost reflective while taking cognisance of the need to deviate from this objective to mitigate impacts on customers.

2.3 FORM OF THE PRICE CONTROL

The most fundamental aspect of setting a price control/limit is deciding on the form of that control. The form of the price control refers to the high-level structure for setting price limits and involves a number of different elements, such as:

- **the length of the control period**, that is, how often the price limits are reviewed and if there are annual limits within the regulatory control period;
- **what is controlled and how that is achieved**, that is, whether it is a price or revenue control and whether the control applies to a basket of services, or to the prices of individual services; and
- **the link between price and outputs**, that is, the efficiency retention mechanisms used.

Where circumstances are comparable, the RIC has sought consistency between the form of price control used in PRE2 and PRE1. Therefore, in developing the detailed arrangements/elements for PRE2, the RIC has substantially retained the overall framework/model used in PRE1 but has taken some new issues into account and these are detailed in the specific chapters.

With respect to the form of the price control the following documents were released:

- Determining the Length of the Regulatory Control Period
- Establishing an Appropriate Form of Price Control
- Po Adjustment – Passing Cost Savings to Customers
- Annual Price Adjustments – Are they a necessary feature of Incentive Regulation?
- The Treatment of Input Price Inflation in Price Control Reviews

The overall form of price control used for PRE2 is briefly discussed below.

2.4 STRUCTURE OF THE PRICE CONTROL

2.4.1 Incentive Regulation

The RIC will continue to apply incentive regulation, broadly based on the RPI-X model, in which efficiencies are built into the Opex and Capex allowances and the resulting revenue is profiled over the period.

In its most general form, RPI-X involves limiting price/revenue changes to general inflation less a specified "X"-factor. The X-factor is used is to reflect the expected change in productivity of the regulated service provider over and above the expected change in RPI[7]. Price cap/incentive regulation is characterised by several key factors, of which the best known are:

- A cap on tariffs, average prices or total revenues;
- A formula for updating the cap on tariffs (average prices or total revenues) from year-to-year (e.g. RPI-X formula), so that the cap develops independently of actual costs; and
- A pre-specified regulatory period, at the end of which the formula is reviewed.

RPI-X regulation is intended to provide strong incentives for efficiency, as any savings above the predicted rate "X" can be kept by the service provider. It is therefore in the interest of the service provider to outperform the "X" as it can increase the rate of return that it earns.

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, several relevant factors are considered, such as demand, costs and underlying efficiency. A basic price cap formula is shown in **Box 2.1** below.

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

[7] For this reason, the "X" is sometimes referred to as the "productivity offset".

Z = adjustment for unforeseen events (typically treated as "pass-through items" because these events are outside of the firm's control)

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

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

The RIC has utilised an *ex-ante* approach to setting price controls, as *ex-ante* rules enhance certainty, predictability and credibility of regulatory determinations. That approach involves specifying upfront performance targets/obligations to be delivered/met, and the monitoring of the service provider's compliance with those obligations/targets. The service provider has an incentive to achieve, at least, the efficiencies anticipated by the regulator, because if it fails to do so, it will not recover the allowed costs. At the same time, the service provider has an incentive to achieve greater efficiencies because it can earn higher profits for the remainder of the regulatory control period. Since the creation of incentives to reduce costs to efficient levels is one of the main aims, then it is crucial that the service provider bears the consequences of changes in its costs so as to create these incentives. To do this, the service provider's revenue requirement, based on the efficient costs of providing services, must be determined *ex-ante* and its revenue must be "capped" in line with this revenue requirement for the control period.

2.4.2 Length of the Control Period

The length of the regulatory control period is a fundamental part of the regulatory framework. It is the duration of time for which the RIC determines the service provider's revenue requirement, tariff and other price control arrangements, such as outputs and incentives. Therefore, it is of critical importance to all stakeholders. The options that different regulators have generally considered are:

- A five-year control period;
- A longer control period, such as eight or ten years; or
- A shorter control period of less than five years.

The RIC sets five-year price limits in accordance with the provisions of its Act. A cornerstone of incentive regulation is that the length of the control period must be long enough so that the service provider can implement initiatives to reduce cost and enjoy the resulting profits for a reasonable length of time. If this were not the case, the service provider would have no incentive to reduce costs since gains would be immediately returned to customers. The price limits reflect the maximum the service provider is allowed to charge to provide services and deliver its obligations to customers. In essence, the prices limit the quantum of revenue the service provider can raise from the customers of its regulated business.

On the one hand, the advantages of a longer determination period include stronger incentives for the service provider to increase efficiency, greater stability and predictability of the revenue stream of the service provider (which lowers business risk and assist investment decision-making), and reduced regulatory costs. A longer period would also give customers greater certainty over future tariffs, which can assist them with their own planning and budgeting. On the other hand, the longer the regulatory period, the longer customers must wait to share in the benefits of out-performance (because prices are not set to account for these gains until the next determination). Additionally, the longer the control period the greater the likelihood that cost differentials could arise that would allow the service provider to make profits or losses well over those anticipated by the regulator. Furthermore, there is also the ever-present risk that changes in the sector/industry may affect the appropriateness of the determination.

After consideration of all relevant issues, the RIC settled for the continued use of a five-year price control, as it strikes an appropriate balance between risks and the ability to undertake cost savings. Furthermore, the RIC is constrained by its Act to a period of five years or shorter. A detailed justification for the continuation of a five-year price control was discussed in **"Determining the Length of the Regulatory Control Period"**, which was published in January 2021.

2.4.3 Revenue Cap

In PRE1, the RIC's preferred form of control had been a fixed (total) revenue cap. In its document **"Establishing an Appropriate Form of Price Control"**, published in January 2021, the RIC argued that this form of control remained fit, as the appropriate form of price control for the PRE2. A fixed or total cap provides distinct advantages such as striking an appropriate balance of risk between customers and the service provider. It also incentivises the service provider to reduce costs and make efficiency gains, and provides the service provider with the operational flexibility it needs to meet its service objectives while simultaneously exposing the service provider to risks it could control.

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. 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 authorised 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 variable to allow for adjustments arising out of unforeseen events (these are treated as "cost pass-throughs")

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)].

In PRE1 the RIC supplemented its fixed (total) revenue cap with several secondary controls including:

- A profit-sharing mechanism if profits were to exceed 10% of total revenue;
- A notional unders and overs account; and
- A side constraint on the annual increase in revenue.

The RIC's preferred decision is to continue with a fixed (total) revenue cap as the appropriate form of price control for the second regulatory period.

2.4.4 Incentive Mechanisms

A fairly well-documented drawback of standard RPI-X regulation is that it provides weak incentives for efficiency gains late in the determination period, because such gains would only be retained by the service provider until the end of that regulatory period. In fact, there is an incentive for the service provider to defer efficiency gains that could be made late in the determination period until the start of the next determination period.

A mechanism that rewards efficiency improvements to be retained for a fixed period for five (5) years – from when they are made, provides a stronger incentive to pursue efficiency improvements than under a standard RPI-X approach. Thus, the RIC saw merit in including mechanisms to strengthen the service provider's incentive to pursue efficiency gains over the entire control period. One such mechanism was the Efficiency Carryover Mechanism whereby the service provider was allowed to retain the benefits for a fixed period of five (5) years regardless of when the efficiency gains were made. This five-year rolling retention mechanism was expected to deliver the most even distribution of efficiency savings across the duration of the control period.

The Efficiency Carryover Mechanism was provided for both Opex and Capex. For Opex, the service provider was permitted to retain the annual savings provided such savings were not made at the expense of performance and quality of service. In assessing the gains to be retained by the service provider on Capex, the RIC proposed to examine the cost, volume, necessity and quality of the investment made. For example, no benefits were to be retained if savings are made through deferring or reducing the quantum of allowed investment. Similarly, inefficient Capex would not be allowed into the RAB at the next price control period and revenue earned on Capex not spent would generally be clawed back, except where the service provider can justify that the avoided spend was due to efficiencies achieved.

During PRE1, many of the efficiency improvements manifested themselves more through the delivery of better levels of service rather than as cost reductions. Hence, the RIC considers that the challenge for T&TEC, a State-owned and run utility, should be framed more in line with this evidence. Thus, for PRE2, the RIC is proposing a number of additional mechanisms and tools which may be used to provide incentives and to encourage specific desirable behavior. These include:

- stipulating minimum binding targets with upfront reduction of allowed revenue;
- an incentive to reduce the level of transmission and distribution losses below a target level;
- using specific financial incentives under the Guaranteed and Overall Standards Scheme to compensate customers;
- an incentive related to the delivery of capital projects; and
- incentives to keep customer interruptions below target levels.

Notwithstanding the above, the RIC will continue to allow latitude to outperform over the regulatory period, while maintaining focus on controlling costs.

2.4.5 Approach to Determining Revenue Requirements

The first step in determining price/revenue controls is to establish the allowable revenue of the service provider upon which to base a price control. The RIC's decision is to use a **"building-block approach"** to estimate maximum revenue/price controls. The building-block methodology is widely used by economic regulators. The revenue profile for the control period is built up from an assessment of forecasts of key cost components comprising:

- the regulatory asset base to apply to the service provider;
- a rate of return on regulatory asset base (including any forecast capital expenditure) and a return of capital (depreciation) over the regulatory period; and
- a forecast of operating, maintenance and other non-capital costs over the control period.

The RIC must ensure that price/revenue controls comply with the regulatory principles outlined in the RIC Act. Specifically, the RIC Act [Section 67, sub-sections (2) (3) and (4)] mandate that price/revenue controls to be set to take into account:

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

The building-block approach ensures that the full, efficient costs of providing the regulated services are measured and monitored in a rigorous and transparent way. The 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.

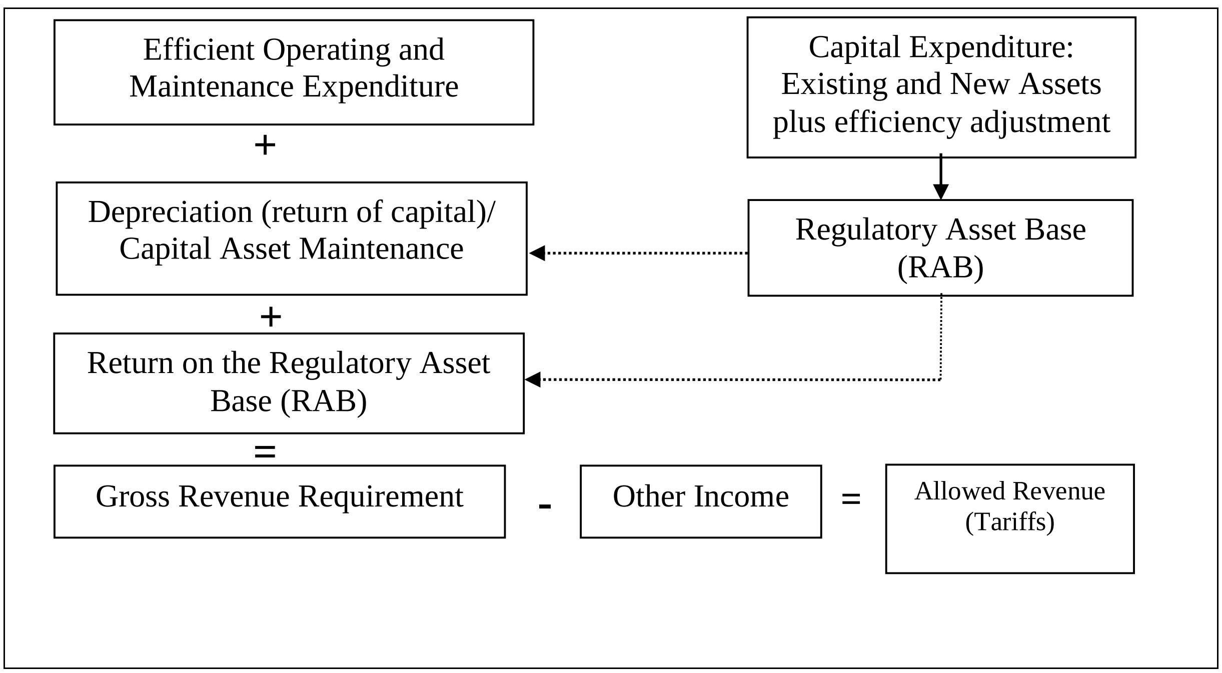
The RIC's legal mandate, regulatory objectives and the industry-specific context[8] make it appropriate to adopt the building-block approach to establish the price controls. The approach enables the regulator to be satisfied that costs are close to efficient levels, particularly when there are concerns as to whether prices are adequate to meet cost pressures. It can serve to operationalise a cost-recovery policy, provide increased transparency with respect to the

[8] T&TEC is the sole operator in the Transmission and Distribution Sector and, as explained in later chapters, has a number of uncontrollable cost items.

performance of the service provider, and provide a framework to increase the effectiveness of performance agreements. Because it is forward-looking, it still provides incentives to improve efficiency, and because it is largely based on utility specific costs, it provides some assurance that the service provider will be able to recover reasonable costs incurred. For these reasons, it is particularly well-suited for a State-owned and operated utility. The RIC will therefore continue to utilise this methodology for PRE2.

The following chart (figure 2.1) provides an overview of the building-block approach to determining the revenue requirement.

Figure 2.1: Building-block Approach and Revenue Requirement



2.4.6 Dealing with Uncertainty

Ensuring that the service provider has sufficient revenue throughout the control period to maintain effective operations is a core concern of the price control. The service provider should be able to finance its planned investment, operating and maintenance costs and meet its financing costs. As input prices are assessed prior to the finalisation of price controls for a forthcoming price control period, there will inevitably be an element of uncertainty about the evolution of input prices. Increases in costs arising from price inflation might not be recovered if they were not accounted for in the revenue requirements of the service provider. A number of mechanisms such as, adjustment clauses, ad hoc allowances, cost drivers/ triggers, re-openers, and interim determinations, can be employed to treat with the issue of input cost pressures. The RIC published the document, "**The Treatment of Input Price Inflation in Price Control Reviews"**, on its website, and it discussed in detail many of these mechanisms.

As the majority of T&TEC's allowed revenue is derived from a few sizeable cost items. The RIC applied the under-mentioned approach to account for input prices and their increases for PRE1:

- Conversion and fuel costs, which constituted about 70% of T&TEC's total costs in PRE1, were treated largely as pass-through items as these are considered non-controllable input costs for T&TEC and are subject to contractual arrangements;

- Labour costs, which accounted for 50% of T&TEC's Transmission and Distribution costs, were escalated by the factors agreed to by the Industrial Court in T&TEC's settled wage negotiations;

- Depreciation and the return on capital were adjusted for inflation using the Retail Price Index (RPI). The RPI was best suited for this as it reflects changes in purchasing power and the value of money; and

- The remainder of T&TEC's Transmission and Distribution Costs were adjusted for inflation using the RPI (specifically the Core Index, which removes the effects of food inflation).

The RIC intends to continue to utilise indexation to account for changes in input prices for PRE2 and to utilise its existing mechanisms for dealing with uncertainty.

A summary of the RIC's current regulatory framework for setting tariffs is presented in table 2.1 below. A more detailed discussion of different elements of the tariff setting approach is presented in **Annex 1**.

Table 2.1: RIC's Current Regulatory Framework for Setting Tariffs

Area of Regulation	Main Characteristics
Setting Outputs	Largely focused on quality-of-service targets, where the service provider is held accountable for the delivery of outputs.
Setting Revenue Allowances for the Five-Year Control Period	Review of pricing principles every five years including: • modelling of investment needs over the 5-year period. • forecasting of efficient operating and maintenance costs over the control period inclusive of expected productivity improvements. • developing asset life assumptions and depreciation profiles. • determining asset base (i.e. invested assets) on which return equal to cost of capital is permitted. • developing cost of capital scenarios. • benchmarking of costs with international utilities. • setting *ex-ante* targets and upfront reduction of costs.
Incentive Framework	• Setting maximum revenue allowance to reduce costs within price control period. • Rolling incentive scheme for reduction of Opex and Capex. • Specific incentive schemes (e.g. loss reduction). • Guaranteed standards scheme.
Adjustments during Price Control Period	Various measures to manage risk and uncertainty between periodic reviews, including reopeners and revenue drivers.

2.5 COMMENTS AND RESPONSES

The RIC published twenty (20) technical documents (see Box 1.1) and invited stakeholders to comment on the scope of the review and its intended methodological approach. A summary of the comments received and RIC's responses is provided in **Annex 2**.

3 REGULATORY ASSET BASE

3.1 INTRODUCTION

One of the most important issues when determining maximum tariffs is the amount of revenue that the service provider is allowed to collect from customers so that it can efficiently provide services and earn a reasonable return on its asset base. The regulatory asset base (RAB) is the accumulated value of the assets used in providing the regulated services. The regulatory asset base plays a key role in the determination of the amount of depreciation that the service provider receives and is the base to which the rate of return/cost of capital is applied when determining the return on capital assets.

The initial/opening value of the RAB must be established first before rolling forward the values over the control period. This is done by assessing the past capital expenditure over the current regulatory control period to decide whether it was prudent and should therefore be included in the opening value of the RAB. The values for the forecast RAB are established by:

- assessing the past capital expenditure over the current regulatory control period to decide whether it was prudent and should therefore be included in the opening value of the RAB;
- assessing forecast Capex to determine whether it is efficient and prudent and should therefore be included when rolling forward the RAB;
- calculating the allowance for depreciation; and
- calculating the annual values of the RAB over the regulatory control period, considering adjustments for depreciation, inflation and expected disposals.

The forecast RAB can be expressed by the following equation:

$$RAB_t = RAB_{t-1} + Capex_t - Depreciation_t - Disposals_t$$

A number of interrelated issues must be addressed in order to determine the service provider's RAB, including:

- the methodology used to value the assets;
- the depreciation method used;

- the length of asset lives;
- the regulatory treatment of assets funded by Government and/or capital contributions and grants; and
- the regulatory treatment of additions to the RAB, that is, assets over and above allowed Capex, and claw-back of revenue earned on Capex for projects that were not undertaken.

The overall approach for the assessment and determination of each issue is discussed below.

3.2 VALUATION OF THE REGULATORY ASSET BASE

The valuation methods used to evaluate the RAB are generally categorised into cost-based or value-based approaches. The cost-based methods include historic cost, indexed historic cost, replacement cost and depreciated optimised replacement cost. The value-based methods include fair market value, net present value, deprival value and optimised deprival value. The common approaches used by regulators include:

- Acquisition/Historic Cost – assets are valued at their original cost of construction. The value of assets is not indexed for inflation nor is its value linked to the cost of replacement.
- Replacement Cost – assets are valued at the cost needed to replace existing assets. There are two approaches to replacement cost: indexing the acquisition cost of assets; and revaluing the asset base using a modern equivalent asset (MEA) approach.
- Deprival Value – assets are valued at the lower of their optimised depreciated replacement cost (ODRC) or economic value (in the event they could not be replaced).
- Replacement Cost less Stranded Assets – assets not utilized in the current system are excluded. The remaining assets are valued at what it would cost to build a replacement system.

Each of these methods has distinct advantages and disadvantages, which are presented in table 3.1. The selected method is based on the level of appropriateness for a particular utility and local circumstances, as different methods can result in different estimates of the RAB. Therefore, in this instance the core issue would be whether RAB should reflect the cost to replace the current asset (replacement value) or the cost of acquisition (acquisition cost).

Table 3.1: Advantages and Disadvantages of different Valuation Methods

Approach	Advantages	Disadvantages
Actual/Acquisition Cost	• Simplest of all approaches. • Requires no adjustment to RAB except new Capex and depreciation.	• Does not reflect economic value of assets. • May reduce incentives to invest. • May not provide sufficient cash flow to fund investment.
Replacement Cost: • **Modern Equivalent Asset (MEA)**	• Provides a better indication of changes in market values. • Ensures the RAB is directly linked to the cost of new assets.	• Complex, as it requires all assets to be reviewed and valued. • Controversial, as to whether valuation should reflect optimal or existing network. • Risky especially when treating stranded assets - changes in technology since the asset was constructed and different expectations of the use of the assets may cause the modern equivalent or optimised assets to be different from existing assets (although the service provided is the same).
• **Indexed Acquisition Cost**	• Simpler to apply than MEA, as it does not require in-depth review of the assets.	• Simple indexation means there could be over or under valuation of assets when compared to the true market value. • Does not take into account technical efficiency.

Approach	Advantages	Disadvantages
Deprival Value	• Provides most accurate economic valuation.	• Highly complex as it requires a detailed modeling of system to determine asset values.
Replacement Cost less Stranded Assets	• In addition to the advantages as per those for Replacement Cost, it has the benefit of removing stranded assets.	• Considerable judgement will have to be utilized to identify the stranded assets in the distribution system. • Can be a deterrent to investment if the utility believes the regulator will strand an asset.

Source: RIC

The RIC, having balanced and considered all factors, decided to continue using the acquisition cost approach, indexed with inflation, to value the assets. The adopted method is a reasonable proxy for the replacement cost approach and reduces the risk of overvaluation of the asset base and the associated return on assets. The RIC had chosen this approach for the PRE1 to maintain regulatory certainty, and to ensure that T&TEC could earn a reasonable return on its assets and support future investment. Finally, the RIC had carefully chosen this approach for PRE1 and having completed one review, has revisited the approach, and still considers it appropriate and relevant.

3.3 REGULATORY DEPRECIATION

Depreciation profiles allocate the original capital cost of projects over their useful lives. There are several methods to depreciate assets. However, the most common methods are straight-line, declining balance, and sum-of-years-digits. For the first control period, the RIC adopted the straight-line method as it considered this method to be superior to alternatives in terms of simplicity, consistency and transparency. In addition, this method has other benefits, notably:

- It fully depreciates the assets over its useful life.
- It is generally considered to be a reasonable representation of economic depreciation for network assets in this industry given the design life of these assets.

The declining balance method calculates depreciation as a portion of the declining value of the asset; while the sum of digits method is generally considered to be more appropriate for industries which have greater production capacity in its earlier years.

The RIC intends to continue to apply the straight-line method of depreciation for PRE2 to calculate the allowance for regulatory depreciation because of its inherent advantages but also because it maintains regulatory certainty. To apply the approach, the economic life and remaining life of the assets were calculated based on the written-down values for each asset category.

3.4 LENGTH OF THE ASSET LIVES

The length of asset lives applied to assets impacts the level of depreciation that the service provider receives on those assets each year during the regulatory control period. **The RIC has decided to continue using the asset lives established for PRE1** as these continue to be broadly in line with international benchmarks and in order to maintain regulatory precedent and regulatory certainty. The asset lives and depreciation rates are shown in table 3.2 below.

Table 3.2: Class of Assets and Depreciation Rates

Class of Assets	Depreciation Rate (%)	Standard Useful Life (Years)
	T&TEC	T&TEC
Land – Leasehold	2.0	50
Buildings	3.33	30
Generating Assets:		
- Steam Production Plant	-	-
- Hydraulic Production Plant	-	-
- Diesel Generators	5.0	20
- Gas Turbine	-	-
Transmission Assets:		
- Control gear/Switchgear	4.0	25
- Transformers	4.0	25
Distribution Assets:		
- Overhead Mains	3.33	30
- Underground Mains	2.5	40
- Submarine Cables	6.67	15
- Meters	6.67	15

Other:		
- Street lights	5.0	20
- Test Equipment	6.67	15
- Supervisory Control System	4.0	25
- Electronic Equipment	10.0	10
- Communication Equipment	20.0	5
- Computer Equipment	16.67	6
- Furniture & Office Equipment	10.0	10
- Automobiles	25.0	4

3.5 ROLLING FORWARD THE RAB

After calculating the initial value of the RAB, further steps are required to establish RAB values for each year of the regulatory control period. In order to roll forward the RAB to the end of PRE1, the RIC:

- indexed the annual RAB for forecast inflation. It should be noted that the inflation adjusted amount is generally treated as a revaluation gain and as such does not receive a return;
- added the forecast efficient capital expenditure to the RAB of the previous year;
- deducted regulatory depreciation; and
- deducted forecast disposals of assets.

The derived RAB values for each year are used to establish the value of the building-blocks for calculating the annual forecast revenue requirements for PRE2. Table 3.3 below shows the approved RAB for each year over the second control period.

Table 3.3: RIC's Approved Annual Values of RAB ($'000)

	2023	2024	2025	2026	2027
Opening Value	5,415,045	5,700,732	6,026,476	6,198,458	6,350,224
Inflation Adjustment	249,092	216,628	126,716	123,969	120,654
Capex	316,870	389,140	326,820	308,830	335,660
Less Depreciation	(279,275)	(279,024)	(280,554)	(280,033)	(280,835)
Less Disposals	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)
Closing RAB	5,700,732	6,026,476	6,198,458	6,350,224	6,524,703

Source: RIC

4 COST OF CAPITAL

4.1 INTRODUCTION

The rate of return or cost of capital plays a central role in compensating the service provider for its past investment. It also provides guidance as to the return on future investment. The amount of revenue to be collected by the service provider from its customers to cover this cost is calculated by multiplying the cost of capital by the annual value of the RAB over the regulatory control period. The cost of capital is a very significant element in the determination of price controls in such a capital-intensive sector, as it is applied not only to future investment, but to the entire RAB. It should enable the service provider to meet its cost of capital and therefore finance its operations. The cost of capital is not intended to provide a floor on returns, since actual returns could potentially fall (or increase) because of under or outperformance of assumptions underpinning the revenue requirements.

Section 6 (1) (c) of the RIC Act stipulates that the RIC must ensure that a service provider, operating under prudent and efficient management, must be on terms that will allow it to earn sufficient return to finance necessary investment. The RIC's objective therefore is to ensure that the allowed rate of return is such that the service provider can finance its efficient operation and earn sufficient return to finance necessary investment. The RIC will also take note of the long-term interests of customers (in relation to price, quality and reliability of services) in considering its approach to determining a value for the rate of return.

4.2 ESTIMATING COST OF CAPITAL

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 future market conditions. Although modern finance theory provides useful tools, there are many judgments and assumptions to be made given national and international economic conditions. Therefore, several issues critical to the determination of the cost of capital, were considered among them being:

- the method for determining the cost of capital;
- the relevant input values; and

- the appropriate level of gearing.

There is considerable discussion within the regulatory literature surrounding the most appropriate approach to setting the cost of capital. Experience from several countries reveals that the cost of capital has been determined using the weighted average cost of capital (WACC) and the capital asset pricing model (CAPM)[9], 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 is State-owned and 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 it is possible for a private utility. Further, it has been argued that the use of a WACC to finance the RAB would impose greater costs on the utility than if it were financed via debt alone.

Under the circumstances, a number of other possible approaches may be considered:

- the use of a rate of return based on what has been utilised by other regulators. The tendency in recent years has been for a cost of capital of between 2% to 5% as the basis on which price controls were set. The obvious disadvantage to this approach is that circumstances in each jurisdiction differ and what may be appropriate in one may not be appropriate in another;

- the application of an average of the observed historic real borrowing costs. This is simple and straightforward but if this approach were to be used, then it would not be appropriate to allow extra costs associated with embedded debt;

- the use of an appropriate discount rate for public sector projects; and

- the application of a modified version of the WACC approach. This entails combining an observed real cost of debt with an estimate of an appropriate rate of return on the retained earnings (i.e. equity portion of T&TEC's RAB) in order to produce an allowed rate of return.

[9] CAPM is the preferred methodology that many regulators utilise for determining the cost of equity.

The RIC's decision on cost of capital was assessed based on its duties under the Act and criteria the RIC set out in PRE1. These criteria are:

- the effect on incentives now and in the longer-term;
- the effect on the service provider's financial sustainability;
- the effect on affordability; and
- consistency.

Consistent with its decision for PRE1, the RIC will continue to allow a current or forward-looking cost of capital for new debt. T&TEC's debt would normally be guaranteed by the Government. While T&TEC's projected a rate of 5.21%, the existing rate for 10-year government issued bonds is 5.1%. The RIC has decided that it will utilise the rate for 10-year government bonds as the projected rate as it is prudent at this stage to assume local circumstances will not change significantly, and has modeled the allowed revenue accordingly. However, if there is a significant change in circumstances, the RIC may review the cost of capital at the mid-term of the control period, to determine if an adjustment is required for the remainder of PRE2.

4.3 FINANCEABILITY

A key component of the RIC's approach to calculating the revenue requirement is assessing the future cash flow needs of the service provider. The allowed revenue must be sufficient to cover Opex; regulatory depreciation; a return on the capital investment; and an allowance for working capital. The sum of these amounts represents the RIC's view of the service provider's total efficient costs over the control period or the allowed revenue requirement. The RIC has an obligation to ensure that service providers are capable of financing their operations as specified by Section 6(1)(c).

The RIC assesses the financeability of a service provider by undertaking the following steps:

- forecasting the service provider's cash flow over the determination period (based on forecast revenue using the building-block method);
- computing financial statements from the forecast cash flows; and
- computing a set of financial ratios from the financial statements.

The RIC's approach to ensuring financeability is discussed in the document, **"Embedding Financial Viability and Sustainability",** which was published for public comments in February 2021 and can be found on the RIC's website.

The RIC calculated four financial ratios as part of the financeability tests as listed in table 4.1 below utilising a notional gearing ratio.[10] The RIC is of the view that its approach remains sound and it will utilise a similar approach in PRE2.

Table 4.1: Financial Ratios to assess financeability

Ratio	Formula	Target
• Funds Flow Interest Cover (times)	(FFO + Net Interest) / Net Interest	About 3
• Debt Payback Period (years)	Net Debt / FFO	Between 5 to 7
• Internal Financing Ratio (%)	(FFO – Dividends) / Net Capex	Greater than 40
• Return on RAB	FFO / RAB	About 9%

Source: RIC

In light of the above discussion and in order to maintain regulatory certainty and precedent, the RIC's decision is:

- **to allow a current or forward-looking cost of capital for new debt. Therefore, for the purposes of calculating the allowance for a return on new investment, a cost of capital of 5.1% will be applied;**
- **not to include a return to the Shareholder (Government); and**
- **to use a notional gearing level as it relates to the calculation of the ratios listed in table 4.1 above.**

[10] The use of a notional (estimated) gearing level is internally consistent with the building block model as it signals to the utility what the regulator believes to be the efficient financing structure.

5 REVIEW OF ELECTRICITY DEMAND AND CUSTOMER FORECASTS

5.1 INTRODUCTION

Demand forecasts are an essential component of a price review process. The setting of price controls involves the following steps:

(1) Estimation of the projected electricity consumption[11] (demand) during the period for which the price control is being established;

(2) Estimation of the efficient projected costs to be incurred by the service provider in supplying the expected consumption;

(3) Estimation of the total projected revenue 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 revenue requirement and the expected revenue from current tariffs.

The RIC must assess the demand forecasts utilised by T&TEC in preparing its capital and operating expenditure forecasts that underlie its proposed tariffs. Demand forecasts potentially play a significant role in two components of a regulatory review:

- In determining the required capital (and to a lesser extent, operating) expenditures. Capital and operating expenditures, in turn, are major inputs into the revenue required.
- In determining tariffs to apply under the revenue cap.

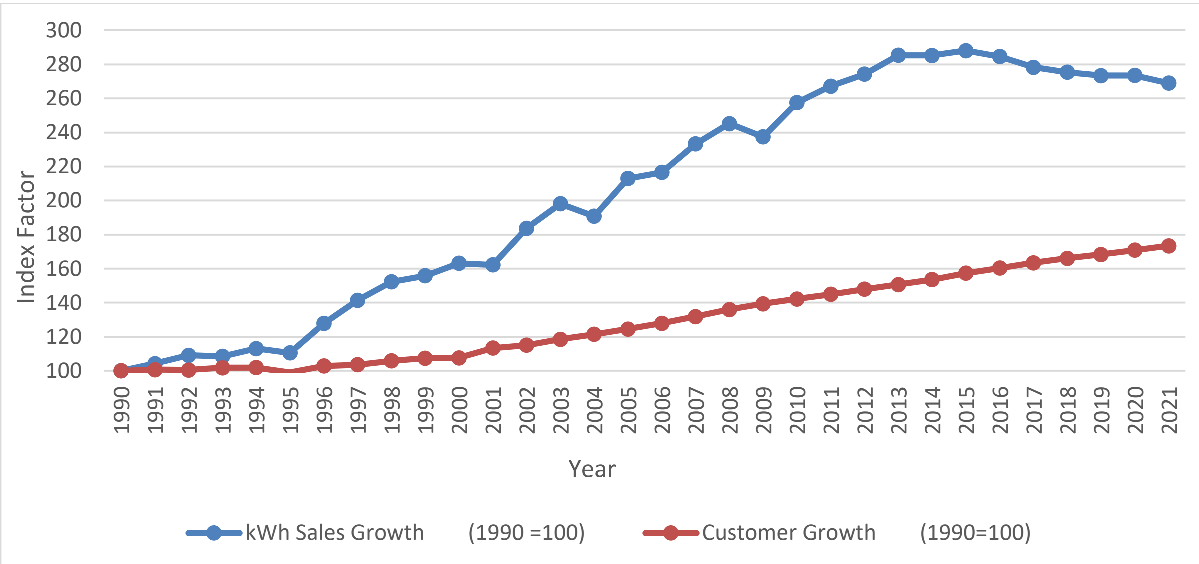
The two components require different, but related demand forecasts. Forecasts of system peak demand (maximum demand) are more relevant to capital expenditure requirements while forecasts of energy demand and customer numbers are more essential to the determination of tariffs. The next section examines the historical performance of T&TEC with respect to system peak demand, energy demand and customer numbers.

[11] Electricity demand is used interchangeably with energy demand, energy consumption, or energy sales.

5.2 ANALYSIS OF HISTORICAL DATA

A brief analysis of energy demand and customer numbers in Trinidad and Tobago, for the period 1990-2021 is provided below, based on data provided by T&TEC. Overall, the sale of electricity doubled for all classes of customers between 1990 and 2021. Figure 5.1 presents a graphical representation of the increase in energy sales and the number of electricity customers from 1990 to 2021.

Figure 5.1: Growth in Sales of Energy and Customers, 1990-2021



Source: RIC

Given that the last regulatory period (PRE1) ended in 2011, the relevant period that was analysed for the remainder of this section is 2010 to 2021.

Table 5.1 shows energy demand/sales by class for the period 2010-2021. Total energy sales increased at a Compound Average Growth Rate (CAGR)[12] of 0.40 % between 2010-2021. A closer examination of the components of overall growth reveal that residential sales grew at a CAGR of 3.45%, commercial sales grew by 1.01% and street lighting sales at a CAGR of 1.45% during this period. Conversely, industrial sales experienced an overall negative growth with a CAGR of -1.62% over the period.

[12] The CAGR is the mean annual growth rate, typically of an investment, over a specified period of time longer than one year. It is used here to show the mean annual growth rate for the specified period.

With respect to the share of different classes of customers in the total energy demand[13], residential, commercial and street lighting classes all increased during the period. Residential share of demand increased significantly over the period from 28.70% in 2010 to 39.88% in 2021 while the share of commercial demand increased from 9.75% to 10.42% over the same period. However, the share of demand for the industrial class declined significantly over the period from 60.16% in 2010 to 48.13% in 2021.

Table 5.1: Energy Demand (GWh) by Class, 2010–2021

YEAR	Residential		Commercial		Industrial		Street Lighting		Total
	GWh Sold	Share (%)	GWh Sold	Share (%)	GWh Sold	Share (%)	GWh Sold	Share (%)	GWh Sold
2010	2,271.09	28.70%	771.26	9.75%	4,761.14	60.16%	110.67	1.40%	7,914.16
2011	2,352.14	28.64%	784.13	9.55%	4,963.54	60.44%	112.16	1.37%	8,211.97
2012	2,447.94	29.04%	813.36	9.65%	5,051.78	59.94%	115.46	1.37%	8,428.54
2013	2,568.78	29.29%	867.39	9.89%	5,216.00	59.48%	117.24	1.34%	8,769.41
2014	2,618.85	29.87%	909.10	10.37%	5,119.86	58.40%	119.16	1.36%	8,766.97
2015	2,753.68	31.11%	976.35	11.03%	5,001.45	56.50%	121.15	1.37%	8,852.63
2016	2,908.27	33.25%	1015.18	11.61%	4,700.37	53.74%	122.60	1.40%	8,746.42
2017	2,939.76	34.37%	1003.48	11.73%	4,487.49	52.46%	123.39	1.44%	8,554.12
2018	2,951.97	34.88%	979.65	11.58%	4,407.45	52.08%	124.02	1.47%	8,463.09
2019	3,082.25	36.69%	996.46	11.86%	4,196.53	49.95%	126.18	1.50%	8,401.42
2020	3,330.40	39.62%	900.60	10.71%	4,045.33	48.13%	129.16	1.54%	8,405.49
2021	3,297.58	39.88%	861.40	10.42%	3,979.22	48.13%	129.62	1.57%	8,267.82
CAGR	3.45%		1.01%		-1.62%		1.45%		0.40%

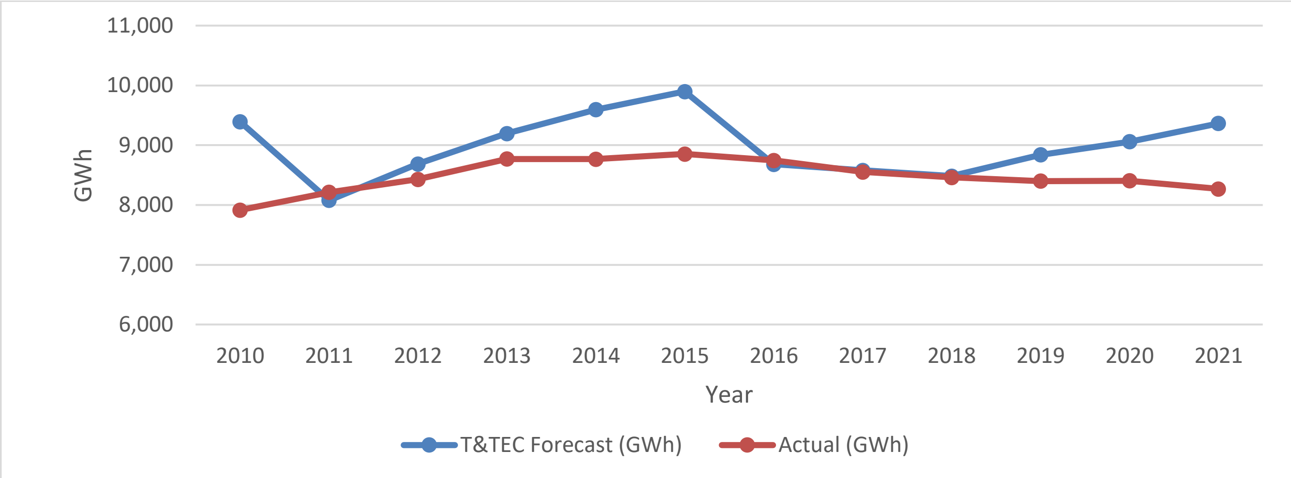
Source: RIC

5.2.1 Comparison of historical data against past T&TEC forecasts

The actual growth in energy consumption over the period 2010-2021 was slightly lower than what was forecast by T&TEC (figure 5.2) for the majority of years within the period. Overall, actual consumption showed a positive trend, and ranged between -1.6% and 18.6%, except in 2011 when there was a negative 1.6% variance, as actual consumption was higher than the corresponding forecast for that year.

[13] Represented in Gigawatt hours (GWh).

Figure 5.2: Energy Consumption: Actual vs. T&TEC Forecast, 2010–2021



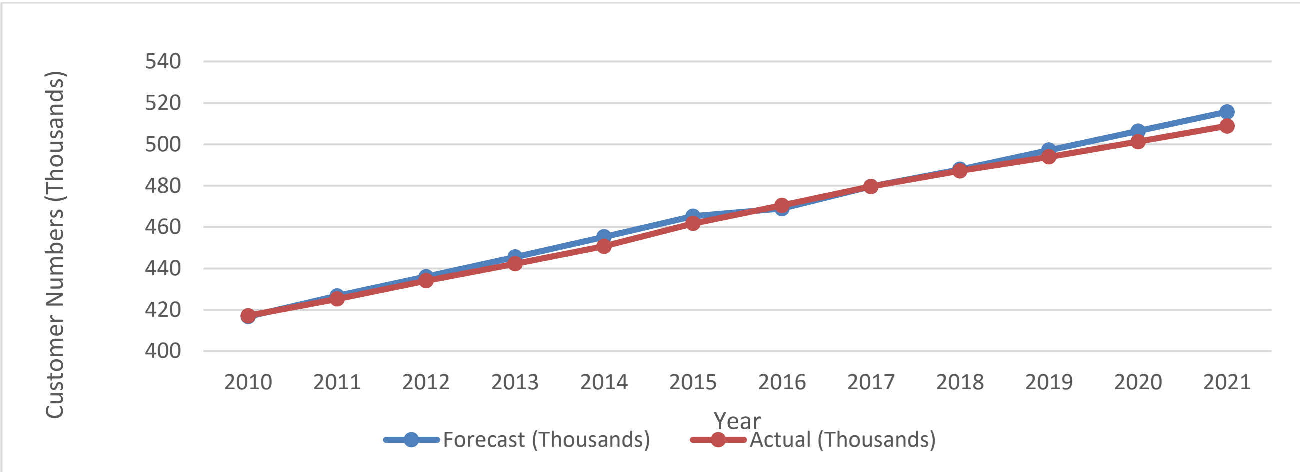
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
T&TEC Forecast (GWh)	9,392	8,080	8,686	9,195	9,594	9,898	8,681	8,579	8,483	8,838	9,058	9,363
Actual (GWh)	7,914	8,212	8,429	8,769	8,767	8,853	8,746	8,554	8,463	8,401	8,405	8,268
Variance (%)*	**18.6**	**-1.6**	**3.1**	**4.9**	**9.4**	**11.8**	**0.1**	**0.2**	**0.2**	**5.2**	**7.8**	**13.3**

Source: RIC

* Variance refers to forecast errors as a percentage (%) of actual.

Over the same period, the forecast growth in customer numbers was fairly accurate, as shown in figue 5.3. The average variation between actual and forecast customer numbers was 0.5% over the period.

Figure 5.3: Customer Numbers: Actual vs. T&TEC Forecast, 2010–2021



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
T&TEC Forecast (Thousands)	416.7	426.7	436	445.5	455.2	465.2	468.9	479.6	487.9	497.1	506.4	515.7
Actual (Thousands)	417.1	425.2	434	442.2	450.7	461.7	470.5	479.6	487.2	493.9	501.3	508.8
Variance (%)*	**-0.1**	**0.4**	**0.5**	**0.8**	**1.0**	**0.8**	**-0.3**	**0.0**	**0.14**	**0.7**	**1.0**	**1.3**

Source: RIC

* Variance refers to forecast errors as a percentage (%) of actual.

5.3 FORECASTS OF SALES, CUSTOMER NUMBERS AND PEAK DEMAND

The level of sales and number of customers have a direct impact on the revenue requirement and tariffs, as forecasts of costs are heavily influenced by the forecast of sales and customer numbers. On the one hand, higher demand and increasing customer numbers lead to a higher revenue requirement. On the other hand, once the revenue is set, higher forecast sales can lead to a lower consumption charge, and higher numbers of customers can lead to lower fixed charge. In cases where forecasts differ significantly from actual figures, this will result in T&TEC over or under-recovering its required revenue. It is important, therefore, that the forecasts of sales and customer numbers are reasonable.

Many forecasting techniques have been developed, ranging from very simple extrapolation methods to more complex time-series techniques, and even hybrid models that combine several approaches. Straight-line extrapolation of historical trends has served well for forecasting electricity demand. However, with the fluctuation in energy prices, the emergence of alternative fuels, new technologies and changes in lifestyles, more sophisticated modelling techniques are also being used. An appropriate method is generally chosen based on the nature of the data available and the desired level of detail of the forecasts. The accuracy of the forecast increases with the size of the database used. However, there is a practical limit to the quantity of data that is cost-effective to collect, in terms of additional value of the information gained.

5.3.1 T&TEC's Forecasts

T&TEC presented its forecasts of customer numbers, energy sales, and system peak demand as part of its Business Plan submission to the RIC. T&TEC utilised a combination of forecasting methods including econometric models, exponential smoothening and judgement forecasting. Its forecasts consist of 10-year projections for residential (Rate A), commercial (Rates B and B1), small and large industrial (Rates D1, D2, D3, D4, E1 and E2) and street lighting customers (Rate S). T&TEC was not in a position to provide forecast customer numbers or demand for the proposed rate class C or High Load Factor (HLF)/ High Density Load (HDL) customers.

Table 5.2 below shows T&TEC's forecasts of electricity sales and customer numbers. T&TEC projected its sales would increase by 14% from 8,526 GWh in 2022 to 9,743 GWh in 2027. Sales to industrial customers are expected to continue to account for the largest portion of total sales and is projected to increase by 10% over the period. Sales to residential and commercial customers are predicted to account for 41% and 11% of total sales, with increases of 21% and 12% respectively over the period 2022-2027. Sales for public lighting is expected to increase by 9% from 134 GWh in 2022 to 146 GWh in 2023 and account for about 2% of total sales for each year in the period.

Based on T&TEC's forecast, residential customers will account for approximately 88% of all customers at the end of the period. The number of residential customers is expected to grow by 8%, from 457,148 in 2022 to 494,223 in 2027. The number of commercial customers is anticipated to increase by 7% from 56,252 in 2022 to 60,134 in 2027 and account for 11% of total customers. There is a forecast 9% increase in the number of industrial customers from

3,930 in 2022 to 4,289 in 2027 and these customers will account for less than 1% of total customers over the period. The number of public lighting[14] accounts is expected to be maintained at 48, over the period.

Table 5.2: T&TEC's Forecasts of Sales and Customer Numbers 2022–2027

	2022	2023	2024	2025	2026	2027
Electricity Sales (GWh):						
Residential	3,298	3,430	3,564	3,701	3,842	3,987
Commercial	974	997	1,020	1,044	1,067	1,091
Industrial	4,120	4,164	4,404	4,439	4,478	4,519
Public Lighting	134	136	138	141	143	146
Total	**8,526**	**8,727**	**9,126**	**9,325**	**9,530**	**9,743**
Customer Numbers (Accounts):						
Residential	457,148	464,563	471,978	479,393	486,808	494,223
Commercial	56,252	57,028	57,805	58,581	59,358	60,134
Industrial	3,930	4,018	4,086	4,154	4,221	4,289
Public Lighting	48	48	48	48	48	48
Total	**517,378**	**525,657**	**533,917**	**542,176**	**550,435**	**558,694**

Source: T&TEC

System peak demand is projected to be 1,371 MW in 2022 and 1,581 MW in 2027. This represents a compounded average growth rate of 2.89%, as shown in table 5.3 below.

Table 5.3: T&TEC's Forecast for Peak Demand (MW) 2022–2027

Year	Peak Demand (MW)	% Change
2022	1,371	
2023	1,407	2.63%
2024	1,472	4.62%
2025	1,507	2.38%
2026	1,544	2.46%
2027	1,581	2.40%
CAGR		**2.89%**

Source: T&TEC

[14] Regional Corporations and other State agencies are now administratively responsible for the public lighting customer class.

5.4 RIC's FORECASTS

The RIC considered several forecasting approaches for estimating future levels of energy demand, customer numbers and system peak demand. The RIC's task was also to determine if the forecast methods and data sources used by T&TEC were robust, represented good electricity industry practice and therefore produced realistic forecasts.

In the past, the RIC undertook analysis, using recognised methodologies to forecast electricity demand and customer numbers. These included Autoregressive Integrated Moving Average (ARIMA) modeling, Vector Autoregression (VAR) modeling and Simple Linear Trending. In PRE1, the RIC found that when the ARIMA model was employed, the results did not closely correspond to observed values over the sample period (*ex-post* forecasting). While the VAR models tended to correspond more closely to observed values and evidenced lower variation between the actual and estimated series, the confidence intervals for these estimates were fairly wide and increasing. However, Simple Linear Trending Analysis produced the best results, that is, results closely approximated the observed sample values to between 1.1 and 3.3%. The RIC subsequently conducted several forecasting exercises, and the outputs of the various approaches were similar to those observed in PRE1. Therefore, scenarios were run using several trending approaches and judgement, and forecast accuracy was measured through forecast variance.

5.4.1 Electricity Demand Forecasts

Based on the various trending approaches employed, the linear trending method produced the lowest average variation for residential, commercial, industrial and public lighting demand. The estimates derived from this technique closely approximated the observed sample values. Observed values of electricity sales with corresponding forecasts, forecast errors for the various classes of customers for the observed period 2010-2021 and an extended forecast for the period 2022-2027, using trending and judgement, are shown in table 5.4 below.

Table 5.4: Actual Values, Forecasts and Forecast Errors for Electricity GWh Sales, 2010–2027

YEAR	Residential			Commercial			Industrial			Street Lighting		
	Actual (GWh)	Forecast (GWh)	Variance %	Actual (GWh)	Forecast (GWh)	Variance %	Actual (GWh)	Forecast (GWh)	Variance %	Actual (GWh)	Forecast (GWh)	Variance %
2010	2,271	2,255	-0.72%	771	775	0.48%	4,761	4,675	-1.81%	111	91	-17.77%
2011	2,352	2,359	0.28%	784	811	3.39%	4,964	5,149	3.74%	112	113	0.75%
2012	2,448	2,463	0.61%	813	847	4.08%	5,052	5,068	0.33%	115	115	-0.40%
2013	2,569	2,567	-0.07%	867	882	1.72%	5,216	4,988	-4.37%	117	117	-0.21%
2014	2,619	2,671	1.99%	909	918	0.99%	5,120	4,907	-4.15%	119	119	-0.13%
2015	2,754	2,775	0.78%	976	954	-2.30%	5,001	4,827	-3.50%	121	121	-0.12%
2016	2,908	2,879	-1.00%	1015	990	-2.51%	4,700	4,746	0.97%	123	122	-0.49%
2017	2,940	2,983	1.48%	1003	1026	2.20%	4,487	4,665	3.96%	123	124	0.49%
2018	2,952	3,028	2.58%	980	1061	8.34%	4,407	4,577	3.85%	124	126	1.60%
2019	3,082	3,089	0.20%	996	1097	10.10%	4,197	4,669	11.26%	126	128	1.44%
2020	3,330	3,150	-5.41%	901	1133	25.79%	4,045	4,762	17.72%	129	130	0.65%
2021	3,298	3,213	-2.55%	861	1169	35.68%	3,979	4,857	22.07%	130	131	0.82%
2022		3,207			906			4,122			131	
2023		3,257			952			3,936			132	
2024		3,308			955			3,838			134	
2025		3,358			959			3,740			135	
2026		3,408			963			3,643			136	
2027		3,458			966			3,545			138	
Average			**-0.15%**			**7.33%**			**4.17%**			**-0.15%**

Source: RIC

Notes

1. Variance refers to forecast errors as a percentage (%) of actual.
2. It is important to note that in 2020 and 2021, the impact of government restrictions because of the COVID-19 pandemic, impacted actual electricity sales for all customer classes, with the exception of public lighting.

5.4.2 Customer Number Forecasts

The linear trending method also produced the lowest average variation for forecasting the number of residential, commercial and industrial customers. The estimates derived from this technique closely approximated the observed sample values. The RIC has decided not to forecast the number of public lighting customers as it is more practical to assume the number of public-lighting customers will remain fixed at the existing level for the forecast period because of the administrative changes which streamlined the billing of public lighting accounts to Regional Corporations and some State Agencies from 2011. Instead, the RIC utilised the existing number of public lighting fixtures (streetlights, traffic lights and recreation ground lights) as the basis for pricing.

Observed values of customer numbers with corresponding forecasts and forecast errors for the various classes of customers for the observed period 2010-2021 and an extended forecast for the period 2022-2027, using trending, are shown in table 5.5 below.

Table 5.5: Actual Values, Forecasts and Forecast Errors for Electricity Customer Numbers, 2010–2027

YEAR	Residential			Commercial			Industrial		
	Actual	**Forecast**	**Variance %**	**Actual**	**Forecast**	**Variance %**	**Actual**	**Forecast**	**Variance %**
2010	375,569	370,639	-1.31%	38,371	39,290	2.40%	3,130	3,101	-0.93%
2011	382,882	378,708	-1.09%	39,027	41,151	5.44%	3,207	3,185	-0.69%
2012	390,188	386,777	-0.87%	40,463	43,013	6.30%	3,266	3,269	0.09%
2013	395,515	394,847	-0.17%	43,284	44,874	3.67%	3,338	3,353	0.45%
2014	400,818	402,916	0.52%	46,441	46,735	0.63%	3,429	3,437	0.23%
2015	408,356	410,985	0.64%	49,781	48,597	-2.38%	3,519	3,521	0.06%
2016	415,001	419,054	0.98%	51,858	50,458	-2.70%	3,605	3,605	0.00%
2017	422,405	427,123	1.12%	53,496	52,320	-2.20%	3,686	3,689	0.08%
2018	429,022	430,008	0.23%	54,453	54,181	-0.50%	3,737	3,773	0.96%
2019	435,439	437,963	0.58%	54,676	56,043	2.50%	3,804	3,857	1.39%
2020	442,415	446,066	0.83%	55,012	57,904	5.26%	3,835	3,941	2.76%
2021	449,680	454,318	1.03%	55,335	59,765	8.01%	3,829	4,025	5.12%
2022		456,680			56,252			4,112	
2023		464,148			56,801			4,114	
2024		471,141			57,171			4,191	
2025		478,134			57,667			4,269	
2026		485,127			58,689			4,346	
2027		492,120			59,702			4,424	
Average			**-1.00%**			**0.96%**			**-0.49%**

Source: RIC

* Variance refers to forecast errors as a percentage (%) of actual

5.4.3 Peak Demand Forecasts

The RIC has generally utilised two methods for producing peak demand forecasts; ARIMA and simple linear trending. Both have produced good results historically, however, the trending method typically produces lower average variation, which is preferable.

The accuracy of peak demand forecasts was measured through an examination of the forecast variance. Observed values of peak demand with corresponding forecasts and forecast errors for the period 2010-2021 and an extended forecast for the period 2022-2027, using trending, are shown in table 5.6 below. The average variation between actual and forecasted customer numbers was 0.10% over the period.

Table 5.6: Actual Values, Forecasts and Forecast Errors for Peak Demand (MW)

YEAR	Actual	Forecast	Variance %
2010	1,222	1,209	-0.01%
2011	1,275	1,238	-0.03%
2012	1,322	1,268	-0.04%
2013	1,348	1,298	-0.04%
2014	1,343	1,329	-0.01%
2015	1,396	1,361	-0.03%
2016	1,339	1,394	0.04%
2017	1,355	1,427	0.05%
2018	1,319	1,388	0.05%
2019	1,370	1,421	0.04%
2020	1,360	1,455	0.07%
2021	1,356	1,490	0.10%
2022		1,389	
2023		1,397	
2024		1,405	
2025		1,414	
2026		1,422	
2027		1,431	
Average			**0.10%**

Source: RIC

5.5 RIC's PROPOSED APPROACH

Forecasting consumption of electricity is normally challenging. From a wider macroeconomic perspective, the current economic climate compounds the challenges. Supply disruptions continue to place inflationary and supply-chain pressure on economies worldwide and the local economy is not immune. Though knock-on effects on demand are anticipated, Trinidad and Tobago continues to benefit from high energy prices including robust natural gas prices and indications are that the economy is slowly recovering after the pandemic[15]. Additionally, the models that were used to predict consumption growth in the past may require modification, as the consumption of electricity increases; this is particularly due to the increasing uptake of electric vehicles.

The RIC has carefully considered T&TEC's forecasts and also produced its own forecasts for electricity consumption and customer numbers. The RIC is confident that its forecasts for residential and commercial customers are robust and has therefore decided to use them for pricing purposes. The RIC's preferred approach for industrial customers and public lighting customers is to use T&TEC's forecasts for electricity consumption and customer numbers. The industrial class comprises a relatively small number of large customers, whose production activity is typically not heavily dependent on local economic drivers. Their entry onto T&TEC's network is relatively infrequent and is also irregular, thereby making statistical forecasting of their numbers and aggregate electricity demand largely infeasible. For these reasons, the RIC prefers to use the forecast changes in customer numbers, energy sales and billed maximum demand provided by T&TEC, as these are based heavily on data from such prospective customers on in-service dates and demand ramp-up schedules. The statistical forecasting of electricity consumption for public lighting is also usually difficult as the public lighting programme administered by the Ministry of Public Utilities is funded under the Ministry's Public Sector Investment Programme (PSIP). Normally, the increase in the number of streetlights depends on budgetary allocations which vary annually, therefore, this affects forecasts for this class.

The RIC's electricity demand and customer number forecasts for pricing purposes are presented in table 5.7.

[15] See Review of the Economy 2022.

Table 5.7: Forecasts to be used for Pricing Purposes 2022–2027

	2022	**2023**	**2024**	**2025**	**2026**	**2027**
Electricity Sales (GWh):						
Residential	3,207	3,257	3,308	3,358	3,408	3,458
Commercial	906	952	955	959	963	966
Industrial	4,122	4,164	4,404	4,439	4,478	4,519
Public lighting	130	136	138	141	143	146
Total	**8,365**	**8,509**	**8,805**	**8,897**	**8,992**	**9,089**
Customer Numbers:						
Residential	456,680	464,148	471,141	478,134	485,127	492,120
Commercial	56,252	56,801	57,171	57,667	58,689	59,702
Industrial	3,930	4,018	4,086	4,154	4,221	4,289
Public lighting	48	48	48	48	48	48
Total	**516,910**	**525,015**	**532,446**	**540,003**	**548,085**	**556,159**

Source: RIC

The RIC notes that under the revenue cap framework, the effects of the forecasts do not impact on the total revenue collected, but instead, they impact on the timing of revenue collection. If the forecast is too high then less revenue is collected than intended resulting in higher tariffs in subsequent periods, and vice versa. Additionally, to reduce the effects of the forecasts, the RIC places greater reliance on the revised forecasts as submitted at the annual price/tariff approval process.

6 REVIEW OF THE PERFORMANCE OF T&TEC

6.1 INTRODUCTION

The RIC is mandated by the RIC Act to prescribe and enforce standards with respect to the quality, continuity and reliability of service as well as to carry out studies of efficiency and economy of operation, and of performance of service providers. As part of a price review, it is important to have an overall understanding of the service provider's performance in areas such as service delivery and its overall financial performance. In the chapters that follow, details of T&TEC's performance in areas such as operating expenditure, capital expenditure and service quality issues will be presented. The RIC also publishes annual reports of T&TEC's performance against Quality of Service Standards (QSS) and other technical performance indicators, on its website.

In this chapter, T&TEC's productivity, financial performance and average tariffs over the past five (5) years (2017-2021) are discussed. In order to contextualise the discussion, key data for the transmission and distribution sector, over the last five years, are presented in table 6.1 below.

Table 6.1: Key Data for T&TEC, 2017–2021

	2017	**2018**	**2019**	**2020**	**2021**
Total Service Area (sq Km)	5,128	5,128	5,128	5,128	5,128
Total Network Length (Km)	22,829	23,064	24,401	24,653	24,887
Maximum Demand (MW)	1,355	1,319	1,370	1,360	1,356
Energy Sold (GWh)					
Domestic Customers	2,952.0	2,952.0	3,082.4	3,330.4	3,297.6
Commercial Customers	990.4	967.6	984.4	893.9	854.7
Industrial Customers	4,479.50	4,418.8	4,208.6	4,052.0	3,985.9
Total Number of Employees	3,149	3,075	2,991	2,903	2,888
Customers					
Total Number of Customers	479,632	483,559	493,965	501,309	508,892
Customers per sq Km of service area	94	94	96	98	99
Customers per Km of network length	21	21	20	20	20

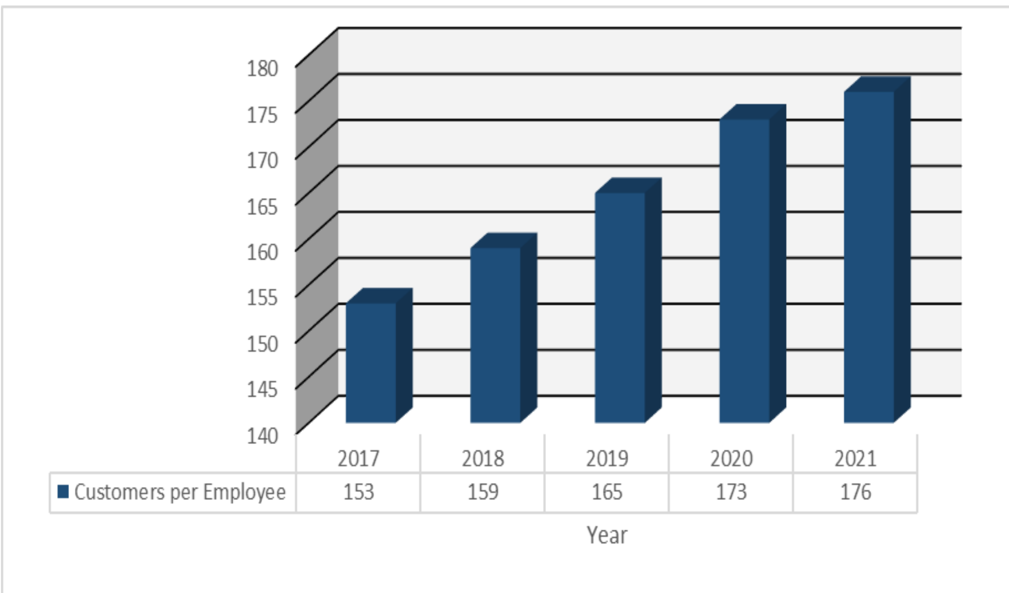
Source: T&TEC

6.2 PRODUCTIVITY TRENDS

6.2.1 Labour Productivity

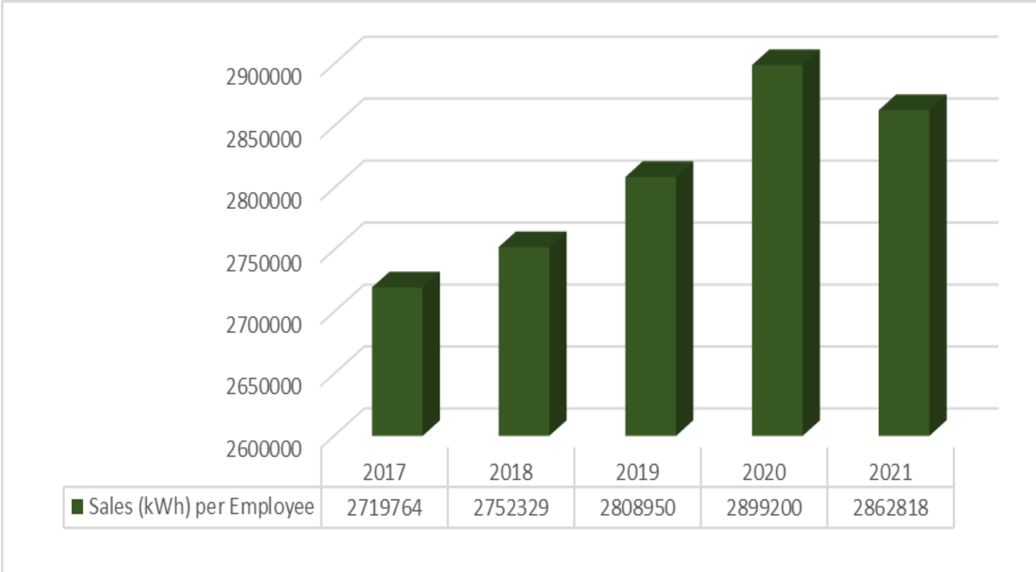
Productivity trends are indicators of the level of efficiency of an entity. In the electricity transmission and distribution sector, customers per employee and electricity sales per employee are the two most widely used indicators of labour productivity. T&TEC's customers per employee indicator improved from 153 in 2017 to 176 in 2021 (see figure 6.1), and was better than some electric utilities in the region such as the Cayman Islands (135) and Dominica (170), but worse than utilities in St. Lucia (256), Belize (334) and Jamaica (526).

Figure 6.1: Customers Per Employee, 2017–2021



T&TEC's kWh sales per employee indicator improved from 2.72 million kWh in 2017 to 2.86 million kWh in 2021, see figure 6.2. In comparison to countries in the region, T&TEC's performance in 2021 was better than several countries including, St. Lucia (1.28 million kWh/employee), Belize (1.75 million), Jamaica (2.37 million), and the Cayman Islands (2.76 million).

Figure 6.2: Sales (kWh) Per Employee, 2017–2021



6.2.2 Other Productivity Indicators

The real operating cost per MWh sales, and the real operating cost per customer are two additional productivity metrics that are measured, see table 6.2. T&TEC's real operating cost per MWh sales declined over the period, at an average of 6.25% annually, while real operating costs per customer decreased annually, by 8.40%. The significant decrease in both indicators for 2021 is attributable to the decrease in operating cost for that year.

Table 6.2: Other Productivity Indicators, 2017–2021

	2017	2018	2019	2020	2021	Average
Real Operating Cost per MWh sales ($/MWh)	355.23	343.33	345.78	412.60	343.88	-
% Change	**-**	**(3.35)**	**0.71**	**19.32**	**(16.66)**	**(0.05)**
Real Operating Cost per customer ($/cust.)	6,342.39	5,962.80	5,880.46	6,917.20	5,586.18	-
% Change	-	**(5.98)**	**(1.38)**	**17.63**	**(19.24)**	**(2.24)**

Source: RIC

6.3 FINANCIAL PERFORMANCE

In table 6.3 a snapshot of T&TEC's financial performance is presented. Overall, T&TEC's financial performance has been weak as it maintained an average annual deficit of $1,132 million over the period. T&TEC's receivables position was also very weak, with $1,624 million owed to the utility at the end of 2021; 81.8% of which is attributable to the Government and Government agencies. Further details on T&TEC's financial performance can be found in the **"Review of Status of T&TEC"** document on the RIC's website.

Table 6.3: Key Financial Statistics, 2017–2021

	2017 $Mn	2018 $Mn	2019 $Mn	2020 $Mn	2021 $Mn
Total Revenue	3,217.50	3,229.68	3,276.37	3,331.00	3,255.66
Operating Expenditure	3,371.20	3,121.67	3,152.01	3,787.14	3,167.22
Depreciation	499.50	477.00	514.28	547.41	542.65
Net Interest Payments	489.60	449.72	632.49	629.32	609.42
Total Expenditure	4,340.30	4,048.32	4,298.78	4,963.87	4,319.29
Surplus (Deficit)	(1,122.80)	(818.71)	(1,022.41)	(1,632.87)	(1,063.63)
Total Assets (Book Value)	11,417.30	11,473.02	11,696.19	19,532.18	18,873.34
Total Liabilities	6,495.00	6,592.12	7,860.34	4,557.19	5,509.30
of which Net Debt	3,869.40	5,350.00	5,350.00	4,694.21	4,437.88
Operating Cashflow	88.10	(3,836.00)	1,744.20	1,420.20	1,501.90

Source: T&TEC

6.3.1 Expenditure

T&TEC's total costs declined by 0.12% over the period as seen in table 6.4 below. A further disaggregation of these costs is found in tables 6.5 and 6.6.

Table 6.4: Generation, T&D & Other Costs, 2017–2021

Year	GENERATION			Transmission, Distribution & Administration ($ Mn)	Depreciation, Interest & Finance and Other ($Mn)	Total Expenditure ($ Mn)
	Conversion ($Mn)	Fuel and Own Generation ($Mn)	Total Generation ($ Mn)			
2017	1,036.9	985.7	2,022.6	1,380.0	937.8	4,340.3
2018	1,071.0	973.4	2,044.4	1,075.3	928.6	4,048.4
2019	1,056.2	1,038.2	2,094.5	1,058.0	1,146.3	4,298.8
2020	1,090.4	1,008.5	2,098.9	1,684.5	1,180.5	4,963.9
2021	983.2	1,077.8	2,061.0	1,108.4	1,149.9	4,319.3
CAGR*	**(1.32)%**	**2.26%**	**0.47%**	**(5.33)%**	**5.23%**	**(0.12)%**

Source: T&TEC *CAGR – Compound Average Growth Rate

Table 6.5: Components of Total Expenditure, 2020–2021

Expenditure Category	2020 TT ($Mn)	2021 TT ($Mn)	% Change
Conversion	1,090.4	983.2	(9.8)
Generation	1,008.5	1,077.8	6.9
Transmission	76.6	77.4	1.0
Distribution	580.7	561.1	(3.4)
Engineering	39.2	36.6	(6.6)
Administrative and General	988.0	433.3	(56.1)
Depreciation	547.4	542.6	(0.9)
Interest and Finance Costs	588.1	572.3	(2.7)
Interest on Suppliers' Credit	41.1	37.1	(9.7)
Loss (Gain) on Exchange	3.8	(2.2)	(157.9)
TOTAL	**4,963.9**	**4,319.3**	**(13.0)%**

Source: T&TEC Management Accounts, December 2021.

Table 6.6: Transmission & Distribution Expenditure, 2017–2021

	2017 ($Mn)	2018 ($Mn)	2019 ($Mn)	2020 ($Mn)	2021 ($Mn)
Transmission	**71.6**	**58.2**	**60.5**	**76.6**	**77.4**
Distribution	**683.1**	**571.9**	**572.1**	**580.7**	**561.1**
- Operations	271.4	265.4	263.6	297.0	281.2
- Maintenance	347.1	252.1	254.1	275.5	269.9
- Commercial	63.1	49.3	48.2	*	*
- Rates, Taxes, Insurance	1.5	5.1	6.2	8.2	10.0
Total Transmission & Distribution	**754.7**	**630.1**	**632.6**	**657.3**	**638.5**

*Note: In 2020 and 2021, T&TEC captured expenditure for Commercial under the Operations category.
Source: T&TEC Management Accounts

6.3.2 Revenue

T&TEC's total revenue from sales increased by 1.2% from $3,217 million in 2017 to $3,256 million in 2021, see figure 6.3. However, total units sold decreased from 8,545.3 GWh to 8,267.8 GWh, a decline of 3.2%, while the unit cost of sales increased by 18.2% over the same period. Figure 6.4 shows the change in the unit cost of sales from 2017-2021.

Figure 6.3: Light & Power Sales ($Mn), 2017–2021

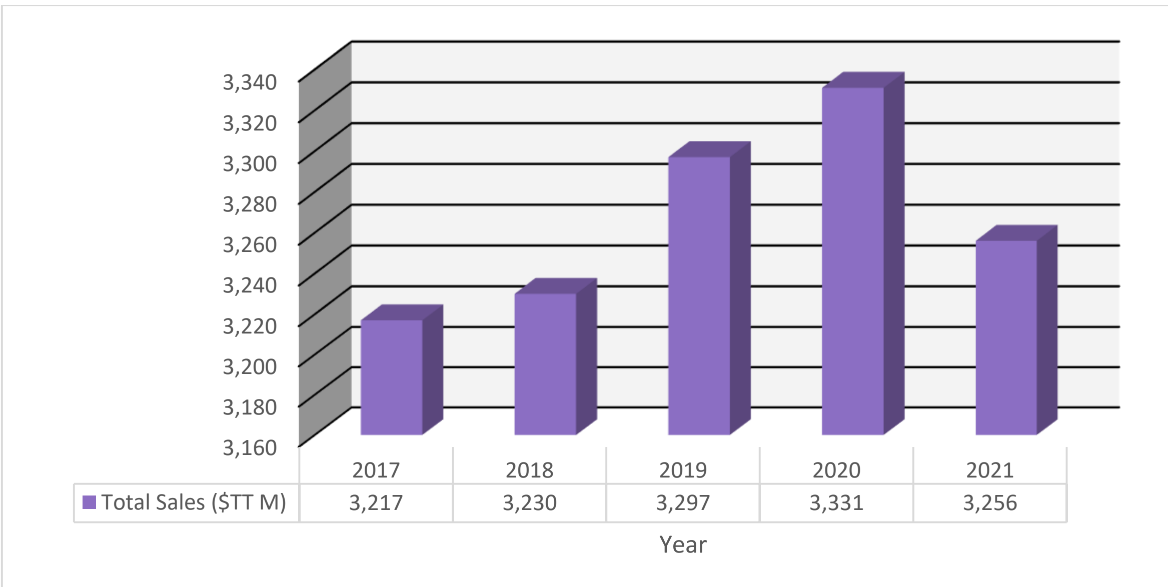
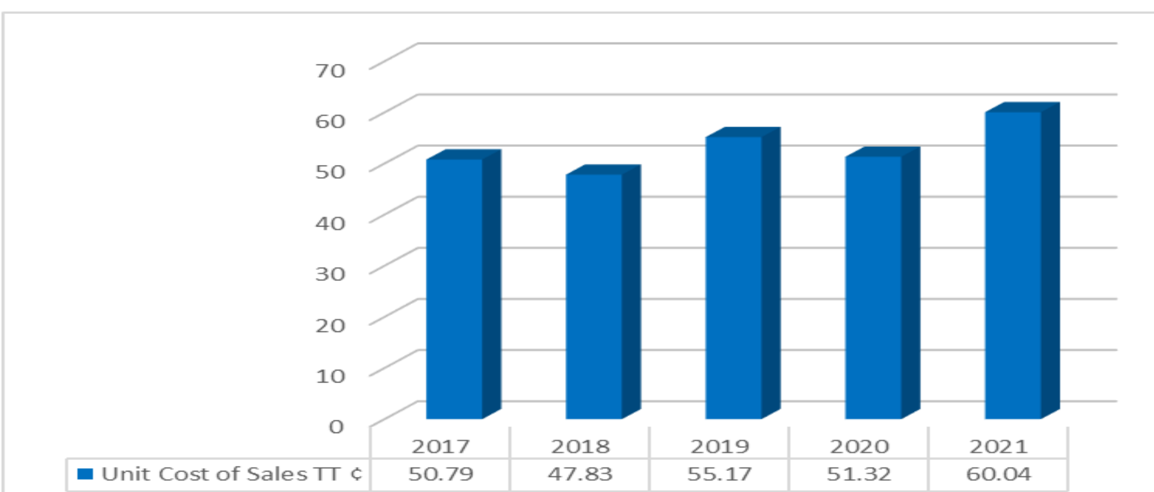


Figure 6.4: Unit Cost of Sales, 2017-2021



6.3.3 Billing and Collections

One indicator that is typically 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 6.7 reveals consistently high levels of receivables including receivables from the Government and Government agencies.

Table 6.7: Aged Analysis of Receivables as at December 2021 ($'000)

	0 - 30 Days	31 - 60 Days	61 - 120 Days	Over 120 Days	Total
Domestic & Commercial	105,575	36,926	33,556	207,903	383,960
Industrial	64,537	54,809	94,221	960,552	1,174,119
Street Lighting	17,505	8,221	17,523	23,147	66,396
Total	**187,617**	**99,956**	**145,300**	**1,191,602**	**1,624,475**
Of Which:					
Government	37,381	27,538	51,451	210,685	327,055
Statutory Boards	37,781	37,480	61,647	864,458	1,001,366
State Enterprises	321	18	10	27	376
Total	**75,483**	**65,036**	**113,108**	**1,075,170**	**1,328,797**

Source: T&TEC, 2021

6.4 TARIFFS

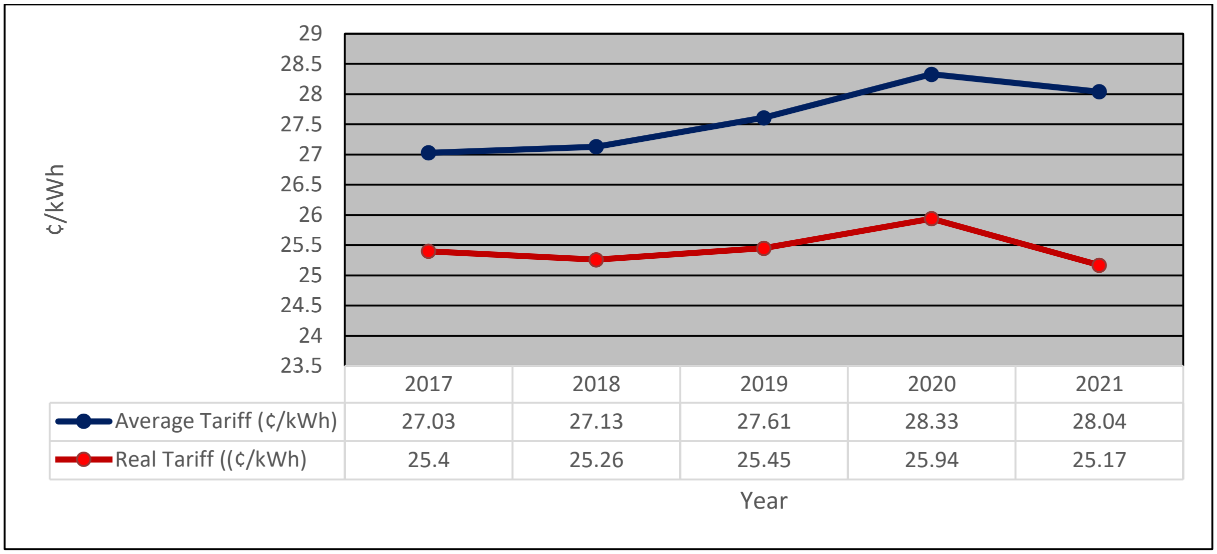
T&TEC's average electricity tariff decreased by 5% over the period 2017 to 2021, as shown in table 6.8 and figure 6.5.

Table 6.8: T&TEC's Average Tariff, 2017–2021

	2017	2018	2019	2020	2021
Average Tariff (¢/kWh)	27.03	27.13	27.61	28.33	28.04
Retail Price Index*	106.4	107.4	108.5	109.2	111.4
Real Tariff (TT¢)	25.40	25.26	25.45	25.94	24.17

*Base year – 2015; Source: Central Bank of Trinidad and Tobago
Table prepared by RIC

Figure 6.5: T&TEC Average Tariff, 2017–2021



Source: RIC

Table 6.9 shows T&TEC's energy sold and revenue between 2017 and 2021, by customer class. Residential customers' share of energy purchased increased from 35% in 2017 to 40% in 2021, with a consequential 12.8% increase in revenue generated from those sales. This occurred even while total kWh sold was declining. In the case of commercial customers their energy purchased evidenced decline of 13.7% over the five-year period, with a corresponding decline in revenue from sales of 12.2%. The share of energy consumption for commercial customers decreased from 11.6% to 10.3% over the period. For industrial customers, the share of energy consumption decreased from 52% in 2017 to 48% in 2021, while the share of revenue from the sale of electricity decreased from 49% to 33%.

Table 6.9: Energy Sold (GWh) and Revenue by Customer Class, 2017 -2021

Year	Residential		Commercial		Industrial		*Total	
	GWh Sold	Revenue $ Million	GWh Sold	Revenue $ Million	GWh Sold	Revenue $ Million	GWh Sold	Revenue $ Million
2017	2,952.04	960.83	990.36	416.07	4,479.52	847.05	8,545.32	2,308.49
2018	2,951.98	962.63	967.60	412.14	4,419.82	836.22	8,463.41	2,295.94
2019	3,082.36	1,008.83	984.39	419.38	4,208.65	806.31	8,401.57	2,320.09
2020	3,330.40	1,097.06	893.93	381.78	4,052.00	773.24	8,405.49	2,340.34
2021	3,297.58	1,084.51	854.73	365.50	3,985.89	761.67	8,267.82	2,298.82

* Total includes Residential, Commercial, Industrial and **Street Lighting**.
Source: T&TEC

The average tariffs across customer classes over the period 2017 to 2021 are shown in table 6.10.

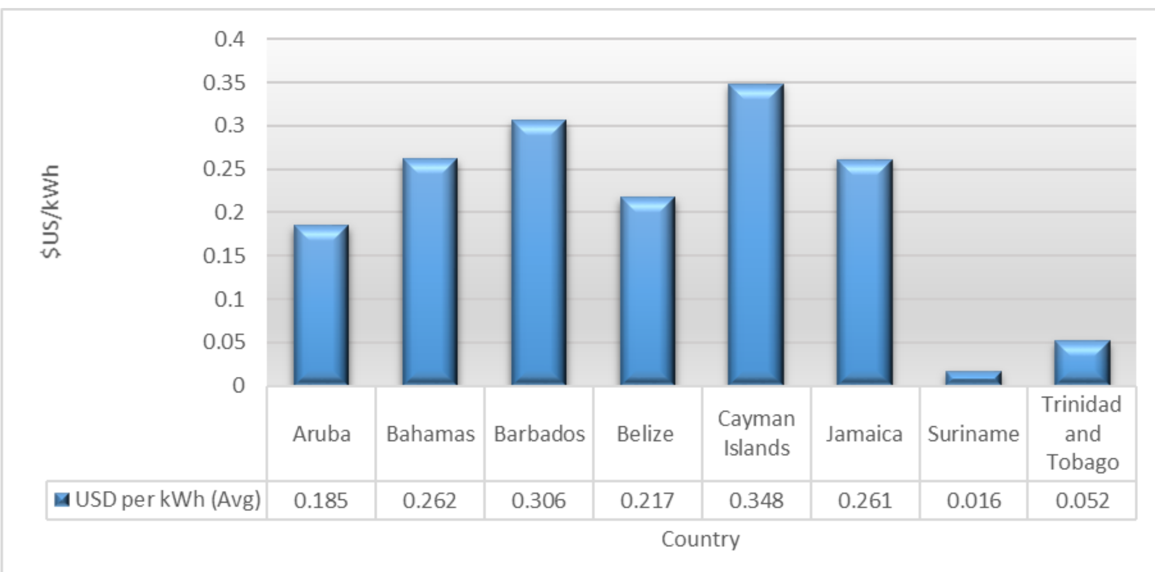
Table 6.10: Per Unit Average Revenue by Class, 2017–2021

Year	Residential Revenue / kWh TT(¢)	Commercial Revenue / kWh TT(¢)	Industrial Revenue / kWh TT(¢)	Total* Revenue / kWh TT(¢)
2017	32.55	42.01	32.76	27.03
2018	32.61	42.59	18.92	27.13
2019	32.73	42.60	19.16	27.61
2020	33.33	42.79	19.08	28.33
2021	33.17	42.71	19.11	28.04

* Total includes Residential, Commercial, Industrial and **Street Lighting**.
Source: T&TEC

Figure 6.6 below shows the average tariff per kWh (in 2021) for selected countries in the Caribbean region.[16] These average tariffs were derived using kWh sold and revenue from electricity sales across the various countries and therefore do not make any distinction by customer class. The analysis reveals that only Suriname at US$ 0.016 has a lower average tariff than Trinidad and Tobago at US$0.052/kWh.

Figure 6.6: Regional Average Electricity Tariffs (USD)



Data obtained from various sources. Figure prepared by the RIC.

[16] It should be noted that comparison of electricity prices across countries is sensitive to the different tariff schemes applied in each country and there can be significant variances (sometimes obscured) depending on fuel charges, width of rate blocks and other factors.

7 OPERATING EXPENDITURE

7.1 INTRODUCTION

Operating expenditure (Opex) covers the typical costs of running the utility and includes all staff costs, repairs and maintenance, generation, fuel and overhead costs. In conducting the second price review, one of the key objectives is to ensure that only the efficient costs of providing services are passed through into tariffs and overall prices. The allowance of only efficient levels of Opex is, therefore, a key concern for the RIC as it accounts for approximately 90% of the overall revenue requirement.

The RIC determined the efficient level of operating and maintenance costs that T&TEC would incur in PRE2 by examining the forecast Opex provided by T&TEC in its Business Plan against appropriate benchmarking[17], and considered the potential for T&TEC to make efficiency improvements. The RIC also carefully considered the ability of T&TEC to fund its operational activities and to provide reliable and quality services to customers.

7.2 OPEX REVIEW PROCESS

The RIC's expenditure review process involved the following stages:

- **Set up stage** – the preparation of the document, "**Information Requirements: Business Plan 2021-2026"** to provide guidance to T&TEC on the information requirements for the price review, inclusive of the specific requirements for Opex. T&TEC was required to provide details of actual expenditure between 2015 and 2020 and forecast Opex, together with supporting explanations and other relevant information. The requested Opex forecasts include base operating and maintenance costs, costs associated with growth in demand and costs arising from new or changed functions/obligations referred to as step changes.

[17] When benchmarking was employed, cognisance was taken of the differences between jurisdictions and the local context to ensure that there was merit in the comparison and to give consideration to T&TEC's specific operating circumstances.

- **Facilitation stage** – where advice is provided, as required, to T&TEC to ensure that the data to be submitted was consistent with the requirements of the Business Plan. The RIC commenced discussion with T&TEC to better understand their submission after it identified a range of issues, including deficiencies and inconsistencies in the information. Eliminating these deficiencies and inconsistencies proved to be a protracted process, as supporting information had to be sourced to ensure that the expenditure forecasts were internally consistent and reconcilable with the information submitted.

- **Assessment stage** – where the data were assessed to ensure that expenditure reflected the efficient cost of service provision. In doing so, the RIC also compared the various elements of cost of supply with the norms applicable to the industry.

7.3 OVERALL APPROACH TO ASSESSING OPEX

The RIC's objective is to understand what represents a reasonable allowance for operating costs. This is usually a level of costs that can realistically be expected to be incurred if the entity is run efficiently within the constraints it faces. In assessing reasonable Opex, the RIC utilised the following process/steps:

- Determining the baseline operating costs;
- Reducing baseline costs through efficiencies; and
- Specifying a generalised efficiency factor for the reduction of forecast (allowed) costs for future "unidentified" efficiencies.

Sections 7.3.1 to 7.3.3 which follow give a brief overview of these processes; the specific details relevant to PRE2 are discussed later in the Chapter.

7.3.1 Determining Baseline Opex

The baseline reflects the normal operating costs of the service provider from which it is possible to assess the impact of future cost changes. The assessment of Opex begins with an in-depth assessment of the service provider's reported actual expenditure, as provided in its audited financial statements, in a base year.[18] One-off costs that are considered to be atypical of the service provider's normal Opex are removed. In the case of T&TEC, the assessed baseline also excludes generation and fuel costs, which are based on contractual arrangements and, therefore, outside of T&TEC's control.

The RIC's assessment of normalised baseline costs separates Opex into categories[19] and seeks justification from the service provider, where necessary. This is undertaken by analysing expenditure by function, that is, the cost to provide a particular service, and by activity, that is, the cost of each activity comprising a service, as appropriate. The RIC also identifies particular significant cost items where it determines that a more detailed review would be instructive. The assessment also considers to what extent the initial results should be adjusted to take account of any special factors that may have been relevant to the service provider.

These normalised costs are then updated to year *t* (starting year) to allow for subsequent developments, including:

- costs being disallowed, if it can be demonstrated that they were imprudently, inefficiently or unnecessarily incurred;
- additional costs (step changes), arising out of new obligations/commitments; and
- inflation, demand growth and other trends in costs.

7.3.2 Assessed Scope for Efficiencies – Reducing Baseline Costs

The RIC also considers wider information and identifies cost items where it is of the view that comparison with other utilities[20] would be useful. To this end, T&TEC's overtime expenditure, absenteeism rate, etc. were compared to similar utilities in other developing countries. The RIC understands that while benchmarking can be a powerful tool, it requires accurate information and careful interpretation. Further, acceptable benchmarking requires comparisons to be like-

[18] The base year for the price review for which full information is available, that is, the starting point for setting forward allowances.
[19] This is sometimes referred to as a "bottom up" approach.
[20] This is sometimes referred to as a "top down" approach.

for-like. Thus, the RIC, recognised circumstances where it was appropriate to adjust costs to account for local factors and to account for uncertainties in the comparisons.

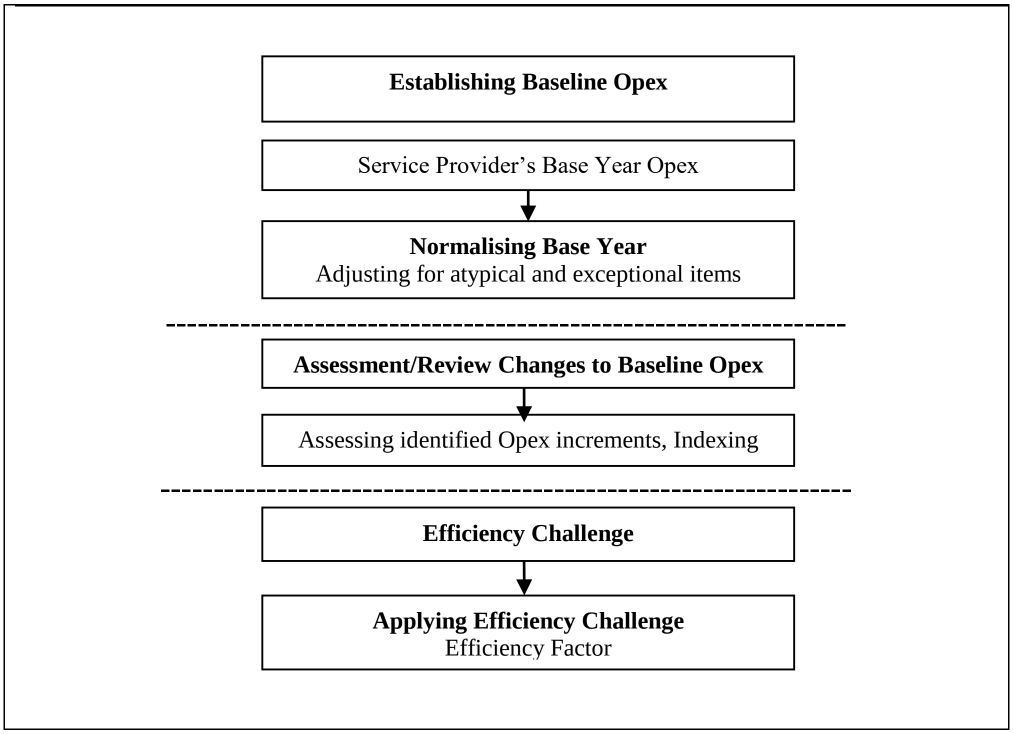
7.3.3 Specification of Generalised Efficiency Factor

Apart from specific reductions to individual items undertaken because of bottom-up and top-down analysis, the RIC believes that the service provider should be able to make further efficiency savings within the regulatory control period. These efficiency savings are not separated by line item, rather they represent a reduction in the overall revenue for Opex costs. It is the service provider that determines how these reductions in Opex are to be achieved across the various line items.

The RIC utilised a generalised efficiency factor to reflect those reductions that T&TEC is expected to achieve in its cost-of-service provision and hence in prices for services. This efficiency target is based on the concept that T&TEC should continue to improve its efficiency through innovation and the introduction of new technologies, as happens in other sectors of the economy. The RIC utilised the "rate of change" as one of the techniques for arriving at these efficiencies. The rate of change is the year-to-year change in Opex for several factors such as, expected productivity improvements in labour and other costs. The rate was established by examining the productivity achieved by T&TEC for a number of past years and thereafter, calculating future cost reductions on the assumption that at least the same rate of change (i.e. productivity improvement) will continue in the future. This potential to achieve efficiency gains was also reflected in the RIC decisions for the first control period. The RIC decided that an Opex efficiency target of 2% per annum is appropriate for PRE2.

The RIC's current approach to setting the allowed level of efficient Opex is depicted in figure 7.1 below. A detailed discussion of the approach can be found in the document, **"Approach to Setting Operating Expenditure"**, which was published, for public comments, on the RIC's website in March 2022.

Figure 7.1: RIC's Current Approach to Setting Opex



7.4 REVIEW OF OPEX OUTTURN

7.4.1 Introduction

This section examines the historical Opex undertaken by T&TEC over PRE1. The outturn has been assessed and compared with the allowed Opex by the RIC for the period. The *ex-post* assessment of Opex is utilised to inform the setting of Opex allowances for the next control period as opposed to Capex where the intent would be to claw back expenditure from the previous control period. Therefore, the main objective of the review of T&TEC's historical Opex is to assess whether T&TEC's Opex has been incurred efficiently while delivering the expected benefits for customers. This review of historical Opex was also used in the RIC's determination of the appropriate allowed Opex for PRE2.

7.4.2 Overview of Historical Opex

A comparison of T&TEC's actual Opex to RIC's allowed, for the PRE1, reveals that overall T&TEC's operating expenditure exceeded the RIC's allowed Opex by 5.6%, in nominal terms. Table 7.1 below provides a high-level summary of Opex, for the period June 2006–May 2011 according to the major line items: Conversion; Fuel; Labour; Transmission and Distribution (T&D); Repairs & Maintenance and Other T&D Expenses; and Administration and General. Actual expenditure was $601.67 million higher than approved. The RIC's allowed Opex profile provided for a gradual and cumulative increase in such expenditures to a maximum of 45.75% over that of 2006, by the end of the control period. However, in actuality, T&TEC's Opex peaked in the period June 2009–May 2010, at a maximum of 51% above the allowed 2006 Opex, thereafter falling slightly in the final year.

Table 7.1: Analysis of Actual Opex by Major Categories

Opex Item	June 2006 - May 2007	June 2007 - May 2008	June 2008 - May 2009	June 2009 - May 2010	June 2010 - May 2011	Total	Difference Actual – Approved	Approved from Actual as a Percentage of Actual[21]
Conversion:								
RIC Approved	792.66	844.08	1,050.27	1192.87	1391.51	5,271.39		
T&TEC Actual	807.85	932.06	942.38	943.05	878.69	4,504.03	-767.36	-17.04%
Fuel:								
RIC Approved	584.1	609.4	651	671.5	716	3,232.00		
T&TEC Actual	557.34	583.52	635.94	725.34	732.91	3,309.08	77.08	2.33%
Labour:								
RIC Approved	273.61	287.3	301.65	316.72	332.54	1511.82		
T&TEC Actual	337.44	355.4	363.65	494.62	528.36	2079.47	567.65	27.30%
T&D Repair, Maintenance and Other T&D Expenses:								
RIC Approved	233.83	245.49	257.53	270.43	280.97	1288.25		
T&TEC Actual	254.18	264.42	314.87	493.33	404.69	1731.49	443.24	25.60%

[21] These percentages measure errors in the forecast (RIC approved) and are given as: $\frac{(Actual\ Opex - Forecast\ Opex) \times 100}{Actual\ Opex}$

Opex Item	June 2006 - May 2007	June 2007 - May 2008	June 2008 - May 2009	June 2009 - May 2010	June 2010 - May 2011	Total	Difference Actual – Approved	Approved from Actual as a Percentage of Actual[21]
Administration & General:								
RIC Approved	134.35	137.91	140.71	144.24	147.38	704.59		
T&TEC Actual	172.53	449.99	223.47	186.22	310.39	1,053.01	348.42	33.09%
Total Expenditure:								
RIC Approved	1,796.00	1,892.34	2,166.40	2,353.35	2,617.71	10,825.80		
T&TEC Actual	1,963.27	2,175.82	2,191.06	2,711.94	2,385.38	11,427.47	601.67	5.27%

Source: RIC

Notes:

Expenditure associated with T&D Repair Maintenance and Other T&D Expenses as well as Administrative and General Expenses, includes Personnel Costs which have also been included in the Labour line item.
Total Expenditure includes other expenditure not shown, including depreciation.

In assessing T&TEC's conversion and fuel costs, which were treated as uncontrollable, adjustments were made to first reflect cost "pass-throughs" of 98% and 90% respectively. A small additional reduction of 2% was then applied.

Employee costs, which comprise wages, salaries and employee benefits, were $567.65 million above forecast. More specifically, T&TEC spent more in each year on labour than was approved. The sharp increase is attributed to increased salaries for management as a result of job evaluation exercises and the payment of back-pay associated therewith in 2009. There were similar payments to employees following new collective bargaining agreements, signed in December 2008. This also accounted, in some measure, for the higher than approved Transmission and Distribution costs and Administration and General Expenses. In addition, the extension of the 1994 T&TEC-PowerGen Power Purchase Agreement, the new treatment of depreciation under IAS17[22] and the repair of the damaged submarine cable between the islands of Tobago and Trinidad also pushed T&D and Administration and General Expenses above RIC approved amounts.

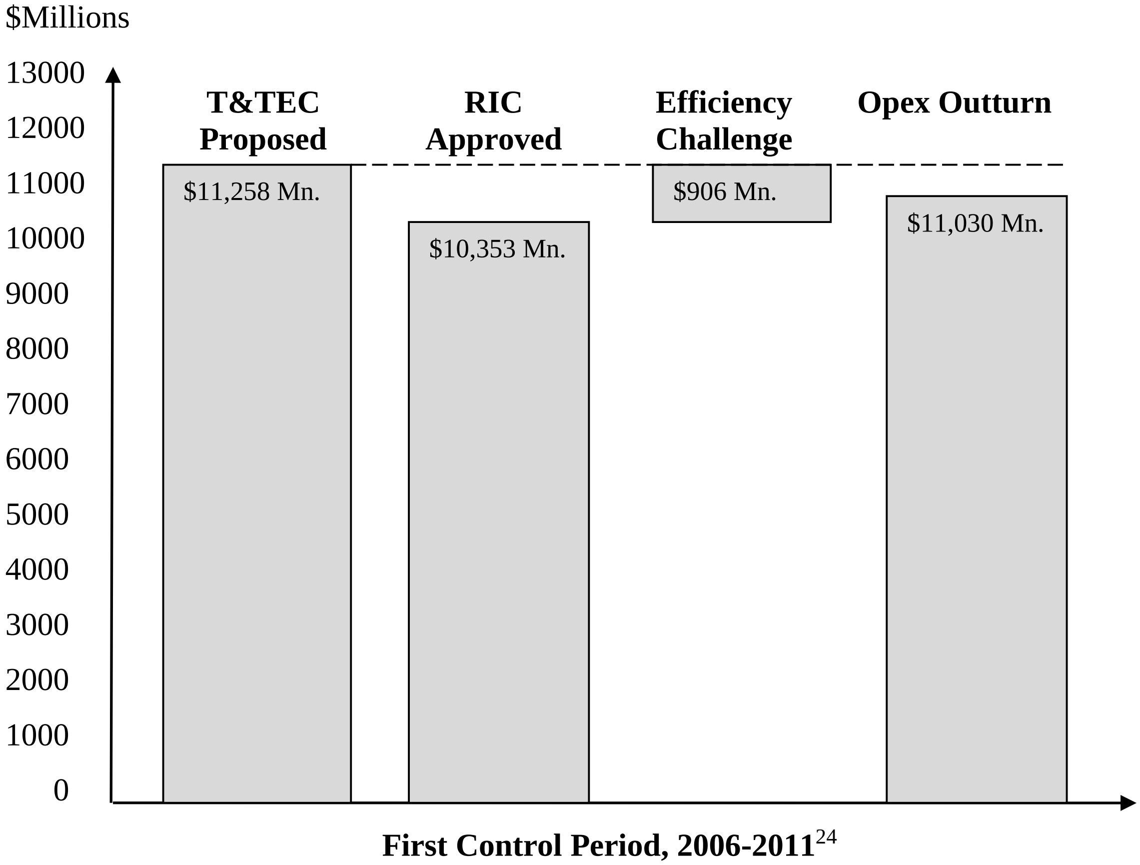
[22] International Accounting Standard 17 (IAS17) – Leases.

The increased expenditure may also be explained, in part, by T&TEC's accounting treatment for its "Retirement Benefit Obligation". At the time of the first price review, T&TEC had not yet adopted the December 2004 amendment to IAS 19[23]. Therefore, such expenditures were not catered for in the original Opex projections submitted for the 2006 Price Determination. T&TEC subsequently adopted this amended standard during the control period. Additionally, T&TEC indicated that this figure is difficult to predict, and can either be an addition to expenditure or 'reduction', but is always recorded on the expenditure side of the Income Statement. For the years 2006–2010, this item was reported as $289.6 million (expenditure), $56.03 million (expenditure), $44.6 million (gain), $57.08 million (expenditure) and $33.74 million (gain) respectively, giving a net addition to expenditure of $324.37 million.

The analysis of T&TEC's Opex performance suggests that no concerted efforts were made to undertake efficiency improvements. However, there were also some occurrences during the control period that affected T&TEC's outturn that were undoubtedly unforeseeable and therefore, outside of the control of the utility. While the RIC has noted the overspend of Opex allowance in some areas, it is the responsibility of the service provider to contain its costs to the full Opex allowance. The RIC considered this issue when assessing the appropriate allowed costs for the PRE2. Stakeholders who are interested in more detail may refer to the RIC document, **"Approach to Setting Operating Expenditure"**, which was published for public comments on the RIC's website in March 2022.

[23] International Accounting Standard 19 (IAS19) – Employee Benefits - which provided for the option of recognising actuarial gains and losses in full, in the period in which they occur, in a statement of recognised income and expense, rather than profit or loss.

Figure 7.2: RIC's Efficiency Challenge for Opex



Source: RIC

7.4.3 Lag Period (2012-2020)[25]

PRE1 ended on May 31, 2011, and hitherto the RIC has not completed a second price review hence there was no allowed (as per an approved revenue requirement) Opex for the period that followed (lag period). Notwithstanding, there is value in reviewing T&TEC's Opex over the lag period (2012–2020), to analyse trends in the various expenditure categories and make comparisons with T&TEC's actual Opex during PRE1. This analysis will give an indication of how well T&TEC managed its Opex without specific efficiency targets set by the regulator.

[24] Figures do not include depreciation.
[25] The lag period was assessed up to 2020.

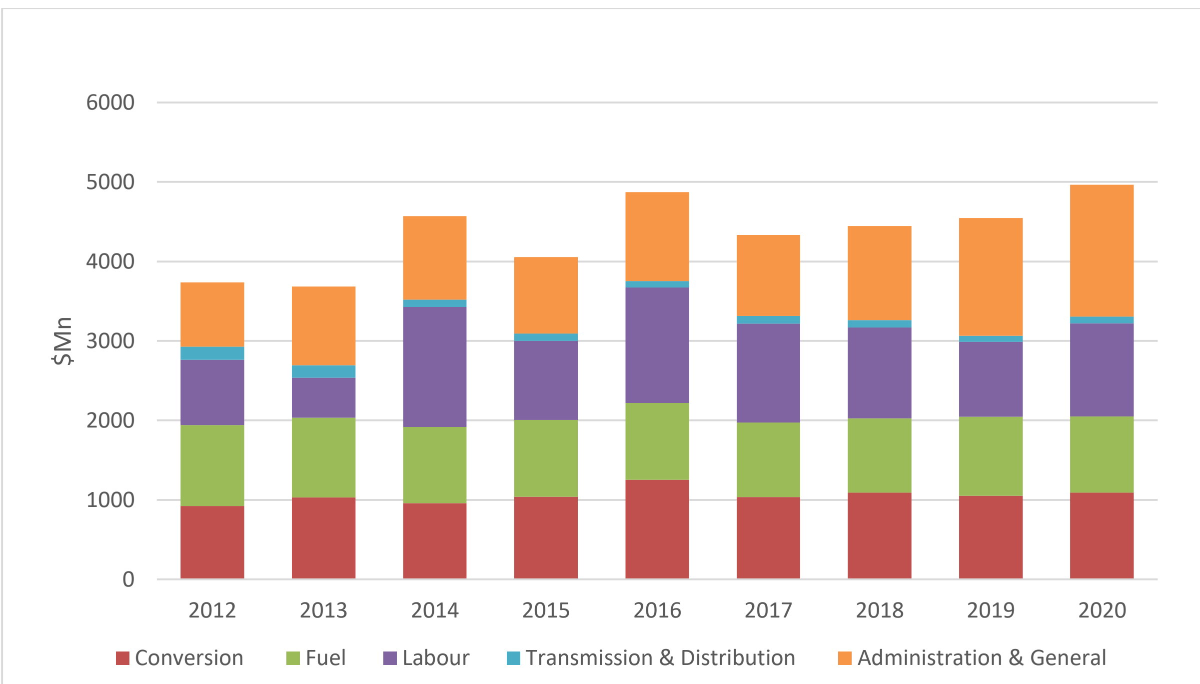
As shown in table 7.2, total Opex was $3,735.42 million in 2012 and peaked at $4,965.31 million in 2020. Total operating expenditure averaged $4,355.72 million annually over the period. The composition of these costs is shown in figure 7.3.

Table 7.2: Actual Opex by Major Categories, 2012-2020

	2012 $Mn	2013 $Mn	2014 $Mn	2015 $Mn	2016 $Mn	2017 $Mn	2018 $Mn	2019 $Mn	2020 $Mn
Conversion	922.92	1,033.12	959.53	1,038.34	1,251.67	1,036.87	1,093.21	1,051.40	1,090.48
Fuel	1,020.55	1,000.26	956.55	967.21	967.14	938.63	933.70	995.58	958.65
Labour	821.03	504.42	1,509.63	994.24	1,454.95	1,241.59	1,141.56	942.18	1,170.39
Transmission & Distribution	163.04	158.24	93.56	94.28	77.19	98.85	92.80	74.17	88.04
Administration & General	807.88	988.08	1,048.57	960.60	1,118.68	1,018.00	1,183.07	1,482.83	1,657.75
Total	**3,735.42**	**3,684.12**	**4,567.84**	**4,054.67**	**4,869.63**	**4,333.94**	**4,444.34**	**4,546.16**	**4,965.31**

Source: T&TEC

Figure 7.3: Changes in the Composition of Opex 2012-2020



Source: Figure prepared by RIC

T&TEC's conversion[26] and fuel costs, together accounted for, on average, approximately 46.85% over the period. Conversion costs increased by 18.2% between 2012 and 2020, with a low of $923 million and a peak of $1,252 million in 2016.

Fuel costs were relatively stable over the period with an overall decrease of 6.1% over the period. There was a reduction of 4.4% from 2013 to 2014, falling from $1,000 million to $957 million, due to the switch from diesel fuel to natural gas in Tobago. In 2019, there was an increase of 6.6% over the previous year, associated with the use of less efficient generating plants, as one of the combined cycle plants was out of service for a period.

Labour costs accounted for approximately 24.6% of the utility's operating expenses during the lag period. Labour costs fluctuated throughout the period, recording a low of $504 million in 2013 and a high of $1,510 million in 2014. From 2012 to 2013, there was a decrease from $821 million to $504 million (a change of 39.0%) due to pension adjustments in accordance with suggestions made by the actuaries. This was followed by a significant increase in 2014 of 199%. These fluctuations were mainly due to the payment of salary arrears with the consequent year-end adjustments to the pension plan increasing in the years that the arrears are paid and thereafter returning to normal levels.

Transmission & Distribution costs accounted for approximately 2.5% of the utility's operating expenses during the lag period. Transmission & Distribution costs evidenced consistent decline between 2012 and 2016, rebounded in 2017 and declined until 2019 before increasing in 2020. These costs peaked at $163 million in 2012, and there was a notable decline in 2019 due mainly to the decrease in tree-cutting contracted services.

Administration & General costs accounted for approximately 26% of the utility's operating expenses during the lag period. Administration & General costs fluctuated but evidenced an

[26] The accounting standard IFRS 16 Leases, which affects how lease agreements are treated in financial statements, was implemented in 2019 by T&TEC. Previously, leases were treated as either finance or operating leases. Finance leases were recognised as assets on the lessees' statement of financial position (balance sheet) and operating leases were not. This distinction has been removed and the vast majority of leases are to be classified as finance leases. This has implications for depreciation and the asset base, however, for the purposes of this paper these costs have been normalised. As a consequence, the adoption of the standard conversion costs falls into the category of "PPA Costs".

overall increase during the period 2012 to 2020. These costs increased from a low of $808 million in 2012 and peaked at $1,658 million in 2020, an increase of 105%.

7.5 REVIEW OF FORECAST OPEX

7.5.1 Introduction

The assessment of T&TEC's forecast Opex involved an examination of its proposed forecast expenditure. The RIC undertook bottom-up analysis and top-down/benchmarking analysis, where appropriate, and considered the potential for T&TEC to make efficiency gains. The sections below set out assessments of T&TEC's:

- baseline operating and maintenance costs;
- scope to reduce baseline costs through efficiencies,
- scope to improve T&TEC's level of service performance; and
- level of allowed Opex for PRE2.

7.5.2 Assessment of Forecast Opex

7.5.2.1 Baseline Costs

The assessment of the Opex to be allowed for PRE2 began with the assessment of T&TEC's baseline Opex in 2020 (the base year for the second price review) alongside a review of the Opex incurred in the prior five-year period. This assessment also considered T&TEC's PRE1 costs, its forecasts and supporting submissions for PRE2, T&TEC's historic accuracy of forecasting of line items and responses provided by T&TEC to queries posed by the RIC. In the assessment, the impacts of one-off costs and other atypical items of normal operating costs, were removed. Additions/increases to normal baseline Opex were scrutinised and necessary changes reflected. The assessment of baseline costs also took account of potential changes in Opex during the control period that the RIC considered to be outside of T&TEC's control. The assessment, at this stage, did not take account of future improvements in efficiency, as these were considered separately. T&TEC's proposed forecast of operating expenditure

(Transmission & Distribution, Administrative & General related only) amounted to $6,620.61 million over the second period, 2023-2027, as shown in table 7.3 below.

Table 7.3: T&TEC's Projected Opex Expenditure for 2023–2027 ($Mn)*

	2023	2024	2025	2026	2027	Total
Transmission & Distribution	582.62	938.54	585.20	1,188.26	614.97	3,908.59
Administrative & General	514.51	623.78	387.84	783.08	402.81	2,712.02
Total	**1,097.13**	**1,562.32**	**973.04**	**1,971.34**	**1,016.78**	**6,620.61**

*** Conversion and Fuel costs not included**

T&TEC estimated that there would be significant increases in its Opex compared to the previous period. These increases were projected in a number of areas and would be influenced by the following objectives:

- changing out of ageing plant;
- satisfying customer demands and expectations;
- reducing the number of planned outages and increasing hotline work;
- restructuring of vegetation management; and
- introduction of new materials to improve public safety.

The RIC did not fully accept T&TEC's forecasts and formed its own assessment. The RIC's allowance is considerably less than T&TEC's projections. The main areas which received close scrutiny from the RIC are discussed below.

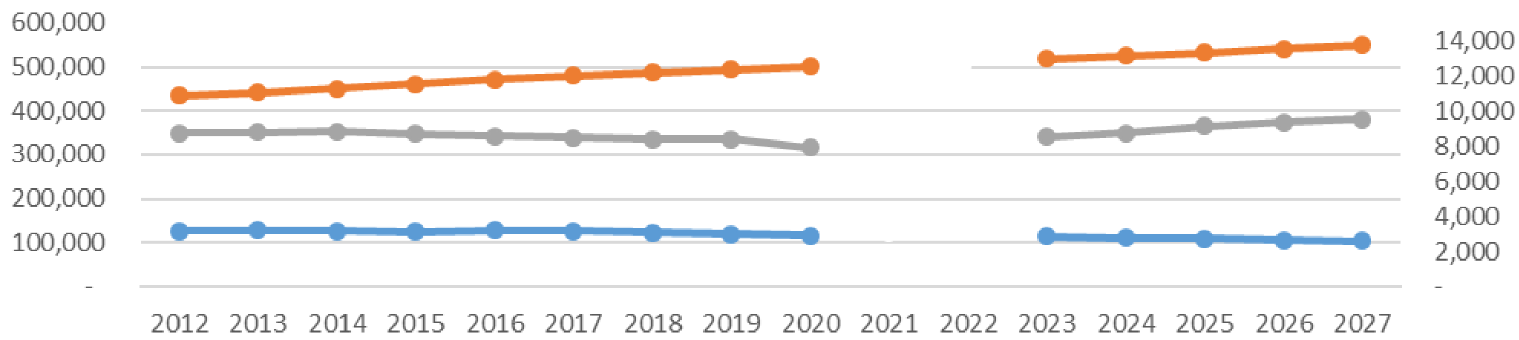
7.5.2.2 Payroll Costs

The assessment of payroll costs includes the benchmarking of wages, salaries, overtime and employee related benefits. Employee costs are a function of the number of employees and the level of wages and salaries. Employee costs account for almost 65% of the total Opex (excluding conversion and fuel costs) during PRE2.

Figure 7.4 presents a comparison of annual increases in staff levels, number of customers and sale of energy for the period 2012-2020, and a projection for the period 2023-2027.

- Staff levels decreased by 7.5% for the period 2012-2020 and are forecast to decrease by about 7.2% during 2023-2027;
- Number of customers increased by 15.5% between 2012 and 2020 and is projected to increase by 6.3% between 2023 and 2027; and
- Actual sales of energy decreased by 9.2% between 2012 and 2020 and are projected to increase by 11.8% between 2023 and 2027.

Figure 7.4: Actual and Forecasts of Staff Levels, Customer Numbers and Energy Sales as submitted by T&TEC, 2012-2027



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2023	2024	2025	2026	2027
Number of Customers	433,940	442,100	450,775	461,733	470,541	479,687	487,314	494,022	501,370	516,652	524,820	532,988	541,157	549,396
Number of employees	3,137	3,200	3,172	3,129	3,174	3,148	3,071	2,991	2,903	2,792	2,742	2,694	2,640	2,592
Energy Sales (GWh)	8,714	8,767	8,820	8,669	8,545	8,463	8,402	8,405	7,908	8,525	8,727	9,126	9,325	9,531

Number of Customers   Number of employees   Energy Sales (GWh)

Salaries and wages per employee are projected to grow by 4.7% between the period 2023 and 2027. Wages and salaries comprise 61.3% of total payroll costs, with overtime and employee benefits accounting for 8.3% and 26.7%, respectively.

In its analysis and assessment of payroll costs, the RIC utilised the adjusted average of salary per employee over the period 2023-2027, forecast employee numbers over the PRE2 period and estimated a 2% increase in salaries and wages annually for PRE2. The 2% estimate took into account the current economic situation in the country as well as the fact that T&TEC's employees were awarded a 10% increase for the period 2012-2014. Additionally, consistent with the historical figures, the RIC assumed an efficient recurring level of overtime of 7% and efficient recurring level of sickness and absenteeism of 3.7%. **The RIC expects T&TEC to adhere to these targets and any variation from these may lead to revenue adjustments at the beginning of the third control period (PRE3)**.

The RIC also examined T&TEC's labour efficiency, as it relates to the composition of its crew sizes. Further details are provided in the Appendix to this chapter. The RIC has noted that the typical crew size for several electric utilities in the United States is two (2). The crew foreman is required to operate the utility's vehicle. In other Caribbean jurisdictions the linesman must have an appropriate heavy-duty drivers' permit by the completion of his/her probation period, which then enables him/her to operate the service vehicle. This eliminates the need for a designated driver within T&D job crews.

RIC's view is that T&TEC can improve its productivity by re-examining the size and composition of its linesman crews. The RIC is aware that the configuration of crews is subject to agreements with it unions, but expects T&TEC to examine its options for achieving productivity gains through rationalisation of its linesman crews, inclusive of the elimination of the position of a designated driver.

T&TEC is therefore required to submit a detailed Report to the RIC, within 18 months of the publication of the Final Determination for PRE2, indicating what steps had been undertaken and what are proposed to improve efficiency with respect to the size and

composition of its T&D crews. T&TEC must also outline the changes to be made in the future regarding the composition of linesman crews for typical construction and maintenance jobs of the utility.

To ensure that customers do not continue to pay for any inefficiencies, the RIC has not included the cost of designated drivers into allowed Opex from the third year of the regulatory control period. The RIC has also included an overall efficiency adjustment of 1.5% to the overall cost allocated to maintenance crews from year three.

On the basis of the above discussion, the RIC has approved the following as employee costs for the years 2023 to 2027 (table-7.4). Overall, it is expected that payroll costs will decrease by 2.8% over the period 2023-2027 provided T&TEC achieves efficiencies.

Table 7.4: Requested and RIC's Allowed Employee Costs, 2023–2027 ($Mn.)

	T&TEC Requested	RIC Approved	2023	2024	2025	2026	2027
Wages	1,789.92	1,372.05	293.62	303.58	282.81	258.97	233.07
Salaries	1,726.61	2,148.27	408.08	423.33	434.73	440.56	441.57
Overtime	402.05	246.42	49.12	50.88	50.23	48.97	47.22
NIS	-	213.20	42.50	44.02	43.46	42.36	40.86
Employee Related	1,503.09	386.68	73.45	76.20	78.25	79.30	79.48
Charged to Revenue	5,421.67	4,366.62	866.77	898.01	889.48	870.16	842.20

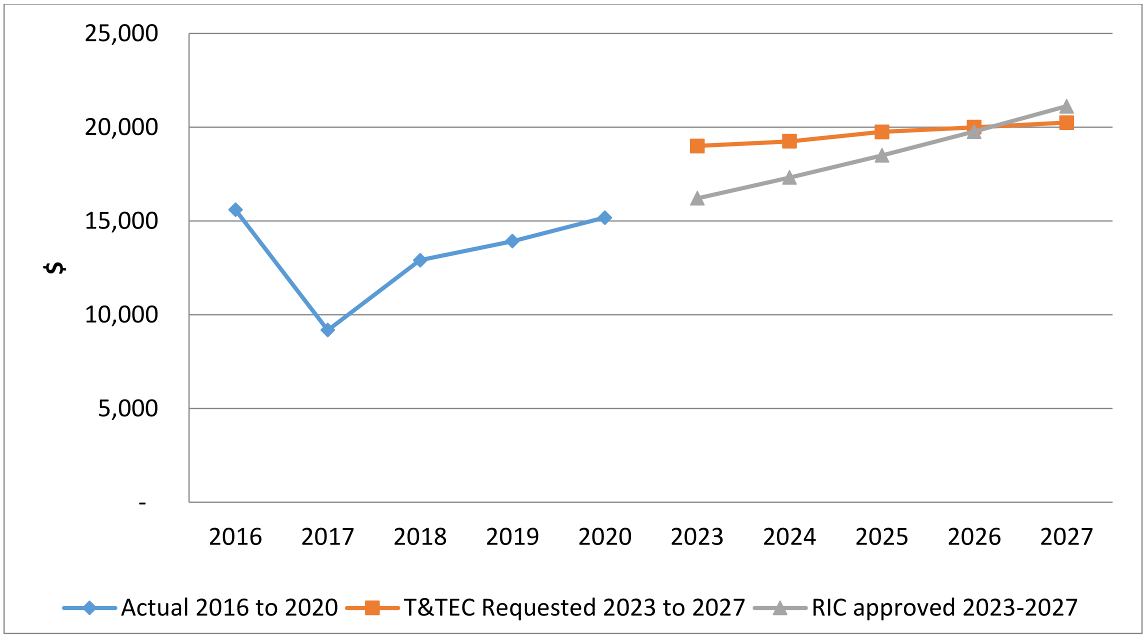
7.5.2.3 Rates, Taxes and Insurances

This expense item mainly consists of land taxes paid by T&TEC for property owned such as offices, substations and any parcel of land owned and utilised for the transmission and distribution of electricity. The baseline for this item was determined from historical trends in capital expenditure over the period 2016 to 2020. The average increases in rates, taxes and insurance over PRE2 is projected to be 30.2%.

Figure 7.5 shows T&TEC's Actual expense (2016 to 2020) and forecasts for the period under review. This information was compared with the RIC's allowed expenditure for

PRE1. The RIC's allowed expenditure for PRE2 will provide T&TEC with the necessary funding to cover its rates, taxes and insurance, as this category of expenditure fluctuates according to any land purchases made by T&TEC or legislative changes to adjust land taxes in the country.

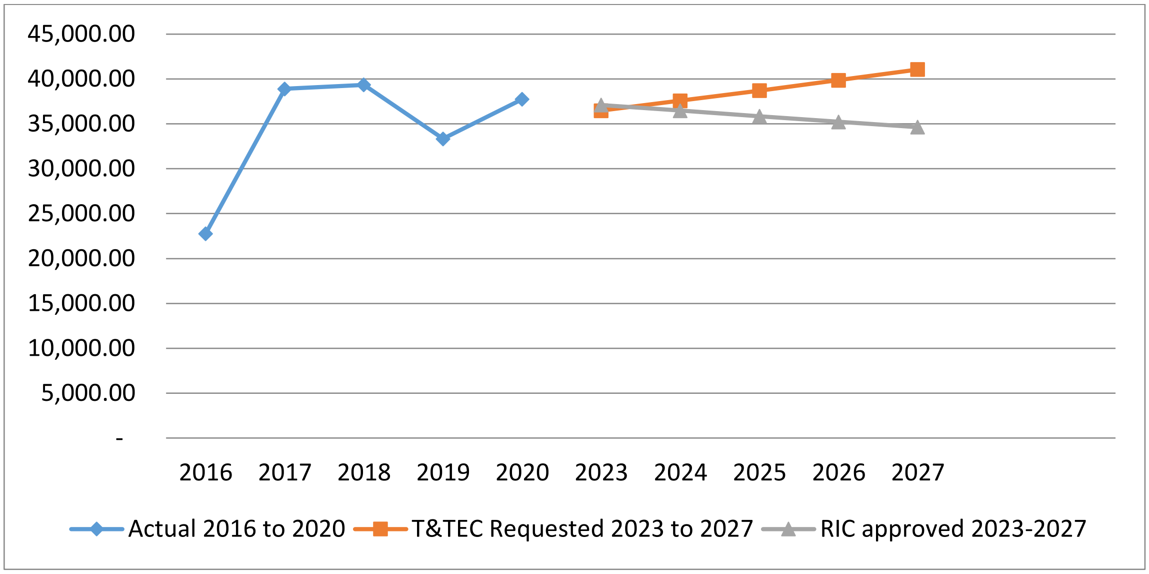
Figure 7.5: Rates, Taxes and Insurance Expenditure ($'000)



7.5.2.4 Materials

This expense mainly consists of consumables utilised by T&TEC to carry out typical business activity. The baseline expenditure was determined using historical trends, projected growth in employees and business activity. It is expected that this expense will decrease by 6.7% over the control period 2023 to 2027 (figure 7.6).

Figure 7.6: Materials Expenditure, 2023–2027 ($'000)



7.5.2.5 Services/Maintenance

The expenditure under this category is used to carry out preventative maintenance and restore damaged items used in the transmission and distribution of electricity. The planned expenditure submitted by T&TEC was not supported by any specific plans. However, the RIC has approved an amount of $558.9 million for the period 2023–2027 (table 7.5) utilising generally accepted benchmarks. The RIC has allowed 1.5% of gross fixed assets for transmission assets and 2.5% of gross fixed assets for distribution assets as maintenance expenditure. Adequate expenditure for this category will lead to enhanced performance of the network system overall, as well as directly impact on the reduction of consumer complaints in the areas of damaged appliances, outages and low voltage problems. **The RIC will require T&TEC to submit its actual expenditure in this category annually**.

Table 7.5: RIC's Allowed Maintenance Expenditure ($Mn)

	2023	2024	2025	2026	2027
Transmission Maintenance	13.50	14.37	15.05	15.61	15.78
Distribution Maintenance	90.67	95.13	96.94	99.13	102.73
Total	**104.17**	**109.50**	**111.99**	**114.74**	**118.51**

7.5.2.6 Advertising and Marketing/Sponsorship

T&TEC regularly undertakes various forms of community sponsorship, supports its sports club and engages in brand marketing. The RIC understands T&TEC's desire for corporate social responsibility. In the circumstances, the RIC encourages T&TEC to pursue the decisions which will enable it to fund these programs out of the surpluses it has earned from efficiency improvements. Therefore, the RIC has disallowed from the revenue requirement, costs in this area in the amount of $6.73 million for PRE2.

7.5.2.7 Prescriptive Annual Targets

Regulators use different techniques to benchmark Opex against other utilities. It is always difficult to benchmark in the absence of local and/or regional comparators. The benchmarking process requires not only accurate information and like-for-like comparisons, but the results require careful interpretation. Despite these difficulties, benchmarking still provides a useful check to ensure that Opex allowance approved by the RIC is efficient and consistent with international comparators. In this regard, **T&TEC will be required to undertake a study of Opex cost efficiency and present the report to the RIC within 30 months of the publication of the final determination**. Some of the areas that should be included in the study are:

- unit cost of faults per km;
- unit cost of tree cutting; and
- non-network Opex cost per unit.

Given the above-mentioned difficulties in selecting suitable comparators, the RIC mainly relied on using and setting prescriptive annual targets in some areas of T&TEC's operations for the PRE2 period. The RIC expects that efficiency improvements will be manifested largely through the delivery of better levels of service. However, it is important that T&TEC maintains its focus on costs, and makes every effort to outperform allowed Opex over the period as a whole.

The figures provided above include savings relative to T&TEC's submission and specific reductions related to individual categories of expenditure. However, the RIC believes that T&TEC should be able to make further efficiency savings of 2% annually during the period 2023 to 2027. These savings reflect annual productivity improvements and have not been separated by category. It is a reduction in the overall revenue associated with operating costs and has been included within the approved revenue detailed in Chapter 11. It will be left to T&TEC to determine how these reductions in Opex will be achieved across the various line items.

Level of Allowed T&D Opex

The level of T&D Opex that the RIC proposes to allow during PRE2 is shown in table 7.6 below. The RIC considers that this level of Opex is robust and should enable T&TEC sufficient scope to outperform over the regulatory control period.

Table 7.6: Requested and RIC's Allowed T&D Opex, 2023–2027($Mn)

	T&TEC Requested	**RIC Approved**	**2023**	**2024**	**2025**	**2026**	**2027**
Labour Cost	5,421.67	4,366.62	866.77	898.01	889.48	870.16	842.20
Rates, Taxes and Insurances	98.25	92.92	16.21	17.32	18.50	19.77	21.12
Materials	193.69	179.29	37.10	36.47	35.85	35.24	34.63
Maintenance /Services	885.28	558.91	104.17	109.50	111.99	114.74	118.51
Rents	21.73	21.73	4.10	4.21	4.34	4.47	4.62
Subtotal	**6,620.61**	**5,219.47**	**1,028.35**	**1,065.51**	**1,060.16**	**1,044.38**	**1,021.08**
Less Promotional Cost	-	6.73	2.43	1.01	0.98	1.11	1.20
Total T&D before Efficiency Savings	**6,620.61**	**5,212.74**	**1,025.92**	**1,064.50**	**1,059.18**	**1,043.27**	**1,019.88**
Less Efficiency Savings (2% per annum)	-	104.26	20.52	21.29	21.18	20.87	20.40
Total Approved T&D Expense	**6,620.61**	**5,108.49**	**1,005.40**	**1,043.21**	**1,038.00**	**1,022.40**	**999.48**

7.5.2.8 Conversion Costs

Two of the major cost components of T&TEC are the cost of power (conversion cost) and fuel cost, comprising approximately 41% of T&TEC's total Opex. Conversion and fuel costs are considered uncontrollable costs, that is, costs over which the actions of the utility have little or no effect, hence they are generally treated as pass-through. These costs are also subject to long-term contractual agreements (Power Purchase Agreements).

On the basis of its assessment of growth in demand, T&TEC submitted forecasts for conversion costs from all the generators. In the case of conventional generation this is comprised of both capacity and energy payments. The generation coming from the proposed Solar PV plants comprise energy payments only. The RIC reviewed T&TEC's requested costs for capacity payments and took cognisance of its decision in PRE1, to allow less than 100% pass-through of conversion costs. At that time the RIC was of the view that an incentive needed to be provided to encourage renegotiation of the existing PPAs. The RIC's view is that a **98% pass-through of capacity payments and 100% pass-through on the energy component of conversion costs is appropriate for PRE2**. With respect to the solar PV plants, it is anticipated that these will be operational from 2025 and the RIC has provided for energy payments. The RIC expects to monitor these costs closely and will make necessary adjustments at the time of its annual tariff adjustment if the Solar PVs are not commissioned as anticipated. Table 7.7 shows the conversion costs projected by T&TEC and the application of the RIC's allowance of those costs.

Table 7.7: Forecast of allowed Conversion Costs, 2023–2027($Mn)

		Capacity		Energy		RIC Approved	
Year	**Contracted Capacity**	**T&TEC's Requested ($)**	**98% RIC Allowed (S)**	**Traditional ($)**	**Solar PV ($)**	**Total Energy (S)**	**Total Conversion ($)**
2023	1,754	1,764	1,729	36	0	36	1,765
2024	1,754	1,787	1,752	37	0	37	1,788
2025	1,754	1,816	1,780	38	79	117	1,897
2026	1,754	1,835	1,798	39	80	119	1,917
2027	1,754	1,860	1,823	40	81	121	1,943

7.5.2.9 Fuel Costs

Under the terms of the Power Purchase Agreements (PPAs), T&TEC has to pay for the fuel that is converted into electricity by the generators. T&TEC buys fuel from the National Gas Company (NGC) at a pre-determined price that is influenced by the Government. The RIC has used a fuel price in keeping with T&TEC's assumption in its Business Plan (T&TEC has indicated it is based on guidance it has confirmed it has received from the Government) and an escalation factor of 3% per annum in its revenue calculation.

T&TEC's fuel costs are dependent on the unit price paid for the fuel and the volume of fuel consumed in the generation of electricity. The volume of fuel consumed depends on both the demand for electricity and the efficiency of the conversion of the fuel to electricity. The heat rate is a measure of the thermal efficiency of a generation plant to convert fuel into electricity. It is the amount of heat supplied (from the fuel source) per kilowatt of energy produced, and is commonly expressed in BTU per kWh (or KJ per kWh). Improving the efficiency of the conversion process allows for a reduction in the volume of fuel consumed and consequently the expenditure on fuel. The RIC had allowed 90% pass-through of fuel costs for the first control period and had identified several areas for improvement in the heat rate in order for T&TEC to save on fuel costs.

There have been changes in the generation matrix since the last determination, and T&TEC had put measures in place for the improvement in the overall system heat rate. T&TEC also made reasonable efforts to contractually obligate the generators to be as efficient as possible. Consequently, the corresponding amount of fuel consumed by the generation plants, to meet the overall electricity demand, was lower than previous requirements. The changes and measures instituted by T&TEC included:

- negotiating with PowerGen to reduce the overall heat rate of its plants from 14,700 kJ/kWh down to 14,000 kJ/kWh or to face a penalty;
- reducing the amount of electricity taken from PowerGen to meet the overall demand and making up the demand from generators with more efficient machines;
- the full commissioning of the TGU combined cycle operations in 2012, which yielded an optimal heat rate for the plant in the range of 10,000 kJ/kWh; and
- utilising the Cove Plant in Tobago with a maximum capacity of 64 MW and a plant heat rate of approximately 9,000 kJ/kWh.

The RIC will allow a fuel cost pass-through of 95% which is greater than the amount allowed in PRE1. The fuel costs projected for the second regulatory control period and the RIC's allowed costs are presented in table 7.8.

Table 7.8: Forecasts of Fuel Costs, 2023–2027($Mn)

Year	T&TEC Projected	RIC Allowed Fuel Cost (95%)
2023	1,844.46	1,752.22
2024	1,957.62	1,859.74
2025	2,129.87	2,023.37
2026	2,252.12	2,139.51
2027	2,380.14	2,261.13

A major issue of concern to the RIC is the failure of T&TEC to honour its contractual monthly payment arrangements to NGC. The RIC strongly recommends that T&TEC remains current in settling its debt related to gas usage and therefore, the following measures will apply:

- T&TEC should promptly provide the RIC with its quarterly report, including details related to the status of payment to NGC; and provide details of its intention to cure any breaches in its payment to NGC.
- Should T&TEC be unable to cure its breaches, the RIC will, after discussions with T&TEC, make a decision on whether it will make adjustments to T&TEC's allowed expenditure of this line item.

7.5.2.10 Conclusions on Total Opex

The RIC's judgment is that the forecasts of Opex provided by T&TEC did not reflect efficient cost of service in some areas. The RIC has, therefore, prepared its own forecast of efficient costs sufficient for T&TEC to provide services at higher than current levels. The RIC has allowed increased expenditure in the operational areas, where necessary, and increased expenditure levels for repairs and maintenance. However, the RIC has also made a number of significant reductions in the Opex amounting to $2,220 million overall for the period 2023-2027 (or $444 million annually), notably in relation to:

- generation (conversion) costs, which have been lowered by $181 million for the period 2023–2027 (or $36 million annually);
- fuel costs, which have been lowered by $528 million for the period 2023–2027 (or $106 million annually);
- total projected payroll costs which have been lowered by $1,055 million for the period 2023–2027 (or $211 million annually);
- marketing/sponsorship expenditure amounting to $6.73 million for the period 2023–2027 has been disallowed; and
- The RIC has also included a 2% (non-compounding) efficiency factor, based on the operating efficiency improvements expected for the period 2023-2027, thereby reducing the T&D costs by $104.25 million.

The RIC's total operating expenditure is set out in table 7.9. These forecasts are used in the calculation of the total revenue requirement in Chapter 11. The RIC believes that it has allowed for a reasonable overall level of operating costs likely to be incurred in improving the level of service provided to customers.

Table 7.9: Determination of Total Operating Costs, 2023-2027 ($Mn)

	T&TEC Requested 2023–2027	RIC Allowed 2023–2027	2023	2024	2025	2026	2027
Conversion Costs	9,492.37	9,311.11	1,764.99	1,788.45	1,896.88	1,917.48	1,943.31
Fuel Costs	10,564.19	10,035.97	1,752.22	1,859.74	2,023.37	2,139.51	2,261.13
Total T&D	6,621.61	5,108.49	1,005.40	1,043.21	1,038.00	1,022.40	999.48
Total Opex Charged to Revenue	**26,677.17**	**24,455.57**	**4,522.61**	**4,691.40**	**4,958.25**	**5,079.39**	**5,203.92**

7.6 REPORTING FRAMEWORK FOR OPEX

During its review of Opex the RIC experienced some challenges attributable to the lack of clear separation of some cost items by activity and the need for Opex costs to be split into individual costs/activity. To address these issues and as part of its efforts to ensure that T&TEC improves the quality and reliability of its Regulatory Accounts (RAGs), the RIC will be collaborating with T&TEC to establish a more comprehensive reporting framework for Opex costs. Furthermore, as an input to determining efficient costs and setting of price controls in the future it would be useful to benchmark, in greater detail, T&TEC's Opex expenditure against expenditure incurred by similar utilities elsewhere. For example, three measures of unit Opex costs that may be appropriate are: Opex per network length (kilometre); Opex per GWh; and Opex per customer. Inadequate information is available at this time to derive reasonable estimates of these efficiency indicators and the RIC will work with T&TEC to improve this area. The RAGs that have been agreed to with T&TEC are included in Chapter 9.

Appendix

Examination of T&TEC's Labour Efficiency – Crew Sizes

Over the period 2012 to 2020, T&TEC's staff has decreased from 3,137 to 2,903 (7.5%). T&TEC's labour productivity over the same period has improved, as demonstrated by an increase in its customer-per-employee ratio from 158 in 2011 to 176 in 2021. T&TEC's ratio of employee per thousand customers is relatively high when compared to other electric utilities, as seen in table 1 below. For instance, the Jamaican electricity utility (JPS), with a much larger customer base than T&TEC, has a significantly lower ratio of employees per thousand customers. When compared to the Saudi Electricity Company, which operates in a similarly industrialised nation as Trinidad and Tobago with large industrial customers, T&TEC's employee per thousand customers is high.

Table 1: Customer per employee for selected countries

Utility	Country	Staff Numbers	Customer Numbers	Customers per employee	Employees per thousand customers
T&TEC	Trinidad and Tobago	2,888	508,892	176	5.7
LUCELEC	St Lucia	276	70,744	256	3.9
JPS	Jamaica	1,300	683,887	526	1.9
DOMLEC	Dominica	210	35,702	170	5.9
Caribbean Utilities Co.	Cayman Islands	239	32,000	133	7.5
Florida Light and Power	USA	9,100	5,700,000	626	1.6
The Hawaiian Electric Companies	USA	2,504	470,612	187	5.3
Scottish and Southern Energy	UK	12,489	3,800,000	304	3.3
Saudi Electricity Company	Saudi Arabia	33,437	10,122,895	303	3.3

Source: Derived by the RIC

In addition to specialised equipment, significant labour resources are required for the operation and maintenance of a reliable transmission and distribution (T&D) network. The deployment of suitable staff for maintenance and overhead line works impacts on the overall productivity of the utility. One of the factors that directly impacts labour productivity is scheduling the right size crew for the job. In general, the conventional thinking is that smaller crew sizes are more productive; however, analysis suggests that utilities change their crew composition to fit specific jobs. A survey of utility crew productivity practices in the United States undertaken by First Quartile Consulting[27] suggests that even though one-person crews are used for simpler overhead jobs, the most common practice is to send a two-person crew for overhead service (from an existing overhead transformer). The RIC's research has confirmed that the typical crew size for several electric utilities in the United States is two. The crew foreman is responsible for driving the utility's vehicle to the jobsite. This crew size is typical for transformer installation, streetlight repair and trouble-calls. New overhead line construction or new pole installations are often contracted out by many utilities in the United States, therefore, the contractors have control of their crew size. In the case of transmission line work and some line maintenance, multiple two-man crews may be used.

The RIC has examined T&TEC's linesman crew sizes for typical construction and maintenance jobs to assess efficiency in its use of labour for such work, in particular, the typical crew sizes deployed by T&TEC for various types of jobs. [28] As seen in table 2 below, T&TEC's crew size for overhead line works is notably different in its inclusion of a designated driver compared to other jurisdictions in the region. In the other jurisdictions, the linesmen must have the appropriate heavy-duty drivers permit by the completion of their probation period, which then enables them to drive the service vehicle. This eliminates the need for a designated driver within T&D job crews.

[27] https://www.power-grid.com/customer-service/benchmarking-results-t-d-crew-size-and-equipment-analysis/

[28] The crew sizes used by T&TEC conform to the registered agreements between the majority trade union and T&TEC.

Table 2: Benchmarking of typical crew composition by job type

Utility	Job Type					
	Overhead line and Emergency Crews	Cable Crew	Connection Crew	Corrective Maintenance	Live Line Activity	Standard Crew Size
T&TEC (Trinidad and Tobago)	**Five (5) man crew** including: One (1) crew supervisor Three (3) linesmen **One (1) driver**	**Five (5) man crew including:** One (1) supervisor Three (1) jointers **One (1) driver**	**Five (5) man crew including:** One (1) supervisor Three (3) linesmen (two in the case of disconnection **One (1) driver**			
JPSCO (Jamaica)	**Two (2) man crew (No designated driver)**			**Eight (8) man crew (No designated driver)**	**Five (5) man crew (No designated driver)**	
DOMLEC (Domnica)						**Five (5) man crew (No designated driver)**
BL&P (Barbados)						**Two (2) person crew (No designated driver)**

Source: Compiled by the RIC

The RIC understands that both the availability of equipment and suitable staff is crucial to the operation and maintenance of a reliable transmission and distribution (T&D) network and has allowed revenue for T&TEC to expand its fleet of specialised vehicles that are utilised for the construction and maintenance of T&D lines. In addition, the RIC has made financial provisions to support T&TEC's thrust towards automation of various components along their T&D network, including improvement in their SCADA management system. Through the revenue requirement, the RIC will continue its support for T&TEC's investment in equipment that will improve their response time to trouble reports and overall efficiency of operations. The RIC's view is that T&TEC can improve its productivity by re-examining the size and composition of its linesman crews, inclusive of the elimination of the position of a designated driver.

8 CAPITAL EXPENDITURE

8.1 INTRODUCTION

The allowance for capital expenditure (Capex) within the revenue requirement is provided *ex-ante*[29] based on a detailed review of the service provider's historical performance and efficiency of past Capex, and a rigorous examination of forecast Capex. When setting the Capex allowance, the RIC must have regard to its duties and obligations as defined in the RIC Act. In particular, the RIC must strike a balance between incentivising efficient behaviors and ensuring that service providers are able to finance their Capex programme and earn sufficient return. In addition to the revenue allowance, adjustment mechanisms are also included in response to changes in the Capex plan. At each price control period, the RIC can also undertake an *ex-post* efficiency assessment[30] of Capex and can retrospectively allow or disallow Capex that was efficiently or inefficiently incurred.

Capital related costs can account for a very significant portion of total costs of a service provider. As a result, such costs can have a notable impact on the final prices paid by customers. Capex enters the revenue requirement of the service provider indirectly through the return on capital and through the return of capital (or depreciation). More specifically, past Capex, deemed to be efficiently incurred, is included in the starting RAB and the forecast Capex is added to the forecast of the annual RAB for the succeeding control period. The inclusion of only efficient and prudent Capex in the RAB, ensures that customers do not pay for Capex that is incurred from poor investment decisions. Therefore, the regulator's decision vis-à-vis the appropriate level of Capex to be allowed into the RAB, is a critical one. To determine the amount of past and forecast Capex that should be included when rolling forward the value of the RAB, the RIC assessed whether:

- past Capex was prudent, and
- forecast Capex for PRE2 is also prudent and efficient.

[29] Allowances for Capex set in advance of when the expenditure on capital projects actually occurs.
[30] Assessment of events after they have occurred, inclusive of the results/outcomes.

8.2 CAPEX REVIEW PROCESS

In establishing Capex requirements for T&TEC, the key issues for the RIC are to ensure that:

- Capex reflects the level of capital expenditure that would be undertaken by an efficient service provider;
- there is no evidence of unnecessary or inappropriate Capex;
- there was evidence of, and consistency with, a well-developed asset management plan, and processes that demonstrated that forecasts took account of the planning horizon which extends beyond the five-year control period;
- 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;
- the service provider's Capex forecasts are credible in light of the outturn results; and
- the proposed programme of Capex is deliverable within the five-year control period.

As in the case of Opex, the expenditure review process for Capex consists of the same three stages; set up stage, facilitation stage and assessment stage. T&TEC was, therefore, required to provide details of Capex forecasts, 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 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 and network control.

After preliminary analysis of the information, the RIC identified a number of anomalies and aberrations that required clarification. Subsequently, the RIC discussed the submission with

T&TEC to improve its understanding. The process to eliminate the anomalies was protracted, as supporting information, such as demand forecasts, remaining asset lives, network reliability, quality targets and long-term asset management plans, had to be sourced from T&TEC to ensure that the expenditure forecasts were internally consistent and reconcilable with the information submitted.

8.3 APPROACH TO ASSESSING CAPEX

The overall aim of assessing the service provider's Capex is to ensure that proposed investments are necessary, efficient and should be funded within the price limits. The assessment is generally undertaken utilising a number of tools and methods.

The common forms of incentive-based regulation set *ex-ante* allowances for Capex when calculating the price limits. The standard approach is to review the service provider's Capex forecast submitted in its business plan, primarily through bottom-up analysis. An adjustment for achievable efficiencies is applied, generally using benchmarking.

In order to assess T&TEC's proposed Capex, the RIC adopted a relatively intensive review of the projected projects. The steps undertaken included:

- Evaluating the reasonableness of the proposed Capex by performing:
    - (i) **Efficiency Tests** – to determine if the proposed Capex was representative of the best way to meet customers' needs for services.
    - (ii) **Prudency Tests** – to establish whether the decision to invest is prudent, given the particular and specific circumstances at the time.
    - (iii) **Used and useful Tests** – to examine whether the particular assets/equipment/plant are utilised in, and contribute to, the provision of the particular service.

- Engaging with T&TEC throughout the exercise to obtain the necessary information to undertake a thorough assessment. This facilitated the bottom-up assessment of the capital programme and provided the rationale for the decisions taken, concerning the selection and execution of projects under the programme.

- Categorising the Capex according to four major categories: Transmission, Distribution, Other Network Related and Non-Network Related projects, thereby allowing an in-depth analysis of the level and the timing of the proposed investments.
- Undertaking an *ex-post* review of T&TEC's Capex for PRE1.

In PRE 1, the RIC included the following measures to incentivise efficient Capex:

- a financial incentive to T&TEC through the adoption of an Efficiency Carryover Mechanism, which allows T&TEC to retain a share of efficiency gains[31], in the delivery of the capital programme for the control period. Such financial incentive mechanisms are used to encourage utilities to incur efficient expenditures.
- a monitoring programme that requires quarterly and annual reporting by T&TEC on its capital expenditures for PRE1.

A detailed discussion of the RIC's overall approach can be found in the document, **"Approach to Assessing Capital Expenditure for Price Reviews"**, which was published for public comments in May 2021.

8.4 REVIEW OF CAPEX OUTTURN

8.4.1 First Regulatory Control Period (June 01, 2006, to May 31, 2011)

The main objectives for the review of T&TEC's historical Capex were to assess whether the Capex had been incurred efficiently, and the expected benefits had been achieved. The following activities were performed:

- comparing the outturn Capex with the RIC's allowed Capex;
- understanding the differences between the RIC's allowed Capex and the outturn Capex;

[31] Efficiency gains are essentially savings in Capex resulting from completion of projects below forecasted costs, where outputs have not been delivered late or at the expense of deterioration in service to customers.

- assessing cost drivers and their impact on performance of the Capex programme and considering any requests for efficiently incurred cost increases; and
- assessing Capex projects required by the Government but not included in the RIC's allowed Capex, as this may have had an impact on T&TEC's capacity to deliver the full Capex programme allowed by the RIC.

T&TEC spent approximately $1,944.04 million on capital works/projects over the period, of which, $738.60 million was spent on projects under the Government's Public Sector Investment Programme (PSIP), and for ring-fenced projects.[32] These capital works should not have been funded by tariff revenues, but by the Government. It is noteworthy that of the $738.60 million spent by T&TEC on these capital works/projects, only $33.70 million in funding was provided by the Government. The quantum of expenditure on these projects for which funding was neither allowed by the RIC, nor fully provided by Government, undoubtedly affected T&TEC's ability to carry-out the allowed Capex programme for PRE1.

The amount spent by T&TEC on RIC allowed Capex projects for PRE1 exceeded the quantum allowed by the RIC for the period. More specifically, while the RIC allowed a total of $800.00 million for Capex over PRE1, T&TEC reportedly spent $1,205.44 million, approximately $405 million over the allowed amount. It is important to note that while T&TEC spent less than the allowed Capex for the each of the first four years of the regulatory control period, it reported expenditure totalling $758.94 million on RIC allowed projects in the fifth year even though the allowance was $148.20 million as shown in table 8.1 below.

Table 8.1: Comparison of T&TEC's Capex vs RIC Allowed 2006–2011 (TT$ Millions)

	2006-2007	**2007-2008**	**2008-2009**	**2009-2010**	**2010-2011**	***Total 2006-2011***
Total Capex (**Out-turn**) **(1) + (2)**	228.00	385.00	268.00	204.00	859.04	1,944.04
(1) Capex on PSIP/ Ring-fenced Projects **(Out-turn)**	127.10	250.40	177.80	83.20	100.10	738.60
(2) Capex on RIC Allowed Projects (**Out-turn**)	100.90	134.60	90.20	120.80	758.94	1,205.44

[32] Typically, a ring-fence is a virtual barrier that segregates a portion of an individual's or company's financial assets from the rest. For PRE1, some projects were ring-fenced to ensure that no tariff monies were expended on those projects and the projects were explicitly identified.

RIC Allowed Capex	153.20	191.40	169.40	137.80	148.20	800.00
Variance on Allowed Projects **(Out-turn vs RIC Allowed)**	**-52.3**	**-56.8**	**-79.2**	**-17.0**	**610.74**	**405.44**

Source: RIC

T&TEC provided no rationale for exceeding the RIC's total Capex allocation for the allowed list of projects by 50.7%. However, the variance of actual to forecasted expenditures may be attributed to a number of reasons including:

- higher than anticipated prices of materials and/or services used in the undertaking or delivery of projects;
- under-estimation of expected project costs; or
- poor implementation of the capital programme.

In some instances, utilities have deliberately understated project costs in Capex forecasts, in order to have said projects included in the rate base, with full knowledge that in actuality such costs may be notably higher. T&TEC's overspending is directly related to the priority given to Government directed projects and explains why RIC allowed projects were either not completed or initiated.

T&TEC was not able to complete several projects that were viewed by the RIC as critical to service delivery. T&TEC undertook just over 64% (or 69 of 107) of the projects that the RIC had allowed for the entire period. Thus, 38 allowed capital projects were not undertaken. Details of the number of projects delivered by T&TEC are presented in table 8.2 below.

Table 8.2: Completion Status of RIC Allowed Projects 2006-2011

Category	Sub-Category	No. Allowed	No. Completed	No. Incomplete	No. Not Started
Transmission	Substation Rehabilitation	14	5	1	8
	New Substations	16	8	2	6
	Sub-Total	**30**	**13**	**3**	**14**
Distribution	Network Upgrade	19	0	11	8
	Substation Upgrade	29	11	9	9
	Sub-Total	**48**	**11**	**20**	**17**

Category	Sub-Category	No. Allowed	No. Completed	No. Incomplete	No. Not Started
Other Network Related	**Sub-Total**	**4**	**1**	**3**	**0**
Non-Network Related	Upgrade of Information Technology Systems	14	10	3	1
	Establishment of Customer Service and Call Centres	2	1	-	1
	Strengthening Of Administrative Services	9	1	3	5
	Sub-Total	**25**	**12**	**6**	**7**
Grand Total		**107**	**40**	**29**	**38**

Source: RIC

In many instances the completed projects incurred costs that were greater than the allowed or projected amounts. Therefore, T&TEC could not benefit from the Efficiency Carryover Mechanism which was included as part of the overall incentive framework under PRE1. Under the mechanism, where the service provider can show that avoided Capex is due to efficiencies in its Capex investments, the service provider is allowed to retain the revenue associated with the unspent Capex for a period of five years under the rolling retention of efficiency savings. However, the RIC also specified that a reduction in the volume of investment would not simply be accepted as efficiency.

8.4.2 Lag Period (2011-2020)

The main objectives in reviewing T&TEC's Capex, for the lag period (2011–2020), were to assess whether the out-turn Capex was prudent, and the extent of the benefits derived from the capital works which were financed by tariff revenues.

T&TEC's total capital expenditure over the period January 2011–December 2020 amounted to approximately $3,454.15 million. Approximately $2,383.08 million (69% of total Capex) was sourced from tariff revenue and $1,071.07 million (31% of total Capex) was financed by the Government either through the Public Sector Investment Programme (PSIP) or other government derived funding (ring-fenced), see table 8.3. By way of comparison, the total capital expenditure for PRE1 amounted to approximately $1,944.04 million, with funding of approximately $1,205.44 million derived from tariff revenue (62% of total Capex).

Table 8.3: T&TEC's Capital Expenditure 2011-2020 (TT$ Millions)

	Tariff Funded	PSIP Funded	Ring Fenced	Total
2011	206.33	66.83	4.76	**277.92**
2012	190.47	54.04	14.90	**259.41**
2013	254.03	67.95	21.92	**343.90**
2014	312.15	104.78	58.99	**475.92**
2015	182.87	62.32	33.94	**279.13**
2016	281.47	24.21	32.19	**337.87**
2017	232.06	199.21	36.67	**467.94**
2018	399.23	98.41	39.19	**536.83**
2019	179.57	44.09	58.3	**281.96**
2020*	144.90	32.56	15.81	**193.27**
Total 2011–2020	**2,383.08****	**754.40**	**316.67**	**3,454.15**
		1,071.07		
Total 2006–2011	**1,205.44**	**738.60**		**1,944.04**

*** T&TEC's Business Plan provided Capex summary information for January–December, 2020.**
**** The total for 2011-2020 given in table 8.3 differs from the total presented in table 8.4 because the total for the tariff funded capital expenditure reported in table 8.3 covered the period January to December, 2020 while the breakdown of the tariff funded capital expenditure reported in table 8.4 covered the period January to May, 2020.**

As seen in table 8.4 the annual total out-turn Capex funded from tariff revenue, varied between $41.53 million in 2020 (January to May) (minimum) and $399.23 million in 2018 (maximum). The out-turn Capex under the different investment categories funded by tariff revenue also varied significantly on an annual basis. There is no indication that T&TEC had attempted to smooth the spending levels over the period. It should be noted that there was significant capital expenditure on distribution assets. The distribution network constitutes a major portion of T&TEC's installed infrastructure. The annual expenditure on these assets was approximately 58% of the total Capex funded from tariff revenue every year during the period 2011 to 2020.

Table 8.4:Tariff Revenue Funded Capex Out-turn by Investment Category 2011–2020 (TT$ Millions)

Category / Year	Transmission	Distribution	Other-Network Related	Non-Network Related	Total
2011	39.05	154.44	2.89	9.95	**206.33**
2012	53.12	124.80	4.17	8.38	**190.47**
2013	77.95	127.32	8.98	39.78	**254.03**
2014	129.15	149.47	18.06	15.47	**312.15**
2015	31.02	136.62	4.66	10.57	**182.87**
2016	81.06	168.88	10.7	20.83	**281.47**
2017	61.31	139.28	9.21	22.26	**232.06**
2018	66.81	187.85	17.65	126.92	**399.23**
2019	52.67	107.19	10.92	8.79	**179.57**
2020*	6.04	22.35	5.29	**7.85**	**41.53**
Total	**598.18**	**1,318.20**	**92.53**	**270.8**	**2,279.71****

*** T&TEC's Business Plan provided Capex breakdown for January–May 2020.**
**** The total for 2011–2020 given in table 8.3 differs from the total presented in table 8.4 because the total for the tariff funded capital expenditure reported in table 8.3 covered the period January to December, 2020 while the breakdown of the tariff funded capital expenditure reported in table 8.4 covered the period January to May, 2020.**

The out-turn for this period (2011- 2020), while not covered via a price review, has benefitted customers through enhanced service and reliability. The out-turn has been included into the RAB because the investments are considered to be prudent and useful.

8.5 ISSUES AND PROPOSALS ARISING FROM CAPEX ASSESSMENT

8.5.1 Use of Tariff Revenues for Government Driven (Non-Allowed) Projects

The extent of spending on Government projects for which funding was neither allowed by the RIC in PRE1, nor fully provided by Government, undoubtedly affected T&TEC's ability to undertake and complete the projects that were allowed by the RIC. **In this regard, and to ensure that tariff revenue will not be used for purposes other than those specified in PRE2, the RIC proposes that the Board of T&TEC provide self-certification assurances, in writing, for projects listed under the heading "Use of Tariff Revenues". This will provide a documented commitment (certification assurances) by T&TEC's Board to fulfil**

regulatory mandates, and to desist from using tariff revenues for activities, not approved by the RIC.

8.5.2 Under or Over-spend on (RIC Allowed) Capex Projects, and Incomplete (RIC Allowed) Projects

T&TEC's total spending on the RIC's allowed projects in PRE1 was higher than the allowed amounts, yet there were many projects that were either incomplete (and/or over budget) or not commenced. To address this issue, there is need for a mechanism(s) to account for under and over-spend on projects, projects not undertaken and those not completed.

With respect to **under-spends** on Capex, which arise when expenditure is less than the allowed amounts, either due to efficiencies or if a project is not undertaken, the corresponding options for adjustment of the RAB are as follows:

- **(a)** Where allowed projects are not undertaken, excess returns can be clawed-back[33] at the end of the regulatory period.
- **(b)** Where allowed projects are undertaken and the associated expenditure is less than the allowed amount, two options may be used as follows:
    - i. The RAB can be adjusted downward at the end of the period. The service provider would have benefitted from the savings during the past period and customers would now benefit from a lower than anticipated increase at the beginning of the new control period, when the RAB is adjusted; or
    - ii. The approved expenditure is retained in the closing RAB with no adjustment for actual spending. This option provides strong efficiency incentives, as utilities benefit from earning a return on forecast rather than the actual RAB and are not disadvantaged if they reduce their actual spending on the approved capital programme. However, in such a case there is also a strong incentive for inflated Capex projections to be presented.

With respect to **over-spends** on allowed Capex, as a result of cost overruns, the possibilities for adjustment of the RAB are as follows:

[33] Claw back results in downward adjustment of the revenue requirement for the subsequent regulatory period.

(a) Where over-spends are determined to be inefficient, the associated excess spend may not be allowed in the RAB, so consumers will not have to fund that expenditure into the next period.

(b) Where overspends are determined to be efficient the associated excess spend will be allowed in the RAB.

For PRE1, T&TEC's lack of execution of the allowed capital programme resulted in 38 projects not being undertaken. The RIC's allocation for those projects was $170.1 million, thereby resulting in excess returns (on capital) provided via the revenue requirement of about $13.6 million. The RIC is cognisant that considerable time has elapsed between PRE1 and the conduct of PRE2; however, if this occurs in the future the RIC will consider the following three options:

(a) Adjusting the revenue requirement for the subsequent regulatory period, as is the common practice of regulators, in similar circumstances. However, such an approach may have the unintended consequence of signaling to customers that the cost of delivering the service has decreased, which would not be true.

(b) Providing rebates to customers to account for the excess returns provided. This option would send strong signals to T&TEC about the importance the RIC places on the completion of priority projects, and the consequences of not undertaking them.

(c) Identifying specific projects that any excess returns would be spent on, in order to improve the quality of service to customers. However, this would introduce issues relating to appropriate project selection, as any project selected would have to be such that there is no perceived bias in terms of the beneficiaries thereof.

In a few instances during PRE1, T&TEC made changes to the allowed capital programme by substituting allowed projects with others, on the basis that the new projects achieved better outcomes than the originally allowed ones. The RIC's view on the treatment of investment funds provided *ex-ante*, for projects which, have been cancelled or delayed, is that the service provider should retain the revenue associated with such projects, provided that the decision was based on sound reasoning, and that the overall outcome of such a decision, is beneficial to customers.

8.5.3 The Capex Incentive Mechanism

Government or State-owned and run utilities often do not respond to financial incentives like private firms, which generally seek to maximise their profit. This may be largely due to the way in which the Government perceives and executes its ownership function, and the type of financial support/arrangements provided. If a Government-owned utility is operated as a commercial enterprise, where its viability depended on its ability to recover costs and improve efficiency, it would respond more favourably to efficiency incentive mechanisms. Even though T&TEC is State-owned, the RIC favours the use of some tools to incentivise the utility, whether via efficiency carryover or other types of incentives mechanisms. Such mechanisms can include:

- **Capex Triggers** – when rates and charges have been set for a control period, a guaranteed level of revenue is allowed based on projected levels of Capex and as such, there may be an incentive for the service provider to delay the investment. Hence, the RAB based approach unintentionally incentivises firms to overstate their investment plans at the time of a review in order to influence the size of the RAB and defer investments during the control period to benefit from the "saving". A Capex trigger can address this issue by making allowances in rates and charges conditional on the achievement of project milestones. Triggers can be positive or negative, thereby either increasing or decreasing revenues if an event occurs. The use of triggers would be most suitable for large, clearly identifiable projects. Capex triggers can be complex to design and, determining the proportion of revenue that should be at risk for failure to meet the target or project milestone is a challenging process.
- **Provisions for the inclusion of Contingent Projects in the revenue determination** – contingent projects are those that may be necessary, but which are excluded from the *ex-ante* allowance in the revenue requirement, based on uncertainty of the projects themselves or of their costs. The provision is exercised only if such contingent projects are actually undertaken, in which case, the service provider will be allowed the revenue, with the regulator's approval. The cost of such contingent projects must exceed a minimum amount (expressed as a percentage of the allowed revenue) before it is considered for inclusion in the

allowed revenue. This mechanism is viewed as less suitable to distribution expenditure than it is to transmission expenditure given that distribution expenditure tends to be smaller and can be less discrete than transmission capital expenditure. Further, it can also be administratively burdensome.

- **Logging Up** – this allows for the inclusion of Capex not previously funded in the current price control to be included and accounted for in the subsequent price control period.
- **Capex Information Quality Incentive** – under this incentive, the service provider will be rewarded for its accuracy in forecasting, that is, if the service provider's forecast is within 10% of the RIC's assessment, the service provider will be provided additional income at the beginning of the next control period, equivalent to the allowed cost of capital multiplied by the difference in the RIC's allowed Capex and T&TEC's proposed Capex.

The RIC has carefully considered the above and will utilise "logging up", as required, and employ a Capex Information Quality Incentive as described above in the review that will follow PRE2.

8.5.4 The Capex Reporting Framework

The RIC is of the view that monitoring, and reporting on projects, are critical to ensure the successful execution of T&TEC's capital programme. As a result, the following measures are being proposed:

- Implementation of a system of regular engagement with T&TEC to monitor Capex projects and ensure that Capex spend is in line with the RIC's allowances.
- Establishment of a semi-annual reporting framework in which T&TEC will be required to submit Capex reports, which are suitable for public release. The RIC is hopeful that the conditionality of public reporting will motivate T&TEC to conscientiously undertake and complete the allowed capital programme. Specifically, these reports will include information on the status of projects, particularly timing and cost variances. The format of these reports will be determined by the RIC inclusive of the level of granularity.

- Provision by T&TEC of detailed data on **each project** annually (to be called **Annual Investment Return**[34]). The information to be submitted in the Return will include:
  - forecast and actual project spend for the year;
  - explanations of financial variances;
  - total forecast spend on the project; and
  - physical progress of the project against defined milestones.
- Establishment of fixed dates by which T&TEC must meet and achieve Capex related Directives. Where deadlines are not met T&TEC will be held accountable.
- Conduct of a mid-term review of Capex at the RIC's discretion.
- Implementation of a Capex Safety Net – this allows for the review of the Capex allowance where the Capex underspend/overspend in any given year of the control period, is greater than 20% of the allowed Capex.
- Employment of Public Disclosure of Non-Compliance and/or Public Register notices on the RIC's website. Through these notices, the RIC will publish the occurrences and the way T&TEC has not complied with any targets set for its achievement, inclusive of allowed capital investment projects.

8.5.5 Other Issues

In order to improve the quality of Capex submissions and, to treat with the other issues that had arisen in PRE1, or may arise in future price controls, relating to T&TEC's execution of the allowed capital programme, the RIC may require:

- The use of a self-assurance process, the details of which must be submitted by T&TEC to the RIC at the time of a submission of a Business Plan, in which there is an assurance by T&TEC's Board that the Capex projections accurately reflect the underlying information base. This is an internal process which does not necessarily entail external scrutiny or assurance.
- The employment of a "reporter" (independent consultant/engineer) to interrogate T&TEC's Capex plan. The RIC will take the Reporter's

[34] T&TEC will also be expected to submit quarterly returns to facilitate ongoing monitoring.

proposals into account. The service provider will pay the Reporter's costs, but the Reporter is approved by the RIC and will report to the RIC.

- The development and submission of detailed Asset Management Plans alongside longer-term capital investment plans, with a view to assess how T&TEC's proposed Capex relates to, and corresponds with same. The RIC may also require the service provider to include in its business plan a review of "unit cost" trends, where possible.
- The continuation of detailed *ex-post* efficiency reviews of T&TEC's performance with respect to capital expenditures.

8.6 REVIEW OF FORECAST CAPEX

8.6.1 Overview

The objective of the review of the Capex programme for PRE2 is to ensure that the Capex is necessary and represents value for money for the customers. In order to achieve this objective, the RIC reviewed:

- T&TEC's strategies to ensure that the planned Capex is needed, can be delivered in the timeframe and represents best value for the customers;
- the benefits that Capex programme will bring to the network and whether these benefits are valued by the customers;
- the drivers and nature of the projects making up the forecast Capex Programme; and
- the potential efficiencies in the delivery of the forecast Capex programme.

The RIC believes that there are opportunities for T&TEC to achieve efficiencies/savings in Capex. The RIC also expects that general productivity increases in Capex projects should be achievable, although to a lesser extent than what may be achievable for T&TEC's operational activities as a large portion of Capex costs may be related to materials and contractors. The benefits that result from Capex efficiencies achieved in terms of avoided asset related costs, that is, reduction in depreciation and return, will be passed on to customers within PRE2.

8.6.2 T&TEC's Proposed Capex

T&TEC has submitted a Capex programme valued at $2,238.7 million, for PRE2. The disaggregated Capex submitted by T&TEC is shown in table 8.5 below. The Capex programme is aimed primarily at the rehabilitation and replacement of assets to ensure they perform at a level that meets the standards established for customers and customer expectations. The following sections present the review and assessment of the requested Capex and provide details on the RIC's decisions.

Table 8.5: T&TEC's Capex Submission for 2023–2027, $Mn.

Category	2023	2024	2025	2026	2027	Total
Transmission-Sub-transmission - Refurbishments and Replacements	41.6	72.1	78.0	55.8	24.7	**272.2**
Transmission and Sub-transmission – New Substations	0.0	20.8	27.5	40.0	9.7	**98.0**
Distribution	209.9	126.6	90.0	89.9	80.5	**596.9**
Street Lighting	21.2	11.8	8.8	10.3	5.8	**57.9**
Other Network Related	10.0	5.0	4.0	4.0	4.0	**27.0**
Non-Network Related	306.6	295.3	352.2	159.9	72.7	**1,186.7**
Total	**589.3**	**531.6**	**560.6**	**359.8**	**197.4**	**2,238.7**

Source: T&TEC

8.6.3 Assessment and RIC's Allowed Capex

Tables 8.6 and 8.7 summarise T&TEC's submission and the RIC's decision for Capex in PRE2. The RIC's allowed Capex for PRE2 is $1,677.3 million, which is $561.4 million, or 25% less than that requested by T&TEC. Some of the main considerations in determining the allowed Capex were that**:**

- reduction of Capex for projects that were deemed not to be prudent;
- exclusion or ring-fencing of projects to be funded by Government;
- revaluation of expenditure on projects that were too loosely defined, and lacking supporting information and project detail;
- adjustment for expenditure on projects with similar scopes of works/materials but with inconsistencies in costing; and

- exclusion of expenditure for projects whose duration extended beyond the second control period, and inclusion of only the costs associated with the parts of the project works which will terminate within the control period.

Table 8.6: T&TEC's Requested and RIC's Allowed Capex, 2023–2027 (TT$Mns)

	Projects													
YEAR	Transmission - Refurbishment and Replacements		Transmission & Subtransmission new Substations		Distribution		Street-Lighting		Other Network-Related		Non-Network Related		Grand Total	
	Req. $	All. $	Req. $	All. $	Req. $	All. $	Req. $	All. $	Req. $	All. $	Req. $	All. $	Req. $	All. $
2023	41.55	**36.08**	0.00	**0.00**	209.93	**178.48**	21.22	**6.25**	10.00	**9.70**	306.56	**86.35**	589.26	**316.86**
2024	72.15	**50.53**	20.80	**10.00**	126.55	**109.11**	11.80	**21.46**	5.00	**4.85**	295.28	**193.19**	531.58	**389.14**
2025	78.05	**56.33**	27.50	**5.00**	90.05	**81.64**	8.80	**11.16**	4.00	**3.88**	352.24	**168.81**	560.64	**326.82**
2026	55.77	**44.58**	40.00	**11.20**	89.86	**81.05**	10.30	**10.00**	4.00	**3.88**	159.89	**158.13**	359.82	**308.83**
2027	24.70	**24.50**	9.70	**6.20**	80.51	**76.17**	5.80	**5.64**	4.00	**3.88**	72.72	**219.27**	197.43	**335.66**
Total	**272.22**	**212.02**	**98.00**	**32.40**	596.89	**526.45**	57.90	**54.50**	27.00	**26.19**	1,186.69	**825.75**	2,238.72	**1,677.30**

Source: RIC

The Capex allowance set by the RIC reflects assumptions about load growth and new connection numbers. As seen during PRE1, outturn Capex can be different from the allowed Capex as ultimately it is the service provider’s responsibility to plan and develop the network system efficiently. While the RIC’s Capex allowance is based on T&TEC’s submission for PRE2, given the possibility of changing circumstances, the onus is on the service provider to determine which projects are progressed, which new projects (not included in its submission) are necessary and efficient, and which projects are deferred subject to the overall cap on Capex. The RIC will review the outturn at the end of PRE2 and only efficient and necessary Capex will be added to the RAB.

Table 8.7: Assessment of T&TEC's Capex Forecast, 2023–2027

Project Area	Total Amounts ($Mn)		Remarks
	Forecast	Allowed	
Transmission – Sub-transmission Refurbishments and Replacements	$272.2	$212.0	Adjustments were made to the Capex forecast to correct for inconsistencies in the costing of projects with similar scopes and based on the RIC’s determination of an average unit cost for major plant/equipment, and application of such costs to projects with a degree of similarity.
Transmission & Sub transmission – Development Projects	$98.0	$32.4	Adjustments were made to the Capex forecast to correct for inconsistencies in the costing of projects with similar scopes and based on the RIC’s determination of an average unit cost for major plant/equipment, and application of such costs to projects with a degree of similarity.
Distribution	$596.9	$526.4	Adjustments were made to the Capex forecast as follows: • Projects with similar scopes were adjusted according to an average unit cost for major plant/equipment. • Forecasted growth and other criteria unique to the Distribution Area were used to adjust “blanket projects” with inadequate information.
Street Lighting	$57.9	$54.6	Adjustment for projected efficiency gains in project execution was made to the Capex forecast.
Other Network Related	$27.0	$26.2	Adjustment for projected efficiency gains in project execution was made to the Capex forecast.
Non-Network Related	$1,186.7	$825.7	Adjustments were made to the Capex forecast as follows: • Projected efficiency gains in the execution of most of the projects in this category.

Project Area	Total Amounts ($Mn)		Remarks
	Forecast	Allowed	
			• Fifty percent of the Capex required to finance the portion of the AMI replacement project, to be carried out during PRE2, has been allowed from 2024. The existing AMI was implemented in 2007–2009 notwithstanding concerns expressed by the RIC. Some features, such as the Outage Management System (OMS) have not yet been fully implemented. This has delayed the automatic payment for breaches of the Guaranteed Electricity Standard, GES1. The RIC is of the view that the planned replacement of approximately 50% of all meters during PRE2 will allow for proper planning of the project's rollout and the sourcing of a robust system with full OMS capability and which supports advanced rate options.
Total	**$2,238.7**	**$1,677.3**	

Source: RIC

The RIC's annual Capex allowances for the control period are rolled forward into T&TEC's regulatory asset base (less depreciation and disposal). The annual RAB values for PRE2 are listed in table 8.8.

Table 8.8: RIC's Allowed Regulatory Asset Base for 2023–2027 ($'000)

	2023	2024	2025	2026	2027
Opening RAB	5,415,045	5,700,732	6,026,476	6,198,458	6,350,224
Inflation Adjustment	249,092	216,628	126,716	123,969	120,654
Capex	316,870	389,140	326,820	308,830	335,660
Less Depreciation	(279,275)	(279,024)	(280,554)	(280,033)	(280,835)
Less Disposals	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)
Closing RAB	5,700,732	6,026,476	6,198,458	6,350,224	6,524,703

Source: RIC

9 INCENTIVES AND PERFORMANCE MONITORING

9.1 INTRODUCTION

One of the most important functions of the regulator is to set challenging and achievable levels of performance for the service provider to promote customers' interests. Consequently, the regulator must monitor progress against the minimum acceptable performance level that it sets, and verify that service levels do not decline as a result of any action by the service provider to reduce costs. During the regulatory control period, it is important to monitor T&TEC's progress in reducing costs and improving service levels. Performance reporting enables stakeholders to assess compliance with regulatory determinations and compare the performance of service providers. Consequently, it is essential for customers that the RIC effectively monitors T&TEC's performance in accordance with the regulatory framework being established for PRE2.

Incentive regulation includes mechanisms within the regulatory framework to maintain or improve service quality. These incentive mechanisms include:

- specifying service standards and obligations to be met during a regulatory period;
- reporting performance against service standards/obligations as part of the performance monitoring and reporting regime;
- designing financial incentive mechanisms to reward and penalise the service provider for performance that varies from pre-determined benchmarks/standards; and
- any combination of the above.

In PRE1 the RIC utilised a combination of mechanisms; of both non-financial incentives (e.g. performance monitoring and reporting), and financial incentives (such as an efficiency carryover mechanism and the guaranteed standards of service scheme). The RIC's intends to continue with many of the existing incentives and to propose a number of additional mechanisms and tools to encourage specific desirable behavior by the service provider.

This chapter will discuss T&TEC's past performance in relation to the non-financial and financial incentives utilised by the RIC in PRE1. It will identify the existing incentives the RIC proposes to continue with and the additional mechanisms and tools that will be utilised to encourage specific desirable behaviour by the service provider during PRE2. It will also describe how the RIC will continue to monitor, analyse and report on T&TEC's performance in PRE2.

9.2 ROLE OF INCENTIVES IN GOVERNMENT-OWNED UTILITIES

Some of the more intractable problems associated with incentive-based regulation occur where the utility is State-owned. These problems can be exacerbated when the government, as owner, is not focused on performance, as would occur under private ownership. The misalignment of incentives between owners and directors of entities when they are not the same is well-known. Compared with private sector companies where directors are accountable to shareholders, the Board/management of the government-owned entities can pursue their own objectives more freely in the absence of these checks and balances. Although some accountability mechanisms exist in the public sector, once the Board/management has the freedom to pursue its own objectives, incentive-based regulation becomes difficult for several reasons, including:

- Board/management is less incentivised because the penalties for failure are minimal, and the rewards for success are also smaller;
- public sector managers are often not subject to performance management systems and associated rewards and consequences as obtains in the private sector;
- there is no real bankruptcy threat as even a poor-performing entity can expect to be bailed out by the State; and
- the market for corporate control is also absent.

The poor performance of entities with government ownership is also due to a number of other factors, including:

- complex and sometimes conflicting social, political and economic objectives;
- short-term focus due to changing political objectives;
- pressure from ministerial intervention at the expense of accountability; and
- selective representation of customer needs.

Some measures have been implemented to align management incentives in government-owned entities with the regulatory regime. Critical to improving performance and encouraging positive action in a State-owned entity is strengthening the governance regime to better align the incentives of the Board and management to clear service quality and financial performance objectives. The impact of the incentives can be both financial and reputational, that is, where poor service quality performance is prominently reported in the media. Therefore, for government-owned entities, where the profit-motive is absent, management is likely to be more focused on achieving outputs as this will directly impact the reputation of the entity and its senior management.

The RIC believes that the performance targets being established for PRE2, both existing and new, are challenging but achievable and will encourage T&TEC to maintain or improve its performance.

Stakeholders who require further information should refer to the RIC's documents, **"Regulating Quality of Service", "Performance Monitoring and Reporting", and "Incentive Mechanism for Managing System Losses",** which has been published on the RIC's website.[35]

9.3 SERVICE RELIABILITY INDICATORS

In PRE1, the RIC did not establish any financial incentive mechanism to improve supply reliability. However, T&TEC was required to collect information on three reliability measures (generally referred to as a **"paper-trial" S-factor**). The paper-trial S-factor focused on three reliability measures: System Average Interruption Frequency Index (SAIFI), which measures the average number of interruptions per customer, System Average Interruption Duration Index (SAIDI), which measures the average number of minutes of interruption per customer and Customer Average Interruption Duration Index (CAIDI), which measures the average outage duration per customer.

[35] www.ric.org.tt

Based on the data that the RIC has collected from T&TEC over the first regulatory period, the calculated values for both SAIDI and SAIFI are over four times larger than the North American Median. Table 9.1a and 9.1b below show T&TEC's performance regarding continuity of supply to its customers.

Table 9.1a: Network Reliability Indicators for T&TEC, 2005–2016

Indicator	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	NAU*
SAIFI (No. per Customer)	11.43	9.93	10.1	6.94	5.55	6.61	5.68	5.71	5.21	4.42	4.4	4.7	1.1
SAIDI (minutes)	1116	996	1020	603	487	563	486	464	398	326.2	307.8	400	90
CAIDI (minutes)	98	100	100	93	87	85	86	81	76	73.8	70	86	82

* NAU – Median values for North American Utilities according to IEEE Standard 1366-1998.
Note that this table displays the IEEE standards at 1998.

Table 9.1b: Network Reliability Indicators for T&TEC, 2012-2021

Indicator	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	NAU**
SAIFI (No. per Customer)	5.71	5.21	4.42	4.4	4.7	4.5	3.9	4.8	5.01	3.75	1.11
SAIDI (minutes)	464	398	326.2	307.8	400	417	389	463	483.0	308.4	58.49
CAIDI (minutes)	81	76	73.8	70	86	93	99	97	96.41	82.24	96.47

** NAU – Median values for North American Utilities reported by the American Public Power Association APPA in accordance with IEEE Standard 1366-2012.
Note that this table displays the new IEEE standards, which were updated in 2012.

In its document, **"Regulating Quality of Service"**, the RIC discussed in detail the complexity associated with implementing an S-Factor scheme. Among other things, the RIC also noted the difficulty of measuring service standards, calibrating the level of service into a dollar measure based on customers' values and designing a scheme to reward or penalise the service provider. Other issues concerned the RIC, including the accuracy and availability of data, and the observed variability of the service performance indicators of T&TEC.

Given the issues discussed, the RIC is concerned that the S-factor scheme, if introduced, at this time, might not work as intended. However, the RIC is of the view that there is a strong case for introducing regulatory measures to encourage further reliable service performance. **In this regard, the RIC will continue to monitor the performance indicators and quality of service standards introduced in PRE1 and to publish T&TEC's performance accordingly in the RIC's Performance Indicator Report. The RIC also implemented a revised guaranteed service standards scheme in 2021 and will continue to monitor and publish annually T&TEC's performance under this scheme.** The RIC will evaluate T&TEC's performance against the standards to ensure that that they remain "fit for purpose" (this is generally done on a three-year cycle) and will be revised as necessary.

The RIC has provided funding in the revenue requirement to undertake works on the network during PRE2 to aid reliability improvements, and the RIC will monitor the completion of these works. Reliability improvements must be a central operational issue for T&TEC, and both management and supervisors must be continuously briefed on this issue, inclusive of the financial implication of outages for the utility. The cost of interruptions must be made known at the operational level to influence work practices, and the utility should undertake various measures which can include:

- instituting monthly management meetings in each area;
- a change of practice whereby outages are planned for half a day instead of a whole day, where possible and feasible;
- greater utilisation of live-line working techniques alongside strict adherence to highest levels of safety practices; and
- setting performance targets for each area, and increasing supervisory and operational staff awareness of the real financial cost of customer interruptions and lost service hours.

The RIC requires T&TEC to report semi-annually on its efforts in this area.

9.3.1 Improving Service to Worst-Served Customers

SAIFI and SAIDI targets incentivise the service provider to reduce the total levels of interruptions to customers. However, many areas in the country are experiencing frequent outages. Outages in these areas will have only a small impact on the overall interruption statistics. Table 9.2 below shows the areas with the most outages for 2021. The outages experienced in these areas range from two (2) per month to over twenty-nine (29) per month. T&TEC has indicated that most of the outages are because of animals coming into contact with overhead lines as well as contact made by vegetation. To reduce these outages, T&TEC must undertake appropriate measures, including:

- installing overhead line covers;
- installing tall insulators and short pins;
- increasing the use of covered conductors;
- replacing porcelain insulators with polymeric insulators;
- installing new auto reclosers;
- an aggressive approach to line clearing (tree-cutting/trimming); and
- installing a second transformer within each substation.

Table 9.2: Frequency of Outages in Different Areas for 2021

SOUTH		NORTH		CENTRAL		EAST		TOBAGO	
Area	**Outages**	**Area**	**Outages**	**Area**	**Outages**	**Area**	**Outages**	**Area**	**Outages**
Princes Town	211	Maraval	223	Chaguanas	189	Sangre Grande	359	Scarborough	98
Penal	189	Diego Martin	200	Couva	167	Arima	357	Mason Hall	79
Mayaro	180	Santa Cruz	158	Cunupia	166	Toco	194	Mt. Irvine	64
Point Fortin	132	Morvant	114	Freeport	159	Manzanilla	179	Plymouth	63
San Fernando	125	Laventille	91	Grand Couva	104	St. Joseph	169	Bon Accord	57
Rio Claro	119	San Juan	72	Claxton Bay	80	Wallerfield	140	Moriah	44
La Romain	106	Petit Valley	71	Carapichaima	75	Valencia	122	Bethel	39
Moruga	106	Blanchisseuse	65	Carlsen Field	59	Cumuto	118	Patience Hill	38
Barrackpore	105	St. James	63	Charlieville	59	Arouca	115	Hope	37
Siparia	94	Cascade	62	Longdenville	56	Matelot	100	Mt. St. George	35

Source: RIC

While the Guaranteed Standards Scheme (GSS) protects these worst served customers from long outages, there is a need to address such customers more proactively. The GSS is only effective in ensuring a minimum level of service and provides little incentive for the service provider to improve beyond that threshold level. Other Service Incentive Mechanisms may have to be introduced into the quality-of-service framework. One such mechanism is a **Direct Revenue Adjustment**. A Direct Revenue Adjustment rewards or penalises the service provider by directly adjusting allowed revenue in response to differences between the expected or target service level and the actual service level.

The RIC proposes to use the Direct Revenue Adjustment mechanism for the "Number of Customer Interruptions per month" (Interruptions Incentive Scheme). This indicator is closely linked to approved projects in the Capex programme and will be assessed annually to provide a continuous incentive to improve performance. The penalty associated with this performance indicator will be capped at a level that does not endanger the service provider's continued operation.

Consequently, the RIC proposes a target of no more than three (3) interruptions per month in any area of the country to improve service to worst-served customers over PRE2. **The total incentive payment to T&TEC for this mechanism will be capped at $7.5 million during the relevant year, and the total penalty for this mechanism will be capped at $10 million during the relevant year**. **The RIC will adjust T&TEC's allowed revenue yearly before setting/approving T&TEC's tariffs for each subsequent year. This mechanism will commence from the third year of the control period, thereby giving enough time for T&TEC to put systems in place (inclusive of an appropriate system to facilitate the submission of quarterly reports to the RIC).**

9.4 CUSTOMER RESPONSIVENESS AND SERVICE

In PRE1, the RIC introduced three major initiatives aimed at improving the quality-of-service customers receive from T&TEC:

- The Codes of Practice - a set of guiding principles that T&TEC must consistently use in dealing with specific consumer issues. They are designed to improve the delivery and quality of service to customers. The Codes were revised in early 2022 and can be found on the RIC's website;

- Benchmarking and monitoring the quality of supply - which involves quantitative measures to be monitored regularly. The RIC publishes annual reports on these performance metrics, which are made available through the RIC's website; and
- The Customer Satisfaction Survey - a qualitative survey conducted at the beginning of each price control period by the RIC. The survey for PRE2 is scheduled to take place in 2023.

T&TEC was required to establish a suitable system to track their call centre performance in PRE1, given the importance of the telephone as a medium of communication for T&TEC's customers, and to commence the 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).

The RIC observed a reduction in the number of complaints in many areas and improved customer satisfaction over the period 2006–2020. However, although T&TEC undertook steps to establish and implement a system to capture the information, there were data accuracy and reliability issues in their call centre performance.

The RIC has initiated the process of establishing the appropriate call centre metrics for T&TEC. The selected KPIs are expected to transform the customer service experience and ultimately improve customer satisfaction. The KPIs would be grouped into three (3) broad categories below:

- **Service Responsiveness -** a measure of how efficient calls are being handed by call centre agents.

- **Call Quality -** a measure of the efficiency and effectiveness of conversations between the agent and customers. It is considered one of the most effective and efficient approaches to improving customer experience; and
- **Customer Satisfaction -** a measure of how pleased customers are with the most important aspects of a positive call centre experience: fast call resolution, real–time support, and the agent's friendliness. This would be gauged by the utility via a survey instrument.

The RIC considers the KPIs listed below, which fall under Service Responsiveness to be of critical importance:

- *Service Level* - This metric commonly defines X amount of output in Y amount of time. For example, 80% of calls are answered in 20 seconds. Service Level (SL) is an effective KPI used to assess call centre efficiency. It is often used as a good indicator of customer service quality.
- *Average Handle Time* - one of the most commonly measured metrics. It indicates the length of time an agent spends working on a task and, therefore, cannot deal with a new work item.
- *Average Speed of Answer* - a metric that shows the amount of time it takes for an agent to answer a typical call once it has been routed to the contact centre, that is, from the ring tone up until the time an agent answers the call. It is one of the main factors affecting how customers judge the level of service, and it is often associated with customer satisfaction.
- *Call Abandonment Rate* - the percentage of inbound phone calls that are abandoned by customers before speaking to an agent. The rate is usually a reasonable gauge of the customer service experience. It measures how many customers terminate their call before it is answered in the call centre.

The KPIs would establish new performance standards that T&TEC must follow. Establishing these KPIs would include a comprehensive analysis to determine the appropriate performance standards for ten (10) selected KPIs. Once the KPIs are established T&TEC will be required to report quarterly to the RIC on its performance and thereafter the RIC will publish T&TEC's performance periodically as it sees fit. The project of establishing Call Centre Metrics for

T&TEC is anticipated to be completed in 2023 and is expected to be implemented in the second year of PRE2.

T&TEC will also be required to undertake a Customer Satisfaction Survey, commencing from the third year of PRE2. The survey must be administered by a third party but commissioned by the service provider, and should cover four areas: Voltage Complaints; Unplanned Outages; Planned Outages and New Connections. These attributes will be used as a means of getting customer feedback on how the issue was dealt with, rather than the nature of the issue itself. A random sample of customers who dealt with the service provider in the previous six months will be interviewed and the survey is to be undertaken once per year. A copy of the survey report is to be submitted to the RIC.

9.5 SYSTEM LOSSES

Losses are generally divided into technical and non-technical losses. Technical losses arise due to physical reasons and are dependent on the energy flowing through the network, the materials used to construct transmission and distribution lines, transformers, and the way the network is configured and operated. Non-technical losses, sometimes called commercial losses, arise when energy is delivered to customers but no revenue is collected. These losses usually result from measurement errors, recording errors, and theft. Any reduction in energy losses will have positive economic and environmental benefits, as the generation of less electricity will lower the volume of greenhouse gases produced.

As part of PRE1, the RIC instituted a measurement and incentive mechanism for managing system losses to encourage T&TEC to manage its transmission and distribution network efficiently. This was a critical area for the RIC as ultimately, consumers pay for energy losses throughout the network via their tariffs. Although some of the losses are unavoidable, they can be reduced (but never completely eliminated) by utilising suitable techniques and equipment. Other elements of the losses are avoidable, with accurate measurement of electricity consumption and good management of the network.

The specific directives on the management of transmission and distribution losses in PRE1 defined the formula for calculating system losses and the terms and conditions of the incentive mechanism. The RIC used the following formula for the calculation of the total system losses:

$$\textbf{Total System Losses} = 1 - \left\{ \frac{\textbf{Energy Units Billed}}{\textbf{Energy Units Purchased}} \times \frac{\textbf{Collection in \$}}{\textbf{Billing in \$}} \right\}$$

The calculated system losses in Trinidad and Tobago were benchmarked against the system losses of selected countries.

The RIC stipulated five conditions in the incentive mechanism for total system losses:

- The RIC adopted an initial level of total system losses of 7.9% for T&TEC based on the average value computed over 1999-2003, which at the time compared favourably with some developed countries. A target for reduction in loss levels for the first regulatory control period was then set at 6.75%.

- T&TEC was allowed to keep 90% of the gains derived from savings realised, if the total system losses fell below 6.75%, with the sharing of these gains set to occur at the end of the regulatory control period.

- The RIC indicated support for the principle of taking into account the value of loss reduction measures into the asset base when it is to be rolled forward into the succeeding regulatory control period, to encourage investment in loss reduction equipment.

- T&TEC was required to install appropriate metering/monitoring equipment at strategic locations of its network during PRE1.

T&TEC's total system losses varied from year to year for the period 2006 to 2011, as presented in table 9.3.

Table 9.3: T&TEC's Transmission and Distribution Losses 2006–2011

Year	2006	2007	2008[36]	2009	2010	2011	Average
% Losses	7.73	8.45	7.84	9.40	6.46	6.50	7.73

Source: RIC

T&TEC was not able to achieve any sustainable reduction of total transmission and distribution system losses during the period. The annual systems losses were above the 6.75% target for all years except 2010 and 2011 and averaged 7.73%, with the highest annual loss of 9.40% recorded in 2009. Although the annual systems losses showed improvement in the last two years, in aggregate, T&TEC did not achieve the set target of 6.75% for the reduction in loss levels for PRE1.

In the period that followed, 2012 to 2020, system losses showed a slight improvement up to 2015 but deteriorated thereafter, resulting in an overall average of 7.85%, as shown in table 9.4. Except for 2012, all annual values were above the 6.75% level.

Table 9.4: T&TEC's Transmission and Distribution Losses 2012–2020

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	Average
% Losses	6.67	7.08	6.93	7.40	7.99	8.08	8.26	9.22	9.05	**7.85**

Source: RIC

The initial improvement observed for this period may have been influenced by the use of the higher transmission voltage of 220 kV on part of the network, and this was introduced with the commissioning of the 720 MW combined-cycle power plant in La Brea, as well as the upgrade from 66 kV to 132 kV of the transmission lines from the Bamboo substation in Valsayn to the Gateway Substation in Port of Spain. It is estimated that if the set target of 6.75% was achieved and maintained throughout the entire period of 2006 to 2019, the reduction in total system losses

[36] All computations for 2008 were based on data from the first three quarters of that year. The data for the last quarter was not used because T&TEC had conducted a retroactive billing exercise which resulted in the reporting of more **Energy Units Billed** than **Energy Units Purchased** for that quarter, thereby, resulting in a considerable and inaccurate decrease in the value of total system losses for the entire year of 2008.

would have saved T&TEC at least TT$ 315 million, or approximately TT$ 23 million per annum.

System losses have been trending upward since PowerGen closed its power station in Port of Spain at the end of 2015. The average over the years 2016 to 2020 was 8.52%. Overall, the incentive mechanism was unsuccessful in stimulating T&TEC to reduce the total system losses either by the benefit derived from cost savings, or the additional benefit of retained gains that could have been realised by surpassing the target of 6.75% set by the RIC for the first regulatory period.

The RIC posits that the level of losses on T&TEC's transmission and distribution system translates into higher prices for all customers, as T&TEC must purchase greater quantities of energy than that which is being consumed by its customers. This underscores the need to pay attention to this metric and take steps to bring it to an acceptable level. After reviewing the original formula for calculating the total system losses, the RIC is of the view that less emphasis can be placed on non-technical (commercial) losses because T&TEC has substantially reduced meter reading/recording errors on the network after Advanced Metering Infrastructure was implemented. Hence, the RIC proposes the continuation of the application of an incentive mechanism for managing the total system losses for PRE2, as a measure to encourage T&TEC to minimise those losses.

The RIC believes that establishing an **annual reduction target,** instead of a target to be achieved over the full regulatory period, is more practical and would encourage compliance with the set target. **Failure to achieve the annual reduction target in any given year will incur a penalty of $10 million for that year.**

The incentive mechanism for PRE2 will be implemented with the following features:

- Calculate **Total System Losses** as**:** $$\mathbf{1 -} \left\{ \frac{\textbf{Energy Units Billed}}{\textbf{Energy Units Purchased}} \right\}$$
- Set the base value of total system losses for the next regulatory control period as the average monthly value computed over the year preceding the commencement of the

period, and set a target for an annual reduction in loss levels for the control period at 0.25% towards an overall target of 6.75% for the control period;

- Allow T&TEC to keep 90% of the gains if total system losses fall below the target set for that year, and share the gains at the end of the regulatory control period. However, given the current uncertainty in relation to the measurement of losses, no incentive payment will be made until the data has been verified to be accurate;

- Require T&TEC to include in the capital expenditure programme, projects which entail:

    - The installation of appropriate metering/monitoring equipment at strategic locations of its network; and
    - Network modification to reduce the level of total system losses, which include but are not limited to shortening the lengths of long distribution lines and the installation of capacitors on feeders. The execution of these projects is to be given high priority during PRE2.

- Take into account the value of loss reduction equipment in the asset base when it is rolled forward to encourage investment in loss reduction equipment. The full cost incurred would be incorporated into the asset base if the annual target for actual total system losses is achieved, and the cost will be prorated for the partial achievement of the target. However, if the total system losses increase above the initial and successive values calculated by the RIC, T&TEC will be penalised by not having the value of installed loss reduction equipment included in the asset base, and a directive will be issued to institute loss reduction measures at no cost to customers in the following control period; and

T&TEC must report annually to the RIC on all the proposed initiatives taken to reduce losses beyond the investment in its capital programme.

9.6 GUARANTEED PAYMENTS

The RIC implemented a Guaranteed Payments scheme in 2004 which outlined standards/targets. The standards are divided into guaranteed and overall standards. In the case of guaranteed standards, if the service provider fails to meet these targets, it makes a payment to the affected customers. This scheme provides both an incentive for the service provider to improve performance and guarantees payments to worst-served customers who receive poor service. Revised standards were introduced in 2010, with changes in the quantum of the guaranteed payment, and the introduction of automatic payment for some standards. The scheme was further revised, and the amended scheme implemented in June 2021. The current scheme includes a new overall standard which targets reliability indicators and modifies the guaranteed standards related to voltage irregularities and new connections of supply. Details regarding the RIC's Quality of Service Scheme can be found on the RIC's website. These arrangements have not been modified further as part of PRE2; they are mentioned here for information purposes only.

9.7 REGULATORY ACCOUNTING GUIDELINES (RAGs)

All businesses are required to comply with a range of reporting requirements., inclusive of statutory accounts. Regulated utilities are normally required to submit regulatory accounts, in addition to statutory accounts. These accounts are required for specific regulatory purposes and differ from statutory accounts, as they incorporate accounting information as well as other performance indicators. Regulatory accounts are a critical source of information for the RIC, as they help ensure that the service provider is in compliance with the RIC's decisions, and can be used to inform customers and other stakeholders about the performance of the service provider.

Regulatory Accounts 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
- give effect to the objectives of the RIC, as stated in Section 6 of the RIC Act.

In its Final Determination for PRE1, the RIC indicated that it would publish regulatory accounting guidelines and require T&TEC to submit regulatory accounts. Pursuant to this decision, the requisite guidelines were published, and T&TEC was mandated to submit the information in the required format. However, upon review of the various submissions, it was clear that T&TEC's efforts were lacking. T&TEC has indicated that this was due in part to the difference between the financial reporting year, in respect of its statutory accounts, and the regulatory year. The RIC will align the reporting requirement for **financial information** to T&TEC's statutory year-end accounts to mitigate this problem

The RAGs required for submission by T&TEC are shown in **Annex 3** at the end of this document.

10.7.1 Publication of Regulatory Accounts

The RIC Act (Sections 56-60) attaches significant importance to improving transparency and accountability, and mandates that "information collected and the results of the research carried out, be furnished to any person." As a consequence, the RIC proposes placing finalised regulatory accounts on its website and making hard copies available on request. The RIC may also publish a condensed version of the regulatory accounts in a daily newspaper. The RIC is of the view that information about a monopoly business should generally be subject to full disclosure and full publication of regulatory accounts would not damage the service provider's interests because the requested information is not commercially sensitive.

Consequently, T&TEC will be required to submit quarterly information in the format of the RAGs, and full-year regulatory accounts to the RIC by the end of the third month of each year within the regulatory control period. The full-year regulatory accounts must be reconciled with the quarterly submissions, as necessary. The RIC considers this to be an appropriate time frame, as undue delays in publication would negate the benefits or, at minimum, reduce its immediate significance. The regulatory accounting information must be submitted in hardcopy and electronic formats.

10.7.2 Process for Revision of Regulatory Accounts

The RIC will amend and expand the guidelines from time to time, when necessary, to meet the changing needs of the RIC, service provider or customers and to reflect evolving regulatory practice and experience. The RIC will, however, consult the service provider and other stakeholders as appropriate before making any adjustments to these guidelines.

10.7.3 Information Verification and Independent Assurance

The service provider must maintain reporting arrangements which provide information that can be verified. In this regard, the service provider will be required to provide a responsibility statement confirming that the information being submitted is accurate and properly reflects its activities. The responsibility statement will be signed and dated by the Chief Executive Officer or a designated senior officer of the service provider.

The RIC may require, from time to time, an independent assurance (audit) on information submitted. In this regard, the RIC will specify the required scope of any audit or other form of independent assurance. The audit must be undertaken by an independent expert nominated and paid for by the service provider but approved by the RIC.

9.8 PERFORMANCE REPORTING

Information, reporting and compliance are and will remain central to effective regulation. The RIC considers that performance reporting enhances the effectiveness of its regulatory regime, as it promotes the transparency and accountability of the service provider through:

- **Education** – Access to the information will encourage a greater understanding of and participation in the regulatory process. It will also educate stakeholders on the service provider's performance and the outcomes of regulatory processes.

- **Transparency** – Performance reporting promotes transparency and allows for comparisons to be made over time, and between service providers, where possible. It will also provide an insight into the service provider's operations, practices and decision-making.
- **Accountability** – Performance reporting enhances accountability through outcomes monitoring and provides information to all stakeholders with the opportunity to assess the actual performance of the service provider against the specified performance targets.

- **Improved Performance** – Performance reporting enables comparisons to be made over time, and encourages the service provider to adopt more efficient processes, thereby providing an incentive to increase service performance.

The information may be reported using internal or external benchmarks, and will afford the regulator an opportunity to "name and shame" the service provider for poor performance. The RIC has already established a **"Performance Monitoring and Reporting Framework (PMR)"**, which is a significant performance driver and a useful tool for:

- informing customers and other interest groups about the level of service they are receiving;
- providing information and data for developing regulatory standards where 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 intends to continue monitoring the performance of T&TEC using the relevant performance indicators. However, the RIC will initiate a number of measures to improve its monitoring and reporting activities. Among these are:

- reviewing and modifying the templates used to collect data from T&TEC to ensure greater relevance in the data reported;

- requiring T&TEC to employ an independent auditor to review its data collection and dissemination process, and to verify that the data and computations used to derive the values of the indicators are both valid and reliable. The auditor should be hired and the report submitted to the RIC by the third year of PRE2. The RIC will also ensure that the independent auditor's report is made public;
- the employment of all its enforcement powers contained in the RIC Act, to obtain timely and reliable information from the service provider, including:
  - caution letters;
  - publication of non-compliance notice in the media; and
  - Any other action necessary to achieve compliance;
- reporting on an abbreviated list of major indicators at six-month intervals to give a snapshot of the performance and financial health of the service provider. In order to create a broad picture "traffic signal" indicators were chosen to cover **financial health**, **reliability**, **operational efficiency** and **customer responsiveness**. The rationale behind the list of indicators chosen is to depict the overall health and performance of the service provider using no more than six indicators (the RIC has selected five) that are of interest to customers and other stakeholders and easily understood by them (see table 9.5 below); and
- the inclusion of the above "traffic signal" indicators in the electricity bills of customers once annually.

Table 9.5: List of Major Indicators

INDICATOR	What it Measures
Total System Losses (Transmission & Distribution)	The amount of electrical energy that is lost in the system
Current Ratio	Financial Health – Liquidity
System Average Interruption Frequency Index (SAIFI)	Reliability
Customers per Employee Ratio	Operational Efficiency of the company
Written Complaints Response Rate	Customer Responsiveness

Source: RIC

The RIC will continue to produce and publish on the RIC's website its Performance Monitoring Report, which scrutinises and provides an in-depth analysis of the T&TEC's operation in keeping with the RIC's regulatory role. In addition, a more reader-friendly version of the report that could generate public and media discussions will be prepared. This report will also be published in other media, including newspapers and on social media platforms like Facebook and Twitter, to allow readers to post their comments.

As indicated, the service provider is subject to a range of incentive mechanisms against which it can earn rewards or face penalties. The service provider also faces a number of specific obligations/targets which can attract penalties if not met. Table 9.6 presents a summary of these incentives.

Table 9.6: Incentive Mechanisms in Operation/Proposed for T&TEC

Mechanism	Brief Summary
Opex and Capex Incentives:	
• **Efficiency Carry-over Mechanism**	Five-year rolling incentive for both Opex and Capex where the service provider retains the benefits from efficiency gains for a period of five (5) years, irrespective of the year in which the gains are made.
• ***Ex-post* Efficiency Review**	*Ex-post* Capex review to decide whether customers should be exposed to bearing costs based on prudency test.
• **Capex Safety-net (new)**	Annual review of allowed Capex to determine if the Capex underspend/overspend is greater than 20% of the allowance.
• **System Losses Incentive (revised)**	Penalty for not achieving a set target for reducing the level of losses on the system.
• **Capex Information Quality Incentive (new)**	Rewarding service provider for honesty in Capex forecasting.

Mechanism	Brief Summary
Uncertainty Mechanisms:	
• **Re-openers**	Provision to open price limits during the price control period (e.g. if allowed revenue fell short by 10%).
• **Logging Up and Down**	Enables a revenue adjustment in the next control period for specified items or areas of expenditure.
• **Pass-through**	Provision for an uncontrollable cost pass-through.
Incentives Relating to Output Delivery:	
• **Reliability and Customer Service Incentives**	To improve performance in reliability and customer service (e.g. number and duration of interruptions, telephone call response).
• **Worst Served Customers (new)**	The incentive to improve service for those experiencing three (3) or more interruptions.
Guaranteed and Overall Standards Scheme:	Stipulating minimum binding targets in a number of areas (e.g., supply restoration, notice of planned outages, keeping appointments, etc.), with financial penalties.

Source: RIC

9.9 ENFORCEMENT AND SANCTIONS

Designing and implementing sanctions are among the essential functions of any regulatory regime, as the two core tasks of economic regulation are tariff setting and the specification and enforcement of performance requirements. Performance requirements must be associated with sanctions of some kind for them to be effective. This is especially important in a regime using *ex-ante* price setting in which the service provider gains if it can find a way to reduce costs. There are a number of different types of sanctions, including:

- **penalties** – where the service provider pays a specified sum of money for each instance of non-compliance;

- **compensation to customers** – where the payments are made directly to the affected customers; and

- **an adjustment** – where the revenue requirement at the next control period is adjusted to reflect divergences of performance.

Some regulators adopt a regime of "deficiency points", where a pre-determined number of deficiency points accrue for each instance of a breach, and the regulator takes a specified action. The different levels of action corresponding to a different levels of deficiency points could involve:

- warning notice to the service provider;
- more intensive monitoring of performance at the service provider's expense;
- a requirement for the service provider to produce a remedial plan; and
- a full technical audit by an independent auditor at the service provider's expense.

The RIC experienced several challenges in incentivising T&TEC to implement and comply with some of the directives, critical decisions and recommendations for improved sector performance as articulated in RIC's PRE1 Final Determination. This challenge inhibited the sector's development and precluded the benefits envisioned for all stakeholders as embodied in the PRE1 Final Determination. The RIC is mindful that PRE1 was the first time that Incentive Regulation and a Revenue Cap were used in the regulation of the sector and that T&TEC may have required some time to become acquainted with the methodology. However, the RIC now considers that sufficient time has elapsed to allow the service provider to understand the methodology and become patently aware of the importance of meeting set targets. The RIC's experience provided useful insight into how positive incentives or "carrots" are sometimes inadequate, particularly in the case of utilities that are State-owned monopolies. The RIC is mindful that perhaps a combination of "carrots" and "sticks" may be more effective in such instances.

In this regard, the RIC has identified four (4) critical areas in which T&TEC's compliance and commitment must be paramount. These are:

- implementation of tariffs as and when approved by the RIC;
- meeting specific directives and targets;
- accountability, transparency and stakeholder participation; and
- submission of information as and when requested.

Where T&TEC fails to meet the required standards/obligations, the RIC will initiate an enforcement action consistent with best practices and within the provisions of the RIC Act. Some of the regulatory sanctions may include administrative actions and enforcement of the statutory powers as outlined below:

- **Additional Reporting** – Performance reports are generally undertaken annually. In case of repeated failures, the RIC will require more regular reporting by the service provider, outside the annual system. This may also include directives to the service provider to produce reports and make them public;

- **Investigation** – This will involve detailed investigation of the service provider's performance and data quality by the RIC's approved Auditor; and

- **Enforcement and Fines** – The RIC will, if necessary, use this major sanction in keeping with Section 66 of the RIC Act.

10 MISCELLANEOUS AND OTHER REGULATED CHARGES

10.1 INTRODUCTION

T&TEC's revenue is derived from regulated and unregulated services, with the latter accounting for approximately 3.5% of total revenue over the last five years. Regulated services comprise electricity sales, miscellaneous services and incidental charges. Miscellaneous charges include; disconnection/ reconnection, meter installation and repositioning, visits for non-payments, repositioning of secondaries, and meter checks at the customer's request. Incidental charges include; service deposits, late payment fees, and capital contribution. Unregulated services currently include; the rental of poles and transformers, high voltage (HV) isolation, temporary supply, and installation/removal of pennants and banners.

Regulated and unregulated services are reviewed during a price review. Regulated services are examined to determine whether current charges remain adequate for the extant circumstances. The list of unregulated services is revisited to determine whether these should be brought under the purview of the regulator.

The sections below discuss specific issues relating to miscellaneous and other regulated charges and the RIC's proposals for addressing them in PRE2.

10.2 MISCELLANEOUS SERVICES & CHARGES

Miscellaneous charges are fees levied for non-routine services which are incidental to T&TEC's core service of providing electricity. The recovery of the cost of providing miscellaneous services is not usually factored under the price control mechanism used to set tariffs, as they do not collectively account for a significant proportion of T&TEC's total annual revenue (<1%). However, miscellaneous charges can significantly impact individual customers, particularly those in low-income groups. Therefore, the regulator attempts to protect consumers by ensuring that these charges are as reasonable as possible. Three issues must be considered when setting charges for miscellaneous services; these are discussed below.

A. Determining Miscellaneous Services

In PRE1, T&TEC proposed that a procedure for introducing new services should be agreed upon. The RIC had argued that it did not seem possible, within the confines of the Act, to provide the flexibility to automatically adjust the list of services or charges within the price control period. The RIC's view was that the opportune time for changing the list of services was during a determination exercise, owing to the process that had to be followed, including the need for public consultation. This view was reinforced by the impracticality of engaging in a separate determination exercise during the price control period to introduce a new service, given the very small proportion of income from miscellaneous charges relative to the total revenue of the service provider. Thus, the RIC's decision in PRE1 was not to provide the flexibility to automatically adjust the list of services or charges during the price control period.

T&TEC did not raise this issue in its proposals for PRE2. Therefore, there will be no automatic adjustment to the list of current services or charges. The RIC's view remains that the list of miscellaneous services and their corresponding charges should be reviewed periodically.

B. Fee Structure for Miscellaneous Service Charge

In PRE1, T&TEC proposed the introduction of a price adjustment mechanism that could be utilised to allow for cost increases over the regulatory control period. The RIC maintains its view that any analysis of the "true cost" of delivering miscellaneous services would entail detailed and disaggregated cost analyses of the various operational and administrative activities required to deliver a particular service. This information would facilitate an appropriate cost allocation methodology to support the respective charges.

The RIC considered several options for the initial change in price (Year 1) and thereafter, the annual adjustment of these charges, including:

- by the annual change in the RPI. This is the simplest approach and assumes that the costs of providing these services will change in line with general inflation;

- by the average annual increase in electricity prices under this determination. This option assumes that miscellaneous charges will increase at the same rate as overall costs; and
- by the annual increase in the operating expenditure portion of the revenue requirement. This option also assumes that miscellaneous charges will increase at the same rate as operating costs.

For PRE2, T&TEC did not propose any price adjustment mechanism or increase in Miscellaneous Services Charges and in this regard, a detailed cost analysis of the disaggregated costs associated with miscellaneous charges was not available. Notwithstanding, since T&TEC's overall costs have increased over the last decade, it is reasonable to conclude that the cost to provide these services has increased since PRE1. Therefore, the RIC proposes to utilise the annual change in inflation as the basis for setting new starting charges for miscellaneous services, the exception being Disconnection for non-payment which the RIC believes should at minimum, be equal to the charge applied for a visit for non-payment of account.

Charges should reflect the full, efficient costs of providing these services, hence, **T&TEC will be required to submit a detailed breakdown of the typical costs to provide the miscellaneous services that are on the current list, by the end of the second year of PRE2. At the same time, T&TEC must submit a customer impact analysis and must have regard to the impact of any changes on vulnerable/low-income groups, and ensure that customer impacts are not unreasonable.** The information will be assessed to determine whether new charges for miscellaneous services are to be applied from the mid-point of PRE2. Changes to miscellaneous charges within PRE2 would only occur on evidence that existing prices do not cover the reasonable costs associated with that particular service, and after approval by the RIC.

Therefore, the charges should be established as follows:

Miscellaneous Charge = Base Cost + Direct Material Cost

Where: - Base Cost is a portion of Business Unit Overheads (to be determined by the RIC in conjunction with T&TEC); and
- Direct Material Cost is the cost of materials used.

The current list of Miscellaneous Services, their existing charges and the new **charges proposed for PRE 2** are shown in table 10.1 below.

Table 10.1: Miscellaneous Charges

List of Services	Existing Charges ($)	New Charges for PRE2 ($)
Meter check (at customer's request) - If found in working order - If found defective	 194.00 No charge	 246.00 No charge
Visit for non-payment of account	234.00	297.00
Install meter and reconnect secondaries	194.00	246.00
Reconnect: disconnect and/or change meter	194.00	246.00
Reposition of secondaries	194.00	246.00
Change and/or reposition of meter	194.00	246.00
Disconnection for non-payment	118.00	297.00
Reconnection after disconnection for non-payment	118.00	150.00

Source: RIC

11.2.1 Meter Checks

T&TEC tests meters at its discretion or at the request of the customer. Meter checks at the customer's request incurs a miscellaneous charge if the meter is found to be registering correctly. Any meter found to be registering within a range of plus or minus two percent either fast or slow is considered as registering accurately. In PRE1, the RIC decided that there should be at least one free meter test every five (5) years. The customer would be required to pay the fee established by the RIC for an additional meter check within the five-year period, depending on the outcome of the test. If the meter was found to be reading accurately, the customer would pay the fee but if the meter was found to be defective, there would be no charge.

The RIC engaged T&TEC on its proposals for metering in PRE2. On the basis of these discussions, the RIC noted that most existing AMI meters are approaching the end of their useful life and meter accuracy is starting to decline. The RIC has made provision in PRE2 towards the upgrade of the meter reading framework and replacement of 50% of meters over the five-year period. Because a significant number of existing meters will remain in use, the RIC proposes to reduce the timeframe for a free meter check, since the probability of inaccurate meter reading will be heightened.

The RIC therefore requires that T&TEC provide a free meter check every four (4) years instead of every five (5) years. Where the customer makes another request for a meter check within the four-year period, the current policy will remain intact, that is, there be no charge if the meter is found to be defective, but the customer will pay the relevant charge if the meter is reading accurately.

10.3 SERVICE DEPOSITS

A service/security deposit (SD) is implemented as a measure that safeguards the recovery of cost for electricity supplied to consumers. The main rationale for having a SD is to minimise the risk of financial loss associated with bad debts arising from non-payment of bills by customers. Utilities and regulators worldwide consider the application of a SD as a fair and reasonable approach to mitigate such risks.

During PRE1, consumers raised two main areas of concern: the structure and value of the SD, and the payment of interest. As indicated above, utilities impose service deposits[37] for different reasons, but some pay interest on the SD at a rate and on terms approved by regulators. The

[37] Most utilities utilise service deposits as part of their connection charging policy. A connection charging policy establishes how connection charges are set for customers for a new or modified connection to the network.

RIC addressed these issues following the recommendations from a Working Group, which was established to discuss key regulatory issues. The RIC's decision in PRE1 was that the SD would attract no interest and the existing $95.00 charge would not be adjusted.

T&TEC proposed that for PRE 2, the SDs for Residential and Commercial customers be increased to the value of two (2) billing periods, based on an average monthly kWh consumption of 627kWh for residential customers and 1,361 kWh for commercial customers. Also, for industrial customers, T&TEC proposed that the SDs should be double the existing rate (the higher of 75% reserve capacity and minimum kVA consumption).

In its consideration of T&TEC's proposals, the RIC notes the following:

- Historically, some customers (tenanted and non-tenanted) of T&TEC have vacated their accommodation/building without settling their outstanding bills. T&TEC has already implemented measures to identify delinquent customers by assigning a unique customer number. Therefore, regardless of location, the payment history of the customer is identifiable by T&TEC thereby reducing the risk of bad debt. Also, with respect to tenanted arrangements, the RIC previously suggested that once it is legally permissible, T&TEC should advise the owner, at the time that a request is being made to change the name on the account to an occupier, that the owner (not the occupier) will be responsible for non-payment of the account.
- Some customers that have been responsible for illegal electricity consumption in the past may seek to be connected to a new supply. The RIC recognises that these customers are not typical. Therefore, appropriate risk-mitigating measures should be implemented by T&TEC to safeguard the utility from financial loss/risk presented by these customers when they request a new supply.
- T&TEC provided no basis for their proposal of the SDs being increased to the value of two billing periods, especially since all residential and commercial customers will be moving to monthly billing. The RIC notes that this change may require the timelines for disconnection to be reviewed.

- In many jurisdictions[38], the service deposit is returned to the customers after a defined period where the customer has not defaulted in meeting its obligations to the utility. In several instances, this period is twelve (12) months for Residential customers and twenty-four (24) months for businesses (inclusive of commercial and industrial). The RIC has also observed in other jurisdictions, the accrued interest, on the service deposits held by the utility, is included in the funds that are eventually returned to the customer.

The RIC recognises that service deposits are linked to connection charging and will further consider this issue as part of the process of reviewing the feasibility of connection charging. Notwithstanding, the RIC's view is that T&TEC's proposal[39] for the increase in the SD for residential and commercial customers is not reasonable, considering the quantum of the existing SD and the impact of new rates on the proposed SD. Therefore, **for Residential and Commercial customers requesting a new account, T&TEC can increase the SD from the existing $95.00, to the value of one month's average bill for customers within the respective class** based on an average monthly kWh consumption of 627kWh for residential customers ($234.30) and 1,361 kWh for commercial customers ($878.82). **This SD is to be retained by T&TEC for one year (12 months) and thereafter, returned to the customer.** The RIC and T&TEC will discuss how this is to be implemented including circumstances that may delay the return of the SD, conditions under which the requirement of an SD can be reintroduced, whether the SD should be returned to the existing account holder or applied to the account and other implementation issues. The SD will attract no interest for the period that it is retained by T&TEC. When implementing this new SD requirement for residential customers, T&TEC should use discretion when assessing customers that are considered to be vulnerable, such as, those in receipt of government pensions and other government grants.

The RIC believes that there may be merit to doubling the existing requirement for industrial customers, given the greater financial loss that may be incurred by T&TEC, if these customers default. However, the RIC's view is that effecting such a change may not be prudent at this

[38] These include various individual states in the USA.
[39] T&TEC proposed a service deposit of $580 for residential customers and $2,220.10 for commercial customers.

time. **Therefore, for industrial customers requesting a new account, T&TEC can increase the SD to the value of one month's average bill (the higher of 75% reserve capacity or minimum kVA consumption). This SD is to be retained by T&TEC for one year (12 months) and thereafter returned to the customer.** The RIC and T&TEC will discuss how this is to be implemented. The SD will attract no interest for the period that it is retained by T&TEC.

10.4 LATE PAYMENT FEE (INTEREST CHARGES)

The late payment of bills imposes costs on T&TEC, such as costs related to disconnections and field visits. In PRE1, the RIC introduced a late payment fee to allow T&TEC to recover the efficient costs incurred to treat with delinquent customers. The absence of a late payment fee would also reduce the incentive for customers to pay their bills on time and could result in T&TEC having to send more reminder notices, thereby giving rise to longer delays between billing and collection. Late payment costs ought to be recovered from those customers who make late payments and not from all customers through tariffs. **Therefore, T&TEC is required to retain the late payment fee (interest charges) of 1.5% per month or part thereof and maintain the current conditions related to imposing a late payment fee**, that is, that the late payment fee will only be levied:

- on or after a date at least 15 days after the due date;
- by informing the customer via a specific line item on the next bill; and
- where T&TEC seeks the recovery of undercharges for electricity consumption, in instances where the customer is deemed culpable, under the RIC's Code of Practice COP 4.4 (2).

However, the late payment fee must not be levied:

- during a period in which there has been an agreed extension of time between the customer and T&TEC;
- where a customer has made a billing-related complaint to T&TEC or the RIC and that complaint has not been resolved;
- where a customer has entered into a deferred payment arrangement with T&TEC, in accordance with COP 2.4;

- where T&TEC seeks the recovery of undercharges for electricity consumption, in instances where the customer is not deemed culpable, under the RIC's Code of Practice COP 4.4 (1); and
- where a customer has been identified as experiencing payment difficulties under COP 2.3.

10.5 CAPITAL CONTRIBUTION

Capital Contribution is defined as an advance lump sum payment made to T&TEC by the customer to facilitate infrastructure works for an electricity supply. In essence, it is the customer's contribution to the capital cost of new network development. For instance, it may apply for partial or full payment of the capital cost to extend the network where a customer's premises are not located close to the existing network, or where the network is already fully used and new capacity is required.

Customers and service providers respectively can have concerns regarding the impact/effect of capital contributions for the following reasons. Capital contribution can have a negative impact on customers' finances as such expenses are typically significant in value and not part of the normal planned expenditure. Additionally, the charging methodology raises equity issues, as it encourages parties seeking connections to delay in the hope that someone else will fund the necessary infrastructure to which they would subsequently be able to connect at no cost (free-rider problem). Alternatively, if a large proportion of the network extension costs is recovered through tariffs rather than through capital contribution payments, the customer being connected enjoys a significant benefit at the expense of other customers on the system. Thus, masking these costs can lead to inefficient network investments.

There are a number of issues to consider in respect of capital contributions, and these may be grouped into the following areas:

- definition of a connection point;
- reimbursement entitlements;
- definition of shared assets;

- funding of connection works; and
- asset ownership.

The RIC had established a Working Group made up of different stakeholders, during PRE1, to examine and report on capital contribution issues that were considered to be complex, and to have far-reaching effects. The Working Group's proposals and the RIC's assessment of all the issues, resulted in the development and implementation of a new Capital Contribution Policy in 2009. Several implementation issues arose over time, and that led to a revision of the policy in 2022. The RIC consulted with stakeholders to ensure that the policy remained fit for purpose. In October 2022, the RIC issued a revised policy which applies to new connection points and alterations to existing connection points that require network upgrades or extensions of existing network assets. It does not apply to customers seeking connections for embedded generation. **Therefore, T&TEC will be required to implement the revised Capital Contribution Policy (2022)** and the RIC will monitor implementation of the CCP during PRE2.

10.6 UNREGULATED CHARGES

Some services offered by the utility are currently unregulated by the RIC and these must be reviewed periodically, to determine whether they should be reclassified as regulated services. Services that are currently unregulated include pole and transformer rentals, high voltage (HV) isolation, temporary supply, and installation/removal of pennants and banners.

The RIC has examined the scope of these services against what is typically included under miscellaneous services and found that HV isolation, temporary supply, and transformer rentals are non-routine and incidental to T&TEC's core business. **Therefore, the RIC has decided that HV isolation, temporary supply and transformer rentals should be regulated going forward.** However, the RIC does not currently have detailed and disaggregated cost analyses of the various operational and administrative activities involved in these services. I**n the interim, therefore, T&TEC will continue to apply the charges that were set for these services as shown in table 10.2 below. Transformer rental services will continue at the existing rates.**

Table 10.2: New Miscellaneous Services and Interim Charges

NEW Miscellaneous Service*	Interim (2023) Charges TT$
HV isolation during normal working hours	4,689.36
HV isolation during weekends and public holidays	16,300.44
Direct single phase temporary supply	3,024.7
Direct three phase temporary supply	5,718.41
Temporary Supply (URD) "Stick in meter"	2,131.44

*Includes transformer rental services

Source: RIC

By the end of the second year in PRE2, T&TEC will be required to submit a detailed breakdown of the typical costs to provide HV isolation, temporary supply, and transformer rental services. This information will form the basis upon which the RIC may determine new charges to be applied by the mid-point of PRE2.

The RIC has found that **pole rentals and installation/removal of pennants and banners are not incidental to T&TEC's core business and therefore, the RIC's decision is that these services will remain unregulated in PRE2.** It should be noted that even though pole rentals are generally considered non-distribution services and, therefore, are not generally subject to regulation, regulated assets that are paid for by customers of the utility are used to provide this service. To address this issue/conflict, the RIC has adjusted the revenue requirement in PRE 2 to account for income from pole rentals and other income not generally subject to regulation.

11 REVENUE REQUIREMENT

11.1 INTRODUCTION

One of the most important issues that has to be considered when determining prices is the amount of revenue the service provider should be allowed to receive to efficiently provide services and earn a return on its asset base. This forecast (or notional) revenue requirement must be sufficient to cover:

- the operating and maintenance costs of the service provider;
- regulatory depreciation (or return of capital) to allow for the progressive use of assets;
- a return on the capital investment; and
- an allowance for working capital.

The RIC utilised the building-block approach to calculate the above cost items and allowances for the control period. This chapter combines the individual building-block components, discussed in detail in Chapters 4, 7 and 8, to estimate the forecast revenue requirement. The incorporation of efficiency gains in the forecast revenue requirement provides the service provider with the opportunity to fulfil its potential to improve the efficiency of its Opex and Capex, without reducing the quality of service. A well-defined and targeted efficiency intervention is considered an enabling factor to convert gains into cost savings. The efficiency savings that the RIC expects T&TEC should be able to achieve, are assessed in several ways, including through benchmarking with similar utilities. Any variations from forecast revenue, whether favorable or not, will either redound to the benefit or will be borne by the service provider.

11.2 CALCULATING REVENUE REQUIREMENT

Once the forecast/notional revenue requirement is established, any necessary revenue adjustments (either positive or negative) are made to arrive at the annual revenue requirement (ARR) forecasts upon which the price controls are based. These adjustments include offsetting non-tariff revenues and any other adjustments the regulator makes in its determination of the service provider's revenue needs.

The functional form of the model utilised by the RIC for estimating the forecast revenue is shown below:

$$\mathbf{Rev._{Max} = WACC * (RAB + WC + Capex) + D + Opex_{TD} + PP + F}$$

where: $Rev._{Max}$ = Maximum Revenue

WACC = Weight Average Cost of Capital

RAB = Regulatory Asset Base

WC = Working Capital[40]

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.

This functional form is consistent with the RIC Act, as Section 67(4) states that the RIC 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.

In establishing the annual revenue requirements (ARR) for PRE2, the RIC utilised a cost of capital of 5.1%, straight-line depreciation (discussed in Chapter 3), operating and maintenance expenditure requirements, conversion and fuel costs (discussed in Chapter 7), and capital

[40] A detailed discussion on how Working Capital is calculated can be found in the RIC's Final Determination Document "Regulation of the Electricity Transmission and Distribution Document, June 1, 2006 to May 31, 2011," page 150, which is available on the RIC's website, www.ric.org.tt

expenditure (discussed in Chapter 8). Table 11.1 summarises the major assumptions used in arriving at the revenue requirements.

Table 11.1: RIC's Major Assumptions for Determining Revenue Requirements

Variable	Main Assumptions
• Personnel Costs	Wages and salaries to increase by 2% per year.
• Repairs and Maintenance Expenses (R&M)	R&M expenditure set at 1.5% of gross fixed assets for transmission assets and 2.5% of gross fixed assets for distribution assets.
• Generalized Efficiency Factor	2% efficiency gains per annum on Opex (Transmission and Distribution).
• Cost of Capital	Cost of capital of 5.1%, to be applied to RAB, inclusive of new Capex.
• Return on RAB	No return on equity. No return on inflation indexed part of RAB.
• Macro-economic assumption	Inflation (core) rate of 1.1% per year.

Source: RIC

To calculate the revenue to be recovered from tariffs, the RIC made a number of adjustments to the forecast (notional) revenue requirements. Consistent with PRE1, non-tariff income from shared assets (e.g. rental of poles) was removed from the revenue requirements.[41] Another adjustment was made to account for the periodic dividends received by T&TEC from its investment in PowerGen.[42] Since T&TEC received subventions from Government, the assets in question are essentially paid for by taxpayers who are also rate payers. As a result of this, the RIC has determined that any returns from these assets should be returned to the rate-paying base. Therefore, no return on capital was included in the forecast revenue for those assets.

The annual revenue requirements for PRE2, 2023–2027 are detailed table 11.2 below.

[41] The revenue adjustments can also be made based on the service provider's "unders and overs" account, as well as for items such as disposal of assets, change in asset lives, etc. These deductions ensure that customers do not contribute twice to the revenue requirement.

[42] T&TEC's 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).

Table 11.2: T&TEC Requested and RIC Approved Forecast Revenue Requirements, 2023-2027 ($Mn)

	T&TEC REQUESTED	RIC APPROVED	2023	2024	2025	2026	2027
Conversion Cost	9,492.37	9,311.11	1,764.99	1,788.45	1,896.88	1,917.48	1,943.31
Fuel Cost	10,564.19	10,035.97	1,752.22	1,859.74	2,023.37	2,139.51	2,261.13
T&D Cost	6,620.61	5,108.49	1,005.40	1,043.21	1,038.00	1,022.40	999.48
Depreciation	1,844.44	1,399.70	279.27	279.02	280.55	280.03	280.83
Return on Capital	1,466.88	1,447.90	282.97	287.35	290.00	291.82	295.76
Return on Working Capital	140.33	12.63	1.53	1.54	1.56	3.99	4.01
Unsmoothed Revenue Forecast	**30,128.82**	**27,315.80**	**5,086.38**	**5,259.31**	**5,530.36**	**5,655.23**	**5,784.52**
Less: Revenue from Non-Tariffs*	1,000.00	1,005.00	201.00	201.00	201.00	201.00	201.00
Unsmoothed Rev. Req. before NGC Debt	**29,128.82**	**26,310.80**	**4,885.38**	**5,058.31**	**5,329.36**	**5,454.23**	**5,583.52**
Add: NGC Debt	-	1,157.42	-	-	-	578.71	578.71
Unsmoothed Rev. Req.	**29,128.82**	**27,468.22**	**4,885.38**	**5,058.31**	**5,329.36**	**6,032.94**	**6,162.23**

***This includes dividends, capital contributions, pole and transformer rentals, asset disposal, etc.**
Source: RIC

The RIC's approved revenue requirement, exclusive of NGC debt is $2,818.02 million lower than T&TEC's proposal over the five years of this regulatory control period. This difference reflects a number of decisions to ensure efficiency and prudency, including:

- reduction in forecast of operating expenditure ($1,512.12 million):
- reduction in conversion ($181.26 million);
- reduction in fuel costs ($528.22 million); and
- reduction in depreciation charges ($444.74 million).

The RIC included $1,157.42 million into the revenue requirement to cover a portion of the outstanding sum payable to the NGC for natural gas purchased over the period 2019-2022. The total revenue requirement shown in table 11.2 is considered to be sufficient for T&TEC to adequately meet the expenditure required for the effective exercise of its core functions, as well as to comply with quality-of-service standards and other RIC requirements for improvement in customer service. As indicated above, once allowed revenue is established, prices are set for individual services to recover costs.

11.3 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 11.3 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 11.3: Implied Average Annual Price Changes, 2023-2027

	2023	2024	2025	2026	2027
Annual Unsmoothed Revenue Requirement ($Mn) **% Change**	4,885.38	5,058.31 **3.54%**	5,329.36 **5.36%**	6,032.94 **13.20%**	6,162.23 **2.14%**
Forecast Consumption (GWh)	**8,509**	**8,805**	**8,897**	**8,992**	**9,089**
Implied **Nominal** Price (¢/kWh) **Year-on-Year Percentage Change (%)**	0.57	0.57 **0.0**	0.60 **5.3**	0.67 **11.7**	0.68 **1.5**
Implied **Real** Price (¢/kWh)* **Year-on-Year Percentage Change (%)**	0.52	0.51 (1.9)	0.53 3.9	0.58 9.4	0.58 0.0

Source: RIC ***Base year 2015 (core RPI – 1.1%)**

11.4 REVENUE SMOOTHING AND CALCULATION OF THE X-FACTOR

12.4.1 Introduction

After determining the revenue requirements for each year, the RIC calculated the amount by which T&TEC's revenue can be adjusted in each year of the regulatory control period to generate the calculated revenue requirements, so as to smooth the revenue over the control period. As can be seen from table 11.3, there is an increase in the revenue requirement of 3.54% between 2023 and 2024. The increase in the annual revenue requirement fluctuates each year thereafter, eventually decreasing to 2.14% between 2026 and 2027. It must be noted that the true revenue of T&TEC for each year will depend on actual sales of electricity and costs and therefore may be more or less than forecast revenue requirements.

Under RPI-X regulation, the regulator determines the X-factor. The X-factor is the real change (inflation adjusted) in revenue or prices each year. To determine this X-factor, the regulator must determine:

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

12.4.2 Form of the X-Factor and Smoothing

In Chapter 2 the RIC indicated its preference to continue with a fixed (total) revenue cap form of regulation for PRE2. The fixed amount (cap) is usually subject to an annual adjustment for productivity gains (called the X-factor) and inflationary effects.

A core issue in setting the trajectory of prices is the relative value of X and the starting price level. By changing the value of X, the price control formula profiles the distribution of revenue over time, while maintaining the same net present value (NPV) of revenue. Therefore, the X-factor is used to smooth-out the allowed revenue over the control period so customers are not faced with volatile tariffs.

The X-factor can 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_0 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 must be "smoothed" over the regulatory control period in order to allow for the use of a stable X-factor.

In considering any revenue smoothing, the RIC must consider conflicting objectives. In particular, the RIC Act specifically requires that the service provider can earn sufficient return to finance necessary investment (that is, over the regulatory period and not necessarily in any given year), while having regard to the ability of consumers to pay rates.

There are four alternative approaches for calculating the amount by which revenue may be adjusted to deliver the forecast revenue requirements to the service provider over the regulatory period. These include:

- 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_0 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_0 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 so that it equals its forecast revenue requirement in the final year of the control period (as under the straight-line approach).

In deciding which approach to use, the implications of each approach must be considered, including price stability; revenue recovery; incentives for efficiency and transitional issues going into the next regulatory period. A revenue-cap plan must begin from a "fair" starting point, which must provide the utility with a reasonable opportunity to recover its just and reasonable cost of doing business, including cost of capital.

In the calculation of a constant X-factor, straight-line smoothing and net present value (NPV) smoothing methods are more commonly used. 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 smoothed revenue requirement for the last year equals the unsmoothed revenue in the last year of the regulatory period. In this approach, 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 total smoothed and unsmoothed revenues are equal in NPV terms, where average revenue grows by RPI-X every year. In other words, 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. Equating 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 also the simpler "Average Growth Rate Smoothing" method which can be utilised to meet the stated criteria of price stability, revenue recovery and treat with transitional issues to the next control period.

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. Smoothed revenues were derived utilising the three methods of revenue smoothing. A comparison of outcomes under these methods is presented in table 11.4.

Table 11.4: Comparison of Outcomes of Smoothing

	NPV Smoothening	**Straight Line Smoothening**	**Average Growth Rate Smoothening**
Constant X-Factor (includes RPI)	3.80%	4.72%	6.06%
Level of Revenue Recovery ($Mn) (Unsmoothed)			
2023-4,885.38	5,078.29	5,123.55	5,189.00
2024-5,058.31	5,271.15	5,365.53	5,503.50
2025-5,329.37	5,471.34	5,618.94	5,837.06
2026-6,032.94	5,679.13	5,884.32	6,190.83
2027-6,162.23	5,894.82	6,162.23	6,566.05
Total -27,468.26	**27,394.73**	**28,154.58**	**29,286.44**
Revenue Recovery Over 5 years	**Almost full in NPV Terms**	**Over by $686.32**	**Over by $1,818.18**
Final Year Revenue Recovery	**Under by $267.41**	**Equal**	**Over by $403.81**

Source: RIC

The results show that the NPV method would require revenues to go up by 3.80% (RPI+ X) for each year of the control period and the X factor is 2.7%, given that the RPI used is 1.1%. In the case of straight-line and average growth rate methods, it would require revenue increases of 4.72% and 6.06% respectively. However, both the straight-line smoothing and average growth rate smoothing will over recover revenue by $686.32 million and $1,818.18 million respectively, over the regulatory control period.

In essence, the NPV smoothing provides a more reasonable and acceptable balance of the interests of all stakeholders. In light of the above, the RIC utilised the NPV smoothing approach which achieves an equivalent NPV to the unsmoothed revenues.

NPV smoothing of T&TEC's annual revenue requirements eliminates year-to-year volatility while still returning the same amount of revenue (in NPV terms) over the regulatory control period, see table 11.5.

Table 11.5: NPV Smoothed Annual Revenue Requirements, 2023-2027

	2023	2024	2025	2026	2027
Unsmoothed Revenue Requirement:					
- $Millions	4,885.38	5,058.31	5,329.37	6,032.94	6,162.23
% Change		**3.54%**	**5.36%**	**13.20%**	**2.14%**
Smoothed Revenue Requirement:					
- $Millions	5,078.29	5,271.15	5,471.34	5,679.13	5,894.82
% Change		**3.80%**	**3.80%**	**3.80%**	**3.80%**

Source: RIC

Under the NPV smoothing approach the average revenue will increase by 3.80% per year (in real terms). 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 the guaranteed quality of service standards. **Consequently, the RIC's decision is to adopt the NPV smoothing approach as it allows the service provider to fully recover its revenue requirements, as well as minimise price volatility for customers.**

11.5 ASSESSING FINANCIAL VIABILITY

12.5.1 Importance of Financial Viability Analysis

In this section the financial viability analysis of the price control settlement is undertaken. 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.

A key element here is the cost of capital. 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 standpoint, an efficiently financed utility should be expected to be able to attract sufficient funds to finance its functions, given an appropriate rate of return on both equity and debt. However, capital investment programmes may be "lumpy" and a large Capex programme might leave a utility with temporarily low interest cover ratios. Consequently, regulators often use financial indicators and tests to adjust allowed returns.

The major objective of the financial indicator analysis is to monitor the ability of the service provider to attract equity and its ability to raise debt financing and service its debt. Since no provision was made for equity, this is not a concern for the RIC at this time. The second focuses on the credit worthiness of the regulated business. This objective will be met if the cash flows implied by the regulated revenues could sustain a commercially satisfactory credit rating. The results of the financial analysis can also be utilised as a "check" on the proposed initial regulatory asset base (RAB). For instance, if the service provider's initial RAB 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.

12.5.2 Indicators of Financial Viability

The focus of an assessment of financial viability is the ability of an entity to meet its cash obligations. Therefore, 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, and are likely to provide a misleading impression of the actual needs of the service provider. In fact, cash-based financial ratios are used by privatised 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 tariffs and debt. The RIC expects T&TEC to be broadly compliant with the target value for these ratios (see table 11.6).

The cash flow-based indicators generally measure the ability of a 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 indicator in any specific year. 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 to ensure that T&TEC is able to earn, on average, a return at least equal to the assessed (5.1%) cost of capital. There may be variations in the cash-based indicators from year to year, despite being allowed an adequate return on capital. This is 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: Projection of Key Financial Ratios for T&TEC, 2023-2027

Ratio	Purpose	2023	2024	2025	2026	2027	Outcomes
Funds Flow Interest Cover (times) – [(FFO + Net Interest) / Net Interest]	Measures the level of protection the entity must meet its interest cost after paying its cash operating expenses.	6.97	8.11	3.44	4.51	6.35	Values for all years above target. Hence, the ability to meet interest payments is satisfactory.
Debt Payback Period (years) – [Net Debt / FFO]	Measures the length of time that the entity could retire its debt if it devoted all funds from operations.	16.22	15.26	16.87	14.09	11.29	Values for all years exceed the target but declining. Improvement should be realised.
Internal Financing Ratio (%)– [(FFO – Dividends) / Net Capex]	Measures the extent to which an entity has cash remaining to finance prudent capital expenditure.	18%	15%	16%	19%	21%	Values for all years less than target but improving.
Return on RAB - [FFO / RAB]	Net cash flow returns on the regulatory asset base. (Similar to the return on capital).	10%	10%	8%	9%	11%	Generally, values are satisfactory when compared to target.

Source: RIC

Target Values:

Funds Flow Interest Cover - Greater than 3
Debt Payback period - Between 5 to 7
Internal Financing Ratio - Greater than 40%
Return on RAB - About 9%

Given T&TEC's current financial position and the fact that the cash-based ratios are mainly used by privatised 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 expected to be sustainable when considered as a package over the length of the regulatory control period. Even though all the cash-based financial ratios do not fully comply with target ratios, the majority are trending in the right direction.

12 ESTABLISHING PRICE CONTROLS

12.1 INTRODUCTION

The next step in the price review process is to identify the broad pricing approaches that are utilised to translate the revenue requirement into prices and to assess their impact on customers and the service provider. The RIC Act outlines the matters that it must consider in determining price levels, including the service provider's financial viability and the impact of prices on customers.

This chapter sets out the issues related to the design and structure of tariffs. It also discusses how the service provider's revenue is allocated to recover costs from each of the end-user categories. Finally, it presents the starting tariffs (base tariffs) for the first year of PRE2 and the impact of these on customer bills, T&TEC's financial viability and the wider economy.

12.2 COST ALLOCATION

Cost allocation 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 these 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[43]), costing periods (e.g. peak, off-peak, non-time differentiated), and customer classes (residential, commercial, industrial). Three common approaches are used to allocate costs and set prices; a marginal cost approach, an average/embedded cost/fully distributed approach, and the avoidable cost/equity and social rate-making approach. All methods have advantages and disadvantages and there is no unique method that is used internationally and accepted as best practice.

[43] 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.

The common approaches to cost allocation are outlined below:

- ***Marginal Cost-based Approach*** – the service provider's revenue requirement is achieved using marginal costs as the basis for class revenue development. This is done by determining what the revenue realisation would be if marginal costs[44] 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;

- ***Average/Embedded/Fully Distributed Cost Approach*** – revenue responsibility is assigned using the results of a cost-of-service 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. This is the most common method used for cost allocation.

- ***Avoidable Cost/Equity and Social Ratemaking*** – costs recovered from each customer to 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.

T&TEC uses the Fully Distributed Cost Method for undertaking its 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:

- **Functionalisation** – assignment based on functional categories, e.g. generation, transmission and distribution.

[44] The marginal concept in economics refers to the rate at which one quantity changes with respect to extremely small increases in another quantity. Marginal Cost is often distinguished between short run marginal cost (SRMC) and long run marginal cost (LRMC). SRMC is defined as the change in short run total cost (when at least one of these costs are fixed) for an extremely small change in output and long run marginal cost (LRMC) (when all costs vary) for an extremely small change in output.

- **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 functionalised and classified.

After functionalisation, it is necessary to decide what predominant criteria should be employed for classification of the cost. Under this method, if an account is predominantly (>51%) energy related it is classified as energy costs, and likewise for demand related accounts and 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. There are three methods for allocating demand cost:

- **Coincident System Peak Responsibility Method** – in this method the entire capital costs are imputed to those services that are rendered at the time of the system peak.

- **Non-coincidental Demand Method** – this method apportions capacity entirely based on 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 they 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 above 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 and is arguably the fairest method of allocating demand costs.

The revenue allocation for each class of customers, based on the fully distributed cost method is presented in table 12.1. The fully distributed cost method is akin to the "impactor pays principle”, in which costs are allocated to users of the service in proportion to the contribution that each group of users makes to creating the costs or the need to incur the costs. This principle ensures that electricity users meet the costs they impose on the system. This principle is slightly different from the “beneficiary pays principle”, where charges would be paid by users on the basis of them benefiting from the service.

Table 12.1: Revenue Allocation by Class of Customer

	2023	2024	2025	2026	2027
Residential (45.40%)					
Allocation ($Mn)	**2,305.77**	**2,393.34**	**2,484.24**	**2,578.59**	**2,676.52**
Customers (No.)	464,148	471,141	478,134	485,127	492,120
Consumption (kWh ‘000)	3,257,000	3,308,000	3,358,000	3,408,000	3,458,000
Commercial (11.40%)					
Allocation ($Mn)	**578.88**	**600.87**	**623.69**	**647.37**	**671.96**
Customers (No.)	56,801	57,171	57,667	58,689	59,702
Consumption (kWh ‘000)	952,000	955,000	959,000	963,000	966,000
Industrial (37.85%)					
Allocation ($Mn)	**1,921.74**	**1,994.72**	**2,070.48**	**2,149.11**	**2,230.73**
Customers (No.)	4,018	4,086	4,154	4,221	4,289
Consumption (kWh ‘000)	4,164,000	4,404,000	4,439,000	4,478,000	4,519,000
Street Lighting (5.35%)					
Allocation ($Mn)	**271.89**	**282.22**	**292.94**	**304.06**	**315.61**
Consumption (kWh ‘000)	136,000	138,000	141,000	143,000	146,000
Total Revenue Requirement ($Mn)	**5,078.29**	**5,271.15**	**5,471.34**	**5,679.13**	**5,894.82**

Source: RIC

12.3 ASSESSING CROSS-SUBSIDY

13.3.1 Overview

This section briefly discusses cross-subsidies and presents the results of the analysis to determine whether or not there is cross-subsidisation between classes of electricity consumers under the existing rates. The definition and measurement of cross-subsidy has always been an important regulatory issue. This is so because utilities tend to exhibit cross-subsidies in a more extreme fashion than other sectors of the economy.

It is incumbent on for the RIC to reduce/eliminate any cross-subsidy and move the tariffs towards the "cost of supply". The RIC, in specifying the terms and conditions for the determination of tariffs for PRE1, considered the following:

- factors which could encourage efficiency, economical use of the resources, good performance and optimum investments;
- safe-guarding the customers' interest;
- rewarding efficiency in performance;
- ensuring affordability and availability of electricity to consumers at reasonable rates while ensuring financial viability of the service provider; and
- setting tariffs that reflect the cost of supply of electricity and also, eliminating cross-subsidisation between customer classes.

13.3.2 Price Differentials

The term cross-subsidy is often used to refer to a situation where one group of customers is charged more to lower the price for another group for the same product or service. However, this situation is not necessarily a cross-subsidy but can be variations of price differentiation not justified by costs. Two situations arise under price differentials:

- **Price Differentiation not justified by Costs**. An entity may charge two customers (or two customer groups) a different price for a similar service when that price differential is not justified by objective differences in the costs of supply. There are several examples of this:
  - Unmeasured tariffs are a form of price differentiation that is not justified by costs.
  - Paying a capped bill – where a household pays a capped amount regardless of the electricity used.

- Volumetric charge greater than what can be justified by cost differences, for example, under inclining block tariffs.

- **No Price Differentiation in the presence of Cost Differences**. This applies where a firm charges two customers the same price despite differences in the costs of supplying them. There are a number of examples of this:
  - Geographical averaging – where rural and urban customers pay the same tariff.
  - No differentiation according to payment mechanism and creditworthiness. For example, costs of late payment and bad debt may be recovered from all customers rather than only those who pay late or contribute to bad debt.
  - No seasonal variation in tariffs.

The two situations discussed above describe pricing decisions for groups of customers unrelated to the differences in the costs of supplying them.

13.3.3 Economic Theory of Cross-Subsidy

A more formal definition of cross-subsidy has been developed in economic literature and is based on the work of Gerald Faulhaber[45] who defined subsidy-free pricing and presented two tests for the existence of cross subsidisation:

- a service is the recipient of a cross-subsidy if the revenue generated by producing the service is less than the incremental cost (IC)[46] of providing the service.

[45] Faulhaber, G.R. (1975) Cross-subsidisation: Pricing in public enterprises, American Economic Review, 65(5) December, p. 966-77.

[46] **Incremental cost** – is the additional cost incurred by producing that service (in addition to other services the entity produces). Another way to define it is to ask, "what costs would be avoided, in the long run, if the service was no longer offered." If revenue from each service is at least as great as the incremental cost of that service, then no cross-subsidy exists.

- a service is a potential source of subsidy if the revenue generated by providing the service is greater than the stand-alone cost (SAC)[47] of providing it. Whether or not such a service is an actual source of subsidy depends on whether or not the above first test is satisfied.

The incremental cost test is a **floor test** with two parts:

- Revenue from each service must at least equal its incremental cost for the service to not be the recipient of a subsidy.
- The combined revenue from all possible combinations of a firm's services must at least equal the incremental cost of providing those services.

The stand-alone test is a **ceiling test** with two parts:

- Revenue from each service must not exceed its stand-alone cost for the service to not be a potential source of a subsidy.
- The combined revenue from all possible combinations of a firm's services must not exceed the stand-alone cost of providing those services.

When the entity is subject to a **break-even constraint** (zero profit), the tests are equivalent, that is, to establish cross-subsidy, one need only identify a violation of either the stand-alone test or the incremental cost test. For example, if the revenue from one group of consumers fails to cover the incremental costs incurred, this implies that all other consumers as a group pay more than their stand-alone cost. The obverse is also true. Thus one group's outlay may exceed the stand-alone costs if and only if all other consumers collectively fail to cover their incremental costs. Under a non-zero constraint, the two tests are no longer equal, nor do they imply each other. Failing the stand-alone test does not, of itself, indicate the presence of a cross-subsidy; the entity may simply be making economic profit. In such a case, the focus of cross-subsidy shifts

[47] **Stand-alone cost –** is the cost of producing that service in isolation. In the case of **common costs**, Faulhaber's tests require considering not only each individual service, but also each group of services. Common costs are defined as costs that are borne by a multiproduct firm that cannot be causally attributed to variations in the output of any single product or subset of products.

to the IC test alone, as the SAC test is not helpful under conditions of positive economic profits.

In the case of T&TEC (since it is not subject to a break-even constraint), it is necessary to establish that:

- revenue from a class/group of customers, for example residential customers, is less than the incremental cost of providing service to that particular class of customer and if it is not less, whether revenue from the residential class/group is less than its stand-alone cost; and
- revenue from another class/group of customers (for example, industrial) is greater than the stand-alone cost of providing service to that group of customers.

In short, a test for cross-subsidy is strictly defined as follows:

- a unit of output or a service A is not the source of cross-subsidy if $P_A \leq SAC_A$, where P is the price and SAC is the stand-alone costs
    - a unit of output or a service A is not the recipient of cross-subsidy if $P_A \geq IC_A$, where P is price and IC is incremental cost. A second (or other) output which does not cover its incremental cost is the recipient of such a cross-subsidy.

There is no cross-subsidy when the price of an output A is greater than or equal to its IC and less than or equal to its SAC. **An output A is the source of cross-subsidy if $P_A > SAC_A$, and is the recipient of cross-subsidy if $P_A < IC_A$. An output A is neither the source of, nor the recipient of, cross-subsidy when $IC_A \leq P_A \leq SAC_A$.**

13.3.4 Measuring Cross-Subsidies

While the above cost subsidy definitions are quite clear conceptually, the practical implementation of defining an appropriate measurement method has been one of the more difficult problems in regulatory economics. The simplicity of the examples in the previous section belies a host of theoretical and practical complexities in the application of subsidy analysis in practice. Therefore, all published empirical studies start from cost allocation. Additionally, utilities rarely keep financial records based on the economic cost concepts of stand-alone and incremental costs. In financial records these concepts are generally based on accounting data and provide a proxy for what the true economic incremental or stand-alone costs may be.

There are three general approaches to cost allocation for the purpose of assessing cross subsidies. Apart from SAC and IC, the **Fully Distributed Cost (FDC)** is the third method. The FDC involves the adoption of systematic procedures through which all costs, including common/joint costs, are allocated to a particular service/product. In fact, FDC subsumes different procedures producing different results, especially when a significant proportion of costs are fixed, possibly sunk. Therefore, it is often difficult to find convincing bases for overhead cost allocation.

Despite the above limitations, FDC methodologies form the basis of cross-subsidy estimates. Electricity costs cover four major areas: customer services, distribution services, transmission services and generation services. Costs for the first three areas are largely "fixed", but generation costs vary significantly over time and location. Reflecting this variability in the marginal costs of generation services is a key feature of efficient rates. Costs are identified as direct to a service, attributable account items or unattributable account items. These are defined below:

- **Direct account items** are those account items that are solely associated with a particular service and are, therefore, fundamental to providing that service. Given the nature of operations and network involved, there are only very few items that are direct cost items.

- **Attributable account items** are part of a pool of common account items and can be readily allocated to a particular service and/or class of customers based on relevant allocation factors.

- **Unattributable account items** are part of a pool of common account items and are not readily identifiable to any particular service/class, for example, senior management and central support functions, such as finance and corporate affairs.

Table 12.2 below summarises the treatment of various categories of costs under each cost allocation method and whether the cost is included or not under each method.

Table 12.2: Treatment of Costs under Different Allocation Methods

Cost Category	FDC	Marginal Cost		Incremental/ Avoidable Cost
		SRMC	LRMC	
• **Direct Costs** (e.g. direct labour, material, etc.)	Yes	Yes	Yes	Yes
• **Corporate/ Executive Costs**	Yes	No	No	No
• **Rent**	Yes	No	Not always	Not always
• **Other Overhead Costs**	Yes	No	Yes	To the extent that they are avoided if the activity is not undertaken
• **Capital Costs exclusive to the activity**	Yes	No	Yes	Yes
• **Joint/ Common Capital Costs**	Yes	No	Not in all cases	To the extent that costs can be avoided if the activity is not undertaken

Source: RIC

13.3.5 Calculating Cross-Subsidy

T&TEC uses activity-based costing to allocate costs. Common costs are distributed using different allocation factors, such as, share of direct costs or by some physical measure, such as electricity sales to each class. The RIC calculated SRMC and LRMC for each customer class, using data from 2020, to determine the existence of cross-subsidisation. In simple terms, the marginal cost is the cost of producing another kWh of electricity. Generally, the SRMC just looks at the additional operating costs that would be caused by producing another kWh. The LRMC, on the other hand, also considers the cost of providing additional capacity in the system if many additional kilowatt-hours are produced. Therefore, LRMC measures the **incremental** operating and capital costs associated with meeting additional future demand.

- **Short Run Marginal Cost of Producing another kWh (2020)**

Fuel costs change (increase/decrease) with usage and, as such, are included in the cost of producing another kWh.

Total Fuel Cost	-	$874.68 million
Total kWh Sales	-	$7,721.03 million
Cost per kWh	-	$0.11

T&TEC has contractual arrangements to purchase electricity from generators based on take-or-pay contract. Therefore, fuel cost should be treated as a fixed component not related to volume and should ideally be excluded from the short-run marginal cost calculation. Similarly, depreciation, equipment maintenance, labour and many materials would not be included, as they are treated as fixed and do not increase with usage.

- **Long-term Cost of Producing additional kWh**

The primary long-term cost that needs to be added to the SRMC is the future cost of augmenting the capacity to cope with future demand. This cost may reasonably be represented by the kWh conversion cost of TGU, as this is the latest generating plant to be added to the total capacity. It was calculated to be $0.15 and will be added to the SRMC to calculate the total cost of producing additional kWh (i.e. LRMC). If there was no planned augmentation cost, then this cost would have been omitted and the total long-run cost of producing another kWh would be the same as the SRMC.

As discussed previously, a cross-subsidy only occurs if one group is paying below the LRMC, that is, where one group is not paying for the cost of another kWh, let alone the fixed costs associated with the service. Furthermore, a cross-subsidy can be declared only if a consumer group is paying less than the LRMC, after taking account of any government contributions. Table 12.3 below clearly highlights the non-existence of cross subsidisation between different customer classes at existing rates.

Table 12.3: Cross-Subsidy Calculation (2020)

	Residential (cents per kWh)	**Commercial (cents per kWh)**	**Industrial (cents per kWh)**
• **Cost of Producing additional kWh**	0.26	0.26	0.26
• Average price paid by consumers	0.33	0.44	0.35
• Direct Government contribution (if any)	-	-	-
• **Difference** (contribution toward fixed costs)	0.07	0.18	0.09
• **Cross Subsidy** (Yes/No)	**No**	**No**	**No**

Source: RIC

12.4 OBJECTIVES OF A TARIFF STRUCTURE AND KEY ISSUES

The most important issue to consider 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 and rate design generally include:

- **simplicity** – the tariff structure should be easy to understand. It is more likely that customers who understand the tariff structure will respond more appropriately to the price signals given by the structure;
- **social equity** – the tariff structure should be consistent with the social needs of the society. For instance, the price of electricity for essential use[48] should not be excessive, where excessiveness is defined in terms of the maximum bill that an individual pays as a percentage of their income;
- **cost recovery** – the prices should fully recover the costs of an efficiently operated utility (including an adequate return on capital/investment) but not over-recover costs; and
- **economic efficiency** – the tariff structure should encourage productive, allocative and dynamic efficiency, including the optimal use of scarce resources.

While the RPI-X formula provides the broad framework within which individual tariffs are set, it is the structure of the tariffs that has a more direct impact on consumers and consumption patterns. Thus, the tariff structure is fundamental and equally important as the change in the 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.

The RIC Act contains a number of regulatory objectives that relate specifically to the establishment of price controls. Therefore, the principles/objectives that must be considered

[48] Affordability describes the condition whereby consumers can pay for utility services without foregoing the purchases of other goods and services that are essential to their livelihood.

while designing the tariff structure have to be consistent with these as well as regulatory best practice. These objectives are detailed in table 12.4 below.

Table 12.4: RIC Act - Objectives of Tariff Determination

Objective in the Act	Mechanism to meet the Objective
• Promote efficiency and economy **[Sections 6(1) (d) and 6(3) (a)]**	- Recovery of only reasonable costs of operation from customers (i.e. forward-looking costs). - Providing incentives to reduce costs and improve performance. - Designing tariffs that promote optimum level of consumption and avoid wastage. - Promoting quality and reliability of supply and service to customers.
• Ensure the financial viability and sustainability of the service provider **[Section 6(1) (c) and 67(3) (a) (b)]**	- Recovery of reasonable costs of operation and maintenance. - Recovery of capital costs including a reasonable return on investment. - Stable revenue stream.
• Tariff should be fair, just and non-discriminatory **[Section 6(3) (b) (c)]**	- Tariff should reflect the cost of supply of service provision. - No discrimination against any consumer(s) to burden them with unjustified costs. - Cost of providing different services should be shown separately.
• Ability of consumers to pay rates **[Section 67(1) (c)]**	- Promoting social equity and value for money. - Provision of targeted subsidies for lower income groups.

Source: RIC

The above issues are discussed at length in the RIC's paper **"Principles of Rate Design and Tariff Structures"** which is available on the RIC's website.

12.5 TARIFF RE-BALANCING AND SIDE CONSTRAINTS

The RIC is required to consider several 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 constraint" that limits 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 of how this is applied 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 can have adverse effects in terms of the ability of the regulated firm to fully recover its revenue requirement. Notwithstanding this, the RIC believes that in the economic environment, price stability is a key concern and will therefore continue to incorporate a rebalancing control (side constraint) as part of PRE2.

12.6 PROCESS FOR ANNUAL TARIFF APPROVAL

An integral part of establishing the tariff structure and the annual revenue requirements over the regulatory control period, is the process for annual tariff approval for T&TEC. This section discusses matters that need to be addressed for adjusting prices within the regulatory control period.

The price control mechanism/formula sets out the way 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 have 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 Trigger mechanism to cater for such events.

An important feature of incentive regulation is that once the pricing mechanism/formula is established, the regulator does not adjust it within the regulatory control period, in the event of differences between the actual and forecast revenue requirements. Consequently, the service provider has 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.

The RIC will require T&TEC to submit proposed prices at least three months before the beginning of each year of the regulatory control period and the RIC will give its decision within two months of the submission.

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 method of calculation and other necessary information for understanding the objectives and rationale of the tariffs to be implemented. Once new tariffs are approved by the RIC, the service provider must inform its customers of the new tariffs at least two weeks before implementation.

Finally, T&TEC must produce a report, on an annual basis, explaining how the tariffs had been implemented. The report must provide information on whether the RIC's recommendations/directives made in pricing policy reviews have been implemented, and reasons must be given for any non-implementation thereof.

12.7 OTHER TARIFF ISSUES

As part of its pricing submission for PRE2, T&TEC has proposed changes to the current tariff structure. The RIC also discussed a number of tariff issues and published its document **"Principles of Rate Design and Tariff Structures" for public comments in March 2022**.

This paper includes the following issues on which the RIC will engage T&TEC in future discussions: demand side management, time-of-use pricing and rates for electric vehicle (EV) charging.

Demand Side Management

Demand side management (DSM) 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 to optimise the use of available supply resources, thus postponing or deferring the need to add generating capacity. While there is currently excess capacity locally, T&TEC has indicated in its Business Plan that by 2029, it intends to enter into negotiations to contract more generation capacity. Any progress in DSM can help to defer the acquisition of additional capacity, which will redound to the benefit of customers. Therefore, 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 the Government, service provider, and customers.

DSM programmes aim to achieve three broad objectives:

- **Energy conservation** – the reduction of the overall consumption of electricity by modifying behaviour and habits;
- **Energy Efficiency** – encouraging customers to implement technology that require less energy to perform the same function; and
- **Load Management** – 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 RIC's primary focus is on using non-price DSM techniques[49], which are briefly discussed below.

Non-Price Related DSM Techniques

- **Efficient Energy Use**

[49] The RIC will continue its inclining block structure for residential customers to encourage conservation.

Energy efficient appliances save energy, cost less to run and are environmentally friendly. The use of these appliances should be encouraged.

- **Consumer Tips for Energy Conservation**

  A comprehensive plan should be devised by the Service Provider, outlining its approach to educating the public about energy conservation techniques. Listed below are some basic examples of energy conservation techniques:

  - avoid leaving appliances on standby;
  - replace regular (incandescent) light bulbs with energy saving ones (CFLs, LEDs);
  - fill electric kettles 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.

The RIC is also doing its part by publicising conservation tips for consumers. However, the service provider can also implement initiatives for reducing household and commercial energy consumption. These initiatives can include:

- providing reasonably priced energy assessments, power saver kits and advice (currently there is a 150% allowance on the cost of energy audits if these are carried out by a certified energy efficiency consultant); and
- rebates to small businesses/households installing small-scale solar photovoltaic (PV) systems.

Time-of-Use Tariffs (TOU)

TOU rates fall under the umbrella of a time-varying rate structure[50], and they provide an alternative to traditional flat or linear rates.[51] **T&TEC is required to undertake and complete a comprehensive study on the feasibility of the implementation of TOU rates and provide the RIC with a report on its findings.**

Electric Vehicle rates

Trinidad and Tobago is in the initial stages of EV adoption, with fewer than two hundred (200) EVs on the nation's roads at this time. In keeping with its commitment to reduce greenhouse gas emissions in the electricity generation, transportation and industrial sectors, effective January 1, 2022, the Government removed motor vehicle tax and value-added tax on the importation of battery-powered electric vehicles. Since Government policy is to promote the uptake of EVs locally, the RIC has addressed various regulatory issues below. It is hoped that the eventual replacement of some vehicles with internal combustion engines with hybrid or electric vehicles, less fossil fuels will be consumed.

At present, **individual EV owners can charge at home subject to the applicable charges for residential customers.** The RIC is mindful that over PRE2 the local scenario can change and there are two areas that need to be considered: the implementation of an appropriate EV charging rate for residential customers and applicable rates for a public EV charging network. In its Business Plan: 2022–2026 to the RIC, T&TEC made proposals regarding tariffs for EV charging. T&TEC's proposals and the RIC's response/views are outlined below:

- **T&TEC proposes that where any upgrade to the local network is required to facilitate EV charging, the cost will be borne entirely by the customer.** The RIC is not convinced that upgrades to the local network are required for these instances, in the

[50] Time-varying rates consist of a few different forms that range in complexity, from the simplest (TOU rates), to more complex programmes such as Critical Peak Pricing (CPP) and Peak Time Rebates, and to the most complex and arguably most difficult to implement, Real Time Pricing (RTP). It is important to note that in some countries, such as Great Britain, the term "TOU" is used to broadly refer to all time-varying rates, inclusive of real time pricing. This is not the case in other jurisdictions such as the USA.
[51] This rate can also be defined as a flat, unchanging charge that allows the user to consume energy and pay a fixed amount to the utility. These rates are also sometimes called fixed rates.

near future. The RIC believes that Level 2 chargers[52] (which typically carry a 40amp load), can easily be incorporated into existing household electricity infrastructure. Some customers have installed Level 2 chargers with the approval of the Government Electrical Inspectorate (GEI) and have safely operated this installation for sole use with no apparent burden on their local networks. The RIC is aware that where upgrades to the local network are required to facilitate EV charging on a commercial basis or for a private fleet of EVs (more than 2 EVs), the costs associated with same will conform to the principles outlined in the RIC's Capital Contribution Policy (2022).

- **T&TEC proposes that all tariffs for EV charging (residential and commercial) be based on energy usage that is measured by a separate meter, used solely for EV charging.**

  T&TEC's proposal that EV charging (for sole use) be billed by a separate meter will impose significant costs to these customers. Installing a separate meter can require costly upgrades to the customer's electrical wiring installation. Additionally, not all residences and businesses are owned by its inhabitants; the installation of a separate meter in such instances is an administratively burdensome process for the tenant and landlord, apart from the cost for electrical upgrades. Whenever tenants are vacating these premises, removal of these installations are expected to pose similar challenges. The additional burden and cost surrounding installation of a separate meter for sole-use EV charging may even preclude many potential customers from considering the purchase of an EV.

  The RIC is of the view that T&TEC's proposal of the installation of separate meter as an unnecessary imposition of significant costs on customers, which will most likely be a disincentive to purchasing an EV. Notwithstanding, where customers own a private fleet of EVs – more than two (2) EVs – a separate meter should be installed, and the costs associated with same be borne by the customer.

[52]The amount of electricity used to charge an EV is based on the size of charger used and the charging rate assigned to that specific EV model. EVs are charged by three main types of chargers: Level 1 and Level 2, and Level 3 Direct Current (DC)/fast chargers. Level 1 and Level 2 chargers use standard 110/120 and 240 volt outlets respectively and are generally used for domestic/private charging. DC fast chargers use a 480volt outlet and take a much shorter time to fully charge EV batteries.

- **T&TEC proposes that initially, EV charging tariffs for public EV charging does not contain a demand charge component.**

  T&TEC is proposing that Level 3 charging (service stations) be initially billed at the new B2 (formerly B1) rate, and not include a demand charge (at this time). The rationale is that "demand charges were designed for commercial and industrial customers" and "demand charges may unfairly penalise such owners (service stations) for brief and occasional demand spikes." T&TEC's proposal is that as EV penetration increases and utilisation of the Level 3 chargers increase, then the inclusion of a demand charge can be considered.

  In keeping with the principle that the rating categories should consider customers who are similarly placed, customers (commercial or industrial) who wish to offer public EV charging will have the relevant rate (and its components) applied to them, inclusive of any demand charge. Therefore, all non-residential charging stations are to be billed at commercial (which do not carry a demand charge) or higher rates depending on the rating category applicable to that customer.

- **T&TEC proposes that TOU rates be established for EV charging in the future.**

  The RIC understands that there are benefits to the electricity network and the environment from establishing TOU rates and has directed that T&TEC undertake a comprehensive study on the feasibility of the implementation of TOU rates 24 months after the start of PRE2.

12.8 RIC'S TARIFF PROPOSALS

13.8.1 Inclining Block Tariffs

The RIC continues to support an inclining block tariff (IBT) structure as it is likely to discourage wastage at higher levels of consumption, send better conservation signals and provide incentives for sustainable use of electricity, while at the same time cater for the needs of the lowest consumers of electricity. These reasons were key drivers for the RIC's decision when it first introduced an IBT structure in 2006. However, because the IBT has been operational for some time it is necessary to ascertain if the current configuration of the IBT remains fit for purpose.

Internationally, while the application of IBTs have resulted in benefits to low income/low usage customers, the research is inconclusive as to whether inclining block structures have been effective in achieving reduced electricity demand. In fact, electricity customers' consumption patterns are more likely to respond to changes in their incomes rather than to changes in the price of electricity. The appropriate configuration for each jurisdiction will, therefore, depend upon the number of customers, their associated average usage patterns and the multiple priorities to be achieved by the tariff structure.

The analysis of IBT application in several jurisdictions shows that while IBTs have varied widely, there are some similarities in design across many jurisdictions, such as, in the choice of the number of blocks or tiers in the structure. In most jurisdictions where IBTs have been implemented the number of blocks has been restricted to between two and three blocks. The choice of two or three blocks has been mostly to keep in line with the design principle of administrative simplicity. The outcome should ensure that each block/tier applies to a significant number of customers. Whether or not an additional block encourages conservation will depend on the distribution of customer usage, magnitude of price changes and the price elasticity of demand for electricity.

Based on experience from several jurisdictions, another common rule of thumb in IBT design is that the tariff applied to the largest block should be about two to three times the rate applied to the first block. This design feature is crucial to achieving energy conservation and encouraging efficiency, as the block should be significant enough to be noticed by customers. The steeper the rise between tiers, the more apparent the price differences are to customers, hence the greater the possibility of encouraging energy conservation and efficiency initiatives.

IBT implementation for T&TEC (2006-2020)

The inclining block tariff structure implemented by the RIC in 2006 (table 12.5), was designed to achieve three main objectives. It was structured to ensure protection of low-income consumers that are "generally" also classified as low consumption customers. The first tier of the three-tiered structure offered a low tariff to cover bi-monthly basic needs electricity consumption of households. The IBT was also structured to promote energy conservation and efficiency, as higher tariffs were imposed for higher (above average) levels of residential consumption. Further, the tariff structure sought to achieve cost recovery for the residential customer class and to ensure revenue neutrality to the utility.

Table 12.5: Residential Block/Tier Structure Trinidad and Tobago, 2006

Block (Tier) 1	Block (Tier) 2	Block (Tier) 3
Basic needs electricity consumption	Average Usage[53]	High electricity consumption
1-400 kWh	401-1000 kWh	> 1000 kWh
27 cents	31 cents	34 cents

At that time, 28% of residential customers were using less than 400 kWh bi-monthly. The RIC considered benchmarking information and analysed the energy consumption of appliances in a typical household to meet basic needs, to establish the upper threshold of the lifeline (basic-needs) block. The second block was set at 401-1000 kWh which accounted for 45% of residential customers. The third block (>1000 kWh) accounted for the remaining 27% of customers. However, this situation changed with time as seen in table 12.6 below for consumption data at the end of 2010.

[53] Average bimonthly residential usage was 911 kWh in 2005.

Table 12.6: Residential Consumption Analysis for the Bi-Monthly Period November - December 31, 2010

kWh Range	No. of Customers	% of Total Customers	Cumulative %	kWh-Units	% of Total Units	Cumulative %
1-400	77,193	20.92	20.92	17,804,716	4.56	4.56
401-1000	160,466	43.48	64.41	108,238,167	27.69	32.25
1001-1500	62,845	17.03	81.43	76,506,986	19.58	51.83
1501-2000	28,606	7.75	89.18	41,891,763	10.72	62.55
>2000	39,957	10.82	100.00	146,389,526	37.45	100.00
TOTAL	**369,067**			**390,831,158**		

Source: T&TEC

Over the next ten (10) years, there were noteworthy changes in the consumption profile of residential customers, especially at the higher levels of electricity consumption, as shown in table 12.7 below.

Table 12.7: Residential Consumption analysis for the Bi-Monthly Period November - December 31, 2020

kWh Range	No. of Customers	% of Total Customers	Cumulative %	kWh-Units	% of Total Units	Cumulative %
1-400	80,304	18.59	18.59	16,436,654	2.87	2.87
401-1000	145,808	33.75	52.34	100,469,748	17.53	20.40
1001-1500	76,086	17.61	69.95	93,505,874	16.32	36.71
1501-2000	46,276	10.71	80.66	80,055,137	13.97	50.68
>2000	83,548	19.34	100.00	282,653,564	49.32	100.00
TOTAL	**432,022**			**573,120,977**		

Source: T&TEC

The data from tables 12.6 and 12.7 show that the number of residential customers increased by 17%, from 369,067 in 2010 to 432,022 in 2020. This increased trend was also observed as kWh demand increased from 390.8 million kWh to 573.1 for the same period. There was a considerable shift in the number of customers and kWh consumption across the consumption bands of the inclining block. The percentage of the residential customer base that typically consumed 1000 kWh or less, decreased from 64.4% in 2010 to 52.3% in 2020. Correspondingly, the percentage of residential customers that consume over 1000 kWh on a bi-monthly basis increased from 35.6% in 2010 to 47.7% in 2020.

In 2020, 83,548 or 19.34% of the 432,022 residential customers consumed >2000 kWh of electricity on a bimonthly basis. It is noteworthy that this group of customers comprised 49% or 282.6 million kWh of cumulative residential electricity consumption. This is significant considering that in 2010, 39,957 customers were consuming more than 2000 kWh and these customers accounted for 37.5% of cumulative residential electricity consumption.

As noted in the RIC's March 2022 technical paper on tariff design, on the one hand, the RIC believed that maintaining the current consumption thresholds (the blocks and their existing limits) and adjusting the corresponding prices alone was one possible approach and the other was increasing the number of tiers. On the other hand, the RIC considered that for customers that enjoy a significant amount of discretionary consumption, maintaining the current tiered structure, even with price adjustments, may not elicit the response required. In order to further incentivise conservation and to send a price signal that better reflects the higher long-run cost that will be incurred to procure additional electricity capacity, the RIC believed that it may be necessary to introduce an additional block to the existing IBT structure.

The RIC initially proposed[54] that the first two blocks of the existing structure be maintained. The 225,000 customers that currently consume electricity within the lifeline and those within the 401-1000kWh block comprise 52% of the residential customer base but consume only 20 percent of the total electricity used by this class of customers. The RIC proposed that the last block could be split into two, to distinguish different consumption levels of larger users, and encourage more efficient use of electricity by these customers through pricing. Further, the additional block/tier in the tariff structure at the higher end of the consumption spectrum should discourage wastage of electricity and conserve natural gas resources as this remains the primary fuel for electricity generation in Trinidad and Tobago. If one assumes that low-income customers consume less energy than high-income customers it can be argued that there may be a positive impact on the distributional effect of the overall subsidy.[55]

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[54] See the RIC's **"Principles of Rate Design and Tariff Structures" (March 2022).**

[55] The price for natural gas to be paid by T&TEC is a policy matter for the Government and has historically been subsidised.

Considering the above, the RIC, in its paper "Principles of Rate Design and Tariff Structures" proposed a four-block IBT structure for residential customers as shown in table 12.8 below. The proposed four block IBT structure is associated with a monthly billing cycle. Based on residential customer consumption data for 2020, this proposed structure reallocated the 48 percent of customers that currently consume more than 500kWh monthly or 1000kWh on bi-monthly into two tiers. In effect, the RIC proposed to maintain the first two blocks, and make an adjustment to facilitate monthly billing. The width of Tier 3 was initially proposed to be 501-1200kWh, which is the range of consumption for 34.9 percent of the residential customer class (in 2020), while the final block catered to residential consumption greater than 1200kWh.

Table 12.8: IBT Tiers for Monthly Residential Consumption initially proposed[56]

	Tier 1	Tier 2	Tier 3	Tier 4	
kWh Range	**0-200**	**201-500**	**501-1200**	**>1200**	**TOTAL**
% Total Customers	18.6%	33.8%	34.9%	12.7%	**100%**
% of kWh	2.9%	17.5%	41.4%	32.2%	**100%**

Source: RIC

The RIC has further reviewed its initial proposal[57] and has decided to widen the second and third tiers. We believe that widening the second and third tiers will provide an opportunity for consumers whose real incomes have fallen, to maintain their electricity consumption with moderate increases in their bill. The new proposed structure for residential customers now consists of:

- a customer (fixed) charge;
- a variable component for the first 200 kWh consumed (Tier 1);
- a variable component for the next 500 kWh consumed (Tier 2);
- a variable component for the next 700 kWh (Tier 3); and
- a variable component for consumption thereafter (Tier 4).

[56] The customer and kWh data is relevant to the bimonthly period November 1 - December 31, 2020.
[57] RIC (March 2022) Op. Cit.

The fixed component is consistent with the fixed costs of providing electricity and the variable components which broadly coincide with lower, middle, high and very 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.

Table 12.9: Revised IBT Tiers for Monthly Residential Consumption[58]

	Tier 1	**Tier 2**	**Tier 3**	**Tier 4**	
kWh Range	**0-200**	**201-700**	**701-1400**	**>1400**	**TOTAL**
% Total Customers	18.6%	48.5%	22.9%	10.0%	**100%**
% of kWh	2.9%	30.7%	33.6%	32.8%	**100%**

The RIC will continuously focus its attention on aligning the rates for all categories of consumers with the cost of supply and will be examining 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, through the provision of flexible payment plans where appropriate.

The lowest increase has been proposed for lower income groups. With respect to low-income groups, the RIC's two main proposals for reducing the impact of increased prices are:

(a) **Discount/Tariff Mechanism:** A lifeline tariff which allows households to pay a lower rate for electricity usage up to a specified (monthly) consumption level.

(b) **Service Provider Support Programme:**
T&TEC must be proactive and assist customers before their financial obligation to the Commission reaches a crisis stage by:

- offering preventative measures such as payment plans, in accordance with the Codes of Practice; and
- advising them about Government-sponsored support.

[58] Data relevant to the period November 1 to December 31, 2020.

T&TEC will also be mandated to implement an Energy Efficiency Programme, to ensure consumers take steps to reduce and/or manage energy consumption, and thereby mitigate the impact of rising electricity costs. Education is an important component of an efficiency programme to help customers make wise electricity usage choices which can lead to lower bills. Other measures to assist low-income groups that are available to the service provider include:

- waiving of interest payments on outstanding accounts;
- protection from service termination; and
- extended payment arrangements by providing the option of arranging alternative payment schedules and paying bills in smaller installments (this is to be agreed between the customer and service provider).

There are also Government-sponsored Assistance Programmes:

- Customers registered with the Ministry of Public Utilities can receive assistance for the payment of the electricity bills under the Utility Assistance Programme (UAP). Assistance is also provided for electrical repairs.
- Government also currently provides a 35% rebate to T&TEC residential customers on bills that are $300.00 or lower (inclusive of value added tax).

13.8.2 High Density Load or High Load Factor Customers

T&TEC proposed a new customer rate class for High Density or High Load Factor Industrial Customers. These customers operate high-density technological businesses such as, server farms and data or cryptocurrency mining facilities. The RIC supports this addition of a new rate class "C" with a uniquely predefined energy and demand charge given the markedly different characteristics to other industrial customers. T&TEC will enter into a supply contract with these customers and generally, the supply will be via Overhead Lines/Underground Cables at 12,000, 33,000 or 66,000 volts ± 6%, 3 phase, 4 wire, 60 Hertz. For the purpose of capital contribution, the RIC's 2022 Policy will apply, and this class will be treated as industrial customers.

13.8.3 Commercial (Rate B1 and B2)

In PRE1, the RIC had agreed to divide the Commercial Class into Rate B and B1. For PRE2, T&TEC has proposed that the categories be reclassified as B1 and B2 respectively. Hence, existing B customers will be reclassified as B1 and existing B1 as B2 customers.

The RIC had no objection to this proposal and has adjusted the categories accordingly.

13.8.4 Billing Frequency for Residential and Commercial B (now B1) customers

The RIC had extensively discussed the merits of moving to monthly billing for all customers in its paper "Principles of Rate Design and Tariff Structures". T&TEC is also in favour of the move to monthly billing. Hence, all customers will be billed monthly under the new tariff structures.

13.8.5 Cross-subsidies and proposed tariffs

If there had been regular price reviews following the expiry of PRE1 the resultant price increases would have been sufficient to offset any cost incurred by T&TEC to provide services, hence there would have been no need to provide cross–subsidies. In the circumstances, the RIC has sought to balance the initial impact of full cost recovery on residential customers by allowing some cross-subsidies to them by industrial customers. Ideally, these cross-subsidies should be unwound in the shortest possible time and the RIC intends to "phase-in" tariffs so that residential customers will pay cost-reflective prices by the end of PRE2.

In table 12.10 below the RIC's proposed tariff structure and charges for 2023 are presented.

Table 12.10: RIC's Proposed Tariffs for 2023

Rate Class		Energy Charge ($/kWh)	Customer Charge ($)	Demand Charge ($/KVA)
Residential (Monthly) kWh Range			7.50	N/A
0	200	0.28		
201	700	0.40		
701	1400	0.54		
>1400		0.68		
Commercial (Monthly)				
B1*		0.62	35.00	
B2**		0.67	35.00	
High Density (Monthly)				
C1		0.6269	50.00	93.00
C2		0.5858	50.00	93.00
C3		0.5487	50.00	93.00
C4		0.5114	50.00	93.00
Industrial (Monthly)				
D1		0.3453	50.00	86.75
D2		0.3859	50.00	88.50
D3		0.3418	50.00	79.37
D4		0.2877	50.00	68.90
D5		0.2756	50.00	63.74
E1		0.3305	100.00	96.90
E2		0.3305	100.00	95.74
E3		0.3305	100.00	93.63
E4		0.3305	100.00	92.30
E5		0.3305	100.00	91.33
Public Lighting (Monthly)				
Street Lights		82.50 (monthly)		
Traffic Lights		71.50 (monthly)		
Recreation Grounds		306.50 (monthly)		

*** B1 (formerly B) customers.**
****Minimum Bill of 5000kWh applies to B2 (formerly B1) customers.**
N/A – not applicable

12.9 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, the service provider, household expenditure and welfare, and the country's competitiveness. In essence, the RIC sought to balance the need for T&TEC to recover its efficient costs with the goal of achieving fair and acceptable outcomes for all stakeholders. Therefore, in assessing the impact of tariffs, the RIC focused both on potential impacts on users and on T&TEC's forecast level of cost recovery. Consequently, 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 was aimed at transformation in the desired direction. A provision for sharing gains from productivity improvements in excess of the X-factor requirement between consumers and T&TEC has also been outlined.

The RIC's analysis concentrated on the overall effect on customers' total bills. It examined how the increased prices would impact bills and the energy consumption of customers.

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. Affordability outcomes would be particularly influenced by changes to the tariff structure such as the low usage (lifeline) charge, 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 12.11, a typical **residential** customer using 400 kWh would currently pay $110.00 bi-monthly. After the new consumption bands and corresponding rates are implemented, this customer (assuming a consumption level of 200kWh monthly) will now pay $127.00 over two months. However, as discussed above, all customers will be on monthly billing cycle, therefore, this customer's actual monthly bill for 200kWh consumption will be

$63.50. It is useful to note that customers using up to 400 kWh bi-monthly currently comprise about 20% (or 90,685 customers) of T&TEC's total residential customer base. Residential customers whose average consumption is 627kWh per month, for instance, will receive a bill of $234.30 per month or 18% increase when compared on a two-month basis. Since the Residential tariff structure is an inclining block, it should be noted that the percentage increases in monthly bills can vary for customers whose consumption fall within the higher tiers. For instance, consumers who are currently using 3000kWh bi-monthly will experience a 36% increase over a two-month period.

For customers reliant on government pensions, or falling into similar low-income groups, whose monthly income is about $3,000.00 and consume about 200 kWh monthly, their total monthly expenditure of $63.50 on electricity will be about 2.1% of their monthly income, well below the internationally accepted target of about 10%.

Table 12.11: Impact of Price Increases on Bills of Typical Residential Customers, 2023

Bi-monthly Consumption (kWh)	Current Total Bill Bi-Monthly TT $	New Rates Total Bill Bi-Monthly TT $	Change Bi-Monthly TT $	Change Bi-Monthly %	Monthly Consumption (kWh)	New Rates Monthly Bill TT $
200	58.00	71.00	13.00	22%	100	35.50
400	110.00	127.00	17.00	15%	200	63.50
600	174.00	207.00	33.00	19%	300	103.50
800	238.00	287.00	49.00	21%	400	143.50
1500	487.00	581.00	94.00	19%	750	290.50
3000	1,042.00	1,419.00	377.00	36%	1,500	709.50
7000	2,522.00	4,139.00	1,617.00	64%	3,500	2,069.50

NB: Bi-monthly information for new rates are presented for comparative purposes only. All customers will now be on a **monthly** billing cycle.

The impact of the RIC's decisions on commercial and industrial customers will generally vary depending on their level of usage. Commercial and industrial customers are much more diverse in terms of their usage patterns than residential customers, therefore, it is difficult to draw general conclusions about the impact of this decision on these customers. Notwithstanding, a typical **commercial** B1 (formerly B) customer (table 12.12) using 500 kWh bi-monthly currently pays $232.50. After the new rates are implemented, this customer will effectively pay $380.00 over two months, but will actually incur a monthly bill of $190.00 for 250kWh of electricity consumed per month.

Table 12.12: Impact of Price Increases on Bills of Typical B1 Commercial Customers, 2023

Consumption (kWh)	Current	New Rates	Change			
	Bi-Monthly	Bi-Monthly	Bi-Monthly		Monthly Consumption	New Rates Monthly
	TT$	TT$	TT$	%	kWh	TT$
500	232.50	380.00	147.50	63%	250	190.00
800	357.00	566.00	209.00	59%	400	283.00
1200	523.00	814.00	291.00	56%	600	407.00
1500	647.50	1,000.00	352.50	54%	750	500.00
2500	1,062.50	1,620.00	557.50	52%	1,250	810.00
5000	2,100.00	3,170.00	1,070.00	51%	2,500	1,585.00

NB: Bi-monthly information for new rates is presented for comparative purposes only. All customers will now be on a **monthly** billing cycle.

The impact on typical bills of B2 (formerly B1) customers will be in the range of 10-11% monthly, as seen in table 12.13 below.

Table 12.13: Impact of Price Increases on Bills of Typical B2 Commercial Customers, 2023

Consumption (kWh)	Current	New Rates	Change	
	Monthly	Monthly	Monthly	
	TT$	TT$	TT$	%
5000	3,050	3,385	335	11%
7000	4,270	4,725	455	11%
9000	5,490	6,065	575	10%
11000	6,710	7,405	695	10%

***B2 (formerly B1) customers pay a minimum bill of 5000kWh.**

As discussed above, a new class was created for high-density/high load factor customers, Industrial C class. Sample bills for this newly introduced class of (industrial) customers are shown in table 12.14 below while the impact on industrial D and E classes are shown in table 12.15 below.

Table 12.14: Sample Bills of Industrial (C) Customers, 2023

Class	Sample kWh and kVA	Current Monthly Bill	New Rates Monthly Bill	Change Monthly	
		TT$	TT$	TT$	%
C1	150,000 kWh, 200 kVA	N/A	**112,735**	N/A	--
C2	5,000,000 kWh, 7,000 kVA	N/A	**3,580,100**	N/A	--
C3	10,000,000 kWh, 15,000 kVA	N/A	**6,882,100**	N/A	--
C4	25,000,000 kWh, 35,000 kVA	N/A	**16,040,100**	N/A	--

Table 12.15: Impact of Price Increases on Bills of Typical Industrial Customers, 2023

Industrial (D) - Sample Bill Impacts					
Class	Sample kWh and kVA	Current Monthly Bill	New Rates Monthly Bill	Change Monthly	
		TT$	TT$	TT$	%
D1	**20,000 kWh, 90 kVA**	8,480	14,764	6,234	73.5%
D2	**1,000,000 kWh, 2,500 kVA**	343,000	607,200	264,200	77.0%
D3	**2,000,000 kWh, 10,000 kVA**	791,000	1,477,350	686,350	86.8%
D4	**4,000,000 kWh, 10,000 kVA**	1,068,000	1,839,850	771,850	72.3%
D5	**30,000 kWh, 14,000 kVA**	522,800	900,678	377,878	72.3%
E1	**2,000,000 kWh, 39,000 kVA**	2,025,500	4,440,200	2,414,700	120%
E2	**10,000,000 kWh, 110,000 kVA**	6,290,000	13,836,500	7,546,500	120%
E3	**60,079,900 kWh, 75,775 kVA**	11,969,911	26,951,320	14,981,410	125%
E4	**80,079,900 kWh, 102,774 kVA**	15,928,094	35,952,547	20,024,454	126%
E5	**101,347,472 kWh, 226,368 kVA**	23,976,471	54,169,629	30,193,157	126%

Impact on Household Expenditure and Welfare

The RIC has also considered the welfare impact of its proposals and impact on household expenditure. The RIC has not considered the broader impact on inflation as data to conduct this analysis was not available when this document was being prepared. The RIC requested the latest available data on average monthly household expenditure from the Central Statistical Office (CSO). The CSO indicated that their latest available data was from their 2008/2009 Household Budgetary Survey (HBS).

Based on the data from the CSO, in establishing these rates, the RIC remained within the United Nations guidelines on the percentage of income that should be spent on utilities. In each case, the RIC has attempted to set rates which would not represent more than 10% of average monthly household expenditure. For instance, based on a current monthly average consumption of 627kWh, the total bill will be $234.30 of household income of $7,223.40 or 3.3% of average monthly household expenditure.

Impact on Country Competitiveness

Based on the proposed increases for commercial and industrial customers, the actual increase in electricity bills will depend on the specific customer, their assigned customer class and their actual consumption level. On average, Commercial (B1) customers will see an increase in their bills in the range of 50%–60%, while the increases for Industrial customers will range from 72% to 126%.

The RIC considered the likely impact of increased electricity charges on different productive sectors of the economy and, consequently, on competitiveness of these sectors. The CSO provided data on electricity as a percentage of operating costs for various productive sectors, which was available up to 2015. Table 12.16 shows that for 2015, on average, electricity constituted 1.5% of the total production costs of commercial/industrial entities in Trinidad and Tobago. The RIC notes that for some sectors/firms this percentage may be higher, however, it is also true that for other sectors/firms, electricity as a percentage of total operating costs would be lower than the average. In this regard, despite the proposed increases in rates, and on the assumption that electricity costs have been averaged to represent 1.5% of total costs across industries, the expectation is that the increased costs of electricity would not have a major impact on total operating expenses of different industries in the country. Also, it is likely that total operating expenses of productive sectors have increased since 2015, therefore, the percentage increases in electricity would translate to a lower percentage impact, on their total operating expenses.

Table 12.16: Contribution of Electricity to Total Operating Expenses of Industries, 2015

Industry/Sector	**Electricity as a percentage (%) of Total Operating Costs (2015)**
Agriculture, forestry and fishing	3.0
Mining and quarrying	0.5
Food, Beverages and Tobacco Products	1.0
Textiles, wood, paper and printing	1.1
Petroleum and Chemical Products	0.8
Other manufactured products	1.7
Water supply and sewerage	5.6
Construction	1.9
Trade and repairs	1.0
Transport and storage	0.5
Accommodation and food services	2.6
Information and communication	1.9
Financial and insurance activities	0.3
Professional, scientific and technical services	1.8
Administrative and support services	0.5
Public administration	1.1
Education	0.8
Human health and social work	0.9
Arts, entertainment and recreation	1.3
Other service activities	1.3
Domestic services	1.2

Source: Central Statistical Office (2022)

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 12.15). As can be seen from the table below, a typical industrial customer in Trinidad and Tobago currently has a lower total bill when compared to other Caribbean countries, except for Suriname. The situation will remain largely the same after the implementation of new rates.

Table 12.17: Typical Industrial Customer Bills in various Caribbean Countries, 2021

Country	Total Monthly bill (US $)
Barbados	26,560
Belize	18,300
British Virgin Islands	29,891
Curacao	34,719
Dominica	45,000
Grand Cayman	33,283
Grenada	30,922
Guyana	23,500
Jamaica	35,300
Suriname	5,000
Trinidad and Tobago (2021)	4,980
Trinidad and Tobago (new rate from 2023)	**9,876**

Source: CARILEC

Calculations for Trinidad and Tobago done by RIC.

Financial Impact on T&TEC

Table 12.18 and figures 12.1 and 12.2 below demonstrate that the proposed starting tariffs will result in a positive operating profit[59] and operating cashflow during the regulatory control period. Using the proposed starting tariffs, total revenue for the first year of the control period is projected to be $5,078.29 million. After deducting all expenses inclusive of depreciation, operating profit is projected to be $476.41 million, as shown in figure 12.1. T&TEC's operating profits are expected to remain robust for the next two years, however, the impact of inclusion of the NGC Debt in 2026 is expected to negatively affect T&TEC to such an extent that they are likely to incur a loss. It should be noted that these projected values may change as annual tariffs reviews could result in tariff changes for each year, as well as actual kWh outturn may differ from projections.

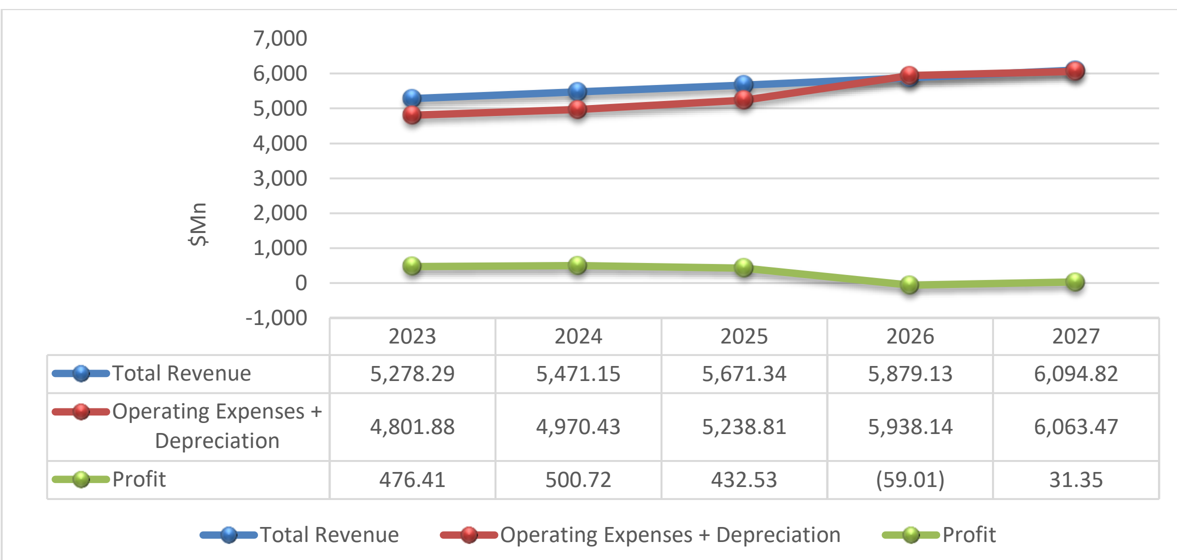
[59] This is an operating profit. The price limits include a provision for financing capital expenditure.

Table 12.18: Profit and Loss Account with New Tariffs ($Mn)

	2023	2024	2025	2026	2027
Operating Revenue	5,078.29	5,271.15	5,471.34	5,679.13	5,894.82
Expenditure:					
Operating Expenditure	1,005.40	1,043.21	1,038.00	1,022.40	999.48
Conversion Cost	1,764.99	1,788.45	1,896.88	1,917.48	1,943.31
Fuel Cost	1,752.22	1,859.74	2,023.37	2,139.51	2,261.13
Net Surplus (Deficit) before Interest & Depreciation	555.68	579.75	513.09	599.73	690.90
Depreciation	279.27	279.02	280.55	280.03	280.83
N.G.C. Debt	0	0	0	578.71	578.71
Net Surplus (Deficit) after Interest & Depreciation*	**476.41**	**500.72**	**432.53**	**(59.01)**	**31.35**

*Excluding other income.
Source: RIC

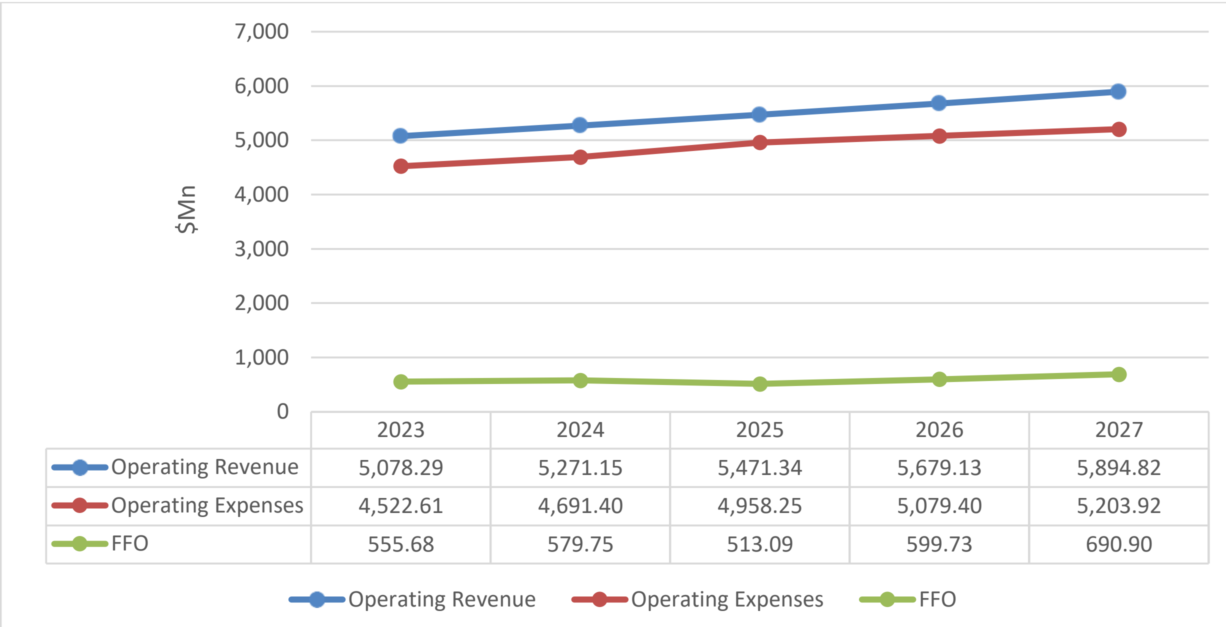
Figure 12.1: T&TEC's Profits under New Tariffs



Source: RIC

All cashflow (or Funds from Operations) parameters also show improvements under the proposed tariffs. Operating cashflow in 2023 is projected to be $555.68 million, eventually increasing to $690.90 million by 2027. The RIC believes that T&TEC's financial position will continue to remain sufficiently strong to maintain appropriate levels of financeability in the foreseeable future.

Figure 12.2: T&TEC's Operating Cashflows (FFO) under New Tariffs



	2023	2024	2025	2026	2027
Operating Revenue	5,078.29	5,271.15	5,471.34	5,679.13	5,894.82
Operating Expenses	4,522.61	4,691.40	4,958.25	5,079.40	5,203.92
FFO	555.68	579.75	513.09	599.73	690.90

Source: RIC

12.10 DRAFT PRICE DETERMINATION

The following is the RIC's **Draft Determination** in respect of electricity transmission and distribution services for the five-year period 2023 to 2027.

1. Period of Determination

The provisions below will apply for the five-year period from 2023 to 2027.

2. Services to be Regulated

Revenue Cap for Transmission and Distribution Services:

- For the first year of the regulatory control period 2023-2027, 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.

Table 12.19: Tariffs for 2023

<table>
<tr><th colspan="2">Rate Class</th><th>Energy Charge ($/kWh)</th><th>Customer Charge ($)</th><th>Demand Charge ($/KVA)</th></tr>
<tr><td colspan="2">Residential (Monthly)
kWh Range</td><td></td><td rowspan="5">7.50</td><td rowspan="5">N/A</td></tr>
<tr><td>0</td><td>200</td><td>0.28</td></tr>
<tr><td>201</td><td>700</td><td>0.40</td></tr>
<tr><td>701</td><td>1400</td><td>0.54</td></tr>
<tr><td colspan="2">>1400</td><td>0.68</td></tr>
<tr><td colspan="2">Commercial (Monthly)</td><td></td><td></td><td></td></tr>
<tr><td colspan="2">B1*</td><td>0.62</td><td>35.00</td><td></td></tr>
<tr><td colspan="2">B2**</td><td>0.67</td><td>35.00</td><td></td></tr>
<tr><td colspan="2">High Density (Monthly)</td><td></td><td></td><td></td></tr>
<tr><td colspan="2">C1</td><td>0.6269</td><td>50.00</td><td>93.00</td></tr>
<tr><td colspan="2">C2</td><td>0.5858</td><td>50.00</td><td>93.00</td></tr>
<tr><td colspan="2">C3</td><td>0.5487</td><td>50.00</td><td>93.00</td></tr>
<tr><td colspan="2">C4</td><td>0.5114</td><td>50.00</td><td>93.00</td></tr>
<tr><td colspan="2">Industrial (Monthly)</td><td></td><td></td><td></td></tr>
<tr><td colspan="2">D1</td><td>0.3453</td><td>50.00</td><td>86.75</td></tr>
<tr><td colspan="2">D2</td><td>0.3859</td><td>50.00</td><td>88.50</td></tr>
<tr><td colspan="2">D3</td><td>0.3418</td><td>50.00</td><td>79.37</td></tr>
<tr><td colspan="2">D4</td><td>0.2877</td><td>50.00</td><td>68.90</td></tr>
<tr><td colspan="2">D5</td><td>0.2756</td><td>50.00</td><td>63.74</td></tr>
<tr><td colspan="2">E1</td><td>0.3305</td><td>100.00</td><td>96.90</td></tr>
<tr><td colspan="2">E2</td><td>0.3305</td><td>100.00</td><td>95.74</td></tr>
<tr><td colspan="2">E3</td><td>0.3305</td><td>100.00</td><td>93.63</td></tr>
<tr><td colspan="2">E4</td><td>0.3305</td><td>100.00</td><td>92.30</td></tr>
<tr><td colspan="2">E5</td><td>0.3305</td><td>100.00</td><td>91.33</td></tr>
<tr><td colspan="2">Public Lighting (Monthly)</td><td colspan="3"></td></tr>
<tr><td colspan="2">Street Lights</td><td colspan="3">82.50 (monthly)</td></tr>
<tr><td colspan="2">Traffic Lights</td><td colspan="3">71.50 (monthly)</td></tr>
<tr><td colspan="2">Recreation Grounds</td><td colspan="3">306.50 (monthly)</td></tr>
</table>

*** B1 (formerly B) customers**
**** Minimum monthly bill of 5000kWh for B2 (formerly B1) customers**
N/A. Not applicable

- T&TEC to set prices for year *t* such that the reasonable forecast annual revenue requirement (ARR_t) received from the service complies with the following formula in Box 12.1 below:

Box 12.1: Formula for Establishing Annual Revenue Requirement

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

Where:

Year *t*	X_t
2023	2.7%
2024	2.7%
2025	2.7%
2026	2.7%
2027	2.7%

ARR= Annual Revenue Received from Services.

ARR_{2023} = $5,078.29 million.

RPI means the Retail Price Index and has been fixed for the purpose of the RIC's calculation at 1.1% per year.

X = The efficiency factor

U = Unused charge. T&TEC will be permitted to carry over any unused change in charges from one year to the following years.

The overall side constraint is set at (RPI + X) = 3.80%.

*** 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. Side Constraint

The overall side constraint is set at (RPI + X) = 3.8%.

4. Regulated Miscellaneous Services and Charges from 2023

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

Table 12.20: Regulated Miscellaneous Services and Charges from 2023

List of Services	New Charge ($)
Meter check (at customer's request) - If found in working order - If found defective	 246.00 No charge
Visit for non-payment of account	297.00
Install meter and reconnect secondaries	246.00
Reconnect: disconnect and/or change meter	246.00
Reposition of secondaries	246.00
Change and/or reposition of meter	246.00
Disconnection for non-payment	297.00
Reconnection after disconnection for non-payment	150.00

The charges for the regulated services may be reviewed at the mid-point of the second control period, based on the approved charging principles and after consultation with the RIC.

5. Annual Price Approval Process during the Control Period

- At least three 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 three 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.

6. Trigger Event

The trigger event will apply only if a situation imposes a total annualised cost of more than 1% of allowed revenue.

7. Tariff Implementation

T&TEC must take steps to ensure that any future decision to not charge a maximum determined price is appropriately authorised by the Board of T&TEC and written reasons are provided to the RIC.

13 CONCLUDING REMARKS AND WAY FORWARD

The RIC produced its first Price Determination for the Electricity Transmission and Distribution Sector in 2006 (PRE1) utilising the incentive regulation framework. It was the first time that T&TEC had its pricing proposal subject to the RIC's independent scrutiny, and in many respects, it represented a complete paradigm shift in the way the electricity transmission and distribution sector would be regulated therefrom. The proposals were intended to support new investment requirements, and to ensure the financial viability of T&TEC while creating a regulatory environment that incentivised efficiency improvements.

T&TEC responded positively to many of the incentive mechanisms by increasing the quality of its service to its customers, and its financial situation improved. However, there were concerns about T&TEC's delivery of projects approved in the RIC's allowed capital programme. Many of the approved capital projects were either not delivered or delivered behind schedule and over budget. Of equal importance has been T&TEC's failure to reduce operating costs in any significant way. Perhaps because the regulatory regime was new to T&TEC it needed time to put systems in place to meet the requirements of the new regime. The RIC considers that sufficient time has elapsed for T&TEC to make the required changes to its systems and expects to see strict adherence to directives, reporting requirements and reporting deadlines.

For PRE2, the T&TEC is reminded that where it fails to meet the required standards/obligations, the RIC will not hesitate to take enforcement action as provided for under Sections (6)1(e)(f)(g), 65 and 66 of the RIC Act. Some of the regulatory sanctions the RIC intends to enforce include:

- **Additional Reporting** – the RIC will require more regular reporting by the service provider, outside of the established annual reporting system. In the case of repeated failures, the RIC may consider publication of such reports;

- **Investigation** – This will involve a detailed investigation of the service provider's performance and data quality by the RIC's approved auditor; and

- **Enforcement and Fines** – The RIC will, if necessary, use this power in keeping with Section 66 of the RIC Act.

T&TEC must take note that the decisions within the Final Determination must be incorporated within its operational and financial plans to ensure that they are implemented. The RIC's pricing decision should not be viewed simply as an adjustment to tariffs but as a comprehensive package of service quality improvements for customers premised on the approved price limits. Consequently, the RIC intends to pay close attention to T&TEC's implementation of RIC's allowed Capex programme, and its efforts towards cost containment during PRE 2.

The importance of good corporate governance and the role it can play in improving a service provider's performance cannot be over-stated. The RIC expects that the measures outlined below will be incorporated into the operational activities of T&TEC. For a full discussion on the outlined measures, please see **"Improving Transparency and Accountability in the Electricity and Water Sectors"** which was published on the RIC's website for public comments in February 2021.

The RIC therefore requires that:

- T&TEC must develop a consultation code inclusive of an obligation to consult with the public on plans/proposals to undertake any significant activity in the execution of its core functions. While undertaking its consultative activities T&TEC must ensure that those consumers who are likely to be affected by major infrastructure and large construction projects are fully apprised and informed about these activities. The factors to be considered in determining whether to consult include; the number of customers affected, the geographic area impacted, and cost thresholds for infrastructural works.

- T&TEC must promote openness and facilitate public knowledge about, and participation in, its core activities by:
  - making information and documentation available on its website;
  - making the website more interactive and putting a more human face to the website, including contact details for key personnel (e.g. e-mail, telephone); and

- including a prominent section on its website to highlight its planning and development activities (on-going and completed), which must be periodically updated (annually).

- T&TEC must produce quarterly revenue and expenditure statements in accordance with the regulatory accounting guidelines established by the RIC and make these statements widely accessible on its website, and to the media.

- T&TEC must provide information on its website about the number of complaints and their effectiveness in dealing with those complaints.

- T&TEC must demonstrate, in the future, that it consulted with its customers prior to the submission of its Business Plan and that due regard has been given to the views that customers expressed during the consultation process.

- T&TEC should hold one (1) formal Annual Public Meeting, in a public place, and should make arrangements for consultation and deputation of individuals (where required) to question the Board and the Chief Executive Officer/General Manager.

- T&TEC must provide information on its website about its procurement process, which must conform to directions issued by the Office of Procurement Regulation, and the Public Procurement and Disposal of Public Property Act (2015)[60]. This information would allow customers access to its procurement processes that are underway, completed, or pending approval, including information such as requirements for submitting bids, important dates, and the amounts bid by tenderers.

[60] The Office of Procurement Regulation is an independent regulatory body established pursuant to an Act of Parliament, namely the Public Procurement and Disposal of Public Property Act, 2015. The Act aims to provide for public procurement, and for the retention and disposal of public property in accordance with the principles of good governance, namely accountability, integrity, transparency, and value for money and to promote local industry development, sustainable procurement and sustainable development.

- T&TEC will be required to disclose the identity of all their contractors, the value of the contracts and the main evaluation criteria used in selecting successful bidders.[61] This information should be made available on its website, in the interest of transparency and openness.
- T&TEC will be required to have a general anti-corruption policy, produce a code of conduct policy, and publish these documents on its website.
- T&TEC will be required to have records and procedures in place by which it can demonstrate that its procurement and hiring practices occur at arms-length.
- T&TEC must establish an ethics and sanctions committee to investigate and take appropriate action against transgressors.
- T&TEC must collect more systematic data on public viewpoints through its customer service centres to better understand the experience of those who have had cause to complain and to ascertain how their concerns were addressed.
- T&TEC must publish its performance against all customer service targets, on its website[62], and produce a half-yearly overview report for the public with commentary on where and why this performance has not met the targets. Reports on these findings should be submitted to the RIC on an annual basis.
- T&TEC must disclose information about how many complaints it receives and resolves annually, and publish data on its performance with respect to quality of service and its operations.
- T&TEC must utilise independent researchers, approved by the RIC, to undertake more generalised surveys regarding customers' experience with utility services, either before the end of the regulatory control period or at least every five years. The results of this survey must be included in its Business Plan submission for the next regulatory control period.

[61]Open Contracting Partnership (2013), Open Contracting: A New Frontier in Transparency and Accountability, World Bank. *"An organ of the state is bound by constitutional obligation to conduct its operations transparently and accountably. Once it enters into a commercial contract of a public character…the imperative of transparency and accountability entitles the members of public, in whose interest the organ of the state operates, to know what expenditure such an agreement entails"* - The Supreme Court of South Africa, Transnet Ltd vs SA Metal Machinery Co (Pty) Ltd 2006.

[62] These reports can also be shared on social media.

- T&TEC must provide bi-annual updates on performance for key performance indicators with utility bills.

The RIC understands that a State-owned and operated utility faces constraints that its private-sector counterpart does not. However, the RIC wishes to reiterate the need for service providers to operate as public commercial enterprises rather than public administrative bodies. In this regard, the Government may wish to consider implementing appropriate reforms, and the RIC is willing to offer its views on the long-term structure and viability for the sector.

Finally, the RIC is confident that T&TEC will embrace the opportunity to improve its performance in all areas and rise to the challenges that have been set for it in PRE2, thereby ensuring that customers obtain value for money from the service provider.

ANNEX 1

Details of RIC's Tariff Setting Approach

Element	RIC's Approach
Overall Regime	• Incentive-based regulation of the RPI-X form. • Price control is a revenue cap. • Revenue reviews are carried out every five years and smoothing techniques are used to determine annual revenue from which tariffs are calculated. • Price control includes a correction factor for under and over recovery of revenue on an *ex-post* basis.
Length of the Control Period	• The control period is five (5) years, but the RIC Act allows for an interim review provided it is well-justified. This multi-year determination period facilitates long-term planning, provides greater budget certainty and also reduces the cost of regulation. It provides greater scope to deliver on the efficiency targets built into the determination. It also provides customers with a better indication of how tariffs are likely to move over the five-year period.
Process for Setting Tariffs: • ***Building Blocks Approach***	• The "building-block" approach is used to estimate the revenue that the service provider requires to deliver the proposed/specified standards and outcomes. Demand forecasts play an important role in determining prices needed to raise the required revenue. • Revenue requirement allowance = (Regulatory Asset Base * Regulated Rate of Return) + Regulatory Depreciation + Efficient Operating and Maintenance Expenditure – Capital Contributions. Capital contributions are based on forecast figures with no *ex-post* true-up. Non-tariff revenue is subtracted to get the net annual revenue requirements that need to be generated via tariffs. • Smoothing technique used to determine the NPV of the revenue stream using an appropriate discount rate (allowed rate of return)

Element	RIC’s Approach
	and then specifying the smoothed revenue for each year of the price control: - NPV considers the timing difference between costs and revenue. - While smoothing implies that revenue will not necessarily match expenditure in any particular year, total revenue recovered is expected to be sufficient to meet total expenditure over the five years of the control period. • Allowances for efficiency improvements, inflation and risks are given due consideration. Uncontrollable costs are largely subject to pass-through arrangements.
• ***Rolling Forward of RAB*** • ***Opex***	• The RAB is rolled forward to account for new Capex, inflationary gain and depreciation. • The movement in the core RPI used to adjust the RAB. • The Service provider is required to outline in its business plan forecast Opex for each year of the control period, the key drivers of expenditure, justification for forecast expenditure levels and evidence of productivity improvements. • Based on assessing “underlying” operating costs at the time of the price review but using actual audited data for the last completed year before price control is set, against which proposed Opex evaluated. • In assessing the prudence and efficiency of Opex forecasts, several factors are considered: - the scope for efficiency savings, based on primarily bottom-up analysis of the service provider’s business plan and supplemented by international benchmarking. - adjustments for one-off/exceptional items, expenditure that can be justified as efficient for the future and included in base Opex, factors affecting base Opex (e.g. pensions). - the potential for efficiency improvements and/or building efficiency targets into the Opex forecasts and upfront reduction of expenditure based on these targets.

Element	RIC's Approach
	- trends in forecast Opex from trends in historical Opex, especially over the last five (5) to six (6) years, and whether differences can be readily justified. - whether increases or decreases are consistent with the timing of major capital projects. - whether forecast Opex clearly reflects imposed obligations or improvements demanded by customers.
• ***Capex***	• Service Provider's business plan required to identify: - Capex by different categories, such as, growth-related (required to meet growing demand of new and existing customers), capital maintenance (required to refurbish/replace assets), capital enhancement (required to meet quality standards or improved reliability) etc. - the cost of the programme for each year of the control period; expected starting and delivery dates of the projects and the outcomes that will be delivered from each project. - the discreet projects to be delivered over the regulatory control period. - Government-related and financed projects to be shown separately. These projects are not funded through tariffs. • Proposals to significantly increase Capex to be substantiated by supporting information: - for growth-related Capex, evidence of growth in the numbers of new connections and/or in the demand for the services. - for capital maintenance, evidence that network needs to be renewed to deliver services that meet customers' expectations. - for capital enhancement, evidence of customer demand for enhanced service levels. • In assessing Capex efficiency and prudency, the RIC considers whether: - proposed projects are deliverable over the five-year control period. - the Capex clearly reflects obligations that are required by customers. - the proposed trends in Capex are related to trends in historical expenditure and any difference in the expected

Element	RIC's Approach
	level can be identified together with any other relevant factors. - there is evidence of well-developed asset management planning and processes that demonstrate that forecasts have been determined over a long planning horizon. • *Ex-ante* Capex allowance covering expected investment. • No allowance for contingent projects so far. • Failure to deliver required outputs (and/or underspend) results in a reduction of the RAB at the next price review. • Efficient overspend relating to additional outputs and sound investment can both be logged up in the RAB at the next price review.
• ***Depreciation*** • ***Return on Assets/Cost of Capital***	• Although other approaches were considered, the straight-line depreciation approach on an inflation indexed asset base is considered to be most appropriate. • Asset lives proposed by the service provider but reviewed by the RIC and, if necessary, compared with international best practice. • Regulatory depreciation is included on assets when they are completed, and the service provider receives a sufficient return on the asset while under construction to ensure that working capital is available to finance the asset. • Regulatory depreciation on new assets taking more than one year to construct is deferred until the project is commissioned. • Based on the Regulatory Asset Base and the RIC's assessed likely cost of future borrowing by the service provider, but subject to achieving financial viability in terms of ratios such as interest cover. • Cost of capital is based on a notional level of gearing rather than actual.

Element	RIC's Approach
	• Where the service provider has borrowed at rates that are higher than present/future levels, the actual cost of existing debt is included in the revenue requirement allowance as a separate item. • Ability of the service provider to finance its activities is assessed using a set of financial ratios. • So far, no specific additional revenue (upliftment) to address financeability concerns has been allowed.
Dealing with Uncertainty	
• ***Re-opener (Shipwreck)***	• No formal/automatic clause or mechanism that allows for a determination to be fully re-opened. However, there is a statutory right for the service provider to have an interim review. • The service provider may apply for adjustment during (RIC Act allows this) the regulatory period to take account of events that were uncertain or unforeseen at the time of the price review process. • A threshold of 10% of annual allowed revenue is included for the consideration to take account of deviation in revenue from allowed for any reason (not necessarily from uncertain or unforeseen shock) at the time of making a determination. This is a special consideration that is not the same as a trigger event. • Where indexing is required, the RIC has not used indices other than general inflation (Core Index) as part of the price control decision. • For the Opex allowance, separate "costs items" with specific indicators of input cost trends (e.g. for labour inputs).
• ***Pass-through (Z-factor)***	• No automatic adjustment for unforeseen events (typically treated as "pass-through items" because these events are outside of the firm's control).
Incentives	
• ***Overall Incentives***	• A five-year control and the service provider retains any unanticipated benefits for five (5) years but also bears the loss if costs higher than allowed.

Element	RIC's Approach
	• Assessment of efficient Opex and Capex is made *ex-ante* to set the price control allowances. • *Ex-post* efficiency review of both Opex and Capex expenditure. • Use of a notional unders and overs account • A rolling Efficiency carryover mechanism for Opex and Capex, as both treated on an *ex-ante* basis with any unanticipated savings kept for five years from the date of the saving. There is no *ex-post* prudency review for Opex. However, the service provider's ability to meet efficient level of Opex and its service performance over the control period is considered in the next control period. In the case of Capex, methodology for rolling forward the RAB takes into account whether expenditure has been efficiently and prudently incurred. • Provision is made for Capex logging up/down, with the resulting addition or deduction made at the end of the control period. • Capex Information – Quality incentive for honesty in Capex forecasting.
• ***Productivity Improvement***	• The use of the "rate of change" as the generalised efficiency factor to apply to total Opex.
Service Performance	• Public Reporting Scheme (i.e. Performance Monitoring and Reporting) as a basis for measurement of overall average performance, where average/minimum service standards established for different aspects of the service provider's operations. • Guaranteed Standards Scheme, whereby failure to meet guaranteed service levels against a basket of service quality measures involves payments to customers. • No Service Incentive Scheme (S-factor), whereby a direct revenue adjustment is included to reward or penalise the service

Element	RIC's Approach
	provider by directly varying the maximum allowed revenue pre-determined for the year. • New proposal to include the use of the Direct Revenue Adjustment mechanism to improve service quality in a key area of concern to customers (i.e. number of customer interruptions). A specified amount of service provider's allowed revenue is to be automatically adjusted for success or failure in meeting these outcomes. • Incentive mechanism for managing system losses.
Customer Involvement in Review Process	• Consultation with all stakeholders is an important part of the rate review process. Extensive consultation process includes releasing for public comment Consultative and Information papers, Draft Determination, conducting public meetings and meetings with business organisations and customer groups. • All consumer protection issues, such as protecting consumers from abuses of monopoly power, standards of quality, reliability and safety of the services, are considered within the price review. • Particular regard paid to the impact of the RIC's decisions on customers (especially on the affordability of services and intergenerational equity). • Service provider encouraged to undertake consultations prior to undertaking any significant activity in the exercise of their core functions and affected by their infrastructure and construction projects. • Customer Service Department of the RIC receives and facilitates the resolution of complaints and identifies systematic issues and refers these to service providers.
Reporting and Compliance	• The RIC is mandated to prescribe, publish standards of service and monitor compliance and carry out studies of efficiency and economy of operation and of performance and publish results. Public reporting and scrutiny of service provider's performance act as a substitute for competitive pressure, counterbalancing any

Element	RIC's Approach
	tendency for the service provider to let its quantity or quality of service decline, and creating effective incentives for it to maintain or improve its service performance. • The RIC has developed a Performance Monitoring and Reporting framework and performance indicators to be reported include financial indicators, customer service, service quality and network characteristics. • The RIC may undertake audits to assess compliance with specific obligations. • Under the established regulatory reporting guidelines, the service provider is required to maintain accounts, and reporting templates are to be populated by the service provider. Information to be supplied include detailed revenue and expenditure information, cash flow, balance sheet, and other related information. These templates are the basis for the formats to be submitted for future regulatory proposals. • Quarterly information is submitted on Guaranteed and Overall standards. • For rate reviews, service providers are required to submit draft and final Business Plans which must contain detailed information on Opex, Capex, revenue, etc. • Frequent reporting on the progress of Capex programme: - Six-monthly reporting on status of projects - Providing detailed data on each project annually. • Service providers are required to make available all information reasonably requested by the RIC from time to time for the purpose of enabling it to confirm that service providers are complying with the Determination.

ANNEX 2

Key Issues Raised and RIC's Responses

Key Issues Raised	RIC's Response
Po Adjustment – Passing Cost Savings to Customers	
T&TEC noted that the RIC provided for the following to be considered: a) The inclusion of only efficient cost upfront in the tariff, with subsequent adjustments in the annual rate review b) Any gains derived from the over-achievement of targets are passed on to the customer over the five-year period. T&TEC recommended the use of the former, as it has worked well thus far, as it was applied in the first review period. It is also easier to apply administratively, as only efficient costs are included upfront. There is no need to apply credits to customers over the period based on their level of consumption or any other factor, which can be an administratively challenging.	As noted in the RIC's document, the RIC considers that the approach adopted in PRE1, that is to set *ex-ante* (upfront) efficiency targets and to reduce costs upfront so that customers are guaranteed that only efficient costs are included in the revenue requirements remains fit for purpose. The RIC notes T&TEC's concurrence with this approach.
Annual Price Adjustments –Are they a Necessary Feature of Incentive Regulation	
T&TEC preferred the option of having biennial (every two (2) years) rather than annual price adjustments, which reduces the administrative cost by half for T&TEC, but may double the increase for the customer. Most jurisdictions however implement annual adjustments and therefore this has become the norm. T&TEC noted that it is in favour of the annual rate review, as the potentially lower annual increase will be more easily acceptable by the customer.	Annual adjustments are a central feature of jurisdictions that utilise incentive regulation. In fact, they are the norm for both water and electricity regulators in the United Kingdom and Australia. It is also the preferred approach for regulatory bodies in the Caribbean such as the Office of Utilities Regulation (OUR) in Jamaica. The RIC notes T&TEC's concurrence with this feature.

Key Issues Raised	RIC's Response
Performance Monitoring and Reporting (PMR) T&TEC proposed that with respect to Total System Losses, billings and collections should not be incorporated into the formula.	The RIC understands T&TEC's concerns and proposed an appropriate change in its document, "Incentive Mechanisms for Managing System Losses" discussed further in Chapter 9.
T&TEC cited concerns with some of the Performance Indicators outlined in the Appendix: Table 1 in the document "Review of PMR Framework for the Electricity Transmission and Distribution Sector"	The Appendix cited is a listing of applicable Performance Indicators which can be used for utilities operating in the electricity sector. The RIC has, over time, settled on a set of Performance Indicators applicable to T&TEC, which are reported annually by the RIC in its "T&TEC Annual Performance Indicator Report"
With respect to proposal to include six key performance indicators with the bill as stated in section 4.0, T&TEC recommended the option of publishing this data on all three (3) daily newspapers once every six (6) months.	The RIC acknowledges T&TEC's willingness to implement the "traffic signal" measure, as a means to enhance its service to customers. T&TEC's willingness to publish the relevant data on all three daily newspapers once every six (6) months, is commendable. However, the RIC is cognisant of the cost associated with the publication and will not make it a mandatory requirement to publish same every six (6) months.

Key Issues Raised	RIC's Response
The Ministry of Energy and Energy Industries proffered the following comments: Given the concerns highlighted in Section 3.2 Issues encountered with the PMR Scheme, is the RIC in a position to say all issues encountered have been resolved? If not, why and what is currently being done to address this? Additionally, how would the learnings be incorporated to ensure the items to be implemented as a result of the Final Determination of the second control period are better implemented. Were the templates in accordance to established standards and norms within the sector? a) If yes, should T&TEC in turn not follow these same standards and norms with regards to collating and reporting data?	The PMR scheme was established in 2006, and the RIC has observed improvements in T&TEC's performance since that time. The RIC has worked with T&TEC to address challenges faced during the initial implementation of the scheme. The efforts included streamlining data requests, harmonising data collection methods and revising data templates, improving data verification procedures, and conducting audits of T&TEC's data collection and reporting systems. The RIC has also conducted a Data Mapping Exercise with T&TEC to examine the validity and reliability of T&TEC's data. Based on the result of this exercise, the RIC recommended that T&TEC produce a "Standard Operating Procedure Manual" to improve its regulatory data collection and reporting. This was done and T&TEC is in the process of rolling-out implementation of its Manual. The RIC reviewed the data collection and reporting practices within the sector and developed templates that are relevant to the local context. Further, the RIC continues to work with T&TEC to ensure that these templates are consistent, and the data being captured remains relevant, meaningful and take into account new developments within the sector. In general, T&TEC has been following the agreed-upon approaches for collecting and reporting data. The RIC's general approach is always to discuss implementation issues with T&TEC,

Key Issues Raised	RIC's Response
b) If no, were these templates discussed with T&TEC ahead of their implementation? i)Possibly a forum should be made available to T&TEC to be part of the reviewing and revising of these templates, taking on board the limitations of T&TEC with their current procedures and the norms or standards within the sector. ii)To further close the gap, a series of indicators tracking T&TEC's performance in becoming compliant with the standards and norms with collecting data then reporting same to the RIC as regulator. Additional measures to improve monitoring and reporting activities: iii) As a part of the reports, the RIC should consider the inclusion of a section filled out by T&TEC's internal audit department. This section of the report should also verify the past five (5) reports, or a period deemed appropriate to the RIC, should more accurate data have been received since submitted. Signatures of two witnesses could also be implemented for further transparency, with one of them being from the internal audit unit. RIC should include an indicator on T&TEC's performance at the audits that directly relates to either a bonus or fine situation if this is within the realm of the RIC's abilities under the RIC Act. A metric should be included under "Customer Responsiveness and Service" to factor in the satisfaction of the customer after a complaint has been "dealt with/responded to" to obtain a better understanding of whether the issue was actually resolved and if it was done so in an efficient manner. The title Performance Indicators for The Electricity Sector" forms the backbone of any penalties/incentives scheme. Which indicators cover the transition to more environmentally sustainable systems?	before any policy or new reporting requirement is rolled out. Notwithstanding this T&TEC is accountable for any information that it submits to the RIC based on its regulatory obligations under the RIC Act. Further, the RIC interrogates all data reported by the utility to ensure the soundness of its performance assessments for T&TEC. The RIC notes the suggestions of the respondent. Matters related to enforcement and compliance are discussed in Chapter 9, inclusive of the use of an independent auditor. The RIC, as discussed in Chapter 9, proposes to use the Direct Revenue Adjustment mechanism for the "Number of Customer Interruptions per month" (Interruptions Incentive Scheme). This indicator and its financial impact will be closely linked to approved projects in the Capex programme and will be assessed annually to provide a continuous incentive to improve performance. The performance indicator "5.5 complaints resolved by type" in the Appendix of the RIC's document, measures T&TEC's ability to address/respond to customer complaints.

Key Issues Raised	RIC's Response
	While the RIC takes into account national environmental policies in the performance of its functions, monitoring of T&TEC's performance against environmental metrics is outside of the scope of the RIC's remit as economic regulator.
The Trinidad & Tobago Chamber of Commerce proffered the following comments: The Chamber has concern over the long lag time in reporting within the existing Performance Monitoring and Reporting Framework. The 2019 Performance Report was issued in January 2021. In order for performance monitoring to have an effect in assisting to create a culture of continuous improvement, the metrics need to be timely and regular. Delays in reporting means that the quality of information is being received over a year after it was generated, making it useless as a management tool for improvement. For monitoring information to be of use, it must be frequent, accurate and timely in its presentation. Quarterly reporting or reporting every billing cycle is strongly recommended. KPls should be chosen for relevance as well as the sector's ability to collect and disseminate data. Providing the public with lengthy reports can be done once per year, but the plan to include such data on bills should be kept to the simplest KPIS and be updated regularly. The Utility will need to apply dedicated resources to implement a special office to achieve this, if they have not already done so.	The RIC agrees that in order to create a culture of continuous improvement, metrics need to be collected on a timely basis. The RIC acknowledges that the 2019 Report was published thirteen months after the end of 2019 however, the challenges brought about by the COVID-19 Pandemic affected the timely reporting of some data. From a regulatory perspective the publication of performance reports on an annual basis are the norm. Although quarterly information may be collected, it is not generally published. Additionally, the regulator's publication of information on an annual basis does not negate the responsibility of the service provider to ensure that it sets and monitors metrics on a timely and regular basis. The RIC acknowledges the TT Chamber's endorsement of including key data on customer bills or "traffic signal" indicators as a measure to enhance the RIC's monitoring and reporting activities. As proposed in the PMR Framework, this measure will require the service provider to include, in the electricity bills of customers, a set of "traffic signal" indicators at six-month intervals to give a snapshot of its performance and financial health. The RIC proposes to undertake periodic reviews of the performance indicators to

Key Issues Raised	RIC's Response
The reporting of information is of little value if it not used to create platforms for continuous performance improvement within the organisation. Metrics should be linked to responsible teams and improvement plans and action items included in internal reports. Linking performance improvements to team and management incentives provides strong positive reinforcement.	ensure that they take into account future developments and remain relevant and meaningful. The RIC agrees that performance metrics should be linked to responsible teams and improvement plans and action items included in internal reports. This is an initiative that the RIC would want to encourage the Board and management of the service provider to consider. However, it is beyond the purview of the RIC to mandate performance targets for service provider's staff/teams.
Length of the Regulatory Control Period T&TEC noted that 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. Therefore, to effect a period greater than five (5) years would require changes to the RIC Act, resulting in unnecessary delays in the implementation of a new tariff which is unfavourable for T&TEC, especially at this time.	The RIC did discuss the advantages and disadvantages of both a longer and shorter regulatory period, and noted that any attempt to implement a control period longer than five years would require changes to the RIC Act. The RIC's view, however, is that a five-year control period remains suitable for the electricity transmission and distribution sector at this time and notes T&TEC's concurrence with this approach.
Incentive Mechanism for Managing Systems Losses T&TEC made the following comments: - Reference is made to the comment on page 9 immediately below Table 4. The use of the higher transmission voltage of 220 kV is not a factor that can explain loss reduction, as this 220 kV infrastructure was established for the sole purpose of delivering power from electrically distant TGU, a new requirement, which however met, would increase the percentage losses. Doing so at 220 kV was simply the means that minimised that increase.	The RIC notes T&TEC's response.

Key Issues Raised	RIC's Response
Further, in addition to the upgrade from 66 kV to 132 kV of the transmission lines from Bamboo substation in Valsayn to Gateway substation in Port of Spain, was the active and aggressive pursuit of power factor improvement using pole-mounted capacitor banks on distribution feeders.	
- With respect to the comment at the top of page 11 "T&TEC did not undertake any significant capital projects or activities to reduce total system losses", power factor correction has been undertaken on the 12 kV system. The Commission has installed over 1,200 capacitors on feeders over the years valued at almost $5M following studies conducted by our Engineering Division in 2016.	The RIC notes T&TEC efforts in this area. However, the RIC stands by its original assessment as the Service Provider has not disclosed if these 1,200 capacitators fulfill the needs of the system.
- With respect to the system loss formula in page 12, T&TEC is in agreement with this formula rather than the one on page 7, but with the term 'Energy Purchased' changed to Energy Sent Out or Net Energy Generated.	It is understood that T&TEC is primarily a purchaser of energy from the Independent Power Producers (IPPs), but it also generates electricity for supply in Tobago. In this regard, the RIC will consider the proposal put forward by T&TEC, along with the facts and circumstances, in reviewing the matter.
- Also on page 12, the second bullet point, the basis for the .25% reduction is unclear and should be properly determined. In addition, the base year should be set at the existing percentage loss, which is at 9% and not the 8% suggested. At the 9% base and the annual target reduction of 0.25%, the target of 6.75% will not be achieved within the 5-year period. This issue requires a proper review and analysis, especially as it may now attract a penalty.	The target of 6.75% for system losses was established under the first Price Determination, which included consultation with T&TEC, the public and other key stakeholders. The target was considered reasonable, given the performance and topology of the network. T&TEC's proposal must be supported by cogent arguments and should provide a rationale for the increases observed/proposed for consideration by the RIC.
- With respect to the final bullet point on page 12, it is to be noted that distribution circuits from existing substations are typically as short as practicable, and further shortening would usually involve the establishment of new substations. The cost of doing that sort of gross system re-configuration cannot be	- The measures proposed by the RIC are intended to improve system performance through economically efficient activities. Therefore, the RIC would not approve of non-optimal capital expenditures that result in a negative net benefit, such as the construction

Key Issues Raised	RIC's Response
justified by the value of energy savings alone. The RIC should not establish an incentive/penalty structure that would reward T&TEC for expending capital non-optimally. - Page 13 second bullet point of the document, refers to the proration of cost incurred if only say 50% of the system loss target is achieved, which can be a disincentive. For example, if T&TEC spends say $1M on a successful loss reduction initiative, but the overall system target is only 50% achieved, then T&TEC is credited only 50% of the capital cost ($0.5m) of that completely successful project.	of a new substation merely for the shortening of a distribution circuit. The mechanisms proposed by the RIC are intended to incentivise T&TEC to optimise its system performance through prudent investments. The RIC does not intend to disallow expenditure on loss reduction equipment, it merely intended to clarify that such expenditure would be included in the rate base.
Establishing an Appropriate Form of Price Control T&TEC made the following comment: The revenue cap has generally worked well in the first five-year price control period to encourage the reduction in expenses and efficiency improvements in operation. It is also noted that the RIC is of the view that the revenue cap remains fit as the appropriate form of price control.	This was the view proffered by the RIC in its paper and the RIC notes T&TEC's endorsement of the continued use of the revenue cap as the appropriate form of price control.
Regulating Quality of Service The Ministry of Energy and Energy Industries expressed the following concerns: Was an Efficiency Benefit Sharing Scheme considered as a Service Incentive Scheme rather than adopting an "S" factor and a Direct Revenue Adjustment?	An Efficiency Carryover Mechanism is a component of the RIC's overall regulatory framework and was extensively consulted on in PRE1. It is, however, not a mechanism specifically related to quality of service, which was the focus of this paper.

Key Issues Raised	RIC's Response
Given the RIC encountered "delays in reporting, quality of information in certain instances", could a Service Performance Measure reflecting these issues be incorporated into its schemes thereby incentivising the service provider to improve?	The RIC, as noted in its paper, has already taken steps to improve the quality of data it receives from the service provider. Further, as discussed in Chapter 8, the RIC intends to employ a number of measures to ensure overall compliance by the service provider.
Under what timeline is the following poised to be completed – To further improve the quality of data submitted by T&TEC the RIC engaged in a data mapping exercise and plans to employ an Independent Auditor, in the future, to verify the process of the service provider's information collection and quality of information? Also, shouldn't such be expedited thereby potentially increasing meaningfully the actions implemented out of the second review (if any)?	The details of the independent auditor to be utilised are discussed in Chapter 9.
The Service Incentive Schemes as worded incentivises/penalises the finances of the Service Provider, however, shouldn't it go further by matching similarly to those charged with running the organisation, with continued tenure being heavily influenced by such as well?	The RIC understands the concern raised, however, the RIC's purview is to incentivise the organisation. It is the responsibility of the Board of T&TEC to decide how to incentivise its managers to achieve the targets set by the RIC.
Given the need for the Service Provider to align themselves eventually with environmentally sustainable mandates, how has this been reflected in the incentivisation schemes put forward for consideration?"	The RIC, in carrying out its regulatory remit, considers all environmental and other mandates with which the service provider is required to comply. The incentives identified in the quality-of-service scheme are specifically aimed at improving the level of service that T&TEC delivers to its customers.
As acknowledged by the RIC "In its Final Determination for the first price control period, the RIC further identified measures that should be implemented in order to properly measure and collect data on the quality of supply. The installation of equipment for monitoring quality of supply at each zone substation to better monitor voltage problems was only partially completed,	The RIC has taken appropriate measures as a result of the lessons learnt from PRE1. Additionally, the Quality-of-Service Standards Scheme has been reviewed and amended over the years, the last time being in 2021. The investigation of voltage complaints is now a guaranteed standard and T&TEC is required to investigate and rectify (where necessary) such

Key Issues Raised	RIC's Response
making measurement difficult, so there is an inadequate collection of baseline data to enable the RIC to set any targets in this area.". Given the recommendations arising out of the Final Determination for the first control period, shouldn't the RIC find ways not only to make up for where they fell short but ensure implementation learnings are incorporated to ensure the Final Determinations of the second control period are fully implemented.	complaints and make compensatory payments when the standard is breached.
With respect to the Guaranteed Standard Scheme, in the case that there is a failure to meet guaranteed service levels, what measures are in place to ensure the customer is fairly compensated?	The Guaranteed Standards Scheme has a schedule of fixed penalties associated with the guaranteed standards. These penalty payments are applied to the customer's accounts when T&TEC fails to meet a guaranteed level of service.
Do the Target/ Performance band-based S-factor schemes as well as the indicators measure the performance of the service provider for the country as whole or measures the performance based on separate regions of the country?	Performance Targets would normally be based on a country average, unless otherwise stated.
The latter would be able to give more precise results and also would aid areas that have a history of lower quality of service such as rural areas. This should also be considered for the Direct Revenue Adjustment.	The RIC, as discussed in Chapter 8, proposes to use the Direct Revenue Adjustment mechanism for the "Number of Customer Interruptions per month" (Interruptions Incentive Scheme). This indicator and its financial impact will be closely linked to approved projects in the Capex programme and will be assessed annually so as to provide a continuous incentive to improve performance.
What would occur with respect to rewarding the service provider if a scenario arrives where there can be no more improvements to the quality of service? A possible approach would be to revert to the Guaranteed Standard Scheme and attempt to	As noted in the RIC's paper, mechanisms such as the S-factor can be symmetrical, that is both penalise and reward the service provider, the S-factor was not recommended for use.

Key Issues Raised	RIC's Response
ensure that the worst served customers meets the specified target as the average customer has been already met.	The RIC, in Chapter 9, has proposed the use of the Direct Revenue Adjustment to deal with worst served areas in terms of customer interruptions. Guaranteed standards are designed to be applicable across the board.
The Trinidad and Tobago Chamber of Commerce provided the following comments: The Chamber welcomes a Service Incentive Mechanism but is concerned regarding the structure of the incentive. The incentive is intended to provide both positive and negative reinforcement to the Utility in terms of cash flow, but there is no link between the incentive to the organisation as a whole and its management and employees. Without such a link, will there be any real motivation to improve efficiency among the management and staff, especially in the case where, as an essential service, the Utility is 100% government owned? If, for example, the Utility fails to achieve the objectives of the incentive in one period, this will result in a reduction in revenue for the subsequent period, further exacerbating the utility's ability to achieve the objectives as cash flows become negatively impacted, this negative reinforcement can, if unchecked, provide a disincentive to improvement. Furthermore, it is the Chamber's view that incentives and disincentives will not work well if focused on the Utility as a whole as opposed to being focused on the performance of the employee teams and management. The incentivisation of employees has been a proven method of continuous improvement over the years; it is the people of the organisation that finds ways to improve service and efficiency. If for example, there is a customer service KPI, but the customer service employee does not benefit from its	The RIC understands that incentivisation throughout the utility will lead to continuous improvement. However, the RIC's purview is to provide incentives for improvement to the utility as a whole. The RIC, however, is not responsible for managing the utility and it is the responsibility of the Board of T&TEC to ensure that the utility is effectively managed to meet its targets.

Key Issues Raised	RIC's Response
improvement, he or she will not be motivated to change behaviour. Finally, the frequency of measurement and price adjustment based on the incentive should be more than once per year, and should preferably be every billing cycle.	
Improving Transparency and Accountability in the Electricity and Water Sectors T&TEC made the following comments: Page 11 speaks to participatory budgeting, as a mechanism that gives customers an avenue to express their views on how funds are spent for capital projects, by involving customers in setting of investment priorities. This can be counterproductive, as most customers would not have a holistic view of the operation of T&TEC and would naturally request that projects in their community or from which they benefit, be prioritised.	The intent behind participatory budgeting is to encourage T&TEC to allow its customers to have a say in terms of projects which they believe are required to improve service delivery in their areas. Participation can take the form of customer focus groups etc. In doing so it is expected that customers will put forward proposals which otherwise may not have been conceptualised by T&TEC. In turn, T&TEC will have the opportunity to explain how projects are prioritised.

ANNEX 3

Regulatory Accounting Guidelines

The Tables in this Annex comprise the Regulatory Accounting Guidelines referred to in Chapter 9.7 and are the templates that T&TEC must use in their periodic submission to the RIC.

Balance Sheet BS01

		As at - xxxx			
		1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
		$'000	$'000	$'000	$'000
FIXED ASSETS					
	- Regulated Assets				
	- Non-Regulated Assets				
	Investment in Subsidiary				
	Retirement Benefit Assets				
	Total Fixed Assets				
CURRENT ASSETS					
	Inventories				
	Light and Power Debtors				
	Sundry Debtors and Prepayments				
	Less: Provision for Bad and Doubtful Debts				
	Cash at Bank and in Hand				
	Call Deposits				
	Other investments				
	Due from Subsidiary				
	Total Current Assets				
CURRENT LIABILITIES					
	Trade Creditors				
	Sundry Creditors and Accruals				
	Natural Gas (NGC)				
	Total Current Liabilities				
TOTAL NET ASSETS					
FINANCED BY					
	Capital Funds				
	Capital Reserves				
	Non-Refundable Capital Contributions				
REVENUE RESERVES					
	Accumulated Surplus/Deficit				
	Net capital Funds				

	Customer' Service Deposits				
	Retirement Benefit Obligations				
EXTERNAL LOANS					
	GORTT Advances				
	Natural Gas (NGC)				
CAPITAL EMPLOYED					

Fixed Asset Schedule BS02

AS AT - xxxx

	Land $'000	Structures $'000	Transmission Assets $'000	Distribution Assets $'000	Meters $'000	Communications Equipment $'000	Computer Equipment $'000	Motor Vehicles $'000	Street Lighting $'000	TOTAL $'000
Regulatory Asset Base as at										
Additions Based on Approved Projects During the Qtr										
Depreciation for the quarter										
Disposals during the quarter										
Regulatory Assets Base as at										
Non Approved Completed Capital Expenditure during the period										
Funded by:										

Ring Fenced										
Government (PSIP)										
Capital Contributions - Residential										
Capital Contributions - Non Residential										
Regulatory Asset Base at (Unadjusted)										
Adjustments										
Closing Regulatory Asset Base (Adjusted)										

	CAPITAL ADDITIONS $000				**TOTAL $000**	**DISPOSALS $000**
	Tariff Funded	**Capital Contribution**	**Ring Fenced**	**Government**		
TRANSMISSION ASSETS						
Control Gear/ Switchgear			-	-	-	-
Transformers			-	-	-	-
Transmission Lines						
Submarine Cable						
Other						
Subtotal						
DISTRIBUTION ASSETS						
Overhead Lines						
Underground Lines						
Transformers						
Other						
Subtotal						
METERS						
COMMUNICATIONS EQUIPMENT						

COMPUTER EQUIPMENT						
MOTOR VEHICLES						
STRUCTURES						
LAND						
STREET LIGHTING						
GRAND TOTAL						

		NON-LOAD RELATED		**NON-NETWORK**	
CAPEX CATEGORY $000	**LOAD RELATED (GROWTH)**	**ASSET RENEWAL/ REPLACEMENT**	**RELIABILITY & QUALITY IMPROVEMENT**	**ENVIRONMENTAL, SAFETY & LEGAL OBLIGATIONS**	**OTHER**
Land **Structures** **Transmission (Substations, Overhead lines, Underground cables, Transformers)** **Distribution (Substations, Overhead lines, Underground cables, Transformers)** **Meters** **Communications Equipment** **Computer Equipment** **Motor Vehicles**					
Sub Total (RIC Approved)					
Street Lighting **Government PSIP** **Ring Fenced**					
Sub Total (RIC Non-Approved)					
TOTAL					

Capital Expenditure BS03

RIC Approved Projects $000

Category	Current Qtr: RIC Approved	Current Qtr: Actual	Transfers	YTD: RIC Approved	YTD: Actual	Total for year: RIC Approved
Transmission- Refurbishments & Replacements						
Transmission & Sub Transmission - Development Projects						
Distribution						
Structures						
Land						
Meters						
Communications Equipment						
Computer Equipment						
Motor Vehicles						
Street Lighting						
Total						

NB - The above information should be categorised as follows:

	Current Qtr: RIC Approved	Current Qtr: Actual	Transfers	YTD: RIC Approved	YTD: Actual	Total for year: RIC Approved
Load Related (Growth)						
Non-Load Related . Asset Renewal/Replacement						
Reliability & Quality Improvement						
Non-Network . Environmental, Safety & Legal Obligations						
Other						
Total						

NB - Both Tables must agree

Government Policy Driven Projects $000 (PSIP)

Category	Current Qtr			Transfer	YTD			Total for year		
	Budgeted Cost	Received	Spent		Budgeted Cost	Received	Spent	Budgeted Cost	Received	Spent
Transmission- Refurbishments & Replacements										
Transmission & Sub Transmission - Development Projects										
Distribution										
Structures										
Land										
Meters										
Communications Equipment										
Computer Equipment										
Motor Vehicles										
Street Lighting										
Total										

NB - The above information should be categorised as follows:

	Current Qtr			Transfers	YTD			Total for year		
	Budgeted Cost	Received	Spent		Budgeted Cost	Received	Spent	Budgeted Cost	Received	Spent
Load Related (Growth)										
Non-Load Related . Asset Renewal/Replacement										
Reliability & Quality Improvement										
Non-Network . Environmental, Safety & Legal Obligations										
Other										
Total										

NB - Both Tables must agree

Capital Contribution Projects $000

Category	Current Qtr			Transfers	YTD			Total for year		
	Budgeted Cost	**Received**	**Spent**		**Budgeted Cost**	**Received**	**Spent**	**Budgeted Cost**	**Received**	**Spent**
Transmission- Refurbishments & Replacements										
Transmission & Sub Transmission - Development Projects										
Distribution										
Meters										
Street Lighting										
Total										

NB - The above information should be categorised as follows:

	Current Qtr			Transfers	YTD			Total for year		
	Budgeted Cost	**Received**	**Spent**		**Budgeted Cost**	**Received**	**Spent**	**Budgeted Cost**	**Received**	**Spent**
Load Related (Growth)										
Non-Load Related . Asset Renewal/Replacement										
Reliability & Quality Improvement										
Non-Network . Environmental, Safety & Legal Obligations										
Other										
Total										

NB - Both Tables must agree

Ring Fenced Driven Projects $000

Category	Current Qtr			Transfers	YTD			Total for year		
	Budgeted Cost	Received	Spent		Budgeted Cost	Received	Spent	Budgeted Cost	Received	Spent
Transmission- Refurbishments & Replacements										
Transmission & Sub Transmission - Development Projects										
Distribution										
Structures										
Land										
Meters										
Communications Equipment										
Computer Equipment										
Motor Vehicles										
Street Lighting										
Total										

NB - The above information should be categorised as follows:

	Current Qtr			Transfers	YTD			Total for year		
	Budgeted Cost	Received	Spent		Budgeted Cost	Received	Spent	Budgeted Cost	Received	Spent
Load Related (Growth)										
Non-Load Related . Asset Renewal/Replacement										
Reliability & Quality Improvement										
Non-Network . Environmental, Safety & Legal Obligations										
Other										
Total										

NB - Both Tables must agree

Work in Progress BS04

	Consolidated $000			
	WIP Bal B/F	Work for the Quarter	Transfers out	Closing W.I.P.
Tariff funded				
Transmission				
Distribution				
Structures				
Land				
Meters				
Communications Equipment				
Computer Equipment				
Motor Vehicles				
Street Lighting				
Total				
PSIP				
Transmission				
Distribution				
Structures				
Land				
Meters				
Communications Equipment				
Computer Equipment				
Street Lighting				
Total				
Capital Contribution				
Transmission				
Distribution				
Meters				
Street Lighting				
Total				
Ring Fenced				
Transmission				
Distribution				
Structures				

		Load (Growth) Related $000		
	WIP Bal B/F	Work for the Quarter	Transfers out	Closing W.I.P.
Tariff funded				
Transmission				
Distribution				
Structures				
Land				
Meters				
Communications Equipment				
Computer Equipment				
Motor Vehicles				
Street Lighting				
Total				
PSIP				
Transmission				
Distribution				
Structures				
Land				
Meters				
Communications Equipment				
Computer Equipment				
Street Lighting				
Total				
Capital Contribution				
Transmission				
Distribution				
Meters				
Street Lighting				
Total				
Ring Fenced				
Transmission				
Distribution				
Structures				

Land				
Meters				
Communications Equipment				
Computer Equipment				
Street Lighting				
Total				
GRAND TOTAL				

Land				
Meters				
Communications Equipment				
Computer Equipment				
Street Lighting				
Total				
GRAND TOTAL				

NON-LOAD RELATED

	Asset Renewal/Replacement $000			
	WIP Bal B/F	**Work for the Quarter**	**Transfers out**	**Closing W.I.P.**
Tariff funded				
Transmission				
Distribution				
Structures				
Land				
Meters				
Communications Equipment				
Computer Equipment				
Motor Vehicles				
Street Lighting				
Total				
PSIP				
Transmission				
Distribution				
Structures				
Land				
Meters				
Communications Equipment				
Computer Equipment				
Street Lighting				
Total				
Capital Contribution				

	Reliability & Quality Improvement $000			
	WIP Bal B/F	**Work for the Quarter**	**Transfers out**	**Closing W.I.P.**
Tariff funded				
Transmission				
Distribution				
Structures				
Land				
Meters				
Communications Equipment				
Computer Equipment				
Motor Vehicles				
Street Lighting				
Total				
PSIP				
Transmission				
Distribution				
Structures				
Land				
Meters				
Communications Equipment				
Computer Equipment				
Street Lighting				
Total				
Capital Contribution				

Transmission				
Distribution				
Meters				
Street Lighting				
Total				
Ring Fenced				
Transmission				
Distribution				
Structures				
Land				
Meters				
Communications Equipment				
Computer Equipment				
Street Lighting				
Total				
GRAND TOTAL				

Transmission				
Distribution				
Meters				
Street Lighting				
Total				
Ring Fenced				
Transmission				
Distribution				
Structures				
Land				
Meters				
Communications Equipment				
Computer Equipment				
Street Lighting				
Total				
GRAND TOTAL				

NON-NETWORK

	Environmental, Safety & Legal Obligations $000			
	WIP Bal B/F	**Work for the Quarter**	**Transfers out**	**Closing W.I.P.**
Tariff funded				
Transmission				
Distribution				
Structures				
Land				
Meters				
Communications Equipment				
Computer Equipment				
Motor Vehicles				
Street Lighting				
Total				
PSIP				
Transmission				
Distribution				

		Other $000		
	WIP Bal B/F	**Work for the Quarter**	**Transfers out**	**Closing W.I.P.**
Tariff funded				
Transmission				
Distribution				
Structures				
Land				
Meters				
Communications Equipment				
Computer Equipment				
Motor Vehicles				
Street Lighting				
Total				
PSIP				
Transmission				
Distribution				

Structures				
Land				
Meters				
Communications Equipment				
Computer Equipment				
Street Lighting				
Total				
Capital Contribution				
Transmission				
Distribution				
Meters				
Street Lighting				
Total				
Ring Fenced				
Transmission				
Distribution				
Structures				
Land				
Meters				
Communications Equipment				
Computer Equipment				
Street Lighting				
Total				
GRAND TOTAL				

Structures				
Land				
Meters				
Communications Equipment				
Computer Equipment				
Street Lighting				
Total				
Capital Contribution				
Transmission				
Distribution				
Meters				
Street Lighting				
Total				
Ring Fenced				
Transmission				
Distribution				
Structures				
Land				
Meters				
Communications Equipment				
Computer Equipment				
Street Lighting				
Total				
GRAND TOTAL				

Receivables BS05

As At - xxxx	TOTAL	0-30 Days	31-60 Days	61-90 days	91-120 Days	121 Days - 1 Yr	1 yr - 4 yrs	Over 4 yrs
	TT$000	TT$000	TT$000	TT$000	TT$000	TT$000	TT$000	TT$000
Residential A	-	-	-	-	-	-	-	-

Commercial	-	-	-	-	-	-	-	-
Rate B1	-	-	-	-	-	-	-	-
Private	-							
Public	-	-	-	-	-	-	-	-
Central Government	-							
Statutory Boards	-							
State Enterprises	-							
Rate B2	-	-	-	-	-	-	-	-
Private	-							
Public	-	-	-	-	-	-	-	-
Central Government	-							
Statutory Boards	-							
State Enterprises	-							
Industrial D	-	-	-	-	-	-	-	-
Rate D1	-	-	-	-	-	-	-	-
Private	-							
Public	-	-	-	-	-	-	-	-
Central Government	-							
Statutory Boards	-							
State Enterprises	-							
(T&TEC to add rows foe other Industrials)								

Industrial E	-	-	-	-	-	-	-	-
Rate E1	-	-	-	-	-	-	-	-
Private	-							
Public	-	-	-	-	-	-	-	-
Central Government	-							
Statutory Boards	-							
State Enterprises	-							
Rate E2	-	-	-	-	-	-	-	-

Private	-							
Public	-	-	-	-	-	-	-	-
Central Government	-							
Statutory Boards	-							
State Enterprises	-							
Rate E3	-	-	-	-	-	-	-	-
Private	-							
Public	-	-	-	-	-	-	-	-
Central Government	-							
Statutory Boards	-							
State Enterprises	-							
Rate E4	-	-	-	-	-	-	-	-
Private	-							
Public	-	-	-	-	-	-	-	-
Central Government	-							
Statutory Boards	-							
State Enterprises	-							
Rate E5	-	-	-	-	-	-	-	-
Private	-		-					
Public	-	-	-	-	-	-	-	-
Central Government	-							
Statutory Boards	-							
State Enterprises	-							
Public Lighting	-	-	-	-	-	-	-	-
Streetlamps	-							
Traffic Lights	-	-	-	-	-	-	-	-
Recreational Grounds	-							
TOTAL	-	-	-	-	-	-	-	-
Sundry Debtors								

Debt Financing BS06

AS AT - xxxx		*Year ended Dec 31►*					TOTAL
			QTR1	QTR2	QTR3	QTR4	
			$'000	$'000	$'000	$'000	$'000
EXISTING LOANS							
N.G.C.:							
Interest Rate		Balance B/F		-	-	-	-
Loan Type		Principal Payment					-
Issue Date		Interest Paid					-
Maturity Date		Balance C/F	-	-	-	-	-
Loan Purpose		Interest Capitalised					-
Other Loans:							
Interest Rate		Balance B/F		-	-	-	-
Loan Type		Principal Payment					-
Issue Date		Interest Paid					-
Maturity Date		Balance C/F	-	-	-	-	-
Loan Purpose		Interest Capitalised					-
	Please add rows as needed						
		TOTAL EXISTING DEBT B/F	-	-	-	-	-
		Total Principal Paid	-	-	-	-	-
		Total Interest Paid	-	-	-	-	-
		TOTAL EXISTING DEBT C/F	-	-	-	-	-
		Total Interest Capitalised					-

NEW LOANS							
Interest Rate		Balance B/F		-	-	-	-
Loan Type		Principal Payment					-
Issue Date		Interest Paid					-
Maturity Date		Balance C/F	-	-	-	-	-
Loan Purpose		Interest Capitalised					-
Interest Rate		Balance B/F		-	-	-	-
Loan Type		Principal Payment					-
Issue Date		Interest Paid					-
Maturity Date		Balance C/F	-	-	-	-	-
Loan Purpose		Interest Capitalised					-
	Please add rows as needed						
		TOTAL EXISTING DEBT B/F	-	-	-	-	-
		Total Principal Paid	-	-	-	-	-
		Total Interest Paid	-	-	-	-	-
		TOTAL EXISTING DEBT C/F	-	-	-	-	-
		Total Interest Capitalised					-
		TOTAL DEBT B/F	-	-	-	-	-
		Total Principal Paid	-	-	-	-	-
		Total Interest Paid	-	-	-	-	-
		TOTAL DEBT C/F	-	-	-	-	-
		Total Interest Capitalised					-

		RECONCILIATION					
		TOTAL DEBT AS PER MANAGEMENT ACCOUNTS (BALANCE SHEET)					
		DIFFERENCE BETWEEN RAG AND MANAGEMENT ACCOUNTS	-	-	-	-	
		REASON FOR DIFFERENCE :					

Cash Flow Statement BS07

For the period ended - xxxx	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	$000'	$000'	$000'	$000'
Cash Flows from Operating Activities				
Net Surplus (Deficit) for the year				
Interest Expense				
Depreciation and Amortisation (RAB)				
Depreciation and Amortisation (Non RAB)				
Dividend Income				
Term Deposit Income				
Deferred Interest				
(Decrease)/Increase in Retirement Benefit Obligations				
(Decrease)/Increase in Retirement Benefit Assets				
Loss/(Profit) on Asset Disposal				
	-	-	-	-
Changes in Working Capital:				
Decrease/(Increase) in Inventories				
Decrease/(Increase) in Trade and Other Receivables				
(Increase)/Decrease in Debt Securities				
Increase/(Decrease) in Customer Service Deposits				
(Decrease)/Increase in amounts due to Subsidiary				
Increase/(Decrease) in Trade Payables				
	-	-	-	-
Cash Generated By Operations				
Interest Paid				
	-	-	-	-

Net Cash Generated By Operating Activities	-	-	-	-

Cash Flows from Investing Activities				
Debenture Redemption				
Dividend Received				
Capital Contributions				
Interest Received				
Purchase of Fixed Assets				
Net Decrease/(Increase) in Investments				
Interest Paid				
Proceeds from the sale of Fixed Assets				
Net Cash (Used in)/Provided by Investing Activities	-	-	-	-
Cash Flows from Financing Activities				
Government Advances				
Proceeds from Loans				
Repayment of Loans				
Net Cash (Used in)/Provided by Financing Activities	-	-	-	-
NET CASH AND CASH EQUIVALENTS FROM/(USED IN) PERIOD	-	-	-	-
CASH AND CASH EQUIVALENTS AT THE START OF THE YEAR QUARTER				
CASH AND CASH EQUIVALENTS AT THE END OF THE YEAR QUARTER	-	-	-	-
Cash and Cash Equivalents Represented By:				
Cash and Cash Equivalents				
Bank Advances and Demand Loans				
	-	-	-	-

Income Statement IS01

PERIOD ENDED - xxxx			1st Quarter ended	2nd Quarter ended	3rd Quarter ended	4th Quarter ended	YTD
			xxxx	xxxx	xxxx	xxxx	xxxx
			$	$	$	$	$
REGULATED REVENUES							
	Sale of Electricity						-
	Other Operating Revenues						-
		Total operating revenues	-	-	-	-	-
REGULATED EXPENSES							
	Fuel						-
	Purchased Power						-
	Internal Generation						-
	Transmission						-
	Distribution						-
	Engineering						
	Administrative and General						-
		Total Operating Expenses	-	-	-	-	-
REGULATED INCOME BEFORE DEPRECIATION			-	-	-	-	-
	Less:	Depreciation Regulated					
NET OPERATING INCOME			-	-	-	-	-
NON-REGULATED INCOME							
	Investment Revenues						-
	Dividend from Subsidiary						-
	Net Increase in Retirement Benefit Obligations						-
	Interest Income						-
	Profit on Disposal of Fixed Assets						-
	Loss on Foreign Exchange Transactions						-
	Miscellaneous Revenues						
			-	-	-	-	-

NON-REGULATED EXPENSES					
Non Regulated Depreciation					-
Net Decrease in Retirement Benefit Obligations					-
Interest Expense and Financial Charges					-
Loss on Disposal of Fixed Assets					-
(Gain) on Foreign Exchange Transactions					-
Other Expenses					
	-	-	-	-	-
SURPLUS/(DEFICIT)	-	-	-	-	-
INCOME BEFORE TRANSFERS	-	-	-	-	-
TRANSFERS TO OTHER FUNDS	-	-	-	-	-
NET SURPLUS/(DEFICIT)	-	-	-	-	-
ACCUMULATED FUND B/F					
ACCUMULATED FUND C/F	-	-	-	-	-
RECONCILIATION					
Total Surplus/(Deficit) as per Management Accounts					
Difference between Management accounts and RAG					
Reason for Difference					

Operating Expenditure IS02

FOR QUARTER ENDED - xxxx	Total $	MW / MWh	Cost per Unit	Account Nos.	Actual Year to Date xxxx $	Forecast Next Quarter $
CONVERSION						
- Capacity						
PowerGen						
Normal Capacity Purchases						
Excess Capacity Purchases						
Trinity Power						
Normal Capacity Purchases						
Excess Capacity Purchases						
TGU						
Normal Capacity Purchases						
Excess Capacity Purchases						
Energy						
PowerGen						
Energy Purchases						
Trinity Power						
Energy Purchases						
TGU						
Energy Purchases						
SUB TOTAL CONVERSION	-	-	-		-	-
FUEL						
Fuel Purchases						
SUB TOTAL FUEL	-	-	-		-	-

FOR QUARTER ENDED - xxxx	Total $	Cost per Unit	Account Nos.	Actual Year to Date xxxx $	Forecast Next Quarter $	
TOBAGO / COVE / INTERNAL GENERATION						
- Advertising/Promotion						
Contracted Labour & Services						
Fuel						
Information Technology						
Material/Supplies						
Other Direct Costs						
Personnel - Employer Contribution to other Benefits						
Personnel - Employer Contribution NIS						
Personnel - Employer Contribution Pension						
Personnel - Overtime						
Personnel - Salaries						
Personnel - Wages						
Rates, Taxes & Insurance						
Rentals/Leases						
Repairs & Maintenance - Buildings						
Repairs & Maintenance - Line & Pole (Fault)						
Repairs & Maintenance - Line & Pole (planned)						
Repairs & Maintenance - Tools & Equipment (Fault)						
Repairs & Maintenance - Tools & Equipment (planned)						
Repairs & Maintenance - Vehicles						
Security						
Sponsorships						
Training						
Vegetation Management						
Vehicle Costs						
SUB TOTAL	-	-		-	-	
MWh Produced Internally						
Number of Employees						

FOR QUARTER ENDED - xxxx	Total $	Cost per Unit	Accoun t Nos.	Actual Year to Date xxxx $	Forecast Next Quarter $
TRANSMISSION					
Advertising/Promotion					
Contracted Labour & Services					
Information Technology					
Material/Supplies					
Other Direct Costs					
Personnel - Employer Contribution to other Benefits					
Personnel - Employer Contribution NIS					
Personnel - Employer Contribution Pension					
Personnel - Overtime					
Personnel - Salaries					
Personnel - Wages					
Rates, Taxes & Insurance					
Rentals/Leases					
Repairs & Maintenance - Buildings					
Repairs & Maintenance - Line & Pole (Fault)					
Repairs & Maintenance - Line & Pole (planned)					
Repairs & Maintenance - Tools & Equipment (Fault)					
Repairs & Maintenance - Tools & Equipment (planned)					
Repairs & Maintenance - Vehicles					
Security					
Sponsorships					
Training					
Vegetation Management					
Vehicle Costs					
SUB TOTAL TRANSMISSION	-	-		-	-
Network Length kms					
Number of Employees					

FOR QUARTER ENDED - xxxx	Total $	Cost per Unit	Account Nos.	Actual Year to Date xxxx $	Forecast Next Quarter $
DISTRIBUTION					
Advertising/Promotion					
Contracted Labour & Services					
Information Technology					
Material/Supplies					
Other Direct Costs					
Personnel - Employer Contribution to other Benefits					
Personnel - Employer Contribution NIS					
Personnel - Employer Contribution Pension					
Personnel - Overtime					
Personnel - Salaries					
Personnel - Wages					
Rates, Taxes & Insurance					
Rentals/Leases					
Repairs & Maintenance - Buildings					
Repairs & Maintenance - Line & Pole (Fault)					
Repairs & Maintenance - Line & Pole (planned)					
Repairs & Maintenance - Tools & Equipment (Fault)					
Repairs & Maintenance - Tools & Equipment (planned)					
Repairs & Maintenance - Vehicles					
Security					
Sponsorships					
Training					
Vegetation Management					
Vehicle Costs					
SUB TOTAL DISTRIBUTION	-	-		-	-
Network Length Kms					
Number of Employees					

FOR QUARTER ENDED - xxxx	Total $	Cost per Unit	Account Nos.	Actual Year to Date xxxx $	Forecast Next Quarter $
ENGINEERING					
Advertising/Promotion					
Contracted Labour & Services					
Information Technology					
Material/Supplies					
Other Direct Costs					
Personnel - Employer Contribution to other Benefits					
Personnel - Employer Contribution NIS					
Personnel - Employer Contribution Pension					
Personnel - Overtime					
Personnel - Salaries					
Personnel - Wages					
Rates, Taxes & Insurance					
Rentals/Leases					
Repairs & Maintenance - Buildings					
Repairs & Maintenance - Line & Pole (Fault)					
Repairs & Maintenance - Line & Pole (planned)					
Repairs & Maintenance - Tools & Equipment (Fault)					
Repairs & Maintenance - Tools & Equipment (planned)					
Repairs & Maintenance - Vehicles					
Security					
Sponsorships					
Training					
Vegetation Management					
Vehicle Costs					
SUB TOTAL ENGINEERING	-	-		-	-
Number of Employees					

FOR QUARTER ENDED - xxxx	Total $	Cost per Unit	Account Nos.	Actual Year to Date xxxx $	Forecast Next Quarter $
ADMINISTRATIVE AND GENERAL					
Advertising/Promotion					
Audit Fees					
Call Centre Operations (internal)					
Contracted Labour & Services					
Customer Service Call Centre Operation (Outsourced)					
Disaster Fund					
Fees & Consultancy					
Information Technology					
Insurance - Buildings					
Insurance - Tools & Equipment					
Insurance - Vehicles					
Legal Fees					
Materials & Supplies					
Meter Billings & Collection					
Meter Reading					
Other Direct Costs					
Pension Plan Admin. Costs					
Personnel - Employer Contribution NIS					
Personnel - Employer Contribution Pension					
Personnel - Employer Contribution to other Benefits					
Personnel - Overtime					
Personnel - Salaries					
Personnel - Wages					
Rates and Taxes					
Rentals/Leases					
Repairs & Maintenance - Buildings					
Repairs & Maintenance - Tools & Equipment(fault)					
Repairs & Maintenance - Tools & Equipment(planned)					
Repairs & Maintenance - Vehicles					
RIC - Cess					
Security					
Sponsorship					
Standards Scheme /Penalties					
Street Lighting - Operations, Complaints, Crews					
Training					
Vehicle Costs					
SUB TOTAL ADMINISTRATIVE AND GENERAL	-	-	-		-
Number of Employees					

FOR QUARTER ENDED - xxxx	Total $	Cost per Unit	Account Nos.	Actual Year to Date xxxx $	Forecast Next Quarter $
OTHER					
Depreciation					
Amortization of Capital Contributions					
Interest & Finance Costs					
Loss / (Gain) on Exchange					
Loss / (Gain) on Disposal of Fixed Assets					
SUB TOTAL OTHER	-	-	-		-
TOTAL EXPENDITURE	-	-	-		-

RECONCILIATION BETWEEN RAG AND T&TEC MANAGEMENT ACCOUNTS					
Total OPEX as per T&TEC Management Accounts					
Difference Between RAG and T&TEC					
Reason for Differences:					

Revenue IS03

Electricity Sales					Revenue from	Revenue from	Revenue from		YEAR TO DATE $
Quarter Ended - xxxx		No of	Energy	Capacity	Fixed	Energy	Capacity	Total	
		Customers	Consumption	Consumption	Charge	Charge (kWh)	Consumption (kVA)	Revenue	
			kWhs	kVAs	$	$	$	$	
Residential A									
	Up to 200 kWh								-
	201-700 kWh								-
	701-1400 kwh								
	over 1,400 kWh								-
	Total Residential	-	-	-	-	-	-	-	-
Commercial									
	Rate B1								-
	Rate B2								-
	Total Commercial	-	-	-	-	-	-	-	-
Industrial									
	Rate D1								-
	Rate D2								-
	Rate D3								-
	Rate D4								-
	Rate D5								-
	Rate E1								-
	Rate E2								
	Rate E3								
	Rate E4								
	Rate E5								-
	Total Industrial	-	-	-	-	-	-	-	-
Public Lighting									
	Streetlamps								
	Traffic Lights								
	Recreational Grounds								
	Total Public Lighting	-	-	-	-	-	-	-	-
	TOTAL REVENUES	-	-	-	-	-	-	-	-

Other Revenue IS04

PERIOD ENDED - xxxx	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	YTD
	$'000	$'000	$'000	$'000	$'000
Other Regulated Income					
Meter Check at customer's request					-
Visit for non-payment of accounts					-
Install meter and reconnect secondaries					-
Reconnect, disconnect and/or change meter					-
Reposition of secondaries					-
Change and/or reposition meter					-
Disconnection for non-payment					-
Reconnection after disconnection for non-payment					
(List to amended to include new miscellaneous charges for newly regulated services)	-	-	-	-	-
Other Non-Regulated Income					
Temporary Connection (non-metered)					-
Pole Rentals -TSTT/Cable TV					-
					-
Rentals - other utility property					-
Profit/Loss major contracting					-
Other Light & Power Revenues					-
Dividend Income					-
Other non-regulated revenue					-
Capital Contributions					
	-	-	-	-	-
TOTAL OTHER INCOME	-	-	-	-	-
RECONCILIATION					
Total Other Income as per Management Accounts					
Difference between Management accounts and RAG					
Reason for Difference :					

Employee Absenteeism and Sick Leave IS05

For the Quarter Ended xxxx				
Staff Complement				
Classification	Permanent	Temporary	Total	
Executive & Management				
Professional/Technical				
Administrative				
Security				
Hourly Rated				
Total				
Staff Absenteeism				
Classification	Sick Leave	Extended Sick Leave	Emergency	Total
Executive & Management				
Professional/Technical				
Administrative				
Security				
Hourly Rated				

Annual Performance Review IS06

	For the Year Ended xxxx	
	Total as per Determination $ '000	Actual $ '000
Revenue:		
Sale of Electricity		
Other Regulated Income		
Total	-	-
Operating and Maintenance Expenditure:		
Conversion Costs		
Internal Generation		
Fuel Costs		
Engineering		
Transmission and Distribution Costs		
Administrative and General		
Total	-	-
Operating Surplus(Deficit)	-	-
Regulatory Depreciation		
Return on Capital/RAB		
Adj: Other Revenue		
Return on Working Capital		
Total Revenue Requirement	-	-

Worksheet Reference No: CS-01
Worksheet Name Number of Complaints Reported by Type
Reporting Period

Complaint Type	No. Complaints Unresolved Brought Forward	No. Complaints B/F Resolved in the Current Period	No. Complaints Received for the Current Period	No. Current Complaints Resolved	No. Complaints Unresolved Carried Forward
Billing Classification					
Billing Query					
Retroactive Billing Adjustment					
Disconnection / Reconnection					
Inaccurate Meter Reading					
Reduction in Reserve Capacity					
High Voltage					
Low Voltage					
Voltage Fluctuations					
Line Phase Out					
Burst Service Leads					
Wires Clashing/ Sparking					
Over-Hanging / Burst Wires					
Removal/Relocation of Lines					
Momentary Power Outages					
Power Outages					
Defective Street Lights					
Installation of Streetlight					
Rotten / Leaning / Broken / Termite Pole					
Tree Trimming					
Value of Capital Contribution					
Request for Service					
Damage to Property					
Other Types of Liability Claims					
Illegal Connection					
Malfunctioning / Broken Meter					
Other					
Total	**0**		**0**	**0**	**0**

Service Provider T&TEC
Worksheet Reference No: CS-02
Worksheet Name Disconnections/Reconnections
Reporting Period

Rate Category	No. of Disconnections						No. of Re-connection	No. of New Payment Plans Taken Out	Average time for reconnection after payment arrangement (hours)
	Non Payment of Bill	Illegal Connection	Customer Request	Unsafe Installation	Meter Tampering	Other			
Residential A									
Commercial									
Industrial									
Total	0	0	0	0	0	0	0	0	

Worksheet Reference No: CS-03
Worksheet Name Retroactive Billing
Reporting Period

Reasons for Retroactive Billing	No. of Customers Notified	No. of cases Responded Within 2 Weeks	No. of Second Notifications Issued/Sent	No. of Customer Agreed with the Retroactive Bill	No. of Customer Disputing the Retroactive Bill
Classification incorrect					
Billing Incorrect					
Meter Malfunction					
Meter Inaccessible					
Tampered installation					
Change in use					
Other					
Total	**0**	**0**	**0**	**0**	**0**

Worksheet Reference No: CS-04
Worksheet Name Disconnections In Error
Reporting Period

Rate Category	No. of Disconnection in Error	Average Time Out of Supply (hours)	No. of Customers reconnected within 8 Hrs	No. of Apology Issued within 3 days
Residential A 0-400 kWh > 400 kWh Commercial Industrial				
Total	**0**	**0**	**0**	**0**

*To be amended for new tiers

Worksheet Reference No: CS-05
Worksheet Name Damaged Appliance/Equipment
Reporting Period

Rate Category	No of Claims B/F	No. of New Claims Received	No. of new Claims Processed	No. Notified of Position on Settlement Within 1 Month	No. Settlement Accepted	* Average time for payment
Residential A Commercial Industrial						
Total	**0**	**0**	**0**	**0**	**0**	**0**

SYSTEM LOSSES - PMR 1

Quarter/Year	Energy Units Billed (kWh)	Energy Units Purchased/ Generated (kWh)	Collections in $	Billings in $
January - March				
April - June				
July - September				
October - December				
Total	**0**	**0**	**0**	**0**

TRANSMISSION TRIPS AND INTERRUPTIONS AFFECTING CUSTOMERS - PMR 2

Month	Number of Transmission circuit interruptions			Number of interruptions restored within 3 hrs			Number of interruptions restored between 3-5 hrs			Number of interruptions restored after 5 hrs		
	33kV	66kV	132kV	33kV	66kV	132kV	33kV	66kV	132kV	33kV	66kV	132kV
Jan-												
Feb-												
Mar-												
Apr-												
May-												
Jun-												
Jul-												
Aug-												
Sep-												
Oct-												
Nov-												
Dec-												
TOTAL												

Heat Rate - PMR 3

Plant	Energy (GWh	Energy (TJ)	Volume (mscf)	Heat Rate (kj/kWh
PowerGen Pt. Lisas 1994				
Power Gen Pt Lisas 2005				
PowerGen Penal				
Trinity Power				
Cove Estate, Tobago				
Trinidad Generation Unlimited (TGU)				