Report of the Independent Expert in the Matter of the Public Utilities Commission Initial Decision In the 2008 Annual Review Proceeding for Belize Electricity Limited

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EXECUTIVE SUMMARY

On 2 May 2008, the Belize Public Utility Commission (PUC) issued its "Initial Decision for the Annual Review Proceedings for Belize Electricity Limited" ("Initial Decision"). The Initial Decision noted that 350 interested parties submitted comments to the PUC regarding BEL's rate filing and application to increase the tariffs currently levied as set out in Schedule 4 of the BEL Application. On 12 May 2008, BEL filed its objections to the Initial Decision. Given those objections, the PUC was obligated to appoint an Independent Expert pursuant to Sections 32(1) and 32(2) of the Byelaws within 20 days of Initial Decision. On 22 May 2008, the PUC appointed Dr. Jonathan A. Lesser as the Independent Expert. The Independent Expert is required to submit a final written report to the PUC documenting his review and recommendations on the regulated values, mean electricity rate, tariffs, charges and fees for the next ATP within 20 days of his appointment, or 11 June 2008. Moreover, the Independent Expert is required to submit a Draft Report to all parties within 15 days of his appointment, in this case 6 June 2008.

The Rate Setting Methodology (RSM) applied in this case was initially developed in the 2005 FTRP and presented as part of the PUC's Final Decision in that case. The methodology was modified on 22 December 2007, under S.I. No. 141, Electricity (Tariffs, Charges and Quality of Service Standards) (Amendment) Byelaws, 2007, as detailed under Schedules 3 and 4 of those amended Byelaws. However, these amended Byelaws were subsequently repealed by the new government on 28 March 2008. The PUC issued an updated RSM (2008 RSM) on the same day that it issued the Initial Decision in this ARP. The 2008 RSM is similar in design to the FTRP Tariff Methodology and, furthermore, corrected a number of the conceptual flaws in the FTRP Tariff Methodology.

Like its predecessors, the 2008 RSM is a "hybrid" methodology that combines elements of incentive regulation – specifically a revenue cap with a variety of incentive mechanisms, together with the pass-through of "uncontrollable" power costs. Under the 2008 RSM, a Tariff Basket Revenue (TBR*), also called the Required Revenue (RR*), is determined each year. TBR* is the sum of (1) the forecast Cost of Power (COP*), primarily purchased power from the Comisíon Federal de Electricidad (CFE) in Mexico, BECOL, and Hydro Maya; a "value added of delivery" (VAD*) component that includes operating expenses, depreciation, return on capital, and taxes; recovery of deferred power costs (CPRSA*) and costs associated with hurricane damages (HRCSA*); and adjustments to costs carried over from the previous calendar year (AC).

Summary of Initial Decision

The PUC's Initial Decision, issued on 2 May 2008, leaves the overall Mean Electricity Rate (MER) unchanged at BZ$0.441/kWh. (The PUC also left unchanged the current tariffs for all customer classes.) The specific parameter values proposed by BEL and the PUC's values are shown in Table EX-1.

Table EX-1: Proposed and Initial Decision Parameter Values for the ARP 2008*

Regulated Parameters	ARP 2007 Final Decision ($/kWh)	BEL Proposed Values ($/kWh)	ARP 2008 Initial Decision ($/kWh)
COP	0.253	0.287	0.307
VAD	0.168	0.168	0.131
CPRSA	0.020	0.045	0.004
MER	**0.441**	**0.500**	**0.441**

* -totals may not add owing to rounding.

BEL Objections

BEL submitted a 28-point rebuttal to the PUC's Initial Decision. These objections cover a variety of issues, including:

- Implications for BEL's creditworthiness owing to the PUC's decision to reduce BEL's allowed rate of return to 8.5% from the previous 12% target value in the RSM;
- Concerns that the 2008 RSM was released after BEL filed its Tariff Application on the mandatory filing date, raising concerns over "retroactive" ratemaking;
- Disallowance of a portion of BEL's actual power costs for the months of January and February 2008;
- Disallowance of all costs paid by customers associated with hurricane cost recovery;
- The continued exclusion of the Mollejon Transmission Line from rate base, thus preventing BEL from earning a return on that capital asset;
- The adoption of a new concept, called "working RAV" with which to estimate BEL's overall return on investment;
- Changes to how adjustments reflecting differences between actual and forecast costs (such as depreciation and rate of return); and

- A requirement that BEL now pay interest on customer deposits at a rate "consistent" with the rate earned by BEL on its deferred cost account.

Findings of the Independent Expert

- COP: Based on projected power costs and projected sales data provided to me by the PUC, I calculated a COP for the 2008 ATP of $0.298/kWh. Although I understand the concerns raised by the PUC about a growing CPRSA balance, I recommend this projected value be used, as it is consistent with *Good Utility Practice*, rather than the $0.307/kWh value in the Initial Decision. Additionally, both the PUC and BEL have expressed a desire to abandon the CPRSA and, instead, adopt an automatic cost adjustment mechanism that reflects changing power costs. I strongly recommend both parties work together to adopt such a mechanism, which will help reduce the complexity of the existing RSM.

- VAD: I recommend accepting the PUC's estimate of operating expenses (OPEX). After examining accounting textbooks, as well as the typical practice by regulators in the U.S. and elsewhere, I concur with the PUC's exclusion of both construction work in progress (CWIP) and the undepreciated value of the Mollejon Transmission Line from BEL's rate base;

- Depreciation: After examining accounting textbooks, as well as the typical practice by regulators in the U.S. and elsewhere, I recommend the PUC include the depreciation costs associated with the Mollejon Transmission Line;

- Rate of Return: Given that the risk-free rate for bonds issued by the Government of Belize have a market interest rate of over 9%, as indicated by the IMF, setting the ROR at 8.5% will not allow BEL the opportunity to recover their financing costs, not even if the company were 100% leveraged with a loan from the Government of Belize at the risk-free rate. Moreover, the 8.5% is inconsistent with the 2008 RSM, which specifies a target return of 12% and minimum return of 10% for BEL;

- Disallowance of a Portion of Actual COP for January and February 2008: No evidence was provided to me by the PUC for the disallowance of actual power costs incurred by BEL during the months of January and February 2008. BEL's drawdown of the Chalillo Reservoir for generation production was consistent with the rule curve for the reservoir. Therefore, in the absence of any evidence of poor operations, I do not concur with the PUC's disallowance;

- Disallowance of Previous HCRSA Costs: I reviewed accounting textbooks, accounting guidelines, and how self-insurance programs for catastrophic costs are addressed by other utilities and their regulators. BEL's stated treatment of its hurricane cost self-insurance programs is consistent with that of other utilities. However, BEL's discussion of the self-insurance scheme in its Annual Reports have

changed over time, which is troubling. The Annual Reports (ARs) for the years 1999 through 2003 refer to "funds set aside in a fixed deposit account to cover the appropriate retained earnings." The 1999 and 2000 ARs refer to specific dollar amounts set aside set aside in fixed deposits against appropriated retained earnings. The other Annual Reports refer only to the appropriation of retained earnings for the insurance reserve. The language in the 1999 through 2003 ARs could be interpreted to mean that cash was, in fact, deposited into a special account. As I am not a forensic accountant, I cannot determine the precise nature of the language in the ARs. Therefore, while I do not recommend accepting the PUC's disallowance of previously incurred hurricane recovery costs, I believe further investigation is warranted.

- Depreciation and return adjustments: The adjustments made by the PUC to account for differences between actual and projected depreciation and returns to the CPRSA may contribute to regulatory uncertainty. Moreover, it is not clear whether working capital is included in RAV, as is customary.

Recommended Rates

Table EX-2 reproduces Table EX-1, with the addition of my recommended parameter values, based on my independent estimation of those parameters using PUC models. As can be seen, I recommend an overall MER of $0.477/kWh.

Table EX-2: BEL, Initial Decision, and Recommended Parameter Values 2008 ARP*

Regulated Parameters	ARP 2007 Final Decision ($/kWh)	BEL Proposed Values ($/kWh)	PUC Initial Decision ($/kWh)	Recommended Values ($/kWh)
COP	0.253	0.287	0.307	0.298
VAD	0.168	0.168	0.131	0.154
CPRSA	0.020	0.045	0.004	0.025
MER	**0.441**	**0.500**	**0.441**	**0.477**

* -totals may not add owing to rounding.

Recommended Tariffs

In developing recommended tariffs, I considered the economic theory behind efficient tariff design. This was discussed in the report of the Independent Expert for the 2007 ARP, and so, in the interest of brevity, I will not reproduce that discussion. In developing my recommended set of tariffs, I have attempted to maximize economic efficiency, reduce revenue volatility, and provide greater bill stability for consumers.

Table EX-3 compares the tariffs in the Initial Decision with my recommended tariffs, which reflect the higher overall MER I estimated.

Table EX-3: Initial Decision and Recommended Tariffs

Customer Class and Consumption	Initial Decision	Recommended
Social Rate Customers		
Minimum Monthly Charge	$4.00	$4.00
0 – 50 kWh	$0.26	$0.26
Residential Customers		
Monthly Service Charge	n/a	$6.00
Minimum Monthly Charge	$5.00	n/a
0 – 50 kWh	$0.35	$0.35
51 – 200 kWh	$0.44	$0.48
Above 200 kWh	$0.47	$0.505
Commercial Customers		
Monthly Service Charge	$100.00	$100.00
0 – 10,000 kWh	$0.45	$0.45
10,001 – 20,000 kWh	$0.44	$0.47
Above 20,000 kWh	$0.43	$0.505
Industrial 1 Customers		
Monthly Service Charge	$100.00	$100.00
Monthly Demand Charge per kVA	$35.00	$35.00
Off Peak Energy Rate per kWh	$0.33	$0.33
Peak Energy Rate per kWh	$0.33	$0.505
Industrial 2 Customers		
Monthly Service Charge	$100.00	$100.00
Monthly Demand Charge per kVA	$21.00	$21.00
Off Peak Energy Rate per kWh	$0.28	$0.28
Peak Energy Rate per kWh	$0.28	$0.505
Street Lights		
Energy Rate per kWh	$0.55	$0.60

Other Findings

The "hybrid" nature of the current RSM and its predecessors is complex and somewhat opaque. As a result, the methodology is more likely to result in protracted litigation and exacerbate regulatory uncertainty. I recommend BEL and the PUC work together to develop a simpler regulatory approach that maintains performance incentives for the utility, whilst providing for greater understanding on both sides.

I INTRODUCTION

1. Background of Proceedings

On 2 April 2008, Belize Electricity Limited (BEL) submitted its tariff application in compliance with Section 29 of the Electricity (Tariffs, Fees and Charges) Byelaws ("Byelaws"). The cost components of BEL's filing appear to have incorporated the requirements of Statutory Instrument No. 141 (S.I. 141) of 2007, which became law on 22 December 2007. S.I. No. 141 amended the Byelaws and the methodology included as Schedule 1 with the PUC's Final Decision of 14 July 2005. That decision established the Full Tariff Review Proceeding (FTRP) and methodology for determining the annual updates to BEL's rates, known as the Annual Review Period (ARP). BEL's filing triggered this ARP proceeding. As required under Section 29 of the Byelaws, BEL filed its application 90 days prior to the start of the ATP that commences 1 July 2008 and ends 30 June 2009.

On 2 May 2008, the Belize Public Utility Commission (PUC) issued its "Initial Decision for the Annual Review Proceedings for Belize Electricity Limited" ("Initial Decision"). The Initial Decision noted that 350 interested parties submitted comments to the PUC regarding BEL's rate filing and application to increase the tariffs currently levied as set out in Schedule 4 of the BEL Application.[1] Also on 2 May 2008, the Belize PUC issued revisions to the published Methodology for Electricity Tariffs and Mean Electricity Rates. It is my understanding that these revisions were made subsequent to the repeal of S.I. No. 141 on 28 March 2008, five days before BEL filed its tariff application.

2. Appointment of the Independent Expert

On 12 May 2008, BEL filed its objections to the Initial Decision. Given those objections, the PUC was obligated to appoint an Independent Expert pursuant to Sections 32(1) and 32(2) of the Byelaws within 20 days of Initial Decision. On 22 May 2008, the PUC appointed me as that Independent Expert, based on my qualifications as set out in Section 4.0 of the Terms of Reference (ToR) issued by the PUC. A copy of my curriculum vitae is attached as Appendix 1 to this report.

3. Scope of Work

The ToR specifies the scope of work to be undertaken by the Independent Expert. Specifically, the ToR states that:

[1] Initial Decision, pp. 6-7.

> The Independent Expert will review the 'Initial Decision' of the PUC and the objections received by the PUC. In conducting the review, the Independent Expert will give due regard to the BEL Application and data submissions. The Independent Expert will also give due regard to the Amended First Schedule (Rate Setting Methodology), ARP 2007 Independent Expert's report, the PUC Regulatory Model, and the Full Tariff Review Proceedings Final Decision.

Under the ToR, the Independent Expert is required to submit a final written report to the PUC documenting his review and recommendations on the regulated values, mean electricity rate, tariffs, charges and fees for the next ATP within 20 days of his appointment, or 11 June 2008. Moreover, the Independent Expert is required to submit a Draft Report to all parties within 15 days of his appointment, in this case 6 June 2008.

4. Work Plan

I began by first reviewing documents that were provided to me by the PUC and other publicly available documents published on the PUC website. I also reviewed the objections filed by BEL and developed a set of questions and requests for information and documents from both BEL and the PUC. Next, I met personally with PUC Staff and PUC Chair Mr. John Avery, staff and officers of BEL, including Mr. Lynn Young, BEL's Chief Executive Officer, and the Minister of Public Utilities, Transport, Communications and National Emergency Management, the Hon. Melvin Hulse. I questioned all of the individuals I met with in detail and gratefully acknowledge their willingness to answer all of my questions candidly and in great detail.

Having met with all of the parties, I then reviewed all of the documents and models provided to me. I carefully reviewed all of the objections filed by BEL and the responses to those objections developed by PUC Staff. I have relied on the body of best international regulatory practice, mainly that from the United States, as many experts claim (including myself) that sets out "good utility practice" based on the more than seven decades of experience. As I explain in Section 2 of this report, the nature and timing of the repeal of S. I. No. 141, as well as the appropriateness of several of the specific findings of the PUC's Initial Decision, are best reviewed in the context of what constitutes "good utility practice."

5. Organization of this Report

Following this introduction, Section 2 provides an overview of the current Tariff Methodology used to determine the mean electricity rate (MER) and its various components. This review provides the necessary background for examining the specific objections filed by BEL, the responses to said objections by PUC Staff, and my ultimate recommendations based on the tenets of good regulatory practice. Section 3 provides an overview of the recommendations in the PUC's Initial Decision and BEL's objections. Next, in Section 4, I provide a brief introduction to what *Good Utility Practice* commonly means. I do this because,

as I discuss in Section 5, where I present my findings and recommendations, several of the PUC's findings, as well as its treatment of several key components that make up the MER in its Initial Decision do not constitute *Good Utility Practice*. Of crucial importance to the recommendations I make in this report is that, whilst some of the findings made by the PUC will provide short-term rate relief to ratepayers, the longer term consequences of those findings, if enacted, are likely to exacerbate future rate increases and economic harm to those same ratepayers.

II THE EXISTING RATE SETTING METHODOLOGY

1. Introduction

The Rate Setting Methodology (RSM) applied in this case was initially developed in the 2005 FTRP and presented as part of the PUC's Final Decision in that case.[2] To the best of my understanding, this methodology was modified on 22 December 2007, under S.I. No. 141, Electricity (Tariffs, Charges and Quality of Service Standards) (Amendment) Byelaws, 2007, as detailed under Schedules 3 and 4 of those amended Byelaws. However, these amended Byelaws were subsequently repealed by the new government on 28 March 2008. The PUC issued an updated RSM on the same day that it issued the Initial Decision in this ARP.[3] The 2008 RSM is similar in design to the FTRP Tariff Methodology and, furthermore, corrected a number of the conceptual flaws in the FTRP Tariff Methodology. Those conceptual flaws were addressed in the report issued by the Independent Expert for the 2007 ARP.[4] Nevertheless, there are several key differences between the two methodologies. Moreover, the current RSM, while including a "coherent narrative describing the form of regulation" as recommended by the Sotkiewicz Report, the current methodology fails to comport with the requirements of *Good Utility Practice*.

2. Overview of the 2008 RSM

Like its predecessors, the 2008 RSM is a "hybrid" methodology that combines elements of incentive regulation – specifically a revenue cap with a variety of incentive mechanisms, together with the pass-through of "uncontrollable" power costs.[5] Under the 2008 RSM, a

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[2] Final Decision, First Full Tariff Review Proceedings for Belize Electricity Limited, Appendix 1, 14 July 2005 ("FTRP Tariff Methodology").

[3] "Amended First Schedule to the Public Utilities Commission Final Decision (initially issued July 14, 2005) for Belize Electricity Limited, May 02, 2008," Appendix 1, "Methodology for Electricity Tariffs and Mean Electricity Rates." ("2008 RSM").

[4] P. Sotkiewicz, "Final Report of the Independent Expert in the Matter of the Public Utilities Commission Initial Decision in the 2007 Annual Review Proceeding for Belize Electricity Limited," 14 June 2007 ("Sotkiewicz Report"). I note one small error in this report. Specifically, on page 56 of the report, the difference between the forecast, target Value Added for Delivery (VAD) and actual, allowed VAD, shown in equations (C.5) and (C.6) neglects to include the difference between forecast and actual depreciation, and forecast and actual investment returns. These differences are a key issue in the current proceeding, as I discuss in Section 4.

[5] The Sotkiewicz Report provides a detailed description of the RSM developed for the 2005 FTRP. In the interest of brevity, I will not reproduce that discussion in its entirety, but instead focus on key elements of that methodology that I believe to be most problematic.

Tariff Basket Revenue (TBR*), also called the Required Revenue (RR*), is determined each year. TBR* is the sum of (1) the forecast Cost of Power (COP*), primarily purchased power from the Comisíon Federal de Electricidad (CFE) in Mexico, BECOL, and Hydro Maya; a "value added of delivery" (VAD*) component that includes operating expenses, depreciation, return on capital, and taxes; recovery of deferred power costs (CPRSA*) and costs associated with hurricane damages (HRCSA*); and adjustments to costs carried over from the previous calendar year (AC). Thus,

$$TBR^*_{ATP} = RR^*_{ATP} = COP^*_{ATP} + VAD^*_{ATP} + CPRSA^*_{ATP} + HCRSA^*_{ATP} + AC_{t-1}, \quad (1)$$

where ATP refers to the current annual tariff period, t refers to the current calendar year.

a. The COP Component

Not surprisingly, given the rapid increase in fossil fuel prices, the COP component has become a contentious issue in this ARP. COP also includes technical (line) losses, as well as "commercial" losses. The former are losses inherent in transmitting and distributing generation over power lines, whilst the latter include losses arising from metering errors and power theft.

COP is considered to be a pass-through.[6] That is , assuming that the utility's wholesale purchases of power and the operating costs of its own diesel plants are found to be prudent[7], those costs are simply passed through to BEL consumers. Of course, since forecasts of electricity demand and supply costs are unlikely to be perfect, there will always be a difference between COP* and the actual COP. Those differences are supposed to be reconciled using the CPRSA, which is a form of "regulatory asset."[8]

The current pass-through mechanism is confusing and can be designed more efficiently. From my discussions with the parties, it appears that both the PUC and BEL would prefer an automatic power cost adjustment mechanism. Such mechanisms are commonly used and I strongly recommend such an approach, as it would eliminate the need for customers to pay interest (currently 12%) on CPRSA balances owed to BEL. An automatic power cost adjustment mechanism would also improve BEL's creditworthiness by reducing the company's regulatory asset account balances.

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[6] A regulatory asset is a deferred cost owed to the utility.

[7] The prudence of BEL's operating decisions, specifically with its actual power costs in the months of January and February 2008, are an issue in this ARP review. I discuss the concept of prudence in Section 3. In Section 4, I discuss the reasonableness of the PUC's disallowance of a portion of BEL's actual cost of power in those two months.

[8] If the COP < COP*, then the CPRSA balance will drop. Thus, it is conceivable that BEL customers can receive a credit on their monthly bills for negative CPRSA balances.

b. The VAD Component

The VAD consists of operating expenses (OPEX), depreciation costs (D), a return on BEL's invested capital (TOR), taxes and license fees paid (TL), other revenues earned by BEL (OR), *force majeure* costs, such as those associated with hurricane damages (FM), and a reliability incentive adjustment (RIA). The equation for VAD is thus

$$VAD^{*}_{ATP}{}^{*}_{ATP} = OPEX^{*}_{ATP} + D^{*}_{ATP} + TOR^{*}_{ATP} + TL^{*}_{ATP} - OR^{*}_{ATP} + FM^{*}_{ATP} + RIA^{*}_{ATP} \qquad (2)$$

According to the Tariff Methodology published by the PUC,

> VAD is considered to be '***Almost, but not Quite Revenue Capped***.' Some component/s of VAD could experience an incentive/penalty treatment.[9]

This description of the VAD is confusing, to say the least. The reason is that, in addition to imposing a revenue cap, which in itself provides an incentive mechanism for the utility, the PUC imposes additional incentives and penalties on operating costs through the use of an efficiency factor.[10] Moreover, the Tariff Methodology states that the PUC can reset the target OPEX within the FTRP "after two or three repeated performance of actual OPEX above the target OPEX." While adjustments within the FTRP may be reasonable in extraordinary circumstances, a better approach would be to set the efficiency parameter for OPEX carefully. Offering to reset the OPEX target in the middle of the FTRP is likely to reduce the incentive for BEL to improve its operating efficiency. Most countries that adopt revenue caps or revenue yields, set the initial prices for five years and use an efficiency factor (X) to adjust the revenue target until the next tariff review, by increasing the revenues by the inflation rate minus the X-factor (known as RPI-X). This is standard practice in the UK and Mexico.[11]

The 2008 RSM has changed the return on investment component of the VAD (TOR). Specifically, the 2008 RSM bases the calculation of BEL's return on investment based on the allowed rate of return (ROR) times the *Working* Regulated Asset Value (RAV), where the RAV is just the undepreciated value of BEL's capital assets.[12] Under the 2008 RSM, the

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[9] 2008 RSM, p. 4 (emph. in original).

[10] 2008 RSM, pp. 19-21.

[11] A discussion of methods used to estimate the X-factor can be found in Lesser and Giacchino, *op. cit.*, pp. 188-192. See also, M. Armstrong, S Cowan, and J. Vickers, *Regulatory Reform: Economic Analysis and British Experience*, (Cambridge, MA: MIT Press 1994).

[12] The 2008 RSM specifically excludes from RAV all of the costs paid for by capital contributions (2008 RSM, p. 21). I understand that the issue of "contributed capital" stems primarily from assets that were originally owned by the government, but then transferred to (cont.)

working RAV equals the beginning of year RAV plus one-third (33%) of the value of capital investments put into place during the year. I find this definition of working RAV to be somewhat different from standard international practice. Typically, the value of a utility's capital assets for a given test year are assumed to equal either the average of the monthly values, or an average of the start-year and end-year values. Since monthly data is available from BEL, I recommend using the former. Additionally, the 2008 RSM is silent regarding the treatment of working capital. As best I could determine from the PUC's models, working capital has not been included in the RAV estimates, contrary to standard regulatory treatment.[13]

Depreciation expenses themselves can be problematic in the 2008 RSM. The reason stems from the PUC's treatment of actual vs. forecast depreciation costs. Specifically, the 2008 RSM states that the difference between actual and forecast depreciation "may be applied to any cost component approved by the Commission in the next ATP of FTP."[14] As I discuss in Section 4, in its Initial Decision in the 2008 ARP, the Commission retroactively subtracted excess depreciation costs (reflecting too high a forecast of capital investment) from the CPRSA. However, as discussed below, the CPRSA is designed to track differences between actual and forecast power costs. Moreover, the 2008 RSM also states that differences between forecast and actual depreciation costs should be incorporated into the Annual Correction (AC).[15]

One issue that has arisen in the 2008 ARP is the treatment of construction work-in-progress (CWIP), which is designated $\mathbf{I_{WP,t}}$ in the 2008 RSM. The 2008 RSM excludes CWIP from the RAV, and instead provides for the utility to recover interest during construction or an allowance for funds used during construction (AFUDC).[16] Since assets that are under construction are, by definition, not "used and useful,"[17] it is appropriate to exclude such assets from the RAV until they are incorporated into service.

BEL. The Mollejon transmission line lies at the heart of this controversy. I address the treatment of the capital costs of that transmission line in Section 4.

[13] See, e.g., J. Bonbright, A. Danielson, and D. Kamerschen, *Principles of Public Utility Rates (*Vienna, VA: Public Utilities Reports, Inc. 1998), pp. 242-243. See also, R. Hahne and G. Aliff, *Accounting for Public Utilities*, (Washington, DC: Lexis-Nexis 2007), p. 5-1, and Lesser and Giacchino, *op. cit*, p. 57.

[14] 2008 RSM, p. 26.

[15] 2008 RSM, p. 35.

[16] 2008 RSM, p. 21.

[17] I discuss the "used and useful" concept briefly in Section 3. A thorough review of "used and useful" and its origins can be found in J. Lesser, "The Economic Used-and-Useful Test: (cont.)

The return component (TOR) of the VAD is equal to the target rate of return (ROR) times the working RAV. In addition to the issue of using the working RAV, based on my discussions with the Commission, there appears to be some misunderstanding as to how the target ROR (12%) and the lower bound (10%) and upper bound (15%) on that return component function.

After the utility's target rate of return (ROR) is set, the upper (ROR_{UI}) and lower (ROR_{LI}) bounds for the rate of return define what is known as a "deadband." The utility's earnings are allowed to fluctuate freely within that deadband. This provides the utility with an incentive to improve the efficiency of its operations, subject to maintaining well-defined service quality and reliability standards. Outside of the deadband, additional earnings or costs are typically shared between the utility and its customers. Typically, but not always, the sharing mechanisms are symmetric. For example, if the utility must share 50% of earnings above the deadband with customers, then customers will be required to reimburse the utility for 50% of the earnings shortage below the deadband.[18] Within the deadband, however, no additional adjustments to allowed returns are required. The target return itself is sometimes adjusted, especially in multiyear rate setting processes like the FRP. The usual approach in those cases is to use a formulaic adjustment, such as one tied to prevailing interest rates.

In the 2008 RSM, changes in total return are accounted for in the Annual Correction (see Section 2.2.4, infra.).[19] This correction should only be applied based on the difference between forecast and actual RAV.

c. The CPRSA and the HCRSA Components

The Cost of Power Rate Stabilization Account (CPRSA) and the Hurricane Cost Rate Stabilization Account (HCRSA) are types of regulatory assets. The goals of these accounts are to shield ratepayers from large and disruptive cost increases. The CPRSA is designed to recover the difference between the forecast COP and the actual COP. In any given year, the actual COP will differ from the forecast COP because it is impossible to predict actual electric sales and actual generating costs perfectly.

Its Origins and Implications for a Restructured Electric Industry," *Energy Law Journal* 23 (November 2002), pp. 349–82.

[18] Sharing mechanisms can also be based on revenues. See, Lesser and Giacchino, *op. cit*, pp. 71-72, for an example of a utility that proposed such an regulatory scheme.

[19] 2008 RSM, p. 35. Note that the difference between actual and forecast return shown, $\mathbf{\Delta ROR}_t$, is incorrect. It should be $\mathbf{\Delta TOR}_t$.

d. The AC Component

The Annual Correction (AC) is, in essence, a "catch all" to adjust the revenue requirement for differences between forecast and actual tax and licensing fees, other revenues, depreciation expenses, and capital asset returns. Thus, AC is really designed to address all of the differences (except for power costs, hurricane recovery costs, and other *force majeure* costs) between actual and forecast values.

As part of the Annual Correction, the 2008 RSM states that

> In an ARP the Commission reserves the right to set the allowed value for any cost item, for example Opex, for any calendar year in a FTP. Such item or items will experience an annual correction if the actual cost in any calendar year is greater than the cost previously set for that calendar year, by the Commission.[20]

I find this language troubling for several reasons. First, the AC is done on a calendar year basis, while the ARP is not. Moreover, the AC reflects changes from the previous calendar year. Second, the Commission's ability to reset the allowed values for any cost item in a FRP will exacerbate regulatory uncertainty, which should be avoided under the general rubric of *Good Utility Practice*.

3. Aggregation of ARP Cost Discrepancies Over Time

A number of the discrepancies between actual and forecast values are aggregated over each year of the FTP, including technical and commercial losses that are incorporated into the COP, operational expenditures, and the reliability incentive. The problem with this aggregation approach is that, by not adjusting values on an annual basis, the discrepancies between actual and allowed values are likely to be larger. Not only does the utility not receive a more timely incentive to improve its operating efficiency and reliability, but the adjustments may lead to larger than anticipated adjustments to overall revenue requirements and, hence, tariffs, in the next FTP.

[20] 2008 RSM, p. 35.

III. REVIEW OF PUC INITIAL DECISION AND BEL OBJECTIONS

1. Introduction

The PUC's Initial Decision, issued on 2 May 2008, leaves the overall Mean Electricity Rate (MER) unchanged at BZ$0.441/kWh. (The PUC also left unchanged the current tariffs for all customer classes.) The specific parameter values proposed by BEL and the PUC's values are shown in Table III-1.

Table III-1: Proposed and Initial Decision Parameter Values for the ARP 2008*

Regulated Parameters	ARP 2007 Final Decision ($/kWh)	BEL Proposed Values ($/kWh)	ARP 2008 Initial Decision ($/kWh)
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* -totals may not add owing to rounding.

On 9 May 2008, the PUC issued a document entitled, "Summary of Issues and Actions Taken in ARP 2008" ("2008 Decision Summary"). On 12 May 2007, BEL filed its objections to the Initial Decision, which triggered retention of the Independent Expert.

2. Summary of the PUC's Reasons for the Initial Decision

The PUC applied several components of the 2008 RSM that allow the PUC to apply immediate corrections to the revenue requirement (RR), rather than waiting to apply those corrections at the end of the FTP. The PUC determined that, because the CPRSA account had been growing, it made sense to increase the COP from 0.253 $/kWh to 0.307 $/kWh. Second, the PUC applied several corrections (including retroactive correction) to the CPRSA. As I discuss in more detail in Section 4.4 below, the PUC adjusted the CPRSA for the variance between actual and projected depreciation, and the variance between actual and projected returns on the RAV.

The PUC adjusted the VAD to reflect higher allowed operating expenditures, a lower capital asset base (RAV), and a lower target return on that asset base. Specifically, the PUC eliminated the undepreciated book value of the Mollejon Transmission line (approximately $26 million), eliminated over $40 million in Construction Work in Progress, adjusted the value of capital assets placed into service this year to reflect the new working RAV concept

in the 2008 RSM, and eliminated an additional $19.9 million in "contributed" capital. The PUC also reduced the allowed rate of return (ROR) going forward from the 12% target value set in the 2008 RSM to 8.5%.

With respect to the CPRSA and HCRSA accounts, the PUC stated it disallowed all previous HRCSA charges, "given the previously approved decisions to establish a self-insurance scheme, including a $5 million insurance reserve."[21] The PUC also disallowed 20% of the reported CPRSA deferrals for January and February of this year because of concerns that, "BEL diverted considerably from its planned energy dispatch profile for the 1st Quarter 2008, resulting in considerably higher deferrals to the CPRSA."[22]

3. Summary of BEL's Objections to the Initial Decision

BEL submitted a 28-point rebuttal to the PUC's Initial Decision.[23] The objections cover a variety of issues, including the implications for BEL's creditworthiness, assumptions about future oil prices, the timing of the issuance of the 2008 RSM, concerns over retroactive ratemaking, and a variety of other issues. I summarize the major issues in the following subsections.

a. Violation of Bond Covenants

BEL states that the PUC's Initial Decision places BEL in violation of the bond covenants associated with BEL debt held by Scotia Bank, the Caribbean Development Bank (CDB), and the International Bank for Reconstruction and Development (IBRD). Bond covenants are specific requirements by lenders as conditions for underwriting loans. Covenants serve to protect the financial interests of these lenders, for example, by ensuring the company has enough cash to service the bonds (i.e., make the required principal and interest payments. If a company violates its bond covenants, then the lender may be within its rights to "call" the loans and demand immediate repayment of the entire remaining principal balance.

Based on my review of the actual covenants, the Scotia Bank covenants require BEL to maintain a minimum cash flow coverage ratio, while the CDB and IBRD covenants require BEL to maintain minimum ratios of net revenues to debt service costs. Specifically, the Scotia Bank covenants provided to me by BEL require that BEL maintains a "cash flow

[21] 2008 Decision Summary, p. 6.

[22] Ibid. In conversations with the PUC, I was made to understand that the PUC disallowed 80% of the CPRSA deferrals during those two months, not 20% as stated in the Initial Decision.

[23] A copy of BEL's filed objection, not including the voluminous attachments, is included as Appendix 2.

coverage ratio" of 1.6. This is defined as the ratio of earnings before interest, taxes, and depreciation (EBITDA) divided by total loan interest and principal obligations. The CDB and IBRD bond covenants require net revenue to bond service ratios of 1.5. These are defined as the ratio of earnings before interest and depreciation charges, but after tax and licensing fees are paid (EBIDA) divided by bond interest expense.

b. Timing of 2008 RSM

BEL also objected to the timing of the repeal of the Amended Byelaws (S.I. No. 141) on 28 March 2008, and the introduction of the 2008 RSM on 2 May 2008. BEL stated that the repeal of S.I. No. 141 four days before the deadline for filing its 2008 ARP was insufficient time for it to revise its filing, which conformed to the requirements of S.I. No. 141.[24] BEL also states that introducing the 2008 RSM 30 days after its ARP submission and applying the new methodology to 2007 constitutes retroactive ratemaking, introduces additional regulatory uncertainty, and creates a financial environment in which it cannot finance company operations.

c. Reduction in Target Rate of Return

BEL objects to the PUC's reducing its target rate of return (ROR) for the 2008 ARP to 8.5%. BEL states that this reduction violates the requirements in the 2008 RSM, which targeted a ROR of 12% and established a ROR band between 10% and 15%. BEL states that reducing its target return to 8.5% is only 10 basis points (0.1%) above the return on "low-risk" 90-day securities issued by the Belize Central Bank. BEL states that, given the rate on these short-term securities, the company's ROR should be on the order of 15%.

d. Disallowance of Actual Power Costs in Jan-Feb 2008

BEL objects to the disallowances of its actual power costs for the months of January and February of this year. BEL states that the PUC provided no explanation for the disallowance, and that BEL dispatched the hydro resources based on projected water flows and the need to maintain water levels in the Chalillo Reservoir during the dry season, contrary to the PUC's assertion that BEL "diverted considerably from its planned energy dispatch profile."[25]

e. Disallowance of All Previous HCRSA Balances

BEL objects to the PUC's disallowance of all HCRSA balances. BEL states that the decision by the PUC reverses a previous decision by the PUC in 2002 that established the HCRSA

[24] BEL also raised a legal issue. Specifically, BEL states that the repeal of S.I. NO. 141 leaves it with no legally authorized rate setting methodology. As I am not an attorney, I cannot comment on this issue.

[25] BEL Objection, p. 3, quoting from the 2008 Decision Summary, p. 6.

and prior approvals of all HCRSA balances in previous ARPs. BEL also asserts that, by disallowing all of the HCRSA balances, the PUC is jeopardizing BEL's financial integrity.

f. Objections to the 2008 RSM

BEL presents a number of objections to the 2008 RSM. These include how variances in depreciation expenses from forecast values are addressed; the lack of a stable regulatory environment because of the 2008 RSM's allowing the PUC to change the treatment of components as it sees fit; requirements that BEL further justify all capital expenditures; and requiring BEL to pay interest on consumer deposits when the company is prevented from charging interest on overdue account balances.

g. Rate Treatment of Mollejon Transmission Line

BEL objects to the continued exclusion by the PUC of the undepreciated value of the Mollejon line in BEL's rate base. By excluding the line, BEL does not earn a return on the investment, as it does for capital assets that are included in the rate base.

h. Disparity of requiring interest be paid on customer deposits

BEL objects to the requirement under the 2008 RSM that it pay interest on customer deposits "consistent with the CPRSA rate, whilst not being allowed to charge interest on overdue accounts. BEL complains that such disparate treatment is "patently unfair," both to itself and customer who do pay their bills in a timely manner.[26]

[26] BEL Objection, par. 27

IV GOOD UTILITY PRACTICE

1. Introduction[27]

Good Utility Practice constitutes a broad-based set of standards that provide guidance as to how utilities should operate and how regulators should review those operations. Good utility practice incorporates everything from how utilities ought to make investment decisions that affect the availability and reliability of their services, to how costs should be classified and allocated amongst different customer groups. For example, the U.S. Federal Energy Regulatory Commission (FERC) defines *Good Utility Practice* as follows:

> Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known *at the time the decision was made*, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.[28]

If a utility's decisions and actions do not conform to *Good Utility Practice*, the firm's actions may not be in the public interest, and thus lead to regulatory disputes, such as the current dispute between the PUC and BEL. Yet is not only regulated firms that must follow the tenets of *Good Utility Practice*; regulators, too, must follow established practices to ensure that the financial integrity of the utilities they regulate is maintained. For example, Section 6(2)(b) of the Electricity Act (Revised Edition 2000) states that PUC shall "secure that licence holders are able to finance the carrying on of the activities which they are authorized by their licences to carry on," while Section 6(2)(d) requires the PUC to protect the interests of consumers in terms of the prices charged and the reliability of service.

a. The Revenue Requirement Standard

The revenue requirement remains the basis standard of utility rate regulation. As Phillips (1994) states:

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[27] Portions of this discussion are taken from J. Lesser and L. Giacchino, *Fundamentals of Energy Regulation* (Vienna, VA: Public Utility Reports, Inc. 2007), Chapter 3.

[28] Federal Energy Regulatory Commission, Pro Forma Open Access Transmission Tariff (OATT), Appendix B (emph. added), 72 Fed Reg. 12,266—12531 (March 15, 2007) (to be codified at 18 C.F.R. pts. 35 and 37).

> Simply stated, a regulated firm must be permitted to set rates that will both cover operating costs and provide an opportunity to earn a reasonable rate of return on the property devoted to the business.[29]

After establishing a revenue requirement, regulators then have an obligation to establish a rate structure that is non-discriminatory and fair. This is why the U.S. Supreme Court long ago stated that

> The establishment of a rate for a regulated industry often involves two steps of different character … The first is the adjustment of the general revenue level to the demands of a fair return. The second is the adjustment of a rate schedule conforming to that level, so as to eliminate discrimination and unfairness from its details.[30]

2. The Regulatory Compact

Together, the requirements to maintain the financial integrity of a regulated utility and to protect the interests of consumers embody what is commonly termed "the regulatory compact." The regulatory compact is a long-standing, but unwritten rule that governs cost recovery and lies at the heart of establishing regulated tariffs. Under the regulatory compact, the regulator grants the utility a protected monopoly, essentially a franchise, for the sale and distribution of electricity within a defined service territory. In the case of BEL, the service territory is the entire country. In return for this franchise, the utility commits to supply the full quantities demanded by consumers at a price calculated to cover all of the utility's legitimate operating costs, plus a "reasonable" return on the company's invested capital.

Whereas the regulatory company is nowhere codified in law, one may question whether it, in fact, exists from a legal standpoint. Although that question is beyond the scope of this report, as well as my expertise, from an economic standpoint, the existence of the regulatory compact is of crucial importance. Without it, there is neither a foundation for a proper regulatory framework nor for well-functioning, regulated utilities. Moreover, in the context of this Tariff Proceeding, the absence of a regulatory company would mean there would be no basis for establishing "just and reasonable" rates for BEL and its customers.

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[29] C. Phillips, *The Regulation of Public Utilities*, 3d Ed. (Vienna, VA: Public Utilities Reports, Inc., 1993), p. 176.

[30] *Federal Power Comm'n v. Natural Gas Pipeline Co.*, 315 U.S. 575, 584 (1942).

3. The Just and Reasonable Standard

The origin of the "just and reasonable" standard is the "just price" doctrine from medieval Europe.[31] In the U.S., the just and reasonable standard can be traced to the Takings Clause of the Fifth Amendment of the U.S. Constitution. Moreover, the standard has been adopted in other countries and, in my opinion, is embedded within Section 6(2) of the Electricity Act. The just and reasonable standard does not give regulated firms *carte blanche* to recover any and all costs. Rather, only those costs that are deemed just and reasonable are recoverable by the utility. Thus, the regulator must investigate the utility's costs, including its invested capital, to determine whether those costs are prudent, "used and useful," and "known and measurable."

Under *Good Utility Practice*, the regulated utility's operating and investment decisions are generally deemed prudent unless proven otherwise. In other words, utility management is given the benefit of the doubt, and *the decisions made by management are presumed reasonable unless the facts show otherwise*. Moreover, as highlighted in the quote from the decision by the U.S. FERC, the prudence of managerial decisions must be judged on their reasonableness at the time those decisions were made and based on information that was then currently available. In other words, determining the prudence of a regulated utility's actions is not meant as an exercise in hindsight or clairvoyance. A prudent decision is one that a reasonable person would have made, given the information available at the time. As Goodman states, "Prudence thus involves foresight, not hindsight."[32] Thus, when a regulator disallows costs incurred by a utility, the regulator is obligated to provide a reasoned explanation why, and to demonstrate that the decisions made by the utility at the time were not reasonable.[33]

a. Prudence and Retroactive Ratemaking

Goodman defines "retroactive ratemaking" as the "improper recovery of costs that were properly recoverable only in a past period or periods. In the absence of express statutory

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[31] See, M. Glaeser, *Public Utilities in American Capitalism* (New York: Macmillan Co., 1957), p. 196.

[32] C. Phillips, *op. cit.*, p. 340. See also, *In re Western Mass. Elec. Co.*, 80 PUR4th at 501.

[33] For example, Section 556(d) of the U.S. Federal Administrative Procedures Act of 1946 (USC Title V, Subsection II) states that "Except as otherwise provided by statute, the proponent of a rule or order has the burden of proof. … A sanction may not be imposed or rule of order issued except on consideration of the whole record or those parts thereof cited by party and supported by and in accordance the reliable, probative, and substantial evidence."

direction, it is unlawful for an agency to alter the past legal consequences of past actions."[34] In concert with the concept of retroactive ratemaking, U.S. regulators have established what has become known as the Filed Rate Doctrine.[35] Under the Filed Rate Doctrine, "The attempt to recover past costs, or otherwise attempt retroactively to charge something other than the tariff rate that was in effect for the period, is a violation of the Filed Rate Doctrine."[36] In other words, "once a rate is in place with ostensibly full legal effect and is not made provisional, *it can then be changed only prospectively*."[37] However, the U.S. Supreme Court has ruled that, if the past rate was unreasonable, that the Filed Rate Doctrine may not be enforceable.[38]

b. The Used and Useful Concept

In addition to demonstrating its costs are prudent, a utility must demonstrate that its assets are "used and useful." In other words, are the assets *used* to provide actual services and, if so, are those services *useful* to ratepayers. For example, a diesel generating unit used to meet customer demand during peak hours is still considered useful even if it does not run in every hour.

c. Known and Measurable

Regulators usually also require that a utility's costs be "known and measurable." That is, the regulated firm must be able to justify, using documents, facts, and methodology, all of the costs that it wishes ratepayers to reimburse. Typically, a regulated firm is required to prove that all of the costs it is requesting to recover are legitimate expenditures that benefit ratepayers.

The known and measurable standard can also be applied to forecasts of costs. For example, forecasts of fuel prices can be developed by independent parties. Or, if the forecasts are developed by the regulated utility, regulators can review and ensure that those forecasts are based on accurate models and historic data.

d. The Need for Regulatory Certainty

Electric utilities are capital intensive operations that require careful planning and operation, if they are to provide cost-effective and reliable service. For example, in the face of growing

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[34] L. Goodman, *The Process of Ratemaking*, Vol. 1. ((Vienna, VA: Public Utilities Reports, Inc., 1994), p. 166, citing *Bowen v. Georgetown Univ. Hospital*, 288 U.S. 204 (1988) and *American Min. Congress v. U.S. Environmental Protection Agency*, 965 F.2d 759, 769 (9th Cir. 1992).

[35] Goodman, *op. cit.*, pp. 169-177.

[36] Ibid., p. 170.

[37] *Texas Eastern Transmission Corp. v. F.E.R.C.*, 102 F.3d 174 (5th Cir. 1996).

[38] *Maislin Industries, U.S., v. Primary Steel*, 497 U.S. 116, 128 (1990).

customer demand, utilities will need to build or acquire new generating resources, build sufficient transmission capacity, and expand their local distribution system. Those actions require significant capital investment and lead time. The utility must have confidence that decisions found to be reasonable today will not be considered unreasonable tomorrow.[39]

This does not mean that regulation must never change. In fact, *Good Utility Practice* requires that regulators ensure the regulatory framework in place is consistent with new market developments and changes in other laws that affect a utility's operation and investment decisions. As such, it is both appropriate and necessary for regulation to adjust to changing conditions over time. What is not appropriate is to invoke such changes retroactively in ways that fail the "hindsight" test: the concept of prudence and penalize the utility for decisions that were previously approved based on reliable and accurate information, or based on new information that could not have been known by the utility at the time.[40]

[39] In a news release accompanying the release of a recent study published by the Fraser Institute of Canada, the authors state that, "Almost all energy projects are planned years in advance and often involve billions of dollars. With so much at stake, investors need to be confident that governments aren't going to change the rules in the middle of the game." See, http://www.fraserinstitute.org/commerce.web/newsrelease.aspx?nID=5169, The report is, "A Vision For a Continental Energy Strategy," and was published in February 2008. The authors of the report are the former Premiers of British Columbia and Alberta (Brian Tobin and Ralph Klein, respectively), and Gerry Angevine of the Fraser Institute. A copy of the paper can be downloaded at: http://www.fraserinstitute.org/COMMERCE.WEB/product_files/ContinentalEnergyStrategy2008.pdf.

[40] For a discussion of the importance of regulatory certainty in regard to competitive bidding for generation supplies, see A. Makler and S. Schleimer, "Preserving the Benefits of Competition through Effective Competitive Bidding Rules for Utility Resource Procurement," *The Electricity Journal* 16 (July 2003), pp. 27-36.

V FINDINGS AND RECOMMENDATIONS

In this section, I first present my findings and recommendations regarding each of the cost components that make up the MER. Then, I present my recommendations regarding BEL's tariffs. In making my recommendations, I have relied on the tenets of good utility practice as discussed in Section 4, as well as written evidence supplied by the PUC and BEL.

1. COP

Owing to the country's dependence on power from CFE, and because the contract price for that power is based on an index of fossil fuel prices, BEL has clearly experienced an increase in its COP. Moreover, the cost of running the diesel generators owned by BEL has also increased significantly. In its Initial Decision, the PUC set the COP to BZ$0.307. The basis for this price was a combination of actual power costs during the first few months of calendar year 2008 and the forecast of power costs for the remainder of the year. The PUC stated in its 2008 Decision Summary that

> [T]he Reference Price of Power has consistently resulted in the growth of the CPRSA. The Commission is required to reduce the CPRSA to zero by June 20, 2009, and at the same time prefers to pay the monthly CWP; hence the decision to set the Reference Price of Power at $0.307.[41]

BEL did not provide any objections to setting the COP at the PUC's recommended value. I independently calculated the COP for the 2008 ATP based on data provided to me by the PUC. The value I estimated is $0.298/kWh. Although I understand the PUC's concern over growth in the CPRSA account, *Good Utility Practice* suggests that the actual projected COP be used. Therefore, I recommend the COP be set to $0.298/kWh.

2. VAD

As discussed in Section 2, the VAD consists of operating expenses (OPEX), depreciation costs (D), a return on BEL's invested capital (TOR), taxes and license fees paid (TL), other revenues earned by BEL (OR), *force majeure* costs, such as those associated with hurricane damages (FM), and a reliability incentive adjustment (RIA). The allowed depreciation expense and the allowed return on invested capital both hinge on the proper regulated asset value (RAV). Thus, after first discussing operating expenses, I turn to a discussion of RAV.

[41] 2008 Decision Summary, p. 2.

a. OPEX

According to the 2008 Decision Summary, the PUC increased the Target OPEX higher than the previous target value. The PUC set the 2008 OPEX value to $19,922,000. There were no objections from BEL. Therefore, I recommend adoption of the PUC's recommended Target OPEX for the 2008 ARP.

b. RAV

RAV represents the undepreciated amount of invested capital. In this ARP, there is a dispute between the PUC and BEL as to what is the correct RAV. Specifically, the PUC reduced the proposed RAV value by subtracting out: (1) the undepreciated value of the Mollejon transmission line; (2) other contributed capital; (3) construction work in progress (CWIP); and two-thirds (2/3) of the value of assets put into service during the calendar year. The RAV calculation is not clear as to the treatment of working capital, which is commonly included in rate base. Compounding these disputes, the PUC's methodology to calculate the projected RAV values is not straightforward. By clarifying the methodology, the PUC will enable all parties to interpret its methodology more accurately.

As I understand the PUC's process, the initial 2008 RAV value was derived from the RAV value at the end of calendar year (CY) 2007 by projecting new capital additions and subtracting out forecast depreciation for CY 2008. Depreciation was estimated for CY 2009 using the same process. The PUC's RAV estimates are summarized in Table V-1.[42]

Table V-1: PUC Estimates of RAV (CY 2008 and CY 2009)
(All values in $1000s)

Year	Initial RAV	Less Mollejon Trans. Line	Less Other Contributed Capital	Less CWIP	Less 2/3 Current Assets	Final RAV
CY2008	**$352,244**	$25,278	$22,264	$26,000	$23,439	**$255,263**
CY2009	**$357,811**	$24,390	$23,764	$16,000	$19,800	**$273,857**

[42] The 2008 Decision Summary contains a mathematical with respect to its calculation of the adjusted RAV for 2005. Specifically, the value shown on page 6 under the column "2005" should be $187,285, rather than the $261,234 value shown.

(1) Treatment of CWIP

The treatment of CWIP differs across different regulatory jurisdictions. Some regulators permit the inclusion of CWIP into rate base; whilst others do not. Moreover, the treatment of CWIP has changed over time in response to different circumstances. Typically, regulators are reluctant to include CWIP in rate base, because the assets are, by definition, not used and useful whilst under construction.[43] However, in the U.S., different states have taken different approaches depending on the anticipated time before the assets would placed be in service, as well as the magnitude of AFUDC balances created as a result of construction.[44] For example, in a 1991 case, the West Virginia Public Service Commission allowed Monogahela Power to place CWIP expenditures associated with emissions control equipment required under the U.S. Clean Air Act Amendments of 1990 into rate base, while admitting that doing so was a "significant departure from normal ratemaking procedure."[45]

Many countries in Central and South America treat CWIP as Plant not in Service (and not part of RAV). Bolivia, for instance, regulates electric distribution companies, such as Electropaz, and a generator, COBEE, using a system similar to the US. CWIP is treated as a regulatory asset that is included in the asset base only when the asset is placed into service. Other Central and South American countries that calculate the VAD based on a yardstick competition model ("model company"), such as Guatemala and El Salvador, do not include CWIP in their estimation of the value of the assets at tariff reviews. Panama takes an historical cost approach to the value of the assets and does not include CWIP. Finally, Mexico has a revenue yield for natural gas pipelines and does not include CWIP in the asset base.

Owing to the lack of uniform treatment of CWIP by regulators in the US and the standard practice in the region, the PUC's exclusion of CWIP from RAV appears reasonable. Moreover, Appendix 1, Paragraph 75 of the PUC's FTRP Decision in July 2005 states that

> Capital assets under construction shall be adjusted annually to take account of interest costs, at the average cost of debt incurred by the licensee. When such assets are commissioned the value included in the RAV for the

[43] See, Goodman, *op. cit.*, Volume II, p. 805 and cases cited therein (fn. 4). Goodman also notes that in a case he was personally involved with, the Court of Appeals did conclude that, funds are not necessarily 'used and useful' only when they are currently invested in completed plants." *Goodman v. Public Serv. Comm'n.*, 497 F.2d 661 (D.C. Cir. 1974).

[44] Philips, *op. cit.*, pp. 354-355.

[45] *Re. Monogahela Power Co.*, 130 PUR4th 1, 10 (W.Va. PSC, 1991).

> purposes of this Schedule shall be their construction cost plus the accumulated interest costs.

The language of this paragraph clearly excluded CWIP from rate base. Additionally, Paragraph 53 of the First Schedule to the now repealed S.I. No. 41 treats CWIP similarly: "When [capital assets] are commissioned, the value included in the RAV for the purposes of this Schedule shall be their construction cost plus the accumulated interest costs…" Given this evidence, the PUC's exclusion of $26 million in CWIP in the 2008 ARP is not unreasonable.

(2) Exclusion of Contributed Capital

The PUC has excluded just under $22.3 million in contributed capital from the RAV estimate. It is my understanding that this figure refers to capital investments that are funded by the Government that are used to improve electric service. As such, I believe it is reasonable to exclude those investments from RAV for purposes of determining BEL's return on investment (TOR). As stated by Goodman,

> [d]onated and other cost-free capital is generally excluded from the computation of the fair rate of return. It may be deducted from rate base, consistent with the terms of the donation.[46]

This is consistent with existing treatment by many regulators. For example, Section 3.4.1.2 of the Ontario Energy Board Rate Handbook specifically states that contributed capital shall not be included in rate base.[47] This is also the standard practice in Central and South America.[48] Of course, depreciation expenses associated with these capital assets should be included as part of the VAD.[49]

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[46] Goodman, *op. cit.*, p. 609. See also, R. Hahne and G. Aliff, *op. cit.*, p. 4.04[7].

[47] Ontario Energy Board, *Electricity Distribution Rate Handbook*, pp 3-5 – 3-6, 9 November 2000. Prior to the year 2000, the OEB did allow contributed capital into rate base.

[48] See, e.g., Resolution CNEE-05-2008 of 17 January 2008, Article 4.4.10 (Guatemala).

[49] The Guatemalan Resolution includes a formula, although incorrect and currently disputed in arbitration, to recognize depreciation on capital contributions. Hahne and Aliff, *op. cit.,* p. 4.04[8], also state that depreciation costs associated with contributed capital should be included.

(3) Treatment of the Mollejon Transmission Line Investment

Based on my discussions with PUC and BEL, there is significant disagreement as to whether the cost of the Mollejon Transmission line belongs in RAV. These disagreements appear to stem from how the transmission line asset was transferred to BEL from BECOL, and how the initial power purchase agreement between BECOL and BEL was modified.

On 19 April 1991, BEL, which was then a government-owned entity known as the Belize Electric Board (BEB),[50] and the Government of Belize signed an agreement (known as the Purchase Power Agreement) with Dominion Energy, Inc. and International Energy Equities, Inc. ("Dominion") to develop a 20 MW run-of-river hydroelectric facility on the Macal river at its confluence with Mollejon Creek, in Cayo District, Belize. Additionally, Dominion agreed to build a 139 kilometer 115kv transmission line from the project to the switchyard in Ladyville. The cost of the transmission line was estimated to be about US$16 million. To recover the costs of the entire project, BEB agreed to a take-or-pay agreement whereby it agreed to purchase a minimum of 120 GWH per year. The price of this energy was set at $0.0875/kWh, escalating at 1.5% per annum.[51]

Without upstream storage, however, the Mollejon dam could not generate anywhere close to the 120 GWh envisaged under the take-or-pay agreement.[52] On 18 December 1996, only six months after the plant began commercial operation, a Second Master Agreement (SMA), amending the FMA was signed by the parties. Under the SMA, the take-or-pay agreement was modified. First, the take-or-pay quantity was reduced from 120 GWH to 85 GWh. Second, the SMA incorporated a capacity charge, the amount of which depended on actual generation at the hydro facility. Specifically, the capacity charge would be $0, if the facility generated 85 GWh or more, and $0.0875 times the difference between actual production and 85 GWh, if production fell below 85 GWh. Additionally, the $0.0875 value was to be increased each year by 1.5%.[53] On 21 November 2001, the Third Master Agreement (TMA) was signed. The TMA eliminated the capacity charge that had been added in the SMA.

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[50] On 28 December 1992, pursuant to the Electricity Act No. 13 of 1992, all rights and obligations of BEB were transferred to BEL.

[51] The First Master Agreement (FMA) was signed by the parties – and in several cases, their successors – on 30 December 1993. Section 3.2 of the FMA incorporated the energy purchase agreement of the original Purchase Power Agreement.

[52] According to data provided to me by BEL, between 1996 and 1999 generation at the hydroelectric facility averaged about 68 GWh.

[53] SMA, Section 3.1. Section 3.2 set the price of energy at $0.0875/kWh for the first 100 GWh. The price declined to $0.05/kWh for the next 20 GWh of production, and to $0.01/kWh for amounts greater than 120 GWh.

In 1999, the Mollejon transmission line was "sold" to BEL for US$1. However, the undepreciated cost of the line has remained on BECOL's books. BEL insists that, in exchange for eliminating the capacity payment, BECOL required BEL to pay back the unamortized cost of the line. There is also an Agreement, dated 21 November 2001, entitled the "Mollejon Transmission Agreement," stating that BEL will pay BECOL the unamortized portion of the transmission line cost, US$14,896,212.21, and the interest rate for such payments shall be 10%.[54]

The original transfer of the Mollejon Line to BEL for US$1 is a form of "contributed capital." As discussed previously in Section V.2(b)(2), Goodman states that cost-free capital is generally excluded from rate base for purposes of computing total returns. Similarly, HanhI note also that U.S. Financial Accounting Standards Board (FASB) Statement No. 116 sets out accounting treatment for contributed capital, stating that a capital asset account would be debited for the fair market value of the asset, and an account with a name such as "contributed capital" would be credited for the fair market value of the asset [55]

The key regulatory question, therefore, is whether eliminating the capacity charge associated with the Purchase Power Agreement in exchange for eliminating the capacity payment that was required under the SMA meant that the undepreciated value of the line should have been added to rate base. I conclude it should not be.

In substance, elimination of the capacity payment in exchange for a stream of payments on the transmission line does not represent acquisition of a capital asset, because the actual asset transaction – the sale of the line to BEL for US$1 – took place earlier. Rather, the capacity charge on the PPA was simply being paid upfront in advance in full, with BEL choosing to pay over time by taking on the wholesale supplier's liability. Therefore, it appears to me that the payments (other than the principal component) constitute interest expense to the utility, just as with any other loan.

With these facts in mind, under accepted regulatory accounting practices[56] as I understand them, I agree with the PUC's exclusion of the Mollejon line from BEL's RAV. However, in

[54] Section 2(b). A copy of the signed Agreement is attached as Appendix 3. In comments on my draft report, BEL disagreed with my finding that the Mollejon Line is a form of contributed capital. While I continue to believe my finding is correct, I recommend the parties engage the services of a certified forensic accountant to investigate the issue further.

[55] Financial Accounting Standards Board, Statement of Financial Accounting Standards No. 116, *Accounting for Contributions Received and Contributions Made*, June 1993.

[56] While I am not an accountant, regulatory accounting is an economist's field. For instance, Bates White's economists have been in the forefront developing regulatory accounting (cont.)

my review, the PUC appears to have erred by also excluding annual depreciation charges for the fair market value of the line.

(4) Adjustments to the Rate of Return

One of the most basic tenets of utility regulation is that a utility is entitled to earn a fair and compensatory rate of return on its capital investment.[57] In setting an allowed ROR for a utility, regulators need to account for the financial condition of the utility, its capital structure, its cost of debt and, most difficult of all, an appropriate allowed return on equity. These factors are, in fact, noted in the 2008 RSM.[58] As Justice Douglas of the U.S. Supreme Court stated over 60 years ago,

> From the investor of company point of view, it is important that there be enough revenue not only for operating expenses but also for capital costs of the business. … By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.[59]

Equity investors have a junior claim to a firm's assets to that of bond holders. In other words, if a firm goes bankrupt, bond holders are paid before equity holders. As such, equity holders face greater financial risk then bond holders. This means that equity holders will demand a higher expected return on their investment than bond holders. Based on data I received from BEL, the company's average cost of debt is approximately 10%. Moreover, the risk-free rate for debt issued by the Government of Belize is estimated by the International Monetary Fund to have a market interest rate of over 9%.[60] Given that the risk-free rate for bonds issued by the Government of Belize have a market interest rate of over 9%, as indicated by the IMF, setting the ROR for BEL at 8.5% does not allow BEL the opportunity to recover their financing costs, not even if the company were 100% leveraged with a loan from the Government of Belize at the risk-free rate. A ROR of 8.5% will clearly

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standards in Mexico, Peru, Puerto Rico and South Africa in the electricity, milk, natural gas and oil industries.

[57] Phillips, *op. cit.*, p. 176.

[58] 2008 RSM, pp. 28-29, pars. 79-83.

[59] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) (Douglas J.).

[60] International Monetary Fund, "Belize: Selected Issues," IMF Country Report No. 08/92, March 2008, p. 18.

not "be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital."

The PUC's action is also inconsistent with respect to the 2008 RSM, which the PUC itself issued on the same day as issuing the Initial Decision. The 2008 RSM maintained the target ROR of 12%, as well as maintained the existing lower and upper ROR bounds of 10% and 15%, respectively. As such, the PUC's decision to reduce the ROR to 8.5% obviously sets the target below the lower band of its own RSM.

The reason given by the PUC for reducing the ROR is not well substantiated. The PUC stated, "Given the current economic conditions, the PUC has decided that a ROR of 8.5% of the RAV translates to a reasonable return on investment."[61] That is incorrect from an economic point of view: the country's current economic conditions do not translate into lower interest rates or lower cost of capital. Rather, they likely translate into a higher cost of capital because of investors' perception of greater country risk.

Thus, the PUC"s reduction of the target ROR send the wrong market signals, for several reasons. First, BEL will be unable to attract capital given the rate established by the PUC. If BEL cannot attract capital, capital investment will obviously decrease, leading to reduced reliability and higher maintenance costs. Second, the PUC's actions send a bad signal to the international investment community. The perception amongst the investment community will cause lenders to increase their assessments of financial risk associated with investments in the country, which could further damage the economy.

I therefore recommend that the ROR be set to 12% for the 2008 ARP.

c. Taxes, Other Revenues, and Force Majeure Costs

The PUC estimated taxes and license fees of approximately $4.1 million. The PUC estimated "other revenues" of approximately $4.9 million. These estimates are consistent with 2007 actual data. I am not aware of any *force majeure* costs beyond those associated with hurricane cost recovery, which is treated separately as part of the HCRSA. Since I am not aware of any objections raised by BEL to the PUC's estimates of these VAD components, I recommend the PUC's Initial Decision values be incorporated into the VAD.

d. Summary: Recommended VAD Buildup

Based on the previous discussion of the VAD components, Table V-2 provides a summary of my recommended VAD estimate for CY 2008 and CY 2009.

[61] 2008 Decision Summary, p. 6.

Table V-2: Recommended VAD Buildup – CY2008
(1000$)

	PUC Initial Decision	PUC Initial Decision	Rec. Values	Rec. Values
VAD Component	**CY 2008**	**CY 2009**	**CY 2008**	**CY 2009**
OPEX	$19,922	$20,519	$19,.922	$20,519
Depreciation	$12,048	$12,714	$12,936	$13,602
Return Components				
RAV	*$255,263*	*$273,857*	*$255,263*	*$273,857*
ROR	*8.5%*	*8.5%*	*12.0%*	*12.0%*
TOR	$21,697	$23,278	$30,632	$32,863
Taxes & License Fees	$4,119	$4,417	$4,119	$4,417
Subtotal	**$57,786**	**$60,927**	**$67,608**	**$71,400**
Less Other Revenues	$4,940	$5,039	$4,940	$5,039
Net VAD Costs	**$54,432**	**$55,888**	**$62,668**	**$66,361**
Projected Sales (kWh)	403,067,961	436,759,945	403,067,961	436,759,945
VAD Rate ($/kWh)	**$0.130**	**$0.128**	**$0.156**	**$0.152**

3. CPRSA and HCRSA Values

I next turn to the PUC's treatment of the CPRSA and HCRSA account values. BEL objects to the PUC's adjustments to the CPRSA account. The PUC reduced the CPRSA in four ways: (1) disallowing 80% of BEL's actual COP for the months of January and February 2008, claiming that BEL did not dispatch sufficient hydro resources and drawing down the Chalillo Reservoir too little; (2) correcting for differences between projected and actual depreciation for the years 2005 through 2007; (3) correcting for actual v. projected TOR; and (4) eliminating all previous balances in the HRCSA account, based on BEL's requirement to self-insure against hurricane damages. Together, the PUC's reductions in the CPRSA

reduced that account by almost $28 million, from a balance of $18,959 at the end of CY 2007 to -$8,982., as shown in Table V-3. Using this negative starting value for the CPRSA the forecast COP over the ARP 2008 period, and the requirement that the CPRSA account be zeroed out prior to the start of the next FTRP in July 2009, the PUC recommended a CPRSA value of $0.004/kWh.

Table V-3: PUC CPRSA Deductions
($1000s)

Beginning Balance, January 1, 2008	**$18,959**
COP Disallowance	($4,879)
Depreciation Adjustment	($6,932)
Return Adjustment	($17,177)
HCRSA Disallowance	($4,844)
Revised CPRSA Balance	**($14,873)**

a. Disallowance of Actual COP

In the 2008 Decision Summary, the PUC stated that "BEL diverted considerably from its planned energy dispatch profile for the 1st Quarter of 2008.[62] BEL objected, stating that the PUC provided no evidence whatsoever of this.

To investigate this issue, I first discussed it with BEL. Specifically, I examined the "rule curve" used by BEL to draw down the Chalillo Reservoir. In essence, a rule curve provides a periodic (in this case annual) guideline for drawing down a reservoir so that the reservoir will be available for generation during times when electricity is most expensive and to ensure that the reservoir will refill. Such rule curves are common for most hydroelectric systems.[63]

The data provided by BEL indicate it was drawing the reservoir level down for the months of January and February 2008 coincident with the rule curve. I also shared these data with the PUC, specifically inquiring whether the indicated draw downs of the reservoir were unreasonable and, if so, to explain how the drawdowns were unreasonable from the perspective of the reservoir's rule curve. The PUC indicated to me that the draw downs were reasonable and that BEL clearly followed the rule curve. Since there is agreement that

[62] Ibid.

[63] See, e.g., J. Little, "The Use of Storage Water in a Hydroelectric System," *Journal of the Operations Research Society of America* 3 (May, 1955), pp. 187-197.

BEL did, in fact, dispatch the reservoir appropriately, there is no reasonable explanation for disallowing 80% of BEL's actual costs. I am not aware, at this time, of other evidence that justifies such disallowance. Therefore, if the PUC wishes to disallow BEL's costs in this manner, it needs to provide evidence to justify that decision, specifically evidence with regard to the "considerable" diversion from BEL's planned energy dispatch profile. Since no such evidence was presented to me, I recommend that the PUC's disallowances be excluded from the CPRSA reduction.

b. Reduction in Depreciation Expenses

Under the 2008 RSM, the PUC can apply the differences between projected and allowed depreciation to any cost component in the next ATP or FTP.[64] This is a change from the previous RSM, under which these differences would be accumulated and applied to the first ATP of the next FTP.[65] BEL notes that, in adopting the 2008 RSM approach, the company's financial statements for previous years are no longer correct.

The PUC's adoption of the 2008 RSM one month after BEL had already filed its Tariff Application, and implementation of rules that retroactively adjust depreciation expenses for the last three years that reduce the CPRSA as a result, do not comport to *Good Utility Practice*. The new regulations allowing the PUC to apply to depreciation adjustment to any account it so chooses in the next ATP increases regulatory uncertainty and may adversely affect BEL's financial stability.

The magnitude of the corrections is also troubling and I do not understand why BEL did not inform the PUC previously of the large and increasing disparity between forecast and actual depreciation expenses. Moreover, delaying the adjustments until the 2009 FTP would exacerbate the adjustments necessary at that time. Although I am tempted to recommend that the PUC <u>not</u> apply the retroactive depreciation adjustments to the CPRSA, delaying those adjustments will create an even larger problem. A potential solution would be to develop a mechanism to recover the cost differences over a longer time period, but this would violate the 2008 RSM (and the 2005 RSM). This is one more indication to me that an entirely new rate methodology is needed.

c. Reduction in Returns

As with depreciation expenses, the PUC has applied corrections for BEL's TOR to the CPRSA account, as allowed under the 2008 RSM. The reduction reflects the lower allowed RAV for BEL. And, as with the depreciation expense adjustment, I do not believe that the retroactive adjustments comport to *Good Utility Practice*. The magnitude of the corrections is

[64] 2008 RSM, p. 26, par. 74.

[65] 2005 RSM, par. 83.

also troubling and I do not understand why BEL did not inform the PUC previously of the large and increasing disparity between forecast and actual allowed returns. Moreover, delaying the adjustments until the 2009 FTP would exacerbate the adjustments necessary at that time. Although I am tempted to recommend that the PUC not apply the retroactive depreciation adjustments to the CPRSA, delaying those adjustments will create an even larger problem. A potential solution would be to develop a mechanism to recover the cost differences over a longer time period, but this would violate the 2008 RSM (and the 2005 RSM). This is one more indication to me that an entirely new rate methodology is needed.

d. HCRSA Disallowance

I understand that the HCRSA account was established to spread out the costs associated with Hurricane damages, thus avoiding the need for large rate increases to compensate BEL for recovery costs. In its Final Decisions for the 2002 ARP, PUC approved an HCRSA value of $5,814,601. On 16 October 2002, the PUC Chairman sent a letter to BEL requesting that BEL document the damages costs, financing costs, and insurance proceeds. On 24 October 2002, BEL responded with documentation. Over time, the HCRSA balance was reduced. According to the PUC's Final Decision in the 2007 ARP, the HCRSA balance as of 31 December 2006 was $282,737. Owing to the small remaining balance, the PUC ordered that that balance be transferred to the CPRSA.

My conversations with the PUC indicate that they accept the costs that made up the HCRSA. However, it the 2008 Decision Summary, the PUC now disallows all previous HCRSA charges to consumers owing to a requirement BEL establish a self-insurance scheme, including a $5 million insurance reserve. BEL, in fact has established such a reserve. In its 2007 Annual Report, BEL's Balance Sheet shows a $5 million reserve,[66] which would otherwise be recorded as additional retained earnings. The PUC appears to believe that the self-insurance scheme meant setting aside cash for self-insurance and that, because BEL did not do so, BEL's previous HCRSA collections are now unjustifiable. I must disagree.

BEL established a self-insurance approach because the costs of hurricane insurance had become prohibitively expensive or because the insurance companies do not provide coverage. This is typical in many Central American and Caribbean countries, as well as electric utilities in Florida and along the Gulf Coast of the United States. Thus, BEL's ratepayers benefited through not having to pay those insurance premiums. The insurance reserve was established and is shown on the balance sheet under stockholders equity, as is typical of best regulatory practices. For example, a report prepared by the Edison Electric

[66] BEL 2007 Annual Report, p. 23.

Institute stated that numerous state utility commissions in the U.S. allow regulated electric utilities to establish such reserve accounts.

> A storm reserve is an accounting technique that allows utilities to smooth out the earnings impact of major storms. With the exception of FPL [Florida Power & Light], storm reserves are not funded with cash and therefore do not minimize the cash-flow impact of having to pay the costs of a major storm. When a utility establishes a storm reserve, it credits a fixed amount each year to the reserve through monthly accruals. These monthly accruals are deducted from the current month's earnings even though no actual storm costs are incurred. When a major storm strikes, the storm costs are charged against the balance in the storm reserve account. The reserve, however, provides no cash to pay the actual storm costs. The big benefit of this type of accounting treatment is that it allows utilities to smooth out the earnings impact of major storms. When a big storm strikes, the only charge to earnings the utility incurs is its normal monthly accrual to its storm reserve account, assuming that it has a balance in its storm reserve account.[67]

BEL's stated treatment of its hurricane cost self-insurance programs is consistent with that of other utilities. However, BEL's discussion of the self-insurance scheme in its Annual Reports have changed over time, which I find troubling. The Annual Reports (ARs) for the years 1999 through 2003 refer to "funds set aside in a fixed deposit account to cover the appropriate retained earnings." The 1999 and 2000 ARs refer to specific dollar amounts set aside set aside in fixed deposits against appropriated retained earnings. The other Annual Reports refer only to the appropriation of retained earnings for the insurance reserve. The language in the 1999 through 2003 ARs could be interpreted to mean that cash was, in fact, deposited into a special account. As I am not a forensic accountant, I cannot determine the precise nature of the language in the ARs. Therefore, while I do not recommend accepting the PUC's disallowance of previously incurred hurricane recovery costs, I believe further investigation is warranted.

e. Recommended CPRSA Balance and Recovery Rate

Table V-4 summarizes by recommendations for the adjustments to the CPRSA balance. Again, I am recommending that there be no disallowance of power costs incurred by BEL for the months of January and February 2008. I also recommend that all of the HCRSA balances not be eliminated. Finally, whilst I believe the subtractions made by the PUC for

[67] B. Johnson, "After the Disaster: Utility Restoration Cost Recovery," Report prepared for the Edison Electric Institute, February 2005. Available at: http://www.eei.org/industry_issues/reliability/nonav_reliability/Utility_Restoration_Cost_Recovery.pdf.

depreciation and return adjustments are inconsistent with *Good Utility Practice*, I have included those adjustments in my recommended CPRSA balances and recovery rates.

Table V-4: Recommended CPRSA Deductions ($1000s)

	PUC Initial Decision	Recommended Values
Beginning Balance, January 1, 2008	**$18,959**	**$18,959**
COP Disallowance	($4,879)	$0
Depreciation Adjustment	($6,932)	($6,932)
Return Adjustment	($17,177)	($17,177)
HCRSA Disallowance	($4,844)	$0
Revised CPRSA Balance	**($14,873)**	**($5,150)**

Using the ($5,150,000) value as the beginning balance for the CPRSA, I then calculated the necessary CPRSA recovery rate that would be expected to zero out the CPRSA balance by the end of June 2009, as required by the 2008 RSM.[68] To do that, I relied on a spreadsheet model provided to me by the PUC. I used the PUC's forecast of power sales and the COP, together with the recommended COP charge of $0.004/kWh. Next, I used the Microsoft Excel™ "Solver" function to calculate the value of the CPRSA recovery that would zero out the projected CPRSA balance at the end of the 2008 ATP, 30 June 2009. The result was a CPRSA recovery value of $0.025/kWh. (Appendix 4 provides a table of the monthly power costs and CPRSA balances.

4. Summary and Recommended MER

In considering all of the previously discussed recommendations, I have determined my recommended MER value, as shown in Table V-5.

[68] 2008 RSM, p. 33, par. 106.

Table V-5: BEL, Initial Decision, and Recommended Parameter Values 2008 ARP *

Regulated Parameters	ARP 2007 Final Decision (BZ$/kWh)	BEL Proposed Values (BZ $/kWh)	PUC Initial Decision (BZ $/kWh)	Recommended Values ($BZ /kWh)
COP	0.253	0.287	0.307	0.298
VAD	0.168	0.168	0.131	0.154
CPRSA	0.020	0.045	0.004	0.025
MER	**0.441**	**0.500**	**0.441**	**0.477**

* -totals may not add owing to rounding.

Based on forecast sales of approximately 400.3 GWh for the 12-month period 1 July 2008 – 30 June 2009, the overall revenue requirement (or "tariff basket revenue") I calculate is $200.3 million.

5. Recommended Tariffs

In developing recommended tariffs, I considered the economic theory behind efficient tariff design. This was discussed in the report of the Independent Expert for the 2007 ARP, and so, in the interest of brevity, I will not reproduce that discussion.[69] In developing my recommended set of tariffs, which are shown in Table V-6, I have attempted to maximize economic efficiency, reduce revenue volatility, and provide greater bill stability for consumers.[70]

In determining any set of tariffs, revenues from the tariffs must be reconciled with the total revenue requirement. Based on the COP, VAD, and CPRSA value, the tariff basket revenue (TBR) for the 2008 ARP is approximately $200.3 million. Thus, the expected revenues collected from the proposed tariffs must be reconciled with that value.

a. Social Rate

The PUC may wish to consider two different options associated with setting the social rate. First, from an economic efficiency standpoint, the social rate could be set to the expected COP, $0.298/kWh, which could increase monthly bills for social rate customers by at most $2.00. Then, to the extent that this presents an undue financial hardship on some or all of these customers, the Government of Belize could provide cash subsidies to assist those

[69] Sotkiewicz Report, pp. 40-42.

[70] The reconciliation of the proposed tariffs with the TBR requirement is provided in Appendix 5.

customers with their electric bills. Alternatively, the PUC could maintain the social tariff at $0.26/kWh and distribute the additional costs onto other rate classes. Based on BEL's forecast of electric sales for the next ATP, the difference in expected revenue collection under the different social rates is just over $72 thousand. Since this is a relatively small amount, and even though the lower social tariff rate is not, in the strictest sense, an economically efficient rate, I nevertheless recommend it, as it could avoid additional costs of the Government to address an otherwise higher cost of electricity for social rate customers.

Table V-6: Initial Decision and Recommended Tariffs

Customer Class and Consumption	Initial Decision	Recommended
Social Rate Customers		
Minimum Monthly Charge	$4.00	$4.00
0 – 50 kWh	$0.26	$0.26
Residential Customers		
Monthly Service Charge	n/a	$6.00
Minimum Monthly Charge	$5.00	n/a
0 – 50 kWh	$0.35	$0.35
51 – 200 kWh	$0.44	$0.48
Above 200 kWh	$0.47	$0.505
Commercial Customers		
Monthly Service Charge	$100.00	$100.00
0 – 10,000 kWh	$0.45	$0.45
10,001 – 20,000 kWh	$0.44	$0.47
Above 20,000 kWh	$0.43	$0.505
Industrial 1 Customers		
Monthly Service Charge	$100.00	$100.00
Monthly Demand Charge per kVA	$35.00	$35.00
Off Peak Energy Rate per kWh	$0.33	$0.33
Peak Energy Rate per kWh	$0.33	$0.505
Industrial 2 Customers		
Monthly Service Charge	$100.00	$100.00
Monthly Demand Charge per kVA	$21.00	$21.00
Off Peak Energy Rate per kWh	$0.28	$0.28
Peak Energy Rate per kWh	$0.28	$0.505
Street Lights		
Energy Rate per kWh	$0.55	$0.60

b. Residential Rate

For residential customers, I recommend instituting a monthly service charge to account for the fixed costs associated with providing those customers service, as discussed last year in

the Sotkiewicz Report.[71] I also recommend increasing the energy charges in the first two consumption blocks by $0.02/kWh, and in the third consumption block by $0.03/kWh. The larger increase in the third block will send an improved economic signal to customers to consume power efficiently, given the rapidly escalating cost to provide peak power using BEL's diesel generators. This rate signal will help promote energy efficiency.

c. Commercial Rate

For commercial customers, I recommend changing the proposed decreasing block structure to an increasing block one. I recommend adopting the same rate for the first block as set by the PUC in its Initial Decision. However, rather than lowering the rates for successive blocks, I recommend increasing the rate for the second block to $0.48/kWh and for the third block to $0.52/kWh. Again, given the rapidly escalating cost to provide peak power using BEL's diesel generators, rate signals should be established to promote energy efficiency.

d. Industrial 1 & 2 Rates

As with the other customer groups, I recommend increasing the peak-hour rates to more accurately reflect the true costs of consumption and encourage energy efficiency.

e. Revenue Allocation by Customer Class

The revenue allocation by customer class is similar to that for the rates proposed by BEL, as shown in Table V-7.

Table V-7: Revenue Allocation by Customer Class

Customer Class and Consumption	BEL Proposal	Recommended
Social Rate Customers	0.90%	0.98%
Residential Customers	55.73%	55.17%
Commercial Customers	31.84%	32.22%
Industrial 1 Customers	0.29%	0.30%
Industrial 2 Customers	2.85%	3.02%
Street Lights	8.31%	8.39%
TOTALS	**100.00%**	**100.00%**

[71] Sotkiewicz Report, pp. 40-41.

6. Other Charges

Section 123(f) of the 2008 RSM requires BEL to pay interest on customer deposits. I believe this is reasonable and is typical of electric and natural gas utilities in the U.S. In its objections, BEL states that requiring it to pay interest on customer deposits, whilst not allowing the company to collect interest on overdue accounts is "patently unfair to the utility." The PUC proposes an interest rate on customer deposits "consistent with the CPRSA."[72] This language is somewhat vague, as it can be interpreted to mean an identical interest rate as is paid to BEL for CPRSA balances (currently 12%), or some other rate. Typically, however, U.S. utilities pay an interest rate on customer deposits equivalent to the rate on bank savings accounts or an equivalent risk-free rate. I recommend the PUC clarify the language of this section.

If BEL is to pay interest on customer deposits, which is typical regulatory practice, a reasonable *quid pro quo* is to allow the company to charge interest on overdue accounts. I recommend the PUC work with BEL to develop a reasonable approach to charging interest on overdue accounts.

[72] 2008 RSM, p. 47, par. 123(f).

APPENDIX 1

BATES WHITE

Jonathan A. Lesser, Ph.D.

Partner

Summary of experience

Dr. Jonathan Lesser is a Partner with Bates White, LLC, with more than 20 years of experience working for regulated utilities, government, and as an economic consultant. He has addressed critical economic and regulatory issues affecting the energy industry, including gas and electric utility structure and operations, mergers and acquisitions, cost allocation and rate design, resource investment decision strategies, cost of capital, depreciation, risk management, incentive regulation, economic impact studies, and general regulatory policy.

Dr. Lesser has designed complex models to value nuclear, fossil fuel, and renewable generating assets, as well as long-term power contracts in the presence of market, regulatory, and environmental uncertainty. He has also actively participated in negotiations for qualifying facilities under PURPA, relicensing of hydroelectric plants, and electric industry market design. Dr. Lesser has testified before utility commissions in Alaska, Arkansas, Connecticut, Illinois, Maryland, Missouri, New Jersey, Ohio, Oklahoma, Rhode Island, and Vermont; before the Federal Energy Regulatory Commission (FERC); before regulators in Mexico and Puerto Rico; in commercial litigation cases in Arizona, Vermont, and Washington; and before legislative committees in Connecticut, Maryland, Texas, Vermont, and Washington. He is most recently `the coauthor of *Fundamentals of Energy Regulation*, published in 2007 by Public Utilities Reports, Inc., numerous academic and trade press articles, and a contributing columnist and Editorial Board member for *Natural Gas & Electricity*.

Areas of expertise

- Commercial damages estimation
- Cost of capital, return on equity, and capital structure
- Cost of service, depreciation, cost allocation, and rate design
- Economic impact analysis
- Environmental strategy analysis
- Generating asset valuation
- Market power analysis
- Regulatory policy and market design
- Risk management

Selected expert testimony and reports

Dogwood Energy, LLC

- Proceeding before the Missouri Public Service Commission, *In the Matter of the Application of Aquila, Inc., d/b/a Aquila Networks - MPS and Aquila Case No. EO-2008-0046, Networks - L&P for Authority to Transfer Operational Control of Certain Transmission Assets to the Midwest Independent Transmission System Operator, Inc.*, Case No. EO-2008-0046.

  Subject: Cost-benefit analysis to determine whether Aquila should join either the Midwest Independent System Operator (MISO) or the Southwest Power Pool (SPP).

Independent Power Producers of New York

- FERC proceeding (*Re: New York Independent System Operator, Inc.*, Docket No. ER08-283-000)

  Subject: Revisions to the installed capacity (ICAP) market demand curves in the New York control area, which are designed to provide economic incentives for new generation development.

Empresa Eléctrica de Guatemala

- Rate proceeding before the Comisión Nacional de Energía Eléctrica

  Subject: Weighted average cost of capital.

Electric Power Supply Association

- FERC proceeding (*Re: Midwest Independent Transmission System Operator, Inc.*, Docket No. ER07-1182-000)

  Subject: Critique of cost-benefit analysis by MISO Independent Market Monitor concluding that permanent establishment of Broad Constrained Area mitigation was appropriate.

Constellation Energy Commodities Group, LLC

- FERC rate proceeding regarding rate application for ancillary services by Ameren Energy (*Re: Ameren Energy Marketing Company and Ameren Energy, Inc.*, Docket Nos. ER07-169-000 and ER07-170-000)

- Subject: Analysis and testimony on appropriate "opportunity cost" rates for ancillary services, including regulation service and spinning reserve service. Case settled prior to testimony being filed.

Suiza Dairy Corporation and Vaquería Tres Monjitas, Inc.

- Rate proceeding before the Office of Milk Industry Regulatory Administration of Puerto Rico.
- Subject: Analysis and testimony on the appropriate return on equity for regulated milk processors in the Commonwealth of Puerto Rico.

DPL Inc.

- Proceeding before the Ohio Board of Tax Appeals (*DPL, Inc. and its subsidiaries v. William W. Wilkins, Tax Commissioner of Ohio*, Case No. 2004-A-1437)

  Subject: Economic impacts of generation investment and qualification of electric utility investments as "manufacturing" investments for purposes of state investment tax credits.

IGI Resources, LLC and BP Canada Energy Marketing Corp.

- FERC rate proceeding regarding the rate application by Gas Transmission Northwest Corporation (*Re: Gas Transmission Northwest*, Docket No. RP06-407-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Baltimore Gas and Electric Co.

- Maryland Public Service Commission (Case No. 9099)

  Subject: Standard Offer Service pricing. Testimony focused on factors driving electric price increases since 1999, and estimates of rates under continued regulation

- Maryland Public Service Commission (Case No. 9073)

  Subject: Stranded costs of generation. Testimony focused on analysis of benefits of competitive wholesale power industry.

- Maryland Public Service Commission (Case No. 9063)

Subject: Optimal structure of Maryland's electric industry. Testimony focused on the benefits of competitive wholesale electric markets. Presented independent estimates of benefits since 1999.

Pemex-Gas y Petroquímica Básica

- Expert report in a rate proceeding. Presented analysis before the Comisión Reguladora de Energía on the appropriate return on equity.

BP Canada Marketing Corp.

- FERC rate proceeding regarding the rate application by Northern Border Pipeline Company (*Re: Northern Border Pipeline*, Docket No. RP06-072-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Transmission Agency of Northern California

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER05-1284-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket Nos. ER03-409-000, ER03-666-000)

  Subject: Analysis and development of recommendation for the appropriate return on equity, capital structure, and overall cost of capital.

State of New Jersey Board of Public Utilities

- Merger application of Public Service Enterprise Group and Exelon Corporation (*I/M/O The Joint Petition Of Public Service Electric And Gas Company And Exelon Corporation For Approval Of A Change In Control Of Public Service Electric And Gas Company And Related Authorizations, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-050*)

  Subject: Proposed merger between Exelon Corporation and PSEG Corporation. Testimony described the structure and results of a cost-benefit analysis to determine whether the proposed merger met the state's positive benefits test, and included analysis of market power, value of changes in nuclear plant operations, and merger synergies.

Sierra Pacific Power Corp.

- FERC rate proceeding regarding the rate application by Paiute Pipeline Company (*Re Paiute Pipeline Company* Docket No. RP05-163-000)

  Subject: Depreciation analysis, negative salvage, and natural gas supplies. Case settled prior to filing expert testimony.

Matanuska Electric

- Regulatory Commission of Alaska rate proceeding (*In the Matter of the Revision to Current Depreciation Rates Filed by Chugach Electric Association, Inc.*, Docket No. U-04-102)

  Subject: Analysis of the reasonableness of Chugach electric's depreciation study.

Duke Energy North America, LLC

- FERC proceeding (*Re: Devon Power, LLC*, et al., Docket No. ER03-563-030)

  Subject: Appropriate market design for locational installed generating capacity in the New England market to ensure system reliability.

Keyspan-Ravenswood, LLC

- FERC proceeding, *KeySpan-Ravenswood, LLC v. New York Independent System Operator, Inc.*, Docket No. EL05-17-000

  Subject: Estimation of damages arising from a failure by the NYISO to accurately calculate locational installed capacity requirements in New York City during the summer of 2002.

Electric Power Supply Association

- FERC proceeding (*Re: PJM Interconnection, LLC*, Docket No. EL03-236-002)

  Subject: Analysis and critique of proposed pivotal supplier tests for market power in PJM identified load pockets.

Vermont Department of Public Service

- Vermont Public Service Board Rate Proceedings
    - Concurrent proceedings: *Re: Green Mountain Power Corp.*, Dockets No. 7175 and 7176. Subject: Cost of capital and allowed return on equity under cost of

service regulation, as well as under a proposed alternative regulation proposal.

- *Re: Shoreham Telephone Company*, Docket No. 6914. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
- *Re: Vermont Electric Power Company*, Docket No. 6860. Subject: Development of a least-cost transmission system investment strategy to analyze the prudence of a major high-voltage transmission system upgrade proposed by the Vermont Electric Power Company.
- *Re: Central Vermont Public Service Company*, Docket No. 6867. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
- *Re: Green Mountain Power Corporation*, Docket No. 6866. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Pipeline shippers

- FERC rate proceeding (*Re: Northern Natural Gas Company*, Docket No. RP03-398-000)

  Subject: Gas supply analysis to determine pipeline depreciation rates as part of an overall rate proceeding.

Arkansas Oklahoma Gas Corp.

- Oklahoma Corporation Commission rate proceeding (*Re: Arkansas Oklahoma Gas Corporation*, Docket No. 03-088)

  Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

- Arkansas Public Service Commission rate proceedings
  - *In the Matter of the Application of Arkansas Oklahoma Gas Corporation for a General Change in Rates and Tariffs*, Docket No. 05-006-U. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - *In the Matter of the Application of Arkansas Oklahoma Gas Corporation for a General Change in Rates and Tariffs*, Docket No. 02-24-U. Subject: Analysis and

development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Entergy Nuclear Vermont Yankee, LLC

- Vermont Public Service Board proceeding (*Re: Petition of Entergy Nuclear Vermont Yankee for a Certificate of Public Good*, Docket No. 6812)

  Subject: Analysis of the economic benefits of nuclear plant generating capacity expansion as required for an application for a Certificate of Public Good.

Central Illinois Lighting Company

- Illinois Commerce Commission rate proceeding (*Re: Central Illinois Lighting Company*, Docket No. 02-0837)

  Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Citizens Utilities Corp.

- Vermont Public Service Board rate proceeding (*Tariff Filing of Citizens Communications Company requesting a rate increase in the amount of 40.02% to take effect December 15, 2001*, Docket No. 6596)

  Subject: Analysis of the prudence and economic used-and-usefulness of Citizens' long-term purchase of generation from Hydro Quebec, including the estimated environmental costs and benefits of the purchase.

Dynegy LNG Production, LP

- FERC proceeding (*Re: Dynegy LNG Production Terminal, LP*, Docket No. CP01-423-000). September 2001

  Subject: Analysis of market power impacts of proposed LNG facility development.

Missouri Gas Energy Corp.

- FERC proceeding (*Re: Kansas Pipeline Corporation*, Docket No. RP99-485-000)

  Subject: Gas supply analysis to determine pipeline depreciation rates as part of an overall rate proceeding.

Green Mountain Power Corp.

- Vermont Public Service Board rate proceedings
    - *In the Matter of Green Mountain Power Corporation requesting a 12.93% Rate Increase to take effect January 22, 1999*, Docket No. 6107. Subject: Analysis of the appropriate discount rate, treatment of environmental costs, and the treatment of risk and uncertainty as part of a major power-purchase agreement with Hydro-Quebec.
    - *Investigation into the Department of Public Service's Proposed Energy Efficiency Utility*, Docket No. 5980. Subject: Analysis of distributed utility planning methodologies and environmental costs.
    - *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Analysis of distributed utility planning methodologies and avoided electricity costs.
    - *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Valuation of a long-term power purchase contract with Hydro-Quebec in the context of a determination of prudence and economic used-and-usefulness.

United Illuminating Company

- Connecticut Dept. of Public Utility Control proceeding (*Application of the United Illuminating Company for Recovery of Stranded Costs*, Docket No. 99-03-04)

  Subject: Development and application of dynamic programming models to estimate nuclear plant stranded costs.

Other commercial litigation experience

- *IMO Industries v. Transamerica.* Estimated the appropriate discount rate to use in estimating damages over time associated with a failure of the insurance companies to reimburse asbestos-related damage claims and the resulting losses to the firm's value.
- *John C. Lincoln Hospital v. Maricopa County.* Performed statistical analysis to determine the value of a class of unpaid hospital claims.
- *Catamount/Brownell, LLC. v. Randy Rowland.* Prepared an expert report on the damages associated with breach of commercial lease.
- *Lyubner v. Sizzling Platters, Inc.*. Performed an econometric analysis of damage claims based on sales impacts associated with advertising.
- *Pietro v. Pietro*. Estimated pension benefits arising from a divorce case.
- *Nat'l. Association of Electric Manufacturers v. Sorrell.* Testified on the costs of labeling fluorescent lamps and the impacts of labeling laws on the demand for electricity.

Selected business consulting experience

- For Exelon Generation, Inc., prepared reports of the economic benefits of nuclear plant operations.
- For the Electric Power Supply Association, prepared numerous policy papers addressing wholesale market design and competition.
- For the California Energy Commission, developed a new policy approach to renewables feed-in tariffs and developed portfolio analysis models to develop an "efficient frontier" of generation portfolios for the state.
- For several electric utilities undergoing restructuring, developed complex economic models to value buyer offers associated with nuclear power plant divestitures.
- For a large owner and operator of nuclear generating plants, assessed the likelihood of relicensing a specific nuclear plant in New England, given state regulatory concerns over on-site spent fuel storage.
- For a major New York brokerage firm, performed a fairness opinion valuation of a gas-fired electric generating facility.

- For a large municipal electric utility in Florida, analyzed real option values of alternative proposed purchased generation contracts whose strike prices were tied to future natural gas and oil prices, and developed contract recommendations.
- For a municipal electric utility in Florida, developed an analytical model to determine risk-return tradeoffs of alternative generation portfolios, identify an efficient frontier of generation asset portfolios, and recommended asset purchase and sale strategies.
- For Central Vermont Public Service Corp. and Green Mountain Power Corp., developed analyses of distribution capacity investments accounting for uncertainty over future peak load growth.
- For a major electric utility in Latin America, developed risk management strategies for hedging natural gas supplies with minimal up-front investment; prepared training materials for utility staff; and wrote the utility's risk management Policies and Procedures Manual.
- For a large investor-owned utility in the Southeast, analyzed alternative environmental compliance strategies that directly incorporated uncertainty over future emissions costs, environmental regulations, and alternative pollution control technology effectiveness.
- For a Special Legislative Committee of the Province of New Brunswick, served as an expert advisor on the development of a deregulated electric power market.
- For the Bonneville Power Administration, developed models to assess the economic impacts of local generation resource development in Washington State and Oregon.
- For an electric utility in the Pacific Northwest, assisted in negotiations surrounding relicensing of a large hydroelectric generating facility.
- Served as an expert advisor for the Northwest Power Planning Council regarding future power supplies, load growth, and economic growth.

Education

- Ph.D., Economics, University of Washington
- M.A., Economics, University of Washington
- B.S., Mathematics and Economics (with honors), University of New Mexico

Professional activities

- Reviewer, *Journal of Regulatory Economics*
- Reviewer, *The Energy Journal*
- Reviewer, *Northwest Journal of Business and Economics*
- Reviewer, *Contemporary Economic Policy*

Professional associations

- Energy Bar Association
- International Association for Energy Economics

Publications

Peer-reviewed journal articles

- Lesser, J.A.. and X. Su. "Design of an Economically Efficient Feed-in Tariff Structure for Renewable Energy Development." *Energy Policy* 36 (March 2008) 981–990.
- Lesser, J.A. "The Economic Used-and-Useful Test: Its Origins and Implications for a Restructured Electric Industry." *Energy Law Journal* 23 (November 2002): 349–82.
- Lesser, J.A., and C. Feinstein. "Electric Utility Restructuring, Regulation of Distribution Utilities, and the Fallacy of 'Avoided Cost' Rules." *Journal of Regulatory Economics* 15 (January 1999): 93–110.
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- Lesser, J.A., and D. Dodds. "Can Utility Commissions Improve on Environmental Regulations?" *Land Economics* 70 (February 1994): 63–76.
- Lesser, J.A. "Estimating the Economic Impacts of Geothermal Resource Development." *Geothermics* 24 (Winter 1994): 52–69.

- Lesser, J.A. "Application of Stochastic Dominance Tests to Utility Resource Planning Under Uncertainty." *Energy* 15 (December 1990): 949–61.
- Lesser, J.A. "Resale of the Columbia River Treaty Downstream Power Benefits: One Road From Here to There." *Natural Resources Journal* 30 (July 1990): 609–28.
- Lesser, J.A., and J. Weber. "The 65 M.P.H. Speed Limit and the Demand for Gasoline: A Case Study for the State of Washington." *Energy Systems and Policy* 13 (July 1989): 191–203.
- Lesser, J.A. "The Economics of Preference Power." *Research in Law and Economics* 12 (1989): 131–51.

Books and contributed chapters

- Lesser, J.A., and L.R. Giacchino. *Fundamentals of Energy Regulation*, Vienna, VA: Public Utilities Reports, 2007.
- Lesser, J.A., and R. Zerbe. "A Practitioner's Guide to Benefit-Cost Analysis." In *Handbook of Public Finance*, edited by F. Thompson, 221–68. New York: Rowan and Allenheld, 1998.
- Lesser, J.A., D. Dodds, and R. Zerbe. *Environmental Economics and Policy*, Reading: MA: Addison Wesley Longman, 1997.

Trade press publications

- Lesser, J.A., "The Energy Independence and Security Act of 2007: No Subsidy Left Behind," *Natural Gas & Electricity* (February 2008): 29-31.
- Lesser, J.A. "Control of Greenhouse Gases: Difficult with Either Cap-and-Trade or Tax-and-Spend." *Natural Gas & Electricity* (December 2007): 28-31.
- Lesser, J.A. "Déjà vu All Over Again: The Grass was not Greener Under Utility Regulation." *The Electricity Journal* 20 (December 2007): 35–39.
- Lesser, J.A. "Blowin' in the Wind: Renewable Energy Mandates, Electric Rates, and Environmental Quality." *Natural Gas & Electricity* (October 2007): 26-28.
- Lesser, J.A. "No Leg to Stand On." *Natural Gas & Electricity* (August 2007): 28–31.
- Lesser, J.A. "Goldilocks Chills Out." *Natural Gas & Electricity* (July 2007): 26–28.
- Lesser, J.A. "Goldilocks and the Three Climates." *Natural Gas & Electricity* (April 2007): 22–24.

- Lesser, J.A. "Command-and-Control Still Lurks in Every Legislature." *Natural Gas & Electricity* (February 2007): 8–12.
- Lesser, J.A., and G. Israilevich. "The Capacity Market Enigma." *Public Utilities Fortnightly* 147 (December 2005): 38-42.
- Lesser, J.A. "Overblown Promises: The Hidden Costs of Symbolic Environmentalism." *Livin' Vermont* 1 (January/February 2005): 7, 27.
- Lesser, J.A. "Regulation by Litigation." *Public Utilities Fortnightly* 145 (October 2004): 24–29.
- Lesser, J.A. "ROE: The Gorilla is Still at the Door." *Public Utilities Fortnightly* 145 (July 2004): 19–23.
- Lesser, J.A., and S. Chapel. "Keys to Transmission and Distribution Reliability." *Public Utilities Fortnightly* 144 (April 2004): 58–62.
- Lesser, J.A. "DCF Utility Valuation: Still the Gold Standard?" *Public Utilities Fortnightly* 142 (February 15, 2003): 14–21.
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- Lesser, J.A. "Regulating Distribution Utilities in a Restructured World." *The Electricity Journal* 12 (January/February 1999): 40–48.
- Lesser, J.A. "Is it How Much or Who Pays? A Response to Rothkopf." *The Electricity Journal* 10 (December 1997): 17–22.
- Lesser, J.A., and M. Ainspan. "Using Markets to Value Stranded Costs." *The Electricity Journal* (October 1996): 66–74.
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- Lesser, J.A. "Long-Term Utility Planning Under Uncertainty: A New Approach." Paper presented for the Electric Power Research Institute: *Innovations in Pricing and Planning*, May 1990.
- Lesser, J.A. "Centralized vs. Decentralized Resource Acquisition: Implications for Bidding Strategies." *Public Utilities Fortnightly* (June 1990).
- Lesser, J.A. "Most Value—The Right Measure for the Wrong Market?" *The Electricity Journal* 2 (December 1989): 47–51.
- Lesser, J.A., et al. "Global Warming: Implications for Energy Policy." Washington State Energy Office, Energy Policy and Planning Research Series, July 1989.

Selected speaking engagements

- "Financial Risks Faced by Regulated Utilities: Implications for the Cost of Capital and Ratemaking Policies," Law Seminars International, Las Vegas, NV, February 7, 2008.
- "Alternative Regulatory Structures and Tariff Mechanisms: Practical approaches to providing low-cost, environmentally responsible energy and how to avoid some dangerous pitfalls." Western Energy Institute, October 1, 2007.
- "Economics and Energy Regulation." Law Seminars International, Washington, DC, March 15-16, 2007.
- "Energy in the Northeast: Resource Adequacy & Reliability." Law Seminars International, Boston, MA, October 16–17, 2006.
- "Energy in the Southwest: New Directions in Energy Markets and Regulations." Law Seminars International, Santa Fe, NM, July 14, 2006.

- "Energy and the Environment." Vermont Journal of Environmental Law, South Royalton, VT, March 10, 2006.
- "Electricity and Natural Gas Regulation: An Introduction." Law Seminars International, Washington, DC, March 17–18, 2005.

APPENDIX 2

Belize Electricity Limited
Objections/Comments to PUC ARP 08/09 Initial Tariff Decision
May 12, 2008

1. In its decision on Threshold Event Review Proceeding of March 28, 2008, the Public Utilities Commission (PUC) decided not to amend the cost of power component of the rates even though the bylaws of 2005 and the bylaws as amended in 2007 clearly required the PUC to adjust the cost of power component of the rates. The reasons given by the PUC were unrelated to the issue of rising cost of power and the refusal to comply with the law is causing the company to not meet one of the conditionality of its Scotia Bank Facilities - forecasted Cash Flow Coverage Ratio.. The ARP decision also puts the company in violation of a key financial covenant with the Caribbean Development Bank (CDB) and the International Bank for Reconstruction and Development (IBRD) relating to loans that were lent to the Government of Belize and on-lent to BEL. Under these loans, the Company cannot borrow any money without the approval of the CDB and the IBRD once in violation of the covenants. (See list of covenants and letter to CDB in attachment A)

2. The earlier TERP and the 2008 ARP were based on the Energy Information Administration (EIA), www.eia.doe.gov, forecast of approximately US$95 per barrel for West Texas Intermediate (WTI) crude in 2008. Since then, the EIA has increased its forecast for 2008 to over $110 per barrel (see graph in attachment B). As of May 9, 2008 the price of oil has surpassed US$126 per barrel and the price of firm power from CFE has increased to BZ$362 per MWh. Based on these latest forecasts, the Wholesale Cost of Power in 2008 will significantly exceed the value in BEL's submission, and will even exceed the PUC's determination. The company's cash flows are even more strained than projected and it is very likely that another threshold event will be triggered shortly after the implementation of the Final 2008 decision.

3. The bylaws as amended in 2007 were repealed on March 28, 2008, four (4) days before the submission of the Annual Rate Proceeding was due with no consultation or advance notice. There was insufficient time for the company to redo its submission in accordance with the 2005 bylaws which required that the RSA balance be zeroed by the end of the Full Tariff Period which according to the 2005 bylaws ends on June 30th, 2009.

4. The company carried out various actions and reported its financial results for 2007 on the basis of the 2007 bylaws which were in effect at the time. Repealing the bylaws does not retroactively change established financial positions and approved actions taken by the company such as the balance in the Rate Stabilization Account, the Regulated Asset Values, and the approval of various Power Purchase Agreements. These were reported on and acted upon in accordance with the prevailing law.

5. The repeal of the 2007 bylaws leaves us with no legally authorized Rate Setting Methodology as the Rate Setting Methodology (RSM) which was introduced after the company had submitted its submission for the Full Tariff Review in 2005, and to which the company objected, was not promulgated by law. BEL has challenged the legality of the 2005 methodology.

6. A new RSM has again been introduced in the 2008 ARP after the company made its rate submission. This new RSM is being applied historically to calendar year 2007 and prior years, reversing previous decisions and agreements that dictated the historical results of the company's operations and set the stage for how the utility operated in the most recent calendar year.

7. The new RSM has been introduced to justify the 2008 decision and yet again, it has been introduced without any genuine consultation with the utility as required by law (as documented in our letter dated April 21, 2008). The repeal of the December 2007 RSM that was incorporated in the December 2007 amendments to the tariff byelaws (SI No. 141 of 2007) effectively means that there is no legally authorized RSM in place. The importance of having the RSM properly promulgated by law is manifest given the repeated attempts to change the rules with retroactive effect during the review process.

8. This pattern of arbitrarily changing the methodology, retroactively changing past decisions, refusing to honor past agreements and ignoring the requirements of the bylaws makes it impossible for the utility to rely on the tariff setting regulations or the decisions of the PUC. This of itself makes it impossible for the company to finance its operations. The company's past financial results cannot be relied upon, nor can the company make any commitments with respect to any financial covenant even when operating as a well managed utility. The bylaws of 2007 which included the only legally approved RSM should be re-instated and the 2008 ARP should be in accordance with that bylaw. Modification of the 2007 bylaw and the RSM should only be undertaken after due consultation with all stakeholders and proper consideration of the effect of changes on the industry.

9. One of the key principles enshrined in the Electricity Act is that the Utility must be allowed to earn a fair return. The Central Bank's average annual interest rate on low-risk 90-day deposits in 2007 was 8.4%. This would suggest that BEL's return should be in the range of 15%. The company's return on assets net of contributed capital in 2007 was 10.3%. In a public statement, the Chairman of the PUC explained that the 2008 decision lowered the allowed return to 8.5%. This rate of return on regulated assets is not in accordance with the very RSM supposedly being followed by the PUC. The rate of return in the RSM is a target of 12% with a range of 10% to 15%. The RSM also states that the return is a regulated value which can only be changed during an FTRP. The recent decision to reduce the return is therefore contrary to the rules of the 2005 and the 2008 RSM's.

10. Benchmark studies submitted to the PUC shows that the company is one of the most efficient when compared to similar sized utilities. Excluding cost of power, the company has reduced its operating cost per customer by 17% and its operating cost per megawatt hour by 32% over the last eight years. Yet, its return is low when compared to similar sized utilities in other jurisdictions (see attachment C).

11. The original RSM introduced in 2005 set out that the utility's total return would be evaluated every four years (the FTP) with any adjustments applied to the first ATP of the subsequent FTP. This gives the utility a window in which to operate efficiently for the benefit of consumers and its investors. The recently introduced RSM now adjusts the

utility's revenues annually for variances in total return (sections 19(d) and 78) violating this principle.

12. The 2008 RSM that was developed during the tariff review and used by the PUC now gives the PUC the right to penalize the company for having exceeded targeted operating expenses (opex) in a given year by including a penalty in the next Annual Tariff Period (ATP). This is clearly an erroneous position. In the year that the opex target is exceeded the utilities profits/returns would have been reduced in that year and penalizing the company in the subsequent ATP for this same variance doubles the impact of exceeding target opex on utility profits/returns. The same occurs in the reverse. Additionally this same section 51 of the 2008 RSM states in Note 4 to the section that the utility is not to be penalized for opex performance above the target (opex variance less than zero). There is an obvious inconsistency in the 2008 RSM.

13. On page 4, section 3 of the new RSM, reference is made to the CPRSA balance being $20 million. The $0.004 RSA recovery component of the tariff cannot reduce this balance to zero by the end of the FTP as required by law (sections 15(2) and 28(2) of the byelaws). In public statements, the Chairman of the PUC stated that the RSA balance was reduced to $740,000. (See copy of news report attachment D). He also stated that the CPRSA was reduced by corrections arising from variances related to the Value Added of Delivery (VAD) component of the tariff which goes contrary to the concept of the CPRSA, i.e., a rate stabilization account established to manage cost of power only.

14. In the final decision of June 26th, 2007, the PUC had approved a CPRSA balance of $16,098,216 which is the subject of a challenge by the company. In its 2008 decision, the PUC did not produce any calculations to show how the new balance of the CPRSA was determined. (See Attachment E, Final Decision of June 26th, 2007).

15. Regarding excess cost of power deferred into the CPRSA for the current year 2008, the PUC appears to have arbitrarily disallowed 20% of January and February's deferrals (no mention is made of March's deferrals in the explanations offered). In its justification, the PUC stated that BEL "diverted considerably from its planned energy dispatch profile...". No other details or calculations are provided in support of this decision. This is an unacceptable approach to take regarding the current high cost of power. It appears that the PUC continue to take issue with the price of power from CFE. However, in December 2007 the PUC approved an increase in power from CFE from 15 MW to 20 MW under the terms of the August 2006 contract (See attachment F letter from the PUC).

16. The company carries out dispatch in the most economical manner but giving consideration to the need for maintaining a certain level of water in the Chalillo reservoir to carry through the dry season based on historical average water inflows. Rainfall in the early part of 2008 was much below average since Chalillo was commissioned. As pointed out to the PUC before, not maintaining an adequate level of water in January through March would result in running the Gas Turbine and the Diesels more often in April and May and possibly June and July, which will cost consumers much more. The company sometimes takes more expensive power from CFE to maintain a prudent reservoir level. Moreover, running down the reservoir puts the reliability of the system in jeopardy should there be an extended outage from CFE or the Gas Turbine as has happened in previous years. The PUC has been kept informed of the dispatch methodology and

reasons for deviating from the target dispatch on a regular basis and has approved all power purchase agreements for pass through (See attachment F letters from PUC approving PPAs with CFE, BAL and BECOL).

17. In its final decision of June 26th, 2007, the PUC increased the VAD from 16 cents per kWh to 16.8 cents per kWh based on the fact that sales were lower than projected in the FTRP. Sales in 2007 were also lower than that projected in the FTRP. However, the PUC has now reduced the VAD to 13 cents per kWh and did not demonstrate any calculations in its 2008 decision to support this.

18. The PUC has also stated that it has disallowed all previous Hurricane Cost Rate Stabilization Account (HCRSA) charges to customers. This arbitrarily reverses a previous decision by the PUC when it approved the establishment of the HCRSA in 2002 and the subsequent recoveries and balances in the account each year thereafter up until last year's decision. In relation to calculations supporting the PUC's initial tariff decision, it must be noted that not until after repeated requests for this support did the PUC provide a narrative explanation of their calculations on Friday May 9 at 4 p.m., fully one week after their initial decision and one working day before the deadline for objections. This response level is not conducive of a proper regulatory environment. Additionally, during the current ARP the PUC is jeopardizing the financial stability of the utility when it arbitrarily changes it past decisions on which the utility based its financial operations and reported its audited results.

19. After repeated requests, the PUC finally provided a draft and incomplete narrative explanation of their calculations on Thursday May 8th, showing that some of the calculations were incomplete. An updated report was received on Friday May 9, fully one week after their initial decision and one working day before the deadline for objections. The calculations in the final report do not support the initial decision. During the process, the PUC kept requesting information for past years that had already been provided in the ARPs for those years. These actions and lack of organization constitutes a very difficult and unreliable regulatory environment and undermines the credibility of the 2008 decision. At no time did BEL unduly delay the delivery of information to the PUC. In fact, a number of information requests from the PUC were submitted at the last moment and as noted, each year the PUC receives a significant amount of information for that year that they could have readily accessed.

20. On page 7, the fifth paragraph of the introduction to the new 2008 RSM, the PUC states that the RSM can be amended from time to time over the FTP. This does not support a stable and fair regulatory and financial environment for the utility and will only serve to discourage investments in the industry.

21. As noted previously, the PUC has changed the regulatory rules in the middle of an ARP and during an FTP. The changes result in negative financial repercussions on the utility which had been operating and reporting its financial results on a different set of rules. An example of this can be seen in section 59 where the PUC now disallows work in progress as a regulated asset value (RAV) and therefore disallows a return on this asset that the company has obtained debt financing and shareholder funds to finance. A utility cannot operate in such an environment which would then result in insufficient returns to the

utility to finance work in progress. Additionally the PUC introduces new terms and parameters such as "working RAV" and investments "commissioned and in service" in the new RSM that further limits the level of RAV that can earn a return exacerbating the utility's financial position. The PUC then applies these new rules retroactively.

22. In sections 73 and 74 of the new RSM the PUC now requires that the variance in actual depreciation expense over forecast depreciation expense be adjusted for annually in the next ATP. In the previous RSM which formed the basis of previous rate decisions, the depreciation variance was to be computed only for each 4 year FTP and adjusted for in the first ATP of the next FTP. The principle behind the latter approach was that in the industry, capital expenditures (capex) form a significant part of operations and therefore the utility would need a window in which to properly plan and execute its capex program which then drives depreciation expense. Annual adjustments for depreciation expense variance do not take into consideration external uncontrollable factors that may force a utility to amend its capex program one way or the other. Additionally, depreciation on existing assets ("D exist" as the PUC calls it) are not taken into consideration in determining the depreciation variance. Furthermore this major retroactive adjustment to the RSM renders invalid the financial results of operations of the Company for the past years in the FTP that the PUC had already reviewed and accepted.

23. In section 99, one of the VAD components is depreciation expense, "D cs" as the PUC calls it, and it appears to exclude depreciation on existing assets as referred to by the PUC as "D exist". This would make the calculation of the VAD incomplete.

24. In section 112 of the new RSM, the delta ROR is not defined anywhere else in the document. Additionally, the comment in this section in bold allows the PUC to set any component of VAD on an annual basis which in effect negates the need for an FTRP that employs a longer period for review of the actual 4 year historical operating performance of the utility in the previous FTP which should then used as a basis to forecast VAD over the next FTP. This is an unstable and unworkable regulatory and financial environment for an investor or financier and is unreasonable.

25. Section 114 needs clarification. What is meant by "Any AC that is not accomplished in any ARP,..."?

26. Section 120 notes that the utility is to further justify significant investment that are individually or in the aggregate for the year in excess of $250,000 and $1,000,000, respectively. There is no reference to a timeframe for the PUC to evaluate the investment and provide feedback to the utility. The company annually submits to the PUC for approval its capital expenditures program but has not received a response. Undue delays in investment decisions will lead to negative impacts on quality of service standards. Some of the targets that the PUC has set for the Utility require the company to make substantial capital investments. Capital expenditures are also required to improve productivity and reduce operational expenses. It is not fair for the PUC to handcuff the company in its capital program then penalize the company for not meeting targets. At any rate, requiring individual approval for these levels of capex will be bureaucratic and unworkable.

27. Section 123 (f) now requires the utility to pay interest on consumer deposits. The utility notes that interest on overdue balances from customers is not charged. This is patently unfair to the utility and to the good paying customers.

28. The PUC continues to insist that the Mollejon Transmission Line is not a regulated asset value on which the utility is to earn a return despite the PUC being a party to agreements that resulted in BEL paying for the line via a loan with Belize Electric Company Limited (BECOL). BEL reiterates its position that in the amendments to the Power Purchase Agreement between BECOL and BEL and the Transmission Facility Agreement between the Government of Belize, BECOL and BEL, BEL agreed to pay for the transmission line separately from the price it paid for power and in return, BECOL modified the PPA to exclude capacity charge in addition to other commitments (see copy of agreement attachment G). The PUC and the Government are obligated to honor their commitments and allow the company to earn a fair return on this asset to be able to meet its financial commitments.

APPENDIX 3

MOLLEJON TRANSMISSION FACILITY AGREEMENT

This Mollejon Transmission Facility Agreement is made and entered into this 21st day of November, 2001, by and among:

GOVERNMENT OF BELIZE, CENTRAL AMERICA, (including any and all successor governments, the "Government"),

- and -

BELIZE ELECTRICITY LIMITED, a corporation incorporated under the *Companies Act* (Belize) (together with its successors and assigns, the "Utility"),

- and -

BELIZE ELECTRIC COMPANY LIMITED, a corporation incorporated under the *Companies Act* (Belize)(together with its successors and assigns, the "Producer").

W I T N E S S E T H T H A T:

WHEREAS the Government, the Utility and the Producer are party to a Franchise Agreement dated April 19, 1991 (as amended and/or assigned prior to the date hereof, the "Franchise Agreement") and to a Guaranty Agreement dated April 19, 1991 (as amended, acknowledged and/or assigned on or prior to the date hereof, the "Guaranty Agreement") and the Utility and the Producer are parties to a Power Purchase Agreement dated April 19, 1991 (as amended and/or assigned prior to the date hereof, the "Power Purchase Agreement");

AND WHEREAS the Producer has agreed to eliminate the requirement that the Utility pay the capacity charge that the Power Purchase Agreement currently requires the Utility to pay from April 1, 2001;

AND WHEREAS it is proposed that the Power Purchase Agreement and the Franchise Agreement be amended and restated on the date hereof;

AND WHEREAS the Government and the people of Belize will benefit from such amendment and restatement;

AND WHEREAS in consideration of the Producer agreeing to enter into such amended and restated Power Purchase Agreement which eliminates the capacity charge that had been payable to it under the Power Purchase Agreement, the Utility has agreed to pay to the Producer the amount of US14,896,212.21, such amount being equal to the unamortized cost of the Mollejon Transmission Facilities as at April 1, 2001 in accordance with the terms hereof;

NOW, THEREFORE, for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the parties agree as follow:

1. **Definitions.** Capitalized terms used but not defined herein shall have the respective meanings given to such terms in the Amended and Restated Power Purchase Agreement dated as of the date hereof between the Producer and the Utility.

2. **Agreement to Pay.**

(a) The Utility hereby promises to pay to or to the order of the Producer the principal amount of 14,896,212.21 (the "Principal Amount") in the lawful money of the United States of America, together with interest accrued thereon as hereinafter provided.

(b) The unpaid portion of the Principal Amount and all unpaid and outstanding interest thereon shall bear interest from and after April 1, 2001 until paid, both before and after demand and judgment, at the rate of 10% per annum, calculated monthly in arrears on the last day of each month, commencing as of the last day of April, 2001.

(c) Payments of the Principal Amount and interest payable hereunder shall be made by the Utility in accordance with the payment schedule attached as Schedule A hereto and on the day specified in such schedule unless such day is not a Business Day, in which case the relevant payment shall be made on the next succeeding Business Day.

(d) If the Utility fails to pay any amount payable to the Producer hereunder on the date specified herein for payment and such failure continues for a period of 5 days after written notice, the entire principal amount may, by written notice, be declared immediately due and payable in full, together with interest thereon as provided above.

(e) Payments hereunder must be made at Belize Bank Limited, Belize City Main Branch, account no. 21120017.

(f) The Utility waives presentment for payment, notice of non-payment, protest and notice and diligence in collection or bringing suit.

(g) The term "Business Day" shall mean any day, other than a Saturday or Sunday, on which banks in Belize City, Belize are open for business.

3. **Confirmation of Guaranty.** The Government acknowledges and agrees (i) that the obligations of the Utility hereunder shall form part of the obligations of the Utility guaranteed by the Government under the Guaranty Agreement, (ii) the Guaranty Agreement shall be interpreted, read and construed so as to guarantee the obligations of the Utility hereunder and (iii) that the Guaranty Agreement remains in full force and effect.

4. **Taxes and Duties.** The Government acknowledges and agrees that for the purposes of the *Mollejon Hydroelectric Project (Exemption from Taxes and Duties) Act*, Chapter 59 of the Substantive Laws of Belize, 2000 all payments made to the Producer hereunder are directly related to the Project (as that term is defined in such Act).

5. **U.S. Currency.** All payments hereunder shall be made in United States dollars in same day funds.

6. **Bank Accounts.** The Government represents and warrants to the Producer and the Utility that each of them may establish, maintain and utilize a bank account in United States dollars, or other foreign currency, with a bank in Belize for the purposes of the transactions contemplated hereby. Further, the Government represents and warrants that it has the authority and power, and covenants and agrees that it will exercise such authority and power, to permit the maintenance by each of the Producer and the Utility of bank accounts in United States dollars or other foreign currency with a bank in Belize (including, without limitation, to permit the deposit and withdrawal of all United States dollars received under this Agreement into such accounts) as is necessary or useful in implementing the transactions contemplated hereby.

7. **Foreign Exchange.** The Government shall expedite, permit, guarantee and insure the free transfer of all funds and financial settlements necessary or useful for the transactions contemplated hereby. The Government represents and warrants that there is no limit upon expatriation, repatriation or free exchange of funds from Belize by the Producer or upon the free exchange by the Utility from Belizean dollars of amounts due hereunder into United States dollars, and that the Government shall not impose, and shall not permit any governmental agency or instrumentality to impose, any such limitation for the term of this Agreement.

8. **Notices.** All notices or other communications (together "Notices") to be given or made hereunder shall be in writing and shall be given in accordance with Section 21.1 of the Franchise Agreement.

9. **Variations in Writing.** All additions, amendments and variations to this Agreement shall be binding only if in writing and signed by duly authorized representatives of the parties.

10. **Governing Law**. This Agreement shall be governed by the laws of Belize.

11. **Successors and Assigns.**

(a) This Agreement shall inure to the benefit of, and be binding upon, the successors and permitted assigns of the parties.

(b) Except as provided in Section 11(c) below, this Agreement shall not be assigned in whole or in part by any party hereto without the prior written consent of the other parties, which shall not be unreasonably withheld or delayed.

(c) The Producer may, without the prior written consent of the Government or the Utility:

(i) assign, mortgage or pledge this Agreement in favour of any person or entity providing financing for the Mollejon Project, the New Project or any Additional Macal Project and any such person or entity may assign this Agreement to any subsequent assignee upon and after the exercise of its rights and enforcement of its remedies under the security agreement creating an interest in its favour at law or in equity;

(ii) assign all or any of its rights hereunder to one or more of its Affiliates.

The Government and the Utility shall each execute all such acknowledgements of any assignment pursuant to, or security created in accordance with, this Section 11(c) as are reasonably requested by the Producer to give effect to the foregoing.

IN WITNESS whereof the parties have entered into this Agreement as of the date first above written.

SIGNED AND DELIVERED)
in the presence of:)
)
)
)

Witness: The Honourable Ralph Fonseca
Minister of Budget Management
Investment and Public Utilities

GOVERNMENT OF BELIZE, CENTRAL AMERICA

By _____
The Honourable Said Musa
Prime Minister, Minister of Finance and
Foreign Affairs

SIGNED AND DELIVERED)
in the presence of:)
)
)

Witness:

BELIZE ELECTRICITY LIMITED

By _____
Lynn Young
President and Chief Executive Officer

SIGNED AND DELIVERED)
in the presence of:)
)
)

Witness:

BELIZE ELECTRIC COMPANY LIMITED

By _____
Stanley Marshall
President

APPENDIX 4

CPRSA Balances
July 2009 - June 2009

		Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08
Total Generation	kWh	41,854,680	42,667,052	40,511,203	40,786,169	35,717,231	34,874,016
Cost of Wholesale Power	Bz$	11,455,973	10,820,279	9,492,563	7,862,061	7,646,539	7,652,813
Total Sales (E_{PS})	kWh	35,131,209	35,285,143	35,892,039	34,161,634	33,063,712	31,798,521
$/per kWh (generated & purchased)	Bz$/kWh	0.274	0.254	0.234	0.193	0.214	0.219
Reference price per Kwh	Bz$/kWh	0.298	0.298	0.298	0.298	0.298	0.298
Additions to CPRSA							
Reference COP (Revenue collected)	Bz$	10,472,521	10,518,408	10,699,322	10,183,493	9,856,205	9,479,055
Net Cost of Wholesale Power	Bz$	11,455,973	10,820,279	9,492,563	7,862,061	7,646,539	7,652,813
Deferred CWP	Bz$	983,451	301,871	(1,206,759)	(2,321,432)	(2,209,667)	(1,826,242)
Recoveries							
ΔCPRSA per kWh	Bz$/kWh	0.025	0.025	0.025	0.025	0.025	0.025
CPRSA Recoveries	Bz$	869,002	872,809	887,822	845,018	817,860	786,565
Balance of CPRSA							
brought forward	Bz$	10,012,895	10,228,046	9,756,533	7,749,045	4,644,253	1,648,030
balance before carrying charge	Bz$	10,127,345	9,657,108	7,661,953	4,582,594	1,616,725	(964,776)
carrying charge	12%	100,701	99,426	87,092	61,658	31,305	3,416
BALANCE OF CPRSA	Bz$	**10,228,046**	**9,756,533**	**7,749,045**	**4,644,253**	**1,648,030**	**(961,360)**

CPRSA Balances
July 2009 - June 2009

		Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09
Total Generation	kWh	38,766,172	36,133,099	42,580,579	42,333,374	45,487,560	43,577,753
Cost of Wholesale Power	Bz$	9,584,746	10,216,122	12,319,916	12,464,380	13,156,341	12,628,537
Total Sales (E_{PS})	kWh	34,123,578	31,942,609	32,983,347	37,908,054	38,408,331	39,635,188
$/per kWh (generated & purchased)	Bz$/kWh	0.247	0.283	0.289	0.294	0.289	0.290
Reference price per Kwh	Bz$/kWh	0.298	0.298	0.298	0.298	0.298	0.298
Additions to CPRSA							0.298097368
Reference COP (Revenue collected)	Bz$	10,172,149	9,522,008	9,832,249	11,300,291	11,449,422	11,815,145
Net Cost of Wholesale Power	Bz$	9,584,746	10,216,122	12,319,916	12,464,380	13,156,341	12,628,537
Deferred CWP	Bz$	(587,403)	694,114	2,487,667	1,164,089	1,706,919	813,392
Recoveries							
ΔCPRSA per kWh	Bz$/kWh	0.025	0.025	0.025	0.025	0.025	0.025
CPRSA Recoveries	Bz$	844,077	790,129	815,873	937,690	950,064	980,412
Balance of CPRSA							
brought forward	Bz$	**(961,360)**	**(2,392,840)**	**(2,488,855)**	**(817,061)**	**(590,661)**	**166,193**
balance before carrying charge	Bz$	(2,392,840)	(2,488,855)	(817,061)	(590,661)	166,193	(827)
carrying charge	12%	0	0	0	0	0	827
BALANCE OF CPRSA	Bz$	**(2,392,840)**	**(2,488,855)**	**(817,061)**	**(590,661)**	**166,193**	**(0)**

APPENDIX 5

Proposed Tarrifs for ATP 08/08

				MER	**$ 0.477**	**$ 200,289,422** **TBR**
				Tariff Totals	**$ 0.476**	**$ 200,275,549** **TB**
Category	*Demand (annual)*	*Customers*	*ATP08/09 (kWh)*	*Rate*	*Forecast Revenue*	*ARP 2007 values*
Social						
Minimum Charge				$4.00		$ 4.00
0-50 kWh		7,397	6,957,150	$0.260	$ 1,808,859	$ 0.26
Residential						
Minimum Charge				$6.00		
Service Charge		67,473		$0.000	$ -	$ 10.00
0-50 kWh			37,967,461	$0.350	$ 13,288,611	$ 0.35
51-200 kWh			77,512,647	$0.480	$ 37,206,070	$ 0.44
> 200 kWh			118,790,485	$0.505	$ 59,989,195	$ 0.47
			234,270,593	$0.472	$ 110,483,877	
Commercial						
Service Charge (per month)		726		$100.00	$ 871,122	$ 100.00
0-10,000 kWh			48,925,950	$0.450	$ 22,016,678	$ 0.45
10,001-20,000 kWh			17,994,182	$0.470	$ 8,457,266	$ 0.44
> 20,000 kWh			65,723,574	$0.505	$ 33,190,405	$ 0.43
			132,643,707	$0.487	$ 64,535,470	
Industrial 1						
Service Charge (per month)		1		$100.00	$ 1,200	$ 100.00
Demand Charge per KVA per mth	3,066			$35.00	$ 107,296	$ 35.00
Off Peak Energy, kWh			1,317,043	$0.330	$ 434,624	$ 0.33
Peak Energy, kWh (6-9pm, Mon-Fri)			126,442	$0.505	$ 63,853	$ 0.33
			1,443,485	$0.420	$ 606,973	
Industrial 2						
Service Charge (per month)		3		$100.00	$ 3,600	$ 100.00
Demand Charge per KVA per mth	49,234			$21.00	$ 1,033,916	$ 21.00
Off Peak Energy, kWh			15,958,948	$0.280	$ 4,468,505	$ 0.28
Peak Energy, kWh (6-9pm, Mon-Fri)			1,066,738	$0.505	$ 538,703	$ 0.28
			17,025,686	$0.355	$ 6,044,724	
Street Lights		1	27,992,744	$0.600	$ 16,795,646	$ 0.55
Totals		75,601	420,333,365	$0.476	$ 200,275,549	
					$ 13,874	