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BY E-MAIL

October 21, 2011

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: Board Staff Interrogatories
Norfolk Power Distribution Inc.
2012 Electricity Distribution Revenue Requirement and Rates
Board File No. EB-2011-0272

In accordance with Procedural Order No. 1, please find attached Board staff interrogatories for this proceeding. Please forward the attached to Norfolk Power Distribution Inc. and to all intervenors in the proceeding.

Sincerely,

Original signed by

Harold Thiessen
Case Manager – EB-2011-0272
Senior Project Advisor - Applications

Attachment

BOARD STAFF INTERROGATORIES
NORFOLK POWER DISTRIBUTION INC. (“Norfolk Power”)
2012 ELECTRICITY DISTRIBUTION COST OF SERVICE RATES
October 21, 2011

General

1. Responses to Letters of Comment
Following publication of the Notice of Application, did Norfolk Power receive any letters of comment? If so, please confirm whether a reply was sent from Norfolk Power to the author of the letter. If confirmed, please file that reply with the Board. If not confirmed, please explain why a response was not sent and confirm if Norfolk Power intends to respond.

2. Conditions of Service
a) Please identify any rates and charges that are included in Norfolk Power’s Conditions of Service, but do not appear on the Board-approved tariff sheet, and provide an explanation for the nature of the costs being recovered.

b) If any rates or charges are identified in part a), please provide a schedule outlining the revenues recovered from these rates and charges from 2006 to 2010 and the revenue forecast for the 2011 bridge and 2012 test years.

c) If any rates or charges are identified in part a), please explain whether in Norfolk Power’s view, these rates and charges should be included on the Norfolk Power tariff sheet.

3. Conditions of Service
How does Norfolk Power determine billing demand for General Service customers >50 kW, ie, the kW meter reading and/or 90% of the kVa demand? Is the method of billing documented in Norfolk Power’s Conditions of Service?

4. Revenue Requirement Work Form (RRWF)
The Revenue Requirement Work Form as filed by Norfolk Power with the application does not appear to be consistent with the values found in the body of the pre-filed evidence (ie, net fixed assets, rate base, etc) Please provide a revised RRWF with the appropriate entries.

5. Updated Revenue Requirement and RRWF
Upon completion of responses to all interrogatories, please identify any adjustments to the proposed service revenue requirement that Norfolk Power wishes to make relative to the original application. In addition, please provide an

updated RRWF with any corrections or adjustments that Norfolk Power wishes to make to the amounts in the previous version of the RRWF in the middle column. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

Rate Base

6. Ref: Exhibit 1/Tab 3/Sch 2
At this reference, Norfolk Power indicates that for 2007, 2008, and 2009 it had not adopted the half-year rule for depreciation in the year of acquisition in its audited financial statements and has made an adjusting entry in 2010.

Please provide a depreciation continuity table for the years 2007 to 2012 consistent with the tables found at Exhibit 2/Tab 2/Sch1 pages 1-5 that show the depreciation and net fixed asset values if the half-year adjustments referred to above had not been made and clearly show the impact on 2012 Rate Base in both CGAAP and IFRS.

7. Ref: Exhibit 2/Tab 1/Sch 1/p. 7
In this summary under Substations, Norfolk Power indicates that,

> "The renewal or retirement of NPDI's 4.16 kV and 8.32 kV substations is the subject of an ongoing review being undertaken as part of the Asset Management Plan. NPDI has been expanding their 27.6 kV system for several years with the objective of eliminating much of the 4.16 kV network, which will eventually lead to a reduction in the number of distribution stations, a reduction in the number of distribution feeders, and improved electricity distribution efficiency."

How much of the older 4.16 kV and 8.32 kV system has been replaced with the newer 27.6 kV system? How was this issue addressed in the Asset Management Plan review? Is there an end date for when the 4.16 kV system is to be entirely replaced?

8. Ref: Exhibit 2/Tab 1/Sch 1/p. 7
In this summary under Customer Connections and Metering, Norfolk Power indicates that,

> "In 2009 NPDI began installation of smart meters and will complete the program in 2011."

However, the 2010 Financial Statements, at page 15, indicate that,

> "As at December 31, 2010, all residential and small commercial customers have had smart meters installed."

Please reconcile these two statements and provide a current update on Norfolk Power's Smart Meter deployment.

9. Ref: Exhibit 2/Tab 3/Sch 2/p.31
Under the category of Miscellaneous Overhead Projects for 2010, 2011 and 2012 Norfolk Power indicates these are reactive renewal projects of overhead system assets with a "run to failure" replacement strategy.

Please explain Norfolk Power's position on a capital replacement strategy based on "run to failure". How much of the Norfolk Power system is governed by this strategy and how is it coordinated with the Asset Management Plan?

MIFRS Related

10. Ref: Exhibit 2/Tab 5/Sch 1
In the Letter of the Board regarding *Transition to IFRS – Amendment to Board Policy, November 8, 2010, the* Board stated:

> "9.1.2 Electricity distributors filing cost of service applications for rates in the year they choose to adopt IFRS for financial reporting must provide the required actual years, the bridge year and the forecasts for the test year(s) in CGAAP based format. An electricity distributor may choose to present modified IFRS based forecasts for the bridge and test years, if the distributor seeks to have rates set on the basis of modified IFRS. If the distributor is seeking rates based on modified IFRS accounting, the distributor must identify financial differences and resulting revenue requirement impacts arising from the adoption of modified IFRS accounting."

The Board also stated on page 14 of the July 2009 Report of the Board, Transition to IFRS:

> "The Board agrees that regulated net book value should 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."[4]

For financial reporting purposes, on the date of transition to IFRS, the December 31, 2010 net book value becomes the January 1, 2011 gross value for PP&E (with accumulated depreciation set to zero). However, the Board has stated that the integrity of the December 31, 2010 gross value and accumulated depreciation values should be preserved for regulatory purposes and carried forward to January 1, 2011 values.

The continuity of historic cost should be established by Norfolk Power by using the December 31, 2010 regulatory gross capital cost and accumulated depreciation values as the opening January 1, 2011 regulatory gross capital cost and accumulated depreciation values.

Norfolk Power has filed for 2012 rates based on MIFRS. Board staff would like additional information to complete the record. Please provide the following:

a) The Bridge Year in MIFRS, maintaining asset continuity by using the December 31, 2010 regulatory gross capital and accumulated depreciation as the opening January 1, 2011 regulatory gross capital cost and accumulated depreciation values;

b) The Test Year with the opening balances based on the closing Bridge Year balances based on MIFRS from a) above;

c) The Test Year in CGAAP-based format;

d) Two RRWFs for the Test Year, one based on CGAAP, and one based on MIFRS;

e) Updated Appendix 2-B Fixed Asset Continuity Schedule of the chapter 2 filing requirements; and

f) A summary of the dollar impacts of MIFRS to each major component of the revenue requirement (e.g. rate base, operating costs, etc), including the overall impact on the proposed revenue requirement.

11. Ref: Exhibit 2/Tab 5/Sch 1
In the Letter of the Board regarding *Transition to IFRS – Amendment to Board Policy, November 8, 2010, the* Board stated on page 15:

> "The Board will require utilities to adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS."

IAS 16 Property, Plant and Equipment states that the cost of PP&E comprises of any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. IAS 23 states that directly attributable borrowing costs are capitalized upon qualifying assets only. It also indicated that a qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use or sale. The Board also said on page 40:

> "The Board will continue to publish interest rates for CWIP as it does now. Where incurred debt is acquired on an arms length basis, the actual borrowing cost should be used for determining the amount of carrying charges to be capitalized to CWIP for rate making during the period, in accordance with IFRS. Where incurred debt is not acquired on an arm's length basis, the actual borrowing cost may be used for rate making, provided that the interest rate is no greater than the Board's published rates. Otherwise, the distributor should use the Board's published rates."

Board staff is interested in the impact of MIFRS on Norfolk Power's capital expenditures.

a) Please confirm if the costs capitalized are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. If not, please explain.

b) Has Norfolk Power consulted with its external auditors or professional advisors regarding the change in capitalization of overhead within IFRS requirements? If yes, please provide supporting documentation. If not, please identify if there is any plan in the near future for such a consultation.

c) Please identify all overhead related items (e.g. indirect costs, corporate centre costs) and identify the items that are ineligible and how much overhead in total has been removed from capitalization for ineligible costs.

d) Please identify the burden rates related to the capitalization of costs of self-constructed assets:

   i) Prior to transition (from the last rebasing application to January 1, 2011), and
   ii) After transition (on or after January 1, 2011).

e) Please provide the following information in detail for overhead costs on self-constructed assets for the bridge and test years.

Nature of the Overhead Costs	Dollar Impact Bridge Year	Dollar Impact Test Year	Directly Attributable: Yes or No	Reasons for Capitalization under MIFRS

f) Please identify the overall level of increase (decrease) in OM&A expense in the test year in relation to a decrease (increase) in capitalized overhead. Please provide a variance analysis for this increase in OM&A expense for the test year in respect to each of the bridge year and historical years.

g) Please confirm that all borrowing costs that are directly attributable to the acquisition, construction, or production of PP&E costs are capitalized to PP&E and not expensed. If this is not the case, please explain.

h) Where incurred debt is not acquired on an arm's length basis, are the actual borrowing costs used? Please explain.

i) Please confirm that if the interest rate is greater than the Board's most recently published CWIP interest rates, Norfolk Power has used the Board's published rates to calculate borrowing costs included in the construction costs. If this is not the case, please explain.

12. Ref: Exhibit 2/Tab 5/Sch 1

With regard to gains or losses on the Retirement in a Group of Like Assets/Asset Impairment Losses, page 19 of the July 2009 Report of the Board, Transition to IFRS stated:

> "Where a utility for financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the utility shall reclassify such gains and losses as depreciation expense and disclose the amount separately. Where a utility for financial reporting purposes under IFRS has reported a gain or loss on disposition of individual assets, such amounts should be identified separately in rate filings for review by the Board."

Also at page 41 of the same report:

> "Where for financial reporting purposes under IFRS a utility has recorded an asset impairment loss, for rate application filings such losses shall be reclassified to PP&E and identified separately to allow consideration of whether and how such amounts are to be reflected in rates."

a) Please confirm that Norfolk Power has identified the gain or loss on the retirement of assets in a group of like assets. Please provide the treatment of the retirement for rate application purpose and disclose the amount. Please state the reasons if the gains/losses are not charged to depreciation expense.

b) Please disclose any asset impairment loss recorded under IFRS which should be reclassified to PP&E. Please describe the nature of the losses, the amounts of the losses and the consideration whether and how such amounts are to be reflected in rates.

13. Ref: Exhibit 2/Tab 5/Sch 1
With regard to Asset Retirement Obligations, page 40 of the July 2009 Report of the Board, Transition to IFRS stated:

> "Utilities shall identify separately in their rate applications the depreciation expense associated with amortizing asset retirement costs and the accretion expense associated with the amortization of the asset retirement obligations. The Board will assess these costs independently of other amortization costs to determine the portion, if any, of these costs that should be recovered in revenue requirement."

It appears that Norfolk Power did not present the accounting policy change on asset retirement obligations. As IFRS requires that asset retirement obligations include estimates of the cost of constructive obligations which was not required under CGAAP, and revaluation of those obligations during the lives of the assets.

Please confirm whether or not Norfolk Power has any asset retirement obligations.

a) If yes, please identify and provide a detailed breakdown of the major asset components.

b) If no, please provide a proposal for how the asset retirement obligations should be recovered in rates.

c) Has Norfolk Power identified the accounting change on asset retirement obligations? If so, please provide the accounting policy change and quantify the changes due to the adoption of IFRS for the test year and bridge year. If not, please provide the reasons and the plan when this is to be addressed.

d) For the AROs identified, please provide the depreciation expenses and accretion expenses and how these expense are currently included in the rate application.

14. Ref: Exhibit 2/Tab 5/Sch 1
With regard to borrowing costs, page 15 of the July 2009 Report of the Board, Transition to IFRS, stated:

> "The Board will require utilities to adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS."

IAS 16 Property, Plant and Equipment indicates that the cost of PP&E is comprised of any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

IAS 23 states that directly attributable borrowing costs are capitalized upon qualifying assets only. It also indicated that a qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use or sale.

Page 40 of the July 2009 Report of the Board, Transition to IFRS stated:

> "The Board will continue to publish interest rates for CWIP as it does now. Where incurred debt is acquired on an arms length basis, the actual borrowing cost should be used for determining the amount of carrying charges to be capitalized to CWIP for rate making during the period, in accordance with IFRS. Where incurred debt is not acquired on an arm's length basis, the actual borrowing cost may be used for rate making, provided that the interest rate is no greater than the Board's published rates. Otherwise, the distributor should use the Board's published rates."

a) Please confirm if the costs capitalized are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. If not, please explain.

b) Please confirm that borrowing costs that are directly attributable to the acquisition, construction, or production of qualifying PP&E are capitalized, with respect to incurred debt acquired on an arm's length basis. Please explain.

c) Where incurred debt is not acquired on an arm's length basis, are the actual borrowing costs used? Please explain. Please confirm that if the interest rate is greater than the Board's most recently published CWIP interest rates, the Applicant has used the Board's published rates to calculate borrowing costs included in the construction costs. If this is not the case, please explain.

d) Please confirm that that the amount of borrowing costs capitalized in a period in total does not exceed the actual borrowing costs incurred. If this is not the case, please explain.

15. Ref: Exhibit 2/Tab 5/Sch 1

With regard to Intangible Assets, IFRS requires certain assets to be recorded as intangible assets (e.g. computer software and land rights) that were previously included in PP&E. As stated at page 40 of the July 2009 Report of the Board, Transition to IFRS:

> "Where IFRS requires certain assets to be recorded as intangible assets that were previously included in PP&E (e.g. computer software and land rights), utilities shall include such intangible assets in rate base and the amortization expense in depreciation expense for determining revenue requirement."

It appears that Norfolk Power did not present the accounting policy change on asset reclassification from PP&E to intangible assets.

a) Has Norfolk Power identified the accounting policy change on asset reclassification from PP&E to intangible assets? If so, please provide the accounting policy change and quantify the changes due to the adoption of IFRS for the test year and bridge year. If not, please provide the reasons and the plan when this is to be addressed.

b) For the assets identified in a), please propose the regulatory treatment in accordance with the Board report.

16. Ref: Exhibit 2/Tab 5/Sch3

Table 5.8 compares Rate Base under CGAAP and MIFRS for 2012. Please provide further detail on how the average net book value was derived.

17. Ref: Exhibit 4/Tab 4/Sch 2/p. 1&2

Board policy articulates that LDCs shall use the Board sponsored Kinectrics study or sponsor their own study to justify changes in useful lives. The typical useful lives (TUL) from the Kinectrics report is the recommended reference point. The Board will no longer prescribe service lives for PP&E. *As the Board said in its Report of the Board Transition to International Financial Reporting Standards ("IFRS") July 28, 2009 EB-2008-0408 on page 21*

> "The Board will facilitate a joint depreciation study for electrical distribution utilities. The aim of the study will be to determine depreciation methodologies and rates that will be applied to all electrical distribution utilities for the purpose of setting rates and regulatory reporting. The study must give due weight to the IFRS requirements regarding depreciation, including componentization."

And also in the Letter of the Board Depreciation Study for Use by Electricity Distributors, July 8, 2010

> "The Kinectrics Report provides information that the Board expects distributors will consider as they develop asset service lives suitable in their particular circumstances. The Board expects distributors to reflect their consideration of the information contained in the Kinectrics Report when they present an IFRS-based rates application to the Board."

a) What changes has Norfolk Power made to its Depreciation Policy due to MIFRS (e.g. pooling of assets is not permitted under IFRS).

b) Please provide a list of detailed asset service lives and identify all exceptions from the Typical Useful Lives ("TUL") in the Kinectrics Report and provide detailed justification for using service lives that are different from the TULs in the Kinectrics Report.

c) For the bridge and test years, please provide a breakdown of the components of the underlying PP&E assets (i.e. pool assets is not permitted), including gross capital cost and accumulated depreciation values, revised useful lives, and the calculation of the depreciation expense based on revised service lives.

d) Please confirm that significant parts or components of each item of PP&E are being depreciated separately.

18. Ref: Exhibit 4/Tab 4/Sch 2
Table 4.2 presents the IFRS Amortization Expense USoA account for both 2011 and 2012 but does not provide details of how this was calculated. Please provide information based on Appendix 2M for 2011 MIFRS.

19. Ref: Exhibit 4/Tab 4/Sch 2

a) Please provide a summary of the changes to Norfolk Power's accounting policies (including capitalization) made since Norfolk Power's last cost of service rate filing.

b) Please provide a copy of Norfolk Power's depreciation/amortization policy or a summary of the depreciation practices followed and used in preparation of this application.

Capital Expenditures

20. Ref: Exhibit 2/Tab 3/Sch 2/p.41
Norfolk Power provides a summary of the 2011 projects related to the GEA. Please provide a current year-to-date update to these GEA related investments. Will all of these projects come into service by the end of 2011? If not, will the GEA related plans for 2012 be affected?

21. Ref: Exhibit 2/Tab 3/Sch 2/p. 49 & p. 61
Norfolk Power's capital budget for 2011 and 2012 includes $303,000 for Subdivision Development in each year. For 2011 the evidence indicates that the "specifics are unknown" and for 2012 it indicates that "approximately 180 new lots are anticipated". Can Norfolk Power provide additional analysis and information on how this budget was developed for 2011 and 2012 and how much of this cost is to be recovered from capital contributions?

22. Ref: Exhibit 2/Tab 3/Sch 2
Norfolk Power's capital contributions fluctuate significantly from 2008 to 2012. How does Norfolk Power forecast capital contributions for 2011 and 2012 and how does this forecast relate to the forecast customer additions in the Load Forecast?

23. Ref: Exhibit 2/Tab 3/Sch 2/p. 64, p. 53 & p. 37
Norfolk Power has budgeted $40,000 for the purchase of a new pick-up truck in 2012, in addition to $440,000 for various vehicles in 2011 and $76,000 in 2010. This follows quite low vehicle expenditures in 2008 and 2009.

a) Why were vehicle expenditures so low in 2008 and 2009?
b) Please provide a summary of the current Norfolk Power vehicle fleet, including vehicle vintage, value and condition.
c) Please provide Norfolk Power's vehicle replacement policy.
d) Please provide a forecast of Norfolk Power's proposed vehicle replacements in 2013, 2014 and 2015, including reasons/rationale and please state if Norfolk Power intends to include Electric Vehicles as part of its vehicle replacement strategy

24. Ref: Exhibit 2/Tab 3/Sch 2
Norfolk Power's investments in SCADA grew from $9,995 and $4,572 in 2008 and 2009 respectively to $550,000 in 2010, $245,000 in 2011 and $100,000 in 2012. Please provide Norfolk Power's rationale for this significant increase in spending on SCADA over the past few years.

25. Ref: Exhibit 2/Tab 3/Sch 2
Norfolk Power's investments in Pole Replacements have fluctuated over the past several years, with a considerable difference in per pole cost (simply dividing total cost by the number of poles replaced). In 2008 the per pole cost was $4,955, in 2009 $4,911 in 2010 $4,971. For 2011 the cost escalates to $6,000 per pole and then back to $4,800 per pole for 2012.

Please provide an explanation and rationale for these fluctuating costs, particularly concerning the forecast for 2011 and 2012.

26. Ref: Exhibit 2/Tab 3/Sch 2/p.62
Why has Norfolk Power not provided for any Transformer Purchases to Increase Transformers in Hand, in 2011 or 2012? Has Norfolk Power changed its policies on these transformers?

27. Ref: Exhibit 2/Tab 3/Sch 3/p.1
Norfolk Power indicates that it did not have a formal asset management plan in the past but has filed the plan developed in 2010. Norfolk Power cautions that the plan is in its early development stage. What are Norfolk Power's plans to improve the Asset Management Plan? Please provide an outline of the work to be undertaken on the Plan from 2011 to 2014 to improve its usefulness to Norfolk Power.

28. Ref: Exhibit 2/Tab 3/Sch 3
Norfolk Power shows that its level of capital expenditures will grow from $3.922 million in 2011, to $4.641 million in 2012, to $4.954 million in 2013 and to $5.129 million in 2014. Does Norfolk Power foresee a period of lower capital spending in future years due to the consistently high levels of spending and consistent increases in these 4 years?

29. Ref: Exhibit 2/Tab 3/Sch 5
Norfolk Power provides its reliability statistics from 2007 to 2011.

a) Please provide Norfolk Power's reliability scores year-to-date for 2011.

b) Has Norfolk Power developed reliability targets for 2012? If so please provide these targets.

c) As it appears that the reliability scores from 2007 to 2011 indicate a good record of service reliability, to what extent has Norfolk Power considered this in its capital spending plans?

Asset Management Plan

30. Ref: Exhibit 2/Appendix A – Asset Management Plan/p.12
Norfolk Power indicates that it expects that all NPDI owned poles will have a unique ID assigned, be mapped onto the GIS system and have associated attribute and condition data, by the end of 2011. Has Norfolk Power met this goal by the end of 2011 and if not, when is this expected to be completed? How has this data contributed to the planed number of poles that are set for replacement in 2012?

31. Ref: Exhibit 2/Appendix A – Asset Management Plan/p.32
Norfolk Power indicates that vegetation management (tree trimming) is scheduled on a 4-year and 7-year cycle for urban and rural service areas, respectively; but that Norfolk Power will in the future combine activities for both areas and scheduled on a 5-year cycle.

a) Why has Norfolk Power decided to increase the frequency of tree trimming?

b) Why has Norfolk Power decided to combine both urban and rural areas in terms of frequency?

c) What evidence has Norfolk Power relied on to make this decision?

d) Was a cost/benefit analysis performed?

e) When will this increase in tree trimming take place?

f) Is there an additional cost of moving to a 5 year cycle?

32. Ref: Exhibit 2/Appendix A – Asset Management Plan/p.38
Norfolk Power indicates that a Feeder Analysis Report is produced and the 4 worst-performing feeders are identified. Please provide a copy of this report and if not included in the report, provide an analysis of the feeder performance and how Norfolk Power addressed this performance in its plans for 2011 and 2012.

Green Energy Plan

33. Ref: Exhibit 2/Appendix C – Green Energy Plan
Please confirm that Norfolk Power is not seeking a prudence review of the GE Plan in this proceeding. If not seeking a prudence review, please provide the rationale for deferring this review until the next rebasing application.

34. Ref: Exhibit 2/Appendix C – Green Energy Plan, p.2 & OPA Letter of Comment
The statistics provided at page 2 of the Plan indicate that 155 microFIT and 14 FIT applications have been received. The OPA Letter of Comment indicates that:

> "The OPA has received 32 capacity allocation exempt FIT applications, 3 capacity allocation required FIT applications and 159 microFIT applications to NPDI's system for a total of 33.59 MW of FIT applications and 1.546 MW of microFIT applications. At this time, 30 microFIT applications have been connected and 22 microFIT applications have been terminated (leaving a total of 1.0393MW of microFIT applications to be connected)".

a) Please reconcile the number of microFIT and FIT applications received by Norfolk Power and the OPA.

b) Please comment on what appears to be a high termination rate for microFIT projects.

35. Ref: Exhibit 2/Appendix C – Green Energy Plan/p.6
With regard to the Board's filing requirements *Filing Requirements* Distribution System Plans – Filing under Deemed Condition of Licence, issued March 25, 2010 [EB-2009-0397], (the "Filing Requirements") Part V, p.11 at Part V, Section 2, bullet point 4:

> "…the method and criteria that will be used to prioritize expenditures in accordance with the planned development of the system".

At page 6 of the Norfolk Power GE Plan, Norfolk Power states:

> "NPDI is in the process of standardizing its approach to connecting renewable generators to streamline the practice through standardized application forms, cost assessments and technical requirements documentation. This will help identify and simplify the process for potential generators to improve cost estimation accuracy and reduce the time from conception to connection."

a) Please provide the Board with Norfolk Power's prioritization methodology.

b) Please indicate how the prioritization is applied to the projects identified for implementation in the coming 5 years.

36. Ref: Exhibit 2/Appendix C – Green Energy Plan
At page 2 of the GE Plan, Norfolk Power indicates that it does not currently have capacity limitations on its feeders or at Bloomsburg MTS, but notes that,

> "…potential circumstances that could limit renewable generation connections include anti-islanding measures on lightly loaded feeders, reverse power flow limitations, Transformer/Distribution Station thermal capacity and short circuit capacity".

Norfolk Power also states at page 6 that,

> "…the plan includes system expansions and enhancements necessary to safely connect renewable generators while maintaining power system quality expectations for <u>existing</u> load customers".

a) With regard to the *Filing Requirements*, Part IV, p.7, bullet #5 do present plans to connect renewable energy projects have any impacts on embedded distributors?

b) Will the connection of renewable projects thus far identified in the GEA Plan have a significant impact on the Norfolk Power distribution system? If yes, will immediate upgrades be required, ie. in 2012?

c) Please expand Table 3.9 found at Exhibit 2/Tab 3/Sch2/p.56 to the remainder of the 5-year planning horizon for the projects that have already been identified. Using the table below as a guide, please indicate the work that will be undertaken, and the feeder associated with it.

d) Will system expansion/REI activities result in premature asset replacements? When applicable please give an estimate of the remaining useful life of the "replaceable" asset and indicate in each case whether there is a residual value.

PROJECT	FEEDER	EXPECTED ONLINE DATE	ACTIVITY	COST ESTIMATE
			SYSTEM EXPANSION ACTIVITIES	
			Building a new line to serve the connecting customer	
			Rebuilding a single-phase line to three-phase to serve the connecting customer	
			Rebuilding an existing line with a larger size conductor to serve the connecting customer	
			Rebuilding or overbuilding an existing line to provide an additional circuit to serve the connecting customer	
			Converting lower voltage lines to higher voltage	
			Replacing a transformer to a large MVA size	
			Upgrading a voltage regulating transformer or station to a larger MVA size	
			Adding or upgrading capacitor banks to accommodate the connection of the connecting customer	
			RENEWABLE ENABLING IMPROVEMENTS ACTIVITIES	
			Modifications to, or the addition of, electrical protection equipment	
			Modifications to, or the addition of, voltage regulating transformer controls or station controls	
			The provision of protection against islanding (transfer trip or equivalent)	
			Bidirectional reclosers	
			Tap-changer controls or relays	
			Replacing breaker protection relays	
			SCADA system design, construction and connection	
			Any other modifications/additions to allow for and accommodate 2-way electrical flows (reverse flows)	
			Communication systems to facilitate the connection of renewable energy generation facilities	

37. Ref: Exhibit 2/Appendix C – Green Energy Plan
The nature of the work to be undertaken by distributors to connect renewable generators has been classified within three categories, namely Connection, Expansion, and Renewable Enabling Improvement ("REI"); each giving rise to a different cost responsibility split between generators and distributors.

From figures shown on Page 3 of the Plan, will some generator connections require work in more than one category (as specified above)?

a) Please provide the statistics on Page 3 in terms of capacity units rather than "per connection".

b) Please explain why expansion costs shown on page 3 for MicroFIT projects are limited to 30% of generator connections. (whereas the DSC provides for $90,000/MW relative to expansion costs).

c) In order to understand the amount of work involved, please complete the table below.

Number of Projects per Category of Work

	2011	2012	2013	2014	2015	2016
Connection						
(≤10kW)						
(>10kW to ≤250kW)						
(> 250kW)						
Expansion						
(≤10kW)						
(>10kW to ≤250kW)						
(> 250kW)						
REI						
(≤10kW)						
(>10kW to ≤250kW)						
(> 250kW)						

d) To clarify cost responsibilities, please expand Table 3 on page 6 by completing the table below.

	Expected CAPEX						Expected Capital Contribution					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Connection												
(≤10kW)												
(>10kW to ≤250kW)												
(> 250kW)												
Expansion												
(≤10kW)												
(>10kW to ≤250kW)												
(> 250kW)												
REI												
(≤10kW)												
(>10kW to ≤250kW)												
(> 250kW)												

38. Ref: Exhibit 2/Appendix C – Green Energy Plan &
Exhibit 9/Tab 6/Sch 1/p.3

OM&A costs associated with the implementation of the GE Plan are not reflected in Norfolk Power's application.

a) Please confirm that no additional human resources will be required to implement the GE Plan.

b) Please indicate what OM&A expenditures, if any, will be associated with the capital expenditures at Table 3.

	Expected Up-Front OM&A					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Connection						
Expansion						
REI						

39. Ref: Exhibit 9/Tab6/Sch1/p.2/Table 6.1Renewable Capital Investment

If applicable, please use any revised CAPEX figures to re-evaluate overall connection cost responsibilities and derive the subsequent direct benefits accruing to Norfolk Power ratepayers.

In addition, if applicable, please use revised CAPEX & OM&A figures and provide an adjusted estimate of the funding adders.

Smart Grid

40. Ref: Exhibit 2/Appendix C – Green Energy Plan
The Norfolk Power GE Plan appears to focus exclusively on the connection of renewables with no Smart Grid related expenditures. The *Filing Requirements* Distribution System Plans – Filing under Deemed Condition of Licence, issued March 25, 2010 [EB-2009-0397], Part V, p.18 presently limits smart grid activities to: "smart grid demonstration projects, smart grid studies or planning exercises and smart grid education and training".

Please confirm that Norfolk Power is not planning to undertake any of the eligible activities over the Basic Plan planning horizon? Why is Norfolk Power not planning for any Smart Grid related activities at this time?

Load Forecast

41. Ref: Exhibit 3/Tab 2/Sch 1/p. 3/Table 2.1
Please provide a year-to-date update of 2011 actual kWh consumption for Norfolk Power. Is actual consumption for the Bridge year tracking expected load? Is there evidence that the load forecasts for 2011 and 2012 may need adjustment? Why or why not?

42. Ref: Exhibit 3/Tab 2/Sch 1/p.10/Table 2.5
Table 2.5 shows a reasonable track record of actual vs predicted load from 2003 to 2009. In 2010 a much greater variance is reported. Please provide an explanation for the 2010 forecast results showing this larger variance.

43. Ref: Exhibit 3/Tab 2/Sch 1/p.11
Norfolk Power indicates that it makes a manual adjustment to reflect the CDM savings target for 2011 and 2012. Does Norfolk Power have any evidence for 2011 to indicate that his manual adjustment is appropriate? Is there evidence in actual CDM results for 2011 that may indicate that the load forecast CDM adjustment for 2012 is not accurate?

44. Ref: Exhibit 3/Tab 2/Sch 1/p.12
Norfolk Power indicates that it uses the geometric mean of 1.3% per year from 2003 to 2010 to forecast customer connections for 2011 and 2012. Considering the deterioration in economic conditions evident in 2011 is it still realistic to make this assumption? What is the year-to-date increase in residential customer connections for 2011?

45. Ref: Exhibit 3/Tab 2/Sch 1/p.13/Table 2.10
Regarding Usage per Customer Connection, can Norfolk Power explain:

a) Why the usage per customer in the Residential class grows in 2010 when this measure has declined over the previous years?

b) Why the Usage per Connection increases so significantly in the Street Lighting and Sentinel Lighting classes in 2010?

Other Distribution Revenue

46. Ref: Exhibit 3/Tab 3/Sch 1
Table 3.1 shows that Late Payment Charge revenue drops from $155,219 in 2009, to $86,593 in 2010.

a) What is the reason for this significant drop in revenue?

b) What are the assumptions that were made to forecast an increase to $138,000 in both 2011 and 2012?

47. Ref: Exhibit 3/Tab 3/Sch 1
Table 3.1 shows that Miscellaneous Service revenue drops from $101,896 in 2010 to a projected $88,000 in 2011.

a) What is the reason for this significant projected drop in revenue in 2011?

b) What are the assumptions that were made to forecast the identical level in 2012?

48. Ref: Exhibit 3/Tab 3/Sch 1
Table 3.1 shows that Other Income and Expenses revenue drop from $147,454 in 2011 to a projected $95,880 in 2012. Please provide further detail of the components that make up this change and the rationale for the 2012 forecast.

Operating Costs

49. Ref: Exhibit 4/Tab 1/Sch 1/p.2
Please provide an update of Norfolk Power's Operating Costs, year-to-date in 2011. If there are significant discrepancies (in the major line items) with the forecast costs filed for 2011, please provide the reasons. Also please discuss if the 2012 forecast will be affected, why or why not?

50. Ref: Exhibit 4/Tab 1/Sch 1/p.6
Table 1.9 shows Norfolk Power's OM&A cost per customer to be $269 in the 2012 Test Year, up from the $226 2008 Board Approved level. Does Norfolk Power track OM&A cost per customer of other utilities in its cohort (Mid-Size Southern Low and medium Undergrounding) comprised of Innisfil Hydro Distribution, Niagara Peninsula Energy, Orillia Power Corporation, Haldimand County Hydro and Canadian Niagara Power? Can Norfolk Power provide a comparison of OM&A cost per customer with its cohort companies from 2008 to 2010?

51. Ref: Exhibit 4/Tab 1/Sch 1/p.9
Table 1.11 shows Norfolk Power's cost for Consultants (for Regulatory Matters) to have increased from $41,551 in 2008 to $120,000 in the 2012 test year. Please provide a rationale for an increase of this magnitude and also provide a further breakdown of the 2012 costs that total to $120,000.

52. Ref: Exhibit 4/Tab 1/Sch 1/p.10
Norfolk Power indicates that it has not made any assumptions for inflation in the 2012 test year but has budgeted based on existing prices and increases if known. Please provide any known increases included in the Test Year OM&A forecast and also comment on why a general inflation assumption is not used for the test year forecast.

53. Ref: Exhibit 4/Tab 2/Sch 2/p.1
Table 2.1 shows that under Operations, Norfolk Power's Meter Expense grows from $124,009 in 2010, to $145,000 in 2011 and on to $214,000 in the test year. Why is this expense increasing at this pace, even as Norfolk Power has essentially completed its Smart Meter deployment?

54. Ref: Exhibit 4/Tab 2/Sch 2/p.2
Table 2.3 shows that under Billing and Collections Expense, Norfolk Power's Meter Reading Expense grows from $199,978 in 2010, drops to $120,900 in 2011 and then grows to $234,395 in the test year. (Board staff acknowledges that the $234,395 amount is broken out at Exhibit 4/Tab2/Sch3/p. 11) Why is this expense falling in the bridge year, but then increasing in the test year? Moreover, at Exhibit 4/Tab2/Sch3/p. 2, under Third Party Services, Norfolk Power indicates a reduction in meter reading expenses of $156,000 in the test year. Please provide a comprehensive picture of the total Meter Reading expense, from 2008 to 2012, explaining the impact of all aspects of this activity and how costs are calculated for the test year.

55. Ref: Exhibit 4/Tab 2/Sch 2/p.2
Table 2.2 shows that total maintenance expenses more than double from the 2008 approved amount to 2008 actual. Can Norfolk Power provide an explanation for this increase?

56. Ref: Exhibit 4/Tab 2/Sch 2/p.2
Table 2.3 shows that customer billing expense grows by 21% from $485,550 in 2011 to $586,501 in the test year. What is the rationale for this steep increase in expense for the test year?

57. Ref: Exhibit 4/Tab 2/Sch 2/p.2
Table 2.3 shows a negative amount (revenue) under Account 5330 – Collection Charges. Please explain what this entry is, why it is growing from 2010 to 2012 and how it relates to the Bad Debt expense in the next line.

58. Ref: Exhibit 4/Tab 2/Sch 2/p.2
Table 2.3 shows that Bad Debt expense falls in 2010 from 2009 levels, and then grows significantly in 2011 and then again in the test year. Please explain the significant increase in light of the fact of a continuing economic recovery through 2011 and 2012.

59. Ref: Exhibit 4/Tab 2/Sch 3/p.3
Norfolk Power explains the level of tree trimming service expense, with a slight reduction in 2012. In light of the desire of Norfolk Power to change the frequency of tree trimming from a 4 and 7 year cycle to a common 5 year cycle, how is the expense budget for tree trimming affected?

60. Ref: Exhibit 4/Tab 2/Sch 5/p.2&3
After Norfolk Power's successful bid to continue to provide billing and collecting services for Norfolk County's water and sewer services, why did Norfolk Power not pursue a similar contract to continue providing billing services for NEI hot water rentals?

Pension Costs and Post Employment Benefits

61. Ref: Exhibit 4/Tab 2/Sch 4/p.8
Norfolk Power indicates that OMERS released a 3-year plan indicating a 1% per year increase in OMERS premiums beginning in 2011 and then includes excerpts from an e-mail from OMERS outlining the 2012 increase. At Table 2.20 pension premium costs are shown to increase 13% in 2011 and 27% in 2012.

a) Please reconcile these increases with the 1% in 2011 (as noted above) and also provide a detailed breakdown of how the 2011 and 2012 amounts were determined.

b) Please reconcile the amounts presented in Table 2.20 with pension amounts found in Table 2.19 for 2011 and 2012.

62. Ref: Exhibit 4/Appendix C
With regard to Pension and Other Post-Employment Benefits:

a) Why was a draft report filed with this application and not a final report? If a final report is available, or if any updates are available please update this application with those reports.

b) What is the accounting treatment of the unamortized actuarial gains and losses and past service costs at the date of transition (January 1, 2011)? What is the proposed regulatory treatment of these amounts – are these amounts incorporated anywhere in the revenue requirement? Please explain.

c) In specific, what regulatory treatment is Norfolk Power proposing for the Unrecognized Actuarial Gain of $82,926 that was projected to exist as at December 31, 2010, as per September 17, 2010 Actuarial Report? What is the regulatory impact on pension expense incorporated into rates?

d) What were the main drivers for this unrecognized actuarial gain of $82,926?

e) Please provide the full Actuarial Valuation as at January 1, 2011.

f) Have Norfolk Power's external auditors audited the September 17, 2010 Actuarial Report (or the final form) and the January 1, 2011 actuarial report? Please provide supporting documentation.

g) Has Norfolk Power applied the optional early adoption to the IASB's June 2011 revisions to IAS 19, Employee Benefits? The revisions are effective January 1, 2013, but early adoption is permitted. These revisions include the elimination of the option to defer recognition of gains and losses, known as the "corridor method". Please explain if Norfolk Power has early adopted this element of IAS 19 and state whether the impacts of this early adoption are incorporated anywhere in the revenue requirement.

63. Ref: Exhibit 4/Tab 2/Sch 4/p.10
At Table 2.21, Norfolk Power shows the Post-Retirement Benefit amounts from 2008 to 2012. In addition, the 2011 draft Post-Retirement Benefit Report is provided at Appendix C. Please provide a road map from the Report to the amount included for 2011 and how the 2012 amount (13% increase over 2011) was determined.

64. Ref: Exhibit 4/Tab 2/Sch 4/Appendix C
The Report shows that a discount rate of 5.50% was used as at December 31, 2010. Please explain the underlying assumptions that resulted in Norfolk Power choosing 5.50% as the discount rate.

Using the same methodology, what discount rate would Norfolk Power choose as at June 30, 2011 given the current state of the domestic and international bond markets? Please describe the assumptions made in answering the question.

Payments in Lieu of Taxes (PILs)

65. Ref: Exhibit 4/Tab 3/Sch 1
Please provide the Federal and Ontario Notice of Assessments, Notice of Reassessments (if applicable), Statements of Adjustments, and any other correspondence with the CRA and Ministry of Finance regarding any tax items, or tax filing positions that may be in dispute, or under consideration or review, for tax years 2008 to 2010.

66. Ref: Exhibit 4/Tab 3/Sch 1
As per “Sch 13 Tax Reserves Bridge” and “Sch 13 Tax Reserves Test” of the PILs Income Taxes Workform there is an amount of $952,575 included as “Other Reserves” in both the bridge and test years.

a) As per the 2010 tax return, this amount may represent regulatory liabilities. Please confirm if this is the case. If this is not the case, please indicate what this amount represents.

b) As per EB-2008-0381, the Board accepted the Settlement Agreement for Issue #4. Complete Settlement for Issue #4 was reached as follows:

> “The Parties agree that regulatory assets should be excluded from PILs calculations both when they are created, and when they are collected, regardless of the actual tax treatment accorded those amounts.”

If the $952,575 amount represents regulatory liabilities, please update the PILs evidence to exclude this amount from Schedule 13 Taxes Reserves

Bridge and Test, all calculations of regulatory taxable income, and all PILs calculations.

Retail Transmission Service Rates

67. Ref: Exhibit 8/Sch 1/p. 13
Norfolk Power indicates that it estimated that 65% of the load previously delivered via Haldimand Hydro will now be routed through Norfolk Power's own transformer station, incurring Network and Line Connection charges from the IESO, but not Transformation Connection charges. The remaining 35% of previous Haldimand load will flow through a Hydro One transformer station, incurring Network, Line Connection and Transformation Connection charges. Please provide justification for using the 65% estimate.

Deferral and Variance Accounts

68. Ref: Exhibit 9/Tab 2/Sch 1
Regarding 2010 IRM – Group 1 Balances Cleared on an Interim Basis: In Norfolk Power's 2010 IRM Decision EB-2009-0238, the Board approved Norfolk Power's December 31, 2008 balances with carrying charges projected to April 30, 2010 on an interim basis.

The Board was concerned with differences between the amount sought for disposition, which had changed as a result of Norfolk Power conducting an extensive review and rebuild of its Group 1 accounts, and the balances reported in Norfolk Power's 2008 audited financial statements. On page 11 and 12 of the Decision, the Board stated:

> "The Board is concerned about the difference between the amount sought for disposition and the balances reported in Norfolk's audited financial statements. The Board notes that Norfolk indicated in its reply submission that it will have its 2008 audited financial statements restated to reflect the rebuilt account balances but that these are not yet available. As a result, the Board will approve the disposition of the December 31, 2008 balances and projected interest to April 30, 2010 as reported by Norfolk but not on a final basis. Any adjustment to the 2008 Group 1 account balances shall be brought forward to the Board in Norfolk's next rate proceeding. For accounting purposes, the respective balance in each of the Group 1 accounts shall be transferred to account 1595 as soon as possible but no later than June 30, 2010 so that the RRR data reported in the second quarter of 2010 reflect these adjustments."

In Norfolk Power's 2011 IRM Decision EB-2011-0049, the Group 1 Balances were not cleared as they did not exceed the preset disposition threshold. On page 7 of this Decision the Board stated:

"Norfolk's Group 1 account balances did not exceed the preset disposition threshold... The Board therefore finds that no disposition is required at this time."

a) Were there any adjustments made to the 2008 Group 1 account balances that were cleared on an interim basis, subsequent to the 2010 IRM decision EB-2009-0238?

b) If the answer to part a) of this question is yes, please explain and provide supporting evidence.

c) If the answer to part a) of this question is no, please provide a reconciliation between the December 31, 2008 Group 1 account balances that were cleared in 2010 IRM, and the restated December 31, 2008 Group 1 account balances that were audited by Norfolk Power's external auditor. Please explain any material differences.

69. Ref: Exhibit 9/Tab 2/Sch 1

a) Has Norfolk Power made any adjustments to deferral and variance account balances that were previously approved by the Board, subsequent to the balance sheet date that was cleared in the most recent rates proceeding? If yes, please provide explanations for the nature and amounts of the adjustments and include supporting documentation.

b) Regarding the net balances of Cost of Power for RSVA accounts:
   i. Please provide breakdown of energy sales revenue and cost of power expense, as reported in the audited financial statements for 2009 and 2010, by Uniform System of Accounts ("USoA") account number.
   ii. Please reconcile the balances to the audited financial statements.
   iii. If there is a difference between energy sales and cost of power, please explain why Norfolk Power is making a profit or loss on the commodity.

c) Regarding the accounting treatment of the IESO Charge Type 146.
   i. Does the applicant pro-rate IESO Charge Type 146 Global Adjustment into the RPP portion and non-RPP portion? If not, why not. If so, please provide the supporting spreadsheet for the year 2010 which prorates the IESO Charge Type 146 Global Adjustment into RPP portion and non-RPP portion.

   ii. Is the RPP portion included in Account 4705 control account and then incorporated into the variance reported in Account 1588 control account? If not, why not. If so, please provide journal entries for the month of December 2010 to record the RPP portion of global adjustment in Account 4705 control account and incorporated into the variance reported in Account 1588 control account.

iii. Is the non-RPP portion included in Account 4705 sub-account Global Adjustment and then incorporated into the variance reported in Account 1588 sub-account Global Adjustment? If not, why not. If so, please provide journal entries for the month of December 2010 to record the non-RPP portion of global adjustment in Account 4705 sub-account Global Adjustment and incorporated into variance reported in Account 1588 sub-account Global Adjustment.

iv. If any of part “i”, “ii”, or “iii” above is not followed, please make appropriate adjustments and file the updated evidence. Please provide explanations for the changes made by Norfolk Power, if any.

70. Ref: Exhibit 9/Tab 2/Sch 1/p.7
With regard to 2010 Account 1572 – Extraordinary Event Costs

a) Please provide information supporting the prudency of costs incurred associated with the procurement of external contractors – $140,831 of costs as reported in Exhibit 9/Appendix B, page 1. Please also provide the rationale for procuring most of the work from two contractors, K-Line Construction and Davey Tree Service, and provide support that they are “low-cost” contractors in comparison to competitors.

b) Please provide copies of all invoices for the $140,831 of costs included in Appendix B, page 3 – those costs incurred by procuring local LDCs and external contractors.

c) Please provide the method used to determine the level of incremental labour costs including the method for tracking overtime hours and labour rates.

d) Does Norfolk Power have a contingency plan for the provision of emergency response services? If so, please summarize the extent to which Norfolk Power followed its contingency plan. If Norfolk Power deviated in any material way from the plan, please identify the deviations and the reasons for those deviations. If not, please explain.

e) Does Norfolk Power have insurance coverage for storm damages? If so, please provide detailed evidence on the insurance coverage.

f) Please confirm that Norfolk Power is proposing to recover the storm damage costs over a one-year period through a separate rate rider.

g) Board staff notes that these costs have not been audited. Please provide reasons why the Board should depart from its general practice of only disposing of deferral and variance account balances that have been audited by an external auditor.

Smart Meters

71. Ref: Exhibit 9/Tab 5/Sch 1
Please confirm that the requested Smart Meter Rate Rider is $1.71 per month per metered customer and not $1.75 per month per metered customer, as shown on line 14 of page 1.

72. Ref: Exhibit 9/Tab 5/Sch 1
Please rerun and submit a revised version of the Smart Meter Model adjusting for the following two matters:

a) It appears the current (and recent models) calculate compounded interest on funding adder revenues. Please revise the model applying simple interest (i.e. interest on the opening monthly balance of the principal only) on funding adder revenues, and

b) Please revise the model to calculate simple interest expense on the opening monthly balance for OM&A and amortization expenses.

73. Ref: Exhibit 9/Tab 5/Sch 1
Please re-calculate the smart meter disposition rider using the following methodology that is based on the approach approved by the Board in PowerStream's 2010 smart meter application (EB-2010-0209):

a) Allocate the total revenue requirement for the historical years, as revised per the previous interrogatory, using the following cost allocation methodology:

- Allocate the return (deemed interest plus return on equity) and amortization based on the allocation of Account 1860 in the cost allocation model (CWMC in the cost allocation model)
- Allocate the OM&A based on the number of meters installed for each class
- Allocate PILs based on the revenue requirement allocated to each class before PILs

b) Sum the allocated amounts and calculate the percentages of costs allocated to customer rate classes.

c) Subtract the revenues generated from the smart meter funding adder from the overall revenue requirement.

d) Allocate the amount calculated in part (c) by using the allocation factors derived in part (b)

e) To calculate the smart meter disposition rider, divide the allocated amount by rate class derived in part (d) by the number of customers in each class, and then divide by 12.

f) If the proposed disposition period is greater than 1 year, divide the result of part (e) by the proposed number of years.

74. Ref: Exhibit 9/Tab 2/Sch 1/p.6

a) Please confirm that Norfolk Power's costs recorded in Account 1555 and Account 1556 are directly related to the smart meter program and are incremental costs. If this is not the case, please explain.

b) Please confirm Norfolk Power's costs recorded in Account 1555 and Account 1556 are in accordance with the Board's August 7, 2007 Decision in the combined proceeding regarding smart meters (EB-2007-0063) (the "Combined Smart Meter Proceeding"), Appendix A.

c) Do the costs recorded in Account 1555 meet the 14 categories of eligible capital cost components (Appendix A to the Board's August 7, 2007 Decision) listed below?

Advance Metering Communication Device (AMCD)
1. Smart Meter
2. Installation Cost
3. Workforce Automation

Advanced Metering Regional Collector (AMRC) (includes LAN)
4. Collectors
5. Repeaters
6. Installation

Advanced Metering Control Computer (AMCC)
7. Computer Hardware
8. Computer Software
9. Computer Software Licence & Installation

Wide Area Network (WAN)
10. Activation Fees

Other AMI Capital Costs related to Minimum Functionality
11. AMI Interface to CIS
12. Professional Fees
13. Integration
14. Program Management

d) Do the costs recorded in Account 1556 meet the certain OM&A expenses identified by the Board as eligible costs? These costs (Appendix A to the Board's August 7, 2007 Decision) are listed below.

AMCD Maintenance
AMRC/LAN Maintenance
AMCC Hardware and Software Maintenance
WAN
Other (Business Process Redesign/Customer Communication/Program Management/Change Management)

75. Ref: Exhibit 9/Tab 2/Sch 1/p.6

a) Please confirm that Norfolk Power does not include borrowing costs relating to money borrowed to finance smart meter installations, if any, as part of the Smart Meter Capital Account 1555 or Account 1556. Please identify, if any, which USoA account Norfolk Power uses to record the borrowing costs.

b) With regard to the Board's Guideline: "Smart Meter Funding and Cost Recovery" (G-2008-0002) (the "Guideline") issued on October 22, 2008, does Norfolk Power use its normal capitalization policy for smart meters? If this is not the case, please provide an explanation.

c) Is Norfolk Power recording Stranded Meter Costs in "Subaccount Stranded Meter Costs" of Account 1555, or fixed assets (i.e., Account 1860, Meters), or both? How does Norfolk Power ensure that the same stranded meter assets are not recorded in both Account 1555 and Account 1860 (i.e. avoid double counting)?

d) Are the stranded meter costs recorded in Account 1555 comprised of the gross costs of the stranded meters, less any capital contributions, less the accumulated depreciation and less any proceeds from the disposition of the meters?

76. Ref: Exhibit 9/Tab 7/Sch 1

Regarding Table 7.1, how was the Return on Rate Base amount of $12,542 derived?

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