MARITIME ELECTRIC
A FORTIS COMPANY

October 29, 2010

Mr. Mark Lanigan
Director, Technical & Regulatory Services
Island Regulatory and Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Mr. Lanigan:

Maritime Electric Company, Limited
2011 Capital Budget

Maritime Electric's responses to the interrogatories filed by the Island Regulatory and Appeals Commission are contained herein.

Yours truly,

MARITIME ELECTRIC

J. W. Geldert
Vice President, Finance & Administration
& Chief Financial Officer

JWG65
Enclosure

S-1 Please provide the Commission with an update on the discussions with the various government agencies related to the possibility of a third cable interconnection with New Brunswick.

Is there a date which can be identified that final decision will become public?

Please update the Commission on the status of the existing cable interconnections with NB Power – life expectancy, capacity constraints, maintenance inspection updates, etc.

Response:

S-1 Maritime Electric has been advised by the Province that their Confederation Bridge Cable Project submission has yet to be formally reviewed in terms of approval. The only response to date is feedback from federal government staff that the application fits well with the Green Infrastructure Fund criteria.

As the decision to proceed with the project is tied to the approval for funding from the federal government, it is not possible to identify project timelines at this time.

The cable interconnections with NB Power are now 33 years old. The expected service life for oil impregnated paper transmission cables is 40 years. In 2007, a diving inspection of the cables showed the cables were adequately buried. Oil impregnated transmission paper insulation deteriorates with time and elevated operating temperature. This is primarily due to the fact that moisture is produced by deterioration of the cellulose component of the insulation. The moisture, in turn, results in a general increase in dielectric losses. Insulation dissipation factor testing of oil-impregnated paper insulation is one of the most suitable, non-destructive, measurements to determine loss-of-life of the cable insulation. Insulation dissipation factor measurement for oil impregnated paper transmission cables is a useful tool to access the general condition of the high voltage insulation. However, since it measures the average dielectric losses of the entire length of the cable system, it may not detect localized problems. It is a tool to assess whether or not there has been generalized deterioration of the high voltage insulation. Insulation dissipation factor measurement results in June 2009 show that the dissipation factor of both cables has not changed substantially since the last test performed in September 1999. The absolute value of the Insulation Dissipation Factor Measurements for all three phases for both cables is within acceptable limits for oil impregnated paper transmission cables. The results show that the general condition of the insulation for these cables is stable under the current operating conditions. The stable dissipation factor reflects diligent management of the cables. Maritime Electric restricts each cable to no more than 100 MW. The total capacity is 200 MW for the two cables compared to the Island peak of 222 MW. On-Island generation provides cable relief during the peak loading times. A cable overload scheme also protects one cable during a sudden loss of the other cable.

As well, a sample of one cable was tested in 1998 resulting from the 1997 incident when a potato shipping vessel severed one cable. A section of damaged cable had to be replaced and a sample was tested. Test results for the sample showed virtually no degradation.

S-2 Please provide further details on the G-1 Charlottetown Plant Buildings and Services Projects ($299,000), G-2 Charlottetown Plant Boiler Projects ($470,000) and G-3 Charlottetown Plant Turbine – Generator Projects ($364,000). What projects are planned, what is the cost per project and what are the consequences of delaying this expenditure? For projects specifically identified please provide an assessment of the consequences of delaying these projects.

Response:

S-2 See the following Tables G-1 Charlottetown Plant Buildings and Services Projects, G-2 Charlottetown Plant Boiler Projects, and G-3 Charlottetown Plant Turbine – Generator Projects.

The Company's generating assets have an approximate net book value of $76.8 million at December 31, 2009 with a wide range of aged equipment. Some equipment is relatively new such as CT3 while a large percentage is aged. Maintaining this equipment such that it can be placed in to service when required is one of the department's primary responsibilities. The 2011 Capital Budget contains a myriad of projects, each addressing a specific need. Management believes that while any one or more of the projects could be deferred, the larger objective is to establish and maintain a sustainable annual program such that expenditures are predictable and manageable. An extreme alternative would be to adopt a reactionary approach and address equipment concerns on a more immediate basis, acting only for critical issues. This approach could result in initial savings, however, the trade off would be in reliability, over time; with aged infrastructure it is difficult to exact "just in time" remedies.

Management has sought, through the Capital Budget process, to find an annual program spending level that balances electricity rate impacts with maintaining a high level of service reliability.

G-1 Charlottetown Plant Buildings and Services Projects	$	Description	Consequence of delaying
G1-CTGS-Parts Storage Improvement	$ 12,100	Improvement to warehousing space within the steam plant.	Could impact on the ability to protect spare parts from damage due to humidity. This project could be deferred a year.
G1-CTGS-Door & Window Replacement	$ 25,100	This project is to replace a certain number of our doors and windows on a yearly basis based on priority.	To ensure security of the building and public safety this project should not be deferred.
G1-CTGS-'Misc Process Pipeline Replacements	$ 25,100	Replacement of corroded process piping.	Could impact on the availability of generation.
G1-CTGS-Emergency Lighting	$ 6,000	Replacement of emergency lighting infrastructure.	Safety issue for employees working in the plant during power outages.
G1-CTGS-Lighting Improvements	$ 12,500	Improvements to lighting throughout the steam plant.	Safety issue for employees working in the plant during normal situations.
G1-CTGS-Safety Equipment	$ 12,500	This project is allocated to replace safety equipment which must be replaced due to damage/deterioration and to purchase new equipment where required	This project should not be deferred as safety should not be compromised.
G1-CTGS-Boiler No.9 Area Heating System Replacement	$ 100,300	A piece of equipment associated with the heating system in the Boiler No. 9 area of the building has suffered from corrosion over the years and replacement is required. Without replacement of this heating system, fire protection, city water and auxiliary cooling water lines are subject to potential freezing and pipe damage.	A failure of this heater could cause the boiler superheater and waterwall tubes in Boilers 9 & 10 to freeze causing significant damage and cost.
G1-CTGS-Sump Pump Replacements	$ 50,400	The sump pumps located in the Charlottetown Plant pump all air heater water, hydrazine treated boiler water, cooling water, to the wastewater treatment plant. This water can be acidic and shorten the life of sump pumps. This amount provides for the replacement of three sump pumps located at the Charlottetown Plant.	These sump pumps are over 15 years old each and are exposed to extremely aggressive chemicals. Should one of these pumps fail we could flood out electrical equipment and incur significant costs.
G1-CTGS-Asphalt Paving CT3 Foundation and Road Behind Shop	$ 25,000	The asphalt paving around the CT3 foundations was completed in 2010. Paving of roadway behind the Mech. Maintenance Shop is included in this project.	This project could be deferred a year.
G1-ECC-Interior Renovations	$ 21,300	Renovations to Control Room and Office Space inside the Energy Control Center.	This project could be deferred a year.
G1-ECC-Backup Control Center	$ 8,700	Renovations to Control Room at the Backup Energy Control Center.	This project could be deferred a year.
Total	**$ 299,000**		

G-2 Charlottetown Plant Boiler Projects	$	Description	Consequence of delaying
G2-BG-Misc. Shop Tool Replacement	$ 24,500	Replacement and purchase of new shop tools.	Deferral of this project means that tools that fail or become damaged will not be replaced. This could impact on ability to repair equipment.
G2-BG-Misc. Elec/Inst Tool Replacement	$ 9,800	Replacement and purchase of new tools for the Electrical Shop.	Deferral of this project means that tools that fail or become damaged will not be replaced. This could impact on ability to repair equipment.
G2-BG-Secondary Containment	$ 3,300	Installation of spill trays and containment curbs for environmental protection.	This project could be deferred one year.
G2-BG-Large Motor Refurbishment	$ 9,800	Each year we budget for the refurbishment of 1 to 2 of our large electric motors on a priority basis.	This project should not be deferred as will impact on availability of generation.
G2-BG-Misc. Boiler Improvements	$ 65,400	This project is a contingency for the boilermaker repair work that is uncovered each year after the annual Boiler & Pressure Vessel inspections are completed each Spring.	This project should not be deferred as will impact on availability of generation.
G2-BG-Boiler Insulation Replacement Improvements	$ 41,000	This project is for the upgrade to non-asbestos insulation as damage is encountered with asbestos insulated equipment.	This project should not be deferred due to the health of the workers in the plant.
G2-BG-Replace No.10 Instrument Air Compressor	$ 57,200	The instrument air compressor associated with Turbine No. 10 has outlived its useful life and requires replacement. In the present configuration Turbines No. 9 and No. 10 each have an instrument air compressor, which can also serve as a backup to the remaining unit. The failure of an instrument air compressor means the loss of redundancy and the loss of protection and control of unit No. 10.	This air compressor has over 100,000 hours on it which is near the end of its useful life. If it is not replaced we run the risk of losing the instrument air for Unit #10 which will impact on availability of the generation.
G2-BG-Upgrade of Plant Heating Piping System	$ 163,500	In 1997, Boiler No. 2 was installed to reduce the inefficient use of power boilers for plant heating purposes. The existing piping systems on site at the time were re-used as much as possible to reduce construction costs. This project will see enhanced efficiency gains by establishing an independent piping system for the return of plant heating water. At today's fuel prices, efficiency gains of $31,000/year could be realized resulting in a payback of approximately 5 years.	This project includes changes that will result in energy savings and therefore this project should not be deferred.
G2-WTS-Plant Waste Handling Improvements	$ 24,700	Project to cover costs to eliminate the use of tipping dumpsters to move sludge from filter press to holding tanks. Sludge press will be installed at higher elevation such that final holding tank can be slid directly beneath the sludge press.	This project could be deferred one year.
G2-WTS-Wastewater Compliance Study	$ 49,100	This study will review the Canadian Council of Ministers of the Environment (CCME) Marine Guidelines & Dilution Factors as they relate to waste streams. The plan is to examine the Company's current waste streams to determine what may be improved in wastewater treatment processes to meet all CCME guidelines. The study is needed to ensure compliance with all applicable guidelines and that the wastewater system will continue to meet the Charlottetown Plant operating requirements.	This project is proactive in nature and could be deferred one year provided legislation does not change.
G2-B9-Replacement of Electronic Instruments on Boilers No.9 & No.1	$ 21,700	This project is to replace electronic instruments which are obsolete with new units which parts are available.	Failure of one of these obsolete units could result in significant downtime on generation.
Total	**$ 470,000**		

G-3 Charlottetown Plant Turbine-Generator Projects	$	Description	Consequence of delaying
G3-TGG-Turbine Insulation Replacement Improvements	$ 50,300	This project is for the upgrade to non-asbestos insulation as damage is encountered with asbestos insulated equipment.	This project should not be deferred due to the health of the workers in the plant.
G3-TGG-Misc. Steam Turbine Upgrades	$ 50,800	This project allots money for any unanticipated capital expenditures required for the plant's steam turbines.	This project should not be deferred as the capital expenditure required could impact on the availability of the generation.
G3-TG9-Turbine No.9 Condenser Water System Upgrades	$ 51,000	Corrosion associated with the equipment that cools the steam in Turbine No. 9 has become an issue requiring attention. This project covers the refurbishment of this equipment to ensure its continued reliability and availability. Without this upgrade, inefficiencies in the cooling water process will escalate and corrosion will ultimately result in the loss of condensation for turbine No. 9 and a reduction in generation capability.	Failure to proceed with this project threatens the availability of #9 Turbine.
G3-CT3-Misc. Combustion Turbine Improvements	$ 50,800	This project allots money for any unanticipated capital expenditures required for the Charlottetown CT3 combustion turbine.	This project should not be deferred as the capital expenditure required could impact on the availability of the generation.
G3-CT3-CT3 Water Treatment Plant Upgrades	$ 161,100	According to the original equipment manufacturer a portion of the Water Treatment Plant requires an upgrade in order to ensure continued reliability of this Plant. This project allows for this upgrade. The upgrade consists of replacing the reverse osmosis membranes which require a 3 to 5 year replacement cycle. 2011 will mark the 6th year that the membranes have been in service. Without properly functioning membranes, impure water could be injected in CT3 resulting in premature loss of life of the unit.	The RO membranes are at the end of their useful life and require replacement. The RO-EDI water treatment plant is required in order to maintain operation of the 50MW CT3 turbine. This project should not be deferred.
Total	**$ 364,000**		

S-3 Please update the Commission on the role of both the Charlottetown plants and the Borden plant within the Company's energy supply system. Taking into consideration the limited Company use of these facilities, what is the business case which supports the continued use of these facilities in their current role? Will this role change if an investment is made in a third cable interconnection with New Brunswick? What is the business case that supports these changed roles?

Please identify what Maritime Electric considers the main benefits of the proposed third cable interconnection and the implications on existing Maritime Electric operations.

Response:

S-3 Maritime Electric maintains a generation fleet as follows:

Station	Location	Unit	MW	Fuel	Generation Type
CTGS*	Charlottetown	10	20	Bunker C	Steam
CTGS	Charlottetown	9	20	Bunker C	Steam
CTGS	Charlottetown	8	10	Bunker C	Steam
CTGS	Charlottetown	7	7.5	Bunker C	Steam
CTGS	Charlottetown	6	7.5	Bunker C	Steam
BGS**	Borden	CT1	15	Diesel	Combustion Turbine
BGS	Borden	CT2	25	Diesel	Combustion Turbine
50 MW CT	Charlottetown	CT3	50	Diesel	Combustion Turbine

* Charlottetown Thermal Generating Station. Nameplate capacity is 65 MW net capacity of 60 MW.
** Borden Generating Station

Prior to the installation of the electrical interconnection (the two 138 kV submarine cables) with NB Power in 1977, Maritime Electric's generation fleet (other than CT3 which was commissioned in 2005) was used exclusively to provide all the energy requirements for the Company's load, as well as all ancillary services. Ancillary services included spinning and non-spinning reserve, black start capability, regulation, load following and capacity.

After the installation of the submarine cables the role of the Maritime Electric generation fleet changed drastically from one of being an all inclusive provider to one of standby and a provider of ancillary services.

Maritime Electric's generation fleet currently provides backup for the existing submarine cables, a backstop or ceiling for energy prices during times of curtailment from NB Power, a source of capacity for Secure and Assured Energy purchases through the Company's Energy Purchase Agreement (EPA) with NB Power, a source of non-spinning reserve for reliability purposes, black start capability, cable loading management, operational flexibility during times of local transmission outages or limitations, and voltage control during peak load times. A more detailed description of these benefits follows:

- For cable loading management. The total capacity of the two submarine cables linking the PEI transmission system to the NB transmission system is 200 MW; however the peak load for PEI has exceeded 220 MW. During periods when the load is above 200 MW, on-Island generation is required to ensure the submarine cables do not become overloaded. The installation of a third cable will negate this role however until such time the cable is installed and operational on-Island generation must be maintained and functional for cable loading management.
- For contingency planning such as back up of off Island energy purchases in the event of a submarine cable failure similar to the incident that occurred in December 1997. During that 26 day outage the Charlottetown Plant generators provided the majority of replacement energy supply with the Borden generators being used for peaking. This submarine cable outage also occurred during the Company's peak load period. Again, with the addition of a third cable the need for on-Island generation for cable contingencies is reduced.
- For contingency planning for off-Island transmission failures. If one or both of the 138 kV transmission lines in New Brunswick supplying PEI were to fail, on-Island generation would be required to service load in PEI.
- On-Island generation provides a price cap in the event of off-Island supply curtailments.
- Operational flexibility during times of local transmission outage or limitations. An outage in the West Royalty Substation would necessitate the need for on-Island generation east of West Royalty in order to continue to provide service to all of Charlottetown and Eastern PEI.

- Voltage control during peak load times. During peak periods in PEI and in New Brunswick, additional voltage support is required on-Island to maintain acceptable voltage levels and this is provided from Maritime Electric's generation fleet.
- The Company's combustion turbines are a source of black start capability.
- As a source of ancillary services. In addition to an electric utility being required to meet its load requirements, utilities must have enough quick start standby generation (Operating Reserve) to accommodate 100% of the loss of the largest generator on the system and 50% of the loss of the second largest generator on the system. In the Maritime Area (New Brunswick, Northern Maine and PEI) the two largest generators are located in New Brunswick and this standby requirement is shared on a load ratio basis amongst the three entities.
- As a source of capacity for energy purchases. All energy purchases must be backstopped with capacity. The Company's generation fleet contributes to lowering the cost of purchased energy every day as a capacity credit.

The annual estimated cost avoidance for ancillary services and capacity supplied by the Maritime Electric generation fleet equates to $4.7 million per year. The benefits of cable loading management, off-Island contingency planning, cable contingency planning, on-Island contingency planning, operational flexibility during local transmission outages, transmission element planning, voltage control, black start capability and price cap during periods of economic curtailment are not factored into the $4.7 million but are all added benefits to Maritime Electric's customers.

The existing electrical interconnection between the Maritime Electric and New Brunswick Power electrical systems consists of two 100 MW 138 kV submarine cables that were installed in 1977. These cables had an initial life of approximately 30 years. These cables have been installed for over 30 years now and recent insulation and dissipation testing have indicated that the cables are in excellent condition and should continue to provide many more years of dependable service.

The on-Island peak load has grown to beyond the 200 MW capability of the submarine cables and as such without on-Island generation, load would have to be shed in order to prevent the existing submarine cables from becoming overloaded. Each year of load growth results in a higher level of required generation of a greater duration. The cost of on-Island generation far exceeds that of the current electricity purchase opportunities off-Island.

Without a third cable, on-Island generation would have to be expanded with the potential addition of another 50 MW combustion turbine in order to meet load growth and cable contingency planning requirements. As well, the generation facilities of the Charlottetown Thermal Generating Station (CTGS) would have to have an infusion of capital expenditures to ensure that the units are functional and meet reliability and safety standards for the next 15 years.

The installation of the third cable interconnection would allow for the retirement of facilities at the CTGS at a much earlier date than if the interconnection did not go ahead.

Good utility practice would also dictate that a utility not depend 100% on equipment or facilities that are beyond their initial service lives. Additional intertie capability should be installed to lessen the dependence of the existing submarine cables.

In order to realize the Province's 10 Point Plan for renewable on-Island generation, much of that renewable energy is for export and the existing submarine cables are limited in how much can be exported. That limit is approximately 300 MW of on-Island renewable generation. In order to meet the 10 Point Plan target of 500 MW, an additional 200 MW of interconnection capacity must be installed.

S-4 The PEI Seniors Federation has provided the Commission with comments (see Appendix A) concerning this budget application. Please provide the Commission with a response to the issues identified in the Seniors Federation filing.

Response:

S-4 See Appendix A.

S-5 What is the budget breakdown between the various categories included in the request for D-1 Replacements due to Storms, Collision, Fire and Road Alterations ($1,091,000)?

Response:

S-5 The budget provision does not distinguish between the various categories of storms, collisions, fire and road alterations. The provisional amount set out in D-1 is to allocate a reasonable budget for labour, material and other costs to be incurred in 2011 for all of the categories based on historical annual costs that exclude damage from extraordinary weather events and reflect more traditional levels of Government road widening activity.

S-6 Please provide the unit cost price changes in the last five (5) years for pole and pad mounted transformers. How many transformers were replaced in each of those years?

Response:

S-6

Transformers Purchased	Year	Unit $/KVA	Unit Change From Previous Year
Pole top	2004	42.57	
	2005	47.31	111%
	2006	57.29	121%
	2007	72.48	127%
	2008	69.46	96%
	2009	69.72	100%
Padmount	2004	28.06	
	2005	19.55	70%
	2006	27.62	141%
	2007	38.43	139%
	2008	41.70	109%
	2009	33.60	81%

Transformers Installed	Year	Number of Units
Pole top	2004	1725
	2005	1519
	2006	1549
	2007	1996
	2008	1824
	2009	1680
Padmount	2004	39
	2005	40
	2006	67
	2007	41
	2008	39
	2009	46

S-7 For aged service lines to be replaced under budget item D-3 Services and Street Lighting ($3,425,000) please provide reliability and service interruption statics which support replacement expenditures.

Response:

S-7 Besides the installation of service infrastructure for new customers added to the system customer service infrastructure is replaced under the following circumstances:

i) upon routine inspection, or as part of a formal inspection program (such as the Field Assessment Program in 2009, the Company's Spill Inspection Program or as part of a formal inspection following a severe storm) aged poles and/or service lines may be designated as being either a current or potential safety and/or reliability issue and is replaced;

ii) the service requirements for a customer location changes (e.g. change from single phase service to 3 phase service, requirement for increased voltage, etc.) requiring, depending on the circumstances, replacement of one or more of secondary conductor, transformers, meter and pole(s);

iii) upon responding to a service call or outage call initiated by the customer, Maritime Electric determines that the condition of one or more service line conductor, poles, or transformer represents a current or potential safety issue or equipment is damaged or deteriorated to a point where customer reliability is an issue; and

iv) when undertaking a distribution line rebuild service lines (which very often reflects the age of the distribution line being replaced) are inspected by the Company, and if any, or all, of these infrastructure items represent a current or potential reliability and/or safety concern they are replaced as a part of the rebuild process.

Maritime Electric's reliability database does not specifically track service line interruptions. The Company's customer outage system, from which reliability data is based upon, recognizes outages only at the transformer level.

S-8 Please provide Company policy for the amount of customer contribution associated with line extensions (D-4). What value to customers can be associated with closing the gaps in the distribution system on the MacIsaac Road in West Prince and on Route 12?

Response:

S-8 Customer contributions for extensions of standard facilities are the sum of all charges related to the extension less the standard facility credit. The Standard Facility allowance is 90 meters for Residential, General Service and Small Industrial rate categories and includes required transformation and metering for single or three phase service. Contributions for Large Industrial customers may depend on whether service is provided at transmission or distribution level. Contributions are required to be paid in advance. Customers are entitled to refunds if additional development takes place within five years.

Closing the 1.3 km gap between Line WL2071 and Line WL3500 on the MacIsaac Road will improve reliability by providing an alternative loop feed for customers in the area and will reduce line losses by an estimated 42 kW or $420,000 over the life of the line. Similarly, closing the 1.5 km gap between Line OL927 and Line OL918 on Route 12 will improve reliability by providing an alternative loop feed for customers in the area and will reduce losses by an estimated 44 kW or $440,000 over the life of the line.

S-9 Please provide further details concerning the line rebuilds (single and three phase) planned for 2011. What is the age of the planned line rebuilds? What are the recent reliability statistics?

Response:

S-9 The table below summarizes the information requested.

Response S-9: Planned Rebuilds in 2011

Rebuild	Line #	km	# of phases	Approximate Age	Comments	2010 YTD Customers Hrs.	2009 Customers Hrs.	2008 Customers Hrs.	2007 Customers Hrs.	2006 Customers Hrs.	2005 Customers Hrs.
Bedford Irving to Linden Road	2R01706	6km	3	late 1950s	# 2 ACSR & 1950's vintage Eastern Cedar Poles both in poor condition. Distrbution Line feeds 302 customers, 11 sub - lines and parts of 5 communities.	0	0	0	0	0	80
North River to Belvedere	IK03440	0.7km	3	mid 1960s	Section of smaller conductor (2/0) which creates a weak link when transfering or backing up feeds. Tthis is an alternate feed source for downtown circuits.	0	0	0	0	0	0
Euston St. to Belvedere	QA02799	1.7km	3	early to mid 1950s	Consists of #4 and 2/0 solid copper conductor. Poles are 1950's vintage. Both poles and wire in very poor condition. Future plan is for this feeder to become an alternate feed source for downtown ccts.	0	1341	0	0	0	0
Graham's Rd.	RT01072	5.4km	1	late 1950s	# 4 ACSR conductor & 1950's vintage Eastern Cedar Poles. Both poles & wire in poor condition. Distribution Line feeds 116 customers, 5 sub-lines and parts of 4 communities.	0	258	0	0	175	0
University Ave.	UA03209	0.7km	3	mid 1960s	Section of smaller conductor (2/0) which creates a weak link when transfering feeds. This is an alternate feed source for downtown circuits.	0	0	0	0	0	0
Lower Newtown	VC01412	9km	3	late 1950s	A mix of # 4 & #2 ACSR conductor as well as 1950's vintage Eastern Cedar poles. Poles & wire in poor condition. Districbution Line feeds 810 customers, 43 sub-lines and parts of 10 communities.	0	861	0	0	2773	0
(Rt. 11 and 124)	WL02066	9km	3	early to mid 1960s	2/0 ACSR & 1960's vintage Eastern Cedar poles, both in poor condition. Distribution Line feeds 630 customers, 32 sub - lines and parts of 9 communities.	1061	947	0	100	0	958

S-10 What is the approximate age of the pole for pole replacements ($700,000) planned? The plan calls for 200 less pole for pole replacements, why? What implications will this have on reliability statistics?

Response:

S-10 Individual poles are replaced when they are deemed not to meet an acceptable utility standard for reliability or safety. Poles are identified for replacement through the process of upgrading transformer services, through visual inspection programs such as the Field Assessment Program or Spill Prevention Program or as a result of a customer service visit. Untreated cedar poles represent the vast majority of pole for pole replacements and these poles have an estimated age in the range of 35 – 45 years.

Since 2006 the Company has proposed, in its budget applications, the pole for pole replacement of between 700 to 900 poles annually. The proposed 700 poles proposed for replacement in 2011 is at the lower end of this range but the Company is cognizant of the need to rationalize overall capital spending requirements and, among other considerations, in 2011 other budgeting provisions were increased in the Distribution section of the evidence including (D-3) Services and Street Lighting and (D-1) Replacement Due to Storms, Collisions, Fire and Road Alterations.

It is a fundamental objective of the Company, in evaluating its annual capital spending requirements (both from an overall, and, by an individual category perspective) to ensure generation, transmission and distribution infrastructure is maintained at a standard so as to meet or exceed reliability benchmarks set by the Commission through the Key Performance Indicator (KPI) process. To this extent, the Company is satisfied that the proposed capital expenditures in the Distribution section of the application proposed for 2011 in each category, including the 700 pole for pole replacement provision, is in the aggregate, an appropriate level of capital spending towards ensuring the distribution infrastructure is maintained at an acceptable standard to meet or exceed the reliability targets.

S-11 How many porcelain cutouts will be replaced in 2011 and how many are in the system? What was the original life expectancy of these cutouts and how many years have they lasted?

Response:

S-11 Approximately 1,250 porcelain cutouts are planned to be replaced with synthetic polymer cutouts in 2011 through the Porcelain Cutout Replacement Program. The Company is targeting specific areas, under the Program, where porcelain cutout failures are occurring more frequently. Another approximate 1,250 cutouts will be changed out through annual transformer replacement activity. There are approximately 27,500 cutouts in the system of which approximately 18,500 are porcelain and 9,000 are synthetic polymer.

Life expectancy can vary for porcelain cutouts depending on the environmental factors under which they operate including winter temperature fluctuations, cold temperature extremes and salt and dirt contamination, as these are key factors in premature failure. PEI's environment is considered to be challenging with respect to all of these factors. In particular, northern climates like PEI's subject porcelain cutouts to go through a "freeze thaw" cycle which can lead to the development of hairline cracks which are then subject to mechanical forces when opening, closing and refusing these porcelain cutouts. All of the Atlantic Province's electric utilities have experienced premature failures with porcelain cutouts and have stopped purchasing them in favor of polymer synthetic cutouts. Maritime Electric has experienced an average of 30 porcelain cutout failures per month over the past 5 years and often these failures result in pole fires. Suppliers of cutouts estimate life expectancies in the 40 year range however, Maritime Electric is experiencing failures in cutouts that are only a few years old.

S-12 What savings per year can be identified with the 10,500 RI meters installed? Has Maritime Electric considered electronic billing in an effort to further reduce billing costs?

Response:

S-12 By the end of 2012 the Company plans to complete the installation of approximately 66,000 single phase Remote Interrogation (RI) meters (or roughly 93% of all Company meters). Approximately 10,500 RI meters will need to be installed in each of 2011 and 2012 for this to be accomplished.

The conversion from electro mechanical meters to RI digital meters will result in several significant benefits including:

i) Reduced Meter Reader Costs – RI meters are interrogated by drive-by devices which eliminates the need for a meter reader to read each electro mechanical meter individually and manually enter a reading. This will significantly reduce meter reader labour and related transportation costs;

ii) Improvement in Customer Service – Remote Interrogation allows the Company to efficiently read all RI meters monthly thus eliminating the estimate process currently used every second month for electro mechanical meters. Because RI meters are read electronically, meter reader input errors are also eliminated. These two factors will result in more consistent and accurate billings on a monthly basis and increased customer satisfaction;

iii) Improved Meter Reader Security – The ability to read meters without entering a customer's property will reduce the frequency of the need for meter readers to enter properties where threats exist (hostile customer, dogs, etc.); and

iv) Improved Meter Security – The digital RI meters being utilized by the Company have enhanced "tamper" security features versus the electro mechanical meters, reducing the probability of electricity theft.

The financial benefits to the Company, and its rate payers, with respect to the conversion of electro mechanical meters to RI digital meters are significant. When the conversion to RI meters began in 2004 the Company had 12 full time meter readers. The Company's Plan was, and remains, the elimination of 8 of those 12 meter reading positions (or 67% of the full time meter reading staff) upon the completion of all single phase RI meters at the end of 2012. In 2011, with the installation of approximately 68% of all single phase RI meters completed, the full time meter reading staff will be reduced by one more position resulting in 5 of the 8 positions targeted for elimination (or 63%) actually eliminated. The Company has been successful to date in managing the reduction in positions through redeployment and attrition.

The Company has had an electronic billing option available for customers since late 2006. Only 1.3% or 922 customers currently use the Company's paperless billing/electronic billing option. Another 2.7% or 1,935 customers use Canada Post's on-line electronic billing service (Maritime Electric provides Canada Post with subscribed customers' electronic billing information and Maritime Electric customers then utilize the Canada Post – hosted website to view their electronic bill).

The Company is evaluating options to encourage more customers to utilize electronic/paperless billing which would facilitate lower costs of processing customer bills for the Company, as well as, making a contribution to the environment by reducing waste.

S-13 Please provide a detail list of the system equipment planned for replacement ($1,289,000) and the implications for delaying these expenditures.

Please provide an estimate of each item that will be purchased for the indicated costs.

Response:

S-13 The following is a detailed items and cost estimate for 2011 system equipment:

SYSTEM EQUIPMENT	MATERIAL	LABOUR	TOTAL
Voltage Regulators, Reclosers and Controllers	**$ 302,000**	**$ 174,000**	**$ 476,000**
Electronic Reclosers	$ 46,000		
Recloser Controllers to Replace Obsolete FXB Controllers	$ 42,000		
Six (6) Voltage Regulator Controllers to Replace Aging Units	$ 20,000		
Six (6) Voltage Regulators Replacements to replace Aging Units	$ 122,000		
Three (3) 437A Regulators for New Annan Substation Rebuild	$ 61,000		
Voltage Regulator and Recloser Parts	$ 11,000		
Circuit Breakers and Power Transformer Upgrades	**$ 142,000**	**$ 82,000**	**$ 224,000**
Power Transformer Refurbishment Parts	$ 25,000		
Transformer Oil	$ 31,000		
69 KV and 138 KV Breaker Contracts	$ 25,000		
Annual Dissolved Gas Analysis	$ 21,000		
Tap Changer Contacts for Auto Transformer	$ 25,000		
Transformer Monitoring System	$ 15,000		
Teleprotection and Relay Replacement	**$ 183,000**	**$ 105,000**	**$ 288,000**
Backup Digital Protection Relays	$ 10,000		
Teleprotection Equipment	$ 23,000		
Fourteen (14) Digital Relay (Replacement for Aged Electromechanical Relays)	$ 150,000		

SYSTEM EQUIPMENT (Cont'd)	MATERIAL	LABOUR	TOTAL
Communication Equipment	**$ 69,000**	**$ 40,000**	**$ 109,000**
Aging Battery Bank Replacement Program	$ 20,000		
Mobile and Portable Radio Parts	$ 5,000		
RTU Replacement Interruptible Customers RTU	$ 16,000		
SCADA RTU Retrofits/Parts	$ 25,000		
Vehicle Radio Antennae and RF Meters Antennae	$ 3,000		
Distribution Switches	**$ 84,000**	**$ 49,000**	**$ 133,000**
Recloser Bypass Switches	$ 18,000		
13.8 KV City Circuit Switches	$ 36,000		
Voltage Regulator Bypass Switches	$ 30,000		
Test Equipment	**$ 38,000**	**$ 21,000**	**$ 59,000**
Submarine Cable Locator	$ 31,000		
Software for Management of Database for High Voltage Test Equipment	$ 7,000		
			$1,289,000

The ongoing investment in rebuilding and strengthening the transmission and distribution system is central to providing reliable service to customers. The system equipment expenditures proposed are required to meet customer growth, address projected overload conditions and to replace aging assets. Delaying these expenditures would decrease reliability to customers.

S-14 What are Company plans for vehicles replaced?

Response:

S-14 Vehicle 060632 will be assigned to the Charlottetown Plant and the existing 11 year old Charlottetown Plant vehicle will be retired from the fleet and disposed of as surplus equipment.

Vehicle 050639 will be retired from the fleet and disposed of as surplus equipment.

Vehicle 060447 will be retired from the fleet and disposed of as surplus equipment.

Vehicle 011262 will be used as a spare unit and eventually be retired from the fleet and disposed of as surplus equipment.

Vehicle 981265 will be retired from the fleet and disposed of as surplus equipment.

Vehicle 011266 will have a new chassis and the existing boom and fiberglass body will be refurbished. The original chassis will be disposed of as surplus equipment.

S-15 What is the anticipated customer take up of payments by kiosk system? What other options currently exist for customer payments? Please provide a summary of approximately how many customers use each of the payment options. Will the kiosk system affect other businesses?

Response:

S-15 An evaluation of a Kiosk payment system is proposed to be conducted in 2011 and, if determined to have feasibility, a test pilot would be conducted.

A Kiosk payment system will be evaluated to determine:

i) The cost of processing payments through a Kiosk system (versus the cost of other options);

ii) It's potential to improve customer service by adding a further payment option for customers;

iii) What customer base would potentially use, and benefit from, a Kiosk payment system;

iv) What potential exists, by introducing a Kiosk system, to reduce the volume of cheques received by mail and walk-in payments at the Company's payment location at 180 Kent Street (the most cost intensive options under which the Company processes payments); and

v) What payment options might be abandoned by customers in favor of a Kiosk system and the relative cost shifting amongst the various payment options.

The current payment options available to our customers and the percentage of customers using these options are as follows:

Payment Option	% Utilized
Payments processed through Financial Institutions (internet, telephone, walk-in and ATM)	55
Company Pre-Authorization Payment Plan	19
Company "CAPS" Sites	6
Company "Walk-in" Payment Center – 180 Kent Street	12
Cheques Mailed to the Company	8

S-16 During the ice storm of 2008, the Company informed the Commission that some metal supports on poles failed prematurely. Have these supports, used in other parts of the PEI transmission system, been replaced?

Response:

S-16 During the severe 2008 ice storm a number of insulator brackets (manufactured by Hughes Brothers) buckled under the extreme ice loading on the T-5 transmission line between Sherbrooke and Wellington where ice loading from the storm was heaviest. The Company examined this incident as part of the post-storm review and determined that insulators used with 477 conductor could be ideally supported with brackets that could withstand an increased level of loading before the insulators themselves failed. The Company made the decision that where 477 conductor was utilized that 12 inch Hughes brackets would be replaced with a new one piece insulator/insulator bracket (which was approved internally and received into inventory in October 2009) and that these 18 inch Hughes brackets would be strengthened by applying a sandwich bracket that was designed, tested and approved internally.

The Company has been successful in replacing/reinforcing brackets to date as follows:

- All applicable brackets in Kings County are complete.
- All applicable brackets in Queens County are complete.
- In Prince County:
  - i) Sherbrooke substation to St. Eleanors substation is complete.
  - ii) St. Eleanors substation to Wellington substation - all but 31 structures with 12 inch brackets remain to be replaced and these will be completed by end of 2010. All 18 inch bracket reinforcements now complete.
  - iii) Wellington substation to O'Leary substation there are 80 structures with 12 inch brackets left to be replaced and 260 structures with 18 inch brackets left to be reinforced.

Recognizing that the failure of these brackets requires extraordinary ice loading and that the failure of the brackets themselves does not cause an outage the

Company is balancing the allocation of “hot line” crew resources (as this work must be done by qualified Power Line Technicians using “hotline” techniques on radial transmission lines while the line is energized) against the needs of these resources for other work in the system. Planned outages, when radial transmission lines are de-energized, have represented a more opportune time to perform the bracket replacement/reinforcement work more safely and efficiently and the next planned outage on the Wellington to O’Leary substation section will not be until 2011 so the Company anticipates that this final section of transmission line will be completed by the end of 2011.

S-17 Please provide a general status report on the transmission system including age of lines, condition, planned upgrades in next 5 years.

<u>Response</u>:

S-17 Maritime Electric's 138 kV transmission lines are routinely inspected by climbing the supporting structures and periodically inspected via a helicopter using an Infrared Radar system. This preventative maintenance technique is used to identify trouble spots which are repaired before a failure occurs. Two parallel lines link the submarine cables to the Maritime Electric system at the Bedeque switching station. Built in the 1970s these lines have operated reliably, however, inspections revealed pole and crossarm deterioration to the extent that the lines were substantially refurbished in 2003. To facilitate this work, additional switches were installed at Richmond Cove to enable the paralleling of both cables to allow for necessary line work without an outage to Maritime Electric customers. This added flexibility also improves reliability. These two parallel lines are owned by the Government of PEI and the refurbishment of these lines was paid for with funds from the Cable Contingency Fund.

As was the case with the interconnection transmission lines, the 174 km Maritime Electric 138 kV transmission system is routinely inspected. Much of this transmission infrastructure, which was built in the 1970s and 1980s, also had extensive pole and crossarm deterioration that show up during routine inspection and these lines have since been refurbished. Other 138 kV transmission lines constructed in the 1980's and 1990's show no signs of significant deterioration.

Maritime Electric's 69 kV transmission lines are routinely inspected and are also periodically inspected via a helicopter using an Infrared Radar system. Most of the 69 kV lines were originally built in the 1950s and 1960s. The 69 kV Transmission System consists of 356 km of transmission lines of which approximately three-quarters are radial lines. Rebuilding activities have been focused on these radial lines, which are being relocated from cross-country routes to along main roadways to improve access and response time. During the next five years, Maritime Electric will continue to rebuild a 9 km stretch of radial 69 kV transmission line in the Bridgetown area in eastern PEI.

The 69 kV transmission line that runs from the Charlottetown Substation to Scotchfort Substation was built in 1965 and is approaching the end of its life. It is purposed to rebuild this line on the existing ROW using single pole construction, increase the energy transfer capability and upgrade it to 138 kV. Replacing this section with a new line built to 138 kV standards using synthetic insulators and armless construction will meet both future load serving requirements as well as foreseeable amounts of wind energy generation located in eastern PEI. New easements on lands between Frenchfort and West Royalty substation will have to be obtained to re-route the existing T4 line when it is upgraded to 138 kV. During the next five years the focus will be on rebuilding the transmission line running from Charlottetown to Lorne Valley.

The following table summarizes the transmission line facilities on PEI:

Line	From Station Name	To Station Name	Voltage (kV)	Length (km)	Year Built/Rebuilt
cable1	Murray Corner	Richmond Cove	138	21.4	1978
cable2	Murray Corner	Richmond Cove	138	21.4	1978
Y101	Richmond Cove	Bedeque	138	9.7	1978/2003
Y103	Richmond Cove	Bedeque	138	9.7	1978/2003
Y105	Bedeque	Sherbrooke	138	15.4	1971/2004
Y107	Borden	Bedeque	138	8.2	1971
Y109	Bedeque	West Royalty	138	41.0	1979/2008
Y111	Bedeque	West Royalty	138	41.0	1987/2008
Y113	Borden	Sherbrooke	138	23.6	1991
Y115	Sherbrooke	West Cape	138	85.0	2007-2009
T1	Sherbrooke	West Royalty	69	54.0	1983/1984
T2	Charlottetown	Lorne Valley	69	36.3	1989
T3	Borden	McCain Foods	69	4.8	1973
T4	Charlottetown	Lorne Valley	69	42.9	1969
T5	Sherbrooke	Wellington	69	19.2	1999-2003

T7	Sherbrooke	Slemon Park	69	2.4	1997
T8	Lorne Valley	Souris	69	45.6	1999-2005
T8	Route 4	Georgetown	69	9.7	1972/2004
T10	Lorne Valley	Dover	69	33.3	1989/1994
T11	Sherbrooke	Summerside	69	3.6	1963/1997
T12	Dingwells Mills	Eastern Kings Wind Farm	69/138	42.8	2006
T13	West Royalty	Charlottetown	69	6.1	1983
T15	West Royalty	Charlottetown	69	9.9	1986
T21	Wellington	Alberton	69	52.2	1966/2002-2007
			Total	**639.2**	

S-18 Please provide the Commission with information on the percentage of the Kent Street office building used by Maritime Electric and other tenants. Now many staff does Maritime Electric house at this location? How many staff do other tenants employ at this location? Has the Company considered if there are any economic benefits and costs saving that could accrue to ratepayers if downtown staff were located elsewhere? What is the value of the downtown office location?

<u>Response</u>:

S-18 The Kent Street office building area is 29,184 square feet (2,711 square meters). Maritime Electric uses 26,444 square feet (77%) for office, storage space lunchroom facilities, meeting space and leases the remaining 2,740 square feet to two tenants. Maritime Electric has 66 employees at this location. The other two tenants, the United Way of PEI and Heart and Stroke Foundation of PEI have 15 employees.

At December 31, 2009, the net book value of the building was $1,531,434 and $130,000 for the land. The value of the location per the 2010 provincial property tax assessment is $1,998,600.

The Company has considered the possible benefits of relocating the office. However this would require a successful sale of the current location. Management has tested the market on several occasions; however, the prices offered meant the building would have to be sold at a substantial book loss. In addition to the recovery of the loss, new facilities would have to be constructed. Management has concluded, at this time, that the sale of this building and movement elsewhere is not economical.

S-19 How old is the mobile meter reading device technology and what is the life expectancy of the proposed replacement ($185,000)?

Response:

S-19 The current mobile meter reading device technology was implemented in December 2004 making it roughly 6 years old. The handheld devices are essentially small computers. The associated computer has a life span of 5 years. The upgrading of the software is consistent with that experienced for other Company software. It is projected that the proposed mobile meter reading device technology would have a life expectancy 5 years.

S-20 Please provide an analysis of the benefits of the proposed inventory management system versus the cost ($100,000).

Response:

S-20 The benefits of the proposed barcode or Radio Frequency Identification (RFID) system include:

- Reduction of inventory record errors;
- Reduction in the time required for the processing and counting of inventory; and
- Reduction in inventory carrying costs as inventory levels could be reduced.

The project would take approximately four months to complete. Sources of costs and benefits are as follows:

Capital Expenditures	IT Costs	Units	Non IT Costs	Total
Labour	40,600		3,400	44,000
Hardware	15,000			15,000
Software	41,000			41,000
Total	55,600		-	**$ 100,000**
Annual Recurring Costs				
Software Maintenance	7,000			7,000
Total	7,000			**$ 7,000**
Annual Cost Savings				
Labour Savings	-		5,000	5,000
Improved Inventory Control			15,000	15,000
Total	-		5,000	**$ 20,000**
Net Total Annual Cost Savings				**$ 13,000**
Cost Type	**Description**	**Units**	**Unit Cost**	**Total**
Labour	Systems Analyst	12	2,250	27,000
	Programmer Technician	8	1,700	13,600
	Storekeeper	2	1,700	3,400
Hardware	RFID or Barcode Readers	4	500	2,000
	RFID Tags or Barcode Printer	1	5,000	5,000

S-21 Please provide a more complete description of the benefits of the customer services training software and related cost savings, if any.

Response:

S-21 The need to further train, educate and develop front line customer service staff is a key focus for the Company as customers generally are more knowledgeable about such issues as electricity pricing and consumption related issues and are increasingly more demanding of receiving quality information in response to questions on a timely basis. It is challenging to find the time for this training during regular work hours while continuing to maintain current staffing levels to serve customers. An "at your desk" training module that could be scheduled for individual staff training during regular working hours while maintaining adequate service levels will help achieve this balance.

This training software is envisioned as an on-line solution to allow for individuals, or small groups of employees, to develop their own knowledge and skills with respect to Company procedures, work practices, the electrical system, safety, energy efficiency, technology changes, etc.

Some of the benefits for an online customer service training software include: flexibility for the time required for individual employee training needs, consistent educational format (no instructor deviance), reduction in overhead (no instructor or physical facility need be available), reduction in training – related travel time costs, avoiding training outside regular working hours (thus avoiding overtime pay), an ability to accommodate different types of learners and a mechanism for management to better measure results of learning outcomes through training assessments completed on-line.

The overall savings, and benefits, of utilizing an effective on-line training system are difficult to quantify but the Company proposes this investment because it represents a cost effective training tool that will result in better trained staff which will enhance the Company's ability to deliver higher quality customer service.

Appendix A

Responses to Interrogatories from PEI Senior Citizen's Federation to IRAC

1. Re-ranking Projects

The funds relieved as a result of deferring/postponing certain Charlottetown Plant projects pending funding for a third PEI and NB transmission cable have simply been distributed to other “re-ranked” projects. How has Maritime Electric justified (to IRAC) and increased investment, by a factor of five times, in the Borden Plant? This Plant historically generates negative net energy which costs over tow times the cost of energy from the Charlottetown Plant.

Response:

1. Management has discussed, at length, the value of the Borden-Carleton generating station in terms of:

- Its capacity value and the reduction in purchased energy costs the Company sees as a result of this capacity;
- The value of the generating station in terms of security of supply;
- The requirement to maintain this facility in proper working order;
- The requirement to make certain expenditures for insurance purposes;
- The requirement to make certain expenditures for the propose of safety; and
- The requirement to have this facility operational at a moment’s notice.

The long-term plan is to retain this facility. In order for it to be operational when needed certain expenditures are required. These expenditures are proposed in this Capital Budget Application.

2. Services and Street Lighting

Maritime Electric originally forecasted an expenditure for 2011 that was similar to 2010; now the explanation for a 23% (net) increase for 2011 is that the average for the years 2007 to 2009 has now been adopted.

Response:

2. In its response to Commission interrogatory S-7 the Company outlined it's rational for the replacement of equipment for Services and Street Lights.

In the 2011 Capital Budget Application the Company has used, as the basis for the estimate, the average expenditure for the years 2007 to 2009 reflecting a more reasonable "estimate" of the actual expenditure. Since these requirements are driven, to a large extent by customer requests, and since the Company is obligated to meet these requests, it is logical to have the budgeted items reflect this experience.

3. Wind Energy Integration and Smart Metering

In response to our suggestion to assign a proportion of the capital investment planned for continued Remote Interrogation (RI) meter deployment to a smart metering project, Maritime Electric consume three pages of explanation to reject this opportunity and describe its passive approach to smart metering and increased wind energy integration. Summerside Utility is investing $2.0M and embracing the concept of offering consumers the opportunity of lower cost off-peak (wind) energy. Whereas our monopoly, major utility is content to watch and invest an “entry fee” of $350,000 over a five year period in a $32M Atlantic Load Control project.

Response:

3. Maritime Electric, like most other utilities, is taking the following approach to Smart Metering and increased wind energy integration:

Smart Metering

There is sufficient evidence in the industry that the expenditures made by other utilities for smart metering initiatives are not reaping the benefits expected. Management is taking a wait and see attitude on this issue. The Company was criticized during the June 2010 rate hearing about “increasing its rate base” so it could earn more profit. The Company is not ready to make such expenditures until it has been proven that there is a reasonable benefit for customers. It should be pointed out that Summerside has received federal and provincial funding for its project, funding that is not available to Maritime Electric. The participation in the Powershift Atlantic initiative is expected to provide tangible future benefits with respect to wind integration and cost rationalization.

Wind Energy Integration

Maritime Electric currently receives in excess of 15% of the total annual requirements from renewable sources and is working to increase that total. Management considers this to be more than a passive approach. The Company has explained, on several occasions, the constraints that come with wind energy, and as such. Increases in the consumption of wind energy have to factor in technical considerations, price considerations and security of supply issues.

4. <u>Organic Growth</u>

This is a (new) term used by Maritime Electric in our interrogatories response document to describe one basis for capital expenditure allocation. This section of the response document describes "new construction, industrial/commercial expansion and Government infrastructure initiatives" as requiring increased capital but does not quantify the specific budget item that applies to each requirement. It appears that Maritime Electric adopts simple subjective criteria to the allocation of capital funds assuming a perpetual annual increase in capital budget and without any affordability restraints. This approach is particularly disturbing when the total energy demand for PEI is actually declining every year.

<u>Response</u>:

4. With respect to the issue of new construction, etc. it is a fact that this new construction by customers requires capital expenditures on our part. As a monopoly service provider we are obligated to serve and to meet customers' requirements. These expenditures, depending on the project, can affect distribution lines, transmission lines, service lines, and street lighting. Our past experience is that these projects take place but the planning on the customer part is not always communicated to the Company.

To make the statement that total energy demand for PEI is actually declining every year is misleading and does reflect the facts. Energy sales growth has been reduced but it is not declining every year.

5. Framework for Evaluation of Capital Budget Expenditures

Without any publicly available information on the IRAC processes used to evaluate the annual applications from Maritime Electric, we respectively suggest the following framework as a basis for evaluation:

Commercial industries, for affordability and shareholder accountability, are required to objectively evaluate the coverage of business risk and opportunities that drive capital expenditures. Typically these capital expenditures are objectively, not subjectively, evaluated by:

a) The operating maintenance cost of capital is exceeding depreciation hence replacement may be warranted.
b) Introduction of new capital reduces short term operating and/or supply expenses, (i.e. a short term payback applies).
c) Introduction of new project capital reduces longer term operating and/or supply expenses, (i.e. a long-term payback applies).
d) For each of the above three categories of capital request, we propose that IRAC seek an assessment of each capital budget line item by posing the questions:
    i) What impact would result by reducing the line item by 30%?
    ii) What impact would result by reducing the line item by 50%?
e) Finally, capital expenditures required to mitigate risk are often the most difficult to quantify. Here a simple objective two question ranking system helps to prioritize: On a scale of 0 to 1 "what is the probability of the risk occurring?" followed by, again on a scale of 0 to 1, "what would the impact or severity to the business if this risk was to occur?" By multiplying these two factors a simple ranking order, again on a scale of 0 to 1, is provided that sets an affordability versus risk decision scale.

Response:

5. Maritime Electric's capital expenditures, for the most part, reflect the following:

- New expenditures required to meet customer demand (growth or infrastructure spending), and
- The replacement of aged or deteriorating equipment.

Maritime Electric expenditures cover, poles, wires, transformers, etc. necessary to ensure the security of supply to customers. It is Management's belief that such expenditures should actually be higher. The Company's energy delivery system is subjected to weather related events, the affect of salt air, etc. It is imperative that the Company review and assess the condition of its assets and that they be replaced as required to ensure system integrity. Increases in the price of metals (wire, transformers) have affected overall capital expenditure significantly over the years, but cannot be used as a reason not to upgrade the system.

Management takes many steps to review and prioritize its proposed expenditures and believes that the projects selected for the 2011 Capital Budget represent urgent priorities. It is our view that maintaining system integrity is the utmost priority and that assignment of % levels to spending does not reflect good utility practices.