KPMG
cutting through complexity

New Policy Options for the Funding of Capital Investments: EB-2014-0219

June 26, 2015

prepared for Ontario Energy Board

Contents

KPMG

1 Introduction

The Ontario Energy Board (the "Board" or "OEB") has retained KPMG LLP ("KPMG") to provide regulatory advisory services in connection with the Board's June 20, 2014 consultation on New Policy Options for the Funding of Capital Investments EB-2014-0219. KPMG is to review the details of the half year rule, the make-up of the Incremental Capital Module ("ICM") Materiality Threshold Formula ("Materiality Threshold Formula") and how working capital is funded through distribution rates in other jurisdictions.

Specifically, KPMG has been engaged to conduct jurisdictional reviews:

- To determine whether rules or approaches, similar to the "half-year rule" for the determination of the return of and on capital in the first calendar year when capital assets enter service, are in use. If not, set out the approach used, including the logic supporting the approach and the mechanical operation of the approach. If so, set out the logic supporting the use of such an approach and mechanical operation of the approach. Analyze the extent to which the rule or approach is compensatory with respect to recovery of capital costs in rates (in cost of service and incentive rate ("IR")-based rate adjustment mechanisms) and discuss the consequences of the rule or approach on process/regulatory efficiency.

- To identify incentive ratemaking approaches, with a focus on:

  - Identifying the mechanisms used to fund new capital investments over the IR period; and

  - Explaining how rates are adjusted to reflect new capital expenditures over the IR period, if applicable.

- To determine how working capital is treated for the purpose of setting rates.

KPMG has also been asked to review the interaction and effect of key variables in the Materiality Threshold Formula, with a focus on:

- Setting out the theoretical and practical driver for the use of the growth factor and dead band variable in the calculation of the Materiality Threshold Formula;

- Determining whether there is a more accurate method of estimating or calculating the growth factor in the Materiality Threshold Formula; and

- Determining whether the transition to International Financial Reporting Standard ("IFRS") and use of Total Factor Productivity ("TFP") to inform the IR rate adjustment mechanism affect the appropriate dead band variable to be used.

1.1 Jurisdictional Reviews

KPMG has considered the regulatory practice relating to the half-year rule, working capital and incentive ratemaking regimes in the following jurisdictions:

Canada:	Ontario electricity distribution, Ontario electricity transmission, Ontario natural gas distribution (Enbridge Gas Distribution Inc. and Union Gas Limited), Alberta, Nova Scotia (Nova Scotia Power Inc.), British Columbia (FortisBC Inc.), Newfoundland (Newfoundland Power Inc.), and Québec (Gaz Métro L.P.).
United States:	Alabama, California, Georgia, Louisiana, Maryland, Massachusetts, Mississippi, New York, and Pennsylvania.
United Kingdom:	Ofgem (RIIO for Electricity Transmission).

The full review for the target entities in each named jurisdiction are set out in the attached Appendices: Appendix 1: Canada; Appendix 2: United States; and Appendix: 3 United Kingdom.

1.2 Draft Report

KPMG has also been asked to prepare this Draft Report, which reflects our work as set out above. The Draft Report will also include options and recommendations with respect to changes that may be required to:

- The half year rule during the IR period;
- Use of the growth factor and dead band variable used in the Materiality Threshold Formula of the ICM; and
- Treatment of working capital allowance under cost of service and/or alternative forms of ratemaking.

This Draft Report is designed to satisfy the requirements of the engagement.

2 Half Year Rule

In Ontario, the "half year rule" generally refers to the following:

> The Board's general policy for electricity distribution rate setting has been that capital additions would normally attract six months of depreciation expense when they enter service in the test year.[1]

The half year rule is a rule of thumb (or proxy) designed to emulate how capital additions are closed to rate base in the test year. It is a ratemaking tool, the purpose of which is to recognize that planned capital additions in a test year do not all enter service at the beginning of the test year. The approach is also illustrative of a ratemaking approach that balances utility and customer interests.

The Board allows the use of alternative approaches or variances from the half year rule, such as calculating depreciation based on the month that an asset enters service. However, the approach must be documented with an explanation of the methodology used.

The process to determine the depreciation expense associated with capital expenditures ("CapEx") closing to rate base in the test year varies from jurisdiction to jurisdiction. The various approaches used in these jurisdictions:

- Recognize that distribution capital additions are closed to rate base throughout the test year and generally reflect the balance between allowing the recovery of approved costs and increasing the likelihood that depreciation expenses recovered in rates relate only to assets that are in-service; and

- Balance the precision of the calculation against the regulatory goal of process efficiency.

Table 1 summarizes the approaches used in the jurisdictions examined and the detailed explanation is contained in the Appendices.

Table 1. Treatment of Depreciation Attributable to CapEx Closed to Rate Base in Test Year

Jurisdiction	Half Year Rule *Cost of Service*	Half Year Rule *Incentive Regulation*
Ontario Electricity Distribution	Half year rule applies to capital additions closed to rate base in the test year. Variations from this approach are permitted and include calculating depreciation based on the month that an asset enters service.	Half year rule reflected in base COS rates and persists throughout the IR plan term. It does not apply in the determination of the ICM revenue requirement in years 2, 3, and 4. However, the half-year rule is used in IR ICM applications when the ICM request coincides with the final year of IR plan term.

[1] Ontario Energy Board. (July 18, 2014). Filing Requirements for Electricity Distribution Rate Applications – 2014 Edition for 2015 Rates Applications – Chapter 2: Cost of Service. Pages 38-39.

Jurisdiction	Half Year Rule *Cost of Service*	Half Year Rule *Incentive Regulation*
Ontario Electricity Transmission	Half year rule applies to capital additions closed to rate base in the test year. Variations from this approach are permitted and include calculating depreciation based on the month that an asset enters service.	N/A (No incentive regime)
Enbridge Gas Distribution	The half year rule is not used. Depreciation is calculated in the month that an asset enters service.	In Enbridge's Multi-Year Cost of Service approach, for assets closing to ratebase in years two through five, depreciation is calculated in the month that an asset enters service.
Union Gas	The half year rule is not used. Depreciation is calculated from the month that an asset enters service.	For assets that qualify for Union's Custom IR mechanism, depreciation is calculated from the month that an asset enters service.
Alberta Natural Gas And Electricity Distribution	The half year rule applies to capital additions closed to rate base in the test year.	The half year rule is applied to net capital additions in the test year of the utility's applied-for capital tracker and is trued-up in the following year.
Nova Scotia Power	The half year rule is not used. Depreciation/accretion expense is based on a monthly roll-up of capital additions and retirements over the test year on a forecast basis.	N/A (No incentive regime)
FortisBC	The half year rule is not used. Depreciation expense for the test year (t) is equal to the product of the relevant depreciation rate for the asset class and the asset balance at the end of the previous period (t-1).	FortisBC's multi-year PBR plan is a partial PBR regime, in which depreciation and other specified costs are a flow-through to rates via an annual review process. The treatment of depreciation in the PBR plan reflects the treatment in cost of service.
Newfoundland Power	The half year rule applies to capital additions closed to rate base in the test year.	N/A (No incentive regime)
Gaz Métro	The half year rule is not used. Depreciation relating to assets closing to rate base during the test year is calculated from the first day of the month following the expected in-service or commissioning date.	N/A (No incentive regime)

Jurisdiction	Half Year Rule *Cost of Service*	Half Year Rule *Incentive Regulation*
Alabama Power Company	The half year rule is not used. Depreciation relating to assets included in rate base is calculated from the first day of the month following the estimated in-service or commissioning date. Projected gross additions to the rate base are estimated using a 13-month average balance.	N/A (No incentive regime)
Southern California Edison	The half year rule is not used. Depreciation relating to assets included in rate base is calculated from the first day of the month following the estimated in-service or commissioning date. Projected gross additions to the rate base are estimated as a twelve-month average balance during a 13-month period.	N/A (No incentive regime)
Georgia Power	The half year rule is not used. Depreciation relating to assets included in rate base is calculated from the first day of the month following the estimated in-service or commissioning date. Projected gross additions to the rate base are estimated as a twelve-month average balance during a 13-month period.	N/A (No incentive regime)
Entergy Louisiana	The half year rule is not used. Depreciation relating to assets included in rate base is calculated from the first day of the month following the in-service or commissioning date. Projected gross additions to the rate base are estimated as an ending value during the 18-month period following the historic test year.	N/A (No incentive regime)
Maryland Public Service Commission	The half year rule is not used. Depreciation relating to assets included in rate base is calculated from the first day of the month following the estimated in-service or commissioning date. Projected gross additions are added to the rate base and estimated depreciation and amortization are subtracted from the rate base on a 13-month average basis.	N/A (No incentive regime)

Jurisdiction	Half Year Rule *Cost of Service*	Half Year Rule *Incentive Regulation*
Massachusetts Electric	The half year rule is not used. Depreciation relating to assets closed to rate base during the test year is calculated from the first day of the month following the in-service or commissioning date.	N/A (No incentive regime)
Mississippi Power	The half year rule is not used. Depreciation relating to assets closed to rate base during the test year is based on a monthly roll up and is calculated using the property value from the first day of the month following the actual in-service or commissioning date. The Performance Evaluation Plan-5 (PEP-5) uses a historical test 13-month average rate base.	N/A (No incentive regime)
Consolidated Edison Company of New York	The half year rule is not used. Depreciation relating to assets included in rate base is calculated from the first day of the month following the estimated in-service or commissioning date. A 12-month average is estimated based on the depreciation rates and expected amounts of plant completed.	N/A (No incentive regime)
PECO Energy Company	The half year rule does not apply. Depreciation relating to assets included in rate base is calculated from the first day of the month following the estimated in-service or commissioning date. A 12-month average is estimated based on the depreciation rates and expected amounts of plant completed.	N/A (No incentive regime)
Ofgem	Cost of Service regime is not in use. RIIO is a comprehensive multi-year rate setting regime that is a hybrid of cost of service and IR rate regimes.	The half year rule does not apply. The full depreciation for capital additions in year (t) is applied in year (t+1).

Source: KPMG Analysis

Our jurisdictional review did not reveal a systemic concern or issue with the treatment of depreciation expense relating to assets closed to rate base during the test year. In addition, in Canadian jurisdictions that employ the half year rule, or a variant thereof, in a cost of service rate-setting environment, little if any discussion of the rationale relating to the half year rule was observed in the rate applications and related decisions that we reviewed.

2.1 Effect of Half Year Rule in Cost of Service

In order to highlight the effect of the half year rule on capital-related costs recovered in rates over a rate-making cycle, KPMG conducted a pro-forma analysis (i.e., the analysis does not reflect actual distributor data), comparing the capital-related costs recovered in rates in a cost of service environment with and without the half year rule. This analysis is presented in Appendix 4 and is summarized below in Table 2. Our analysis reflects a number of assumptions:

- Annual capital expenditures are $200,000 or 157% of depreciation in year 1, the cost of service rebasing year, and are a constant dollar value at this level in each of the subsequent four IR years; and

- Asset retirements are also a constant dollar value in year 1, the cost of service rebasing year, and in each of the subsequent four IR years.

KPMG is conscious of the limitations of this analysis – that the assumptions embedded in the analysis will be different for each distributor subject to rate regulation by the Board. We believe however, that the results of the analysis are directionally correct and will inform the discussion regarding the use of the half year rule generally.

Table 2. Effect of Half Year Rule in Cost of Service

Effect of Half Year Rule in Cost of Service					
Capital-Related Costs Recovered in Rates ($)					
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Cost of Service with Half Year Rule					
Depreciation	127,500	131,250	135,000	138,750	142,500
Return on Capital	199,214	203,848	208,236	212,378	216,274
Taxes/PILs (Grossed-up)	40,461	41,403	42,294	43,135	43,926
Total	**367,176**	**376,501**	**385,530**	**394,263**	**402,700**
Cost of Service without Half Year Rule					
Depreciation	130,000	133,750	137,500	141,250	145,000
Return on Capital	199,132	203,602	207,826	211,804	215,535
Taxes/PILs (Grossed-up)	40,445	41,353	42,210	43,018	43,776
Total	**369,577**	**378,705**	**387,536**	**396,072**	**404,312**
Difference					
Depreciation	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)
Return on Capital	82	246	410	574	738
Taxes/PILs (Grossed-up)	17	50	83	117	150
Total	**(2,401)**	**(2,204)**	**(2,007)**	**(1,809)**	**(1,612)**

Source: KPMG Analysis

Based on the pro-forma analysis in Appendix 4 and the assumptions therein, if:

- a distributor is able to set rates on an annual basis using a cost of service methodology;

- the half year rule is used for calculating the depreciation expense recovered in rates associated with capital additions closed to rate base during the test year (t); and

- the revenue requirement in the test year (t) is rebased to recover the effect of the half year rule in the previous year (t-1);

then it appears that the reduction in capital-related costs recovered in rates over the rate setting period is relatively constant. Based on our example, over the rate setting period, the effect of the half year rule is relatively small and is increasingly offset by the return on capital and taxes/PILs (grossed up) that are recovered in rates. Since the calculation of rate base to which the cost of capital metrics and taxes/PILs are applied is an average of the opening net book value and closing net book value in test year (t), the net effect of the half year rule is that rate base is slightly higher than would otherwise be the case.

The fact that there is a difference between the capital-related costs recovered in rates in the two approaches over the rate setting period is not necessarily indicative of a fundamental problem with the half year rule approach. Rather, in a cost of service rate setting framework, it is a demonstration of the costs that could potentially be recovered from ratepayers in advance of capital expenditures being actually closed to rate base in the test year.

It is important to recognize that the half year rule is a rule of thumb (or proxy) designed to emulate how capital additions are closed to rate base in the test year. It is a recognition that planned capital additions in a test year do not all enter service at the beginning of the test year. It is also illustrative of a ratemaking approach that balances utility and customer interests.

In addition, the OEB does permit alternative approaches, such as calculating depreciation expense in the test year based on the month that an asset is expected to enter service. KPMG is not aware of the number of electricity distributors who make use of this alternative approach or who have designed more customized methodologies. We are aware that more involved methodologies may create additional costs, such as information and data tracking requirements at the distributor level and additional information and evidentiary requirements in the hearing process. The cost associated with these additional requirements may eclipse the benefit associated with greater precision with calculating the depreciation expense using the actual timing of when capital additions are closed to rate base in the test year.

2.2 Effect of Half Year Rule in IR

In Alberta where the Alberta Utilities Commission ("AUC") has recently completed a multi-year process to implement Performance Based Regulation ("PBR")[2], the use of the half year rule figured prominently in the submissions relating to the construction of the capital tracker ("K") feature of the PBR regime and in the generic process to consider the capital tracker applications of five Alberta-based utilities[3].

As set out in the Alberta Natural Gas and Electricity Distribution Utilities schedule in Appendix 1, the half year rule is used in both the periodic cost of service reviews conducted by the AUC and in the K Factor capital adjustment mechanism in PBR. In the latter rate-setting approach, the K Factor does not true up depreciation for capital expenditures that are included in base rates. The half year true-up only relates to capital expenditures that are eligible for inclusion in the capital tracker mechanism. The implementation of the capital tracker mechanism requires subsequent annual regulatory filings to determine the eligibility

[2] Alberta Utilities Commission. (September 12, 2012). Rate Regulation Initiative: Distribution Performance-Based Regulation. Decision 2012-237.

[3] Alberta Utilities Commission. (December 6, 2013). Distribution Performance-Based Regulation 2013 Capital Tracker Applications: AltaGas Utilities Inc., ATCO Electric Ltd., ATCO Gas and Pipelines Ltd., EPCOR Distribution & Transmission Inc., and FortisAlberta Inc. Decision 2013-435.

of applied-for capital expenditures and the forecast costs to be recovered through the K Factor for the upcoming test year.

In Ontario, the half year rule is used in the cost of service proceeding that forms the base for incentive rates pursuant to the Board's Renewed Regulatory Framework for Electricity Distributors ("RRFE")[4]. The half year effect remains a feature of base rates throughout the IR period, consistent with the approach adopted by the AUC. A distributor can potentially eliminate the effect of the half year rule associated capital additions closed to rate base in the cost of service year by filing a Custom IR rate setting approach, as per the Board's RRFE.

In the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, the Board stated that "in calculating the rate relief (associated with incremental capital spending that exceeds the threshold amount during the IR term), the Board has determined not to apply the half year rule so as not to build in a deficiency for subsequent years in the term of the plan."[5] However, the Board also determined in Guelph Hydro's application for 2011 rates that the half year rule would apply in the final year of the Price Cap IR plan term, as "the full year depreciation expense will be explicitly reflected in the determination of the rate base and revenue requirement in the cost of service application for the following test year"[6]. In other words the half year rule does not apply in an ICM during the IR term until the year prior to rebasing.

The question that is relevant for the purpose of this report is: Should the effect of the half year rule, or other regulatory approaches that emulate how capital additions are closed to rate base in the test year, be eliminated for the purpose of calculating the base rates that are subject to annual escalation over the IR period?

In order to assess this question, we undertook the analysis set out below.

KPMG is again aware of the limitations of this analysis – that the assumptions embedded in the analysis will be different for each distributor subject to rate regulation by the Board. We believe however, that the results of the approach are directionally correct and will inform the discussion regarding the use of the half year rule generally.

2.2.1 Half Year Rule in IR – No Customer Growth

We first calculated the capital-related costs recovered in IR rates with no customer growth, assuming that the half year rule continues to be used in the cost of service year (rebasing or Year 1). We then compared the result to the annual cost of service approach, in which capital additions are subject to annual rebasing and the depreciation expense recovered in rates associated with capital additions placed in-service during the test year is subject to the half year rule.

This analysis is presented in Appendix 5 and summarized below in Table 3.

[4] Ontario Energy Board. (October 18, 2012). Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach.

[5] Ontario Energy Board. (September 17, 2008). Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. Page 31.

[6] Ontario Energy Board. (March 14, 2011). Guelph Hydro Electric System Application for Distribution Rates and Other Charges. Decision and Order EB-2010—0130. Page 15.

Table 3. Adequacy of Incentive Rates without Customer Growth – The Half Year Rule

Adequacy of IR Revenue Requirement without Customer Growth					
Capital-related Costs Recovered in Rates ($)					
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Half Year Rule					
IR Half Year Rule in COS Year 1 No Customer Growth	367,176	371,949	376,784	381,683	386,645
COS With Half Year Rule	367,176	376,501	385,530	394,263	402,700
	-	**(4,552)**	**(8,745)**	**(12,580)**	**(16,055)**
No Half Year Rule					
IR Half Year Rule in COS Year 1 No Customer Growth; Half Year Rule Eliminated Years 2 - 5	367,176	374,382	383,989	393,843	403,950
COS With Half Year Rule	367,176	376,501	385,530	394,263	402,700
	-	**(2,119)**	**(1,541)**	**(419)**	**1,251**

Source: KPMG Analysis

As set out in the top of Table 3, the use of the half year rule in an environment with no customer growth (no increase in the number of customers, no change in volumetric and peak load growth) creates a notional revenue deficiency versus the default annual cost of service approach of about $42,000 over the 5-year rate setting cycle.

In order to eliminate the effect of the half year rule in the first year following rebasing, as illustrated in the bottom of Table 3, we used the cost of service metrics that would be in place if the half year rule was not in effect in the rebasing year. That is, prior to increasing depreciation, capital costs and taxes/PILs by the annual revenue adjustment mechanism in the first IR year (assuming no customer growth), these metrics have to be updated to eliminate the effect of the half year rule from the rebasing year. Depreciation increases from $127,500 as set out in Table 2 to $130,000. Capital costs and taxes/PILs also change, declining from $199,214 and $40,461 to $199,132 and $40,445, respectively as per Table 2. These adjusted values were then increased by the annual IR revenue adjustment mechanism for the purpose of setting IR rates in the first and subsequent IR years (years 2 through 5).

As set out in the bottom of Table 3, eliminating the effect of the half year rule in the first year following rebasing has the effect of largely eliminating the revenue deficiency set out in the top half of Table 3. The cumulative revenue deficiency over the 5-year rate setting cycle declines from about $42,000 to approximately $2,800.

2.2.2 Half Year Rule in IR – With Customer Growth

We then calculated the capital-related costs recovered in IR rates with customer growth of 1.25% per annum over the IR period, assuming that the half year rule continues to be used in the cost of service year (rebasing or Year 1). We then compared the result to the annual cost of service approach, in which capital additions are subject to annual rebasing and the depreciation expense recovered in rates associated with capital additions placed in-service during the test year is subject to the half year rule. As set out in the top half of Table 4 below, the continued use of the half year rule in Year 1 cost of service rates does not create a notional revenue deficiency versus the default annual cost of service approach.

Table 4. Adequacy of Incentive Rates with Customer Growth – The Half Year Rule

Adequacy of IR Revenue Requirement with Customer Growth					
Capital-related Costs Recovered in Rates ($)					
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Half Year Rule					
IR Half Year Rule in COS Year 1 with Customer Growth	367,176	376,598	386,263	396,175	406,342
COS With Half Year Rule	367,176	376,501	385,530	394,263	402,700
	-	**98**	**733**	**1,913**	**3,643**
No Half Year Rule					
IR Half Year Rule in COS Year 1 with Customer Growth; Half Year Rule Eliminated Years 2 - 5	367,176	379,061	388,789	398,766	409,000
COS With Half Year Rule	367,176	376,501	385,530	394,263	402,700
	-	**2,561**	**3,259**	**4,504**	**6,300**

Source: KPMG Analysis

In order to eliminate the effect of the half year rule in the first IR year following rebasing, as illustrated in the bottom half of Table 4, we followed the same methodology set out above in section 2.2.1. We used the cost of service metrics that would be in place if the half year rule were not in effect in the rebasing year. That is, prior to increasing depreciation, capital costs and taxes/PILs by the annual IR revenue adjustment mechanism in the first IR year, these metrics have to be updated to eliminate the effect of the half year rule from the rebasing year. Depreciation increases from $127,500 as set out in Table 2 to $130,000. Capital costs and taxes/PILs also change, declining from $199,214 and $40,461 (as per Table 2) to $199,132 and $40,445, respectively. These adjusted values were then increased by the annual IR revenue adjustment mechanism for the purpose of setting IR rates in the first year and in the subsequent IR years.

As set out in the bottom of Table 4, with the exception of the rebasing year when the half year rule remains in effect, adjusting the metrics to remove the effect of the half year rule in the IR term years results in even more of a revenue sufficiency versus a default annual cost of service approach.

There are a few of additional points to consider about this analysis:

- We have focused on the costs typically associated with capital expenditures, namely depreciation, cost of capital and taxes/PILs. We have assumed that the productivity gains achieved by the distributor and the related formulaic increase in other costs in IR, including OM&A, are not necessarily available to address the adequacy of rates set in IR with respect to the quantum of capital expenditures that are currently reflected in customer rates. That is, we have assumed that, if actual utility cost performance is better than the productivity assumptions reflected in the annual IR revenue adjustment mechanism (i.e., the PCI), these gains appropriately accrue to shareholders. We note that while capital investments may result in OM&A cost improvement, we believe that this approach is reasonable and highlight that it is consistent with the assessment of the AUC in is 2013 Capital Tracker Application Decision. In that Decision, the AUC stated:

> these efficiency gains should not be appropriated by the Commission to finance qualified capital trackers that are appropriately recovered in the form of a K Factor. For the Commission to do otherwise would

undermine the credibility and integrity of its own PBR regime, and destroy the very incentives it was intended to create.[7]

- It is implicit in our analysis that, by inflating the cost of capital, depreciation and taxes/PILs costs using a factor that reflects customer growth, we are acknowledging that some of the capital expenditures that can be sustained by base rates may be used to connect new customers and address equipment requirements that may be associated with the additional connections and higher kW and kWh due to this growth. This results in actual revenue during each year in the IR term that exceeds the revenue arising solely from the IPI - (TFP + stretch factor) adjustment.

Finally, we note that if customer growth is approximately 1.1% per annum over the IR period, given the assumptions in our example, the cumulative revenue deficiency noted in the "no growth" analysis is eliminated (i.e., the cumulative revenue deficiency in our analysis is zero) versus the base case annual cost of service approach. In other words, 1.1% growth is a break-even point using the numbers in our example.

2.3 Sensitivity Analysis – Half Year Rule

KPMG participated in a stakeholder consultation at which a draft version of our report was presented and discussed. During the consultation, we were asked to perform additional analysis with respect to the effect of the half year rule. In particular, we were asked to revise our analysis to reflect the following assumptions:

- Adjust annual capital expenditures for both customer growth and inflation;
- Adjust annual removals/retirements for inflation;
- Change the depreciable life of utility assets to 31 years from 40 years, increasing the composite depreciation rate used in the pro-forma analysis to 3.2% from 2.5%;
- Use a composite customer growth rate to determine the total annual customer growth. We were asked to weight the growth in the number of customers, kWh growth, and kW growth at 40%, 30% and 30%, respectively; and
- Adjust the quantum of capital expenditures to be equal to 100%, 200% and 400% of depreciation.

The primary purpose of the sensitivity analysis is to demonstrate whether the half year rule produces a revenue deficiency over a range of capital expenditure levels, and if so, whether that revenue deficiency is material.

The sensitivity analysis arising from the consultation is set out in Appendix 6 and summarized below.

Table 5 highlights our approach, which is consistent with the methodology set out previously in sections 2.1 and 2.2 of this Report. The numerical presentation in Table 5 reflects a capital expenditure assumption equal to 200% of the depreciation expense associated with the opening asset position in the

[7] Alberta Utilities Commission. (December 6, 2013). Distribution Performance-Based Regulation 2013 Capital Tracker Applications. Page 52.

rebasing year. The detailed calculations associated with the 200% scenario are set out in Appendix 6, beginning on page 112 of this Report.

Table 5. Calculation of Revenue Sufficiency/(Deficiency) Attributable to Size of Capital Program

Calculation of Revenue Deficiency Attributable to Size of Capital Program for Sensitivity Analysis										
		Rebasing Year		Year 2		Year 3		Year 4		Year 5
Capital Costs Recovered in Rates										
Annual Cost of Service (COS) with Half Year Rule	$	408,579	$	429,485	$	450,398	$	471,318	$	492,242
Annual Cost of Service without Half Year Rule	$	413,496	$	434,097	$	454,699	$	475,300	$	495,900
Notional Effect of Half Year Rule	**$**	**(4,917)**	**$**	**(4,612)**	**$**	**(4,300)**	**$**	**(3,982)**	**$**	**(3,658)**
Capital Costs Recovered In Rates: Incentive Regulation (IR)	$	408,579	$	416,845	$	425,279	$	433,884	$	442,663
Revenue Sufficiency (Deficiency) IR vs Annual COS with Half Year Rule	$	-	$	(12,640)	$	(25,119)	$	(37,434)	$	(49,580)
Revenue Deficiency Attributable to CapEx vs CapEx in Base Rates	$	-	$	(8,028)	$	(20,819)	$	(33,452)	$	(45,922)
Revenue Deficiency Attributable to CapEx (% of Revenue Deficiency)		0.00%		63.51%		82.88%		89.36%		92.62%

Source: KPMG Analysis

As set out above, we first calculated the capital-related costs (depreciation, return on capital, and taxes/PILS) that are recovered in rates in an annual cost of service rate-setting process, with the half year rule in use. We then calculated the capital-related costs that are recovered in rates in an annual cost of service rate-setting process where the half year is not in use. The difference in annual capital-related costs recovered in rates is the notional effect of the half year rule.

We then calculated the capital-related costs that are recovered in rates using an incentive rate process, without adjusting for or eliminating the effect of the half year rule in the first year of IR. The difference between the costs recovered in IR and COS with the half year rule in use in both approaches results in a revenue sufficiency or deficiency.

Table 6 illustrates the resulting revenue sufficiency/(deficiency) with the half year rule reflected in both the incentive and cost of service rate setting approaches. For example, if CapEx is 200% of depreciation, incentive rates produce a revenue deficiency of $12,640 in Year 2 (first IR year).

Table 6. Revenue Sufficiency/(Deficiency) IR versus Annual COS with Half Year Rule

Revenue Sufficiency (Deficiency) IR vs Annual COS with Half Year Rule										
		Rebasing Year		Year 2		Year 3		Year 4		Year 5
CapEx as Percent of Depreciation										
100%	$	-	$	4,733	$	9,573	$	14,523	$	19,585
120%	$	-	$	1,258	$	2,634	$	4,131	$	5,752
140%	$	-	$	(2,216)	$	(4,304)	$	(6,260)	$	(8,081)
160%	$	-	$	(5,691)	$	(11,242)	$	(16,651)	$	(21,914)
180%	$	-	$	(9,165)	$	(18,181)	$	(27,042)	$	(35,747)
200%	$	-	$	(12,640)	$	(25,119)	$	(37,434)	$	(49,580)
220%	$	-	$	(16,114)	$	(32,057)	$	(47,825)	$	(63,413)
240%	$	-	$	(19,589)	$	(38,996)	$	(58,216)	$	(77,246)
260%	$	-	$	(23,063)	$	(45,934)	$	(68,608)	$	(91,079)
280%	$	-	$	(26,538)	$	(52,873)	$	(78,999)	$	(104,912)
300%	$	-	$	(30,012)	$	(59,811)	$	(89,390)	$	(118,745)
320%	$	-	$	(33,487)	$	(66,749)	$	(99,781)	$	(132,578)
340%	$	-	$	(36,962)	$	(73,688)	$	(110,173)	$	(146,411)
360%	$	-	$	(40,436)	$	(80,626)	$	(120,564)	$	(160,244)
380%	$	-	$	(43,911)	$	(87,564)	$	(130,955)	$	(174,077)
400%	$	-	$	(47,385)	$	(94,503)	$	(141,346)	$	(187,910)

Source: KPMG Analysis

Table 7 illustrates the size of the revenue sufficiency/(deficiency) as a percent of the total capital costs recovered in incentive rates. For example, if CapEx is 200% of depreciation, the revenue deficiency resulting from incentive rates in Year 2 is 3% of the capital-related costs recovered in incentive rates.

Table 7. IR Revenue Sufficient/(Deficiency) as a % of Capital Costs Recovered in IR

IR Revenue Sufficiency(Deficiency) as % of Capital Costs Recovered in IR					
	Rebasing Year	Year 2	Year 3	Year 4	Year 5
CapEx as Percent of Depreciation					
100%	0%	1%	2%	3%	5%
120%	0%	0%	1%	1%	1%
140%	0%	-1%	-1%	-1%	-2%
160%	0%	-1%	-3%	-4%	-5%
180%	0%	-2%	-4%	-6%	-8%
200%	0%	-3%	-6%	-9%	-11%
220%	0%	-4%	-8%	-11%	-14%
240%	0%	-5%	-9%	-13%	-17%
260%	0%	-5%	-11%	-16%	-20%
280%	0%	-6%	-12%	-18%	-23%
300%	0%	-7%	-14%	-20%	-26%
320%	0%	-8%	-15%	-22%	-29%
340%	0%	-9%	-17%	-25%	-32%
360%	0%	-9%	-18%	-27%	-35%
380%	0%	-10%	-20%	-29%	-38%
400%	0%	-11%	-21%	-31%	-41%

Source: KPMG Analysis

Table 8 illustrates the portion of the revenue sufficiency/(deficiency) that is attributable to the size of the capital budget. For example, if CapEx is 200% of depreciation, 64% of the observed revenue deficiency in Year 2 is attributable to the size of the capital expenditures program and 36% is attributable to the notional effect of the half year rule.

Table 8. Portion of Revenue Deficiency Attributable to Size of CapEx Budget

Portion Revenue Deficiency Attributable to Size of CapEx Budget					
	Rebasing Year	Year 2	Year 3	Year 4	Year 5
CapEx as Percent of Depreciation					
100%	0%	0%	0%	0%	0%
120%	0%	0%	0%	0%	0%
140%	0%	0%	30%	55%	68%
160%	0%	35%	69%	81%	87%
180%	0%	55%	79%	87%	91%
200%	0%	64%	83%	89%	93%
220%	0%	69%	85%	91%	94%
240%	0%	72%	87%	92%	94%
260%	0%	74%	88%	92%	95%
280%	0%	76%	89%	93%	95%
300%	0%	77%	89%	93%	95%
320%	0%	78%	90%	94%	96%
340%	0%	79%	90%	94%	96%
360%	0%	79%	90%	94%	96%
380%	0%	80%	91%	94%	96%
400%	0%	81%	91%	94%	96%

Source: KPMG Analysis

The sensitivity analysis highlighted the following:

- As previously observed in section 2.1, notwithstanding the increase in planned capital expenditures to be multiples of depreciation and increase in planned capital expenditures over the 5-year rate setting period arising from inflation and customer growth, the effect of the half year rule is relatively moderate, expressed as a portion of the capital costs reflected in IR rates, and is increasingly offset by the return on capital and tax/PILs (grossed up) that are recovered in rates.

- Whether the revenue deficiency arising from the half year rule in IR is material and would meet the OEB's Materiality Thresholds[8] would be a question of fact, based on the particular situation of each distributor. Our example is focused exclusively on the capital costs recovered in IR rates. We have not constructed a full revenue requirement model, as previously discussed. We have not determined whether the observed revenue deficiency in this example would meet the Board's Materiality Threshold, as calculated in relation to the full revenue requirement.

- The observed IR revenue deficiency appears to be driven primarily by the size of the planned capital expenditures over the 5-year rate-setting period versus the notional amount of capital expenditures reflected in base rates.

- The notional percentage amount of capital expenditures reflected in base rates, as calculated by the ICM/ACM Materiality Threshold Formula, is sensitive to the customer growth rate and relatively insensitive to capital expenditures as a percent of depreciation. Table 9 illustrates the sensitivity of the Materiality Threshold Formula to customer growth rates and the size of the capital expenditure budget. **In other words, Table 9 illustrates how much CapEx is reflected in IR rates at various combinations of customer growth rates and capital budgets, expressed as a percentage of depreciation.**

  For example, if CapEx is 200% of depreciation and growth is 1.00%, IR rates are sufficient to fund CapEx of 143.1% of depreciation or $241,767 as per Table 10. The costs associated with planned capital expenditures equal to 56.9% of depreciation are notionally not funded by IR rates.

Table 9. Sensitivity of Threshold Calculation to Rate of Customer Growth and Size of CapEx Budget

Sensitivity of Threshold Calculation to Rate of Customer Growth and Size of CapEx Budget							
Rate of Customer Growth	CapEx as a % of Depreciation						
	100%	150.0%	200.0%	250.0%	300.0%	350.0%	400.0%
-1.00%	105.3%	105.3%	105.3%	105.4%	105.4%	105.4%	105.5%
-0.75%	110.0%	110.0%	110.1%	110.1%	110.2%	110.2%	110.3%
-0.50%	114.6%	114.7%	114.8%	114.9%	114.9%	115.0%	115.1%
-0.25%	119.3%	119.4%	119.5%	119.6%	119.7%	119.8%	119.9%
0.00%	124.0%	124.1%	124.2%	124.4%	124.5%	124.6%	124.7%
0.25%	128.7%	128.8%	128.9%	129.1%	129.2%	129.4%	129.5%
0.50%	133.3%	133.5%	133.7%	133.8%	134.0%	134.2%	134.3%
0.75%	138.0%	138.2%	138.4%	138.6%	138.8%	139.0%	139.1%
1.00%	142.7%	142.9%	143.1%	143.3%	143.5%	143.7%	144.0%
1.25%	147.3%	147.6%	147.8%	148.1%	148.3%	148.5%	148.8%
1.50%	152.0%	152.3%	152.5%	152.8%	153.1%	153.3%	153.6%
1.75%	156.7%	157.0%	157.3%	157.6%	157.8%	158.1%	158.4%
2.00%	161.4%	161.7%	162.0%	162.3%	162.6%	162.9%	163.2%
2.25%	166.0%	166.4%	166.7%	167.0%	167.4%	167.7%	168.0%
2.50%	170.7%	171.1%	171.4%	171.8%	172.1%	172.5%	172.8%
2.75%	175.4%	175.8%	176.1%	176.5%	176.9%	177.3%	177.6%
3.00%	180.0%	180.5%	180.9%	181.3%	181.7%	182.1%	182.4%

Source: KPMG Analysis

Table 10 illustrates this result in dollar values.

Table 10. Threshold Calculation/$Amount of CapEx in IR Rates and Customer Growth Rates

Threshold Calculation/$ Amount of CapEx in IR Rates and Customer Growth Rates					
	Rebasing Year	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Composite Rate of Customer Growth					
-1.00%	105.3%	$ 174,451	$ 232,652	$ 237,359	$ 242,161
-0.75%	110.1%	$ 182,728	$ 233,239	$ 237,958	$ 242,773
-0.50%	114.8%	$ 191,043	$ 233,827	$ 238,558	$ 243,384
-0.25%	119.5%	$ 199,399	$ 234,414	$ 239,157	$ 243,996
0.00%	124.2%	$ 207,793	$ 235,002	$ 239,757	$ 244,607
0.25%	128.9%	$ 216,228	$ 235,589	$ 240,356	$ 245,219
0.50%	133.7%	$ 224,701	$ 236,177	$ 240,955	$ 245,830
0.75%	138.4%	$ 233,214	$ 236,764	$ 241,555	$ 246,442
1.00%	143.1%	$ 241,767	$ 237,352	$ 242,154	$ 247,054
1.25%	147.8%	$ 250,359	$ 237,939	$ 242,753	$ 247,665
1.50%	152.5%	$ 258,990	$ 238,527	$ 243,353	$ 248,277
1.75%	157.3%	$ 267,661	$ 239,114	$ 243,952	$ 248,888
2.00%	162.0%	$ 276,372	$ 239,702	$ 244,552	$ 249,500
2.25%	166.7%	$ 285,122	$ 240,289	$ 245,151	$ 250,111
2.50%	171.4%	$ 293,911	$ 240,877	$ 245,750	$ 250,723
2.75%	176.1%	$ 302,740	$ 241,464	$ 246,350	$ 251,334
3.00%	180.9%	$ 311,609	$ 242,052	$ 246,949	$ 251,946

Source: KPMG Analysis

We were also asked to perform the same sensitivity analysis normalizing the total capital costs reflected in rates for the effect of the half year rule. We normalized for the effect of the half year rule in the manner set out in section 2.2.1 of this Report.

Table 11 illustrates our approach. We first calculated the capital-related costs (depreciation, return on capital, and taxes/PILS) that are recovered in an annual cost of service rate-setting process, with the half year rule in use. We then calculated the capital-related costs that are recovered in rates in an annual cost of service rate-setting process where the half year rule is not in use. The difference in annual capital related costs recovered in rates is the notional effect of the half year rule.

We then calculated the capital-related costs that are recovered in rates using an incentive rate process that normalized for or eliminated the effect of the half year rule in the first year of IR. We also calculated the capital-related costs recovered in IR rates without any adjustment for the half year rule. The difference between the two IR rates is then calculated.

The difference between the two sets of IR rates is the adjustment for the half year rule and is representative of the notional structural deficiency in IR rates relating to the effect of the half year rule in the rebasing year.

Table 11 illustrates the results of this analysis.

Table 11. Revenue Sufficiency/(Deficiency) Normalized IR versus Annual COS and IR with Half Year Rule

Calculation of Revenue Deficiency Attributable to Size of Capital Program for Sensitivity Analysis										
		Rebasing Year		Year 2		Year 3		Year 4		Year 5
Capital Costs Recovered in Rates										
Annual Cost of Service (COS) with Half Year Rule	$	408,579	$	429,485	$	450,398	$	471,318	$	492,242
Annual Cost of Service without Half Year Rule	$	413,496	$	434,097	$	454,699	$	475,300	$	495,900
Notional Effect of Half Year Rule	**$**	**(4,917)**	**$**	**(4,612)**	**$**	**(4,300)**	**$**	**(3,982)**	**$**	**(3,658)**
Capital Costs Recovered In Rates: Incentive Regulation (IR, Normalized for Half Year Rule)	$	408,579	$	421,862	$	430,398	$	439,106	$	447,990
Capital Costs Recovered in Rates: IR with Half Year Rule	$	408,579	$	416,845	$	425,279	$	433,884	$	442,663
Difference in Capital Costs Recovered in Rates - IR with Half Year Rule vs IR Normalized for Half Year Rule	**$**	**-**	**$**	**(5,017)**	**$**	**(5,118)**	**$**	**(5,222)**	**$**	**(5,328)**
Revenue Sufficiency (Deficiency) IR Normalized vs Annual COS	$	-	$	(7,623)	$	(20,001)	$	(32,212)	$	(44,252)
Revenue Sufficiency (Deficiency) Attributable to CapEx vs CapEx in Base Rates	$	-	$	(8,028)	$	(20,819)	$	(33,452)	$	(45,922)
Revenue Deficiency Attributable to CapEx (% of Revenue Deficiency)		-		105.31%		104.09%		103.85%		103.77%

Source: KPMG

We note the following:

- By adjusting for or eliminating the effect of the half year rule in IR, any observed revenue deficiency is the result of planned CapEx in excess of the notional amount of CapEx reflected in rates.

- If planned CapEx is less than the CapEx notionally reflected in rates, adjusting for or eliminating the effect of the half year rule in IR will result in rates that are compensatory. That is, capital-related costs recovered in adjusted IR rates will exceed the capital costs recovered in COS rates with the half year rule.

- The notional percentage amount of CapEx reflected in base rates as calculated by the ICM/ACM Materiality Threshold Formula continues to be sensitive to the customer growth rate and relatively insensitive to the effect of the half year rule and CapEx as a percentage of depreciation, consistent with our previous observation.

- The amount of CapEx that is reflect in normalized IR rates at various combinations of customer growth and capital budgets, expressed as a percentage of depreciation, is set out in Table 12. For example, if customer growth is 1.00% and planned CapEx is 200% of depreciation, normalized IR rates are sufficient to fund CapEx of 141.8% of depreciation or $246,945 as per Table 13.

Table 12. Sensitivity of Threshold Calculation to Rate of Customer Growth and Size of CapEx Budget

Sensitivity of Threshold Calculation to Rate of Customer Growth and Size of CapEx Budget							
Rate of Customer Growth	CapEx as a % of Depreciation						
	100%	150.0%	200.0%	250.0%	300.0%	350.0%	400.0%
-1.00%	105.2%	105.2%	105.2%	105.2%	105.2%	105.1%	105.1%
-0.75%	109.8%	109.8%	109.8%	109.7%	109.7%	109.7%	109.7%
-0.50%	114.4%	114.4%	114.3%	114.3%	114.3%	114.2%	114.2%
-0.25%	119.0%	119.0%	118.9%	118.9%	118.8%	118.8%	118.7%
0.00%	123.6%	123.5%	123.5%	123.4%	123.4%	123.3%	123.3%
0.25%	128.2%	128.1%	128.1%	128.0%	127.9%	127.9%	127.8%
0.50%	132.8%	132.7%	132.6%	132.6%	132.5%	132.4%	132.3%
0.75%	137.4%	137.3%	137.2%	137.1%	137.0%	136.9%	136.9%
1.00%	142.0%	141.9%	141.8%	141.7%	141.6%	141.5%	141.4%
1.25%	146.6%	146.5%	146.4%	146.2%	146.1%	146.0%	145.9%
1.50%	151.2%	151.1%	150.9%	150.8%	150.7%	150.6%	150.5%
1.75%	155.8%	155.6%	155.5%	155.4%	155.2%	155.1%	155.0%
2.00%	160.4%	160.2%	160.1%	159.9%	159.8%	159.7%	159.5%
2.25%	165.0%	164.8%	164.6%	164.5%	164.3%	164.2%	164.1%
2.50%	169.6%	169.4%	169.2%	169.1%	168.9%	168.7%	168.6%
2.75%	174.2%	174.0%	173.8%	173.6%	173.4%	173.3%	173.1%
3.00%	178.8%	178.6%	178.4%	178.2%	178.0%	177.8%	177.6%

Source: KPMG Analysis

Table 13 illustrates this result in dollar values.

Threshold Calculation/$ Amount of CapEx in IR Rates and Customer Growth Rates					
	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Composite Rate of Customer Growth					
-1.00%	105.2%	$ 179,579	$ 237,837	$ 242,649	$ 247,559
-0.75%	109.8%	$ 187,862	$ 238,438	$ 243,262	$ 248,184
-0.50%	114.3%	$ 196,184	$ 239,039	$ 243,875	$ 248,809
-0.25%	118.9%	$ 204,545	$ 239,639	$ 244,488	$ 249,434
0.00%	123.5%	$ 212,946	$ 240,240	$ 245,100	$ 250,060
0.25%	128.1%	$ 221,387	$ 240,840	$ 245,713	$ 250,685
0.50%	132.6%	$ 229,867	$ 241,441	$ 246,326	$ 251,310
0.75%	137.2%	$ 238,386	$ 242,042	$ 246,939	$ 251,935
1.00%	141.8%	$ 246,945	$ 242,642	$ 247,551	$ 252,560
1.25%	146.4%	$ 255,543	$ 243,243	$ 248,164	$ 253,185
1.50%	150.9%	$ 264,181	$ 243,843	$ 248,777	$ 253,810
1.75%	155.5%	$ 272,858	$ 244,444	$ 249,390	$ 254,436
2.00%	160.1%	$ 281,574	$ 245,045	$ 250,002	$ 255,061
2.25%	164.6%	$ 290,330	$ 245,645	$ 250,615	$ 255,686
2.50%	169.2%	$ 299,126	$ 246,246	$ 251,228	$ 256,311
2.75%	173.8%	$ 307,960	$ 246,846	$ 251,841	$ 256,936
3.00%	178.4%	$ 316,835	$ 247,447	$ 252,453	$ 257,561

Source: KPMG Analysis

- Adjusting for the half year rule in IR has a moderate effect on the amount of capital notionally reflected in rates expressed as a percentage of depreciation and the dollar value of CapEx, beyond which revenue deficiencies result, as set out in Table 14. The difference in capital notionally reflected in rates is directly attributable to the adjustment for the half year rule and is proportionate to the size of the capital budget expressed as a percentage of depreciation.

- As set out in Table 14, adjusting for the half year rule in IR has the effect of modestly reducing the amount of CapEx notionally reflected in IR rates (expressed as a % of depreciation), but increasing the dollar value due to the effect of the increasing the amount of depreciation recovered in rates, which compounds over the IR term. **In other words, normalization of IR rates for the half year rule increases the break-even point (in dollar terms) of the amount of capital notionally reflected in rates versus unadjusted IR rates.**

Table 14. Difference Between IR with Half Year Rule and Normalized IR

Difference Threshold Calculation/$ Amount of CapEx in IR Rates and Customer Growth Rates	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Composite Rate of Customer Growth					
-1.00%	0.2%	$ (5,127)	$ (5,186)	$ (5,291)	$ (5,398)
-0.75%	0.3%	$ (5,134)	$ (5,199)	$ (5,304)	$ (5,411)
-0.50%	0.5%	$ (5,140)	$ (5,212)	$ (5,317)	$ (5,425)
-0.25%	0.6%	$ (5,147)	$ (5,225)	$ (5,331)	$ (5,438)
0.00%	0.7%	$ (5,153)	$ (5,238)	$ (5,344)	$ (5,452)
0.25%	0.9%	$ (5,159)	$ (5,251)	$ (5,357)	$ (5,466)
0.50%	1.0%	$ (5,165)	$ (5,264)	$ (5,371)	$ (5,479)
0.75%	1.2%	$ (5,172)	$ (5,277)	$ (5,384)	$ (5,493)
1.00%	1.3%	$ (5,178)	$ (5,290)	$ (5,397)	$ (5,507)
1.25%	1.5%	$ (5,184)	$ (5,303)	$ (5,411)	$ (5,520)
1.50%	1.6%	$ (5,190)	$ (5,317)	$ (5,424)	$ (5,534)
1.75%	1.8%	$ (5,196)	$ (5,330)	$ (5,437)	$ (5,547)
2.00%	1.9%	$ (5,202)	$ (5,343)	$ (5,451)	$ (5,561)
2.25%	2.1%	$ (5,208)	$ (5,356)	$ (5,464)	$ (5,575)
2.50%	2.2%	$ (5,214)	$ (5,369)	$ (5,478)	$ (5,588)
2.75%	2.4%	$ (5,220)	$ (5,382)	$ (5,491)	$ (5,602)
3.00%	2.5%	$ (5,226)	$ (5,395)	$ (5,504)	$ (5,616)

Source: KPMG Analysis

3 Incentive Rates

For the purpose of the jurisdictional review, KPMG examined 15 separate jurisdictions and the processes to set rates for 19 entities. Comprehensive incentive ratemaking regimes were identified in only three jurisdictions: Ontario, Alberta, and the United Kingdom.

3.1 United States

In the United States, utilities regulated at the state level are generally regulated on an annual cost of service approach. There are a number of trends that have shaped the design of state regulatory approaches over the last 10 years:

- The electricity industry has shifted away from restructuring (i.e., structural and organizational unbundling) and toward the more traditional integrated utility;
- There is a recognition, following the August 2003 Eastern and Midwestern transmission blackout, that accelerated investment may be required to avoid reliability issues in the future;
- There is an understanding that new generation will be needed to replace an aging fleet that is not presently consistent with global trends toward a reduced carbon footprint;
- The decline in natural gas prices, due to dramatically higher supply from non-conventional sources and has led to a resurgence in natural gas-fired generation; and
- There is growing dissatisfaction with conventional revenue requirement approaches, which include both regulatory lag and performance-based (and other incentive-based) ratemaking.

All of these trends, taken together, stimulated changes in ratemaking approaches that moved regulators away from both conventional and incentive-based approaches at the state level. At the federal level, the Federal Energy Regulatory Commission's (FERC) incentive ratemaking approach reinforced rather than supplanted traditional ratemaking, by permitting Construction Work in Process to be included in rate base, limiting investment at risk and increasing the return on common equity. FERC also permitted increasing the use of formula ratemaking in which a litigated proceeding sets the parameters for what costs are included and annual, non-litigated informational filings update the expenditure data as a basis for a change in rates.

At the state level, four general approaches, all of which reduce regulatory lag, are increasingly prevalent:

1. Formula ratemaking similar in spirit to FERC's approach;
2. Earnings-sharing mechanisms to pass through changes in cost and, in some instances, changes in interest rates; and
3. Multi-year revenue requirements that allow companies to change rates in a second and third year after the rate case is decided based on anticipated changes in costs.
4. An expanding array of specialty riders that permit accelerated recovery of capital expenditures, supply costs (fuel and purchased power), transmission charges from regional transmission organizations and benefits (pension funding and post-employment benefits).

Very few states continue to use rate setting plans that permit a change in rates based on an inflationary index less a productivity index. Instead, the states rely increasingly on the four types of mechanisms noted above. Specifically, we observed the following circumstances:

- Alabama and Mississippi are relying on formula rate-making in which rates are changed at the start of every year based on projected cost of service;
- California relies upon a test year and two additional years for setting rates. Adjustments are permitted to the post test-year after the California Public Utilities Commission has issued its order in a General Rate Case (GRC) proceeding;
- Georgia and Maryland permit the utility to adjust rate base and O&M during a "rate year" that begins after the test year and lasts another 12 months; and
- Georgia also has an earnings sharing mechanism that shares excess profits with customers by reducing the revenue requirement – after the first year when rates are in effect – with a share of the profit once the profit exceeds a dead band level in which no adjustment is required.

In addition, all of the states rely heavily on specialty riders, which are used extensively by regulators to carve-out portions of the revenue requirement and recover those expenses on an accelerated basis before the next rate case. The types of expenses identified for such carve-outs typically include:

- Environmental expenditures;
- Fuel and purchased power;
- Capital expenditures for reliability and infrastructure renewal;
- Revenue shortfalls/windfalls due to variations in sales (decoupling);
- Energy efficiency and demand side management;
- Transmission charges arising from application of FERC-regulated service;
- Storm damage cost recovery;
- Pensions and post-employment benefits;
- Stranded cost recovery arising from securitization of industry restructuring costs; and
- General tax and regulatory fee recovery.

3.2 Ontario – Electricity Distribution

The Ontario Energy Board has implemented a comprehensive IR regime for electricity distribution. The IR framework, including the mechanisms to fund new capital expenditures during the IR period and the rate adjustment mechanisms are set out in the following documents:

- *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*. October 18, 2012.
- *EB-2014-0219 Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*. September 18, 2014.
- *Filing Requirements for Electricity Distribution Rate Applications – 2014 Edition for 2015 Rate Applications* – Chapter 3: Incentive Regulation. July 25, 2014.
- OEB's Capital_Module_ACM_Model.xls.
- OEB's 2015_Incremental_Capital_Wrkfrm_v1.1.xlsm.

3.3 Ontario – Union Gas Limited

3.3.1 Mechanism to Fund New Capital Expenditures

On July 31, 2013, Union Gas filed a multi-year Incentive Regulation Mechanism that will be used to set Union's regulated distribution, transportation and storage rates over the 2014 to 2018 period, inclusively. The IR parameters are the product of a comprehensive settlement process and the Board approved the resulting Settlement Agreement on October 7, 2013. There is a custom capital pass-through mechanism, or ICM, in the Settlement Agreement.

As set out in Appendix 1, this ICM is intended to adjust rates during the IR term to reflect the associated impacts of significant capital investments made throughout the IR term deemed to be "not-business-as-usual". "Not-business-as-usual" refers to capital expenditures that are significant and cannot be managed within Union's Board-approved capital budget that is embedded in base rates.

The key features of this mechanism include:

1. Minimum increase or a minimum decrease, of $5 million in net delivery revenue requirement, for a single new project. Net delivery revenue requirement includes incremental OM&A expenses, depreciation expense, municipal property taxes expense, incremental long-term debt costs, and required return and income taxes net of any incremental delivery revenues arising from the project;
2. Capital cost of project, using the same capitalization policies used to set 2013 rates, must exceed $50 million;
3. Project is outside of the base rates on which the IR framework is set;
4. Project must be needed to service customers and/or maintain system safety, reliability or integrity and cannot reasonably be delayed and is demonstrated to be the most cost-effective manner of achieving the project's objective relative to the reasonably available alternatives;
5. Project would be identified to stakeholders and the Board as soon as possible;
6. Project would be subject to a full regulatory review, equivalent to a Leave-to-Construct proceeding, with the appropriate demonstration of need, safety or reliability purposes and economic viability prior to inclusion in rates;
7. Union would allocate the net revenue requirement using the 2013 Board-approved cost allocation methodologies; and
8. Project would include a deferral account to capture any differences between the forecast annual net delivery revenue requirement and actual net revenue delivery requirement for each year of the IR for which the project is included in rates. True-up will occur annually during the period the project is eligible for inclusion in the capital pass-through mechanism.

3.3.2 Rate Adjustment Mechanism

The net delivery revenue requirement for any year in the IR period is determined as follows:

1. Depreciation to be calculated using the 2013 Board-approved depreciation rates;
2. Required return would assume a capital structure of 64% long-term debt and 36% common equity;

3. Incremental long-term debt cost would be calculated based on expected financing costs for the incremental borrowing required by the project, market rates in effect at the time the project is approved;
4. Return would be calculated using the 2013 Board-approved return on equity of 8.93%;
5. Income and other taxes related to the equity component of the return would be calculated using the 2013 Board-approved tax rate of 25.5%;
6. The incremental delivery revenues associated with the project would be calculated as an offset to the delivery revenue requirement;
7. For the in-service year, all components of the calculation except taxes would be calculated only for the period from the month of in-service to the end of the year; and
8. The parameters would not change during the IR term.

3.4 Alberta Utilities Commission

3.4.1 Mechanism to Fund New Capital Expenditures

On September 12, 2012, the AUC issued its Generic Decision regarding its rate regulation initiative to reform utility rate regulation in Alberta. The first phase of the initiative was to implement a form of PBR for electric and natural gas distribution companies, in place of the existing cost of service regulatory system.

In that Decision, the AUC stated that it recognized that a mechanism to fund certain capital-related costs outside of the I-X (i.e. price cap) through a capital factor is required. Accordingly, the Commission has a capital tracker mechanism in the PBR plan. The capital tracker mechanism is warranted in circumstances where the company can demonstrate that a necessary capital replacement project or capital project required by an external party cannot reasonably be expected to be funded by the I-X mechanism.

The applicant must demonstrate the following criteria have been satisfied in order for a capital project to receive consideration or included in the capital tracker. In order to qualify, the project must:

1. Be outside the normal course of the company's ongoing operations;
2. Be for the replacement of existing capital assets or undertaking the project must be required by an external party; and
3. Have a material effect on the company's finances.

3.4.2 Rate Adjustment Mechanism

Annual capital tracker applications are to be submitted by March 1st of the year preceding the test year and must include a business case with respect to projects included in each proposed capital tracker. The business case includes forecast costs, being the amount proposed to be collected on an interim basis through the K Factor in the upcoming test year. If a project is expected to carry into future years, forecasts for the future years should also be included in order to assess the scope and scale of the project, including the materiality of the entire project to be considered.

The half year rule is applied to net capital additions in the test year of the utility's applied-for capital tracker. However, the half year effect is eliminated in the following year, when the opening net PPE of that year is multiplied by the full depreciation rate.

Alberta-based distribution utilities that wish to incorporate a K Factor into rates, must apply to the Commission no later than March 1 of the year preceding the year for which rates are to be effective. For example, if a distributor wants a K Factor to begin January 1, 2016, an application would have to be filed with the AUC no later than March 1, 2015.

The March 1 capital tracker application trues-up the costs of projects that have been completed since the prior year's capital tracker filing together with sufficient information to permit a prudence review of these completed projects. The results of the prudence review and the cost true-up will be an adjustment to the K Factor, included in the following year's rates.

The utility calculates the revenue requirements resulting from the actual capital tracker expenditures and compares them to the forecast amounts that were collected on an interim basis in the prior year. The difference between the approved revenue requirements and the forecast revenue requirement for the prior year will form the basis of the K Factor true-up rate adjustment. In addition, because the capital expenditures will remain in the tracker for the duration of the PBR term, the amounts to be included in the capital tracker revenue requirement calculations in subsequent years during the PBR term will be based on the actual approved expenditures rather than the initial forecasts.

Additional information relating to the rate adjustment mechanism is set out Section 5.2.2 of this report.

3.5 Ofgem – ET1 Price Control

3.5.1 Mechanism to Fund New Capital Expenditures

In 2013, Ofgem introduced RIIO (Revenue = Incentives + Innovation + Outputs), a new performance based model for setting network companies' price controls over 8 years. RIIO builds on the success of the previous RPI-X regime, but is designed to better meet the investment and innovation challenge. It does this by placing much more emphasis on incentives to drive the innovation needed to deliver a sustainable energy network that offers value for money to existing and future consumers. The RIIO framework is designed to promote smarter gas and electricity networks for a low carbon future.

Under RIIO, Ofgem asks companies to submit well-justified business plans detailing how they intend to meet the RIIO framework objectives. The process starts with the publication of a strategy document which sets out the framework against which the companies will develop their plans. Based on the quality of the business plan, past performance and benchmarking of the forecasted spending to others, Ofgem determines the level of review; either a "fast track" or "slow track" review. Where a company's business plan is of particularly high quality, Ofgem can determine whether the company's new price control settlements can be agreed early – i.e. "fast-tracked". Those companies that are not fast-tracked are asked to resubmit their business plans to Ofgem and are subject to a "slow track" review.

Network companies must provide forecasts of Total Expenditures (Totex) in the COS year to determine base rates. Totex comprises of: (1) controllable operating expenditures; (2) load related capital expenditures; (3) asset replacement capital expenditures; (4) other capital expenditures; and (5) non-operational capital expenditures. Network companies must also provide high level forecasts of Totex over the RIIO price controls period.[9]

The Price Control Financial Model (PCFM) for RIIO price controls is the financial model which derives the incremental changes to base revenue during the RIIO price control period. It does this by recalculating base revenues based on a limited number of updated variables. These variables fall into four broad

[9] Ofgem. (April 2014). RIIO-T1 Electricity Transmission Price Control – Regulatory Instructions and Guidance: Version 1.5.

categories: the annual cost of corporate debt, Totex components sufficient to apply the Totex incentive mechanism, new or amended allowances on uncertainty mechanisms and certain financial adjustments (such as pension variables, tax variables and legacy adjustments).

The Annual Iteration Process is the formal process of annually updating the variable values in the PCFM and for the calculation of the incremental change, positive or negative, on base revenues. This incremental change on base revenues is known as "MOD". Making these changes on an annual basis reduces the need to true-up financial adjustments during the price control period and simplifies the implementation of uncertainty mechanisms.

3.5.2 Rate Adjustment Mechanism

The Totex Incentive Mechansim (TIM) is the financial reward (or penalty) that companies are given in allowances for under- or over-spend on Totex. For RIIO-Electricity Transmission Term 1 ("ET1"), Final Proposals Opening Base Revenue Allowances have been modelled on the basis that actual Totex expenditure levels are expected to equal allowed Totex expenditure levels (allowances). Both the actual and allowed expenditure values contained in the PCFM can be varied for the purposes of applying the TIM through the Annual Iteration Process.

If actual expenditure differs from allowances, for any Relevant Year during the Price Control Period, the TIM provides for an appropriate sharing (based on the incentive strength, set out below) of the incremental amount, whether an over-spend or under-spend, between consumers and licensees.[10]

The TIM applies adjustments to the Totex figure used in the fast/slow money modelling of recalculated base revenue figures under the Annual Iteration Process. The adjustments reflect the amount of under- or over-expenditure by the licensee against Totex allowances and the Totex Incentive Strength Rate (incentive strength) for each licensee. The incentive strength is a percentage figure specified for each licensee. It represents the percentage that a licensee bears in respect of an over-spend against allowances or retains in respect of an under-spend against allowances. The adjustment that is made to the Totex figures is the Funding Adjustment Rate (often called the 'sharing factor') which is calculated as 1 – incentive strength. Applying the Funding Adjustment Rate to the over (or under spend) gives the amount that is added to (or subtracted from) the Totex allowances included in recalculated base revenues.

The TIM uses the actual Totex expenditure values reported to Ofgem by July 31 each year (subject to any revisions that may be required for corrections of data or for expenditure that is not regarded as efficient) and adjusts revenues in the following Relevant Year using the incremental change on base revenues or MOD term. The incentive mechanism therefore operates with a two year lag.

Totex, once ascertained under the TIM, is apportioned using the Totex Capitalization Rate applicable to the licensee, as:

- fast money – flowing directly to the recalculated base revenue figure for the Relevant Year to which the allowed expenditure relates; and
- slow money - additions to the licensee's regulated asset value (RAV) in the Relevant Year to which the allowed expenditure relates; the return on RAV and depreciation flowing to the recalculated base revenue figure for the Relevant Year.

[9]Ofgem. (April 2014). RIIO-T1 Electricity Transmission Price Control – Regulatory Instructions and Guidance: Version 1.5.

Illustrative examples of the calculation approach are set out below:

Opening position:

Allowed Totex expenditure:		100
Assumed actual Totex expenditure:		100
Over/underspend:		0
Totex amount for fast/slow money treatment:		100

Revised position – scenario 1:

Allowed Totex expenditure:		110	
Actual Totex expenditure			90
Underspend:		(20)	
Incentive strength:	40% (or 0.4)		
Totex adjustment:	(1 - 0.4) X (20)	(12)	

Totex amount for fast/slow money treatment: 110 – 12 = 98

Revised position – scenario 2:

Allowed Totex expenditure:		110
Actual Totex expenditure		120
Overspend:		10
Incentive strength:	40% (or 0.4)	
Totex adjustment:	(1 – 0.4) X 10	6

Totex amount for fast/slow money treatment: 110 + 6 = 116[11]

[10]Ofgem. (April 2014). RIIO-T1 Electricity Transmission Price Control – Regulatory Instructions and Guidance: Version 1.5.

4 Treatment of Working Capital

The treatment of working capital is generally consistent in all of the Canadian and U.S. jurisdictions studied. In the North American jurisdictions reviewed, working capital is generally included in rate base and as such, attracts the weighted average cost of capital permitted by the relevant regulator and taxes/PILs. Working capital balances are not depreciated; however, in some jurisdictions, working capital may include regulatory deferrals and other amounts that may be subject to amortization. The related amortization expense is generally determined in a manner that is separate from the process used to determine depreciation expense and/or cumulative depreciation for assets in rate base.

The treatment of working capital pursuant to the RIIO framework in the U.K. is more unique, reflecting the distinct approach adopted for ratemaking purposes. In the RIIO model, as set out in Appendix 3, working capital is included in the "slow money" calculation that is used to inform the determination of real asset value, or RAV, that attracts a return of and on capital.

Table15 highlights the treatment of working capital in each jurisdiction reviewed, in cost of service and PBR.

Table 15. Treatment of Working Capital in Rate Setting Processes

Jurisdiction	Cost of Service	Incentive Regulation
Ontario Electricity Distribution	Working capital required for operations is included in the determination of rate base in the COS year.	Working capital is not specifically addressed in an IR application. It is embedded in base rates, as per the rebasing year COS proceeding.
Ontario Electricity Transmission	Working capital required for operations is included in the determination of rate base in the COS year.	N/A (No incentive regulation)
Enbridge Gas Distribution	Working capital required for operations is included in the determination of rate base in the COS year.	In Enbridge's 5-Year Custom IR Plan, rate base, including the provision for working capital, is effectively rebased annually.
Union Gas	Working capital required for operations is included in the determination of rate base in the COS year.	Working capital is not specifically addressed in an IR application. It is embedded in base rates, as per the rebasing year COS proceeding.
Alberta Natural Gas And Electricity Distribution	Working capital required for operations is included in in the determination of rate base in the COS year.	An allowance for working capital is not included in the revenue requirement calculation for the K factor rate adjustment.

Jurisdiction	Cost of Service	Incentive Regulation
Nova Scotia Power	Cash working capital is included in the calculation of average rate base for the test year.	N/A (No incentive regulation)
FortisBC	Allowance for working capital is included in the calculation of rate base.	In the Targeted PBR regime in use by FortisBC, rate base, including WC, is calculated annually.
Newfoundland Power	Cash working capital is included in the calculation of rate base in the COS test year.	N/A (No incentive regulation)
Gaz Métro	Working capital is included in the calculation of rate base in the COS test year.	N/A (No incentive regulation)
Alabama Power Company	Non-cash working capital is included in the calculation of rate base.	N/A (No incentive regulation)
Southern California Edison	Both cash and non-cash working capital are included in the calculation of rate base.	N/A (No incentive regulation)
Georgia Power	Both cash and non-cash working capital are included in the calculation of rate base.	N/A (No incentive regulation)
Entergy Louisiana	Both cash and non-cash working capital are included in the calculation of rate base.	N/A (No incentive regulation)
Maryland Public Service Commission	Both cash and non-cash working capital are included in the calculation of rate base.	N/A (No incentive regulation)
Massachusetts Electric	Non-cash working capital is included in the calculation of rate base.	N/A (No incentive regulation)
Mississippi Power	Non-cash working capital is included in the calculation of rate base.	N/A (No incentive regulation)
Consolidated Edison Company of New York	Both cash and non-cash working capital are included in the calculation of rate base.	N/A (No incentive regulation)

Jurisdiction	Cost of Service	Incentive Regulation
PECO Energy Company	Both cash and non-cash working capital are included in the calculation of rate base.	N/A (No incentive regulation)
Ofgem	Working Capital included in rate base through "slow money" calculation.	RIIO is a comprehensive, multi-year rate setting regime that is a hybrid of cost of service and IR rate regimes.

Source: KPMG Analysis

5 ICM Materiality Threshold Formula

5.1 Introduction

The Board introduced the concept of an incremental capital module ("ICM") in its July 14, 2008 *Report of the Board on 3rd Generation Incentive Regulation* and identified a need to establish a materiality threshold. The formula, set out below, was specified following a stakeholder consultation and set out in the Supplemental Report of the Board in September 2008:

$$\text{Threshold Value} = 1 + \left[(RB/d) * (g+PCI*(1+g))\right] + 20\%$$

where:

RB is rate base included in base rates (i.e., approved rate base from last cost of service application) ($)

d is depreciation expense included in base rates (i.e., approved depreciation expense from its last cost of service application)($)

g is distribution revenue change from load growth (%)

PCI is price cap index (%), calculated as 2-Factor IPI – TFP – Stretch Factor

20% is a dead band added to the materiality threshold to prevent marginal applications[12]

The Board recently reviewed its ICM policy in the context of the RRFE and issued a subsequent policy document in September 2014 in which it introduced the Advanced Capital Module ("ACM"). This recent policy review did not result in a change in the Materiality Threshold Formula, although the policy re-specifies how some of the variables in the formula are to be derived.

The Materiality Threshold Formula continues to have two purposes in the Price Cap IR ICM/ACM framework:

1. The product of the Materiality Threshold Formula and the depreciation expense approved in the distributor's last cost of service application establishes the dollar value of capital that is reflected in base rates. As such, total capital expenditures for which an application is made pursuant to the ICM/ACM must be in excess of this amount; and

2. The difference between the forecasted total applied-for capital expenditures and the dollar value associated with the Materiality Threshold Formula result is equal to the maximum amount eligible for recovery pursuant to the ICM/ACM, for the applicable year.

Using the formula set out above, we have calculated an example Materiality Threshold for a pro-forma distributor, using the financial assumptions identical to the analyses presented elsewhere in this report. This analysis is set out in Table 16.

[12] Ontario Energy Board. (September 17, 2008). Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. EB-2007-0673. September 17, 2008. Page 33.

Table 16. Materiality Threshold Formula

Materiality Threshold Formula									
Cost of Service With Half Year Rule									
IR Framework With Customer Growth									
		Rebasing Year		**Year 2**		**Year 3**		**Year 4**		**Year 5**
Revenue Adjustment Mechanism										
Two Factor Inflation Adjustment				1.60%		1.60%		1.60%		1.60%
TFP Adjustment				0.00%		0.00%		0.00%		0.00%
Stretch Factor				0.30%		0.30%		0.30%		0.30%
Total Annual Cost Adjustment				**1.30%**		**1.30%**		**1.30%**		**1.30%**
Customer Growth and Demand Growth										
Composite Growth Rate (g)				1.25%		1.25%		1.25%		1.25%
Capital-Related Cost Recovered With Customer Growth										
Depreciation	$	127,500	$	130,772	$	134,128	$	137,570	$	141,100
Return on Capital	$	199,214	$	204,327	$	209,570	$	214,948	$	220,465
Taxes/PILs (Grossed-up)	$	40,461	$	41,500	$	42,565	$	43,657	$	44,777
Total	**$**	**367,176**	**$**	**376,598**	**$**	**386,263**	**$**	**396,175**	**$**	**406,342**
Threshold Test (No Dead Band)										
Proposed Rate Base	$	3,036,250	$	3,036,250	$	3,036,250	$	3,036,250	$	3,036,250
Threshold Calculation				161%		161%		161%		161%
Assumed Capital in Rates			**$**	**205,418**	**$**	**205,418**	**$**	**205,418**	**$**	**205,418**

Source: KPMG Analysis

We have calculated the Materiality Threshold without the dead band in order to clearly set out the quantum of capital notionally recovered in base rates using the approach. In our example, without the dead band, the amount of capital notionally recovered in rates is approximately $205,000.

5.2 Calculation of *g*

5.2.1 Current Approach

In the Board's policy document re: the Advanced Capital Module, the growth factor used in the Materiality Threshold Formula is described as follows:

> *g* is always to be expressed as an annual growth rate. Growth should be calculated based on the percentage difference in distribution revenues between the distribution revenues from the most recent complete year and the distribution revenues from the most recent approved test year.
>
> In the first and second IR years following rebasing, a distributor will likely not have a complete year of data following the cost of service base year. For these years, the growth factor may be updated to the difference between the Board approved distribution revenues from the last cost of service application and the most recent complete year prior to the rebasing year.[13]

In the *Filing Requirements for Electricity Distribution Rate Applications – 2014 Edition for 2015 Rate Applications*, the value of *g* is described as the percentage difference in distribution revenues between

[13] Ontario Energy Board. (September 19, 2014) Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module. EB-2014-0219. Page 29.

the most current complete year and the base year (i.e., the distributor's most recent Cost of Service test year when rates were rebased). In the actual ICM/ACM workform in the Board-issued model, growth is calculated as the change in revenue arising from growth in billing metrics. The rates are fixed at those approved in the last cost of service and billing metrics from the last current complete year are input, resulting in a revenue calculation that solely reflects the change in load (including customer growth, volumetric growth, and peak load growth) and is exclusive of the impact of PCI adjustments in IR.

This approach is consistent with the initial methodology filed in by Aiken & Associates in July 2008[14] and discussed in the subsequent Board-sponsored Stakeholder Consultation on August 6 and 7, 2008. When the formula was first proposed in 2008, customer growth was described as:

> …basically a weighted revenue growth using the same rates between the Board-approved test year revenues and the bridge year, revenues calculated at the test year rates. So the rates are the same, but then the customer growth, the volumetric growth and the peak growth, all of the different contributors to distribution revenue, would automatically be appropriately weighted using the same revenues[15].

There are a number of potential drawbacks with this approach that have been discussed in various Board processes:

1. The billing metrics from the Board-approved test year are weather normal, whereas the billing metrics associated with the last complete actual year are not weather normal, introducing a potential bias into the Materiality Threshold Calculation. This increases the risk that the formula mis-specifies the amount of capital that can be supported by base rates;

2. If the bridge year or last complete rate year is not immediately prior to or after the year of rebasing, the growth factor will be a multi-year change, not an annual adjustment. This increases the risk that the formula mis-specifies the amount of capital that can be supported by base rates; and

3. For the ACM/ICM rate rider calculation as part of an IRM application, the current approach is a historical calculation, rather than one that is informed by the forward test year data. If future load growth is expected to differ from past load growth, in terms of the amount and composition of growth, there is a risk that the formula mis-specifies the amount of capital that can be supported by base rates.

5.2.2 Approach Used by Alberta Utilities Commission

As set out previously in Section 3 of this report, the AUC has adopted a comprehensive PBR framework, which includes a capital tracker. As discussed, the Capital Tracker is a supplemental funding mechanism with the revenue requirement associated with approved amounts collected from rate payers by way of a "K Factor" adjustment to the annual PBR rate setting formula.

In its Distribution Performance-Based Regulation 2013 Capital Tracker Decision dated December 2013, the AUC approved the use of a growth factor in its Capital Tracker (K) mechanism, equal to the percentage change in distribution revenue from the test year (t) and the previous year (t-1). For

[14] Aiken & Associates. (July 28, 2008). EB-2007-0673: LPMA Notice of Intention to Participate.

[15] Ontario Energy Board. (August 6, 2008). EB-2007-0673: Stakeholder Consultation Transcript. Page 188.

companies under a price cap PBR plan, this percentage change is calculated across all billing determinants, including energy, demand, and number of customer on a forecast basis. For companies under the revenue-per-customer cap PBR plan, the percentage change is calculated as a forecast weighted average change in the number of customers among rate classes[16]. The forecast billing determinants are not trued up to actuals over the PBR period.

The growth factor (Q) in the AUC's framework is used to determine:

1. The amount of revenue the I-X mechanism will provide in a PBR year for a project or program proposed for capital tracker treatment, calculated as:

   Revenue from the I-X mechanism$_t$ = (Going in revenue requirement for project) $*$ $(1+I-X)_t$ $*$ $(1+Q)_t$

2. The portion of the revenue requirement for a project or program proposed for capital tracker treatment that is not funded under the I-X mechanism in a PBR year. This is calculated by taking the difference between the dollar value revenue result of the formula in (1) and the forecast revenue requirement for that project or program for the PBR year. If the difference is negative and certain materiality metrics are met, the difference is included in the K Factor calculation.

5.2.3 Alternative Approaches for Calculating g in Ontario Approach

There are a number of alternative approaches that could be used to calculate *g*:

- **Status Quo:** The current approach is relatively straight forward. It is understood by the distribution community and the stakeholder community. While KPMG understands the potential biases that might influence the current approach, we are not aware of any data that calculate the average difference between weather normal and actual billing metrics over time for each individual distributor or the distribution community on average. We are not aware of whether this approach results in a persistent bias that increases or reduces the calculation of *g* over time. If *g* is overstated due to a persistent bias in the actual weather data, the amount of capital notionally reflected in base rates would be overstated. We are also not aware of data that would make it clear whether the load growth profile over the IR period will be materially different than over the last five years, given that load was adversely affected over the last five years by the global recession that began in late 2008 and government-sponsored CDM initiatives. The change in billing metrics for all distributors in Ontario over the 2009 to 2013 period is set out below in Table 17.

Table 17. Total Ontario Load Growth 2009 to 2013

Ontario Load Growth 2009 to 2013	2009	2010	2011	2012	2013	CAGR
Total Customers	4,748,558	4,788,667	4,839,185	4,893,782	4,944,488	1.02%
Total kWh purchased	124,206,031,903	126,434,515,956	126,237,381,347	125,312,676,862	125,306,563,096	0.22%
Winter peak (kW)	20,444,679	20,361,418	19,985,709	19,257,939	22,532,722	2.46%
Summer peak (kW)	21,481,683	23,091,752	23,454,419	22,868,794	25,948,415	4.84%
Average monthly peak (kW)	17,870,038	19,286,768	18,851,165	18,732,319	21,614,876	4.87%

Source: Ontario Energy Board. Yearbook of Electricity Distributors, 2009 to 2013.

[16] Alberta Utilities Commission. (December 6, 2013). Distribution Performance-Based Regulation Decision 2013-435. Page 112.

- **Historical 5-Year Average Weather Normalized**: As set out in Section 2.6 of the Board's *Filing Requirements for Electricity Distribution Rate Applications* – Chapter 2 Cost of Service, distributors must provide their customer, volume and revenue forecast information in order to substantiate the applied-for operating revenue. As set out in Section 2.6.2 of the Filing Requirements, distributors must file the following information:

  Schedule of volumes (in kWh and in kW for those rate classes that use this charge determinant), revenues, customer/connections count by rate class and total system load in kWh for:

  - Historical Actual for the past 5 years;
  - Historical Board Approved;
  - Historical Actual for the past 5 years – weather normalized, if applicable;
  - Bridge Year;
  - Bridge Year – weather normalized; and
  - Test Year.

  It would be possible to use the weather normalized Historical Actual data for the past 5 years to calculate a geometric rate of growth for use in the Materiality Threshold Formula over the IR period. The primary drawback with this approach is that it continues to rely on historical rather than prospective data and goes back even further than what is currently required for ICM applications in years 1 and 2 following the most recent COS test year.

- **Cost of Service Test Year Versus Weather Normalized Bridge Yea**r: This rate of growth would be symmetrical with the assumptions used to set base rates and reflect estimated/forecast conditions, rather than rely on historical metrics. Both the bridge and test year metrics are weather normal. This growth rate could be used in each year of the IR period, without further modification. No additional data or filing requirements would be needed.

- **Estimate Load Growth for Each IR Year:** Similar to the approach used in Alberta, the rate of growth in billing metrics could be calculated on a weather normal basis for each of the IR periods following the cost of service year. The distributor would use the methodologies set out in the filing requirements to estimate each annual growth factor. This approach is potentially complex and is likely to be associated with additional filing and evidentiary requirements. The estimates are likely to be closely examined in a cost of service proceeding, potentially resulting in longer regulatory processes. It is not clear that the use of forecasts would result in greater accuracy, and it could introduce forecast errors that are larger than the potential biases described previously.

In general, the Board will have to balance a number of competing objectives in the process or method ultimately used to calculate *g*. These objectives include: process efficiency, greater accuracy and consistency with other policy initiatives.

- Process efficiency: There may be additional information and/or filing requirements required to support a revised methodology to calculate *g* or to true-up mechanisms that normalize for weather. There may also be a potential need for additional process, similar to the Alberta requirement for a filing by a defined date to facilitate the timely implementation of rates. Given the large number of annual rate applications processed by the Board, the Board uses a schedule with well-established dates for IR applications. These dates may have to be "backed up" if more complex calculations and evidentiary requirements are implemented in an IR application. Finally, additional complexity in the IR annual rates process may reduce the light-handed nature of the framework, reducing the potential for delegation of pro-forma IR applications to Board staff, requiring a greater time commitment by staff and the Board to process the application and consider the issues in the application.

- Greater accuracy: Although the potential for bias certainly exists within the current formula, KPMG does not have tangible quantitative evidence that the present calculation is resulting in a systemic bias in the Materiality Threshold Formula, resulting in a mis-specification of the amount of capital that is reflected in rates. It is not clear to us that changing the approach to calculating *g* will simply not result in substituting one potential bias for another. For example, moving to a calculation that relies on a forecast methodology without a true-up mechanism may introduce an estimation error that is larger than the potential inconsistency between the use of weather normal and weather actual results.

- Consistency with other policy initiatives: KPMG is aware that the Board initiated EB-2012-0410 in November of 2012 – Rate Design for Electricity Distributors (formerly known as Revenue Decoupling for Distributors). Submissions on this consultative process were filed with the Board on July 8, 2014. As highlighted in the AUC's PBR process, the calculation of *g* is dependent upon the form of PBR: price cap versus a revenue-per-customer cap. KPMG observes that as the Board has not yet issued its policy on this issue. KPMG therefore did not, and was not asked to, determine which calculation of *g* is optimal in a rate-setting environment where all distribution revenue is collected on a per customer basis.

The weight the Board places on each of these objectives in its determination of how to calculate *g* is likely to relate back to the function of *g* in the ICM Threshold Formula. The purpose of specifying *g* is to estimate the growth in billing metrics over the test year or the period for which the ICM/ACM is being considered. Growth in billing metrics increases the revenue collected by a distributor each year over the IR term.

5.3 Dead Band Variable

As set out in the formula, the Materiality Threshold Formula includes a dead band adder of 20%. In our example the use of a 20% dead band has the effect of increasing the amount of capital that is notionally supported in base rates to approximately $231,000 from approximately $205,000.

The dead band factor of 20% was initially set as a discretionary determination of the Board, based on the need to balance a number of competing regulatory policy objectives:

- Prevent marginal applications: the initial intention was that use of the ICM was to be the exception rather than the norm;

- Preserve the incentives associated with comprehensive IR: applications for amounts that could reasonably be managed within the current or existing capital budget of the distributor preserve the integrity of the Board's comprehensive IR framework by avoiding selective rebasing and encouraging distributors to be efficient with capital investment;

- Ensure regulatory process efficiency and simplicity: limit the scope and complexity of issues that should be considered in an IR application, preserving the light-handed and expedited nature of the IR rates process;

- Create a consensus among stakeholders who presented varying approaches to measuring the amount of capital that was notionally reflected in base rates and made different submissions on the quantum of the dead band (ranging from 10% to 50%); and

- Reflect the static nature of the calculation: the Materiality Threshold Formula is a single year calculation. The depreciation expense, cost of capital, and taxes/PILs reflected in actual rates are subject to annual adjustment by the Price Cap Index and the resulting increases are subject to the effect of compounding over the IR period. The Materiality Threshold Formula does not reflect the passage of time, as both the depreciation and rate base that are used in the formula are the metrics approved by the Board in the distributor's last cost of service and adjusted based on a single year's PCI and customer growth. As such, IR rates may notionally support more capital in base rates than is reflected in the Materiality Threshold Formula.

The ACM transitions the Price Cap IR framework somewhat closer to a targeted IR regime by providing distributors with an opportunity (in the cost of service application) to identify discrete projects in their distribution service plan which may qualify for ACM/ICM treatment in the IR years. However, the Board must still balance the following competing regulatory policy goals:

- Encourage effective distributor planning and the development of appropriate Asset Management plans as part of the cost of service applications;

- Reduce the tendency for capital projects to be clustered around the test year;

- Align the schedule for setting rates with the timing of investments dictated by prudent asset management practice;

- Ensure effective or improved access by distributors to the ratemaking tools made available by the Board, subject to the criterion established by the Board governing the use of those tools;

- Ensure regulatory process efficiency and simplicity;

- Preserve the incentives associated with an IR regime that is designed to encourage distributor efficiency; and

- Reflect the static nature of the Materiality Threshold Formula and protect rate payers from paying for incremental capital expenditures that are already notionally reflected in base rates.

The determination of the dead band is ultimately a discretionary determination of the Board, using its expert judgment to balance the competing objectives set out above.

The foregoing regulatory policy goals suggest that the dead band could be reduced for both the ICM and ACM, and still achieve the balance required by the Board.

For example as set out in Table 18, if the dead band is maintained at the 20% level and if we assume that the Board has approved forecast rate base and depreciation in the distributor's last cost of service, consistent with the methodology set out in the ACM Report of the Board, the Materiality Threshold Formula in our example would generate a dollar value of capital in rates which is larger than the notional capital reflected in rates throughout the IR period. Maintaining the dead band at 20% may not be responsive to the regulatory goals related to distributor planning and effective/improved access to available regulatory tools.

Table 18. 20% Dead Band

Threshold Tests with No Dead Band and 20% Dead Band										
		Rebasing Year		Year 2		Year 3		Year 4		Year 5
Capital Expenditures Notionally Reflected in IR Rates (No Dead Band)										
Notional Rate Base	$	3,036,250	$	3,114,168	$	3,194,085	$	3,276,053	$	3,360,125
Threshold Calculation		161%		161%		161%		161%		161%
Amount of Capital in Rates	$	205,418	$	210,689	$	216,096	$	221,642	$	227,330
Theshold Test 20% Dead Band - reflects ACM where Rate Base and Depreciation in Yrs 2 - 5 is Board Approved										
Proposed Rate Base	$	3,036,250	$	3,106,875	$	3,173,750	$	3,236,875	$	3,296,250
Threshold Calculation		181%		181%		180%		180%		179%
Assumed Capital in Rates	$	230,918	$	237,230	$	243,446	$	249,566	$	255,590

Source: KPMG Analysis

Table 19. 0% Dead Band

Threshold Tests with No Dead Band and 0% Dead Band										
		Rebasing Year		Year 2		Year 3		Year 4		Year 5
Capital Expenditures Notionally Reflected in IR Rates (No Dead Band)										
Notional Rate Base	$	3,036,250	$	3,114,168	$	3,194,085	$	3,276,053	$	3,360,125
Threshold Calculation		161%		161%		161%		161%		161%
Amount of Capital in Rates	$	205,418	$	210,689	$	216,096	$	221,642	$	227,330
Theshold Test 0% Dead Band - reflects ACM where Rate Base and Depreciation in Yrs 2 - 5 is Board Approved										
Proposed Rate Base	$	3,036,250	$	3,106,875	$	3,173,750	$	3,236,875	$	3,296,250
Threshold Calculation		161%		161%		160%		160%		159%
Assumed Capital in Rates	$	205,418	$	210,980	$	216,446	$	221,816	$	227,090

Source: KPMG Analysis

However, if the dead band were to be reduced from 20% to 0% as set out in Table 19, the assumed capital reflected in rates declines in our example, and would be roughly equal to the notional capital in IR rates over the IR period. Our example suggests that as long as the ICM/ACM threshold calculation uses the rate base and depreciation metrics approved by the Board for each year in the IR period in the base-year cost of service application, there is only a small risk that customers would pay for incremental capital expenditures that are already notionally reflected in IR rates.

5.4 Effect of Transition to IFRS and TFP

5.4.1 Total Factor Productivity

The Board has used Total Factor Productivity to determine the productivity factor in its formula-based IR rate-setting regime since 2008, as set out in EB-2007-0673 *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*. In the Board's Renewed Regulatory Framework report dated October 18, 2012, the Board determined that the productivity factor will be based on Ontario electricity distribution industry TFP trends, and should be derived from an objective, data-based analysis that is transparent and replicable.

The Board retained Pacific Economics Group Research LLC ("PEG") to advise it on productivity and benchmarking research in support of IR in Ontario. In its November 2013 report, PEG estimated that TFP for the Ontario electricity distribution sector grew at an average rate of -0.33%. PEG also indicated that a negative productivity factor would not be appropriate and instead recommended that the productivity factor in Price Cap IR be set at zero.

The Board subsequently set the TFP metric to be included in Price Cap IR at 0% for the period 2014 to 2019, largely due to concern that the decline in distributor output over the 2002 to 2012 period resulting in negative productivity growth, was the result of a mis-alignment between the costs used as inputs for distributor rate adjustments and the costs actually subject to that rate adjustment. In other words:

> It would not be appropriate for costs previously recovered outside of base rates to be reflected in the TFP trend, and therefore the rate adjustment mechanism, that will apply during an IR term. Doing so would mean increasing future customer rates to pay for costs that have already been recovered in previous customer rates.[17]

The Board Report indicates that there are three unusual and one-time events that caused distributor OM&A costs to be 11.14% higher in 2012 versus 2011[18]: (1) methodology of reporting in relation to OPA CDM program costs; (2) the adoption of IFRS by some distributors impacting regulatory reporting requirements; and (3) unusually large deferral account dispositions, including smart meter investment accounts. The report also highlights that PEG subsequently adjusted its TFP analysis to remove the impact of these items (to the extent practicable).

It is important to note that the Board is aware that future TFP analysis may yield anomalous results:

> The Board acknowledges that achieved industry TFP may be negative due to unforeseen events and/or situations in which costs may be incurred with no corresponding increase in output. However, there are rate setting tools in the Board's Price Cap IR framework to deal with these circumstances (e.g. cost of service rebasing at start of term, Off-ramp, Z-factor; LRAM, deferral and variance accounts to deal with Government policy directives, and the ability to apply for an Incremental Capital Module during the term).[19]

KPMG has been asked to determine whether the use of TFP to inform the IR rate adjustment mechanism affects the appropriate dead band variable to be used, as the PCI-factor in the 3rd Generation IRM mechanism at the time that the ICM was first adopted was based on a Partial Factor Productivity analysis.

As such, we believe that the following observations are relevant:

- Given that TFP is used in both the revenue adjustment mechanism for IR and the Materiality Threshold Formula, we are of the view that no additional biases are introduced into the relationship between these two ratemaking tools that would require a change in the dead band metric.

- However, as set out above, the acknowledgement by the Board that there may be costs, operating and/or capital in nature, that are not reflected in the productivity factor in the IR revenue adjustment mechanism and are recovered via mechanisms outside of base rates, suggests that distributors may

[17] Ontario Energy Board. (November 21, 2013). Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors. EB-2010-0379. Page 21.

[18] Ibid. Page 17.

[19] Ibid. Page 17.

require access to additional funding during the IR term to meet these unforeseen events and/or situations where capital costs may be incurred with no corresponding increase in output. Directionally, these circumstances suggest that the dead band metric in the Materiality Threshold Formula should be lower rather than higher, to ensure that distributors have effective access to the regulatory mechanisms highlighted by the Board in the quote above.

5.4.2 Transition to IFRS

The OEB has issued a number of regulatory policies and accounting policies since 2009 that proactively address the conversion to IFRS by the rate regulated community in Ontario. The key regulatory and accounting policies are set out in Table 20 below.

Table 20. Regulatory and Accounting Policy Documents

Date	Title	Description
July 28, 2009	*Report of the Board: Transition to International Financial Reporting Standards -EB-2008-0408*	Report addresses the adjustments that should be made to regulatory reporting and filing requirements, including: • Adoption of regulated net book value to be used as the basis for setting opening rate base values upon the adoption of IFRS accounting and that historical acquisition cost should be used as the basis for reporting PP&E for regulatory purposes going forward. • Requirement that utilities adhere to IFRS capitalization accounting requirements for ratemaking and regulatory reporting purposes after the date of adoption by IFRS (i.e., no capitalization of overhead and indirect costs in PP&E). The utility is to file a copy of its capitalization policy, identifying any updates to the policy, as part of its first cost of service rate filing after IFRS adoption. Revenue requirement impacts of any change in capitalization policy must be specifically and separately quantified. • Change in depreciation policy to reflect the componentization of asset classes versus the group depreciation approach currently in use. OEB conducted a depreciation study for use by distributors to satisfy the IFRS requirement that a review of useful life, depreciation methods and residual values are to be conducted annually. • Changes to depreciation and capitalization policies would be applied uniformly and in the same timeframe by all distributors. • Assets that are retired are removed at net book value from rate base at the date of retirement.
July 8, 2010	Kinectrics Inc. Asset Depreciation Study	Report commissioned by the OEB to help distributors meet the requirements of the July 2009 policy, including the requirement that distributors adopt useful life estimates that do not depend on the regulator and are determined by independent asset service life studies.
November	Letter Re: Transition to IFRS – Amendment to	Delay of transition to IFRS by 1 year, to January 1, 2012. Letter updates

Date	Title	Description
8, 2010	Board Policy	certain policy statements and mandatory transition date to IFRS.
July 13, 2011	Addendum to Report of the Board: Implementing IFRS in an IR Environment – EB-2008-0408	Board authorizes the creation of a generic IFRS transition PP&E deferral account (1575) to record differences arising as a result of accounting policy changes caused by the transition from CGAAP to MIFRS. Specifically, the account will track the difference between: (1) PP&E using CGAAP that are included in rate base; and (2) adjusted rate base value of PP&E components of rate base. This difference will be tracked for each year between rebasing under CGAAP and the first rebasing under MIFRS. The amount of the cumulative adjustment up or down should be recorded as a balance to be recovered from, or refunded to, ratepayers and as an adjustment to opening rate base in the year of rebasing. The unamortized balance in the deferral account will be included in rate base. Rate base will therefore be comprised of two components: the MIFRS based elements of PP&E and the unamortized balance in the deferral account. The total will attract the same cost of capital in rates.
July 17, 2012	Letter Re: Regulatory Accounting Policy Direction Regarding Changes to Depreciation Expense and Capitalization Policies in 2012 and 2013	Makes the requisite changes to depreciation expense and capitalization policies for regulatory accounting purposes mandatory for January 1, 2013, even if the transition to IFRS/MIFRS is delayed beyond this date. Establishes a new variance Account 1576, Accounting Changes Under CGAAP, for distributors to record the financial differences arising as a result of the election to make these accounting changes under CGAAP in 2012 or to make these changes as mandated by the Board in 2013.
June 25, 2013	Letter Re: Accounting Policy Changes for Accounts 1575 and 1576	Requires disposition of these account balances effective for the 2014 cost of service rate applications and subsequent rate years. The Board will require a rate of return component to be applied to the balance in Account 1576 upon its disposition in rates and will require the use of separate rate riders for the disposition of the balances in 1575 and 1576. Disposition period for accounts 1575 and 1576 will be determined on a case-by-case basis.

Source: KPMG Analysis

The transition to MIFRS on January 1, 2015 and the changes to depreciation and capitalization that were effective January 1, 2013 may alter the relationships between the key variables used in the Materiality Threshold Formula, potentially resulting in the mis-specification of the quantum of capital expenditures that are supported by base rates.

This issue is likely to be transitional:

1. For those utilities where rates fully reflect: (i) the conversion to MIFRS; (ii) adjusted PP&E and are refunding/recovering the difference in rates; (iii) have adopted the new depreciation rates/capitalization approach; and (iv) removal at the net book value of assets retired from service, the threshold formula may produce different results than would be the case under CGAAP, however the new absolute level of each variable and relationship between the variables would be reflected in rates, minimizing the mis-specification potential.

   However, until the balance in Account 1575 is fully amortized (assuming this balance is material), rate base will continue to reflect this transitional balance, suggesting that the application of the Threshold Formula over the amortization period may result in the overstatement of the quantum of capital expenditures that are supported by base rates in IR.

2. For those utilities where rates reflect: (i) adjusted PP&E and are refunding/recovering the difference in rates; (ii) have adopted the new depreciation rates/capitalization approach; and (iii) removal at the net book value of assets retired from service, but not yet converted to MIRFS, there is a greater risk of mis-specification, as discussed below.

As at the date of this report, KPMG understands that:

- Rates for approximately 49 distributors fully reflect adjusted PP&E and the new depreciation rates/capitalization approach. Of these distributors:

  - 13 have also adopted MIFRS;

  - 2 have adopted an alternative accounting standard;

  - 33 will adopt MIFRS effective January 1, 2015; and

  - The planned adoption date of MIFRS by one distributor is unknown.

- Rates for 30 distributors do not yet reflect adjusted PP&E, new depreciation rates/capitalization approach, and MIFRS.

KPMG also understands that the Board does not track the following data (in aggregate), although it would be on the record in each of the rate applications for those individual distributors who rebased their rates from 2012 onwards:

- The average reduction in either the composite depreciation rate or the dollar value of depreciation expense as a result of transitioning to the new depreciation rates as per the Kinetrics report;

- The average change (up or down) in PP&E/rate base resulting from the change associated with the capitalization of overhead and indirect costs; and

- The change in rate base arising from the removal at net book value of assets retired from service.

However, even if this data was readily available, it is not clear that data from any one individual distributor would be representative of the sector as a whole, as the age, state of repair, investment policies, and book value of assets varies across the sector.

What is generally observed in cost of service applications where the changes in depreciation rates, capitalization policy, removal of retired assets at net book value, and where the transition to IFRS have been effected in rebased rates:

- The inability to capitalize overhead and indirect costs in rate base after January 1, 2013 has the effect of lowering rate base.
- The change in depreciation policy from group depreciation to a componentization of asset classes approach and adoption of the Kinetrics depreciation rates has the effect of reducing depreciation expenses, subject to being partially offset by an increase in depreciation expense associated with the inclusion of retirement losses on assets removed from rate base.
- The removal of the net book value of a retired asset from rate base at the date the asset is retired has the effect of reducing rate base.

If the decline in depreciation expense is larger than the decline in rate base, such that the historical relationship between the variables is no longer valid and this new relationship is not yet fully reflected in rates and regulatory accounts, the use of the Materiality Threshold Formula with a 20% dead band will overstate the amount of continuing capital expenditures that can be supported via existing rates.

6 Recommendations

KPMG has been asked to include options and recommendations with respect to changes that may be required to:

- The half year rule during the IR period;
- Use of the growth factor and dead band variable used in the Materiality Threshold Formula of the ICM; and
- Treatment of working capital allowance under cost of service and/or alternative forms of ratemaking.

Based on the work that KPMG has performed in conjunction with this engagement and presented in this report, we offer the following thoughts to the Board for its consideration. We are aware that potential changes to the treatment of working capital, the half year rule in IR, and the *g* and dead band factor in the Materiality Threshold Formula will ultimately be largely discretionary determinations of the Board, using its expert judgment to balance competing interests, largely based on qualitative rather than quantitative considerations.

Our thoughts are as follows:

1. **Treatment of Working Capital:** Based on the jurisdictional review presented herein, we understand that working capital is reflected in rate base in all of the jurisdictions reviewed. As such, it attracts the weighted average cost of capital allowed by the regulator in each jurisdiction and these costs are reflected in both cost of service rates and rates in subsequent IR years. On this basis, it is not clear to us that there is a reasonable basis upon which an alternative treatment would be warranted.

2. **Half year rule during the IR period:** The half year rule is a rule of thumb or proxy designed to emulate how capital additions are closed to rate base in the test year. It is a recognition that planned capital additions in a test year do not all enter service at the beginning of the test year. It is also illustrative of a ratemaking approach that balances utility and customer interests. Our review indicates that virtually all jurisdictions incorporate either the half year rule or a variant thereof, usually a monthly roll-up of capital placed in service.

   Our analysis is primarily concerned with the half year rule associated with capital additions that are closed to rate base in the cost of service or rebasing year. We also assessed whether the elimination of the effect of the half year rule in the first year following rebasing created a revenue deficiency or sufficiency versus the base case annual cost of service approach. We undertook sensitivity analysis pursuant to the stakeholder consultation to determine the materiality of the revenue deficiency that may result from the use of the half year rule.

   Although we acknowledge that our analysis has limitations, we believe that the results are directionally correct. Based on the relationships illustrated by our numerical example and the additional sensitivity analysis conducted pursuant to the stakeholder consultation, we believe that the use of the half year rule associated with capital additions closed to rate base during the cost of service or rebasing year is likely to create a revenue deficiency in the subsequent IR period when capital expenditures are greater than or equal to the amount of capital expenditures notionally reflected in base rates. Whether the revenue deficiency arising from the half year rule in IR is large enough to meet the Materiality Thresholds as per the Board's Filing Requirements for Electricity Distribution Rate Applications would be a question of fact, based on the particular situation of the distributor.

We also note that as capital expenditures grow to levels in excess of the amount of capital expenditures reflected in base rates, the portion of the revenue deficiency attributable to the half year rule declines significantly and is overtaken by the revenue deficiency resulting from the size of the capital budget itself.

If planned capital expenditures are less than or equal to the notional CapEx reflected in rates and IR rates are normalized for the effect of the half year rule, the capital costs collected in IR rates would exceed the capital costs recovered in COS rates with the half year rule in use. If planned capital expenditures are greater than the notional CapEx reflected in IR rates that are normalized for the effect of the half year rule in the rebasing year, all of the revenue deficiency observed is attributable to the size of the capital program in relation to the notional CapEx reflected in rates and is unrelated to the half year rule.

Based on our analysis, we suggest that use of the half year rule in the rebasing year continues to strike a reasonable balance between ratepayer and distributor interests.

We suggest that IR rates **not** be normalized for the effect of the half year rule in the rebasing year on a pro forma basis for all distributors due to the potential for normalized IR rates to be greater than those associated with an annual cost of service rates scenario.

We suggest that if a distributor's specific circumstances are such that IR rates are not compensatory with respect to its planned capital program and the revenue requirement deficiency in IR resulting from the half year rule meets or exceeds the Board's Materiality Thresholds, there are a number of avenues for potential rate relief. For example, the Board permits the use of alternative methods to calculate the depreciation expense associated with capital that is closed to rate base in the cost of service year and has implemented a Custom IR rate making regime in the RRFE, in which a distributor may apply to normalize custom IR rates for the effect of the half year rule in the rebasing year.

This approach would allow the Board to consider whether the combined effect of normalized IR rates and other forms of relief, including our suggestions set out below regarding the Dead Band Variable in the Materiality Threshold, result in rates that are just and reasonable and strike an appropriate balance between the customer and the utility or whether additional tools are required to achieve this balance, such as a capital expenditure tracker mechanism.

3. Calculation of the Growth Factor and Dead Band Variable

- **Growth Factor (*g*):** The current approach to calculating *g* is well understood by the Board, distributors, and stakeholders. While the current approach to calculating *g* has a number of potential issues, we did not have any quantitative evidence to assess the materiality of these identified shortcomings. While we believe that there is a risk that the method used to calculate *g* may give rise to a mis-specification of the amount of continuing capital that is supported by base rates, we are also aware that calculating *g* using one of the alternatives identified may introduce new biases and may not be consistent with other policy initiatives of the Board. Even if a new method of calculating *g* were to be more accurate, it may also introduce additional process requirements which could be a disadvantage.

- **Dead Band Variable:** Based on the following factors and our observations relating to the half year rule, we believe that there is a reasonable basis upon which to support a reduction in the quantum of the dead band variable incorporated into the Materiality Threshold Formula in the ACM/ICM:

- Greater familiarity with the ICM generally, and a view that the mechanism has been tested and is serving the purpose for which it was intended;

- Change in the regulatory policy approach with the creation of the ACM, such that greater use of by the distribution community is expected and anticipated pursuant to the RRFE than in 2008, when the ICM was initially introduced in 3rd Generation IR;

- Greater regulatory policy focus on distributor planning, effective asset management, smoothing of capital investment, and reduction of clustering of capital expenditures around the rebasing or cost of service year;

- Accounting policy changes implemented by the Board and identified in this report suggest that there is a risk that the Materiality Threshold Formula, with a 20% dead band, over-estimates the amount of continuing capital expenditures that can be supported via existing rates; and

- Use of a growth factor, as set out herein, may also introduce a bias into the Materiality Threshold Formula.

We also note that the Board must also balance the following considerations:

- Ensure that customers are not paying again for capital expenditures already reflected in base rates;

- Prevent marginal applications;

- Preserve the incentives associated with comprehensive IR; and

- Ensure regulatory process efficiency and simplicity.

Based on all of these factors, our suggestions relating to the half year rule, and the related numerical and sensitivity analyses set out in this report, we believe there is a reasonable basis upon which to reduce the dead band used in the Materiality Threshold Formula to 0% from 20% for both the ACM and ICM.

KPMG thanks the Board for the opportunity to complete this mandate and would be pleased to discuss this report, at the Board's convenience.

7 Bibliography

Aiken and Associates. (July 2008). What is an appropriate capital expenditure to depreciation threshold value to determine materiality? *London Property Management Association.* Submitted to the Ontario Energy Board on July 28, 2008. EB- 2007-0673. Available at: http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2007-0673/presentation_LPMA_SUB_20080725.pdf

Alabama Power (November 2001). Rate ECR Energy Cost Recovery Rate, November, 2001 Billings. Available at: http://www.alabamapower.com/business/pricing-rates/rate-riders-adjustments.asp

Alabama Power. (October 2011). Rate T Tax Adjustment, October, 2011 Billings. Available at: http://www.alabamapower.com/business/pricing-rates/rate-riders-adjustments.asp

Alabama Power. (September 2013). Rate RSE Rate Stabilization and Equalization Factor. Available at: http://www.alabamapower.com/business/pricing-rates/rate-riders-adjustments.asp

Alabama Power. (October 2013) Rate CNP Adjustment for Commercial Operation of Certificated New Plant. Available at: http://www.alabamapower.com/business/pricing-rates/rate-riders-adjustments.asp

Alberta Utilities Commission. (April 2011). ATCO Electric Ltd., 2011-2012 Phase I Distribution Tariff, 2011-2012 Transmission Facility Owner Tariff. Decision No. 2011-134

Alberta Utilities Commission. (September 2012). Rate Regulation Initiative, Distribution Performance-Based Regulation. Decision No. 2012-237.

Alberta Utilities Commission. (December 2013). Distribution Performance-Based Regulation 2013 Capital Tracker Applications. Decision No. 2013-435.

Algoma Power Inc. (May 2015). 2015 Electricity Distribution Rate Application for Algoma Power Inc. EB-2014-0055

ATCO Electric Ltd. (May 2010). ATCO Electric Ltd. 2011-2012 General Tariff Application, Transmission and Distribution.

ATCO Electric Distribution Division. (May 2014). 2014-2015 Capital Tracker Application & 2013 Capital Tracker Refiling True-Up Application. Page 78

Baltimore Gas & Electric Company. (December 2010). P. S. C. Md. – E-6 (Suppl. 471), 14. Qualified Rate Stabilization Charge – Effective 12/04/10. Available at: http://www.bge.com/myaccount/billsrates/ratestariffs/electricservice/pages/electric-services-rates-and-tariffs.aspx

Baltimore Gas & Electric Company. (April 2013). P. S. C. Md. – E-6 (Suppl. 525), 25. Monthly Rate Adjustment– Effective 06/19/2013. Available at: http://www.bge.com/myaccount/billsrates/ratestariffs/electricservice/pages/electric-services-rates-and-tariffs.aspx

Baltimore Gas & Electric Company. (November 2013). P. S. C. MdE-6 (Suppl. 532), 2. Electric Efficiency Charge– Effective January 2014 Billings. Available at: http://www.bge.com/myaccount/billsrates/ratestariffs/electricservice/pages/electric-services-rates-and-tariffs.aspx

Baltimore Gas & Electric Company. (December 2013). P. S. C. Md. E-6 (Suppl. 535) 3. Miscellaneous Taxes and Surcharges – February 2014 Billings. Available at:

http://www.bge.com/myaccount/billsrates/ratestariffs/electricservice/pages/electric-services-rates-and-tariffs.aspx

Baltimore Gas & Electric Company. (February 2013). P. S. C. Md. – E-6 (Suppl. 520) 12. Sparrows Point (SPE) Revenue Stabilization Rate – Effective 02/23/2013. Available at: http://www.bge.com/myaccount/billsrates/ratestariffs/electricservice/pages/electric-services-rates-and-tariffs.aspx

Baltimore Gas & Electric Company. (March 2014). P. S. C. Md. – E-6 (Suppl. 538), 16. Nuclear Decommissioning and Standard Offer Service Return Credits – Effective 03/01/2014. Available at: http://www.bge.com/myaccount/billsrates/ratestariffs/electricservice/pages/electric-services-rates-and-tariffs.aspx

Baltimore Gas & Electric Company. (March 2014). P. S. C. Md. – E-6 (Suppl. 554), 30. Demand Resource Surcharge - Effective 06/01/2014. Available at: http://www.bge.com/myaccount/billsrates/ratestariffs/electricservice/pages/electric-services-rates-and-tariffs.aspx

Baltimore Gas & Electric Company. (April 2014). *P. S. C. Md. – E-6 (*Suppl. 554), 31. Electric Reliability Investment Initiative Charge – Effective 06/01/2014. Available at: http://www.bge.com/myaccount/billsrates/ratestariffs/electricservice/pages/electric-services-rates-and-tariffs.aspx

British Columbia Utilities Commission. (August 2012). An Application by FortisBC Inc. for Approval of 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan.

British Columbia Utilities Commission. (September 2014). FortisBC Energy Inc. Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 Decision

British Columbia Utilities Commission. (September 2014). FortisBC Inc. Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 Decision

California Public Utilities Commission. "Application of Southern California Edison Company (U338E) for Authority to, among other things, Increase its Authorized Revenues for Electric Service in 2015, and to reflect that increase in Rates" (Docket No. A1311003), Southern California Edison, 2015 General Rate Case Application, SCE-10, Vol. 01 (Public Version): Results of Operations (R/O) Volume 1 – Requested Revenue Requirements, Ratemaking, Forecasts of Sales, Other Operating Revenue, Cost Escalation, Post-Test Year Ratemaking.

California Public Utilities Commission, "Application of Southern California Edison Company (U338E) for Authority to, among other things, Increase its Authorized Revenues for Electric Service in 2015, and to reflect that increase in Rates" (Docket No. A1311003), Southern California Edison, 2015 General Rate Case Application Workpapers – Results of Operations (RO) Plant, Taxes, Depreciation Expense and Reserve, Rate Base, and Productivity SCE-10 Volume 02, Chapter V.

Consolidated Edison Company of New York, Inc. (January 2014). PSC NO: 10 – Electricity: Statement of System Benefits Charge. Available at: http://www.coned.com/rates/elec.asp

Consolidated Edison Company of New York, Inc. (March 2014). PSC NO: Statement of Delivery Revenue Surcharge. Available at: http://www.coned.com/rates/elec.asp

Consolidated Edison Company of New York, Inc. (July 2014). PSC NO: 10 – Electricity: Statement of Surcharge to Collect PSL 18-a Assessments. Available at: http://www.coned.com/rates/elec.asp

Consolidated Edison Company of New York, Inc. (October 2014). PSC NO: 10 – Electricity: Statement of Revenue Decoupling Mechanism Adjustment. Available at: http://www.coned.com/rates/elec.asp

Consolidated Edison Company of New York, Inc. (October 2014). PSC NO: 10 – Electricity: Statement of Charge for Renewable Portfolio Standard Program.

Consolidated Edison Company of New York, Inc. (December 2014). PSC NO: 10 – Electricity: Statement of Monthly Adjustment Clause. Available at: http://www.coned.com/rates/elec.asp

ENMAX Power Corporation. (July 2013). 2014-2015 Transmission General Tariff Application and 2014 Phase I Distribution Tariff Application

Entergy Louisiana LLC. (May 2007). Rider Schedule NFRPCEA: Non-Fuel Rough Production Cost Equalization Adjustment Rider. Available at: http://www.entergy-louisiana.com/your_business/EGSI_Tariffs.aspx

Entergy Louisiana LLC. (May 2007). Rider Schedule RPCEA: Rough Production Cost Equalization Adjustment Rider. Available at: http://www.entergy-louisiana.com/your_business/EGSI_Tariffs.aspx

Entergy Louisiana LLC. (July 2008). Rider SCO: Storm Cost Offset Rider SCO. Available at: http://www.entergy-louisiana.com/your_business/EGSI_Tariffs.aspx

Entergy Louisiana LLC. (July 2008). Rider FSC-ELL: Financed Storm Cost Rider FSC-ELL. Available at: http://www.entergy-louisiana.com/your_business/EGSI_Tariffs.aspx

Entergy Louisiana LLC. (July 2009) *Rider EAC: Environmental Adjustment Clause Rider*. Available at: http://www.entergy-louisiana.com/your_business/EGSI_Tariffs.aspx

Entergy Louisiana LLC. (July 2009). Rider FIORE: FERC Interruptible Order Retail Effects Rider. Available at: http://www.entergy-louisiana.com/your_business/EGSI_Tariffs.aspx

Entergy Louisiana LLC. (July 2010). Rider FSCII-ELL: Financed Storm Cost II Rider FSCII-ELL. Available at: http://www.entergy-louisiana.com/your_business/EGSI_Tariffs.aspx

Entergy Louisiana LLC. (July 2010). Rider SCOII: Storm Cost Offset II Rider – SCOII. Available at: http://www.entergy-louisiana.com/your_business/EGSI_Tariffs.aspx

Entergy Louisiana LLC. (September 2011). Rider SLGO: Securitized Little Gypsy Offset Rider – SLGO. Available at: http://www.entergy-louisiana.com/your_business/EGSI_Tariffs.aspx

Entergy Louisiana LLC. (September 2011). Rider SLGR: Securitized Little Gypsy Recovery Rider SLGR. http://www.entergy-louisiana.com/your_business/EGSI_Tariffs.aspx

Entergy Louisiana LLC. (August 2014). Rider FSCIII-ELL: Financed Storm Cost III Rider FSCIII-ELL. Available at: http://www.entergy-louisiana.com/your_business/EGSI_Tariffs.aspx

Entergy Louisiana LLC. (August 2014). Rider SCOII: Storm Cost Offset III Rider – SCOIII. Available at: http://www.entergy-louisiana.com/your_business/EGSI_Tariffs.aspx

Entergy Louisiana LLC. (October 2014). Schedule EECR-QS: Quick Start Energy Efficiency Cost Rate Rider. Available at: http://www.entergy-louisiana.com/your_business/EGSI_Tariffs.aspx Festival Hydro. (April 2014). 2015 Cost of Service Application. EB-2014-0073

FortisBC Inc. (June 2011). Application for Approval of 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan. Order Number G-110-12

FortisBC Inc. (July 2013). Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018

Fortis Inc. (November 2014). Fortis Inc. Released Third Quarter Results, UNS Energy Acquisition Closed, Strategic Review of Fortis Properties Business Announced. Available at: https://www.fortisinc.com/News/Documents/Q3_2014_Earnings_Release_FINAL.pdf

Gaz Métro. (December 2012). 2013 Rate Case, Distribution of Natural Gas in Quebec. Filing R-3809-2012. Available at: http://www.corporatif.gazmetro.com/data/media/analystes%20-%20pr%C3%A9sentation%20cause%20tarifaire%202013%20ang.pdf?culture=en-ca

Gaz Métro. (October 2013). Gaz Métro - Demande d'approbation du plan d'approvisionnement et de modification des conditions de service et tarif de Société en commandite Gaz Métro à compter du 1er octobre 2013. Phase 3. Record R-3837-2013. Audience B-0101 to B-0108. Available at: http://publicsde.regie-energie.qc.ca/_layouts/publicsite/ProjectPhaseDetail.aspx?ProjectID=210&phase=3&Provenance=B

Georgia Public Service Commission, "Georgia Power Company's 2013 Rate Case, Docket No. 36989", Direct Testimony of Laura I. Patterson and Elliott L. Spencer on Behalf of Georgia Power Company, "Exhibit LIP-ELS-4".

Georgia Power. Local Tax Adjustment Schedule: "LT-1", With Service Rendered on or After June 17, 1975. Available at: http://www.georgiapower.com/pricing/business/schedules.cshtml

Georgia Power. (March 2014). Environmental Compliance Cost Recovery Schedule: "ECCR-3", With Bills Rendered for the Billing Month of March, 2014. Available at: http://www.georgiapower.com/pricing/business/schedules.cshtml.

Georgia Power. (March 2014). Nuclear Construction Cost Recovery Schedule: "NCCR-4", With Bills Rendered for the Billing Month of March, 2014. Available at: http://www.georgiapower.com/pricing/business/schedules.cshtml.

Georgia Power. (March 2014). Demand Side Management Commercial Schedule: "DSM-C-4", With Bills Rendered for the Billing Month of March, 2014. Available at: http://www.georgiapower.com/pricing/business/schedules.cshtml.

Georgia Power. (March 2014). Fuel Cost Recovery Schedule: "FCR-23", With Bills Rendered for the Billing Month of March, 2014. Available at: http://www.georgiapower.com/pricing/business/schedules.cshtml.

Georgia Power. (March 2014). Municipal Franchise Fee Schedule: "MFF-3", With Bills Rendered for the Billing Month of March, 2014. Available at: http://www.georgiapower.com/pricing/business/schedules.cshtml

Georgia Power. (July 2014). Nuclear Waste Fund Rider: "NWFR-1", With Bills Rendered for the Billing Month of July, 2014. Available at: http://www.georgiapower.com/pricing/business/schedules.cshtml.

Hydro One Networks Inc. (December 2013). Rate Base for the test years 2015 to 2019. EB-2013-0416. Exhibit D1, Tab 1, Schedule 1

Hydro One Networks Inc. (May 2014). Cost of Service Summary. EB-2013-0416. Exhibit C1, Tab 1, Schedule 1

Hydro One Networks Inc. (October 2014). 5 Year Custom Distribution Rate Application. Board Staff Submission. EB-2013-0416

Hydro One Brampton Networks Inc. (April 2014). Hydro One Brampton Networks Inc.'s 2015 Cost of Service Electricity Distribution Rate Application. EB-2014-0083

Kinetrics Inc. (July 2010). Asset Depreciation Study for the Ontario Energy Board. Report No: K-418033-RA-001-R000

Louisiana Public Service Commission, "Application Of Entergy Louisiana, LLC for Authority to Change Rates, Approval of Formula Rate Plan and for Related Relief and Charges" (Docket No. U-32708), Direct Testimony of Stacey A. Wilcox on Behalf of Entergy Louisiana, LLC.

Louisiana Public Service Commission Administrative Hearings Division. (December 2013). In re: Application for Authority to Change Rates, Approval of Formula Rate Plan and for Related Relief. Docket Number U-32708. *Report of Proceedings and Submission of Stipulation for Consideration by Commissioners*.

Maryland Public Service Commission, "In The Matter of the Application of Baltimore Gas And Electric Company for Adjustments to Its Electric And Gas Base Rates" (Case No. 9355), Prepared Direct Testimony of David M. Vahos.

Massachusetts Department of Public Utilities, "Investigation as to the Propriety of Proposed Tariff Changes" (Docket No. 90-39), National Grid - Massachusetts Electric Company and Nantucket Electric Company, Testimony and Exhibits of: Howard S. Gorman, Revenue Requirement.

Massachusetts Electric Company and Nantucket Electric Company. (January 2010). M.D.P.U. No. 1169, Transition Cost Adjustment Provision. Available at: https://www.nationalgridus.com/masselectric/home/rates/billing.asp

Massachusetts Electric Company and Nantucket Electric Company. (January 2013). M.D.P.U. No. 1211, Storm Performance Adjustment Provision. Available at: https://www.nationalgridus.com/masselectric/home/rates/billing.asp

Massachusetts Electric Company and Nantucket Electric Company. (December 2013). M.D.P.U. No. 1224, Residential Assistance Adjustment Provision. Available at: https://www.nationalgridus.com/masselectric/home/rates/billing.asp

Massachusetts Electric Company and Nantucket Electric Company. (January 2014). M.D.P.U. No. 1226, Attorney General Consultant Expenses Provision. Available at: https://www.nationalgridus.com/masselectric/home/rates/billing.asp

Massachusetts Electric Company and Nantucket Electric Company. (January 2014). M.D.P.U. No. 1225, Transmission Service Cost Adjustment Provision. Available at: https://www.nationalgridus.com/masselectric/home/rates/billing.asp

Massachusetts Electric Company and Nantucket Electric Company. (January 2014). M.D.P.U. No. 1229, Pension/PBOP Adjustment Mechanism Provision. Available at: https://www.nationalgridus.com/masselectric/home/rates/billing.asp

Massachusetts Electric Company. (February 2014). M.D.P.U. No. 1230, Service Quality Adjustment Provision. Available at: https://www.nationalgridus.com/masselectric/home/rates/billing.asp

Massachusetts Electric Company and Nantucket Electric Company. (February 2014) M.D.P.U. No. 1231, Revenue Decoupling Mechanism Provision. Available at: https://www.nationalgridus.com/masselectric/home/rates/billing.asp

Massachusetts Electric Company and Nantucket Electric Company. (March 2014). M.D.P.U. No. 1232, Energy Efficiency Reconciling Factors ("EERF"). Available at: https://www.nationalgridus.com/masselectric/home/rates/billing.asp

Massachusetts Electric Company and Nantucket Electric Company. (March 2014). M.D.P.U. No. 1235, Renewable Energy Recovery Provision. Available at: https://www.nationalgridus.com/masselectric/home/rates/billing.asp

Massachusetts Electric Company and Nantucket Electric Company. (May 2014). M.D.P.U. No. 1241, Storm Fund Replenishment Provision. Available at: https://www.nationalgridus.com/masselectric/home/rates/billing.asp

Massachusetts Electric Company and Nantucket Electric Company. (July 1, 2014). M.D.P.U. No. 1245, Solar Cost Adjustment Provision. Available at: https://www.nationalgridus.com/masselectric/home/rates/billing.asp

Massachusetts Electric Company and Nantucket Electric Company. (August 2014). M.D.P.U. No. 1238, Smart Grid Adjustment Provision. Available at: https://www.nationalgridus.com/masselectric/home/rates/billing.asp

Mississippi Power. (November 1989). Ad Valorem Tax Adjustment Clause Schedule "ATA-1": Mississippi Public Service Commission Schedule No. 24. Available at: http://mississippipower.com/my-business/our-pricing/rate-and-rider-details

Mississippi Power. (August 2008). Regulatory Tax Recovery Clause "Rtr-2": Mississippi Public Service Commission Schedule No. 48, Available at: http://mississippipower.com/my-business/our-pricing/rate-and-rider-details

Mississippi Power. (January 2009). System Restoration Rider Schedule "SRR": Mississippi Public Service Commission Schedule No. 53. Available at: http://mississippipower.com/my-business/our-pricing/rate-and-rider-details

Mississippi Power. (January 2010). Performance Evaluation Plan Rate Schedule PEP-5: Mississippi Public Service Commission Schedule No. 28.1. Available at: http://mississippipower.com/my-business/our-pricing/rate-and-rider-details

Mississippi Power. (June 2012). Environmental Compliance Overview (ECO) Plan Rate Schedule "ECO-2": Mississippi Public Service Commission Schedule No. 39. Available at: http://mississippipower.com/my-business/our-pricing/rate-and-rider-details

Mississippi Power. (January 2014). Energy Cost Management Clause Schedule "ECM-2": Mississippi Public Service Commission Schedule No. 49. Available at: http://mississippipower.com/my-business/our-pricing/rate-and-rider-details

Mississippi Power. (January 2014) Fuel Cost Recovery Clause Schedule "FCR-2": Mississippi Public Service Commission Schedule No. 16. Available at: http://mississippipower.com/my-business/our-pricing/rate-and-rider-details

Mississippi Public Service Commission. (March 2013). In Re: Notice of Intent of Mississippi Power Company to Change Rates for Electric Service Pursuant to Its Performance Evaluation Plan, Rate Schedule PEP-5. Docket No. 2003-UN-0898. *Order*.

Newfoundland & Labrador Board of Commissioners of Public Utilities. (2007). In the Matter of 2008 General Rate Application filed by Newfoundland Power Inc. Decision and Order of the Board. Order No. P.U. 32(2007)

Newfoundland Power Inc. (September 2012). 2013/2014 General Rate Application. Volume 1-3

Newfoundland Power Inc. (June 2014). Newfoundland Power's 2015 Capital Budget Application.

Niagara Peninsula Energy Inc. (September 2014). Cost of Service Application for 2015 Distribution Rates. EB-2014-0096

Nova Scotia Power Inc. (May 2012). Nova Scotia 2013 General Rate Application

Nova Scotia Utility and Review Board. (March 2006). In the Matter of and Application by Nova Scotia Power Incorporated for approval of certain Revisions to its Rates, Charges and Regulations. Document No. 112539

Nova Scotia Utility and Review Board. (December 2012). In the Matter of and Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations, including the review of the Fuel Adjustment Mechanism Audit. Document No. 212090

Ofgem. (December 2012). RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas. Final decision – Overview document. Available at: https://www.ofgem.gov.uk/ofgem-publications/53599/1riiot1fpoverviewdec12.pdf

Ofgem. (December 2012). RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas. Finance Supporting Document. Available at: https://www.ofgem.gov.uk/ofgem-publications/53602/4riiot1fpfinancedec12.pdf

Ofgem. (December 2012). RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas. RIIO-ET1: Final Proposals Financial Model. Available at: https://www.ofgem.gov.uk/publications-and-updates/riio-t1-final-proposals-national-grid-electricity-transmission-and-national-grid-gas-%E2%80%93-overview

Ofgem. (March 2013). RIIO Fact Sheet 117, Price Controls Explained. Available at: https://www.ofgem.gov.uk/ofgem-publications/64003/pricecontrolexplainedmarch13web.pdf

Ofgem. (September 2014). ET1 Price Controls Financial Handbook. Version 1.4

Ontario Energy Board. (December 2001). Filing Letter. Electricity Distribution Rate Handbook February 1, 2002 Filing Requirements.

Ontario Energy Board. (January 2002). Backgrounder – Input Price Index for 2002

Ontario Energy Board. (August 2002). Filing Letter. Extension of First Generation PBR – RP-1999-0034 Proceedings

Ontario Energy Board. (December 2006). Cover Letter. Cost of Capital (EB-2006-0088) and 2nd Generation Incentive Regulation Mechanism (EB-2006-0089) Issuance of Report of the Board and Instructions for Filing 2007 Rate Applications.

Ontario Energy Board. (December 2006). Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation Mechanism for Ontario's Electricity Distributors

Ontario Energy Board. (May 2008). Filing Letter. 3rd Generation Incentive Regulation for Electricity Distributors Revised Proposal for an Incremental Capital Module.

Ontario Energy Board. (July 2008). Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. EB-2007-0673. Report available at: http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2007-0673/Report_of_the_Board_3rd_Generation_20080715.pdf

Ontario Energy Board. (July 2008) Incremental Capital Module. Board Staff Presentation. Stakeholder Conference August 5-8, 2008

Ontario Energy Board. (July 2008). Average Age of Plant. Selected Electricity Distributors – 2006

Ontario Energy Board. (August 2008). Stakeholder Consultation on the 3rd Generation Incentive Regulation for Electricity Distributors held on August 6, 2008 (Volume 2). File No. EB-2007-0673. Transcript available at: http://www.ontarioenergyboard.ca/documents/cases/EB-2007-0673/transcripts/Stakeholder_Meeting_Vol2_20080806.pdf

Ontario Energy Board. (August 2008). Stakeholder Consultation on the 3rd Generation Incentive Regulation for Electricity Distributors held on August 7, 2008 (Volume 3). File No. EB-2007-0673. Transcript available at: http://www.ontarioenergyboard.ca/documents/cases/EB-2007-0673/transcripts/Stakeholder_Meeting_Vol3_20080807.pdf

Ontario Energy Board. (August 2008). Summary of Capital Module Threshold Positions.

Ontario Energy Board. (September 2008). Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. File No. EB-2007-0673. Report available at: http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2007-0673/Supp_Report_3rdGen_20080917.pdf

Ontario Energy Board. (May 2009). Application by Hydro One Networks Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2009. Decision. EB-2008-0187

Ontario Energy Board. (June 2009). Application by Oshawa PUC Networks Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2009. Decision. EB-2008-0205

Ontario Energy Board. (March 2011). Application by Guelph Hydro Electric Systems Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective by May 1, 2011. Decision and Order. EB-2010-0130

Ontario Energy Board. (March 2011). Application by Oakville Hydro Electricity Distribution Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2011. Decision and Order. EB-2010-0104

Ontario Energy Board. (March 2012). Application by Port Colborne Hydro Inc. under section 86 of the Ontario Energy Board Act, 1998 seeking an order for leave to sell its distribution system in its entirety to Canadian Niagara Power Inc. Decision and Order. EB-2011-0367

Ontario Energy Board. (March 2012). Application by Woodstock Hydro Services Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2012. Decision and Order. EB-2011-0207

Ontario Energy Board. (March 2012). Application by Centre Wellington Hydro Ltd. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2012. Decision and Order. EB-2011-0160

Ontario Energy Board. (April 2012). Update to Chapter 2 of the Filing Requirements for Transmission and Distribution Applications – Allowance for Working Capital.

Ontario Energy Board. (April 2012). Application by Hydro Hawkesbury Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2012. Decision and Order. EB-2011-0173

Ontario Energy Board. (April 2012). Application by Kingston Hydro Corporation for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2012. Decision and Order. EB-2011-0178

Ontario Energy Board. (July 2012). Accounting Procedures Handbook. Frequently Asked Questions.

Ontario Energy Board. (July 2012). Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013

Ontario Energy Board. (October 2012). Report of the Board. Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach

Ontario Energy Board. (April 2013). Application by Festival Hydro Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2013. Decision and Order. EB-2012-0124

Ontario Energy Board. (April 2013). Application by Toronto Hydro-Electric System Limited for an order approving just and reasonable distribution rates and other charges for electricity distribution to be effective June 1, 2012, May 1, 2013 and May 1, 2014. Decision and Order. EB-2012-0064

Ontario Energy Board. (June 2013). Accounting Policy Changes for Accounts 1575 and 1576

Ontario Energy Board. (November 2013). Report of the Board. Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors. EB-2010-0379

Ontario Energy Board. (February 2014). Application by PowerStream Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2014. Decision and Rate Order. EB-2013-0166

Ontario Energy Board. (March 2014). Application by Espanola Regional Hydro Distribution corporation for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2014. Decision and Order. EB-2013-0127

Ontario Energy Board. (March 2014). Application by Wellington North Power Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2014. Decision and Order. EB-2013-0178

Ontario Energy Board. (March 2014). Report of the Board. Performance Measurement for Electricity Distributors: A Scorecard Approach. EB-2010-037

Ontario Energy Board. (July 2014). Filing Requirements for Electricity Distribution Rate Applications – 2014 Edition for 2015 Rate Application. Chapter 2, Cost of Service Rate Applications Based on a Forward Test Year

Ontario Energy Board. (July 2014). Filing Requirements for Electricity Distribution Rate Applications – 2014 Edition for 2015 Rate Applications. Chapter 3, Incentive Regulation

Ontario Energy Board. (September 2014). Report of the Board. New Policy Options for the Funding of Capital Investments: The Advanced Capital Module. EB-2014-0219

Pacific Economics Group Research, LLC. (June 2006). Presentation on Incentive Regulation for Ontario Power Distribution.

Pacific Economics Group Research, LLC. (February 2013). Presentation on TFP Measurement Issues.

Pacific Economics Group Research, LLC. (March 2013). Presentation on Summary of Inflation, TFP and Benchmarking Issues

Pacific Economics Group Research, LLC. (May 2013). Empirical Research in Support of Incentive Rate Setting in Ontario. Report to the Ontario Energy Board.

Pacific Economics Group Research, LLC. (September 2013). Empirical Research in Support of Incentive Rate-Setting: 2012 Update. Report to the Ontario Energy Board

Pacific Economics Group Research, LLC. (November 2013). Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board

Pacific Economics Group Research, LLC. (July 2014). Empirical Research in Support of Incentive Rate-Setting 2013 Bench Marking Update. Report to the Ontario Energy Board

PECO Energy Company. (December 2014). Electric Service Tariff. Supplement No. 114 To Electric PA. P.U.C. No. 4. Available at: https://www.peco.com/CustomerService/RatesandPricing/RateInformation/Pages/CurrentElectric.aspx

Pennsylvania Public Utility Commission, "Pennsylvania Public Utility Commission v. PECO Energy Company, Electric Division - Docket No. R-2010-2161575", Direct Testimony – Witness: Robert L. O'Brien.

School Energy Coalition. (July 2008). Capital Module and Stretch Factor. Presentation to the OEB Stakeholder Conference on 3rd Generation Incentive Regulation August 5-8, 2008

State of Alabama Public Service Commission. (August 2013). In re: Public Proceedings established to consider any necessary modifications to the Rate Stabilization and Equalization mechanism applicable to the electric service of Alabama Power Company. Dockets 18117 and 18416. *Report and Order*.

State of New York Department of Public Service, Public Service Commission, "Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service" (Case No. 13-M-0030), Accounting Panel – Electric and Electric Rate Case Exhibits.

St. Thomas Energy Inc. (April 2014). 2015 Cost of Service Distribution Rate Application. Board File No. EB-2014-0113

Union Gas Limited. (November 2011). Union Gas Limited 2013 Rebasing Application. EB-2011-0210

Union Gas Limited. (July 2013). Union Gas Limited 2014-2018 Incentive Regulation Application, Evidence and Settlement Agreement. EB.-2013-0202

Valener Inc. (December 2013). Annual Information Form, Fiscal year ended on September 30, 2013. Available at: http://www.valener.com/Data/en/PDF/InfoActions/2013-09-30_Valener_Notice_annuelle_angdarichard20131217081543.pdf

Appendix 1 Canada Jurisdictional Review

Ontario Electricity Distribution

	Description
Treatment of Working Capital	**Working Capital** is the amount of funds required to finance the day-to-day operations of a regulated utility and is included as part of rate base for ratemaking purposes. It is comprised of two amounts: (1) cash working capital; and (2) mid-year materials and supplies inventory. The determination of cash working capital relies on a lead-lag study. In Chapter 2 (Cost of Service) of the Filing Requirements for Electricity Distribution Rate Applications - 2014 Edition for 2015 Rates Applications, the Board indicates that the applicant may take one of two approaches for the calculation of its allowance for working capital: (1) the 13% allowance approach; or (2) the filing of a lead/lag study. The only exception is if the application has been previously directed by the Board to undertake a lead/lag study on which its current working capital allowance is based.
	13% Allowance Approach: Cash working capital can be calculated to be 13% of the sum of the retail cost of power and controllable expenses (i.e., OM&A, capital and income taxes).
	Lead/Lag Study: A lead/lag study analysis for two time periods; namely: (1) the time between the date customers receive service and the date that the customers' payments are available to the distributor (the lag); and (2) the time between the date when the distributor receives goods and services from its supplies and vendors and the date that it pays for them (the lead). The leads and lags are measured in days and are generally dollar-weighted. The dollar-weighted net lag (i.e., lag minus lead) days is then divided by 365 (366 in a leap year) and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations.
	Included In Rate Base: Regardless of the method chosen to calculate cash working capital, the amount of working capital required for operations is included in the applicant's rate base determination.
	ICM Calculation: Working capital is not specifically addressed in an IR application. It is embedded in base rates, as per the cost of service proceeding. In the context of the ICM/ACM, working capital is included in the rate base used in the Threshold Test. The working capital percent metric is the Board-approved WCA from the distributor's last rebasing application. The Threshold Test is set out in Sheet E2.1 Threshold Test of the Incremental Capital Model for 2015 Filers on the Board's website. The calculation of Incremental Capital Adjustment found on Sheet E4.1 IncrementalCapitalAdjust in the same workbook does not include a provision for incremental working capital in the calculation. The additional revenue requirement associated with the ICM reflects: (i) return on rate base; (ii) amortization expense; (iii) grossed up PIL's; and (iv) Ontario capital tax.

	Description
Half Year Rule	**Half Year Rule:** The Board's general policy for electricity distribution rate setting has been that capital additions would normally attract six months of depreciation expense when they enter service in the test year. This is commonly referred to as the "half year rule". Variations from this approach are permitted, and include calculating depreciation based on the month that an asset enters service.
	Cost of Service: Rate base is the sum of: (1) **Working Capital Allowance** - as described previously; and (2) **Average Net Fixed Assets** - the average gross fixed assets (GFA) minus average accumulated depreciation (AD). Average GFA is the average of the opening GFA (beginning of the test year) and closing GFA (end of the test year). Average AD is equal to the sum of opening AD and closing AD, divided by 2. Closing AD is equal to: (1) opening AD; plus (2) depreciation associated with opening GFA; plus (2) depreciation associated with in-service capital additions divided by 2 (half-year application); less (3) depreciation associated with disposals; less (4) depreciation associated with retirements. Closing GFA is equal to: (1) opening GFA; plus (2) in-service capital additions; and less (3) capital retirements. Each of capital additions and capital retirements are "rebased" to capture any adjustments between the closing balance at the end of the prior year (t-1) and the beginning of the test year and any amount that will be closed to rate base during the test year. As set out in the OEB's Filing Requirements for Electricity Distribution Rate Applications - 2014 Edition for 2015 Rates Applications - Chapter 2 (Cost of Service), the half year rule applies to capital additions that enter service in the test year. However, if the applicant uses a different approach, it must be documented with an explanation.
	ICM Calculation: As set out in the Supplement Report on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors dated September 17, 2008, the Board determined that the half-year rule should not apply in the determination of the ICM revenue requirement, so as not to build a revenue deficiency for the subsequent years of the IR plan term. However, the half-year rule has applied in IR ICM applications in cases in which the ICM request coincides with the final year of a Distributor's IR plan term.

	Description
Treatment of Working Capital	**Working Capital** is the amount of funds required to finance the day-to-day operations of a regulated utility and is included as part of rate base for ratemaking purposes. It is comprised of two amounts: (1) cash working capital; and (2) mid-year materials and supplies inventory. The determination of cash working capital relies on a lead-lag study.
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: A lead/lag study analysis for two time periods is required; namely: (1) the time between the date customers receive service and the date that the customers' payments are available to the transmitter (the lag); and (2) the time between the date when the transmitter receives goods and services from its suppliers and vendors and the date that it pays for them (the lead). Leads and lags are measured in days and are generally dollar-weighted. The dollar-weighted net lag (i.e., lag minus lead) days is then divided by 365 (366 in a leap year) and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations.
	Included in Rate Base: The amount of working capital required for operations is included in the applicant's rate base determination.
	ICM Calculation: Not applicable.

	Description
Half Year Rule	**Half Year Rule:** The Board's general policy for rate setting is that capital additions would normally attract six months of depreciation expense when they enter service in the test year. Variations from this approach are permitted, and include calculating depreciation based on the month that an asset enters service.
	Cost of Service: As set out in the OEB's Filing Requirements for Electricity Transmission Applications dated January 2, 2014 - Chapter 2 (Cost of Service), the half year rule applies to capital additions that enter service in the test year. However, if the applicant uses a different approach, such as calculating depreciation based on the month that an asset enters service, it must be documented with explanation.
	ICM Calculation: Not applicable.

	Description
Treatment of Working Capital	**Working Capital** is the amount of funds required to finance the day-to-day operations of a regulated utility and is included as part of rate base for ratemaking purposes. The determination of working capital relies on a lead-lag study to determine working cash allowance. Working cash allowance is one of a number of components that comprise the Allowance for Working Capital that is included in rate base. Other components include: (1) accounts receivable rebillable projects; (2) materials and supplies; (3) mortgage receivable; (4) customer security deposits; (5) prepaid expenses; and (6) gas in storage.
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: A lead/lag study is conducted to determine working cash allowance. The study considers the time between when the utility has received a good or service and when payment is made, known as the Expense Lead and the time between when the utility has provided a good or service and when it receives payment, known as the Revenue Lag. The difference between the Expense Leads and the total Revenue Lags is the Net Lag. A monthly average for each of the components set out above, including working cash allowance, is calculated and an average of the monthly averages is calculated. The average of monthly averages is then summed and the total is added to rate base.
	Included in Rate Base: The amount of working capital required for operations is included in the applicant's rate base determination.
	ICM Calculation: Not applicable. On July 3, 2013 Enbridge Gas Distribution applied for a Custom Incentive Rate-setting plan for the 2014 - 2018 rate years, inclusively. The Board approved the application, with modifications on July 17, 2014. The approved plan provides for an annual rate adjustment process and specific capital plans for each year. Rate base (including working capital), accumulated depreciation and asset continuity schedules are calculated using monthly average balances for each year during the term of the Custom IR period.

	Description
Half Year Rule	**Half Year Rule:** Not applicable. See comments below in Cost of Service.
	Cost of Service/5-Year Custom Incentive Rate-setting plan: Approved by the Board in July 2014, the plan is effectively a five year cost of service plan, in which rate base is an annual average of monthly asset continuity schedules. Rate base, including working capital, for each year of the Custom Incentive Rate-setting plan is set out in the Appendix A of the OEB's August 22, 2014 Decision and Rate Order. Depreciation is calculated in the month that an asset enters service and is consistent with the determination of rate base.
	ICM Calculation: Not applicable.

	Description
Treatment of Working Capital	**Working Capital** is the amount of funds required to finance the day-to-day operations of a regulated utility and is included as part of rate base for ratemaking purposes. The determination of working capital relies on a lead-lag study to determine cash working capital. Cash working capital is one of a number of components that comprise the Allowance for Working Capital that is included in rate base. Other components include: (1) average cost of gas in storage and line pack gas; (2) average cost of balancing gas; (3) average cost of ABC receivable (gas in storage); (4) average cost of inventory of stores and spare equipment; (5) average cost of prepaid and deferred expenses; (6) average customer deposits; and (7) average customer deposit interest.
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: A lead/lag study is conducted to determine cash working capital. The study considers the time between when the utility has received a good or service and when payment is made, known as the Expense Lead and the time between when the utility has provided a good or service and when it receives payment, known as the Revenue Lag. The difference between the Expense Leads and the total Revenue Lags is the Net Lag. A monthly average for each of the components set out above, including cash working capital, is calculated and an average of the monthly averages is calculated. The average of monthly averages is then summed and the total is added to rate base.
	Included in Rate Base: The amount of working capital required for operations is included in the applicant's rate base determination.
	ICM Calculation: On July 31, 2013, Union Gas filed a multi-year Incentive Regulation Mechanism that will be used to set Union's regulated distribution, transportation and storage rates over the 2014 to 2018 period, inclusively. The IR parameters are the product of a comprehensive Settlement Agreement and the Settlement Agreement was approved by the Board on October 7, 2013. Working capital is not specifically addressed in the Settlement Agreement. It is embedded in base rates, as per Union's cost of service model approved by the Board in 2012 for rates effective January 1, 2013. There is a custom ICM mechanism set out in the comprehensive Settlement Agreement. It is unclear whether there is an adjustment for working capital in the cost of the assets that qualify for the capital pass-through mechanism.

	Description
Half Year Rule	**Half Year Rule:** Not applicable. See comments below in ICM Calculation.
	Cost of Service: In a cost of service rates proceeding, rate base, including working capital, is calculated on a monthly average basis. Depreciation is calculated from the month that an asset enters service and is otherwise consistent with the determination of rate base.
	ICM Calculation: The Settlement Agreement includes a capital pass-through mechanism that is intended to adjust rates during the IR term to reflect the associated impacts of significant capital investments made throughout the IR term deemed "not-business-as-usual". "Not-business-as-usual" refers to capital expenditures that are significant and cannot be managed within Union's Board-approved capital budget and embedded in base rates. The key features of this mechanism are: (1) minimum increase or a minimum decrease, of $5 million in net delivery revenue requirement for a single new project. Net delivery revenue requirement includes incremental OM&A expenses, depreciation expense, municipal property taxes expense, incremental long-term debt costs, and required return and income taxes net of any incremental delivery revenues arising from the project; (2) capital cost of project, using the same capitalization policies used to set 2013 rates, must exceed $50 million; (3) the project is outside of the base rates on which the IR framework is set; (4) the project must be needed to service customers and/or maintain system safety, reliability or integrity and cannot reasonably be delayed and is demonstrated to be the most cost-effective manner of achieving the project's objective relative to the reasonably available alternatives; (5) the project would be identified to stakeholders and the Board as soon as possible; (6) the project would be subject to a full regulatory review equivalent to a Leave-to-Construct proceeding, with the appropriate demonstration of need, safety or reliability purposes and economic viability prior to inclusion in rates; (7) Union would allocate the net revenue requirement using the 2013 Board-approved cost allocation methodologies; and (8) the project would include a deferral account to capture any differences between the forecast annual net delivery revenue requirement and actual net revenue delivery requirement for each year of the IR for which the project is included in rates. True-up will occur annually during the period the project is eligible for inclusion in the capital pass through mechanism. The net delivery revenue requirement for any year in the IR period is determined as follows: (1) depreciation to be calculated using the 2013 Board-approved depreciation rates; (2) required return would assume a capital structure of 64% long-term debt and 36% common equity; (3) incremental long-term debt cost would be calculated based on expected financing costs for the incremental borrowing required by the project, market rates in effect at the time the project is approved; (4) return would be calculated using the 2013 Board-approved return on equity of 8.93%; (5) income and other taxes related to the equity component of the return would be calculated using the 2013 Board-approved tax rate of 25.5%; (6) the incremental delivery revenues associated with the project would be calculated as an offset to the delivery revenue requirement; and (7) for the in-service year, all components of the calculation except taxes, would be calculated only for the period from the month of in-service to the end of the year; and (8) the

	Description
	parameters would not change during the IR term.

	Description
Treatment of Working Capital	**Necessary Working Capital** represents the amount of funds required to sustain utility operations from the time expenditures are made until the time payment is received. It is also a component of the rate base for ratemaking purposes. The determination of necessary working capital relies on a lead-lag study. Components of necessary working capital include: operating expenses, income tax expense, materials and supplies inventory, unamortized computer system costs, rate case expense, GST, retailer deposits, depreciation expense, interest expense, preferred equity, and common equity (retained earnings and dividends).
	13%: Allowance Approach: Not applicable.
	Lead/Lag Study: The purpose of the study is to determine necessary working capital, the timing differences between when the distributor provides a good or service and when it receives payment (lead/revenue) and the time between when the distributor receives a good or service and when payment is made (lag/expenses). Leads and lags are measured in days and are dollar-weighted based on the most recent actual operating revenues and expenses data. Lead/lag days in the test period are also forecasted based on the most recent actual lead/lag day data available. Necessary working capital is calculated as follows: the dollar-weighted net lag days (i.e. lag minus lead) is divided by the number of days in the year and then multiplied by the forecast annual test cash expense for each component of working capital.
	Included in Rate Base: The calculated Necessary Working Capital is included in the rate base. Rate base is determined by adding: (1) necessary working capital - as described above; and (2) net mid-year PPE. Net mid-year PPE is calculated using the mid-year base convention; i.e., the average of Adjusted Prior Year net PPE and current year net PPE, as described below.
	ICM Calculation: As set out below, the calculation of the K Factor rate adjustments will be similar to revenue requirement calculations under cost of service, except that the calculation will be limited to the depreciation, taxes and return associated with the incremental rate base for the expenditures that form the capital tracker. An allowance for working capital is not included in the revenue requirement calculation for the K Factor rate adjustment.

	Description
Half Year Rule	**Half Year Rule:** The half year rule is applied to net capital additions in the test year of the applied-for capital tracker, as described below.
	Cost of Service: In a cost of service test year, rate base is calculated by adding (1) necessary working capital; and (2) net mid-year PPE. Net mid-year PPE is calculated using the mid-year base convention (i.e., the average of adjusted prior year net PPE and test year net PPE). Opening gross PPE for the test year (t) is calculated by taking the adjusted gross PPE balance for the previous year (t-1) and adding planned capital additions and deducting retirements. Accumulated depreciation in the test year (t) is then calculated as follows: accumulated depreciation at the beginning of the test year plus forecast gross provision depreciation, retirements, net salvage and adjustments. Gross provision depreciation for the test year (t) is calculated by: (1) applying the full depreciation rate to the previous year's (t-1) net PPE; plus (2) applying the full depreciation rate to net capital additions closed to PPE during the test period and dividing by 2. Net PPE is the difference between gross PPE and accumulated depreciation. The rate base for the test year is used to determine the return the cost of capital to be recovered in rates.
	ICM Calculation: On September 12, 2012, the Alberta Utilities Commission (AUC) issued its Generic Decision regarding its rate regulation initiative to reform utility rate regulation in Alberta. The first phase of the initiative was to implement a form of performance-based regulation (PBR) for electric and natural gas distribution companies, in place of the existing cost of service regulatory system. In that Decision, the AUC stated that it recognized that a mechanism to fund certain capital-related costs outside of the I-X (i.e. price cap) through a capital factor is required. Accordingly, the Commission has a capital tracker mechanism in the PBR plan. The capital tracker mechanism is warranted in circumstances where the company can demonstrate that a necessary capital replacement project or capital project required by an external party cannot reasonably be expected in the I-X mechanism. The applicant must demonstrate the following criteria have been satisfied in order for a capital project to receive consideration or included in the capital tracker: (1) the project must be outside the normal course of the company's ongoing operations; (2) ordinarily, the project must be for the replacement of existing capital assets or undertaking the project must be required by an external party; and (3) the project must have a material effect on the company's finances. The half year rule is applied to net capital additions in the test year of the utility's applied-for capital tracker. However, the half year effect is eliminated in the following year, when the opening net PPE of that year is multiplied by the full depreciation rate. Annual capital tracker applications are to be submitted by March 1st of the year preceding the test year and must include a business case with respect to projects included in each proposed capital tracker. The business case includes forecast costs, being the amount proposed to be collected on an interim basis through the K Factor in the upcoming test year. If a project is expected to carry into future years, forecasts for the future years should also be included in order to assess the scope and scale of the project, including the materiality of the entire project to be

	Description
	considered. The March 1 capital tracker application shall true-up the costs of projects that have been completed since the prior year's capital tracker filing together with sufficient information to permit a prudence review of these completed projects. The results of the prudence review and the cost true-up will be an adjustment to the K Factor, included in the following year's rates. The utility will calculate the revenue requirements resulting from the actual capital tracker expenditures and compare those to the forecast amounts that were collected on an interim basis in the prior year. The difference between the approved revenue requirements and the forecast revenue requirement for the prior year will form the basis of the K Factor true-up rate adjustment. In addition, because the capital expenditures will remain in the tracker for the duration of the PBR term, the amounts to include in the capital tracker revenue requirement calculations in subsequent years during the PBR term will be based on the actual approved expenditures rather than the initial forecasts.

	Description
Treatment of Working Capital	**Cash Working Capital** allowance represents the average amount of capital provided by investors above and beyond investments in plant and other separately identified rate base items. These investments bridge the gap between the time expenditures are made and payment is received.
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: The cash working capital allowance is determined using a lead/lag study, which analyzes cash flows arising from the utility's billing, payment, and collections procedures. The purpose of the analysis is to determine the average amount of outstanding working capital to be included in rate base. Rate base is calculated as set out below.
	Included in Rate Base: The cash working capital allowance is included in the calculation of average rate base for the test year.
	ICM Calculation: Not applicable. Nova Scotia Power Inc. is regulated on a two-year, forward test year basis where rates are determined using a cost of service methodology. The Nova Scotia Utility and Review Board (UARB) has used a rate base approach to rate setting since 2006.

	Description
Half Year Rule	**Half Year Rule**: Not applicable.
	Cost of Service: In the regulatory proceeding before the UARB rate base is calculated as sum of: net regulated plant in service, construction work in progress, deferred charges, allowance for working capital, and allowance for materials and supplies. The rate base for the test year is then added to the rate base calculation for the year prior to the test year (t-1) and an average is taken. This average rate base calculation is used to determine the cost of capital elements to be recovered in rates, using the mid-range cost of capital metrics approved by the UARB, which are: 9% ROE (range 8.75% to 9.25%) and deemed equity of 37.5% (range of 35% to 40%). Net regulated plant in service for the test year is calculated as: beginning gross plant at the commencement of the test year, plus additions, less retirements, and less depreciation. Depreciation reflects the sum of the following: accumulated depreciation at the beginning of the test year, depreciation/accretion expense based on a monthly roll-up of capital additions and retirements over the test year on a forecast basis, and salvage and cost of removal. It is not subject to a half year rule treatment. The calculated depreciation/accretion is combined with other amortization charges and is recovered in rates.
	ICM Calculation: Not applicable.

	Description
Treatment of Working Capital	**Allowance for Working Capital** represents that lag between when revenue is earned and when the funds are received for that revenue, offset by when expenses are incurred and when the funds are released to pay for the expenses.
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: The allowance for working capital is determined using a lead/lag study and represents the amounts required to compensate the utility for the timing difference between when expenditures are required to provide service and when collections are received for that service.
	Included in Rate Base: The Allowance for Working Capital is added to the Rate Base, as set out below.
	ICM Calculation: The allowance for working capital is included in the calculation of base rates, as set out below.

	Description
Half Year Rule	**Half Year Rule:** The half year rule is not in use.
	Cost of Service: Rate base is calculated as the sum of: Gross plant in service at the beginning of the test year plus net additions, CWIP not subject to AFUDC, plant acquisition adjustment and deferred and preliminary charges. Accumulated depreciation and amortization and contributions in aid of construction are then deducted. The remaining amount is called the Depreciated Rate Base. The Depreciated Rate Base for the test year (t) is then added to the Depreciated Rate Base for the prior year (t-1) and an average is taken. This is the Mean Depreciated Utility Rate Base. The allowance for working capital is added. A further adjustment for capital additions is also added or deducted, as discussed below. The final total is the Mid-Year Utility Rate Base. The Mid-Year Utility Rate Base is used to calculate the cost of capital recovered in rates. Depreciation expense for the test year is equal to the product of the relevant depreciation rate for the asset class and the asset balance at the end of the previous period (t-1). Accumulated depreciation reflected in the rate base calculation is the sum of depreciation expense for the test year, depreciation associated with utility plant adjustment, leasehold improvements, rate stabilization, less recoveries. The capital additions adjustment is the difference between total monthly weighted capital expenditures and the simple average of capital expenditures closed to rate base in the test year (total capital expenditures divided by 2). If monthly weighted capital expenditures are less than average capital expenditures, the difference is negative and this negative value is deducted from the Mean Depreciated Utility Rate Base for the test year, as set out previously.
	ICM Calculation: On July 5, 2013 FortisBC applied to the British Columbia Utilities Commission (BCUC) for approval of a multi-year performance based ratemaking plan for 2014 to 2018, inclusively. The application built on FortisBC's most recent PBR plan, which was approved for 2007 to 2009 and extended for 2009 to 2011. Rates for 2012 and 2013 were determined using a cost of service approach. The PBR approved in 2007 did not include a mechanism for capital expenditures, which were approved as part of a separate annual filing or by way of applications for certificates of public convenience and necessity (CPCNs) for major projects. The 2013 application includes a formula that will determine the amount of capital to be spent in each year of the PBR term and is tied to the average number of customers. The PBR is a partial regime, in that O&M will increase annually based on a formula, while interest expense, return on equity, pension/OPEB expenses/insurance costs, power purchase expense, revenues, depreciation and amortization, and the capital expenditures arising from the use of the formula are all pass-throughs to rates in an annual review process. There is an annual review process, the purpose of which is to communicate the utility's actual performance and determine rates for the upcoming year.

	Description
	There is a limited rebasing process re: capital, if actual annual capital expenditures are above or below the formula-based amount by more than 10%. The BCUC approved elements of the proposed plan, but did not approve the treatment of certain capital additions that would have been subject to CPCNs. The Commission has established a further regulatory process to consider the framework for capital that is not included in envelope provided by the PBR plan. The process will consider six questions and has three steps: (1) submission from Fortis due by December 31, 2014; (2) submissions from intervenors due April 30, 2015; and (3) reply submission from Fortis due June 30, 2015.

	Description
Treatment of Working Capital	**Cash Working Capital** allowance represents the average amount of capital provided above and beyond investments in plant and other separately identified rate base items. In the situation where the payment of an expense precedes the collection of its related revenue stream, the utility's investor must supply capital to finance the expense until the receipt of the related revenues.
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: The cash working capital allowance is determined using a lead/lag study, which is informed by: (i) revenue lags; (ii) expense lags; and (iii) leads/lags associated with HST in the test years. Rate base is comprised of the sum of average net regulated plant in service, cash working capital as per the Lead/Lag Study, and a materials and supplies allowance.
	Included in Rate Base: The cash working capital allowance is included in the calculation of rate base for the test year, as set out below.
	ICM Calculation: Not applicable. Newfoundland Power is regulated on a forward test year basis where rates are determined using an Asset Rate Base Method. The Asset Rate Base Method was approved for use by the Board of Commissioners of Public Utilities in conjunction with the utility's 2008 general rate application. Pursuant to this approach, the utility is able to include allowances for deferred charges, regulatory assets, customer finance programs, and other cost recovery deferral amounts in rate base. Deductions from rate base include weather normalization reserve, OPEBs, customer security deposits, accrued pension obligation, and demand management incentive amounts. These amounts are included in the calculation of average rate base to which the cash working capital and materials and supplies allowances are added.

	Description
Half Year Rule	**Half Year Rule:** In use to determine depreciation expense associated with assets closed to rate base during the test period. Net average plant investment is calculated as the opening plant investment at the commencement of the test year plus capital additions expected to close to rate base during the test year. This sum is the closing plant investment for the test year. This value is then added to the closing plant investment for the previous year (t-1) and an average is taken. The composite depreciation rate is then applied to the average plant investment to determine the depreciation expense to be reflected in rates for the test year. This amount is deducted from the average plant investment, resulting in the net average plant investment for the test year. **Cost of Service:** Average rate base reflected in the test year is calculated as follows: Net average plant investment **plus** deferred charges, regulatory assets (defined benefit pension plans), cost recovery deferrals, customer finance programs, **less** weather normalization reserve, other post employee benefits, customer security deposits, accrued pension obligation, future income taxes, and demand management incentive amount. To this amount, described as Average Rate Base Before Allowances, the cash working capital allowance and materials and supplies allowance are added, resulting in the Average Rate Base at Year End. With the exception of the cash working capital and materials and supplies allowances, all other balances are expressed on an average basis (for the test year). The Average Rate Base at Year End is used to determine the cost of capital to be recovered in test year rates. **ICM Calculation**: Not applicable.

	Description
Treatment of Working Capital	**Working Capital** is comprised of cash working capital and materials and gas inventories. Cash working capital is calculated using a lead/lag study, as described below. Materials and gas inventories are averaged by taking the sum of balances at the beginning of the year and the end of each12-month period during the test year and dividing by 13.
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: Cash working capital is determined using a lead/lag study. Leads and lags are measured in days. Expense lead is the time between the date when the distributor receives goods and services from its suppliers and vendors and the date that is pays for them. Revenue lag is the time between the date customers receive service and the date that customers' payments are available to the distributor. The net lag is calculated by subtracting the lead from the lag. Net lag is divided by the number of days in a given year and multiplied by forecast expenses to determine cash working capital.
	Included in Rate Base: Working capital is included in the calculation of rate base, as set out below.
	ICM Calculation: Not applicable. Rates are currently set using a cost of service approach. The GazMétro-QDA incentive mechanism, in effect since October 1, 2007, expired on September 30, 2012. A new incentive mechanism has not yet been approved by the Régie de l'énergie.

	Description
Half Year Rule	**Half Year Rule:** Not in use. Depreciation relating to assets closed to rate base during the test year is calculated using the property value from the first day of the month following the in-service or commissioning date and ceases on the last day of the month in which the asset is removed from service. The monthly average (13 month averaging period) is included in rates. Accumulated depreciation is calculated as: (1) product of composite depreciation rate and opening PPE on the first day of the fiscal year (October 1); plus (2) product of the composite depreciation rate and balance of PPE in each month in the fiscal year (October to September) divided by 13.
	Cost of Service: Average rate base is calculated in a manner similar to Accumulated Depreciation. Rate base is calculated as follows: net PPE less net customer contributions plus working capital plus unamortized costs (including rate stabilization accounts, commercial programs, and deferred natural gas costs). Average rate base is calculated by taking the sum of: (1) rate base on the first day of the fiscal year (October 1); and (2) rate base in each month of the fiscal year (October to September) divided by 13. Net PPE is calculated as: (1) gross assets; minus (2) accumulated depreciation.
	ICM Calculation: Not applicable.

Alabama Public Service Commission – Alabama Power Company

<table>
<tr><th></th><th>Description</th></tr>
<tr><td>Treatment of Working Capital</td><td>Working Capital

<u>Cash</u> component is not included in rate filings

<u>Non-cash</u> component is measured on same basis as rate base (see “ICM Calculation” below) and consists of an projected 13-month average balance from three accounts:
• Fuel Stock (Account 151)
• Materials and Supplies (Account 154)
• Merchandise (Account 155)</td></tr>
<tr><td></td><td>13% Allowance Approach: Not applicable.</td></tr>
<tr><td></td><td>Lead/Lag Study: see “cash” component of working capital above</td></tr>
<tr><td></td><td>Included in Rate Base: Non-cash working capital is included in the calculation of rate base.</td></tr>
</table>

	Description
Half Year Rule	**Half Year Rule:** Not in use. The Alabama Power RSE (Rate Stabilization and Equalization) mechanism uses a 13-month average to represent a calendar year test-year based on projected data for investment not yet closed to plant in service at the time of the filing. Accumulated Depreciation and Amortization (or the Depreciation Reserve) relating to assets included in rate base (before the start of the projected test year) is calculated using the property value from the first day of the month following the in-service or commissioning date and ceases on the last day of the month in which the asset is removed from service. For plant already in service prior to the start of the test year, the expected end-of-year values are used. Projected gross additions to the rate base are estimated using a 13-month average balance.
	Cost of Service: A 13-month average rate base is calculated in a manner similar to Accumulated Depreciation. Rate base is the sum of: (1) Electric Plant in Service, (2) Electric Plant Held for Future Use, (3) Construction Work in Progress, (4) Nuclear Fuel, (5) Non-utility property, (6) Non-cash working capital (see above). Accumulated Depreciation and Amortization is subtracted from the previous summed amount.
	ICM Calculation: Rates are currently set using a cost of service approach. However, there are several additional components subject to adjustment: • Environmental Compliance Costs (Rate CNP) • Energy Cost Recovery Rate (ECR) • Tax Adjustment (Rate T) Rate CNP can be used to recover the capital and operating costs of newly certificated plant, purchased power and environmental expenditures. Filings for Rate CNP occur in November of every year and include: 1. Projections for the next year 2. Mixed actual and projected data for the first nine and last 3 months of the current year respectively 3. Actual data for each of the two preceding years The filing includes data for investment and O&M expenses. In each filing, the historic actual data are used to true-up over and under-recovery relative to projections filed in previous years. Rate ECR recovers estimated fossil fuel and emission credit allowances at plants owned in whole or in part by Alabama Power. Actual data are used to true-up over and under-recovery relative to projections filed in previous years. Rate T allows the company to collect additional revenue to support a change in tax

	Description
	rates that occurred after the most recent re-setting of rates. Details of Alabama Power's tariffs can be found on its website: http://www.alabamapower.com/business/pricing-rates/rate-riders-adjustments.asp

	Description
Treatment of Working Capital	**Working Capital** Cash component is based on a comprehensive lead-lag approach involving separate estimates of days outstanding for revenues and detailed O&M expenses. Operational cash requirements (e.g., minimum bank balances, special deposits and prepayments) are added to this amount. Non-cash component is measured on same basis as rate base (see "ICM Calculation" below) and consists of a 13-month average balance from two accounts: • Materials and Supplies • Emission Credits
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: see "cash" component of working capital above
	Included in Rate Base: Both cash and non-cash working capital are included in the calculation of rate base.

	Description
Half Year Rule	**Half Year Rule:** Not in use. The California GRC (General Rate Case) uses a 13-month test-year based on historical data for the first year and, in subsequent years, projected data for investment not yet closed to plant in service at time of filing. Accumulated Depreciation and Amortization (or the Depreciation Reserve) relating to assets included in rate base (before the start of the projected test year) is calculated using the property value from the first day of the month following the in-service or commissioning date and ceases on the last day of the month in which the asset is removed from service. The GRC projects rates for a total of three years using budgeted data with adjustments. Projected gross additions to the rate base are estimated as a twelve-month average balance during a 13-month period.
	Cost of Service: Average rate base is calculated in a manner similar to Accumulated Depreciation. Rate base is the sum of: (1) Electric Plant in Service, (2) Capitalized software, (3) Other intangibles, (4) Non-cash working capital (see above). Accumulated Deferred Income Taxes and Depreciation and Amortization are subtracted from the previous summed amount.
	ICM Calculation: SCE's rates are set for three years during a General Rate Case (GRC). The company is permitted to file annually for differences between costs included in the order concluding the GRC using the Post Test Year Rate (PTYR) adjustment mechanism. This is a comprehensive mechanism that permits for recovery of both capital and O&M expenditure changes. SCE is required to submit an "Advice Letter" to the California Public Utilities Commission staff. Rates are currently set using a cost of service approach. Details of SCE's tariffs can be found on its website: https://www.sce.com/wps/portal/home/regulatory/tariff-books/rates-pricing-choices

	Description
Treatment of Working Capital	**Working Capital** Cash component is based on a comprehensive lead-lag approach involving separate estimates of days outstanding for revenues and detailed O&M expenses. Operational cash requirements (e.g., minimum bank balances, special deposits and prepayments) are added to this amount. Non-cash component is measured on same basis as rate base (see "ICM Calculation" below) and consists of a 13-month average balance for several accounts: • Fuel inventory • Materials and Supplies • Prepaid pension assets
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: see "cash" component of working capital above
	Included in Rate Base: Both cash and non-cash working capital are included in the calculation of rate base.

	Description
Half Year Rule	**Half Year Rule:** Not in use. The Georgia Power ARP (Alternative Ratemaking Plan) uses a 13-month average for two separate periods: a historical period and a test "year" comprised of projected data for investment not yet closed to plant in service at time of filing. Accumulated Depreciation and Amortization (or the Depreciation Reserve) relating to assets included in rate base (before the start of the projected test year) is calculated using the property value from the first day of the month following the in-service or commissioning date and ceases on the last day of the month in which the asset is removed from service. The ARP projects rates for one year using budgeted data with adjustments. Projected gross additions to the rate base are estimated as a twelve-month average balance during a 13-month period.
	Cost of Service: Average rate base is calculated in a manner similar to Accumulated Depreciation. Rate base is the sum of: (1) Electric Plant in Service, (2) Nuclear fuel, (3) Electric Plant Held for Future Use, (4) Non-cash working capital (see above). Accumulated Deferred Income Taxes, Customer Deposits and Depreciation and Amortization are subtracted from the previous summed amount.
	ICM Calculation: Georgia Power's tariffs include adjustments between base rate filings through the following riders: • Environmental Compliance Cost Recovery Schedule (ECCR-3) • Nuclear Construction Cost Recovery Schedule (NCCR-4) • Demand Side Management Commercial Schedule (DSM-C-4) • Fuel Cost Recovery Schedule (FCR-23) • Municipal Franchise Fee Schedule (MFF-3) • Local Tax Adjustment Schedule (LT-1) • Nuclear Waste Fund Rider (NWFR-1) All of these riders increase retail tariffs by specific percentage. The ECCR-3 tariff recovers capital and O&M expenditures associated with environmental compliance. The NCCR-4 tariff recovers the carrying charges on two new nuclear units (Vogtle 3 and 4) currently under construction. Tariff DSM-C-4 recovers the projected costs for commercial demand side management programs. FCR-23 recovers fuel costs in excess of amounts included in retail rates. The two tax adjustment riders (MFF-3 and LT-1) recover the costs of municipal and local taxes applied to customer bills. Tariff NWFR-1 recovers amounts necessary to pay nuclear waste disposal fees that were designed to fund a government-owned high level nuclear waste depository in the United States. Details of Georgia Power's tariffs can be found on its website:

	Description
	http://www.georgiapower.com/pricing/business/schedules.cshtml

	Description
Treatment of Working Capital	**Working Capital** Cash component is based on a comprehensive lead-lag approach involving separate estimates of days outstanding for revenues and detailed O&M expenses over the 12-month historic test year ending June 30, 2012. Non-cash component is also comprised of a 13-month average. It is comprised of: • Fuel inventory • Materials and Supplies • Prepayments including property insurance reserve, injuries and damages reserves, unfunded pension, commercial litigation and environmental reserves
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: see "cash" component of working capital above
	Included in Rate Base: Both cash and non-cash working capital are included in the calculation of rate base.

	Description
Half Year Rule	**Half Year Rule:** Not in use. The Entergy Louisiana FRP (Formula Rate Plan) uses a year-end rate base for a 12-month historic basis. A second 18-month period, commencing after the end of the historic period is used for estimating adjustments. Accumulated Depreciation and Amortization (or the Depreciation Reserve) relating to assets included in rate base (before the start of the projected period) is calculated using the property value from the first day of the month following the in-service or commissioning date and ceases on the last day of the month in which the asset is removed from service. During the most recent fully-litigated case that was decided in December 2013, the FRP projected data for 18 months following the test year using budgeted data with adjustments. Projected gross additions to the rate base are estimated as an ending value during the 18-month period following the historic test year. The current FRP update will use a shorter projected period of 12 months. The period was selected on a one-time basis to enable rates to be in effect through December 31, 2014. The case highlighted was a renewal of an existing rate plan for which the filing date did not coincide with the start of the calendar year.
	Cost of Service: Year-end rate base is calculated in a manner similar to Accumulated Depreciation. Rate base is the sum of: (1) Plant in Service, (2) Plant Held for Future Use, (3) Plant Acquisition Adjustment (4) Rate case expenses and (5) Working capital (see above). Accumulated Deferred Income Taxes, Customer Deposits and Depreciation and Amortization are subtracted from the previous summed amount.
	ICM Calculation: ELL has 13 riders designed to recover a variety of expenses in excess of levels built into rates: • Energy production costs 1. Rough Production Cost Equalization Adjustment – Rider RPCEA (fuel costs) 2. Non-fuel Rough Production Cost Equalization Adjustment – Rider NFRPCEA • Cancelled plant upgrade cost recovery 1. Securitized Little Gypsy Recovery – Rider SLGR 2. Securitized Little Gypsy Offset – Rider SLGO • Energy Efficiency Programs (QUICK START ENERGY EFFICIENCY COST RATE RIDER) • Environmental remediation costs (Environmental Adjustment Clause Rider)

	Description
	• Retail rate impacts of FERC Interruptible rates (FERC Interruptible Order Retail Rate Effects Rider) • Storm recovery financing 1. Financed Storm Cost Rider – FSC-ELL 2. Financed Storm Cost II Rider – FSCII-ELL 3. Financed Storm Cost III Rider – FSCIII-ELL 4. Storm Cost Offset Rider – SCO 5. Storm Cost Offset II Rider – SCOII 6. Storm Cost Offset III Rider – SCOIII The purpose of these riders is well-described by their titles. The storm financing riders are designed to fund securitization bonds floated to finance the rebuilding of the ELL system after a series of hurricanes over the past 10 years. Offset riders for storms and cancelled plant upgrades are designed to credit customers with any proceeds received from grants, insurance recovery and other funding sources. Details of ELL's tariffs can be found on its website: http://www.entergy-louisiana.com/your_business/ELI_Tariffs.aspx

	Description
Treatment of Working Capital	**Working Capital** Cash component is based on a comprehensive lead-lag approach involving separate estimates of days outstanding for revenues and detailed O&M expenses using information from the 12-months of calendar year 2009. The leads and lags are then applied to 12-month test year revenues and operating expenses. Non-cash component is also comprised of a 13-month average. It is comprised solely of materials and supplies
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: see "cash" component of working capital above
	Included in Rate Base: Both cash and non-cash working capital are included in the calculation of rate base.

	Description
Half Year Rule	**Half Year Rule:** Not in use. The current BG&E rate case uses 13-month average for both the mixed historic and projected test year (9 months actual and 3 months projected) ending August 31, 2014 and the future 13-month rate year beginning on November 1, 2014 and ending November 30, 2015[20]. Accumulated Depreciation and Amortization (or the Depreciation Reserve) relating to assets included in rate base (before the start of the projected period) is calculated using the property value from the first day of the month following the in-service or commissioning date and ceases on the last day of the month in which the asset is removed from service. For the 13-month rate year, projected gross additions are added to the rate base and estimated depreciation and amortization are subtracted from the rate base on a 13-month average basis.
	Cost of Service: Average rate base is calculated in a manner similar to Accumulated Depreciation. Rate base is the sum of: (1) Utility plant in service, (2) Construction work in progress, (3) Property held for future use, (4) Unamortized environmental costs, (5) Unamortized deferred conservation program expenditures and (6) Working capital (see above). Accumulated deferred income taxes, Customer deposits, Customer contributions in aid of construction and Depreciation and Amortization are subtracted from the previous summed amount.
	ICM Calculation: BG&E has eight riders designed to recover the cost of various programs and changes in expenses after implementation of a rate order: 1. Electric Efficiency Charge 2. Miscellaneous Taxes and Surcharges 3. Sparrows Point (SPE) Revenue Stabilization Rate 4. Qualified Rate Stabilization Charge 5. Nuclear Decommissioning and Standard Offer Service Return Credits 6. Monthly Rate Adjustment 7. Demand Resource Surcharge 8. Electric Reliability Investment Initiative Charge Each of these addresses a unique set of expenditures. The last one listed – Electric Reliability Investment Initiative Charge – allows BG&E to recover the cost of infrastructure upgrades that improve system reliability. The individual riders are available from the following BG&E website: http://www.bge.com/myaccount/billsrates/ratestariffs/electricservice/Pages/Electric-Services-Rates-and-Tariffs.aspx

[20] The unstated rationale for the gap in measurement (from August 31 through October 31, 2014) appears to be the avoidance of the period when the Commission holdings hearings and is in the middle of its adjudication process.

	Description
Treatment of Working Capital	**Working Capital** <u>Cash</u> component is based on a comprehensive lead-lag approach involving separate estimates of days outstanding for revenues and detailed O&M expenses over the 12-month adjusted year ending December 31, 2010. The adjusted year is derived from historic test year data for the 12 month period ending December 31, 2008. <u>Non-cash</u> component is also comprised of a 12-month adjusted year ending December 31, 2010 that is derived from historic test year data for the 12 month period ending December 31, 2008. It is comprised solely of Materials and Supplies.
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: see "cash" component of working capital above
	Included in Rate Base: Non-cash working capital is included in the calculation of rate base.

	Description
Half Year Rule	**Half Year Rule:** Not in use. The Massachusetts DPU uses a year-end rate base for the test year. A second 12-month period, commencing after the end of the historic period is used for adjustments. Accumulated Depreciation and Amortization (or the Depreciation Reserve) relating to assets included in rate base (before the start of the projected period) is calculated using the property value from the first day of the month following the in-service or commissioning date and ceases on the last day of the month in which the asset is removed from service.
	Cost of Service: Year-end rate base is calculated in a manner similar to Accumulated Depreciation. Rate base equals (1) Plant in Service <u>Plus</u> (2) Working Capital <u>Less</u> (3 Contributions in Aid of Construction, (4) Accumulated Depreciation and Amortization, (5) Accumulated Deferred Income Taxes and (5) Customer Deposits.
	ICM Calculation: MECo's rate schedules include 13 riders designed to recover a variety of expenses related to different programs: 1. Attorney General Consultant Expenses Provision 2. Energy Efficiency Provision 3. Service Quality Adjustment Provision 4. Storm Performance Adjustment Provision 5. Pension/PBOP Adjustment Mechanism Provision 6. Renewable Energy Recovery Provision 7. Residential Assistance Adjustment Provision 8. Revenue Decoupling Mechanism Provision 9. Smart Grid Adjustment Provision 10. Solar Cost Adjustment Provision 11. Storm Fund Replenishment Provision 12. Transition Cost Adjustment Provision 13. Transmission Service Cost Adjustment Provision The rate schedules for each of these riders is available from MECo's website: https://www.nationalgridus.com/masselectric/home/rates/billing.asp . For each of these riders, MECo files projected levels of expenditures and a reconciliation between actual and previously projected levels.

	Description
Treatment of Working Capital	**Working Capital** Cash component is not included in working capital. Currently, a small amount – for compensating bank balances and working funds – is included Non-cash component is included on a 13-month average basis for the test year. It is comprised of: • Fuel stock • Materials and Supplies • Prepayments
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: not applicable because no cash working capital is included
	Included in Rate Base: Non-cash working capital is included in the calculation of rate base.

	Description
Half Year Rule	**Half Year Rule:** Not in use. PEP-5 uses a historical test 13-month average rate base. Accumulated Depreciation and Amortization (or the Depreciation Reserve) relating to assets included in rate base (before the start of the projected period) is calculated using the property value from the first day of the month following the in-service or commissioning date and ceases on the last day of the month in which the asset is removed from service.
	Cost of Service: Test year-end rate base is calculated in a manner similar to Accumulated Depreciation. Rate base is the sum of: (1) Gross Electric Plant, (2) Construction Work in Progress, (3) Plant Held for Future Use and (4) Working capital (see above). Accumulated Deferred Income Taxes, Customer Advances, Customer Deposits, Injuries & Damages Reserve, and Depreciation and Amortization are subtracted from the previous summed amount.
	ICM Calculation: The Mississippi Public Service Commission has approved seven additional riders for Mississippi Power. The riders flow through the impact of discrete portions of revenue requirement that may be subject to change: • Ad Valorem Tax Rider (ATA-1) • Environmental Compliance (ECO-2) • Energy Cost Management (ECM-2) • Fuel Cost Recovery (FCR-2) • Regulatory Tax Recovery (RTR-2) • System Restoration (SRR) Each of these factors use forward looking data to adjust rates to deal with anticipated changes in a subset of the cost of service. All of these riders adjust rates to recover shortfalls created when expenses were different from levels expected in tariffs. The Ad Valorem tax rider (ATA-1) recovers property and similar value-based taxes in excess of levels incorporated into tariffs. There are no charges to customers under this rider in current rates. The Environmental Compliance (ECO-2) rider recovers projected prudently incurred capital and operating costs for environmental projects in excess of levels incorporated into tariffs. Capital expenditures are estimated on a 13-month average basis. There are no charges to customers under this rider in current rates. The Energy Cost Management (ECM-2) rider recovers the transaction costs associated with futures and transportation contracts for electricity and natural gas. The Fuel Cost Recovery (FCR-2) rider compensates the company for budgeted

	Description
	fuel costs prospectively and adjusts for differences between actual and budgeted costs in previous years. The Regulatory Tax Recovery (RTR-2) rider compensates the company for gross revenue taxes levied by the State of Mississippi. The System Restoration Rider compensates the company for debt service on securitized costs associated with recovery from Hurricane Katrina. Details for Mississippi Power's tariffs may be found on its website: http://mississippipower.com/my-business/our-pricing/rate-and-rider-details

New York Public Service Commission – Consolidated Edison Company of New York (Con Edison) 2013 rate case

	Description
Treatment of Working Capital	**Working Capital** Cash component is based on the application of the FERC formula – one eighth of O&M expenses (also known as "the 45-day rule"). Con Edison removes the following expenses from O&M before applying the formula: • Purchased power and fuel • System benefit charges • Renewable portfolio charges • Interdepartmental rents • Uncollectibles Non-cash component is included on an historical 12-month average basis for the test year and on a projected 12-month average basis for the rate year. It is comprised of: • Materials and Supplies (including liquid fuel inventories) • Prepayments
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: not applicable; see "cash" component of working capital above
	Included in Rate Base: Both cash and non-cash working capital are included in the calculation of rate base.

	Description
Half Year Rule	**Half Year Rule:** Not in use. Con Edison uses a historical 12-month average for the test year rate base. Accumulated Depreciation and Amortization (or the Depreciation Reserve) relating to assets included in rate base is calculated using the property value from the first day of the month following the in-service or commissioning date and ceases on the last day of the month in which the asset is removed from service. For the rate year, a 12-month average is estimated based on the depreciation rates and expected amounts of plant completed during the rate year.
	Cost of Service: Test year-end rate base is calculated in a manner similar to Accumulated Depreciation. Rate base is the sum of: (1) Book Cost of Plant, (2) Non-Interest Bearing Construction Work in Progress (CWIP), (3) Unamortized Debt Discount/Premium/Expense (4) Unbilled Revenues (excluding deferred fuel), (5) Deferred Fuel – Net of Tax and (6) Working capital (see above). Accumulated Deferred Income Taxes, Customer Advances for Construction, and Depreciation and Amortization are subtracted from the previous summed amount.
	ICM Calculation: Con Edison tariffs include six surcharges for its New York customers: 1. Monthly Adjustment Clause 2. PSL 18-a Assessments 3. Revenue Decoupling Mechanism Adjustment 4. Renewable Portfolio Standard Program 5. System Benefits Charge 6. Delivery Revenue Surcharge The surcharges collect additional revenues to support various programs and changes in costs. The Monthly Adjustment Clause collects additional revenues to deal with transmission congestion contracts, restructuring charges, public policy contracts, and several other components. Details can be found in the company's ***General Rules***, Section 26.1 (http://www.coned.com/documents/elecPSC10/GR25-Forms.pdf) The surcharge for PSL 18-a Assessments collects funds to support the regulatory services of the New York Public Service Commission. ConEdison's New York electric rates are available from the following website: http://www.coned.com/rates/elec.asp .

	Description
Treatment of Working Capital	**Working Capital** Cash component is based on a comprehensive lead-lag approach involving separate estimates of days outstanding for revenues and detailed O&M expenses. Non-cash component is included on a projected 12-month future test year that is derived from a 13-month average for the historical test year. It is comprised of: • Materials and Supplies • Prepaid Expenses
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: see "cash" component of working capital above
	Included in Rate Base: Both cash and non-cash working capital are included in the calculation of rate base.

	Description
Half Year Rule	**Half Year Rule:** Not in use. PECO uses a 13-month average for the historical test year rate base and a 12-month average for the future test year rate base. Accumulated Depreciation and Amortization (or the Depreciation Reserve) relating to assets included in rate base is calculated using the property value from the first day of the month following the in-service or commissioning date and ceases on the last day of the month in which the asset is removed from service. For the rate year, a 12-month average is estimated based on the depreciation rates and expected amounts of plant completed during the rate year.
	Cost of Service: Test year-end rate base is calculated in a manner similar to Accumulated Depreciation. Rate base is the sum of: (1) Utility Plant and (2) Working capital (see above). Accumulated Deferred Income Taxes, Customer Deposits, Customer Advances for Construction, and Depreciation and Amortization are subtracted from the previous summed amount.
	ICM Calculation: PECO tariffs include a large number of specialty charges, including: 1. Provision for Surcharge Recovery of Alternative Energy Portfolio Standard Costs 2. Nuclear Decommissioning Cost Adjustment Clause (NDCA) 3. Provisions For Recovery of Universal Service Fund Charge (USFC) 4. Provisions for Recovery of Supplemental Universal Service Fund Costs 5. Transmission Service Charge 6. Smart Meter Cost Recovery Surcharge 7. Provision For The Recovery of Energy Efficiency And Conservation Program Costs (EEPC) 8. Provision for the Tax Accounting Repair Credit (TARC) 9. Provision For The Recovery Of Energy Efficiency And Conservation Program Costs Phase II Details for these tariff provisions are available from PECO's website: (https://www.peco.com/CustomerService/RatesandPricing/RateInformation/Pages/CurrentElectric.aspx)

	Description
Treatment of Working Capital	**Working Capital** is not calculated.
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: Not applicable.
	Included In Rate Base: See description below.
	ICM Calculation: Not applicable

	Description
Half Year Rule	**Half Year Rule:** Ofgem does not use the half year rule. No depreciation is recognized for capital additions closed to RAV in the test year. A full year's depreciation for capital additions in year (t) is applied in year (t+1).
	Cost of Service: Real Asset Value (RAV) is a key building block for the price control review. RAV is the basis upon which the rate regulated entity receives a depreciation allowance and earns a return on capital pursuant with the regulatory cost of capital. Additions to RAV are based on the proportion of Total Expenditure (Totex) allowed as "slow money". Total expenditures are comprised of: (1) controllable operating expenditures; (2) load related capital expenditures; (3) asset replacement capital expenditures; (4) other capital expenditures; and (5) non-operational capital expenditures. The annual net additions to RAV is calculated as a percentage of Totex. Ofgem's approved capitalization percentage of Totex is 85%. In other words, 85% of Totex is considered "slow money" and added to the RAV balance. The closing balance of RAV in year (t) is calculated as: Closing RAV in year (t-1) **plus** transfers **plus** net additions (i.e. "slow money" or 85% of Totex in year (t)) **minus** accumulated depreciation. The full depreciation for capital additions in the test year (t) are applied in year (t+1).
	ICM Calculation: The RIIO price control framework applies an eight year period (1 test year and 7 years in IRM). Under the RIIO, Ofgem asks companies to submit well justified business plans detailing how they intend to meet the RIIO framework objectives. The process starts with the publication of a strategy document in which Ofgem sets out the framework against which the various rate regulated entities will develop their plans. RIIO places a strong emphasis on stakeholder engagement and companies must get stakeholders' input and demonstrate how this has been used to develop their plans. Ofgem reviews these plans to determine what levels of proportionate treatment to apply. The Price Control Financial Model (PCFM) for RIIO price controls is the financial model which derives the incremental changes to the base revenue during the RIIO price control period. It does this by recalculating base revenues based on a limited number of updated variables. These variables fall into four broad categories: the annual cost of corporate debt, Totex components sufficient to apply the Totex incentive mechanism, new or amended allowances on uncertainty mechanisms, and certain financial adjustments (e.g. pension variables, tax variables and legacy adjustments). The Totex Incentive Mechanism (TIM) applies adjustments to the Totex figure used in the fast/slow money modelling of recalculated base revenue figures under the Annual Iteration Process. The adjustments reflect the amount of under or over expenditure by the licensee against Totex allowances and the Totex Incentive Strength Rate (incentive strength) for each licensee. The incentive strength is a percentage figure specified in Special Condition 6C for each licensee. It represents the percentage that a licensee bears in respect of an overspend against allowances or retains in respect of an underspend against allowances. The adjustment that is made to the Totex figures is the Funding Adjustment Rate

	Description
	(often called the 'sharing factor') which is calculated as 1 – incentive strength. Applying the Funding Adjustment Rate to the over (or under spend) gives the amount that is added to (or subtracted from) the Totex allowances included in recalculated base revenues. The TIM uses the actual Totex expenditure values reported to Ofgem by 31 July each year (subject to any revisions that may be required for corrections of data or for expenditure that is not regarded as efficient) and adjusts revenues in the following Relevant Year via the MOD term. The incentive mechanism therefore operates with a two year lag. The half year rule is not used over the IR period. The full depreciation for capital additions in year (t) are applied in year (t+1).

Appendix 4 Half Year Rule Analysis: Cost of Service

In order to highlight the effect of the half year rule on capital-related costs recovered in rates over a rate-making cycle, KPMG conducted a pro-forma analysis (i.e., the analysis does not reflect actual distributor data), comparing the capital-related costs recovered in rates in a cost of service environment with and without the half year rule. This analysis is presented below.

Cost of Service with Half Year Rule

Cost of Service With Half Year Rule ($)	Year 1	Year 2	Year 3	Year 4	Year 5
Assets					
Opening Balance	5,000,000	5,150,000	5,300,000	5,450,000	5,600,000
Additions	200,000	200,000	200,000	200,000	200,000
Removals	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)
Closing Balance	**5,150,000**	**5,300,000**	**5,450,000**	**5,600,000**	**5,750,000**
Accumulated Depreciation					
Opening Balance	(2,000,000)	(2,077,500)	(2,158,750)	(2,243,750)	(2,332,500)
Additions	(127,500)	(131,250)	(135,000)	(138,750)	(142,500)
Removals	50,000	50,000	50,000	50,000	50,000
Closing Balance	**(2,077,500)**	**(2,158,750)**	**(2,243,750)**	**(2,332,500)**	**(2,425,000)**
Net Book Value					
Opening Balance (Jan 1)	3,000,000	3,072,500	3,141,250	3,206,250	3,267,500
Closing Balance (Dec 31)	3,072,500	3,141,250	3,206,250	3,267,500	3,325,000
Average	**3,036,250**	**3,106,875**	**3,173,750**	**3,236,875**	**3,296,250**
Depreciation Expense					
Opening Assets	125,000	128,750	132,500	136,250	140,000
Capital Additions					
Aggregate Average Depreciation Rate					
Years	40	40	40	40	40
Depreciation Rate	2.5%	2.5%	2.5%	2.5%	2.5%
Full Year	5,000	5,000	5,000	5,000	5,000
Half Year	2,500	2,500	2,500	2,500	2,500
Total Depreciation Expense					
Full Year	**130,000**	**133,750**	**137,500**	**141,250**	**145,000**
Half Year	**127,500**	**131,250**	**135,000**	**138,750**	**142,500**

Cost of Service With Half Year Rule ($) cont'd					
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Cost of Capital					
Return on Equity	9.36%	9.36%	9.36%	9.36%	9.36%
LT Debt	4.88%	4.88%	4.88%	4.88%	4.88%
ST Debt	2.11%	2.11%	2.11%	2.11%	2.11%
Capital Structure					
Equity	40%	40%	40%	40%	40%
LT Debt	56.00%	56.00%	56.00%	56.00%	56.00%
ST Debt	4%	4%	4%	4%	4%
WACC	**6.56%**	**6.56%**	**6.56%**	**6.56%**	**6.56%**
Return on Capital					
Deemed Equity	113,677	116,321	118,825	121,189	123,412
Deemed LT Debt	82,975	84,905	86,732	88,457	90,080
Deemed ST Debt	2,563	2,622	2,679	2,732	2,782
Return on Capital	**199,214**	**203,848**	**208,236**	**212,378**	**216,274**
Taxes/PILs					
Aggregate Federal/Provincial Tax Rate	26.25%	26.25%	26.25%	26.25%	26.25%
Aggregate Taxes/PILs (grossed-up)	**40,461**	**41,403**	**42,294**	**43,135**	**43,926**
Capital-Related Costs Recovered in Rates					
Depreciation	127,500	131,250	135,000	138,750	142,500
Return on Capital	199,214	203,848	208,236	212,378	216,274
Taxes/PILs (Grossed-up)	40,461	41,403	42,294	43,135	43,926
Total	**367,176**	**376,501**	**385,530**	**394,263**	**402,700**

Source: KPMG Analysis

Cost of Service With No Half Year Rule ($)					
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Assets					
Opening Balance	5,000,000	5,150,000	5,300,000	5,450,000	5,600,000
Additions	200,000	200,000	200,000	200,000	200,000
Removals	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)
Closing Balance	**5,150,000**	**5,300,000**	**5,450,000**	**5,600,000**	**5,750,000**
Accumulated Depreciation					
Opening Balance	(2,000,000)	(2,080,000)	(2,163,750)	(2,251,250)	(2,342,500)
Additions	(130,000)	(133,750)	(137,500)	(141,250)	(145,000)
Removals	50,000	50,000	50,000	50,000	50,000
Closing Balance	**(2,080,000)**	**(2,163,750)**	**(2,251,250)**	**(2,342,500)**	**(2,437,500)**
Net Book Value					
Opening Balance (Jan 1)	3,000,000	3,070,000	3,136,250	3,198,750	3,257,500
Closing Balance (Dec 31)	3,070,000	3,136,250	3,198,750	3,257,500	3,312,500
Average	**3,035,000**	**3,103,125**	**3,167,500**	**3,228,125**	**3,285,000**
Depreciation Expense					
Opening Assets	125,000	128,750	132,500	136,250	140,000
Capital Additions					
Aggregate Average Depreciation Rate					
Years	40	40	40	40	40
Depreciation Rate	2.5%	2.5%	2.5%	2.5%	2.5%
Full Year	5,000	5,000	5,000	5,000	5,000
Half Year	5,000	5,000	5,000	5,000	5,000
Total Depreciation Expense					
Full Year	**130,000**	**133,750**	**137,500**	**141,250**	**145,000**
Half Year	**130,000**	**133,750**	**137,500**	**141,250**	**145,000**

Cost of Service With No Half Year Rule ($) cont'd	Year 1	Year 2	Year 3	Year 4	Year 5
Cost of Capital					
Return on Equity	9.36%	9.36%	9.36%	9.36%	9.36%
LT Debt	4.88%	4.88%	4.88%	4.88%	4.88%
ST Debt	2.11%	2.11%	2.11%	2.11%	2.11%
Capital Structure					
Equity	40.00%	40.00%	40.00%	40.00%	40.00%
LT Debt	56.00%	56.00%	56.00%	56.00%	56.00%
ST Debt	4%	4%	4%	4%	4%
WACC	**6.56%**	**6.56%**	**6.56%**	**6.56%**	**6.56%**
Return on Capital					
Deemed Equity	113,630	116,181	118,591	120,861	122,990
Deemed LT Debt	82,940	84,802	86,561	88,218	89,772
Deemed ST Debt	2,562	2,619	2,673	2,725	2,773
Return on Capital	**199,132**	**203,602**	**207,826**	**211,804**	**215,535**
Taxes/PILs					
Aggregate Federal/Provincial Tax Rate	26.25%	26.25%	26.25%	26.25%	26.25%
Aggregate Taxes/PILs (grossed-up)	**40,445**	**41,353**	**42,210**	**43,018**	**43,776**
Capital-Related Costs Recovered in Rates					
Depreciation	130,000	133,750	137,500	141,250	145,000
Return on Capital	199,132	203,602	207,826	211,804	215,535
Taxes/PILs (Grossed-up)	40,445	41,353	42,210	43,018	43,776
Total	**369,577**	**378,705**	**387,536**	**396,072**	**404,312**

Source: KPMG Analysis

Appendix 5 Half Year Rule Analysis - RRFE

Half Year Rule Used in Rebasing Year - No Growth					
	Rebasing Year	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Revenue Adjustment Mechanism					
Two Factor Inflation Adjustment	0.00%	1.60%	1.60%	1.60%	1.60%
TFP Adjustment	0.00%	0.00%	0.00%	0.00%	0.00%
Stretch Factor	0.00%	-0.30%	-0.30%	-0.30%	-0.30%
Total Annual Cost Adjustment	**0.00%**	**1.30%**	**1.30%**	**1.30%**	**1.30%**
Capital-Related Cost Recovered No Customer Growth ($)					
Depreciation	127,500	129,158	130,837	132,537	134,260
Return on Capital	199,214	201,804	204,428	207,085	209,777
Taxes/PILs (Grossed-up)	40,461	40,987	41,520	42,060	42,607
Total	**367,176**	**371,949**	**376,784**	**381,683**	**386,645**
Capital Related Costs Recovered in COS with Half Year Rule	367,176	376,501	385,530	394,263	402,700
Difference with COS with Half Year Rule ($)	-	(4,552)	(8,745)	(12,580)	(16,055)

Source: KPMG Analysis

Half Year Rule In Rebasing Year - Eliminated Years 2 - 5 No Growth					
	Rebasing Year	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Revenue Adjustment Mechanism					
Two Factor Inflation Adjustment	0.00%	1.60%	1.60%	1.60%	1.60%
TFP Adjustment	0.00%	0.00%	0.00%	0.00%	0.00%
Stretch Factor	0.00%	-0.30%	-0.30%	-0.30%	-0.30%
Total Annual Cost Adjustment	**0.00%**	**1.30%**	**1.30%**	**1.30%**	**1.30%**
Capital-Related Cost Recovered No Customer Growth ($)					
Depreciation	127,500	131,690	133,402	135,136	136,893
Return on Capital	199,214	201,721	204,344	207,000	209,691
Taxes/PILs (Grossed-up)	40,461	40,970	41,503	42,043	42,589
Total	**367,176**	**374,382**	**383,989**	**393,843**	**403,950**
Capital Related Costs Recovered in COS with Half Year Rule	367,176	376,501	385,530	394,263	402,700
Difference with COS with Half Year Rule ($)	-	(2,119)	(1,541)	(419)	1,251

Source: KPMG Analysis

Half Year Rule Used in Rebasing Year with Growth					
	Rebasing Year	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Revenue Adjustment Mechanism					
Two Factor Inflation Adjustment	0.00%	1.60%	1.60%	1.60%	1.60%
TFP Adjustment	0.00%	0.00%	0.00%	0.00%	0.00%
Stretch Factor	0.00%	-0.30%	-0.30%	-0.30%	-0.30%
Total Annual Cost Adjustment	**0.00%**	**1.30%**	**1.30%**	**1.30%**	**1.30%**
Composite Growth Rate (g)	0.00%	1.25%	1.25%	1.25%	1.25%
Capital-Related Cost Recovered With Customer Growth ($)					
Depreciation	127,500	130,772	134,128	137,570	141,100
Return on Capital	199,214	204,327	209,570	214,948	220,465
Taxes/PILs (Grossed-up)	40,461	41,500	42,565	43,657	44,777
Total	**367,176**	**376,598**	**386,263**	**396,175**	**406,342**
Capital Related Costs Recovered in COS with Half Year Rule	367,176	376,501	385,530	394,263	402,700
Difference with COS with Half Year Rule ($)	-	98	733	1,913	3,643

Source: KPMG Analysis

Half Year Rule Used in Rebasing Year - Eliminated Years 2 - 5 with Growth					
	Rebasing Year	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Revenue Adjustment Mechanism					
Two Factor Inflation Adjustment	0.00%	1.60%	1.60%	1.60%	1.60%
TFP Adjustment	0.00%	0.00%	0.00%	0.00%	0.00%
Stretch Factor	0.00%	-0.30%	-0.30%	-0.30%	-0.30%
Total Annual Cost Adjustment	**0.00%**	**1.30%**	**1.30%**	**1.30%**	**1.30%**
Composite Growth Rate (g)	0.00%	1.25%	1.25%	1.25%	1.25%
Capital-Related Cost Recovered With Customer Growth ($)					
Depreciation	127,500	133,336	136,758	140,267	143,867
Return on Capital	199,214	204,243	209,484	214,860	220,374
Taxes/PILs (Grossed-up)	40,461	41,483	42,547	43,639	44,759
Total	**367,176**	**379,061**	**388,789**	**398,766**	**409,000**
Capital Related Costs Recovered in COS with Half Year Rule	367,176	376,501	385,530	394,263	402,700
Difference with COS with Half Year Rule ($)	-	2,561	3,259	4,504	6,300

Source: KPMG Analysis

Appendix 6 Half Year Rule – Sensitivity Analysis

100% of Depreciation with Customer Growth

CapEx 100% of Depreciation with Customer Growth										
Key Assumptions		**Rebasing Year**		**Year 2**		**Year 3**		**Year 4**		**Year 5**
Revenue Adjustment Mechanism										
Two Factor Inflation Adjustment		0.00%		1.60%		1.60%		1.60%		1.60%
TFP Adjustment		0%		0%		0.00%		0.00%		0.00%
Stretch Factor		0.00%		0.30%		0.30%		0.30%		0.30%
Total Annual Cost Adjustment		1.30%		1.30%		1.30%		1.30%		1.30%
Customer Growth and Demand Growth										
Customer Growth		0.00%		1.02%		1.02%		1.02%		1.02%
kWh Growth		0.00%		0.22%		0.22%		0.22%		0.22%
kW Growth		0.00%		0.80%		0.80%		0.80%		0.80%
Fixed/Variable Split										
Fixed		40%		40%		40%		40%		40%
Variable - kWh		30%		30%		30%		30%		30%
Variable - kW		30%		30%		30%		30%		30%
Composite Growth Rate (g)		0.00%		0.71%		0.71%		0.71%		0.71%
Capital Expenditures as Percent of Depreciation		100%								
Opening Capital Expenditures	$	160,000								
Depreciation Expense										
Opening Assets	$	160,000	$	163,520	$	167,123	$	170,810	$	174,584
Capital Additions										
Aggregate Average Depreciation Rate										
Years		31		31		31		31		31
Depreciation Rate		3.2%		3.2%		3.2%		3.2%		3.2%
Full Year	$	5,120	$	5,224	$	5,329	$	5,437	$	5,547
Half Year	$	2,560	$	2,612	$	2,665	$	2,719	$	2,774
Total										
Full Year	$	165,120	$	168,744	$	172,452	$	176,247	$	180,131
Half Year	$	162,560	$	166,132	$	169,787	$	173,529	$	177,358

A. Cost of Service With Half Year Rule	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Assets					
Opening Balance	$ 5,000,000	$ 5,110,000	$ 5,222,587	$ 5,337,819	$ 5,455,753
Additions	$ 160,000	$ 163,237	$ 166,540	$ 169,910	$ 173,347
Removals	-$ 50,000	-$ 50,650	-$ 51,308	-$ 51,975	-$ 52,651
Closing Balance	$ 5,110,000	$ 5,222,587	$ 5,337,819	$ 5,455,753	$ 5,576,449
Accumulated Depreciation					
Opening Balance	-$ 2,000,000	-$ 2,112,560	-$ 2,228,042	-$ 2,346,521	-$ 2,468,074
Additions	-$ 162,560	-$ 166,132	-$ 169,787	-$ 173,529	-$ 177,358
Removals	$ 50,000	$ 50,650	$ 51,308	$ 51,975	$ 52,651
Closing Balance	-$ 2,112,560	-$ 2,228,042	-$ 2,346,521	-$ 2,468,074	-$ 2,592,781
Net Book Value					
Opening Balance (January 1)	$ 3,000,000	$ 2,997,440	$ 2,994,545	$ 2,991,298	$ 2,987,679
Closing Balance (December 31)	$ 2,997,440	$ 2,994,545	$ 2,991,298	$ 2,987,679	$ 2,983,669
Average	$ 2,998,720	$ 2,995,993	$ 2,992,922	$ 2,989,488	$ 2,985,674
Cost of Capital					
Return on Equity	9.36%	9.36%	9.36%	9.36%	9.36%
LT Debt	4.88%	4.88%	4.88%	4.88%	4.88%
ST Debt	2.11%	2.11%	2.11%	2.11%	2.11%
Capital Structure					
Equity	40%	40%	40%	40%	40%
LT Debt	56.00%	56.00%	56.00%	56.00%	56.00%
ST Debt	4%	4%	4%	4%	4%
WACC	6.56%	6.56%	6.56%	6.56%	6.56%
Return on Capital					
Deemed Equity	$ 112,272	$ 112,170	$ 112,055	$ 111,926	$ 111,784
Deemed LT Debt	$ 81,949	$ 81,874	$ 81,791	$ 81,697	$ 81,592
Deemed ST Debt	$ 2,531	$ 2,529	$ 2,526	$ 2,523	$ 2,520
Return on Capital	$ 196,752	$ 196,573	$ 196,372	$ 196,146	$ 195,896
Taxes/PILs					
Aggregate Federal/Provincial Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%
Aggregate Taxes/PILs (Grossed-up)	$ 40,479	$ 40,442	$ 40,401	$ 40,354	$ 40,303
Capital-Related Costs Recovered in Rates					
Depreciation	$ 162,560	$ 166,132	$ 169,787	$ 173,529	$ 177,358
Return on Capital	$ 196,752	$ 196,573	$ 196,372	$ 196,146	$ 195,896
Taxes/PILs (Grossed-up)	$ 40,479	$ 40,442	$ 40,401	$ 40,354	$ 40,303
Total	$ 399,791	$ 403,147	$ 406,560	$ 410,030	$ 413,557
IR Framework					
Capital-Related Cost Recovered	**Rebasing Year**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Depreciation	$ 162,560	$ 165,849	$ 169,205	$ 172,628	$ 176,121
Return on Capital	$ 196,752	$ 200,733	$ 204,794	$ 208,938	$ 213,165
Taxes/PILs (Grossed-up)	$ 40,479	$ 41,298	$ 42,134	$ 42,986	$ 43,856
Total	$ 399,791	$ 407,880	$ 416,133	$ 424,552	$ 433,142
Difference in Capital-Related Costs Recovered					
IR Framework	**$ 399,791**	**$ 407,880**	**$ 416,133**	**$ 424,552**	**$ 433,142**
COS with Half Year Rule	**$ 399,791**	**$ 403,147**	**$ 406,560**	**$ 410,030**	**$ 413,557**
Difference (IR Less COS)	**$ -**	**$ 4,733**	**$ 9,573**	**$ 14,523**	**$ 19,585**
Difference as % of Capital Costs in IR Rates		**1.16%**	**2.30%**	**3.42%**	**4.52%**
Capital Expenditures In IR Rates (No Dead Band)					
Calculation of Notional Capital in Rates	**Rebasing Year**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Notional Rate Base	$ 2,998,720	$ 3,059,393	$ 3,121,293	$ 3,184,445	$ 3,248,876
Threshold Calculation		137.3%	137.3%	137.3%	137.3%
Amount of Capital in Rates		$ 227,749	$ 232,357	$ 237,058	$ 241,855

KPMG

B. Cost of Service With Half Year Rule Eliminated

	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Assets					
Opening Balance	$ 5,000,000	$ 5,110,000	$ 5,222,587	$ 5,337,819	$ 5,455,753
Additions	$ 160,000	$ 163,237	$ 166,540	$ 169,910	$ 173,347
Removals	-$ 50,000	-$ 50,650	-$ 51,308	-$ 51,975	-$ 52,651
Closing Balance	$ 5,110,000	$ 5,222,587	$ 5,337,819	$ 5,455,753	$ 5,576,449
Accumulated Depreciation					
Opening Balance	-$ 2,000,000	-$ 2,115,120	-$ 2,233,214	-$ 2,354,357	-$ 2,478,629
Additions	-$ 165,120	-$ 168,744	-$ 172,452	-$ 176,247	-$ 180,131
Removals	$ 50,000	$ 50,650	$ 51,308	$ 51,975	$ 52,651
Closing Balance	-$ 2,115,120	-$ 2,233,214	-$ 2,354,357	-$ 2,478,629	-$ 2,606,109
Net Book Value					
Opening Balance (January 1)	$ 3,000,000	$ 2,994,880	$ 2,989,374	$ 2,983,462	$ 2,977,124
Closing Balance (December 31)	$ 2,994,880	$ 2,989,374	$ 2,983,462	$ 2,977,124	$ 2,970,340
Average	$ 2,997,440	$ 2,992,127	$ 2,986,418	$ 2,980,293	$ 2,973,732
Cost of Capital					
Return on Equity	9.36%	9.36%	9.36%	9.36%	9.36%
LT Debt	4.88%	4.88%	4.88%	4.88%	4.88%
ST Debt	2.11%	2.11%	2.11%	2.11%	2.11%
Capital Structure					
Equity	40%	40%	40%	40%	40%
LT Debt	56.00%	56.00%	56.00%	56.00%	56.00%
ST Debt	4%	4%	4%	4%	4%
WACC	6.56%	6.56%	6.56%	6.56%	6.56%
Return on Capital					
Deemed Equity	$ 112,224	$ 112,025	$ 111,811	$ 111,582	$ 111,337
Deemed LT Debt	$ 81,914	$ 81,769	$ 81,613	$ 81,445	$ 81,266
Deemed ST Debt	$ 2,530	$ 2,525	$ 2,521	$ 2,515	$ 2,510
Return on Capital	$ 196,668	$ 196,319	$ 195,945	$ 195,543	$ 195,112
Taxes/PILs					
Aggregate Federal/Provincial Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%
Aggregate Taxes/PILs (grossed-up)	$ 40,462	$ 40,390	$ 40,313	$ 40,230	$ 40,142
Capital-Related Costs Recovered in Rates					
Depreciation	$ 165,120	$ 168,744	$ 172,452	$ 176,247	$ 180,131
Return on Capital	$ 196,668	$ 196,319	$ 195,945	$ 195,543	$ 195,112
Taxes/PILs (Grossed-up)	$ 40,462	$ 40,390	$ 40,313	$ 40,230	$ 40,142
Total	$ 402,250	$ 405,453	$ 408,710	$ 412,021	$ 415,385

IR Framework with Half Year Rule in Rebasing Year and Eliminated for IR Period

Capital-Related Cost Recovered	**Rebasing Year**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Depreciation	$ 162,560	$ 168,461	$ 171,869	$ 175,347	$ 178,894
Return on Capital	$ 196,752	$ 200,647	$ 204,707	$ 208,849	$ 213,074
Taxes/PILs (Grossed-up)	$ 40,479	$ 41,280	$ 42,116	$ 42,968	$ 43,837
Total	$ 399,791	$ 410,388	$ 418,692	$ 427,163	$ 435,806

Difference in Capital-Related Costs Recovered

IR with 1/2 Yr Rule in Rebasing Yr & Not in IR Years	**$ 399,791**	**$ 410,388**	**$ 418,692**	**$ 427,163**	**$ 435,806**
Less COS with Half Year Rule	**$ 399,791**	**$ 403,147**	**$ 406,560**	**$ 410,030**	**$ 413,557**
Difference	**$ -**	**$ 7,241**	**$ 12,132**	**$ 17,134**	**$ 22,249**
Difference as % of Capital Costs in Rates		**1.76%**	**2.90%**	**4.01%**	**5.11%**

Capital Expenditures In IR Rates (No Dead Band)

Calculation of Notional Capital in Rates	**Rebasing Year**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Notional Rate Base	$ 2,998,720	$ 3,058,087	$ 3,119,960	$ 3,183,086	$ 3,247,489
Threshold Calculation		136.7%	136.7%	136.7%	136.7%
Amount of Capital in Rates		$ 230,335	$ 234,995	$ 239,749	$ 244,600

CAPEX 100% of Depreciation with no Customer Growth

CapEx 100% of Depreciation Without Customer Growth					
Key Assumptions	**Rebasing Year**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Revenue Adjustment Mechanism					
Two Factor Inflation Adjustment	0.00%	1.60%	1.60%	1.60%	1.60%
TFP Adjustment	0%	0%	0.00%	0.00%	0.00%
Stretch Factor	0.00%	0.30%	0.30%	0.30%	0.30%
Total Annual Cost Adjustment	1.30%	1.30%	1.30%	1.30%	1.30%
Customer Growth and Demand Growth					
Customer Growth	0.00%	0.00%	0.00%	0.00%	0.00%
kWh Growth	0.00%	0.00%	0.00%	0.00%	0.00%
kW Growth	0.00%	0.00%	0.00%	0.00%	0.00%
Fixed/Variable Split					
Fixed	40%	40%	40%	40%	40%
Variable - kWh	30%	30%	30%	30%	30%
Variable - kW	30%	30%	30%	30%	30%
Composite Growth Rate (g)	0.00%	0.00%	0.00%	0.00%	0.00%
Capital Expenditures as Percent of Depreciation	100%				
Opening Capital Expenditures	$ 160,000				
Depreciation Expense					
Opening Assets	$ 160,000	$ 163,520	$ 167,086	$ 170,698	$ 174,357
Capital Additions					
Aggregate Average Depreciation Rate					
Years	31	31	31	31	31
Depreciation Rate	3.2%	3.2%	3.2%	3.2%	3.2%
Full Year	$ 5,120	$ 5,187	$ 5,254	$ 5,322	$ 5,391
Half Year	$ 2,560	$ 2,593	$ 2,627	$ 2,661	$ 2,696
Total					
Full Year	$ 165,120	$ 168,707	$ 172,340	$ 176,020	$ 179,748
Half Year	$ 162,560	$ 166,113	$ 169,713	$ 173,359	$ 177,053

A. Cost of Service With Half Year Rule

	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Assets					
Opening Balance	$ 5,000,000	$ 5,110,000	$ 5,221,430	$ 5,334,309	$ 5,448,655
Additions	$ 160,000	$ 162,080	$ 164,187	$ 166,321	$ 168,484
Removals	-$ 50,000	-$ 50,650	-$ 51,308	-$ 51,975	-$ 52,651
Closing Balance	$ 5,110,000	$ 5,221,430	$ 5,334,309	$ 5,448,655	$ 5,564,487
Accumulated Depreciation					
Opening Balance	-$ 2,000,000	-$ 2,112,560	-$ 2,228,023	-$ 2,346,428	-$ 2,467,811
Additions	-$ 162,560	-$ 166,113	-$ 169,713	-$ 173,359	-$ 177,053
Removals	$ 50,000	$ 50,650	$ 51,308	$ 51,975	$ 52,651
Closing Balance	-$ 2,112,560	-$ 2,228,023	-$ 2,346,428	-$ 2,467,811	-$ 2,592,213
Net Book Value					
Opening Balance (January 1)	$ 3,000,000	$ 2,997,440	$ 2,993,407	$ 2,987,881	$ 2,980,843
Closing Balance (December 31)	$ 2,997,440	$ 2,993,407	$ 2,987,881	$ 2,980,843	$ 2,972,274
Average	$ 2,998,720	$ 2,995,423	$ 2,990,644	$ 2,984,362	$ 2,976,559
Cost of Capital					
Return on Equity	9.36%	9.36%	9.36%	9.36%	9.36%
LT Debt	4.88%	4.88%	4.88%	4.88%	4.88%
ST Debt	2.11%	2.11%	2.11%	2.11%	2.11%
Capital Structure					
Equity	40%	40%	40%	40%	40%
LT Debt	56.00%	56.00%	56.00%	56.00%	56.00%
ST Debt	4%	4%	4%	4%	4%
WACC	6.56%	6.56%	6.56%	6.56%	6.56%
Return on Capital					
Deemed Equity	$ 112,272	$ 112,149	$ 111,970	$ 111,735	$ 111,442
Deemed LT Debt	$ 81,949	$ 81,859	$ 81,728	$ 81,557	$ 81,343
Deemed ST Debt	$ 2,531	$ 2,528	$ 2,524	$ 2,519	$ 2,512
Return on Capital	$ 196,752	$ 196,536	$ 196,222	$ 195,810	$ 195,298
Taxes/PILs					
Aggregate Federal/Provincial Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%
Aggregate Taxes/PILs (Grossed-up)	$ 40,479	$ 40,435	$ 40,370	$ 40,285	$ 40,180
Capital-Related Costs Recovered in Rates					
Depreciation	$ 162,560	$ 166,113	$ 169,713	$ 173,359	$ 177,053
Return on Capital	$ 196,752	$ 196,536	$ 196,222	$ 195,810	$ 195,298
Taxes/PILs (Grossed-up)	$ 40,479	$ 40,435	$ 40,370	$ 40,285	$ 40,180
Total	$ 399,791	$ 403,084	$ 406,305	$ 409,454	$ 412,531

IR Framework

Capital-Related Cost Recovered	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Depreciation	$ 162,560	$ 164,673	$ 166,814	$ 168,983	$ 171,179
Return on Capital	$ 196,752	$ 199,310	$ 201,901	$ 204,526	$ 207,184
Taxes/PILs (Grossed-up)	$ 40,479	$ 41,005	$ 41,538	$ 42,078	$ 42,625
Total	$ 399,791	$ 404,988	$ 410,253	$ 415,586	$ 420,989

Difference in Capital-Related Costs Recovered

IR Framework	**$ 399,791**	**$ 404,988**	**$ 410,253**	**$ 415,586**	**$ 420,989**
COS with Half Year Rule	**$ 399,791**	**$ 403,084**	**$ 406,305**	**$ 409,454**	**$ 412,531**
Difference (IR Less COS)	**$ -**	**$ 1,905**	**$ 3,948**	**$ 6,132**	**$ 8,459**
Difference as % of Capital Costs in IR Rates		**0.47%**	**0.96%**	**1.48%**	**2.01%**

Capital Expenditures In IR Rates (No Dead Band)

Calculation of Notional Capital in Rates	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Notional Rate Base	$ 2,998,720	$ 3,037,703	$ 3,077,194	$ 3,117,197	$ 3,157,721
Threshold Calculation		124.0%	124.0%	124.0%	124.0%
Amount of Capital in Rates		$ 204,163	$ 206,818	$ 209,506	$ 212,230

B. Cost of Service With Half Year Rule Eliminated

	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Assets					
Opening Balance	$ 5,000,000	$ 5,110,000	$ 5,221,430	$ 5,334,309	$ 5,448,655
Additions	$ 160,000	$ 162,080	$ 164,187	$ 166,321	$ 168,484
Removals	-$ 50,000	-$ 50,650	-$ 51,308	-$ 51,975	-$ 52,651
Closing Balance	$ 5,110,000	$ 5,221,430	$ 5,334,309	$ 5,448,655	$ 5,564,487
Accumulated Depreciation					
Opening Balance	-$ 2,000,000	-$ 2,115,120	-$ 2,233,177	-$ 2,354,208	-$ 2,478,253
Additions	-$ 165,120	-$ 168,707	-$ 172,340	-$ 176,020	-$ 179,748
Removals	$ 50,000	$ 50,650	$ 51,308	$ 51,975	$ 52,651
Closing Balance	-$ 2,115,120	-$ 2,233,177	-$ 2,354,208	-$ 2,478,253	-$ 2,605,350
Net Book Value					
Opening Balance (January 1)	$ 3,000,000	$ 2,994,880	$ 2,988,253	$ 2,980,101	$ 2,970,402
Closing Balance (December 31)	$ 2,994,880	$ 2,988,253	$ 2,980,101	$ 2,970,402	$ 2,959,137
Average	$ 2,997,440	$ 2,991,567	$ 2,984,177	$ 2,975,251	$ 2,964,770
Cost of Capital					
Return on Equity	9.36%	9.36%	9.36%	9.36%	9.36%
LT Debt	4.88%	4.88%	4.88%	4.88%	4.88%
ST Debt	2.11%	2.11%	2.11%	2.11%	2.11%
Capital Structure					
Equity	40%	40%	40%	40%	40%
LT Debt	56.00%	56.00%	56.00%	56.00%	56.00%
ST Debt	4%	4%	4%	4%	4%
WACC	6.56%	6.56%	6.56%	6.56%	6.56%
Return on Capital					
Deemed Equity	$ 112,224	$ 112,004	$ 111,728	$ 111,393	$ 111,001
Deemed LT Debt	$ 81,914	$ 81,754	$ 81,552	$ 81,308	$ 81,021
Deemed ST Debt	$ 2,530	$ 2,525	$ 2,519	$ 2,511	$ 2,502
Return on Capital	$ 196,668	$ 196,283	$ 195,798	$ 195,212	$ 194,524
Taxes/PILs					
Aggregate Federal/Provincial Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%
Aggregate Taxes/PILs (grossed-up)	$ 40,462	$ 40,382	$ 40,283	$ 40,162	$ 40,021
Capital-Related Costs Recovered in Rates					
Depreciation	$ 165,120	$ 168,707	$ 172,340	$ 176,020	$ 179,748
Return on Capital	$ 196,668	$ 196,283	$ 195,798	$ 195,212	$ 194,524
Taxes/PILs (Grossed-up)	$ 40,462	$ 40,382	$ 40,283	$ 40,162	$ 40,021
Total	$ 402,250	$ 405,372	$ 408,420	$ 411,395	$ 414,294

IR Framework with Half Year Rule in Rebasing Year and Eliminated for IR Period

Capital-Related Cost Recovered	**Rebasing Year**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Depreciation	$ 162,560	$ 167,267	$ 169,441	$ 171,644	$ 173,875
Return on Capital	$ 196,752	$ 199,225	$ 201,815	$ 204,438	$ 207,096
Taxes/PILs (Grossed-up)	$ 40,479	$ 40,988	$ 41,521	$ 42,060	$ 42,607
Total	$ 399,791	$ 407,479	$ 412,776	$ 418,142	$ 423,578

Difference in Capital-Related Costs Recovered

IR with 1/2 Yr Rule in Rebasing Yr & Not in IR Years	**$ 399,791**	**$ 407,479**	**$ 412,776**	**$ 418,142**	**$ 423,578**
Less COS with Half Year Rule	**$ 399,791**	**$ 403,084**	**$ 406,305**	**$ 409,454**	**$ 412,531**
Difference	**$ -**	**$ 4,396**	**$ 6,471**	**$ 8,688**	**$ 11,048**
Difference as % of Capital Costs in Rates		**1.08%**	**1.57%**	**2.08%**	**2.61%**

Capital Expenditures In IR Rates (No Dead Band)

Calculation of Notional Capital in Rates	**Rebasing Year**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Notional Rate Base	$ 2,998,720	$ 3,036,407	$ 3,075,880	$ 3,115,866	$ 3,156,373
Threshold Calculation		123.6%	123.6%	123.6%	123.6%
Amount of Capital in Rates		$ 206,740	$ 209,427	$ 212,150	$ 214,908

CAPEX 200% of Depreciation with Customer Growth

CapEx 200% of Depreciation with Customer Growth					
Key Assumptions	**Rebasing Year**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Revenue Adjustment Mechanism					
Two Factor Inflation Adjustment	0.00%	1.60%	1.60%	1.60%	1.60%
TFP Adjustment	0%	0%	0.00%	0.00%	0.00%
Stretch Factor	0.00%	0.30%	0.30%	0.30%	0.30%
Total Annual Cost Adjustment	1.30%	1.30%	1.30%	1.30%	1.30%
Customer Growth and Demand Growth					
Customer Growth	0.00%	1.02%	1.02%	1.02%	1.02%
kWh Growth	0.00%	0.22%	0.22%	0.22%	0.22%
kW Growth	0.00%	0.80%	0.80%	0.80%	0.80%
Fixed/Variable Split					
Fixed	40%	40%	40%	40%	40%
Variable - kWh	30%	30%	30%	30%	30%
Variable - kW	30%	30%	30%	30%	30%
Composite Growth Rate (g)	0.00%	0.71%	0.71%	0.71%	0.71%
Capital Expenditures as Percent of Depreciation	200%				
Opening Capital Expenditures	$ 320,000				
Depreciation Expense					
Opening Assets	$ 160,000	$ 168,640	$ 177,466	$ 186,483	$ 195,694
Capital Additions					
Aggregate Average Depreciation Rate					
Years	31	31	31	31	31
Depreciation Rate	3.2%	3.2%	3.2%	3.2%	3.2%
Full Year	$ 10,240	$ 10,447	$ 10,659	$ 10,874	$ 11,094
Half Year	$ 5,120	$ 5,224	$ 5,329	$ 5,437	$ 5,547
Total					
Full Year	$ 170,240	$ 179,087	$ 188,125	$ 197,357	$ 206,788
Half Year	$ 165,120	$ 173,864	$ 182,796	$ 191,920	$ 201,241

A. Cost of Service With Half Year Rule	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Assets					
Opening Balance	$ 5,000,000	$ 5,270,000	$ 5,545,825	$ 5,827,596	$ 6,115,440
Additions	$ 320,000	$ 326,475	$ 333,080	$ 339,819	$ 346,695
Removals	-$ 50,000	-$ 50,650	-$ 51,308	-$ 51,975	-$ 52,651
Closing Balance	$ 5,270,000	$ 5,545,825	$ 5,827,596	$ 6,115,440	$ 6,409,483
Accumulated Depreciation					
Opening Balance	-$ 2,000,000	-$ 2,115,120	-$ 2,238,334	-$ 2,369,821	-$ 2,509,766
Additions	-$ 165,120	-$ 173,864	-$ 182,796	-$ 191,920	-$ 201,241
Removals	$ 50,000	$ 50,650	$ 51,308	$ 51,975	$ 52,651
Closing Balance	-$ 2,115,120	-$ 2,238,334	-$ 2,369,821	-$ 2,509,766	-$ 2,658,356
Net Book Value					
Opening Balance (January 1)	$ 3,000,000	$ 3,154,880	$ 3,307,491	$ 3,457,775	$ 3,605,674
Closing Balance (December 31)	$ 3,154,880	$ 3,307,491	$ 3,457,775	$ 3,605,674	$ 3,751,128
Average	$ 3,077,440	$ 3,231,185	$ 3,382,633	$ 3,531,725	$ 3,678,401
Cost of Capital					
Return on Equity	9.36%	9.36%	9.36%	9.36%	9.36%
LT Debt	4.88%	4.88%	4.88%	4.88%	4.88%
ST Debt	2.11%	2.11%	2.11%	2.11%	2.11%
Capital Structure					
Equity	40%	40%	40%	40%	40%
LT Debt	56.00%	56.00%	56.00%	56.00%	56.00%
ST Debt	4%	4%	4%	4%	4%
WACC	6.56%	6.56%	6.56%	6.56%	6.56%
Return on Capital					
Deemed Equity	$ 115,219	$ 120,976	$ 126,646	$ 132,228	$ 137,719
Deemed LT Debt	$ 84,100	$ 88,302	$ 92,441	$ 96,515	$ 100,523
Deemed ST Debt	$ 2,597	$ 2,727	$ 2,855	$ 2,981	$ 3,105
Return on Capital	$ 201,917	$ 212,005	$ 221,941	$ 231,724	$ 241,347
Taxes/PILs					
Aggregate Federal/Provincial Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%
Aggregate Taxes/PILs (Grossed-up)	$ 41,542	$ 43,617	$ 45,661	$ 47,674	$ 49,654
Capital-Related Costs Recovered in Rates					
Depreciation	$ 165,120	$ 173,864	$ 182,796	$ 191,920	$ 201,241
Return on Capital	$ 201,917	$ 212,005	$ 221,941	$ 231,724	$ 241,347
Taxes/PILs (Grossed-up)	$ 41,542	$ 43,617	$ 45,661	$ 47,674	$ 49,654
Total	$ 408,579	$ 429,485	$ 450,398	$ 471,318	$ 492,242

IR Framework

Capital-Related Cost Recovered	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Depreciation	$ 165,120	$ 168,461	$ 171,869	$ 175,347	$ 178,894
Return on Capital	$ 201,917	$ 206,002	$ 210,170	$ 214,423	$ 218,761
Taxes/PILs (Grossed-up)	$ 41,542	$ 42,382	$ 43,240	$ 44,115	$ 45,007
Total	$ 408,579	$ 416,845	$ 425,279	$ 433,884	$ 442,663

Difference in Capital-Related Costs Recovered

IR Framework	**$ 408,579**	**$ 416,845**	**$ 425,279**	**$ 433,884**	**$ 442,663**
COS with Half Year Rule	**$ 408,579**	**$ 429,485**	**$ 450,398**	**$ 471,318**	**$ 492,242**
Difference (IR Less COS)	**$ -**	**$ (12,640)**	**$ (25,119)**	**$ (37,434)**	**$ (49,580)**
Difference as % of Capital Costs in IR Rates		**-3.03%**	**-5.91%**	**-8.63%**	**-11.20%**

Capital Expenditures In IR Rates (No Dead Band)

Calculation of Notional Capital in Rates	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Notional Rate Base	$ 3,077,440	$ 3,139,705	$ 3,203,230	$ 3,268,041	$ 3,334,162
Threshold Calculation		137.7%	137.7%	137.7%	137.7%
Amount of Capital in Rates		$ 231,986	$ 236,680	$ 241,468	$ 246,354

B. Cost of Service With Half Year Rule Eliminated

	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Assets					
Opening Balance	$ 5,000,000	$ 5,270,000	$ 5,545,825	$ 5,827,596	$ 6,115,440
Additions	$ 320,000	$ 326,475	$ 333,080	$ 339,819	$ 346,695
Removals	-$ 50,000	-$ 50,650	-$ 51,308	-$ 51,975	-$ 52,651
Closing Balance	$ 5,270,000	$ 5,545,825	$ 5,827,596	$ 6,115,440	$ 6,409,483
Accumulated Depreciation					
Opening Balance	-$ 2,000,000	-$ 2,120,240	-$ 2,248,677	-$ 2,385,494	-$ 2,530,876
Additions	-$ 170,240	-$ 179,087	-$ 188,125	-$ 197,357	-$ 206,788
Removals	$ 50,000	$ 50,650	$ 51,308	$ 51,975	$ 52,651
Closing Balance	-$ 2,120,240	-$ 2,248,677	-$ 2,385,494	-$ 2,530,876	-$ 2,685,013
Net Book Value					
Opening Balance (January 1)	$ 3,000,000	$ 3,149,760	$ 3,297,147	$ 3,442,102	$ 3,584,564
Closing Balance (December 31)	$ 3,149,760	$ 3,297,147	$ 3,442,102	$ 3,584,564	$ 3,724,471
Average	$ 3,074,880	$ 3,223,454	$ 3,369,625	$ 3,513,333	$ 3,654,517
Cost of Capital					
Return on Equity	9.36%	9.36%	9.36%	9.36%	9.36%
LT Debt	4.88%	4.88%	4.88%	4.88%	4.88%
ST Debt	2.11%	2.11%	2.11%	2.11%	2.11%
Capital Structure					
Equity	40%	40%	40%	40%	40%
LT Debt	56.00%	56.00%	56.00%	56.00%	56.00%
ST Debt	4%	4%	4%	4%	4%
WACC	6.56%	6.56%	6.56%	6.56%	6.56%
Return on Capital					
Deemed Equity	$ 115,124	$ 120,686	$ 126,159	$ 131,539	$ 136,825
Deemed LT Debt	$ 84,030	$ 88,091	$ 92,085	$ 96,012	$ 99,871
Deemed ST Debt	$ 2,595	$ 2,721	$ 2,844	$ 2,965	$ 3,084
Return on Capital	$ 201,749	$ 211,497	$ 221,088	$ 230,517	$ 239,780
Taxes/PILs					
Aggregate Federal/Provincial Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%
Aggregate Taxes/PILs (grossed-up)	$ 41,507	$ 43,513	$ 45,486	$ 47,426	$ 49,332
Capital-Related Costs Recovered in Rates					
Depreciation	$ 170,240	$ 179,087	$ 188,125	$ 197,357	$ 206,788
Return on Capital	$ 201,749	$ 211,497	$ 221,088	$ 230,517	$ 239,780
Taxes/PILs (Grossed-up)	$ 41,507	$ 43,513	$ 45,486	$ 47,426	$ 49,332
Total	$ 413,496	$ 434,097	$ 454,699	$ 475,300	$ 495,900

IR Framework with Half Year Rule in Rebasing Year and Eliminated for IR Period

Capital-Related Cost Recovered	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Depreciation	$ 165,120	$ 173,684	$ 177,199	$ 180,784	$ 184,442
Return on Capital	$ 201,917	$ 205,831	$ 209,996	$ 214,244	$ 218,579
Taxes/PILs (Grossed-up)	$ 41,542	$ 42,347	$ 43,204	$ 44,078	$ 44,970
Total	$ 408,579	$ 421,862	$ 430,398	$ 439,106	$ 447,990

Difference in Capital-Related Costs Recovered

IR with 1/2 Yr Rule in Rebasing Yr & Not in IR Years	**$ 408,579**	**$ 421,862**	**$ 430,398**	**$ 439,106**	**$ 447,990**
Less COS with Half Year Rule	**$ 408,579**	**$ 429,485**	**$ 450,398**	**$ 471,318**	**$ 492,242**
Difference	**$ -**	**$ (7,623)**	**$ (20,001)**	**$ (32,212)**	**$ (44,252)**
Difference as % of Capital Costs in Rates		**-1.81%**	**-4.65%**	**-7.34%**	**-9.88%**

Capital Expenditures In IR Rates (No Dead Band)

Calculation of Notional Capital in Rates	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Notional Rate Base	$ 3,077,440	$ 3,137,093	$ 3,200,566	$ 3,265,322	$ 3,331,389
Threshold Calculation		136.5%	136.5%	136.5%	136.5%
Amount of Capital in Rates		$ 237,157	$ 241,955	$ 246,850	$ 251,845

KPMG

CAPEX 200% of Depreciation with no Customer Growth

CapEx 200% of Depreciation Without Customer Growth									
Key Assumptions		**Rebasing Year**		**Year 2**		**Year 3**		**Year 4**	**Year 5**
Revenue Adjustment Mechanism									
Two Factor Inflation Adjustment		0.00%		1.60%		1.60%		1.60%	1.60%
TFP Adjustment		0%		0%		0.00%		0.00%	0.00%
Stretch Factor		0.00%		0.30%		0.30%		0.30%	0.30%
Total Annual Cost Adjustment		1.30%		1.30%		1.30%		1.30%	1.30%
Customer Growth and Demand Growth									
Customer Growth		0.00%		0.00%		0.00%		0.00%	0.00%
kWh Growth		0.00%		0.00%		0.00%		0.00%	0.00%
kW Growth		0.00%		0.00%		0.00%		0.00%	0.00%
Fixed/Variable Split									
Fixed		40%		40%		40%		40%	40%
Variable - kWh		30%		30%		30%		30%	30%
Variable - kW		30%		30%		30%		30%	30%
Composite Growth Rate (g)		0.00%		0.00%		0.00%		0.00%	0.00%
Capital Expenditures as Percent of Depreciation		200%							
Opening Capital Expenditures	$	320,000							
Depreciation Expense									
Opening Assets	$	160,000	$	168,640	$	177,392	$	186,258 $	195,240
Capital Additions									
Aggregate Average Depreciation Rate									
Years		31		31		31		31	31
Depreciation Rate		3.2%		3.2%		3.2%		3.2%	3.2%
Full Year	$	10,240	$	10,373	$	10,508	$	10,645 $	10,783
Half Year	$	5,120	$	5,187	$	5,254	$	5,322 $	5,391
Total									
Full Year	$	170,240	$	179,013	$	187,900	$	196,903 $	206,023
Half Year	$	165,120	$	173,827	$	182,646	$	191,581 $	200,631

A. Cost of Service With Half Year Rule	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Assets					
Opening Balance	$ 5,000,000	$ 5,270,000	$ 5,543,510	$ 5,820,576	$ 6,101,243
Additions	$ 320,000	$ 324,160	$ 328,374	$ 332,643	$ 336,967
Removals	-$ 50,000	-$ 50,650	-$ 51,308	-$ 51,975	-$ 52,651
Closing Balance	$ 5,270,000	$ 5,543,510	$ 5,820,576	$ 6,101,243	$ 6,385,559
Accumulated Depreciation					
Opening Balance	-$ 2,000,000	-$ 2,115,120	-$ 2,238,297	-$ 2,369,634	-$ 2,509,240
Additions	-$ 165,120	-$ 173,827	-$ 182,646	-$ 191,581	-$ 200,631
Removals	$ 50,000	$ 50,650	$ 51,308	$ 51,975	$ 52,651
Closing Balance	-$ 2,115,120	-$ 2,238,297	-$ 2,369,634	-$ 2,509,240	-$ 2,657,220
Net Book Value					
Opening Balance (January 1)	$ 3,000,000	$ 3,154,880	$ 3,305,213	$ 3,450,941	$ 3,592,003
Closing Balance (December 31)	$ 3,154,880	$ 3,305,213	$ 3,450,941	$ 3,592,003	$ 3,728,339
Average	$ 3,077,440	$ 3,230,047	$ 3,378,077	$ 3,521,472	$ 3,660,171
Cost of Capital					
Return on Equity	9.36%	9.36%	9.36%	9.36%	9.36%
LT Debt	4.88%	4.88%	4.88%	4.88%	4.88%
ST Debt	2.11%	2.11%	2.11%	2.11%	2.11%
Capital Structure					
Equity	40%	40%	40%	40%	40%
LT Debt	56.00%	56.00%	56.00%	56.00%	56.00%
ST Debt	4%	4%	4%	4%	4%
WACC	6.56%	6.56%	6.56%	6.56%	6.56%
Return on Capital					
Deemed Equity	$ 115,219	$ 120,933	$ 126,475	$ 131,844	$ 137,037
Deemed LT Debt	$ 84,100	$ 88,271	$ 92,316	$ 96,235	$ 100,025
Deemed ST Debt	$ 2,597	$ 2,726	$ 2,851	$ 2,972	$ 3,089
Return on Capital	$ 201,917	$ 211,930	$ 221,642	$ 231,051	$ 240,151
Taxes/PILs					
Aggregate Federal/Provincial Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%
Aggregate Taxes/PILs (Grossed-up)	$ 41,542	$ 43,602	$ 45,600	$ 47,536	$ 49,408
Capital-Related Costs Recovered in Rates					
Depreciation	$ 165,120	$ 173,827	$ 182,646	$ 191,581	$ 200,631
Return on Capital	$ 201,917	$ 211,930	$ 221,642	$ 231,051	$ 240,151
Taxes/PILs (Grossed-up)	$ 41,542	$ 43,602	$ 45,600	$ 47,536	$ 49,408
Total	$ 408,579	$ 429,358	$ 449,889	$ 470,167	$ 490,190
IR Framework					
Capital-Related Cost Recovered	**Rebasing Year**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Depreciation	$ 165,120	$ 167,267	$ 169,441	$ 171,644	$ 173,875
Return on Capital	$ 201,917	$ 204,542	$ 207,201	$ 209,895	$ 212,623
Taxes/PILs (Grossed-up)	$ 41,542	$ 42,082	$ 42,629	$ 43,183	$ 43,744
Total	$ 408,579	$ 413,890	$ 419,271	$ 424,721	$ 430,243
Difference in Capital-Related Costs Recovered					
IR Framework	**$ 408,579**	**$ 413,890**	**$ 419,271**	**$ 424,721**	**$ 430,243**
COS with Half Year Rule	**$ 408,579**	**$ 429,358**	**$ 449,889**	**$ 470,167**	**$ 490,190**
Difference (IR Less COS)	**$ -**	**$ (15,468)**	**$ (30,618)**	**$ (45,446)**	**$ (59,948)**
Difference as % of Capital Costs in IR Rates		**-3.74%**	**-7.30%**	**-10.70%**	**-13.93%**
Capital Expenditures In IR Rates (No Dead Band)					
Calculation of Notional Capital in Rates	**Rebasing Year**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Notional Rate Base	$ 3,077,440	$ 3,117,447	$ 3,157,974	$ 3,199,027	$ 3,240,615
Threshold Calculation		124.2%	124.2%	124.2%	124.2%
Amount of Capital in Rates		$ 207,793	$ 210,495	$ 213,231	$ 216,003

KPMG

B. Cost of Service With Half Year Rule Eliminated

	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Assets					
Opening Balance	$ 5,000,000	$ 5,270,000	$ 5,543,510	$ 5,820,576	$ 6,101,243
Additions	$ 320,000	$ 324,160	$ 328,374	$ 332,643	$ 336,967
Removals	-$ 50,000	-$ 50,650	-$ 51,308	-$ 51,975	-$ 52,651
Closing Balance	$ 5,270,000	$ 5,543,510	$ 5,820,576	$ 6,101,243	$ 6,385,559
Accumulated Depreciation					
Opening Balance	-$ 2,000,000	-$ 2,120,240	-$ 2,248,603	-$ 2,385,195	-$ 2,530,122
Additions	-$ 170,240	-$ 179,013	-$ 187,900	-$ 196,903	-$ 206,023
Removals	$ 50,000	$ 50,650	$ 51,308	$ 51,975	$ 52,651
Closing Balance	-$ 2,120,240	-$ 2,248,603	-$ 2,385,195	-$ 2,530,122	-$ 2,683,494
Net Book Value					
Opening Balance (January 1)	$ 3,000,000	$ 3,149,760	$ 3,294,907	$ 3,435,381	$ 3,571,121
Closing Balance (December 31)	$ 3,149,760	$ 3,294,907	$ 3,435,381	$ 3,571,121	$ 3,702,065
Average	$ 3,074,880	$ 3,222,333	$ 3,365,144	$ 3,503,251	$ 3,636,593
Cost of Capital					
Return on Equity	9.36%	9.36%	9.36%	9.36%	9.36%
LT Debt	4.88%	4.88%	4.88%	4.88%	4.88%
ST Debt	2.11%	2.11%	2.11%	2.11%	2.11%
Capital Structure					
Equity	40%	40%	40%	40%	40%
LT Debt	56.00%	56.00%	56.00%	56.00%	56.00%
ST Debt	4%	4%	4%	4%	4%
WACC	6.56%	6.56%	6.56%	6.56%	6.56%
Return on Capital					
Deemed Equity	$ 115,124	$ 120,644	$ 125,991	$ 131,162	$ 136,154
Deemed LT Debt	$ 84,030	$ 88,060	$ 91,963	$ 95,737	$ 99,381
Deemed ST Debt	$ 2,595	$ 2,720	$ 2,840	$ 2,957	$ 3,069
Return on Capital	$ 201,749	$ 211,424	$ 220,794	$ 229,855	$ 238,604
Taxes/PILs					
Aggregate Federal/Provincial Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%
Aggregate Taxes/PILs (grossed-up)	$ 41,507	$ 43,498	$ 45,425	$ 47,290	$ 49,090
Capital-Related Costs Recovered in Rates					
Depreciation	$ 170,240	$ 179,013	$ 187,900	$ 196,903	$ 206,023
Return on Capital	$ 201,749	$ 211,424	$ 220,794	$ 229,855	$ 238,604
Taxes/PILs (Grossed-up)	$ 41,507	$ 43,498	$ 45,425	$ 47,290	$ 49,090
Total	$ 413,496	$ 433,934	$ 454,119	$ 474,048	$ 493,716

IR Framework with Half Year Rule in Rebasing Year and Eliminated for IR Period

Capital-Related Cost Recovered	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Depreciation	$ 165,120	$ 172,453	$ 174,695	$ 176,966	$ 179,267
Return on Capital	$ 201,917	$ 204,372	$ 207,029	$ 209,720	$ 212,446
Taxes/PILs (Grossed-up)	$ 41,542	$ 42,047	$ 42,593	$ 43,147	$ 43,708
Total	$ 408,579	$ 418,872	$ 424,317	$ 429,833	$ 435,421

Difference in Capital-Related Costs Recovered

IR with 1/2 Yr Rule in Rebasing Yr & Not in IR Years	**$ 408,579**	**$ 418,872**	**$ 424,317**	**$ 429,833**	**$ 435,421**
Less COS with Half Year Rule	**$ 408,579**	**$ 429,358**	**$ 449,889**	**$ 470,167**	**$ 490,190**
Difference	**$ -**	**$ (10,486)**	**$ (25,572)**	**$ (40,334)**	**$ (54,769)**
Difference as % of Capital Costs in Rates		**-2.50%**	**-6.03%**	**-9.38%**	**-12.58%**

Capital Expenditures In IR Rates (No Dead Band)

Calculation of Notional Capital in Rates	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Notional Rate Base	$ 3,077,440	$ 3,114,853	$ 3,155,347	$ 3,196,366	$ 3,237,919
Threshold Calculation		123.5%	123.5%	123.5%	123.5%
Amount of Capital in Rates		$ 212,946	$ 215,715	$ 218,519	$ 221,360

CAPEX 400% of Depreciation with Customer Growth

CapEx 400% of Depreciation with Customer Growth					
Key Assumptions	**Rebasing Year**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Revenue Adjustment Mechanism					
Two Factor Inflation Adjustment	0.00%	1.60%	1.60%	1.60%	1.60%
TFP Adjustment	0%	0%	0.00%	0.00%	0.00%
Stretch Factor	0.00%	0.30%	0.30%	0.30%	0.30%
Total Annual Cost Adjustment	1.30%	1.30%	1.30%	1.30%	1.30%
Customer Growth and Demand Growth					
Customer Growth	0.00%	1.02%	1.02%	1.02%	1.02%
kWh Growth	0.00%	0.22%	0.22%	0.22%	0.22%
kW Growth	0.00%	0.80%	0.80%	0.80%	0.80%
Fixed/Variable Split					
Fixed	40%	40%	40%	40%	40%
Variable - kWh	30%	30%	30%	30%	30%
Variable - kW	30%	30%	30%	30%	30%
Composite Growth Rate (g)	0.00%	0.71%	0.71%	0.71%	0.71%
Capital Expenditures as Percent of Depreciation	400%				
Opening Capital Expenditures	$ 640,000.00				
Depreciation Expense					
Opening Assets	$ 160,000.00	$ 178,880.00	$ 198,153.57	$ 217,828.82	$ 237,914.03
Capital Additions					
Aggregate Average Depreciation Rate					
Years	31	31	31	31	31
Depreciation Rate	3.2%	3.2%	3.2%	3.2%	3.2%
Full Year	$ 20,480	$ 20,894	$ 21,317	$ 21,748	$ 22,188
Half Year	$ 10,240	$ 10,447	$ 10,659	$ 10,874	$ 11,094
Total					
Full Year	$ 180,480	$ 199,774	$ 219,471	$ 239,577	$ 260,102
Half Year	$ 170,240	$ 189,327	$ 208,812	$ 228,703	$ 249,008

A. Cost of Service With Half Year Rule	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Assets					
Opening Balance	$ 5,000,000	$ 5,590,000	$ 6,192,299	$ 6,807,151	$ 7,434,813
Additions	$ 640,000	$ 652,949	$ 666,160	$ 679,638	$ 693,389
Removals	-$ 50,000	-$ 50,650	-$ 51,308	-$ 51,975	-$ 52,651
Closing Balance	$ 5,590,000	$ 6,192,299	$ 6,807,151	$ 7,434,813	$ 8,075,552
Accumulated Depreciation					
Opening Balance	-$ 2,000,000	-$ 2,120,240	-$ 2,258,917	-$ 2,416,421	-$ 2,593,148
Additions	-$ 170,240	-$ 189,327	-$ 208,812	-$ 228,703	-$ 249,008
Removals	$ 50,000	$ 50,650	$ 51,308	$ 51,975	$ 52,651
Closing Balance	-$ 2,120,240	-$ 2,258,917	-$ 2,416,421	-$ 2,593,148	-$ 2,789,506
Net Book Value					
Opening Balance (January 1)	$ 3,000,000	$ 3,469,760	$ 3,933,382	$ 4,390,730	$ 4,841,665
Closing Balance (December 31)	$ 3,469,760	$ 3,933,382	$ 4,390,730	$ 4,841,665	$ 5,286,046
Average	$ 3,234,880	$ 3,701,571	$ 4,162,056	$ 4,616,197	$ 5,063,855
Cost of Capital					
Return on Equity	9.36%	9.36%	9.36%	9.36%	9.36%
LT Debt	4.88%	4.88%	4.88%	4.88%	4.88%
ST Debt	2.11%	2.11%	2.11%	2.11%	2.11%
Capital Structure					
Equity	40%	40%	40%	40%	40%
LT Debt	56.00%	56.00%	56.00%	56.00%	56.00%
ST Debt	4%	4%	4%	4%	4%
WACC	6.56%	6.56%	6.56%	6.56%	6.56%
Return on Capital					
Deemed Equity	$ 121,114	$ 138,587	$ 155,827	$ 172,830	$ 189,591
Deemed LT Debt	$ 88,403	$ 101,157	$ 113,741	$ 126,151	$ 138,385
Deemed ST Debt	$ 2,730	$ 3,124	$ 3,513	$ 3,896	$ 4,274
Return on Capital	$ 212,247	$ 242,867	$ 273,081	$ 302,878	$ 332,250
Taxes/PILs					
Aggregate Federal/Provincial Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%
Aggregate Taxes/PILs (Grossed-up)	$ 43,667	$ 49,967	$ 56,183	$ 62,313	$ 68,356
Capital-Related Costs Recovered in Rates					
Depreciation	$ 170,240	$ 189,327	$ 208,812	$ 228,703	$ 249,008
Return on Capital	$ 212,247	$ 242,867	$ 273,081	$ 302,878	$ 332,250
Taxes/PILs (Grossed-up)	$ 43,667	$ 49,967	$ 56,183	$ 62,313	$ 68,356
Total	$ 426,154	$ 482,161	$ 538,076	$ 593,894	$ 649,614

IR Framework

Capital-Related Cost Recovered	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Depreciation	$ 170,240	$ 173,684	$ 177,199	$ 180,784	$ 184,442
Return on Capital	$ 212,247	$ 216,541	$ 220,923	$ 225,392	$ 229,953
Taxes/PILs (Grossed-up)	$ 43,667	$ 44,550	$ 45,452	$ 46,371	$ 47,310
Total	$ 426,154	$ 434,776	$ 443,573	$ 452,548	$ 461,704

Difference in Capital-Related Costs Recovered

IR Framework	**$ 426,154**	**$ 434,776**	**$ 443,573**	**$ 452,548**	**$ 461,704**
COS with Half Year Rule	**$ 426,154**	**$ 482,161**	**$ 538,076**	**$ 593,894**	**$ 649,614**
Difference (IR Less COS)	**$ -**	**$ (47,385)**	**$ (94,503)**	**$ (141,346)**	**$ (187,910)**
Difference as % of Capital Costs in IR Rates		**-10.90%**	**-21.30%**	**-31.23%**	**-40.70%**

Capital Expenditures In IR Rates (No Dead Band)

Calculation of Notional Capital in Rates	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Notional Rate Base	$ 3,234,880	$ 3,300,331	$ 3,367,106	$ 3,435,232	$ 3,504,736
Threshold Calculation		138.4%	138.4%	138.4%	138.4%
Amount of Capital in Rates		$ 240,459	$ 245,325	$ 250,288	$ 255,352

KPMG

B. Cost of Service With Half Year Rule Eliminated

	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Assets					
Opening Balance	$ 5,000,000	$ 5,590,000	$ 6,192,299	$ 6,807,151	$ 7,434,813
Additions	$ 640,000	$ 652,949	$ 666,160	$ 679,638	$ 693,389
Removals	-$ 50,000	-$ 50,650	-$ 51,308	-$ 51,975	-$ 52,651
Closing Balance	$ 5,590,000	$ 6,192,299	$ 6,807,151	$ 7,434,813	$ 8,075,552
Accumulated Depreciation					
Opening Balance	-$ 2,000,000	-$ 2,130,480	-$ 2,279,604	-$ 2,447,767	-$ 2,635,368
Additions	-$ 180,480	-$ 199,774	-$ 219,471	-$ 239,577	-$ 260,102
Removals	$ 50,000	$ 50,650	$ 51,308	$ 51,975	$ 52,651
Closing Balance	-$ 2,130,480	-$ 2,279,604	-$ 2,447,767	-$ 2,635,368	-$ 2,842,820
Net Book Value					
Opening Balance (January 1)	$ 3,000,000	$ 3,459,520	$ 3,912,695	$ 4,359,384	$ 4,799,445
Closing Balance (December 31)	$ 3,459,520	$ 3,912,695	$ 4,359,384	$ 4,799,445	$ 5,232,732
Average	$ 3,229,760	$ 3,686,107	$ 4,136,039	$ 4,579,414	$ 5,016,088
Cost of Capital					
Return on Equity	9.36%	9.36%	9.36%	9.36%	9.36%
LT Debt	4.88%	4.88%	4.88%	4.88%	4.88%
ST Debt	2.11%	2.11%	2.11%	2.11%	2.11%
Capital Structure					
Equity	40%	40%	40%	40%	40%
LT Debt	56.00%	56.00%	56.00%	56.00%	56.00%
ST Debt	4%	4%	4%	4%	4%
WACC	6.56%	6.56%	6.56%	6.56%	6.56%
Return on Capital					
Deemed Equity	$ 120,922	$ 138,008	$ 154,853	$ 171,453	$ 187,802
Deemed LT Debt	$ 88,263	$ 100,734	$ 113,030	$ 125,146	$ 137,080
Deemed ST Debt	$ 2,726	$ 3,111	$ 3,491	$ 3,865	$ 4,234
Return on Capital	$ 211,911	$ 241,853	$ 271,374	$ 300,465	$ 329,116
Taxes/PILs					
Aggregate Federal/Provincial Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%
Aggregate Taxes/PILs (grossed-up)	$ 43,598	$ 49,758	$ 55,831	$ 61,816	$ 67,711
Capital-Related Costs Recovered in Rates					
Depreciation	$ 180,480	$ 199,774	$ 219,471	$ 239,577	$ 260,102
Return on Capital	$ 211,911	$ 241,853	$ 271,374	$ 300,465	$ 329,116
Taxes/PILs (Grossed-up)	$ 43,598	$ 49,758	$ 55,831	$ 61,816	$ 67,711
Total	$ 435,989	$ 491,385	$ 546,676	$ 601,858	$ 656,929

IR Framework with Half Year Rule in Rebasing Year and Eliminated for IR Period

Capital-Related Cost Recovered	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Depreciation	$ 170,240	$ 184,132	$ 187,857	$ 191,658	$ 195,536
Return on Capital	$ 212,247	$ 216,199	$ 220,573	$ 225,036	$ 229,589
Taxes/PILs (Grossed-up)	$ 43,667	$ 44,480	$ 45,380	$ 46,298	$ 47,235
Total	$ 426,154	$ 444,810	$ 453,810	$ 462,992	$ 472,359

Difference in Capital-Related Costs Recovered

IR with 1/2 Yr Rule in Rebasing Yr & Not in IR Years	**$ 426,154**	**$ 444,810**	**$ 453,810**	**$ 462,992**	**$ 472,359**
Less COS with Half Year Rule	**$ 426,154**	**$ 482,161**	**$ 538,076**	**$ 593,894**	**$ 649,614**
Difference	**$ -**	**$ (37,351)**	**$ (84,266)**	**$ (130,902)**	**$ (177,254)**
Difference as % of Capital Costs in Rates		**-8.40%**	**-18.57%**	**-28.27%**	**-37.53%**

Capital Expenditures In IR Rates (No Dead Band)

Calculation of Notional Capital in Rates	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Notional Rate Base	$ 3,234,880	$ 3,295,107	$ 3,361,776	$ 3,429,795	$ 3,499,189
Threshold Calculation		136.2%	136.2%	136.2%	136.2%
Amount of Capital in Rates		$ 250,801	$ 255,875	$ 261,052	$ 266,334

KPMG

CAPEX 400% of Depreciation with no Customer Growth

CapEx 400% of Depreciation Without Customer Growth					
Key Assumptions	**Rebasing Year**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Revenue Adjustment Mechanism					
Two Factor Inflation Adjustment	0.00%	1.60%	1.60%	1.60%	1.60%
TFP Adjustment	0%	0%	0.00%	0.00%	0.00%
Stretch Factor	0.00%	0.30%	0.30%	0.30%	0.30%
Total Annual Cost Adjustment	1.30%	1.30%	1.30%	1.30%	1.30%
Customer Growth and Demand Growth					
Customer Growth	0.00%	0.00%	0.00%	0.00%	0.00%
kWh Growth	0.00%	0.00%	0.00%	0.00%	0.00%
kW Growth	0.00%	0.00%	0.00%	0.00%	0.00%
Fixed/Variable Split					
Fixed	40%	40%	40%	40%	40%
Variable - kWh	30%	30%	30%	30%	30%
Variable - kW	30%	30%	30%	30%	30%
Composite Growth Rate (g)	0.00%	0.00%	0.00%	0.00%	0.00%
Capital Expenditures as Percent of Depreciation	400%				
Opening Capital Expenditures	$ 640,000				
Depreciation Expense					
Opening Assets	$ 160,000	$ 178,880	$ 198,005	$ 217,380	$ 237,005
Capital Additions					
Aggregate Average Depreciation Rate					
Years	31	31	31	31	31
Depreciation Rate	3.2%	3.2%	3.2%	3.2%	3.2%
Full Year	$ 20,480	$ 20,746	$ 21,016	$ 21,289	$ 21,566
Half Year	$ 10,240	$ 10,373	$ 10,508	$ 10,645	$ 10,783
Total					
Full Year	$ 180,480	$ 199,626	$ 219,021	$ 238,669	$ 258,571
Half Year	$ 170,240	$ 189,253	$ 208,513	$ 228,024	$ 247,788

A. Cost of Service With Half Year Rule

	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Assets					
Opening Balance	$ 5,000,000	$ 5,590,000	$ 6,187,670	$ 6,793,110	$ 7,406,420
Additions	$ 640,000	$ 648,320	$ 656,748	$ 665,286	$ 673,935
Removals	-$ 50,000	-$ 50,650	-$ 51,308	-$ 51,975	-$ 52,651
Closing Balance	$ 5,590,000	$ 6,187,670	$ 6,793,110	$ 7,406,420	$ 8,027,704
Accumulated Depreciation					
Opening Balance	-$ 2,000,000	-$ 2,120,240	-$ 2,258,843	-$ 2,416,048	-$ 2,592,097
Additions	-$ 170,240	-$ 189,253	-$ 208,513	-$ 228,024	-$ 247,788
Removals	$ 50,000	$ 50,650	$ 51,308	$ 51,975	$ 52,651
Closing Balance	-$ 2,120,240	-$ 2,258,843	-$ 2,416,048	-$ 2,592,097	-$ 2,787,234
Net Book Value					
Opening Balance (January 1)	$ 3,000,000	$ 3,469,760	$ 3,928,827	$ 4,377,062	$ 4,814,323
Closing Balance (December 31)	$ 3,469,760	$ 3,928,827	$ 4,377,062	$ 4,814,323	$ 5,240,470
Average	$ 3,234,880	$ 3,699,293	$ 4,152,944	$ 4,595,693	$ 5,027,397
Cost of Capital					
Return on Equity	9.36%	9.36%	9.36%	9.36%	9.36%
LT Debt	4.88%	4.88%	4.88%	4.88%	4.88%
ST Debt	2.11%	2.11%	2.11%	2.11%	2.11%
Capital Structure					
Equity	40%	40%	40%	40%	40%
LT Debt	56.00%	56.00%	56.00%	56.00%	56.00%
ST Debt	4%	4%	4%	4%	4%
WACC	6.56%	6.56%	6.56%	6.56%	6.56%
Return on Capital					
Deemed Equity	$ 121,114	$ 138,502	$ 155,486	$ 172,063	$ 188,226
Deemed LT Debt	$ 88,403	$ 101,094	$ 113,492	$ 125,591	$ 137,389
Deemed ST Debt	$ 2,730	$ 3,122	$ 3,505	$ 3,879	$ 4,243
Return on Capital	$ 212,247	$ 242,718	$ 272,483	$ 301,533	$ 329,858
Taxes/PILs					
Aggregate Federal/Provincial Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%
Aggregate Taxes/PILs (Grossed-up)	$ 43,667	$ 49,936	$ 56,060	$ 62,036	$ 67,864
Capital-Related Costs Recovered in Rates					
Depreciation	$ 170,240	$ 189,253	$ 208,513	$ 228,024	$ 247,788
Return on Capital	$ 212,247	$ 242,718	$ 272,483	$ 301,533	$ 329,858
Taxes/PILs (Grossed-up)	$ 43,667	$ 49,936	$ 56,060	$ 62,036	$ 67,864
Total	$ 426,154	$ 481,907	$ 537,056	$ 591,593	$ 645,510

IR Framework

Capital-Related Cost Recovered	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Depreciation	$ 170,240	$ 172,453	$ 174,695	$ 176,966	$ 179,267
Return on Capital	$ 212,247	$ 215,006	$ 217,801	$ 220,633	$ 223,501
Taxes/PILs (Grossed-up)	$ 43,667	$ 44,235	$ 44,810	$ 45,392	$ 45,982
Total	$ 426,154	$ 431,694	$ 437,306	$ 442,991	$ 448,750

Difference in Capital-Related Costs Recovered

IR Framework	**$ 426,154**	**$ 431,694**	**$ 437,306**	**$ 442,991**	**$ 448,750**
COS with Half Year Rule	**$ 426,154**	**$ 481,907**	**$ 537,056**	**$ 591,593**	**$ 645,510**
Difference (IR Less COS)	**$ -**	**$ (50,213)**	**$ (99,750)**	**$ (148,602)**	**$ (196,760)**
Difference as % of Capital Costs in IR Rates		**-11.63%**	**-22.81%**	**-33.55%**	**-43.85%**

Capital Expenditures In IR Rates (No Dead Band)

Calculation of Notional Capital in Rates	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Notional Rate Base	$ 3,234,880	$ 3,276,933	$ 3,319,534	$ 3,362,688	$ 3,406,402
Threshold Calculation		124.7%	124.7%	124.7%	124.7%
Amount of Capital in Rates		$ 215,053	$ 217,849	$ 220,681	$ 223,550

B. Cost of Service With Half Year Rule Eliminated

	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Assets					
Opening Balance	$ 5,000,000	$ 5,590,000	$ 6,187,670	$ 6,793,110	$ 7,406,420
Additions	$ 640,000	$ 648,320	$ 656,748	$ 665,286	$ 673,935
Removals	-$ 50,000	-$ 50,650	-$ 51,308	-$ 51,975	-$ 52,651
Closing Balance	$ 5,590,000	$ 6,187,670	$ 6,793,110	$ 7,406,420	$ 8,027,704
Accumulated Depreciation					
Opening Balance	-$ 2,000,000	-$ 2,130,480	-$ 2,279,456	-$ 2,447,169	-$ 2,633,862
Additions	-$ 180,480	-$ 199,626	-$ 219,021	-$ 238,669	-$ 258,571
Removals	$ 50,000	$ 50,650	$ 51,308	$ 51,975	$ 52,651
Closing Balance	-$ 2,130,480	-$ 2,279,456	-$ 2,447,169	-$ 2,633,862	-$ 2,839,783
Net Book Value					
Opening Balance (January 1)	$ 3,000,000	$ 3,459,520	$ 3,908,214	$ 4,345,941	$ 4,772,558
Closing Balance (December 31)	$ 3,459,520	$ 3,908,214	$ 4,345,941	$ 4,772,558	$ 5,187,921
Average	$ 3,229,760	$ 3,683,867	$ 4,127,077	$ 4,559,249	$ 4,980,239
Cost of Capital					
Return on Equity	9.36%	9.36%	9.36%	9.36%	9.36%
LT Debt	4.88%	4.88%	4.88%	4.88%	4.88%
ST Debt	2.11%	2.11%	2.11%	2.11%	2.11%
Capital Structure					
Equity	40%	40%	40%	40%	40%
LT Debt	56.00%	56.00%	56.00%	56.00%	56.00%
ST Debt	4%	4%	4%	4%	4%
WACC	6.56%	6.56%	6.56%	6.56%	6.56%
Return on Capital					
Deemed Equity	$ 120,922	$ 137,924	$ 154,518	$ 170,698	$ 186,460
Deemed LT Debt	$ 88,263	$ 100,673	$ 112,785	$ 124,595	$ 136,100
Deemed ST Debt	$ 2,726	$ 3,109	$ 3,483	$ 3,848	$ 4,203
Return on Capital	$ 211,911	$ 241,706	$ 270,786	$ 299,141	$ 326,763
Taxes/PILs					
Aggregate Federal/Provincial Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%
Aggregate Taxes/PILs (grossed-up)	$ 43,598	$ 49,728	$ 55,710	$ 61,544	$ 67,227
Capital-Related Costs Recovered in Rates					
Depreciation	$ 180,480	$ 199,626	$ 219,021	$ 238,669	$ 258,571
Return on Capital	$ 211,911	$ 241,706	$ 270,786	$ 299,141	$ 326,763
Taxes/PILs (Grossed-up)	$ 43,598	$ 49,728	$ 55,710	$ 61,544	$ 67,227
Total	$ 435,989	$ 491,060	$ 545,518	$ 599,354	$ 652,562

IR Framework with Half Year Rule in Rebasing Year and Eliminated for IR Period

Capital-Related Cost Recovered	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Depreciation	$ 170,240	$ 182,826	$ 185,203	$ 187,611	$ 190,050
Return on Capital	$ 212,247	$ 214,666	$ 217,457	$ 220,283	$ 223,147
Taxes/PILs (Grossed-up)	$ 43,667	$ 44,165	$ 44,739	$ 45,320	$ 45,909
Total	$ 426,154	$ 441,657	$ 447,398	$ 453,214	$ 459,106

Difference in Capital-Related Costs Recovered

IR with 1/2 Yr Rule in Rebasing Yr & Not in IR Years	**$ 426,154**	**$ 441,657**	**$ 447,398**	**$ 453,214**	**$ 459,106**
Less COS with Half Year Rule	**$ 426,154**	**$ 481,907**	**$ 537,056**	**$ 591,593**	**$ 645,510**
Difference	**$ -**	**$ (40,250)**	**$ (89,658)**	**$ (138,378)**	**$ (186,403)**
Difference as % of Capital Costs in Rates		**-9.11%**	**-20.04%**	**-30.53%**	**-40.60%**

Capital Expenditures In IR Rates (No Dead Band)

Calculation of Notional Capital in Rates	Rebasing Year	Year 2	Year 3	Year 4	Year 5
Notional Rate Base	$ 3,234,880	$ 3,271,747	$ 3,314,280	$ 3,357,365	$ 3,401,011
Threshold Calculation		123.3%	123.3%	123.3%	123.3%
Amount of Capital in Rates		$ 225,359	$ 228,289	$ 231,256	$ 234,263

KPMG

Effect of the Half Year Rule with Customer Growth

With Customer Growth	Rebasing Year	Year 2	Year 3	Year 4	Year 5
CapEx 100% of Depreciation					
Capital Costs Recovered in Rates					
Annual Cost of Service (COS) with Half Year Rule	$ 399,791	$ 403,147	$ 406,560	$ 410,030	$ 413,557
Annual Cost of Service without Half Year Rule	$ 402,250	$ 405,453	$ 408,710	$ 412,021	$ 415,385
Notional Effect of Half Year Rule	$ (2,459)	$ (2,306)	$ (2,150)	$ (1,991)	$ (1,829)
Capital Costs Recovered In Rates: Incentive Regulation (IR)	$ 399,791	$ 407,880	$ 416,133	$ 424,552	$ 433,142
Revenue Sufficiency (Deficiency) IR vs Annual COS with Half Year Rule	$ -	$ 4,733	$ 9,573	$ 14,523	$ 19,585
Revenue Deficiency Attributable to CapEx vs CapEx in Base Rates	$ -	$ -	$ -	$ -	$ -
CapEx 200% of Depreciation					
Annual Cost of Service (COS) with Half Year Rule	$ 408,579	$ 429,485	$ 450,398	$ 471,318	$ 492,242
Annual Cost of Service without Half Year Rule	$ 413,496	$ 434,097	$ 454,699	$ 475,300	$ 495,900
Notional Effect of Half Year Rule	$ (4,917)	$ (4,612)	$ (4,300)	$ (3,982)	$ (3,658)
Capital Costs Recovered In Rates: Incentive Regulation (IR)	$ 408,579	$ 416,845	$ 425,279	$ 433,884	$ 442,663
Revenue Sufficiency (Deficiency) IR vs Annual COS with Half Year Rule	$ -	$ (12,640)	$ (25,119)	$ (37,434)	$ (49,580)
Revenue Deficiency Attributable to CapEx vs CapEx in Base Rates	$ -	$ (8,028)	$ (20,819)	$ (33,452)	$ (45,922)
CapEx 400% of Depreciation					
Annual Cost of Service (COS) with Half Year Rule	$ 426,154	$ 482,161	$ 538,076	$ 593,894	$ 649,614
Annual Cost of Service without Half Year Rule	$ 435,989	$ 491,385	$ 546,676	$ 601,858	$ 656,929
Notional Effect of Half Year Rule	$ (9,835)	$ (9,224)	$ (8,600)	$ (7,964)	$ (7,315)
Capital Costs Recovered In Rates: Incentive Regulation (IR)	$ 426,154	$ 434,776	$ 443,573	$ 452,548	$ 461,704
Revenue Sufficiency (Deficiency) IR vs Annual COS with Half Year Rule	$ -	$ (47,385)	$ (94,503)	$ (141,346)	$ (187,910)
Revenue Deficiency Attributable to CapEx vs CapEx in Base Rates	$ -	$ (38,161)	$ (85,902)	$ (133,382)	$ (180,595)

Effect of the Half Year Rule with no Customer Growth

Without Customer Growth	Rebasing Year	Year 2	Year 3	Year 4	Year 5
CapEx 100% of Depreciation					
Capital Costs Recovered in Rates					
Annual Cost of Service (COS) with Half Year Rule	$ 399,791	$ 403,084	$ 406,305	$ 409,454	$ 412,531
Annual Cost of Service without Half Year Rule	$ 402,250	$ 405,372	$ 408,420	$ 411,395	$ 414,294
Notional Effect of Half Year Rule	$ (2,459)	$ (2,288)	$ (2,115)	$ (1,940)	$ (1,763)
Capital Costs Recovered In Rates: Incentive Regulation (IR)	$ 399,791	$ 404,988	$ 410,253	$ 415,586	$ 420,989
Revenue Sufficiency (Deficiency) IR vs Annual COS with Half Year Rule	$ -	$ 1,905	$ 3,948	$ 6,132	$ 8,459
Revenue Deficiency Attributable to CapEx vs CapEx in Base Rates	$ -	$ -	$ -	$ -	$ -
CapEx 200% of Depreciation					
Annual Cost of Service (COS) with Half Year Rule	$ 408,579	$ 429,358	$ 449,889	$ 470,167	$ 490,190
Annual Cost of Service without Half Year Rule	$ 413,496	$ 433,934	$ 454,119	$ 474,048	$ 493,716
Notional Effect of Half Year Rule	$ (4,917)	$ (4,576)	$ (4,231)	$ (3,881)	$ (3,526)
Capital Costs Recovered In Rates: Incentive Regulation (IR)	$ 408,579	$ 413,890	$ 419,271	$ 424,721	$ 430,243
Revenue Sufficiency (Deficiency) IR vs Annual COS with Half Year Rule	$ -	$ (15,468)	$ (30,618)	$ (45,446)	$ (59,948)
Revenue Deficiency Attributable to CapEx vs CapEx in Base Rates	$ -	$ (10,892)	$ (26,387)	$ (41,565)	$ (56,421)
CapEx 400% of Depreciation					
Annual Cost of Service (COS) with Half Year Rule	$ 426,154	$ 481,907	$ 537,056	$ 591,593	$ 645,510
Annual Cost of Service without Half Year Rule	$ 435,989	$ 491,060	$ 545,518	$ 599,354	$ 652,562
Notional Effect of Half Year Rule	$ (9,835)	$ (9,153)	$ (8,462)	$ (7,762)	$ (7,052)
Capital Costs Recovered In Rates: Incentive Regulation (IR)	$ 426,154	$ 431,694	$ 437,306	$ 442,991	$ 448,750
Revenue Sufficiency (Deficiency) IR vs Annual COS with Half Year Rule	$ -	$ (50,213)	$ (99,750)	$ (148,602)	$ (196,760)
Revenue Deficiency Attributable to CapEx vs CapEx in Base Rates	$ -	$ (41,061)	$ (91,289)	$ (140,841)	$ (189,708)

Contact us

Jonathan Erling
Global Infrastructure Advisory
T +1 (416) 777-3206
E jerling@kpmg.ca

Karen Taylor
Global Infrastructure Advisory
T +1 (647) 777-5496
E karentaylor@kpmg.ca

kpmg.ca