1. On Page 3-1 it is stated that Maritime Electric's on-Island generation capacity has an annual value of approximately $4.8 million based on the current Energy Purchase Agreement with NB Power. How has this figure been calculated?

Response:

1. There are 3 types of capacity that are required to meet Maritime Electric's obligations:

- Planning Reserve. This is a long range capacity requirement to ensure that a utility has enough capacity on hand to meet current load requirements and future growth as well as to cover the period between identifying a capacity (generation) requirement and the time it is actually operational. The amount of Planning Reserve that Maritime Electric must have for all hours of a year is equal to 115% of its maximum hourly net peak load for that year. Wind generation is an accepted source of Planning Reserve.

- Reserve Capacity (Operating Reserve). A utility must have enough reserve capacity for all hours of the year, above the hourly load requirement for that given hour, to completely replace the loss of the largest generator on the system within 10 minutes as well as 50% of the loss of the second largest generator on the system within 30 minutes. For the Maritime Area, Reserve Capacity is shared amongst New Brunswick, Prince Edward Island and Northern Maine. Each participant's share is based on its pro-rata share of the Maritime peak (NB, PEI and Northern Maine) only. Normally Point Lepreau (when on line) is the largest generator in the Maritime Area and Beldune is the second largest. During the Point Lepreau refurbishment, Beldune became the largest generator followed by a unit at Colson Cove. Wind generation is not an accepted source of Reserve Capacity.

- Energy Backstop. For all hours, all energy must be backstopped with capacity. For Maritime Electric, some of the backstop capacity is supplied by on-Island generation, Point Lepreau (when on line) and through capacity purchases. Wind generation is not an accepted source of Energy Backstop.

All 3 types of capacity obligation must be met for each hour of the year. When generators are down for scheduled or unscheduled maintenance, replacement capacity must be obtained in order to keep meeting the above obligations.

The recent Energy Purchase Agreement with NB Power placed a value of $2,100 per megawatt of capacity per month. The cost of operating reserve varies and at the time of submission of the Capital Budget the value was $5,190/MW-mo. Using these values, the following table estimates the value of Maritime Electric's on-Island generation in terms of avoided capacity purchases.

	Capacity	Reserve	Capacity	Reserve	Capacity	Reserve	Value
Generation	**MW**	**MW**	**$/MW-mo**	**$/MW-mo**	**$**	**$**	**$**
CTGS	60	0	2100	5190	1,512,000	-	1,512,000
BGS	13.4	26.6	2100	5190	337,680	1,656,648	1,994,328
CT3	50	0	2100	5190	1,260,000	-	1,260,000
Total	**123.4**	**26.6**	**2100**	**5190**	**3,109,680**	**1,656,648**	**4,766,328**

The cost of Reserve can now be obtained for $4391/MW-mo which changes the yearly value from $4.8 million to $4.5 million.

2. In reference to the other benefits of on-Island generation it is further stated on Page 3-1 that it provides energy supply in times of transmission line outages in New Brunswick or PEI. During the past five years, how many times has there been supply curtailment as a result of transmission outages in New Brunswick?

Response:

2. Over the past 5 years there have been 8 outages in New Brunswick that have resulted in reduced energy flow to PEI.

Seven of these outages were planned outages to perform maintenance on circuit breakers, switches, PTs, CTs, etc., and the remaining outage was an emergency outage to repair a hot spot discovered during an inspection of the Murray Corner Substation in New Brunswick.

Not all of these outages necessitated on-Island generation as the timing of the outages was co-ordinated between Maritime Electric and NB Power to occur during light load and high wind conditions in order to avoid expensive on-Island generation.

3. It is stated on Page 3-1 that other benefits of on-Island generation include voltage control during peak load times. Approximately how many times (and hours) per year are the on-Island generating facilities operated for voltage control?

Response:

3. Generation is planned at the Charlottetown Thermal Generating Station (CTGS) every December and late January or early February to facilitate voltage control (there are also many other benefits to running at these times of year other than voltage control as outlined on pages 3-1 to 3-3 of Maritime Electric's 2012 Capital Budget Evidence). During Maritime Electric's peak in December, voltage support required in the Eastern end of the province is supplied from CTGS. CTGS is usually operated from Monday at 6 am to Thursday at 7 pm for the two weeks prior to Christmas. For the Friday through to Sunday periods during these two weeks, CT3 is available if further voltage support is required.

The late January/early February run is scheduled to correspond to the peak in New Brunswick. During the New Brunswick peak, which is electric heat based, NB Power has difficulty maintaining voltage support to the southeast portion of New Brunswick, thus they are unable to provide the necessary voltage support for Maritime Electric to maintain the required voltage support across PEI. The CTGS is normally run for a two week period to provide voltage support.

In addition to the two runs planned for the CTGS, the Borden Generating Facility (BGS) provides voltage support by operating Combustion Turbine #2 (CT2) in synchronous condenser mode. This is done on an as needed basis. The hours of operation of CT2 in synchronous condenser mode for the past 4 years are as follows:

- 2007 1,818 hours
- 2008 2,684 hours
- 2009 2,950 hours
- 2010 1,085 hours

4. In reference to the statement on Page 3-1 that management recognizes that the cost of produced electricity from on-Island generation facilities is high, what is the total unit cost (including fuel, labour, operations and maintenance) in $/MWh of producing electricity at the Charlottetown Thermal Generating Station? At the Borden Generating Station?

Response:

4. All of Maritime Electric's generating facilities are standby generating facilities. Only provisional amounts of generation for contingency and cable overloading purposes is planned, year round generation is not planned or contemplated.

If Maritime Electric's generation facilities were operating with an 80% capacity factor (as do base loaded facilities) the all-in $/MWh costs at today's input fuel costs would be as follows:

Facility	All-in $/MWh
CTGS	$272.91
BGS	$356.40
CT3	$227.83

These costs reflect fuel, consumables and all operating and maintenance activities including labour.

5. At the bottom of the first bullet on Page 3-2 it is stated that wind power is not recognized as a capacity credit by Maritime Electric. Why does Maritime Electric not recognize wind as a capacity credit? Does NB Power recognize wind as a capacity credit?

Response:

5. The first bullet on Page 3-2 does not state that wind power is not recognized as a capacity credit by Maritime Electric. The bullet discusses submarine cable load management. Maritime Electric must manage cable loading in both wind and non-wind situations.

When load is above 200 MW, on-Island generation is required to keep the existing submarine cables from being overloaded and due to the intermittent nature of wind, there may be hours in which wind is not producing when the load is above 200 MW. In these situations, Maritime Electric must have the generation in place to keep the cables from being overloaded while supplying all the load.

Maritime Electric does recognize and claim planning reserve credit from wind power. NB power recognizes wind as a planning reserve source as well. Due to its intermittent nature, wind is not recognized as a source of operating reserve capacity.

6. To meet the required capacity requirements, how much on-Island generation capacity is required in PEI over the next twenty years presuming a third cable of 150 MW loading capability is installed and the average annual electrical load growth is 1.5%?

Response:

6. Assuming the CTGS is retired when the third cable is installed, Maritime Electric will have 350 MW of intertie capacity (ability to make off-Island purchases) and will have 90 MW of on-Island generation (Borden and CT3). Taking into account a single contingency, the loss of the third cable of 150 MW, Maritime Electric's available capacity would be 200 MW (existing submarine cables) plus 90 MW (on-Island generation) for a total of 290 MW. Given the year to date peak of 224.7 MW in 2011, and escalating that at 1.5%, the on-Island load will exceed 290 MW in 2029. At this point additional intertie capability or more on-Island generation would be required. At the end of 2031, 20 years out, the Company would need an additional 13 MW to meet the single contingency criteria.

This 13 MW requirement is solely based on meeting the single contingency criteria, it does not take into account voltage support, black start capability, energy price cap during times of curtailment, on-Island transmission contingencies, planned or forced outages on existing generation or other generation benefits as outlined on pages 3-1 to 3-3 of Maritime Electric's 2012 Capital Budget Evidence.

This also assumes that the existing submarine cables and the Borden combustion turbines are still in service and fully operational. In 2029 the existing submarine cables will be 52 years old and the Borden combustion turbines will be nearing 58 years.

7. Please describe the inputs to the formula for the required capacity to meet ancillary services obligations as stated in the last bullet on Page 3-2. Based on the formula, how much capacity does Maritime Electric require?

Response:

7. The last bullet on Page 3-2 of Maritime Electric's evidence refers to Operating Reserve. Maritime Electric's non-spinning requirements are shown in the table below.

Generator	Nameplate	Reserve %	Reserve MW	Spinning	Non-Spinning	Maritime Electric Share
Beldune	440	100%	440	110	330	10.8
Coleson Cove (1 Unit)	333	50%	166.5	0	166.5	7.7
Total						18.5

A utility must have enough reserve capacity (operating reserve) for all hours of the year, above the hourly load requirement for that given hour, to completely replace the loss of the largest generator on the system within 10 minutes as well as 50% of the loss of the second largest generator on the system within 30 minutes. 25% of the 10 minute reserve described above must be spinning reserve while 75% can be non-spinning reserve (generator must be able to start and be at full load within 10 minutes). For the Maritime Area, Reserve Capacity is shared amongst New Brunswick, Prince Edward Island and Northern Maine. Each participants share is based on its pro-rata share of the Maritime peak (NB, PEI and Northern Maine) only. Normally Point Lepreau (when on line) is the largest generator in the Maritime Area and Beldune is the second largest. During the Point Lepreau refurbishment, Beldune became the largest generator followed by a unit at Colson Cove.

Please note that Maritime Electric can only supply non-spinning reserve from its combustion turbines, and must purchase spinning reserve off-Island.

Besides the non-spinning reserve that is described above, Maritime Electric is also responsible for 10 minute spinning reserve, regulation and load following, real time capacity and planning reserve capacity. The 10 minute spinning reserve and regulation and load following is acquired off-Island while the real time capacity and planning reserve capacity is a combination of Maritime Electric on-Island generation and off-Island purchases.

8. How does the current cost of owning and maintaining Maritime Electric's on-Island generating facilities compare with the cost of buying capacity under the PEI Energy Accord?

Response:

8. In comparing the cost of capacity only and ignoring the other benefits that Maritime Electric's on-Island generation provides for the operation and reliability of the electrical grid, purchased capacity under the Energy Purchase Agreement between Maritime Electric and NB Power is $2,100/MW-month while the cost of owning and maintaining Maritime Electric's on-Island generating facilities equates to $6,600/MW-month (2010 amount).

The $2,100/MW-month purchase price in the Energy Purchase Agreement is not a cost based figure but rather a market based price, well below the actual price of capacity. Past energy agreements with NB Power had capacity priced up to US$4,100/MW-month with a much weaker Canadian dollar, putting the cost in Canadian dollars closer to the $5,000/MW-month figure. As well, in late 2004, Maritime Electric received correspondence from NB Power stating that the price for capacity at that time was $5,000/MW-month.

Certain benefits derived from Maritime Electric's on-Island generating facilities cannot be purchased off-Island, as many of the benefits are due to the location of the generating facilities on PEI and on the load side of the submarine cables. For example, purchasing capacity off-Island would not benefit at all in the event of a cable failure or loss of transmission in New Brunswick or PEI. Off-Island capacity would not help with cable load management or black start capability.

9. It has been stated that this capital budget has been prepared based on limiting expenditures to the Charlottetown Generation Station in anticipation of the province receiving a third cable. Has the budgeting for capital improvements to the Borden generating facility been prepared under the same premise? If not, why not?

Response:

9. The capital budget for the Borden Generating Station (BGS) has not been prepared under the same premise as the CTGS as the 2 combustion turbines in Borden will not be impacted by the addition of a third cable. The BGS adds value as a source of capacity, voltage support and ancillary services. The BGS capacity results in over $1.7 million in avoided capacity and ancillary service purchases. The benefits of the BGS are listed below:

- 10 minute non-spinning reserve
- 30 minute non-spinning reserve
- Quick start generation (less than 10 minutes)
- Black start capability
- Contingency planning capability
- Voltage support
- Backstop for non-firm energy purchases
- Backstop for wind purchases
- Planning reserve

10. On Page 3-8, $506,000 has been allocated to re-furbish air heaters on Units 9 and 10. It is stated that the steel framework and support system are badly corroded. Are there not mitigating measures available to limit corrosion and avoid such costly expense?

Response:

10. The air heaters on Units 9 and 10 are original equipment and built in 1963 and 1968 respectively. Maritime Electric did use mitigating measures to limit corrosion by incorporating Cor-Ten Steel plate (ASTM A-242 or A-588) in the original construction of the air heaters. Cor-Ten is a “Weathering Steel" which means that due to its chemical composition this steel exhibits increased resistance to atmospheric corrosion compared to other steels. Had Maritime Electric not used this weathering steel in the original construction of these units this work would have had to occur much earlier than 2012.

11. There is a provisional budget for large motor refurbishment on Page 3-9. Given the efficiency loss after rewinding a motor, is it not more cost effective to simply replace the motor or is this simply a case of avoiding large expenses for on-Island generating facilities in anticipation of the province receiving a third cable?

Response:

11. A rewind is generally less expensive than a motor replacement, however before a large motor is sent for rewind, the Company compares the rewind cost to the cost of motor replacement and will take the more economic option.

The rewind of a motor does not necessarily result in efficiency loss; a rewind may result in the same efficiency, higher efficiency or lower efficiency. The efficiency change largely depends on the motor and the materials used for the rewind. Maritime Electric has typically requested an in-kind rewind, in which the resulting efficiency is the same as the pre-rewind efficiency.

12. There is a budget of $225,000 allocated on Page 3-11 to replace the automatic voltage regulation on Unit 10. Is it anticipated that repeated excursions beyond the designed maximum voltage regulation will take place? On a yearly basis, how often does Unit 10 operate?

Response:

12. Response to interrogatory #3 gives the expected operation for Unit 10. Historically there have been swings in the voltage output of this unit such that excursions have occurred that are unacceptable to both the generator and the Maritime Electric electrical system. A single excursion could potentially result in the failure of the generator windings resulting in 20MW of standby capacity not being available for an extended period of time and require a costly rewind or generator replacement. One single excursion is unacceptable and thus, given the history of the unit, a budget item was submitted to replace the automatic voltage regulation of Unit 10.

13. In regards to the capital improvements described on Page 3-13 for CT 3, what are the operating hours of this unit since its commissioning? What are the anticipated improvements and upgrade requirements?

Response:

13. The total operating hours for CT3, since commissioning, is 215 hours reflecting a stable and reliable energy supply from off-Island sources. The unit requires regular maintenance activities that are identified by the Original Equipment Manufacturer based on operational experience.

The amount budgeted for CT3 is not project specific, but is a provisional amount to address any unforeseen problems or items identified during the course of the year.

14. On Page 3-14, $1,178,000 has been allocated to mechanically overhaul Turbine 2 (CT2) at the Borden Plant. Approximately how many hours has this unit run since its last overhaul? Presently, what is the expected annual hours of run time for this unit? On what is the budget for the overhaul based (i.e., cost of the previous overhaul)? Given the increase in the 2012 Capital Budget over the previous year, can this expenditure be deferred to another fiscal year?

Response:

14. The previous mechanical inspection of this unit was completed in three stages:

1. In 1996 an inspection was completed by John Brown Engineering on the compressor, as well as an inspection and repair of the unit main gear box,
2. In 1998 an inspection of the auxiliary gear box was completed by Kvaerner, and
3. In 2001 a hot gas path inspection (this includes the combustor, nozzles, and power turbine) was completed by General Electric.

- Hours of operation since 1996 912 hours
- Hours of operation since 1998 858 hours
- Hours of operation since 2001 313 hours

It is anticipated that the unit will be operated for approximately 250 hours annually. The budget is based on the cost of previous outages brought forward to 2012 dollars and anticipates component repairs as discovered during previous inspections.

The overhaul frequency for a combustion turbine is determined by the number of operational hours (i.e., 25,000 – 50,000 hours) or years between inspections (i.e., 5 - 7 years) and is generally based on good utility practice. It is not advisable to defer the overhaul due to the elapsed time from the previous inspection and overhaul. Prudent maintenance practices prevent failure that may render the unit inoperable.

15. It is stated on Page 4-4 and 4-5 that expenses for Distribution Services may be partially offset by customer contributions. How are customer contributions calculated?

Response:

15. The terms and conditions for collecting customer contributions are set out in the Company's Rates, Schedules and Policies Manual as filed with IRAC and amended from time to time. The Standard Facility allowance for services and extensions is 90 metres for Residential, General Service and Small Industrial rate categories and includes required transformation and metering for single or three phase service. Customer needs that exceed 90 metres are billed on a cost recovery basis. Contributions for Large Industrial customers depends on whether service is provided at the 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 on those facilities paid for through customer contributions.

16. The tables on Page 4-7 to 4-10, inclusive, have headings entitled "Customer Hrs". It is assumed that this means the annual outages to these customers. Please confirm this or explain this term.

Response:

16. The "Customer Hours" heading used in tables on pages 4-7 to 4-10, inclusive, refers to the sum of the cumulative annual number of individual customer hours of outage associated with each line. For example, the 810 customers on line VC01412 in Lower Newton experienced a total of 861 customer hours of outage in 2009, or on average, approximately 0.94 hours of outage per customer in that year. These hours of outage relate only to outages incurred at the distribution level and do not include outages upstream or incurred at the transmission level.

17. On Page 4-11 there is $400,000 allocated to a Porcelain Cutout Replacement Program. Please elaborate on the nature and seriousness of the problem with these cutouts. What will be their replacements and is there any assurance that they will perform any better than the porcelain models? Will this be an ongoing annual budget item?

Response:

17. Maritime Electric has experienced an average of 30 porcelain cutout failures per month over the past 5 years. These failures often result in pole fires which can cause further customer outage. This makes the porcelain cutout issue one of the most significant causes of controllable customer outages. Over the 5 year period from 2006 through 2010, a Maritime Electric customer experienced, on average, an outage of 0.39 hour duration due to defective cutouts, annually.

Life expectancy can vary for porcelain cutouts depending on the environmental factors under which they operate including temperature fluctuations, cold temperature extremes and salt and dirt contamination, as these are the 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 "freeze thaw" cycles which can lead to the development of hairline cracks which weaken both the electrical and mechanical integrity of the cutout.

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. The polymer synthetic cutout is considered superior for its ability to withstand the forces that lead to hairline cracks. To date, the Company is aware of only 8 failures of polymer synthetic cutouts, all due to salt contamination.

The Company plans to continue the Porcelain Cutout Replacement Program until all porcelain cutouts have been replaced. Approximately 1,250 porcelain cutouts are planned to be replaced with synthetic polymer cutouts in 2012. The

Company continues to target specific areas, under the Program, where porcelain cutout failures are more prevalent. An additional 1,250 cutouts will be changed out through annual transformer replacement, line rebuild and line maintenance activity. There are approximately 39,800 transformer and line cutouts in the system of which approximately 25,800 are porcelain and 14,000 are synthetic polymer. At the current rate of replacement, it will take approximately 10 years to replace all porcelain cutouts with polymer synthetic cutouts.

18. Within the budget notes on Page 4-12 for the Residential Watt-Hour Meters Program, it is stated that there has been enhanced customer service and improved safety for meter readers. What has been the monetary savings accrued from this program?

Response:

18. By the end of 2012 the Company plans to have completed 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 2012 for this to be accomplished.

RI meters are interrogated (read) by drive-by devices which eliminate the need for a meter reader to read each meter individually and manually record the reading. This significantly reduces meter reader labour and related transportation costs.

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. To date, 5 full time positions have been eliminated. The Company's Plan was, and remains, the elimination of 8 meter reading positions. The elimination of each full-time meter reader position, after considering the salary, benefits and annual cost of operating a vehicle, currently saves the Company approximately $66,000 annually in meter reading costs.

19. Under the heading of Distribution Equipment on Page 4-14, an amount of $1,369,000 has been allocated to "System Equipment". Is this typical of the annual amount that would be spent under this budget item?

Response:

19. During the 1980's and 1990's, the Company's focus in the transmission and distribution areas was on the replacement of poles and conductors. These replacements continue to be important, however, the Company has commenced to replace or upgrade other equipment used to provide voltage support and to protect and control the system. The table below shows that beginning in 2006 the Company began increasing its expenditures in this area.

Expenditures for Distribution Equipment D-7	
Year	**$ Amount**
1997	496,441
1998	450,746
1999	341,886
2000	483,868
2001	651,202
2002	391,090
2003	406,827
2004	539,444
2005	345,463
2006	594,329
2007	645,671
2008	779,748
2009	1,156,220
2010	1,346,616
2011 Forecast	1,419,000
2012 Budget (proposed)	1,499,000

20. In light of the $4 million increase in this capital budget, is it absolutely necessary to replace the Albany transformer as described on Page 5-1 in this fiscal year?

Response:

20. Due to load growth in the Albany/Borden area, the Albany 6.7 MVA transformer is approaching its nameplate capacity. It has been Maritime Electric's practice to increase substation capacity on a proactive basis, prior to equipment reaching its thermal rating. The proposed transformer will supply the local load well into the future and provide emergency backup for a local processing facility.

The Company believes it to be prudent to replace the 6.7 MVA transformer with a 7.5/10 MVA unit in 2012.

21. As described on Page 5-7, upgrades are being proposed for the Church Road Substation. Does this include the replacement of a transformer or is it simply an addition of another transformer? If it is a transformer replacement, can the removed transformer be reused at another location?

Response:

21. The proposed 138 kV transformer for the Church Road substation is a new installation in that there is no transformer at the site now, only one circuit breaker. Maritime Electric's T12 transmission line extends from the Dingwell's Mills substation to Church Road, then on to the Eastern Kings Wind Farm, all at 69 kV. The 2012 plan is to insert a step up transformer to increase the line voltage at Church Road to 138 kV and then operate the section of transmission line between Church Road and the Eastern Kings Wind Farm at 138 kV, thereby reducing line losses on that section of transmission line.

22. On Page 6-2, $956,000 is allocated for Information Technology. Is this a normal annual amount for this category? It is essential that all this amount be expended in 2012?

Response:

22. The level of expenditures for Information Technology in the 2012 Capital Budget is consistent with previous years. The inclusion of Capitalized General Expense in the work order up front rather than at year end results in the total expenditures being relatively the same. The highlights of the 2012 Capital Budget for Information Technology are the installation of new financial reporting software and a project to streamline all communications.

The current financial reporting software is aged and needs to be replaced. It is several releases behind the most current release and maintenance costs are increasing. The project to streamline all forms of communication will provide benefits to customers through increased access to information. The amounts for these projects are provisional.

23. The Capitalized General Expense of $402,000 is described on Page 7-1. It is understood that this expense is allocated to administrative costs that are not specific to any project. What is the total administrative expense to specific and non-specific projects that is considered as a capital expenditure?

Response:

23. General Expense Capital represents internal labour costs incurred to support the capital development and construction program. It reflects the support from professional and administrative staff that provide the engineering, technical, IT and financial support behind all of the capital projects. In prior years these costs were collected separately and then prorated over the projects at year end. As discussed in Response 22, these accounts are now budgeted directly to the specific projects.

The total administrative expense (internal labour costs) charged to specific and non specific projects for 2012 is $2.4 million.

Appendix A