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BY COURIER

April 20, 2012

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Walli:

EB-2010-0377, EB-2010-0378, EB-2010-0379, EB-2011-0043 and EB-2011-0004 - Renewed Regulatory Framework - Hydro One Networks Comments

Hydro One Networks Inc. ("Hydro One") appreciates the opportunity to provide comments on the Ontario Energy Board's ("OEB") Renewed Regulatory Framework initiative. Hydro One believes that a long-term regulatory regime should provide a clear, efficient and realistic environment for distributors and other stakeholders to operate within. There should be expectations for smooth rate increases that allow recovery of required investments and predictable rates for customers.

Hydro One has organized its comments under the following topics:

- Investment Recovery
- Planning
- Performance and Incentives

Key points are provided in bullets immediately following headings for easy reference.

Hydro One believes that issues related to investment recovery and regional planning can be dealt with in the near term while issues related to performance and incentives will require more consideration and a longer term approach to renewal.

Investment Recovery

Hydro One will differentiate between 3 types of capital investments and provide a numerical illustration of why "typical" ongoing investments aren't necessarily covered during Incentive Regulation Mechanism ("IRM") periods between Cost of Service ("COS") rebasings. Hydro One will also provide options for how investments could be treated within a renewed regulatory framework.

Types of Investment:

- Hydro One offers that there are 3 basic types of capital investment for purposes of the investment recovery discussion: “typical” capital spending; “escalated issue” capital spending; and “non-typical” capital spending.
- Each type of investment drives a different level of required scrutiny.

Typical capital spending includes historically approved levels of sustainment and development spending. Sustainment spending includes categories such as wood pole replacements, transformer replacements, investments in distributing and regulating stations, repairing storm damage and the replacement of meters, information technology, fleet, and work and office equipment. Development spending includes categories such as new load connections, and upgrades and system capability reinforcement. Typical capital spending is reviewed in detail at COS rebasings and should not require detailed review during the period of the IRM. Typical includes the capital spending approved in the most recent COS application (i.e. net of any OEB directed reductions) less all capital spending associated with renewable generation and smart grid investments.

A second category covers capital spending on typical categories but at a substantial increase over historically approved levels. The higher level of capital spending would be required to address an escalated issue. For ease of reference, this will be called escalated issue capital in the remainder of this document. For example, a distributor may require a substantial increase over historically approved levels to address a quality issue related to certain poles. This quality issue may relate to asset age or a manufacturer issue. Escalated issue capital spending, would require a more detailed review if introduced during the period of an IRM.

A third category covers “non-typical” spending. This category covers items such as substantial green energy investments including distributed generation connections. Non-typical capital spending would also require a more detailed review if introduced during the period of an IRM.

References to these categories will be made in subsequent sections.

Issues with Current Investment Recovery Model:

- Typical capital spending is not fully recovered by distributors whose typical capital spending is significantly greater than depreciation during the period of an IRM.
- Escalated issue capital, and non-typical spending also need to be recovered during IRM periods.
- The current model results in “step” increases at COS rebasings which are not customer friendly.
- A new model is required to address the cost recovery shortfall during IRM periods and the resulting step increases upon COS rebasing.

Many distributors and stakeholders have indicated that the current Incremental Capital Module (“ICM”) does not allow for sufficient recovery of capital investments during an IRM period. This was a common theme in presentations from the Electricity Distributors Association, the Ontario Energy Association, the Distribution Regulation Review Task Force, Waterloo North Hydro and Hydro One. The current ICM seriously constrains the capital additions that may be considered during an IRM. The OEB has not developed or applied a consistent approach in defining the criteria for investment to be included under the ICM (language such as extraordinary, unanticipated, materiality and non-discretionary have been included in OEB decisions).

There was extensive discussion during the Renewed Regulatory Framework for Electricity Stakeholder Conference on March 30, 2012 around IRM and the ability of a distributor to recover typical capital expenditures during an IRM period. On page 57 line 21, Mr. Sommervile provided an observation in this regard:

> *"…The idea is that that capital budget is a typical, a typical, capital budget. It is not the capital budget for the test year. It is a capital budget that is typical for that utility going forward, and supports its typical capital expenditure requirements for that IRM period.*

In response, Ms. Frank volunteered to provide a numeric illustration to support the notion that the current IRM does not cover typical capital expenditures where typical capital expenditures far exceed depreciation expense. Please refer to Appendix A for this illustration. This illustration uses Hydro One's typical capital expenditures, revenue requirement, OM&A and depreciation approved in its 2011 cost of service application. (EB-2009-0096) The illustration assumes that the IRM period lasts for 2012, 2013 and 2014. The conclusion of this illustration is that Hydro One would incur $41 million in lost revenue over a three year IRM period under the assumption that Hydro One only invests in typical capital during that time and that typical capital spending increases by inflation in each year of the IRM. If one assumes that the typical capital spending does not increase by inflation in each year of the IRM, Hydro One would incur $36 million in lost revenue over a three year IRM period. A full description of assumptions used in the illustration is included in Appendix A.

The current mechanism promotes the harvesting of assets during an IRM period. Distributors are reluctant to spend dollars on rate base for which there is no cost recovery. There are a number of unintended customer outcomes associated with this type of behaviour including: lower reliability as assets are not replaced or refurbished prior to breakdown; not replacing or refurbishing assets when it is economically beneficial to do so; and increased labour costs as a utility is unable to levelize work based on the most efficient use of labour resources. Using the illustration in Appendix A, for 2014 only $278 million[1] would be funded compared to the OEB approved amount in 2011 of $438 million. This is unsustainable.

The under-recovery problem is compounded when there is a need to recover escalated capital spending and non-typical capital spending during IRM periods. Many distributors are experiencing requirements for escalated capital spending due to aged infrastructure and non-typical green energy investments to connect distributed generation customers. Non-recovery of typical, escalated and non-typical investments results in step increases in rates at COS rebasings.

Options for addressing these issues are presented in the next subsection.

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[1] The $278 million of funded capital additions is made up of the 2014 rate base impact of the "Typical" approved CapEx with inflation ($456 million per line 38 of Appendix A) less 2014 cumulative annual unfunded growth in rate base ($178 million per line 42 of Appendix A)

Options for Dealing with Current Investment Recovery Issues:

- There are two main options to deal with the current investment recovery issues: an annual examination of changes to rate base and rates as part of an IRM filing; and a multi-year approach for achieving necessary rate base and rate adjustments.
- The annual examination option would likely work better for distributors who are less comfortable in forecasting and delivering on multi-year plans. These distributors may transition to the multi-year approach in the longer term.
- Distributors that are filing 2012 IRM applications for 2013 rates should be allowed to file under one of the near term approaches

The renewed regulatory framework should allow for annual adjustments to a distributor's capital additions, which will impact on revenue requirement and rate base. The need for adjustments to the current treatment of capital additions is driven by: limitations of the current incremental capital module; the capital intensive nature of the distributor environment; and the desire for rate smoothing for customers.

A near term option to achieve the necessary capital additions is an annual examination of changes to rate base and rates as part of an IRM filing. Two main approaches could be applied to accomplish this change.

The first approach under the near term option would be to establish an annual rate rider based on a detailed review of forecast changes to rate base in each year of the IRM. A "need" and "prudence" review of capital investments driving rate base changes would occur as part of the annual IRM process. This would apply to the full capital program. The determination of the approved rate rider would take into account actual year-end rate base in prior years. The extent of the required review could be determined based on the materiality of the resulting rate change and the nature of the investments. Typical capital spending and escalated issue capital spending may be handled with a written proceeding while non-typical capital spending may require a more detailed oral proceeding.

Another approach under the near term option would be to set an annual rate adder over the IRM period and conduct a detailed review of rate base changes at the next COS rebasing proceeding. The adder could be set annually as part of the IRM process and would include an adjustment for actual year-end rate base in prior years. Under this approach, there would be no detailed review of capital plans during the IRM period. A "need" and "prudence" review of capital spending, including a true-up of the variance account would take place at the next COS proceeding. This approach is more risky for distributors and investors (in the extreme impacting credit rating) but may work quite well for those that do not have a need for large escalated issue and non-typical capital spending over the IRM period.

The second, longer term, option for achieving necessary rate base adjustments is the introduction of multi-year forecasts of rate base as part of a COS filing. Capital plans and in-service additions would be approved in a COS proceeding and the resulting rate base impacts on revenue requirement would be fixed over the IRM period. Under the multi-year approach, the COS review would identify annual changes to rate base to be recovered in rates and no true up would occur. This approach may be more efficient for consideration of capital requirement when examination takes place during a COS filing. It may also provide better context for the asset condition and system demand assessments when integrated with the 5 year plan. This approach would work well for distributors who have experience and are comfortable with multi-year forecasts. During times of uncertainty and increased demands on distributors (e.g. Green Energy related investments) this would be less effective.

Distributors that are filing 2012 IRM applications for 2013 rates should be allowed to file under one of the near term approaches identified above. This would allow for recovery of prudent capital spending and help to avoid the step increases for customers at COS rebasings. Filings using one of the near term approaches would also allow the OEB to become familiar with and test some of the concepts prior to making final changes to filing requirements and the IRM model.

Planning

Hydro One will address coordination, cost responsibility and planning horizon under the planning topic.

Coordination:

- The Ontario Power Authority's ("OPA's") regional planning process is robust and transparent and produces balanced and optimal plans.
- The final review and approval of OPA plans should take place during section 92 and distributor cost of service or IRM proceedings.

On the coordination issue, Hydro One contends that there currently exists a comprehensive planning process that serves customers well. The Ontario Power Authority ("OPA") is the regional planning authority in Ontario and it has carried out regional planning since its inception in 2005. The OPA is directly responsible for broad impact and complex planning activities that involve transmitters and distributors when regional solutions exist and when a number of potential options exist.

Hydro One, in its transmitter capacity, continues to work with distributors directly to conduct ongoing connection activities where adequate upstream capability is known to exist. Hydro One informs the OPA of these activities and provides the OPA with data to ensure that these activities are aligned with the OPA's planning activities.

The OPA follows a comprehensive process in developing regional plans. They form teams with representatives from the OPA, distributors, transmitters, the IESO and others as appropriate. They establish terms of reference for their studies that include: roles and responsibilities of the study team members; objectives, scope and key assumptions; and a schedule for completing the study. They provide a balanced viewpoint which allows for the consideration of conservation, local generation, transmission and distribution solutions that are in the best interests of customers. They integrate government policy, regional studies and broader province-wide planning activities into the plans and solutions. When complete, the OPA plans should be considered optimal.

OPA plans should undergo final stakeholdering and approval during section 92 and distributor cost of service or IRM proceedings. This final review and approval will provide an opportunity for all interested stakeholders to ask questions and comment on the plans to ensure that they are in the best interests of customers.

Cost Responsibility:

- The current process for determining cost responsibility is long, repetitive and often results in the recommended solutions not being implemented.
- Section 6 of the Transmission System Code ("TSC") should be revised to allow distributor line connections to be pool funded on a province wide basis.
- A small working team with representatives from the OPA, transmitters and distributors should be established to recommend the required changes to section 6.3 of the TSC. These changes should be implemented in 2012.

One of the challenges in implementing the OPA-led regional plans is the current cost responsibility rules contained in section 6.3 of the Transmission System Code ("TSC") as they apply to distributors. The current cost responsibility model discourages distributors to come forward with connection requests because the distributor that triggers the investment is typically required to pay a capital contribution. This is problematic for most distributors. Economic evaluations often result in high capital contributions. Most distributors' customers cannot afford to pay the capital contribution to fund the necessary expansion investments. This often drives a very long iterative process that does not reach a solution or results in a sub-optimal short term distribution "fix" to avoid a more economic permanent transmission solution.

Section 6.3.6 states that:

> *"A transmitter shall develop and maintain plans to meet load growth and maintain the reliability and integrity of its transmission system. The transmitter shall not require a customer to make a capital contribution for a connection facility that was otherwise planned by the transmitter, except for advancement costs."*

Section 6.3.6 does NOT alleviate the current cost responsibility issue. The "*otherwise planned by the transmitter*" criteria for not requiring a capital contribution is very difficult to satisfy.

In its September 6, 2007 EB-2006-0189 (an application by Hydro One Networks Inc. and Great Lakes Power Limited for the review and approval of transmission connection procedures) Decision and Order, the OEB explained the differences between plans driven by Customers (i.e. capital contribution required) and plans driven by System Needs (i.e. capital contribution not required). Specifically, on page 22 of the Decision and Order (underline added):

> *Distinguishing Between Plans – Customer Driven versus System Needs*
>
> *"The Board agrees with the submissions by Hydro One and the CLD that there can be ambiguity with respect to whether an enhancement of the system is one which is designed primarily to address system integrity and reliability issues as identified by the transmitter, on the one hand, and those which are primarily of benefit to one or a small group of customers who have a pressing local need, on the other. In the one case, the Code would not require capital contributions, in the other it would.*

That ambiguity is most easily resolved where the transmitter can demonstrate that the enhancement was identified as part of its planning process and not merely because a customer has requested it. To be clear, where planning involves joint studies between Hydro One and one or more distributor(s) to meet different timing and supply needs such as load growth, the Board views such plans as customer-driven, where a capital contribution would be required.

In the Board's view this means that, to qualify for the exception to the general rule, a project must be encompassed in a plan that has been developed by the transmitter substantially independent of customer request. This does not preclude an appropriate level of discourse between the Transmitter and affected customers in order to ensure the accuracy of the plan.

Each of the other transmitters that made submissions in relation to this issue recognized that an integral part of their undertaking involves the establishment by the transmitter of plans that address load growth identified by the transmitter in its ongoing planning process, together with system reliability and safety requirements. Integrating load growth projections, reliability and safety needs is at the heart of the transmitter's planning process. It is the product of that activity that can give rise to the exception contained in section 6.3.6 of the Code.

Whether the plan meets the criteria giving rise to the exception in any given case is a matter of evidence to be considered by the Board on a case-by-case basis."

In practice, it is very difficult to prepare a comprehensive plan that can address system reliability, safety requirements and load growth projections without significant up front distributor participation. The line between customer driven and transmitter driven is very hard to establish. It is much more efficient to spend time determining and implementing the optimal solution and not waste time on whether it was part of a transmitter's original plan or requested by a distributor.

To address this issue Hydro One recommends that all "basic" line connection costs for distributors be pool funded on a province wide basis. It is not recommended that pool funding be done on a regional basis. Pool funding on a regional basis would be too complex and would likely require changes to the distribution bill. The delivery line on the bill would have to include distribution charges, transmission charges and regional charges. Based on how the transmission system has been developed over time, some regions of the province have excess capacity while other regions have insufficient capacity. This is more an accident of geography for distributors that are in regions that have insufficient capacity. From a long term perspective, provincial pooling of distribution line connection costs is the fairest approach for customers.

The "basic" service would be consistent with the OPA's plan. This treatment aligns well with a distributors obligation to serve and eliminates the temptation for distributors to invest in incremental distribution solutions that are duplicative and less economic in the long run. This treatment also aligns with the pooling foundation upon which transmission rates are set. To ensure that only required assets are pooled, Hydro One recommends that any incremental costs associated with premium services be paid for by the distributor that requests the premium service. Examples of premium service would include underground lines where a feasible overhead option exists and steel pole towers where lattice structures are feasible. Network connections would continue to be pool funded. Please refer to Appendix B for a graphic representation of this recommendation.

Planning Horizon:

- The planning horizon should be a minimum of 20 years to ensure the transmission corridors are established in the most efficient and cost effective manner.
- Costs to establish the corridors should be treated as current period costs despite the future-use nature of these assets.

As part of planning efficiency, planning needs to look out a minimum of 20 years in order to ensure that transmission right-of-ways are established ahead of, or coincident to, urban development. This is accomplished through effective coordination between gas utilities, electric utilities, municipalities, the Ministry of Transportation and the OPA. This will help ensure that the establishment of corridors is done in a more thoughtful manner and be less crisis driven. Coordinating with all stakeholders, far in advance of need, will ensure the selection of the least obtrusive route for transmission corridors. Associated costs to establish these right-of-ways should be treated as current period costs despite the future-use nature of these assets. Examples of the types of costs that would be included in current period costs are: EA study costs including landowner consultation; First Nation consultation costs including capacity funding; preliminary engineering and design costs including soil and other geotechnical studies; and costs of acquiring property rights. Including these as current period costs will help ensure that right-of-ways are established at the proper time and at a lower overall cost and may also reduce the need to expropriate.

The changes required to implement Hydro One's planning recommendations should be straightforward and implemented in the near term. A working team comprised of individuals from the OPA, 2 or 3 distributors who have recently participated in the OPA's regional planning process and Hydro One could put forward specific changes to the TSC that could be implemented in 2012.

Performance and Incentives

- Changes to performance and incentives will require further thought and consultation. Implemented metrics should drive appropriate behaviour.

It is important for the Renewed Regulatory Framework initiative to take sufficient time to consider options for performance and incentives. Any performance metrics and resulting incentives should drive the appropriate behaviour. A key input to this effort is an understanding of what customers want. If it is unclear what customers want, it is premature to establish a system that would reward distributors for exceeding the current customer service standards.

In the interim, Hydro One supports the approach to performance used by Waterloo North. Mr. Gatien alluded to the use of balanced scorecards during the Renewed Regulatory Framework for Electricity Stakeholder Conference on March 29, 2012 at page 206 of the transcript. When considering performance and incentives, the Renewed Regulatory Framework work should be informed by the fact that a number of distributors already have balanced scorecards in place that help to drive year over year improvements.

There was also considerable discussion about total bill increases and the need for the OEB to mitigate these increases. Distributors should not be asked to offset bill increases that are not under their control.

Hydro One would also like to make the following points that are specific to Hydro One Remote Communities:

- Capital expansions are quite different for Hydro One Remote Communities because expansions are funded by government.
- Any community expansion has different requirements and different timeframes and therefore multiyear planning is more difficult for Hydro One Remote Communities.
- There are different performance metric considerations for Hydro One Remote Communities. For example, reliability requirements must take into account the fact that remote communities are not grid connected.
- When the OEB changes processes for distributors they should exempt Hydro One Remotes where appropriate.

Hydro One appreciates the opportunity to provide comments on the Renewed Regulatory Framework and looks forward to ongoing participation in this important initiative.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Appendix A – “Typical” Capital Funding under IRM

1		**IRM & ICM Capital Module Parameters for Hydro One**			
2					
3			2012	2013	2014
4		Inflation (GDP-IPI)	1.7%	2.0%	2.0%
5		Productivity Factor	0.72%	0.72%	0.72%
6		Stretch Factor	0.40%	0.40%	0.40%
7	PCI	Allowed IRM Increase	0.58%	0.88%	0.88%
8	g	Load Growth (per ICM Formula)	0.9%	0.9%	0.9%
9	IRM=g+PCI*(1+g)	Combined PCI and Load Growth (per ICM formula)	1.49%	1.79%	1.79%
10					
11					

12		**IRM Approved Revenue Increase Approach**				
13						
14		*This approach determines the growth in Revenue (net of increased OM&A costs) approved under the IRM model and calculates the amount of Rate Base that this additional revenue funds, which is then compared to the "typical" annual CapEx requirements as approved by the Board in the last cost-of-service application to establish the unfunded Rate Base under IRM.*				
15						
16			COS		IRM Period	
17			2011	2012	2013	2014
18	A	"Typical" CapEx approved in 2011 and assumed during IRM period	438	445	452	461
19	B	Approved Revenue Requirement	1149			
20	C	Approved OM&A	525			
21	D	Approved Depreciation	284			
22						
23	E=B*(1+IRM)	Implicit Revenue generated by IRM = prior year Revenue increased to reflect combined PCI and load growth increases		1166	1187	1208
24	F=C*(1+IRM)	Implicit OM&A generated by IRM = prior year OM&A increased to reflect combined PCI and load growth increases		533	542	552
25						
26	G=E-B	Growth in Revenue		17	21	21
27	H=F-C	Growth in OM&A		8	10	10
28	I=G-H	Growth in Revenue available to fund increase in rate base		9.3	11.3	11.5
29						
30	J = solve so I=K	**Growth in Rate Base funded by available growth in Revenue**		**89**	**109**	**110.5**
31		Depreciation (rate base @3.10%)		2.8	3.4	3.4
32		Cost of Debt (60% of rate base @ 5.02%)		2.7	3.3	3.3
33		Cost of Equity (40% of rate base @ 9.12%)		3.2	4.0	4.0
34		Income Tax (ROE @ 17.7%)		0.6	0.7	0.7
35	K =	Total Revenue Requirement associated with growth in Rate Base		9.3	11.3	11.5
36						
37		Rate Base Impacts:				
38	L	Rate Base impact of approved "typical" CapEx [1]		441	448	456
39	M	Less decrease in Rate Base due to Depreciation		-284	-286	-290
40	N=J	Less growth in Rate Base funded by growth in Revenue		-89	-109	-111
41	O=L+M+J	**Unfunded growth in Rate Base driven by "typical" CapEx**		**69**	**53**	**56**
42		*Cumulative annual* unfunded growth in rate base		69	122	178
43		Unfunded growth in rate base over IRM period				368
44						
45	P	**Lost Revenue associated with unfunded growth in Rate Base [2]**		**8**	**6**	**6**
46		*Cumulative annual* lost revenue		8	14	20
47		Lost Revenue over IRM period				41
48						
49		Note 1: Rate Base impact equals 1/2 of CapEx in prior year plus 1/2 of CapEx in the current year. All CapEx assumed to go in-service in the year which it occurs.				
50		Note 2: Lost revenue is calculated in the same manner as "Total Revenue Requirement associated with growth in Rate Base" above.				

Appendix A – "Typical" Capital Funding under IRM

This approach determines the growth in approved Revenue available under the IRM model and calculates the amount of Rate Base that this additional revenue funds. The total Rate Base funded under the IRM model is then compared to the "typical" annual CapEx requirements as approved by the Board in the last cost-of-service application to establish the unfunded increase in Rate Base under IRM.

This approach uses a number of inputs established by the Board's 3rd Generation IRM model. These include the following:

- PCI = Inflation – Productivity – Stretch Factor. For Hydro One the PCI values are 0.58% for 2012 and 0.88% for 2013.
- Load Growth (g) determined per the ICM module as the % revenue change from load growth. For Hydro One, this was calculated to be 0.9% in 2012 based on comparing the 2010 actual revenues adjusted for 2011 approved rates and the 2011 Board-approved revenue requirement.
- The combined PCI and Load Growth determined per the ICM formula as "g + PCI*(1+g)" (referred to as "IRM" growth below). For Hydro One this equals 1.49% in 2012 and 1.79% in 2013

The starting point for the analysis is the Revenue Requirement components approved in the most recent cost-of-service application. This includes the 2011 Board approved values (as per the Rate Order under EB-2009-0096) for the following:

- Revenue Requirement
- OM&A
- Depreciation
- Approved "typical" CapEx. For Hydro One, this is the proposed CapEx amount of $577M less the Board directed reduction to CapEx of $43M less all CapEx associated with Renewable Generation of $34M and less Smart Grid investments of $62M.

The methodology consists of the following steps:

1. Calculate the increased revenue generated under IRM.
   - Rev Req * (1+ IRM Growth)

2. Calculate the increased OM&A funded under IRM.
   - OM&A * (1+ IRM Growth)

3. Calculate the difference between growth in Revenue and growth in OM&A. This additional revenue is assumed to be available for funding growth in Rate Base.

4. Calculate the growth in Rate Base funded by the increased revenue generated by the IRM model. This is done using an iterative approach that calculates the following revenue requirement components associated with a change in rate base:
   - Depreciation (average 2012 depreciation rate for all Hyrdo One Distribution assets)

Appendix A – “Typical” Capital Funding under IRM

- Cost of Debt (Hydro One’s 2012 long term debt rate and the Board’s 2012 short term debt rate)
- Cost of Equity (Board’s 2012 specified ROE)
- Income tax (used income tax as proportion of cost of equity calculated from 2011 Distribution Rate Order)

5. Determine the Rate Base impacts of the typical CapEx level approved by the Board in the last COS application.
    - Currently approved typical CapEx amount is escalated by the combined PCI and Load Growth used in the ICM module
    - Rate Base impact in the current year equals ½ of prior’s CapEx + ½ of the current year CapEx.

6. Calculate the unfunded growth in rate base as:
    - Growth in Rate Base due to approved typical CapEx levels ***less*** growth funded by depreciation ***less*** growth funded by increased revenues generated under IRM.

7. Calculate the lost revenues associated with the unfunded growth in Rate Base (calculated in the same manner as in Step 4 above).

Appendix B – Pool Funding for Basic Service