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REGULATED
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COMMISSION

THE TREATMENT OF UNCONTROLLABLE COSTS IN INCENTIVE REGULATION
- The Case of The Trinidad And Tobago Electricity Commission

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Responding to this Document

All persons wishing to comment on this document are invited to submit their comments by **June 21, 2005**. Responses should be sent by post, fax or e-mail to:

Executive Director
Regulated Industries Commission
Furness House – 1st & 3rd Floors
Cor. Wrightson Road and Independence Square
Port-of-Spain, Trinidad
Postal Address: P.O. Box 1001, Port-of-Spain, Trinidad

Tel. : 1(868) 625-5384; 627-7820; 627-0821; 627-0503
Fax : 1(868) 624-2027
Email : ricoffice@ric.org.tt
Website : www.ric.org.tt

All responses will normally be published on the RIC's website unless there are good reasons why they must remain confidential. Any requests for confidentiality must be indicated.

A copy of this document is available from the RIC's website at **www.ric.org.tt.**

1. INTRODUCTION

1.1 Background and Context

The Regulated Industries Commission (RIC) is a statutory body mandated, *inter alia*, to establish the principles and methodologies for determining rates. In undertaking this process, the RIC must take cognizance of the funding and ability of the service provider to perform its functions.

While there is a variety of price setting methodologies, they are usually classified under two broad headings (which cover the extremes of the options). They are:

- Cost-plus (or rate of return), where the allowed costs are calculated on the basis of the costs of the operator; and
- Incentive-based (price caps, revenue caps etc) where the allowed costs are calculated, in part, on the basis of external information[1].

The RIC Act emphasizes the adoption of the incentive regulation/price cap regulation, when setting price controls.

This consultation paper examines the treatment of uncontrollable costs (foreseen and unforeseen) in the determination of the annual revenue requirement for the Trinidad and Tobago Electricity Commission.

1.2 Structure of the Document

The remainder of the document is structured as follows:

- **Section 2 -** discusses uncontrollable costs, with emphasis on the following:
    - The treatment of uncontrollable costs and cost pass-through provisions.
    - The treatment of unforeseen uncontrollable costs:
        - the Z-factor Approach;
        - the Formal Approach - Licensing Provisions; and
        - the Informal Approach – Case-by-Case consideration.

[1] Information that is not related to the firm's own costs.

- **Section 3 –** discusses the existing cost pass-through provisions for T&TEC.
- **Section 4 –** provides a technical examination of the factors that affect power purchase costs, including:
    - The specific obligations under the Power Purchase Agreements (PPA)[2]; and
    - The specific recommendations with respect to the treatment of these factors and their impact on uncontrollable costs.
- **Section 5** – summarises the RIC's preferred approach to cost pass-throughs for T&TEC.
- **Section 6 –** summarises the issues for consultation.

2. UNCONTROLLABLE COSTS – DEFINITION AND TREATMENT

2.1 Introduction - Basics of Incentive Regulation

Incentive regulation has been a key part of utility regulation for the past twenty years. It has alternatively been referred to as RPI-X Regulation,[3] Performance Based Regulation or Price Cap Regulation. The nomenclature is basically intended to signal a departure from traditional Cost of Service Regulation, otherwise known as Rate of Return Regulation as practiced in North America.

Incentive regulation plans are generally characterized by a definite plan period (e.g. five years), an inflationary adjustment, a productivity adjustment (or anticipated efficiency gains), a reward/penalty mechanism for changes in quality of service, and sometimes a way to share monetary gains between utilities and customers. Incentive regulation is meant to provide incentives that are similar to competitive market forces similar and thus service providers change their behaviour accordingly. Market forces require operators to improve productivity and after accounting for unavoidable increases in their input costs, pass these gains on to their customers in the form of lower prices. A price cap formula is supposed to have a similar effect.

[2] Power Purchase Agreements were signed between T&TEC and PowerGen on 23rd December 1994 , and between T&TEC and Trinity Power (formerly InnCOGEN) on 12th February 1998.
[3] RPI refers to the Retail Price Index, which is a common measure of inflation.

2.2 Uncontrollable Costs and Cost Pass-Through Provisions

Cost pass-through provisions are key components of many incentive regulation plans that cater for uncontrollable costs that is, costs over which the actions of the regulated firm can have little or no impact. In fact, provisions that cater for uncontrollable costs are not unique to incentive regulation and have existed in the form of automatic adjustment clauses that are often included in rate of return regulation. At present in our electricity transmission and distribution sectors, the fuel charge adjustment and exchange rate adjustment are automatic adjustment clauses.

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

- costs due to changes in statutory requirements;
- cost changes due to very rare unforeseen events; and
- cost changes due to non-statutory cost drivers e.g. insurance costs.

Provisions that cater for uncontrollable costs are included because the regulator needs to provide the regulated firms with incentives to reduce costs that are under their control while simultaneously insulating them from losses and precluding abnormal profits arising from costs that are outside their control. In order to cater for uncontrollable costs that are known in advance, regulators often allow full pass through of these costs in the revenue requirement of the firm and only apply the X-factor portion of the price cap formula to the controllable portion of the firm's costs[4]. The provision for unforeseen uncontrollable costs is often made within the price cap or revenue cap formula through the inclusion of a Z-factor. Alternatively, they can be treated by some other licensing condition.

[4] For example, in its review of the Public Electricity Suppliers (PES) in 1999, Ofgem, UK, removed around one third of the operating costs considered to be largely outside the control of companies (the formula thus included a cost pass-through mechanism). Similarly, in Jamaica the price cap formula applies only to "Non-Fuel electricity prices". Fuel costs are treated as a pass-through cost via a Fuel Cost Adjustment Mechanism.

2.3 Case for and Against Cost Pass-Throughs

Cost pass-throughs are, by their very nature, in conflict with the objectives of incentive regulation. A central feature of this form of regulation is the provision of incentives to regulated firms to deliver their outputs at the most efficient costs. Allowing them to pass-through certain costs seems tantamount to undermining such incentives.

However, the basic economic argument in favour of cost pass-throughs is that there are certain costs over which the regulated firm has little or no control and thus the risk of that uncertainty is better imposed on consumers[5]. In such a case, it is argued that the service provider can do little to reduce such costs so the incentive properties of incentive regulation can have little impact in this area. The regulator's focus thus becomes insulating the service provider from losses arising from costs that are outside its control and the preclusion of abnormal profits.

In addition to the degree of controllability, some regulators also choose to limit pass-throughs to items which constitute a significant portion of a service provider's total costs.

The RIC would be extremely careful when allowing cost pass-throughs. There has to be a compelling case in favour of them before they are considered for pass-throughs.

2.4 Degree of Cost Controllability

Determining how to allocate costs between categories of controllable and uncontrollable categories is not straightforward. As a first step to ascertaining what should be treated as uncontrollable costs, the degree of controllability for all the major cost categories in the case of T&TEC is examined in **Table 1** below. The degree of controllability involves more than simply categorizing costs as being either fully controllable or fully uncontrollable, since the degree of controllability may depend on the timeframe involved as well as the fact that only some elements of a cost may be controllable.

[5] Makholm and Quinn (1997) argue that these costs (1) should be passed directly through to ratepayers because that is what would occur in a competitive industry, and (2) can be passed through to ratepayers without affecting the incentive of the firm to reduce costs.

Table 1

Degree Of Controllability For All Major Costs – The Case of T&TEC

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

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

Comments are invited on:

- **the RIC's limitation of foreseen uncontrollable costs to fuel and conversion costs; and**
- **the case for and against cost pass-throughs.**

Whenever the electricity sector of a country is unbundled[6] and a generating company sells to a single buyer, there is generally a concern about the pass-through of power purchase costs. Power purchase costs include the cost of fuel and any other costs associated with the conversion of that fuel into electricity. The latter are also known as conversion costs. Under this single buyer model (as in the case of T&TEC), a distribution company has limited or no discretion to influence volumes, prices, risks allocation or choice in power procurement. Furthermore, the generator(s) has the exclusive legal right to supply all the power needs of the distribution entity. Under such arrangements, the international experience suggests that a full cost pass-through is allowed. The various methodologies for regulating pass-throughs of energy costs are detailed in **Appendix I.**

2.6 Treatment of Unforeseen Uncontrollable Costs

This section focuses on the international experience with respect to the treatment of unforeseen uncontrollable costs. There are at least three broad approaches that can be utilized to deal with these costs:

- the Z-Factor provision;
- the Formal Approach (Licensing Provisions); and
- the Informal approach (Case-by-Case consideration).

2.6.1 Z-factor Approach (the US Approach)

Defining the Z-factor

A common feature of price cap plans in the US is the inclusion of a cost pass-through variable commonly referred to as the Z-factor or sometimes as the exogenous variable. The Z-factor is meant to account for a significant change in input price that is outside the regulated firm's control and not captured by the inflation index. It is argued that adjustments to price cap plans (positive or negative) for passing through cost changes due to exogenous events are theoretically sound[7]. These adjustments

[6] Split into generation, transmission and distribution segments.
[7] Makholm, J. and M. Quinn, Price Cap Plans for Electricity Distribution Companies Using TFP Analysis, NERA Working Paper (1997).

permit cost changes for the regulated firm to affect prices in the same way that cost changes affect prices in unregulated, competitive markets without distorting the incentives of the regulated firm. A price cap formula that includes a Z-factor adjustment takes the form:

$$PCI_t = PCI_{t-1}\ (1 + I_t - X \pm Z_t)$$

Where:

PCI_t = price cap index in the current pricing period

PCI_{t-1} = price cap index in the previous pricing period

I_t = Inflation measure (for the current time period)

I_{t-1} = Inflation measure (for the previous time period)

X = X-Factor (productivity offset)

Z = Z-factor

Determining what constitutes a Z-factor event

In order to promote certainty in the regulatory environment, the regulator needs to define what constitutes an exogenous event, and as such, Z-factor treatment has become a contentious issue.

However, there is general agreement that the under-mentioned considerations are relevant in determining which cost increases may be covered by a Z-factor[8]:

- Legislative, judicial or administrative actions that have significant impact on the regulated operator should be considered since such actions are usually beyond the control of the operator. With respect to "significant" it is advisable that some threshold limit be set.
- Only events that do not represent normal business risk should be considered. The regulator also needs to consider whether the operator can take reasonable

[8] Shuttleworth. G., Updating Price Controls: Rationale and Practicalities, A Report for the Office of the Regulator General, Melborne. Prepared by NERA (1998).

Intven, H.; J. Oliver; E. Sepulveda, Telecommunications Regulation Handbook. Edited by Hank Intven Mc Carthy Tetrault. Info. Dev. 2000.

measures to mitigate the consequences of cost producing events before they can be included in a Z-factor.

- The Z-factor costs should not otherwise be reflected in the price cap formula and must be such that they have specific or disproportionate impact on the firm. The burden of proof should be on the firm to show that the proposed event is not already accounted for in the inflation factor.
- Events such as an economic downturn, that affect the whole economy would not be considered to produce exogenous costs increases eligible for Z-factor treatment. While such an event may have a negative impact on the demand for the service provider's services, and decrease its ability to recover costs, the purpose of the Z-factor is not to guarantee a rate of return for the service provider, as this would not be consistent with the objective of using price cap regulation as a proxy for a competitive market.
- Z-factor costs should be quantifiable and known. The operator must be able to estimate the specific costs in monetary terms.

2.6.2 Formal Approach - Ofwat Approach

Ofwat[9] notes that like all businesses the water industry is subject to external influences and change. These changes carry risks to companies and investors through unanticipated reductions in revenue or increases in costs. Thus, Ofwat, like many other regulators, believes that a price setting methodology must offer some assurance that unexpected events outside management's control, or changes to requirements will not be so large as to outweigh the incentives to continue to improve efficiency[10].

In order to cope with the above, Ofwat utilises licensing provisions such as its the interim determination mechanism and its 'logging up and down' processes. Additionally, it has also amended companies' licences to provide most of them with protection from any change in circumstance which would have a substantial adverse

[9] The Office of Water Services (Ofwat) is the economic regulator for water and waste-water services in England and Wales.
[10] Setting Price Limits for 2005-2010: Framework and Approach , a consultation paper. October 2002. Ofwat

effect on the company, through the inclusion of an article known as the 'shipwreck clause'. The mechanisms differ in that they are designed to deal with different kinds of changes. They include:

- **Interim determinations** allow companies, or the regulator, to seek revised price limits if changes in specified outputs required of a company change such that the total impact on the company amounts to 10% of company turnover in net present value (NPV) terms. This is approximately equivalent to a 1% change in price limits. Ofwat points out that an interim determination is not a mini periodic review. The particular changes targeted here are relevant changes in circumstance, which are listed below, or notified items, which are those items that at the time of the relevant periodic review are specifically recorded as areas of uncertainty. Similar criteria are used in logging up or down.
    - A new or changed 'legal requirement' affecting companies in their capacity as water and sewerage undertakers.
    - A difference in the proceeds of land disposals from that assumed when price limits were last set.
    - A failure to achieve some output, funding for which was provided at the last price setting.
    - A change to the notified index (the change in the construction price index relative RPI) from what was assumed at the last price review (this condition is only present in the licences of three companies, but it is proposed that this condition will be extended to all companies)
- **The shipwreck clause** allows companies, or the regulator, to seek an interim determination if circumstances beyond the companies' control change such that the total impact on the company amounts in NPV terms equal to 20% of company turnover. This is broadly equivalent to a 2% change in price limits.
- **Logging up and down** takes account, at the start of the next price limit period, of changes in outputs required of companies during the previous

price limit period. The logging up or down mechanism is not an alternative to an interim determination, but deals primarily with smaller changes in capital expenditure resulting from the items listed under the interim determinations section. Changes in operating costs and revenue are automatically corrected at the start of the next review period because Ofwat starts with assumptions based on actual costs and revenues in the previous year.

2.6.3 Informal Approach - Ofgem Approach

Unlike Ofwat, Ofgem[11] has no formalized mechanism for dealing with cost uncertainty between reviews. Ofgem believes its applicability may not be appropriate for a number of reasons including:

- the water and energy industries in the UK are quite different and thus the magnitude of cost uncertainties differ;
- it is preferable to address uncertainty *ex ante* rather than assessing after the event whether adjustments should be made (e.g. in the case of distributed generation, pensions and bad debt); and
- it introduces a significant burden on both the regulator and the company as the process for an interim determination by Ofwat has demonstrated.

Consequently, prior to the 2005 Price Review for Distribution Network Operators (DNOs), where companies were exposed to substantial new costs between reviews (or where they were expected to arise) these were treated on a case-by-case basis. In certain cases, Ofgem wrote to companies and/or made statements in its final proposal documents about how costs would be treated if efficiently incurred.

[11] Ofgem is the Office of Gas and Electricity Markets and is the economic regulator for these sectors in the UK.

2.6.4 RIC Act and Cost Uncertainty

The RIC Act makes provision under Section 49 for dealing with cost uncertainty between reviews. Under this section of the Act, the service providers can apply to the RIC for a review of the established principles for determining rates for the service they provide, if in their opinion there has been a fundamental change in circumstances as to warrant such a review. However, the service provider may not request such a review more than once a year.

2.6.5 RIC's Preferred Approach

Given the discussion above, the RIC recognizes that any price setting methodology should seek to provide the regulated firms with incentives to reduce costs that are under their control and to insulate them from abnormal losses arising from costs that are outside their control.

Accordingly, the RIC proposes to allow for cost pass-through of only fuel and conversion costs (foreseen uncontrollable costs) over which T&TEC has little or no control since these costs are subject to long-term contractual agreements. Whether cost pass-through would be 100% or less is discussed in Section 4 below.

In the case of unforeseen uncontrollable costs, the RIC is not inclined to include any of these costs for pass-through via a Z-factor in its first price control review. The RIC will ensure that during its rate review processes, the degree of controllability of all costs is considered and appropriate provisions are made on a case-by-case basis. The RIC also sees merit in dealing with some of these costs through error correction.

Furthermore, the RIC strongly believes that Section 49 of its Act should only be invoked as a last resort and only where the service provider's revenue has been affected by at least 10% of its turnover.

Given the above, the RIC's price control formula would be one that focuses on revenue but allows foreseen uncontrollable costs to be passed through. Consequently, if revenues were forecast for a 5-year period (as proposed in the RIC's consultation paper, "Setting Price Controls: Framework and Approach", the only adjustments in the price control formula would be to incorporate:

- inflation;
- X-factor (efficiency savings/productivity offset);
- over-or under-recovery of revenues; and
- mechanical correction for out-turn uncontrollable costs.

The price control formula would then be:

$$R_{t-1} = R_t \ (1 + RPI - X) - C_t - A_t$$

Where:

R = the level of revenue;

RPI = the level of inflation;

X = the efficiency gain in controllable costs;

C = over-and-under recovery of revenue; and

A = the adjustment for uncontrollable costs.

t = time

Comments are invited on the RIC's proposed approach for dealing with foreseen uncontrollable costs and unforeseen uncontrollable costs.

3. THE EXISTING COST PASS-THROUGH MECHANISMS

Cost pass through provisions are not unique to incentive regulation schemes and as mentioned previously can also form part of a rate of return regulation scheme where they are generally known as automatic adjustment clauses. An automatic adjustment clause is a tariff provision approved in advance by a regulatory commission, in which a change in a pre-selected cost item or items will automatically permit a change in the price charged to consumers, without the delay and expense of a formal regulatory hearing. In the case of T&TEC two such clauses exist, they are:

- **The Exchange Rate Adjustment Clause** which was approved by the former Public Utility Commission (PUC) by Order #81 of 22nd April 1993 and replaced **The Devaluation Clause** of Order #80 of September 1992 (Schedule E). This clause was created to counteract the effect of the floatation of the TT Dollar on the T&TEC's operations. The advent of a floating rate regime in Trinidad and Tobago led to large fluctuations in the TTD to USD exchange rate during the years 1993 to 1996. Movements in foreign exchange rates significantly impacted T&TEC's cost of operations, through imported materials and services which accounted for a substantial percentage of T&TEC's total costs. The Exchange Rate Adjustment clause allows tariffs to be adjusted automatically thereby transferring the risk to the customer.

Any adjustment is applied monthly and is based on the average of the rates for the preceding calendar month as published by the Central Bank of Trinidad and Tobago.

- **The fuel clause** was introduced to reduce the financial burden imposed on T&TEC by frequent adjustments in the fuel cost. The fuel clause stipulated that for a certain increase in fuel price, the consumer's charge per kilowatt-hour would be increased. The last fuel clause amendment was implemented by PUC's Order No. 80, which states that:

  (i) For every one cent change from 218.9 cents in the average gross price per 1,055,100 KJs (1 million BTUs) of fuel used in a month, the charge per kilowatt-hour will be increased or decreased by 0.0154 cents.

  (ii) The fuel charge is to be applied to all kilowatt-hours billed (including that associated with street lighting) in the month corresponding to that for which the charge was calculated.

(iii) The fuel charge revenue will be billed to customers in the month following that for which the charge was calculated and applied.

These clauses hold some clear advantages for the utility including:

- They allow T&TEC to recover increases in costs over which it has little or no control.
- The automatic recovery implies infrequent rate reviews thereby saving regulatory costs.
- By operating swiftly, the regulatory lag is reduced thereby protecting the utility's financial viability.

The clauses also have certain drawbacks:

- Recovery of increased cost for one item may ignore compensating or offsetting savings for economies realized elsewhere in the business through improved technology, labour productivity, and/or operating efficiency.
- By allowing quick and easy recovery of a particular cost item such as fuel, automatic adjustment may reduce the company's incentive for efficient management of operations and/or may discourage hard bargaining in fuel contract negotiations.
- Utilities have risks like non-regulated companies. In the competitive market place the latter survives through innovation, efficiency, and good management. To the extent adjustment clauses dampen efficiency and innovation, the public interest is not served.
- Additionally, the clauses have raised concerns for consumers. Consumers generally appreciate certainty about prices since it allows them to plan future expenditure. Prices that move bi-monthly from bill to bill may make some budgeting decisions difficult for them.

Based on a review of the fuel charge, it is observed that the annual increase in customer bills has fluctuated markedly from 30% in 1997 to as low as 4% in 1999. Over the 11-year period (1993 –2003), there has been an overall increase in generation, and fuel consumption by 70% and 69% respectively. This translates to an overall increase of 229% in the fuel charge over the same period, and this has caused consumers to become concerned as to why their bills keep increasing in spite of there being no tariff reviews of electricity rates.

T&TEC's generation history and average fuel charge for the period 1993 to 2004 is shown **Table 2.**

Table 2

T&TEC's Generation History and Average Fuel Charge, 1993 – 2004

Year	Net Units Generated (GWh)	Total Fuel Consumed (Terajoules)	Increase in Fuel Consumed (%)	Average Fuel Charge (¢/kWh)	Annual Increase in Fuel Charge (%)
1993	3,759	54,482		1.366	
1994	3,978	55,460	2	1.681	23
1995	4,146	59,185	7	1.893	13
1996	4,402	61,843	4	2.171	15
1997	4,762	66,112	7	2.829	30
1998	5,131	72,456	10	3.276	16
1999	5,220	73,151	1	3.420	4
2000	5,414	74,396	2	3.602	5
2001	5,597	77,008	4	3.805	6
2002	6,113	85,170	11	4.105	8
2003	6400	92,085	8	4.492	9
2004	6692	96,588	5	4.832	8

Source: Trinidad and Tobago Electricity Commission

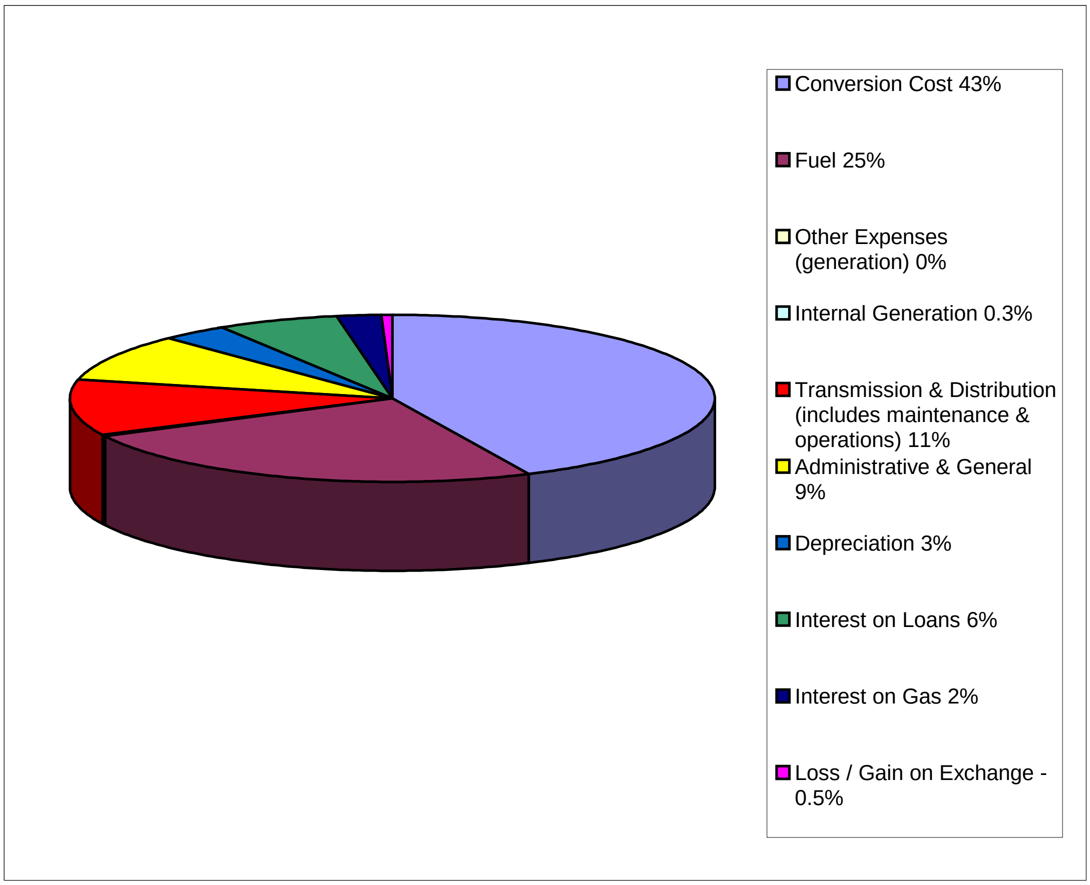
Automatic adjustment clauses do not generally form part of incentive regulation. For this reason and the fact that these clauses have been a source of confusion for customers, the RIC proposes that their use be discontinued.

Comments are invited on the RIC's proposed elimination of the use of adjustment clauses.

4. PROPOSALS FOR NEW COST PASS-THROUGH PROVISIONS

Conversion and fuel costs comprise approximately 70% of T&TEC's annual operating cost. Conversion costs rose by 61.5%, from $425.5 million in 1995 to $686.7 million in 2002. Fuel costs rose by 98.5%, from $197 million in 1995 to $391 million in 2002. By 2002, conversion and fuel costs represented 43% and 25% respectively of total costs. See **Figure 1** for details. In 2003, conversion costs rose by approximately 3% to reach $705.4 million. Fuel cost for 2003 was $442.8 million (an increase of 13% over 2002 costs).

Figure 1: TOTAL EXPENDITURE 2002



Source: Review of the State of the Trinidad and Tobago Electricity Commission 1995-2002

Under the PPAs, which are 'take or pay' contracts, specific obligations are imposed on T&TEC. Important among these is T&TEC's obligation to pay for the cost of fuel that is, natural gas, which is a significant cost component to T&TEC.

The RIC is mindful that although T&TEC is ultimately responsible for power procurement, it responds to Government policy initiatives that often impose specific guidelines and timetables. However, despite these constraints, a regulator's responsibility is to provide the regulated firm with incentives to explore options for reducing uncontrollable costs. Moreover, the RIC believes that T&TEC must pursue every avenue in this regard as T&TEC is the majority shareholder in PowerGen. As such, the technical specifications contained in the contracts and other legal aspects of both PPAs were reviewed with a view to ascertaining how best T&TEC might control fuel and conversion costs.

4.1 Fuel Costs

Fuel costs are dependent on the unit price paid for the various types of fuel utilized in the generation of electricity and the volume of fuel consumed. The latter, of course, is driven by changes in the demand for electricity. The heat rate also affects the efficiency of the conversion process and impacts on the volume of fuel consumed. There are four types of fuel currently used for power generation. The main fuel used is natural gas, which is responsible for more than 90% of the power produced; diesel is used to produce less than 10% of the power; fuel oil and Jet A account for the remainder. Avenues for reducing fuel costs will now be explored.

4.2 Price of Fuel

Natural gas

Natural gas, as previously stated, is the fuel most used to produce power and is purchased by T&TEC for the generating companies. Based on a Cabinet decision of 1995, the price of natural gas has increased annually by 4%. Natural gas is currently charged at US$0.87/MMBTU (as at January 2005). Over the period 1993–2004 fuel prices have increased significantly (see **Table 3**).

The gas is sold to T&TEC at a preferential rate and unless Cabinet revises its decision, there is little room for reduction in the price paid for natural gas by T&TEC at this time.

However, the RIC believes that in order to reduce the impact of annual increases, the Government may wish to consider following:

a. The renegotiation of a long-term gas contract between T&TEC and the National Gas Company. Bearing in the mind the public interest and the substantial natural gas resources of the country, the new contract should be based on a natural gas price that is lower than the current rate.

b. The linking of increases in the annual price of natural gas to the rate of inflation, with a cap of 3%. It is to be noted that inflation rates from 1995 to 2004, have fluctuated over the period from 3.4% to 5.6%. (**Table 3**).

c. In the interim, the revisiting of the 1995 decision with a view to freezing the price of gas until a new contract is negotiated.

Diesel

Diesel is primarily used in Tobago to operate the diesel generators that serve as a standby system. The price of diesel has remained fairly constant with increases in only two (2) years, 25% in 1994 and 2.4% in 1997. Again there is no scope for reduction in the price of diesel at this time.

<u>Table 3</u>

<u>Gas and Diesel Prices and Inflation Rates (1993 – 2004)</u>

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

Source: Trinidad and Tobago Electricity Commission

Comments are invited on the measures proposed by the RIC to mitigate the impact of the price of natural gas on fuel prices to T&TEC and whether there are other considerations in this area.

4.3 Volume of Fuel

As Trinidad and Tobago continues to develop and grow, there is expected to be a concomitant increase in demand for electricity. This naturally means that the volume of fuel consumed will also increase. The increase in gas and diesel usage over the period 1993 to 2004 is seen in **Table 4.**

<u>Table 4</u>

<u>Gas And Diesel Usage (1993 – 2004)</u>

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

Source: Trinidad and Tobago Electricity Commission

Natural gas consumption has grown consistently with increasing demand, however the growth in diesel consumption has been punctuated with some spikes. While diesel is used to keep the standby generators running in Tobago, it is sometimes used to supplement power requirements. For example, diesel consumption increases when there is an interruption in the supply feed from Trinidad to Tobago. This is evidenced by the spike in the diesel usage from late 1996 to 1999 (**Table 4**) that corresponded to the period when the Toco to Tobago 33kV undersea cable was being repaired. These repairs meant that Tobago's diesel generators were actually used to supplement the power requirements of the island during the time of repair to the cable. Under normal operations, little can be done to reduce diesel consumption. However, recognizing the need for additional generation, T&TEC has indicated that it intends to introduce natural gas generators in Tobago. This is significant for two reasons: (1) the volume of diesel consumed should not increase, and (2) better conversion efficiencies are possible with natural gas conversion than with diesel.

The inclusion of a policy of demand side management (which forms part of another document for consultation) in the current rate review would also help modify the consumption patterns as the economy grows. The efficient and economic use of fuel is being addressed below by examination of the heat rate.

4.4 Heat Rate

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

There are two power producers, Powergen and Trinity Power. Both operate according to the terms and conditions in their respective Power Purchase Agreements (PPA). There is no specific guaranteed system heat rate defined in the Trinity Power PPA, while PowerGen's PPA defines it as 14,000 kJ/kWh. Additionally, in the case of PowerGen, there is a ±5% tolerance limit for which either bonuses or compensatory payments would apply. This effectively creates an acceptable heat rate range of between 13,300 to 14,737 kJ/kWh for PowerGen.

The overall average system heat rate for the period 1991 to 2004, based on an average of all the generating stations, is shown in **Table 5.**

Table 5
System Generation Heat Rate, 1991 to 2004

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

Source: Trinidad and Tobago Electricity Commission Engineering Department

Over the 14-year period, the heat rate ranged from 13,745 kJ/kWh to 14,696 kJ/kWh. Further examination of the data shows that while no heat rate was specified for Trinity Power, their heat rate figures (13,086 to 13,451 kJ/kWh) were always at the lower end of the range specified for PowerGen. In the case of PowerGen, with the exception of 2004, the average heat rate was always within the range of 13,300 to 14,737 kJ/kWh. Internationally, heat rates for similar systems are of the order of 10,500 to 11,500 kJ/kWh. (See **Appendix II**). On a regional level, Jamaica achieved an annual system heat rate of 11,554 kJ/kWh for 2003. The OUR[12], in its determination for the JPS for the period 2004 – 2009, expects them to achieve and maintain a system heat rate of 11,200 kJ/kWh for 2004.

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

i) Improving the availability of the Penal combined cycle. This can be done economically by installing General Electric's new maintenance-extender kit on the two gas turbines;
ii) Reducing the large spinning reserve (averaged over 200 MW in Dec'04, maximum was over 360 MW);
iii) Commissioning the Load Share control system on the 8 large generating units at Point Lisas station;
iv) Upgrading the older generators; and
v) Implementing analytical monitoring tools to change the despatch of the plants to a more energy efficient arrangement.

However, improvements in the heat rate can be made only via contract renegotiations. The contract with PowerGen was amended when the new generating company, Trinity Power, started operations. However, the amendment removed several of the clauses that held

[12] The Office of Utility Regulation (OUR), the economic regulator for utilities in Jamaica.

PowerGen liable for poor performance, leaving very little incentive for it to improve performance.

The heat rate from Trinity Power is currently about 12,700 kJ/kWh. This can be reduced, but would require capital investment which the company may not be willing to undertake as it already operating at a heat rate that is lower than PowerGen, and its PPA does not stipulate a specific heat rate.

As stated above, reducing the heat rate can lead to significant savings in the volume of fuel consumed and consequently in costs. In order to examine the possible cost savings from reducing the heat rate, various scenarios were examined (see **Appendix III**). These are summarized in **Table 6** below

Table 6

Summary of Fuel Cost Savings from Heat Rate Reductions

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

PPA costs are uncontrollable costs to T&TEC and are approximately 70% of total operating costs. In 2004, conversion costs were $731.2 million and fuel costs were $483.3 million. The annual saving on fuel costs calculated from the first scenarios is approximately US$6.03 million or 7.8%.

T&TEC must insist that the power generators, especially PowerGen, reduce their heat rates, since any reduction in heat rate would yield savings in fuel costs. **The RIC recognises that there are cost implications to reducing heat rate, however, the medium to long-term savings to the consumers are significant and must be considered. Accordingly, the RIC is of the view that there should be only 94% pass-through of the fuel costs to the consumers. No regulator can knowingly encourage inefficiencies to be passed through to consumers.**

Comments are invited on the RIC's proposal that there should be 94% (and not 100%) cost pass-through of fuel costs to consumers.

4.5 Additional Capacity

It is estimated that by the end of 2006, 80MW of additional capacity will be required to cater for normal growth in demand. This will have implications for the current Price Review. Therefore the RIC, as part of its regulatory function, examined the generation options, that is, simple cycle generation versus combined cycle generation.

There are several advantages and disadvantages to both methods of generation. These must be carefully considered bearing in mind the short and long term cost implications to consumers. Some important aspects of the two options are examined.

- *Case 1* - The addition of a new 86MW gas turbine generator to meet additional capacity.
- *Case 2* – The addition of a new 86MW heat recovery steam generator (HRSG) to meet additional capacity.

Case 1:- Addition of a new 86MW gas turbine generator to meet additional capacity.
Capital cost of such a generating unit is approximately US$15million. The published heat rate on such a machine (John Brown Engineering, Model PG7111) is 11,060kJ/kWH. This would require additional fuel to the amount of approximately US$ 6.6 million annually.

Case 2:- Addition of a new 86MW heat recovery steam generator (HRSG) to meet additional capacity.

A more cost efficient option would be to introduce a steam turbine to generate additional capacity, thereby converting the entire system to a combined cycle plant. This would effectively lower the heat rate since the exhaust from the combustion turbines would drive the steam turbine and additional natural gas would not be required to generate more power. A similarly sized heat recovery steam generator (HRSG) to be used in conjunction with the gas turbines would be in the price range of US$14 - 19 million. This would increase the output to 6486GWh, with no additional cost in fuel and effectively lowering the heat rate to 14,198 kJ/kWh.

4.6 Conversion Costs

Conversion costs, which are paid to both generating companies, consists of the following payments:

- Monthly Capacity Payment;
- Energy Payment;
- Excess Payment.

4.6.1 Capacity Payment

In the context of the PPAs, capacity is defined as the active capability (expressed in MW or KW, as the context may require) of a generating unit or facility to supply energy. The capacity payment is defined as the monthly payment for capacity to be made by T&TEC to PowerGen and Trinity Power. In both PPAs simple formulas are used to calculate the capacity payment. The payment in each case is a function of the base capacity rate, the contracted capacity and the US consumer price index.

PowerGen

Monthly capacity payment is determined as follows:

$$MCP = (BCR \times CC) \times (1 + (CPI \times 0.95))$$

Where:

MCP = the monthly capacity payment (expressed in US dollars)

BCR = the Base Capacity Rate (being US$7.48 per kW per month)

CC = the contracted Capacity (expressed in kW)

CPI = the percentage change in the US consumer price index between that published or determined in the month before the effective date of the Contract (base level) and that determined in the month in respect of which the Monthly Capacity Payment is being determined.

Trinity Power

Capacity payment determined as follows:

$$CP_m = MADC_m \text{ x } HIM_m \text{ x } BRC \text{ x } (1 + 0.275 (CPI_m/CPI_o - 1)$$

Where:-

CP_m = the Capacity Payment for the $month_m$, expressed in US dollars

$MADC_m$ = the Monthly Average Declared Capacity for $month_m$, expressed in kW

HIM_m = the number of hours in $month_m$

BCR = the base capacity rate, being US$0.012 per kWh

CPI_m = CPI for $month_m$

CPI_o = the CPI for the month of September, 1999

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

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

2. While both formulas have a factor to accommodate changes in the US CPI, one formula incorporates 95% of this change (in the case of PowerGen) while the other only 27.5%. The difference this makes is reflected in **Table 7**, which shows the movement in these payment factors from the inception of these PPAs to present.

Table 7
Comparison of Capacity Payment Rate Factors US$/kW/mth

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

Source: Trinidad and Tobago Electricity Commission's Engineering Department

* - November 1999 data.

Future considerations should include renegotiation of the formula used to calculate the monthly capacity payment, especially in the case of PowerGen and definitely in the case of any new generation contracts. Consumers should benefit from the best prices that can be negotiated bearing in mind that conditions have changed since the first PPA was signed.

4.6.2 Energy Payment

As defined in the PPA, Energy means active electrical energy generated by the Facilities. T&TEC makes monthly payments to the generating companies for the energy delivered in accordance with specific formulas stipulated in the contract.

PowerGen

Monthly energy payment determined as follows:

$$MEP = (BER \times (1 + CPI)) \times ED$$

Where:-

MEP = the Monthly Energy Payment (expressed in US dollars)

BER = the Base Energy Rate (being US$0.00055 per kWh)

CPI = the percentage change (whether of a positive or negative value) in the Consumer Price Index between that published or determined in the month before the relevant month in respect of which the Monthly Energy Payment is being determined, and expressed as a fraction of the base level

ED = the Energy Delivered from all the Facilities (expressed in kWh) during the relevant month.

Trinity Power

Energy payment determined as follows:

$$EP_m = DE_m \times (BER \times (CPI_m/CPI_o))$$

Where:-

EP_m = the Energy Payment for the $month_{m,}$ expressed in US dollars.

DE_m = the Energy Delivered (expressed in kWh) to the delivery point for each day in $month_m$

BER = the base energy rate, being US$0.00045 per kWh

CPI_m = CPI for $month_m$

CPI_o = the CPI for the month of September, 1999

Again, there is little scope for reduction of these costs at this time since the base energy rate of both generating companies according to the present PPAs is very small. The energy rate factors, as at November 2004, were: US$0.00070/kWh for PowerGen; and US$0.00051/kWh for Trinity Power.

4.6.3 Excess Payment

This payment applies when T&TEC requires the generating companies to provide Capacity in excess of the contracted capacity.

PowerGen

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

Trinity Power

Excess Demand is charged on an as-used basis at the base rate. This method is quite economical.

There is little scope for reduction by either generator at this time.

Tables 8 & 9 provide a breakdown of the various payments (Capacity, Energy and Excess) made to PowerGen and Trinity Power respectively. The tables also give the contracted capacity for each company and the annual excess load generated by the companies.

Table 8

Annual Payment and Load Schedule for PowerGen, 1999-2004

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

Source: Trinidad and Tobago Electricity Commission

* This represents 32MW for each of the months from July to December.
** This represents 30MW each for November and December 2004.

Table 9
Annual Payment and Load Schedule for Trinity Power, 1999-2004

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

Source: Trinidad and Tobago Electricity Commission

* These amounts were required at different times on the same day in December.
** Individual requests for excess capacity totaling 255MW.
*** Individual requests for excess capacity totaling 441MW.

An examination of the data for excess capacity and excess payment in 2004 for both companies, shows a significant difference. The excess capacity from PowerGen was 60MW, which translated to a payment of $3,567,586, while the excess from Trinity Power was 441MW, which was a payment of $241,660. This significant difference highlights the variation in the method used by each company to calculate the excess payment, and is therefore an area that needs to be closely examined.

International Experience

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

The RIC acknowledges that the scope for reducing the cost of conversion is limited given the existing terms of the both PPAs. **However, the RIC is not inclined to pass-through 100% of these costs because T&TEC/Government should seek to re-negotiate for more favourable terms for clauses as the excess capacity clause.**

Comments are invited on whether there should be 100% cost pass-through of conversion costs.

5. SUMMARY OF THE RIC's INITIAL PROPOSALS

In this section, the RIC pulls together its initial thoughts on the treatment of uncontrollable costs and cost pass-through provisions. It is hoped that this will enable interested parties to consider the core elements of all the issues.

Incentive regulation is predicated on the principle that firms are 'incentivised' to reduce costs in order to retain profits for the duration of the plan. Firms are expected to behave as they would in a competitive market. In a competitive market costs over which the firm has no control would inevitably be passed through to customers. Thus the notion of pass-through is not inimical to incentive regulation plans. Therefore, cost pass-through provisions in price cap plans are meant to cater for uncontrollable costs, that is, costs over which the actions regulated firm can have little or no control. Such costs may arise from **unforeseen** events or they can be known **upfront**. In the case of the latter, neither the firm nor the regulator may be able to predict the extent to which these costs may rise (or fall).

The RIC's initial thinking, subject to the consideration of responses to this consultation paper, is that an approach to the first regulatory control might contain the following core elements on cost pass-through:

- **Foreseen Uncontrollable Costs (Power Purchase Costs)**

Currently T&TEC is the single buyer in a market where there are two generating companies. These companies do not compete with each other and both have 'take or pay' contracts with T&TEC. Based on this type of arrangement, it is typical to have full pass through of power purchase costs. However, the RIC believes that every effort must be made to ensure that these costs are minimized. A major objective of this document was to find ways to incentivise T&TEC to reduce its foreseen uncontrollable costs.

- **Fuel Costs**

Based on the examination of the terms and conditions of both PPAs, **the RIC is inclined to propose that only 94% percent of fuel costs be deemed pass-through costs.** This will provide an incentive for T&TEC to adopt measures that will improve the System Heat Rate and effect whatever minimal savings that can be expected in this area.

The implementation of this proposal would require:

- the renegotiation of a long-term gas contract between T&TEC and the National Gas Company (NGC);
- the renegotiation of the Heat Rate with PowerGen with a reduced tolerance (3% instead of 5%) and a shorter heat rate averaging period (quarterly instead of annually);
- the establishment of a monitoring system to get accurate information on the performance of the different generating sets; and
- the freezing of the automatic annual 4% increases in fuel costs until a new long-term contract is renegotiated with NGC.

- **Conversion Costs**

  Given the terms and conditions of the existing contracts between T&TEC and the generating companies, the **RIC is inclined to provide for 98% of conversion costs as pass-through costs**. Thus the RIC is proposing that:

- T&TEC renegotiate with PowerGen a more favourable option for the calculation of Excess Capacity payment; and
- the part of the burden of conversion costs of PowerGen be borne by the Government directly or that the Government should renegotiate with PowerGen a lower conversion cost.

- **Unforeseen Uncontrollable Costs**

  - **The RIC is not inclined to include any of the unforeseen uncontrollable costs for pass-through via a z-factor provision in its first price control review.**

  - The RIC strongly believes that Section 49 of its Act should only be invoked by service providers as a last resort and only where service provider's revenue has been affected by at least 10% of its turnover.

- **Other Proposals**

T&TEC should aggressively pursue strategies to reduce demand by exploring ways to modify customer load profiles. Some of the considerations include:

- Peak load reduction programs which may include the use of off-peak tariffs/time-of-use rates, direct load control and other load management programs to reduce peak demand;
- Introduction of energy-efficient programs to reduce energy use, both during peak and off-peak periods. This would involve the use of more advanced equipment to produce the same or better level of end-use services with less electricity (e.g. lighting, cooling);
- Customer educational promotions designed to modify behaviour towards energy conservation as a means to reducing demand;
- Interruptible supply contracts; and
- Introduction of a policy of demand side management (DSM). T&TEC must launch DSM activities such as advertisements in the media, seminars,

informational literature and dialogue with community groups in an attempt to motivate customers to change their usage patterns, to achieve DSM objectives.

6. ISSUES FOR CONSULTATION

The RIC seeks views on the issues raised in this consultation document, and more specifically the following:

- the RIC's treatment of limiting foreseen uncontrollable costs to fuel and conversion costs;
- the case for and against cost pass-throughs;
- the RIC's proposed approach for dealing with foreseen uncontrollable costs and unforeseen uncontrollable costs;
- the mitigation measures proposed by the RIC to regulate the price of natural gas and whether there are other considerations to lower the impact of increasing fuel prices to T&TEC;
- the RIC's proposed elimination of the use of adjustment clauses;
- the RIC's proposal that there should be 95% (and not 100%)cost pass-through of fuel costs; and
- whether there should be 98% cost pass-through of conversion costs.

Various Methodologies for Regulating Pass-Through

- **The Full Pass Through of energy costs –** a distribution company has limited or no discretion to influence volumes, prices, risk allocation, or choice in power procurement (purchases), a full pass-through is generally allowed. The most prominent examples are 'vesting contracts' assigned at the time of privatization and restructuring, mandated purchases by 'single buyers' and obligatory purchases under a Build, Operate and Transfer agreement.
    - **The Single Buyer Model –** The Single Buyer Model has been adopted by many countries in the early stages of power sector reform. This means that the generators may only sell their electricity to a single entity. It also implies that this single entity has been granted the exclusive legal right to supply all the power needs of the distribution entity. Under this model, both the distribution company and its customers are captive customers.
    - **Vesting Contracts –** Vesting contracts are established to reduce the purchase price risk faced by distribution companies, to provide a stable cash flow to generators and to promote a gradual transition toward market-based bulk power tariffs.
- **Review of Energy and Power Contracts –** (which can be conducted before or after the signing of a contact, and referred to as "ex ante" and "ex post", respectively), this method is done individually and a decision rendered in terms of the reasonableness of the prices, risk allocation, and other specifics involved. Based on this assessment, the regulator may approve full pass through or prohibit some or all energy costs from being passed on to retail customers – or may decide that contract terms should be modified. The government or legislature may also perform an additional review in lieu of the one performed by the regulator. **Ex Post Reviews are always extremely contentious and given the likelihood that this kind of review may be motivated by political considerations, it should be seen as a last resort.**

- **Administratively Set Benchmarks –** this methodology involves defining a reasonable cost of power purchases using administratively established estimates of investment and operating costs. These are then used to serve as a reference to performance based regulation, where the efficiency (or inefficiency) in power procurement is shared between the distribution company and its customers. This approach is dependent to some extent on the existence of more than one generating company in the market and more than one distribution company. This approach can also be contentious as it is argued that this benchmark can also be politically manipulated.
- **Multi-Market Benchmarks–** this methodology is based on the price of power traded between generation companies and distribution companies. Regulators establish one or more market benchmarks as a baseline for assessing a distribution company's power purchase costs. If the company is able to acquire energy at a price below the established benchmark, it retains all or part of the difference, as an incentive to good procurement. If it pays more than the benchmark, it bears all or part of the additional costs (in other words, it is not allowed to recover these costs through tariffs)
- **Mandated Competitive Procurement for Physical[13] or Financial[14] Contracts –** this methodology involves the introduction of a mandated and competitive procurement process for most of the energy needs of a distribution company. In exchange for this commitment, full pass through of the purchase costs is allowed. This is possibly the best methodology provided that well drafted regulations are in place. Rules and regulations enable a level playing field in the procurement process, without creating unnecessary barriers to entry for new players. This methodology is a viable alternative at several stages of industry and market reform. The nature of the procurement

[13] Physical contracts are usually employed in bilateral markets, where buyers are vertically integrated utilities or separate distribution entities and the sellers are independent generators or marketers. Physical contracts give the buyer an entitlement to energy produced by one or more generating units. Physical contracts require that there be an electrical connection or at least a contract transmission path between the seller and the buyer.

[14] Financial Contracts provide a financial hedge between a seller and a buyer for a specified amount of energy during one or more hours at predetermined prices. The buyer usually does not care where the power comes from, the only assurance sought is for the seller to honour the agreed price.

process will vary, depending on whether the distribution company plays an active or passive role in designing and implementing the procurement.

International Examples of these methodologies are presented in the table below.

Methodologies for incorporating Power Purchase Costs into Price Reviews

METHODOLOGY	VARIATIONS	EXAMPLES
Full Pass Through of Power Purchase Costs	"Prudent" expenses in cost-plus regime	Most USA utilities
	Vesting contracts [a]	Brazil, Argentina, Panama, Nicaragua, Guatemala, El Salvador
	Purchases from a single buyer	Hungary, Northern Ireland
Review of Power Contracts	Ex ante	Guatemala, Panama, Nicaragua, Massachusetts and Nevada (USA)
	Ex post	California (USA), India
Administratively Set Benchmarks	Benchmark based on regulator's estimates of long-run marginal cost for new generation	Normative Value (VN) in Brazil (current)
	Benchmark based on estimates of the disco's "avoided cost"	The United States under the 1978 Public Utility Regulatory Act (PURPA)
Mandated Competitive Procurement	Physical contracts	Florida (USA)
	Financial contracts	Panama, Guatemala, Nicaragua, New Jersey (USA)
Market Benchmarks	Spot	Chile, Peru, El Salvador, Bolivia, Argentina
	Contracts	Brazil (planned)
	Spot and Contracts (Multi-Markets)	Colombia, The Netherlands

[a] Contracts for power purchases that are usually assigned to a new distribution company at the time of privatization.

Source: The World Bank.

Source: Arizu et al 2004

Arizu et al also rank the methodologies in terms of a set of desirable attributes and Mandated Competitive Procurement emerges as the most suitable of the identified methodologies because it allows market forces to determine the price paid for power.

In Trinidad and Tobago the market can be characterized as a 'Single Buyer Model' and the existing Power Purchase Agreements can be viewed as Vesting Contract.

Approximate Heat Rates for Electricity, 1960-2000

(Kilojoules per Kilowatthour)

Year	Fossil-Fueled Steam-Electric Plants	Year	Fossil-Fueled Steam-Electric Plants
1960	11352	1981	11028
1961	11236	1982	11030
1962	11139	1983	11099
1963	11059	1984	11015
1964	11038	1985	11022
1965	11028	1986	11021
1966	10988	1987	10993
1967	11006	1988	10892
1968	10970	1989	11006
1969	11022	1990	10975
1970	11072	1991	11011
1971	11055	1992	10911
1972	10950	1993	10877
1973	10961	1994	10884
1974	11017	1995	10880
1975	10979	1996	10909
1976	10944	1997	10775
1977	11010	1998	10758
1978	10931	1999	10789
1979	10923	2000	10763
1980	10960		

Source: Adapted from *State Energy Data Report*. Energy Information Administration, Office of Energy Markets and End Use, U.S. Department of Energy, Washington, DC.

Various Scenarios for Reducing Heat Rate

Scenario 1: Reducing the overall heat rate for T&TEC's entire operation:

The heat rate is calculated by dividing the fuel consumed by the units generated. For example, using data from 2004, yields the following:

Heat Rate = Fuel consumed/Units generated

= 96,588(Terajoules)/6692(GWh)

=14,433 kJ/kWh (actual for 2003 is 14,433 kJ/kWh)

(a) *Reduction to lower end of acceptable heat rate range i.e. 13,300 kJ/kWh*

Using the same calculations, and reducing the heat rate to 13,300 kJ/kWh, with 6692 GWh still being generated; the fuel consumed would be 89,003 (Terajoules). Assuming that all the fuel consumed is natural gas, this translates into an annual cost difference of approximately US$6,031,732 (shown below), which over the period of the price review will be over US$30,158,664 (assuming a review period of 5 years).

Saving in fuel consumed = 96,588 – 89,003 (Terajoules)

= 7,585 Terajoules ≡ 7,585 x10^9 kJ

Converting kJ to BTU:

1.055055853 kJ	=	1BTU
7,585 x10^9 kJ	=	7,189.192855 x10^9 BTU
	=	7,189,192.855 MMBTU

In 2003 the price of natural gas was US$0.839/MMBTU. **Therefore the savings in dollars:**

= 7,189,192.855 MMBTU x US$0.839/MMBTU

= **US$6,031,732 (> US$30 million over 5 yrs)**

(b) *Further reduction of heat rate to 12,000 kJ/kWh, which is closer to international values.*

Fuel consumed at 12,000 kJ/kWh = 80,304 (Terajoules)

Saving in fuel consumed = 96,588 – 80,304 (Terajoules)

= 16,284 Terajoules ≡16,284 x10^9 kJ

Saving in fuel costs = US$12,949,339.09 (> US$64 million over 5 yrs)

Scenario 2: Reducing the average system net heat rate for Powergen plants only:

(a) *Reduction to lower end of acceptable heat rate range as per PPA, i.e. 13,300 kJ/kWh*

Fuel consumed at 14,752 kJ/kWh = 75,026 (Terajoules)

Fuel consumption 13,300 kJ/kWh = 67,641 (Terajoules)

Saving in fuel consumed = 7,385 Terajoules ≡7,385 x10^9 kJ

Saving in fuel costs = US$5,872,689 (~ US$29 million over 5 yrs)

Scenario 3: Reducing the heat rate for PowerGen's Point Lisas plant:

Reduction to lower end of acceptable heat rate range as per PPA, i.e. 13,300 kJ/kWh

Fuel consumed at 16,557 kJ/kWh = 42,300 (Terajoules)

Fuel consumption 13,300 kJ/kWh = 33,979 (Terajoules)

Saving in fuel consumed = 8,321 Terajoules ≡ x10^9 kJ

Saving in fuel costs = US$6,617,013 (> US$33 million over 5 yrs)

Calculation of Average Heat Rate with the addition of 210MW

Method1: Based on installed capacity.

Existing installed capacity (excluding Tobago) = 1395 MW
Additional installed capacity = 210 MW

Weighted average heat rate = ((1395x13,300) + (210x12,000))/1395+210
= 13,130 kJ/kWh

Method 2: Based on energy delivered.

Using 2004 data.

Energy delivered = 6692GWh
Installed capacity = 1395MW
Possible energy =1395x8760MWh
= 12,220.2GWh

% Actual energy delivered = (6692/12,220.0)x100
= 54.8%

New capacity of 210MW

Possible energy for delivery = (210x8760)MWh
= 1839.6 GWh

Using same percentage as shown by 2004 data:
% Actual energy deliverable = 54.8%x1839.6
= 1007 GWh

Weighted average heat rate = ((6692x13,300) + (1007x12,000))/6692+1007
= 13,130 kJ/kWh

Conclusion: Both methods gave same result. It can be concluded that new average system heat rate will be 13,130 kJ/kWh.

Cost Implications

Following from Scenario 1 for the reduction of the heat rate for T&TEC's overall operation.

Fuel consumed = heat rate x units generated
= 13,130 x 6692
= 87,866 TJ
Fuel Saved = 96,588-87,866
= 8,722 TJ
Convert to BTU = 8,266,861 MMBTU

Cost Saving = US$6,935,896.31 (This is 9% of 2004 fuel cost of $483.3 million).

Recommendation: 94% cost pass-through of fuel costs.