MARITIME ELECTRIC
A FORTIS COMPANY

RECEIVED
JUN 25 2015
The Island Regulatory and Appeals Commission

June 25, 2015

**Hand Delivered**

Island Regulatory & Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Commissioners:

Please find enclosed 10 copies of Maritime Electric's Application and Evidence for the Charlottetown Combustion Turbine 4 Project.

If you require further information, please do not hesitate to contact me at (902) 629-3760.

Yours truly,

MARITIME ELECTRIC

John Gaudet

John D. Gaudet
Vice President, Corporate Planning
& Energy Supply

JDG06
Encl. as noted

**C A N A D A**

**PROVINCE OF PRINCE EDWARD ISLAND**

**BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION**

**IN THE MATTER** of the Application of Maritime Electric Company, Limited for approval of expenditures to be made over a four year period (2015 to 2018) for the design, construction and commissioning of a combustion turbine generator with a nominal rating of 50 MW to be located at the Charlottetown Plant Site. ("The Project")

**APPLICATION AND EVIDENCE**

**OF**

**MARITIME ELECTRIC COMPANY, LIMITED**

**Date: June 24, 2015**

# TABLE OF CONTENTS


| | | |
|---|---|---|
| 1.0 | Application | 1 |
| 2.0 | Affidavit | 4 |
| 3.0 | Executive Summary | 6 |
| 4.0 | Introduction | 10 |
| 5.0 | Review of Existing Generating Resources | 13 |
| 6.0 | Forecast of Peak Load and Capacity Requirements | 18 |
| 7.0 | Comparison of the Project to Potential Alternatives | 20 |
| 8.0 | Reasons for Choosing the Charlottetown Generating Station Site | 25 |
| 9.0 | Impact on Rates | 27 |
| 10.0 | Conclusions | 29 |
| 11.0 | Glossary | 30 |


## SCHEDULES


| | |
|---|---|
| Schedule 1 | Project Timeline |
| Schedule 2 | Forecast of Maritime Electric Peak Load and Capacity Requirements |
| Schedule 3 | New Brunswick Transmission System Single Line Diagram |
| Schedule 4 | Cost of Capital and General Escalation Rate |
| Schedule 5 | Notes for Table 4 - Present Value Calculations for Comparison of Alternatives |
| Schedule 6 | Fixed Charges Rate for Charlottetown Plant Life Extension |
| Schedule 7 | Fixed Charges Rate for Combustion Turbines |

**C A N A D A**

**PROVINCE OF PRINCE EDWARD ISLAND**

**BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION**

**IN THE MATTER** of the Application of Maritime Electric Company, Limited for approval of expenditures to be made over a four year period (2015 to 2018) for the design, construction and commissioning of a combustion turbine generator with a nominal rating of 50 MW to be located at the Charlottetown Plant Site. ("the Project")

## Introduction

1. Maritime Electric is a corporation incorporated under the laws of Canada having its head or registered office at Charlottetown, and carries on business as a public utility within the scope of the Electric Power Act ("EPA" or the "Act") engaged in the production, purchase, transmission, distribution and sale of electricity within Prince Edward Island.

## Application

2. Maritime Electric has an obligation to provide service to all ratepayers within its service area. Part of the obligation to serve requires Maritime Electric to ensure adequate generation is in place to meet the future needs of ratepayers. In discharging this responsibility, Maritime Electric has identified the need for additional generation. This Application details the Company's analysis and its proposed solution to this need.

3. Briefly stated, Maritime Electric requests the Commission's approval for the expenditure of $68 million over a four year period for costs associated with the project.

4. Maritime Electric acknowledges the recent announcements made by the Province of Prince Edward Island and, in particular, its policy to have the option to finance and own new generating facilities. Discussions with the Province on the issue of ownership are ongoing.

**Procedure**

5. Filed herewith is the Affidavit of Frederick J. O'Brien, John D. Gaudet and Robert O. Younker, which Maritime Electric relies upon in this Application.

Dated this 24th day of June 2015.

**D. Spencer Campbell, Q.C.**
**Counsel for the Applicant**
**Whose address for service is:**

STEWART MCKELVEY
65 Grafton Street, PO Box 2140
Charlottetown PE C1A 8B9
Telephone: (902) 629-4549
Facsimile: (902) 892-2485
Email: scampbell@smss.com

**C A N A D A**

**PROVINCE OF PRINCE EDWARD ISLAND**

**BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION**

**IN THE MATTER** of the Application of Maritime Electric Company, Limited for approval of expenditures to be made over a four year period (2015 to 2018) for the design, construction and commissioning of a combustion turbine generator with a nominal rating of 50 MW to be located at the Charlottetown Plant Site. ("the Project")

**AFFIDAVIT**

We, Frederick James O'Brien, of Alberton, in Prince County, John David Gaudet of Charlottetown, in Queens County, and Robert Owen Younker of Cornwall, in Queen's County, Province of Prince Edward Island, MAKE OATH AND SAY AS FOLLOWS:

1. We are the President and Chief Executive Officer, Vice President, Corporate Planning and Energy Supply and Director, Corporate Planning for Maritime Electric respectively and as such have personal knowledge of the matters deposed to herein, except where otherwise noted, in which case we rely upon the information of others and in which case we verily believe such information to be true.

2. Maritime Electric is a public utility subject to the provisions of the Act engaged in the production, purchase, transmission, distribution and sale of electricity within Prince Edward Island.

3. We prepared or supervised the preparation of the evidence and to the best of our knowledge and belief the evidence is true in substance and in fact. A copy of the evidence is attached to this our Affidavit, and is collectively known as Exhibit "A.

SWORN SEVERALLY at
Charlottetown, County of Queens,
Province of Prince Edward Island,
The 24th day of June 2015.
Before me:

Fred O'Brien

Frederick J. O'Brien

John Gaudet

John D. Gaudet

R. O. Younker

Robert O. Younker

A Commissioner for Taking Affidavits
In the Supreme Court of Prince Edward Island.

## 3.0 EXECUTIVE SUMMARY

Maritime Electric, under Section 3 of the Act, has an obligation to serve as changing conditions require. In fulfilling this obligation, the Company undertakes planning studies that identify, among other things, the need for replacement and new electrical generating facilities. Beginning in 2012, the Company identified a change in the electricity peak load that is being driven, in part, by the growth in the use of electricity for space heating. Under utility reliability criteria, adequate energy supply sources are required under a number of contingencies, to ensure the continuity of service.

This Application provides Maritime Electric's assessment of options and timelines to fulfill its obligation to serve and presents economic analyses and impacts based upon its internal financing of the Project. Maritime Electric acknowledges the recent announcements from the Province of Prince Edward Island and, in particular, its policy to have the option to finance and own new generating facilities, with reference to introducing legislation in the Fall sitting of the Legislative Assembly for clarity.

Maritime Electric has communicated with the Province that it is essential that the Application for a new combustion turbine generator with a nominal rating of 50 MW ("the Unit" or "CT4") move forward without delay and that this Application will require the Company to provide evidence on project costs and impacts. The issue of ownership will not influence the need or timing for the Unit. Maritime Electric will be undertaking discussions with the Province to gain a detailed understanding of what the Province is contemplating, the Province's proposed financing and other costs and the related savings to customers. This Application is based on the Company's ownership of the Unit, and the financing and other costs projected by the Company. The Company proposes to keep the Commission apprised of the discussions with the Province and how the Province's new policy impacts the issue of ownership, project financing and other costs contained in this Application.

Maritime Electric seeks approval of the Commission to make an expenditure of $68 million for the design, construction and commissioning of CT4 to be located at the

Charlottetown Plant Site, the site of Maritime Electric's Charlottetown Thermal Generating Station ("CTGS") and Combustion Turbine 3 ("CT3"). The Unit is expected to be in-service by late 2017 or early 2018, depending on lead times for equipment delivery.

CT4 is needed for the following reasons:

1. The CTGS is approaching the end of its useful life, and would need an extensive refurbishment to continue to operate safely and reliably. When operating costs are factored in, installation of CT4 is a lower cost option than conducting a second life extension refurbishment of the three largest units at the CTGS, for what would be a combined refurbished capacity of 50 MW. The three largest CTGS units were installed in the 1960's - the newest unit is 48 years old.

2. Transmission system constraints in New Brunswick require that the generating capacity to replace the CTGS be located either in PEI or on the mainland on the PEI side of Moncton. Given the limited generation options currently available on the mainland, Maritime Electric has concluded that CT4 should be installed in PEI.

3. The best on-Island location for CT4 is in Charlottetown, where it can serve as backup to much of the on-Island transmission system. The CTGS currently provides this benefit, but not as effectively as CT4 will be able to do since CT4 is expected to have 10 minute start capability and synchronous condenser capability, neither of which the CTGS steam units have (the existing CT3 unit does not have synchronous condenser capability).

Constraints on the capacity of the New Brunswick transmission system to supply PEI load is a recent development, and is a separate issue from the capacity limitation of the two existing submarine cables. The recently announced funding assistance from the Federal Government is for a project that will address the capacity limitation and age of the two existing submarine cables by adding two new submarine cables.

CT4 is needed to have sufficient generating capacity in PEI when there is a transmission constraint in New Brunswick. Both projects are needed to reliably supply Maritime Electric's growing electricity load.

In recent years there has been strong load growth in the southeastern part of New Brunswick, particularly in the Moncton area. Because there are no generating plants located in the southeastern part of New Brunswick, this has increased the loading on the transmission lines that supply the Moncton area and the rest of southeastern New Brunswick, which includes the PEI load. The situation has developed to the point where deliveries to PEI are curtailed under circumstances which would result in loss of load if a main transmission line to the Moncton area were to go out of service.

As a result, NB Power has deemed that the maximum amount of <u>firm</u> transmission capacity in New Brunswick that is available to supply PEI load is 80 MW. This means that the transmission system constraint in New Brunswick has effectively replaced a submarine cable outage as the worst-case single contingency limitation to supplying Maritime Electric load. Being able to reliably supply the load requires planning for the worst-case single contingency scenario. Thus, this limited firm transmission capacity on the New Brunswick system means that, even with additional submarine cable capacity installed within the next several years, the amount of generating capacity required has to increase.

If approval is received for CT4, the table below shows how Maritime Electric expects to meet its peak load under the worst-case New Brunswick transmission system constraint until 2019. For 2020 and beyond, additional measures will be required; e.g. additional on-Island generating capacity, participation in a new natural gas fired generating plant in the Moncton area, or upgrades to the New Brunswick transmission system.

| Table 1 - Meeting the Maritime Electric peak load under worst-case NB transmission system constraint | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| | | | | | | | |
| Maritime Electric peak load | MW | 240 | 245 | 251 | 259 | 267 | 275 |
| Less reduction due to DSM [1] | MW | | 2 | 4 | 6 | 8 | 10 |
| Forecast peak load | MW | 240 | 243 | 247 | 253 | 259 | 265 |
| | | | | | | | |
| CTGS | MW | 55 | 55 | 55 | 55 | 38 | 19 |
| Borden Plant | MW | 40 | 40 | 40 | 40 | 40 | 40 |
| Combustion Turbine 3 | MW | 49 | 49 | 49 | 49 | 49 | 49 |
| Wind Effective Load Carrying Capability [2] | MW | 21 | 21 | 21 | 21 | 21 | 21 |
| Maximum from off-Island (includes Point Lepreau) | MW | 80 | 80 | 80 | 80 | 80 | 80 |
| Short term capacity agreement [3] | MW | 27 | 27 | | | | |
| Combustion Turbine 4 | MW | | | 50 | 50 | 50 | 50 |
| Additional capacity | MW | | | | | | 50 |
| Total available capacity | MW | 272 | 272 | 295 | 295 | 278 | 309 |
| | | | | | | | |
| Capacity surplus | MW | 32 | 29 | 48 | 42 | 19 | 44 |

**Notes:**

1. MECL has developed an energy efficiency and demand side management ("DSM") plan that is expected to reduce peak load.
2. This is 23% of the 92 MW of wind generation under contract to Maritime Electric, based on a probabilistic analysis.
3. Maritime Electric has entered into a short-term agreement with NB Power for 27 MW of capacity to be provided in the event of unforeseen circumstances that would otherwise result in a capacity shortage, until additional capacity can be acquired downstream from the New Brunswick constraint. The arrangement expires in early 2017; NB Power has advised that it cannot be extended.

Based on a weighted average cost of capital for Maritime Electric of 6.54% the estimated increase in rates in 2018 due to CT4 is 2.7%. This equates to an increase of $3.25 on an estimated monthly bill of $120.29 (excluding HST) for a Rural Residential customer using 650 kWh per month. For comparison purposes only, on a levelized financing basis over the 50 year life of the asset, the first year revenue requirement due to CT4 corresponds to 1.7% of the 2018 revenue requirement, or an increase of $2.05 on the monthly bill of $120.29.

## 4.0 INTRODUCTION

Maritime Electric is seeking Commission approval to install CT4 at the Charlottetown Plant site. The existing CTGS steam boilers and steam turbine generators are expected to reach the end of their service life in a 5 to 7 year time frame. This document is the Company's evidence in support of its Application for approval to install CT4.

The estimated installed cost for CT4 is $68 million. The Unit will burn diesel fuel and will fill the same standby and peaking role that the Borden Plant combustion turbines (CT1 and CT2), the CTGS steam units and CT3 serve, which is to:

- Provide some of the generating capacity that Maritime Electric needs to meet its capacity requirements under the Interconnection Agreement with NB Power
- Provide back-up generation when there are outages or overloads on the transmission system in PEI or in New Brunswick or on the submarine cables
- Provide generating capacity in PEI at a time when transmission system constraints in New Brunswick limit the amount of firm generating capacity that can be supplied from New Brunswick (These transmission constraints are on the New Brunswick transmission system, not with the submarine cables that connect the PEI electricity system to New Brunswick).

The following table shows how Maritime Electric's existing three combustion turbines were used in this standby and peaking role in 2014. The CTGS steam units have not been included in the table because their generation does not lend itself to the same breakdown. Due to the longer startup time for the boilers and steam turbines, most of the CTGS steam units' generation in 2014 was associated with equipment testing and operator training, with the running of the units usually done when the system load is high, so that some of the generation serves to off load the submarine cables. The CTGS steam units' combined gross generation for 2014 was 4,656 MWh. (In 2012, the CTGS generated 14,000 MWh during repairs to one of the submarine cables)

| Table 2 - Breakdown of Combustion Turbine Gross Generation for 2014 | | | | | | |
|---|---|---|---|---|---|---|
| | **Off load submarine cables** | **Curtailment by NB Power** | **NB Power Hold-To-Schedule** | **Lepreau tripped off** | **On-Island transmission outage/maint** | **Unit testing** |
| | | | | | | |
| CT1 (MWh) | 171 | 7 | 28 | - | - | 21 |
| | | | | | | |
| CT2 (MWh) | 54 | 52 | 20 | - | - | 24 |
| | | | | | | |
| CT3 (MWh) | 2,227 | 666 | 171 | 21 | 131 | 51 |
| | | | | | | |
| Number of occurrences | 30 | 11 | 10 | 1 | 3 | 10 |

**<u>Notes</u>:**

1. "Curtailment by NB Power" is for transmission constraints in NB.
2. "NB Power Hold-To-Schedule" is for transmission constraints in NB resulting from on-Island wind generation being less than forecast, and CTs were run to make up the shortfall.
3. "Lepreau tripped off" is when the Point Lepreau unit unexpectedly tripped off line and Maritime Electric was called on to supply its share of the Maritime Area 10 minute non-spinning reserve requirement.

The installation of two new submarine cables is expected to eliminate the need for on-Island generation to off load the existing cables. However, on-Island combustion turbines will continue to be needed for the other purposes shown in the above table.

Like CT3 and the CTGS steam units, CT4 is expected to operate in the order of 100 to 200 hours per year. This is due to the New Brunswick electricity load being more than 10 times the size of the PEI electricity load, which results in NB Power having access to more than enough spare generating capacity during most of the year to supply as much of the PEI load as needed. It is only during the coldest weather or for constraints on the New Brunswick transmission system that NB Power curtails some of its supply to PEI, and then the on-Island generators are run.

This synergy between the PEI and New Brunswick electricity systems is demonstrated in the following table, which shows Maritime Electric's sources of electricity supply for 2014.

| Table 3 - Maritime Electric Electricity Supply for 2014 | | |
|---|---|---|
| | **MWh** | **%** |
| On-Island oil-fired generation | 8,300 | 0.6 |
| On-Island wind generation | 291,400 | 23.1 |
| Point Lepreau participation (nuclear) | 208,000 | 16.5 |
| System purchases from NB Power | 753,000 | 59.8 |
| **Total** | 1,260,700 | 100.0 |

This mode of operation is expected to continue in the future, enabled in part by the new 50 MW combustion turbine and the planned increase in the capacity of the interconnection with the addition of two more submarine cables.

The proposed Project timeline is shown in Schedule 1. Project development, obtaining approvals and preliminary engineering would be done in 2015. Expenditures in 2016 would be mainly for progress payments on equipment supply. Construction would start in April 2017, with the Unit being available for operation by December 2017. However, final commissioning would not be complete until early 2018. Other expenditures in 2018 would be for progress payments for December 2017 work, release of holdbacks, payments for meeting performance guarantees, operator training, purchase of spare parts, and site restoration.

The breakdown of expenditures by year is as follows:

2015 - $ 1.7 million
2016 - $ 25.1 million
2017 - $ 36.4 million
2018 - $ 4.8 million
Total $ 68.0 million

In addition to Commission approval, the Project requires the following approvals:

- Approval of an Environmental Impact Assessment from the PEI Department of Communities, Land and Environment, and
- A Building Permit from the City of Charlottetown.

## 5.0 REVIEW OF EXISTING GNERATING RESOURCES

The resources currently available to supply the Maritime Electric electricity load include the following:

Charlottetown Thermal Generating Station (CTGS)

Maritime Electric owns and operates the CTGS which consists of five steam units that burn heavy fuel oil (bunker C). The units were installed in the 1950's and 1960's and range in size from 7.5 MW to 20 MW. The demonstrated net capability of the CTGS is 55 MW (it had been 60 MW, but currently the oldest unit is not available for service because of concerns about the integrity of the generator end caps). The plant is normally in a standby mode. It operates when the normal sources of supply on the mainland are not available or when there is a need to manage the loading on the submarine cables interconnection with New Brunswick.

The CTGS underwent a life extension refurbishment in the first half of the 1990's, which was intended to enable the CTGS to continue to operate reliably for an additional 15 years. Currently the CTGS is in need of another life extension refurbishment. If a life extension were to be done, it is expected that only the three largest units, totaling 50 MW of capacity, would be refurbished.

Based on a 2010 consultant's report, the Company has estimated the cost of a 15-year life extension to be approximately $41 million. At that time Maritime Electric determined that replacing the CTGS with a combustion turbine would be more cost effective when operating costs are taken into account.

Given the age of the CTGS, in recent years Maritime Electric has limited capital investment in the facility to items required to ensure the safety of personnel operating the equipment and to maintain the reliability of the facility in the short term. Availability of bunker C fuel has also become an issue – there are currently no suppliers in the Maritimes.

A follow-up assessment of the condition of the CTGS in 2014 further stressed that generation equipment and components are approaching the end of their service life. Refurbishment of the CTGS is not recommended.

To further reduce capital and operating expenditures at the CTGS, the equipment will be put into long term layup in stages after the installation of CT4. In long term layup, the units could be returned to service given sufficient lead time. However, the lead time required would be longer than the 48 hours in winter and 7 days in summer provided for under the current contract with NB Power, and thus the capacity amounts for the CTGS in Table 1 have been reduced to reflect the amount of capacity expected to be in long term layup.

Borden Generating Station

Maritime Electric owns and operates the Borden Generating Station which consists of two combustion turbine units (designated as CT1 and CT2) that burn light fuel oil (diesel fuel). The units were installed in the early 1970's and have a combined net capacity of 40 MW. The Borden Generating Station is normally in a standby mode. It operates when the normal supply of energy is interrupted by outages of other generators or by failure of elements of the transmission system. Because of their 10 minute start capability, the units are also used to supply Maritime Electric's share of the Maritime Area 10 minute non-spinning reserve. (The Maritime Provinces as an Area are required to be able, within 10 minutes, to replace the unplanned loss of the output of the largest generator in the Area, which is usually the 660 MW Point Lepreau unit. This responsibility is shared among the electric utilities on a load ratio basis.)

Based on refurbishment and upgrading of the units in recent years, the Borden Generating Station is expected to operate reliably for at least another 10 years.

Combustion Turbine 3

Maritime Electric owns and operates the combustion turbine generator designated as CT3. It burns light fuel oil (diesel fuel) and is located at the Charlottetown Plant site.

This unit was installed in 2005 and has a net capacity of 49 MW (the gross output is 50 MW; 49 MW is the output delivered to the system after subtracting the load for the unit's auxiliary equipment). CT3 is normally in a standby mode. It operates when the flow of purchased energy is interrupted by outages of other generators or by failure of elements of the transmission system. Because of its 10 minute start capability, CT3 can also be used to supply 10 minute non-spinning reserve.

Wind Generation

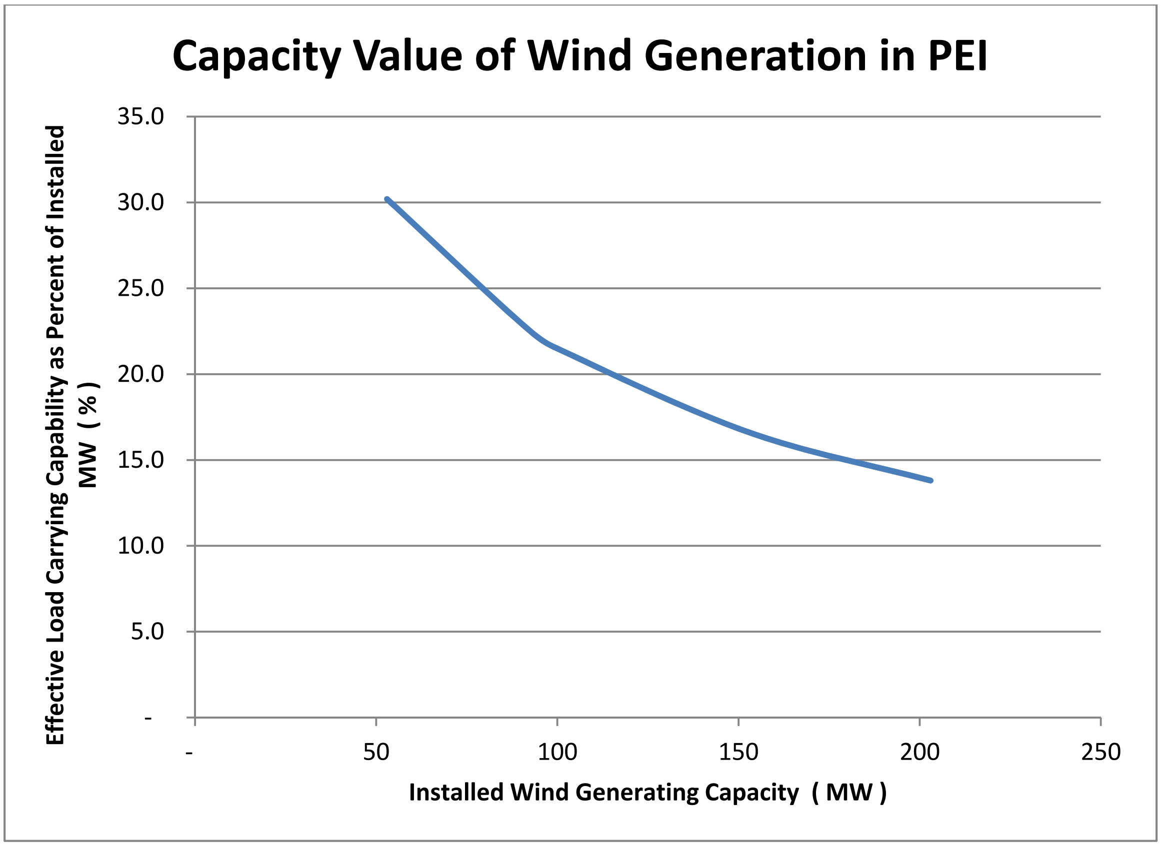
Maritime Electric has contracted with the PEI Energy Corporation to purchase the output from the following on-Island wind farms:

- 10 MW from the North Cape wind farm
- 3 MW from a Vestas prototype V-90 wind turbine near North Cape
- 30 MW from the Eastern Kings wind farm
- 9 MW from the Norway wind farm
- 10 MW from the WEICan wind facility
- 30 MW from the Hermanville / Clearspring wind farm

92 MW total

Due to the intermittent nature of wind generation, only a portion of the nameplate capacity of the wind generators installed in PEI is counted as capacity for planning purposes. Based on the electric utility industry probabilistic Loss Of Load Expectation (LOLE) methodology, Maritime Electric has assigned an Effective Load Carrying Capability (ELCC), or effective capacity value, of 21 MW to the 92 MW of contracted wind generation. The ELCC of 21 MW is the additional load which the system can supply with 92 MW of wind generation added to the system, while still maintaining the same level of reliability of supply.

The graph below shows how the percentage of wind generation that can be considered as ELCC varies as the amount of wind generation installed in PEI increases. For 92 MW of installed capacity, the 21 MW of ELCC corresponds to 23% of the installed capacity, as shown on the graph. The graph shows that further increases in wind generation will result in only a small increase in ELCC. For example, for 200 MW of wind generation, the ELCC would be approximately 14% of 200 MW, or 28 MW. The reason for this is that 92 MW is already a large amount of wind generation relative to the size of the PEI load.




Point Lepreau

The Point Lepreau Unit Participation Agreement provides Maritime Electric with 30 MW (29 MW net of transmission losses at Murray Corner) of base load capacity and associated energy from NB Power's Point Lepreau Nuclear Generating Station. That facility has a capacity of 660 MW, and incorporates Atomic Energy of Canada Limited's CANDU technology. The participation agreement is for the life of the plant, which is expected to be 27 years from the completion of a life extension refurbishment in Fall 2012.

Short Term Purchases

Maritime Electric is currently purchasing system capacity and system energy from NB Power under a contract that extends to February 28, 2019. System purchases are not tied to any particular generating units on NB Power's system. The Company also has an agreement with NB Power for 27 MW of capacity to provide additional support in the event of unforeseen circumstances that would otherwise result in a capacity shortage, until additional capacity can be acquired downstream from the New Brunswick transmission constraint. The arrangement expires in 2017.

Maritime Electric also purchases approximately 6 MW of spinning reserve on an on-going basis to provide for its share of the Maritime Area spinning reserve requirement. Spinning reserve normally can only be supplied by dispatchable generating units that are running but not fully loaded.

Dalhousie

The Dalhousie Participation Agreement had provided Maritime Electric with 20 MW (19 MW net of transmission losses at Murray Corner) of base load capacity and associated energy. With the termination of NB Power's Orimulsion supply agreement with Venezuela, NB Power decided to close the plant because it was not economic to operate with heavy fuel oil as the only available fuel. Maritime Electric's participation in the Dalhousie Plant formally ended as of February 28, 2011.

## 6.0 FORECAST OF PEAK LOAD AND CAPACITY REQUIREMENTS

Schedule 2 contains Maritime Electric's load forecast for the next 10 years, along with a calculation of the amount of generating capacity that Maritime Electric must have either installed or purchased to meet its peak load under the worst-case New Brunswick transmission constraint. Schedule 2 does not take into account the City of Summerside load. The reason is that since 2002 the City of Summerside has contracted to purchase all of its electricity from sources other than Maritime Electric. The Company has recently had preliminary discussions with the City regarding generation additions, and there may be an opportunity for collaboration.

Schedule 2 shows, with the installation of CT4 in 2017 and the ensuing staged long term layup of the CTGS steam units, how Maritime Electric expects to be able to meet its peak load under the worst-case New Brunswick transmission system constraint until 2019.

Schedule 2 also shows that for 2020 and beyond, additional measures will be required, such as additional on-Island generating capacity, participation in a new natural gas fired generating plant in the Moncton area, or upgrades to the New Brunswick transmission system to address the current constraint.

MECL follows a reliability criterion requiring that a utility have sufficient resources available to supply the peak load under the worst-case single contingency event; i.e. the largest single element of the power system out of service. In the past this has been deemed to be the loss of either of the two submarine cables. Since each cable has a capacity of 100 MW, the loss of one of the cables would limit the supply to PEI from New Brunswick to 100 MW, the capacity of the remaining cable. This, along with the age of the existing submarine cables, has led Maritime Electric and the Province to the development of the interconnection upgrade project.

However, constraints on the New Brunswick transmission system have recently replaced a submarine cable outage as the worst-case single contingency limitation to supplying Maritime Electric load. In recent years there has been strong load growth in the southeastern part of New Brunswick, particularly in the Moncton area. Because there are no generating plants located in the southeastern part of New Brunswick, this load growth has increased the loading on the transmission lines that supply the Moncton area and the rest of southeastern New Brunswick, which includes the PEI load.

Schedule 3 shows the single line diagram for the New Brunswick transmission system. The worst case contingency for the supply of load in southeastern New Brunswick is the loss of the 345 kV line between Saint John and Moncton. Under this circumstance, more of the supply for southeastern New Brunswick has to flow through the northern part of the Province, with a resulting increased drop in voltage. If this contingency were to occur during high load periods, some load would have to be shed to restore voltages to normal levels. Rather than risk having to shed load, NB Power limits supply to PEI and Nova Scotia as necessary so that loss of the 345 kV line would not result in load being shed.

Due to this constraint, NB Power has deemed that the maximum amount of firm transmission capacity available to supply PEI load is 80 MW. This is the reason for the limitation of firm generating supply from off-Island to 80 MW in Schedule 2.

This limited firm transmission capacity on the New Brunswick system means that, even with the planned installation of additional submarine cable capacity, the amount of generating capacity required to be maintained in PEI cannot be reduced. However, it is also important to understand that for most hours in the year the 345 kV line between Saint John and Moncton is in service. It is only during times of high system load in New Brunswick that the loss, or potential loss, of this line represents a constraint. Thus, for most hours of the year most of PEI's electricity requirement in excess of on-Island wind generation can still be purchased from the mainland.

## 7.0 COMPARISON OF THE PROJECT TO POTENTIAL ALTERNATIVES

Maritime Electric has performed an economic analysis to compare the cost of the Project to the cost of a life extension refurbishment of the CTGS and to the cost of installing a 100 MW combustion turbine (that would provide economies of scale benefits). A 100 MW unit was chosen for comparison because 100 MW is currently the largest aero-derivative (i.e., based on an aircraft engine design) combustion turbine available. Aero-derivative combustion turbines are best suited for Maritime Electric's purposes because they have 10 minute start capability and frequent starts and stops do not result in shortened maintenance intervals.

Two other alternatives that were considered, but not evaluated, are:

- Participation in a natural gas fired combined cycle plant that NB Power is considering for the Moncton area. This option is not expected to be available until 2019 at the earliest, when additional long term natural gas supply is expected to become available.
- Installation of a 50 MW combustion turbine in New Brunswick at a location near where the Maritimes and Northeast ("M&NP") Pipeline natural gas mainline crosses the transmission lines that connect to the submarine cables at Murray Corner. However, this option is not considered to be viable until 2019, when additional long term natural gas supply is expected to become available.

These alternatives were not evaluated due to the current limited availability in the Maritimes of long term natural gas supply. This situation is not expected to change until 2018 or 2019, when additions to the natural gas pipeline system in the northeastern US are expected to increase the capability for delivery of shale gas to the Massachusetts end of the M&NP pipeline, and the Project is needed before then.

Installation of CT4 at the Charlottetown Plant site will not preclude either of these options in the future. Following the installation of CT4 and the long term layup of the CTGS, Maritime Electric will still be purchasing up to 50 MW of short term generating capacity. Either of these options could displace some of this purchased short term capacity, or provide some of the additional capacity expected to be needed for 2020 and beyond.

Five other possibilities were deemed to not be suitable alternatives to the Project:

- Purchase capacity from Nova Scotia. Supply from Nova Scotia would be on the PEI side of the transmission constraint in New Brunswick, and thus would be in addition to the 80 MW limit from New Brunswick. However, as has been the case in the past, NS Power does not have surplus capacity to sell.
- Purchase from the Lower Churchill hydro development. Most of the output from the Muskrat Falls hydro plant is expected to be used in Newfoundland and Nova Scotia. Any surpluses are expected to be non-firm and available mainly during non-winter months.
- Increase the scale of energy efficiency and DSM programming. These activities will displace short term capacity purchases. However, given that Maritime Electric will still be purchasing up to 50 MW of short term capacity following the installation of CT4 and the retirement of the CTGS, it would be unreasonable to suggest that increasing the scale of energy efficiency and DSM programming would eliminate the need for CT4. (The Company's proposed energy efficiency and DSM Plan is targeting a peak reduction of 10 MW.)
- Build a second 345 kV transmission line between Saint John and Moncton. Studies of increasing the transfer capability between the Saint John and Moncton areas – which would allow Maritime Electric to procure additional firm capacity off-Island – estimate that it would cost at least $200 million. There are currently no firm plans to expand New Brunswick's transmission system. NB Power's most recent 10-Year Plan (Fiscal Years 2016 to 2025) indicates that the existing New Brunswick transmission system is adequate to meet short- to medium-term forecasts of New Brunswick load.
- Increase the use of renewable energy. As explained in Section 3, installing more wind generation would provide more energy, but little additional capacity value. Installing solar power would provide energy, but no capacity – the PEI system

peak occurs between 5:00 p.m. and 6:00 p.m. in December or January, after sunset.

The economic analysis used a weighted average cost of capital for Maritime Electric of 6.54%, based on 41.5% equity at 9.75% allowed return and 58.5% debt at 4.25% interest rate. The 9.75% is the current allowed rate of return on average common equity, as determined by IRAC, and is subject to review and adjustment by the Commission. The 4.25% debt interest rate is the estimated cost for long term borrowing by Maritime Electric (minimum of 30 years, longer if available so as to better match the 50 year life of the generator).

Further details regarding cost of capital, discount rate and escalation rate are shown in Schedule 4. Details of the present value calculations are shown in Schedule 5. The results of the analysis are summarized below.

**Table 4 - Comparison of Alternatives to the 50 MW CT4**

| | **Life Extend CTGS** | **Install 50 MW CT4** | **Install 100 MW CT** |
|---|---|---|---|
| **Nominal generating capacity ( MW )** | 50 | 50 | 100 |
| | | | |
| **Service life ( years )** | 15 | 50 | 50 |
| | | | |
| **Installed costs ($ millions)** | 41.0 | 68.0 | 114.1 |
| | | | |
| **Annual fixed O & M in 2018 $ ($ millions)** | 4.3 | 0.7 | 1.2 |
| | | | |
| **Present value at start of 2018 ($ millions):** | | | |
| - Installed cost | 41.0 | 68.0 | 114.1 |
| - Associated income taxes | 5.5 | 6.5 | 10.9 |
| - Fixed O&M for CTGS for 15 years | 46.1 | | |
| - Fixed O&M for CT4 for 50 years | | 13.7 | 24.3 |
| - Fixed O&M for CTGS assets to be used by CT3 and CT4 | | 11.2 | 11.2 |
| - CTGS fixed O&M for 2018 - 2020 | | 10.0 | 10.0 |
| - Cost to install 50 MW CT in year 16 | 33.9 | | |
| - Credit for accredited capacity in excess of 50 MW for 2018 to 2024 | | | (16.9) |
| - Credit for avoided 50 MW CT in 2024 | | | (50.1) |
| | | | |
| **Total** | 126.5 | 109.4 | 103.5 |

Table 4 shows that installing a new 50 MW combustion turbine has a lower present value cost than a life extension refurbishment of the CTGS, and thus installation of a new combustion turbine is recommended.

Table 4 also shows that the 100 MW combustion turbine has a lower present value cost than the 50 MW combustion turbine. However, installation of a 100 MW combustion turbine is not recommended over the installation of a 50 MW combustion, for the following reasons:

1. Larger upfront capital cost and associated rate increase for the 100 MW unit;
2. Potential reduced opportunity for participation in future generation options that could offer better efficiencies, such as combined cycle or cogeneration; and
3. A limitation on how much of the 100 MW unit's capacity that can be counted towards Maritime Electric's capacity requirements under the Interconnection Agreement with NB Power.

To put the 100 MW combustion turbine on a comparable basis to a refurbished CTGS (50 MW) and the 50 MW combustion turbine, the cost of purchased capacity that would be displaced by a portion of the 100 MW unit's capacity in excess of 50 MW during 2018 to 2024 has been shown as a credit in the analysis. However, the total 100 MW of capacity could not be used for planning purposes in the early years. Under the terms of the Interconnection Agreement with NB Power, the amount of capacity that can be relied on from any one source of generation is limited to 30 % of Maritime Electric's firm peak load. In 2014 the Company's firm peak load was 209 MW, and 30 % of this is 63 MW. This will increase over time as the load grows. Details of the calculation are shown in Page 3 of Schedule 5.

Schedule 2 shows that with the installation of a 50 MW unit, additional capacity will be required in 2024. With the installation of a 100 MW unit, this would not be needed. Therefore, the 100 MW unit is credited with avoiding the need for installation of an additional 50 MW combustion turbine in 2024.

Also, since the service life of the CTGS is assumed to be extended for only 15 years under the "Life Extend CTGS" option, the present value cost of installing a 50 MW combustion turbine in year 16 has been included as a cost in the analysis for that option.

## 8.0 REASONS FOR CHOOSING THE CHARLOTTETOWN PLANT SITE

Three on-Island locations were considered for CT4. The Charlottetown Plant site was chosen because of the benefits it will provide in backing up the on-Island transmission system. The potential benefits of the three sites are discussed in the following paragraphs.

Maritime Electric's Charlottetown Plant site

The main advantage of installing the unit in Charlottetown is the support and back up that it will provide to the on-Island transmission system. These benefits are:

- The unit will be capable of synchronous condenser operation. In this mode it will provide reactive power for the transmission system in the Charlottetown area and eastern PEI. This reactive power supply is needed to maintain acceptable voltages, particularly at high load levels and during outages of one of the 138 kV lines between Bedeque and West Royalty.
- It will enable the staged long term layup of the CTGS and be a second source of dispatchable generation for the Charlottetown area and eastern PEI. When the CTGS is retired, the only dispatchable generation east of Borden would be CT3 (in absence of CT4). During CT3 maintenance periods, there would be none.
- Charlottetown generation is needed to offload the West Royalty 138 kV to 69 kV autotransformers during maintenance outages or peak loading times.

At a Processing Plant that has a Large Steam Load

The main advantage of installing the unit at a processing plant with a large steam load would be the potential for cogeneration. Natural gas would be needed as the fuel. The natural gas would be burned in the combustion turbine and the process steam would be produced in a heat recovery boiler that would recover heat from the combustion turbine exhaust gases. In cogeneration mode the unit could provide close to base load generation, depending on the steam load. Currently there are no opportunities for this type of project in PEI.

Maritime Electric's Borden Plant site

The main advantage of installing the unit in Borden is that it would probably be the location in PEI with the lowest delivered cost for natural gas, should natural gas become available in PEI (CT4 would be capable of burning natural gas). This is based on the following considerations:

- The shortest distance for a natural gas lateral pipeline to PEI would probably be between the M&NP mainline near Port Elgin, NB and Borden.
- The Strait Crossing fabrication yard in Borden would be a suitable location for liquefied natural gas (LNG) offloading, storage and regasification facilities.
- Compressed natural gas trucked to PEI would come across the Confederation Bridge, and thus arrive in PEI at Borden.

Currently there is limited availability in the Maritimes of long term natural gas supply. This situation is not expected to change until 2018 or 2019, when additions to the natural gas pipeline system in the northeastern US are expected to increase the capability for delivery of shale gas to the Massachusetts end of the M&NP pipeline.

The Charlottetown Plant site has been chosen because the benefits of backing up the transmission system are significant and are expected to be realized.

## 9.0 IMPACT ON RATES

The initial impact on rates is a function of the revenue requirement in the first year. The estimated initial increase in customer rates for each option is shown in Table 5 below. The percentage increase in rates is based on a Maritime Electric total estimated annual revenue requirement of approximately $200 million in 2018.

| Table 5 – Estimated Initial Impact on Rates | | | |
|---|---|---|---|
| | **Life Extend CTGS** | **Install 50 MW CT4** | **Install 100 MW CT** |
| **Nominal capacity (MW)** | 50 | 50 | 100 |
| | | | |
| **Service life (years)** | 15 | 50 | 50 |
| | | | |
| **Installed costs ($ millions)** | 41.0 | 68.0 | 114.1 |
| | | | |
| **First year revenue requirement ($ millions)** | | | |
| - 58.5 % debt, interest at 4.25 % | 1.02 | 1.69 | 2.84 |
| - 41.5 % equity, return at 9.75 % | 1.66 | 2.75 | 4.62 |
| - Corporate income taxes at 31 % | 0.75 | 1.24 | 2.07 |
| - Amortization (based on a full year) | 2.73 | 1.36 | 2.28 |
| - Fixed O&M expense | 4.28 | 0.69 | 1.22 |
| - Fixed O&M for CTGS assets to be used by CTs | n/a | 0.56 | 0.56 |
| **Subtotal** | 10.44 | 8.29 | 13.59 |
| | | | |
| Less: | | | |
| - Cost of avoided capacity purchases | n/a | 2.40 | 3.00 |
| - Fixed O&M already being incurred | 4.84 | 0.56 | 0.56 |
| **Net requirement** | 5.60 | 5.33 | 10.03 |
| | | | |
| **Corresponding increase in rates (%)** | 2.8% | 2.7% | 5.0% |
| | | | |

Note:

1. Maximum short term firm capacity purchase from NB is 50 MW (80 MW limit - 30 MW for Point Lepreau). With the 50 MW CT4, Maritime Electric would still need to purchase 10 MW of capacity from NB in 2018, so CT4 would displace 40 MW of short term capacity purchases in 2018 while the 100 MW CT would displace 50 MW.

In Table 5 above, the first year financing related costs for debt interest, equity return, amortization and taxes for the 50 MW CT4 are $7.04 million. In succeeding years these costs (except for amortization) will decrease as the equal annual amortization amounts of $1.36 million are subtracted from the initial $68.0 million, so that the annual revenue requirement declines over the 50 year life of the asset. This is the method that Maritime Electric follows for financial reporting and rate making purposes, as required by accounting principles.

For comparison purposes only, an alternative approach is to express the financing related costs as a fixed annual amount over the life of the asset, similar to a house mortgage payment. The first year revenue requirement for CT4 as a percentage of the 2018 revenue requirement under this approach is shown in Table 6 below alongside the corresponding results from Table 5. (The $5.09 million levelized financing related amount is equal to $68.0 million times the 7.48% fixed charges rate from Schedule 4).

**Table 6 – Comparison of First Year Impact of CT4 on Customer Bills**

| | **Equal amortization every year (from Table 5)** | **Equal financing related revenue requirement every year** |
|---|---|---|
| **First year revenue requirement ($millions)** | | |
| - Capital Related | 7.04 | 5.09 |
| - Fixed O&M Expense | 0.69 | 0.69 |
| | 7.73 | 5.78 |
| - Less cost of avoided capacity purchases | 2.40 | 2.40 |
| Net requirement | 5.33 | 3.38 |
| **Corresponding increase in rates (%)**[1] | 2.7 | 1.7 |
| **Increase in monthly residential bill ($)**[2] | 3.25 | 2.05 |

Note:
1. Based on an estimated 2018 annual revenue requirement of $200 million.
2. The increase in the monthly residential customer bill is based on an estimated 2018 bill of $120.29 (excluding HST) for a Rural Residential customer using 650 kWh per month.

## 10.0 CONCLUSIONS

Maritime Electric recommends the installation of a new combustion turbine with a nominal rating of 50 MW, to be designated as CT4, for the following reasons:

1. The CTGS is approaching the end of its useful life, and would need an extensive refurbishment in order to continue to be able to operate safely and reliably. When operating costs are factored in, installation of CT4 is a lower cost option than performing a life extension refurbishment of the three largest units at the CTGS, for what would be a combined refurbished capacity of 50 MW. The three largest units were installed in the 1960s – the newest unit is 48 years old.

2. Transmission constraints in New Brunswick require that the generating capacity to replace the CTGS be located either in PEI or on the mainland on the PEI side of Moncton. Given the limited options currently available on the mainland, Maritime Electric believes that CT4 should be installed in PEI.

3. The best on-Island location for CT4 is in Charlottetown, where it can serve as backup to much of the on-Island transmission system. The CTGS currently provides this benefit, but not as effectively as CT4 will to be able to do – CT4 is expected to have 10 minute start capability and to have synchronous condenser capability, neither of which the CTGS steam units have.

4. The present value of the 50 MW combustion turbine is only somewhat higher than the 100 MW unit alternative, because the economies of scale of the larger unit are largely offset by not being able to utilize the full capacity of the 100 MW unit due to it being too large for the Maritime Electric system. A 100 MW unit would require a higher up-front capital investment, along with a larger rate increase. The larger size unit may also limit the opportunity to participate in future potential generation options. For these reasons a nominal 50 MW combustion turbine is recommended rather than a 100 MW unit.

## 11.0 GLOSSARY

**Base Load Generating Unit**

A generating unit, usually coal or nuclear, which has high capital cost but relatively low fuel and operating costs. Because of its low variable costs, it is usually more economic to operate a base load unit whenever it is available, and thus it tends to operate at full load. Base load units usually operate about 80% of the time.

**Capacity**

In the electric power industry, this word has two meanings:

1. Power; that is, the rate of delivery of energy. For example, a contract for 50 MW of capacity corresponds to an energy delivery rate of 50 MWh per hour.
2. The maximum amount of power that a piece of equipment is capable of delivering.

**Capacity Factor**

A measure of how much electricity a generating unit produces during a year. Mathematically, it is equal to the number of kWh actually produced divided by the product of the unit's capacity in kW and 8,760, the number of hours in a year.

**Combined Cycle**

The use of a single fuel source to power both a combustion turbine generating unit and a steam turbine generating unit. The fuel is burned in the combustion turbine, and the combustion gases are used to drive the combustion turbine. After leaving the combustion turbine, the combustion gases are passed through a heat recovery boiler to produce steam, which is used to drive the steam turbine.

**Combustion Turbine**

Also referred to as a gas turbine. In a combustion turbine generating unit, the combustion gases produced by burning the fuel are expanded through a turbine, which in turn drives an electric generator.

**Demonstrated Net Capability**

The maximum power that a generating plant can produce over a two hour period when all the units are operating.

**Gigawatt-hour (GWh)**

A measure of electricity usage, equal to one million kWh or 1,000 MWh.

**Interruptible Load**

Load for which a customer has agreed to accept less reliable electric service in exchange for paying less for the service. The customer agrees to discontinue taking service when requested to do so by the utility.

**Kilowatt (kW)**

A measure of power, equal to 1,000 Watts. A kilowatt is approximately equal to 1.33 horsepower.

**Kilowatt-hour (kWh)**

A measure of electricity usage. For example, operating ten 100 Watt light bulbs for one hour will use one kilowatt-hour.

**Megawatt (MW)**

A measure of power, equal to one million Watts or 1,000 kW.

**Megawatt-Hour (MWh)**

A measure of electricity usage, equal to 1,000 kWh.

**Peaking Generating Unit**

A generating unit, often a combustion turbine, which has low capital cost but relatively high fuel and other operating costs. The combination of low capital cost and high operating costs make it the lowest cost source of supply when operated for only a few hundred hours per year. Reserve generating capacity is usually supplied by peaking units.

**Reserve Generating Capacity**

The extra generating capacity required on a power system over and above the expected peak load. This extra generating capacity is required for two reasons - first, in case of unexpected breakdown of generating equipment, and second, in case the actual peak load is higher than forecast. A distinction is made based on the time frame involved:

- The term **operating reserve** is used for the extra capacity required on a day-to-day basis. The amount of operating reserve required is usually a function of the size of the largest generating unit in operation on the system at the time.

- The term **planning reserve** is used for the extra capacity required on a year-round basis.

The amount of planning reserve required is usually a function of the annual peak load for the system. For Maritime Electric it is 15 % of the firm peak load.

**Simple Cycle**

The use of a combustion turbine generating unit where there is no recovery of heat from the combustion gases after they leave the combustion turbine.

**Spinning Reserve**

Operating reserve that is provided by a generating unit that is connected to the grid and operating at less than full output.

**Synchronous Condenser**

A generator that is connected to the grid without its prime mover for the purpose of providing voltage control.

**Ten Minute Non-Spinning Reserve**

Operating reserve that is provided by a generating unit that is shut down but is capable of being started and brought to full output within ten minutes.

**Voltage**

The electrical potential or force that causes a current to flow in a circuit. In the water-in-pipe analogy for electricity, the water pressure corresponds to the voltage. Voltage is measured in Volts (V) or kilovolts (kV).

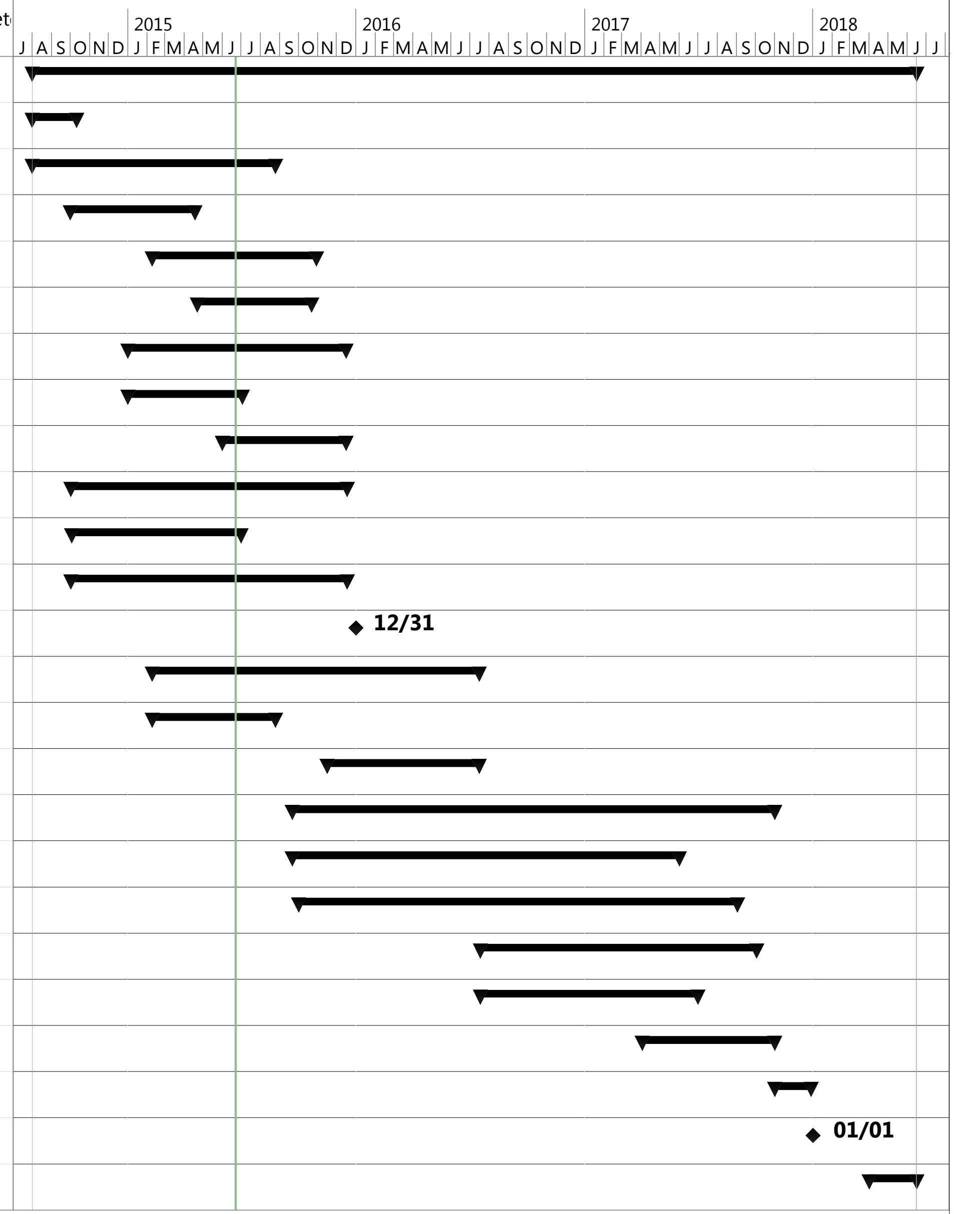
SCHEDULES

MARITIME ELECTRIC COMPANY, LIMITED

CHARLOTTETOWN COMBUSTION TURBINE 4 PROJECT

# Schedule 1 - Project Timeline

| ID | Task Name | Start | Finish | % Complete |
|---|---|---|---|---|
| 1 | **PROJECT DEVELOPMENT AND PROCUREMENT** | 08/01/2014 | 06/15/2018 | 23% |
| 2 | **Feasibility Study** | 08/01/2014 | 10/10/2014 | 100% |
| 6 | **Preliminary Engineering** | 08/01/2014 | 08/24/2015 | 87% |
| 13 | **Board Approval** | 10/01/2014 | 04/17/2015 | 100% |
| 25 | **IRAC Application** | 02/09/2015 | 10/30/2015 | 37% |
| 30 | **Public Consultations** | 04/22/2015 | 10/21/2015 | 52% |
| 36 | **City of Charlottetown Permitting** | 01/01/2015 | 12/15/2015 | 28% |
| 37 | Develop Permit and Background Documentation | 01/01/2015 | 07/03/2015 | 35% |
| 41 | Staff Discussions, Committee Meetings and Approval | 06/01/2015 | 12/15/2015 | 0% |
| 46 | **EIA - Province** | 10/02/2014 | 12/18/2015 | 54% |
| 47 | Sound Level Monitoring | 10/03/2014 | 06/30/2015 | 99% |
| 55 | EIA Submission | 10/02/2014 | 12/18/2015 | 33% |
| 68 | **Approvals Complete** | 12/31/2015 | 12/31/2015 | 0% |
| 69 | **Engineering and EPC** | 02/09/2015 | 07/15/2016 | 34% |
| 70 | Owner's Engineer | 02/09/2015 | 08/24/2015 | 67% |
| 78 | Develop and Award EPC Contract | 11/16/2015 | 07/15/2016 | 0% |
| 85 | **Detailed Design & Equipment Specs** | 09/21/2015 | 10/31/2017 | 0% |
| 86 | Combustion Turbine Spec to On-Site | 09/21/2015 | 06/01/2017 | 0% |
| 93 | Power Transformer Spec to On-Site | 10/01/2015 | 09/01/2017 | 0% |
| 100 | Other Major Equipment Delivery Items | 07/18/2016 | 10/02/2017 | 0% |
| 104 | Detailed Design | 07/18/2016 | 06/30/2017 | 0% |
| 107 | Site Construction | 04/03/2017 | 10/31/2017 | 0% |
| 113 | **Equipment Commissioning** | 11/01/2017 | 12/28/2017 | 0% |
| 116 | **Turbine Commissioned** | 01/01/2018 | 01/01/2018 | 0% |
| 117 | **Plant Site Beautification** | 04/01/2018 | 06/15/2018 | 0% |



FORECAST OF MARITIME ELECTRIC PEAK LOAD AND CAPACITY REQUIREMENTS

| | Actual 2014 | Forecast 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Maritime Electric peak load ( MW ) | 227 | 240 | 245 | 251 | 259 | 267 | 275 | 282 | 291 | 299 | 307 |
| Less reduction due to DSM | | | 2 | 4 | 6 | 8 | 10 | 10 | 10 | 10 | 10 |
| Forecast peak load | 227 | 240 | 243 | 247 | 253 | 259 | 265 | 272 | 281 | 289 | 297 |
| Generating capacity ( MW ): | | | | | | | | | | | |
| - Charlottetown Plant | 60 | 55 | 55 | 55 | 55 | 38 | 19 | | | | |
| - Borden Plant | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 |
| - Combustion Turbine 3 | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49 |
| - Wind Effective Load Carrying Capability | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 |
| - Maximum off-Island (includes Pt Lepreau) | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| - Short term capacity agreement | 27 | 27 | 27 | | | | | | | | |
| - Combustion Turbine 4 | | | | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| - Additional capacity | | | | | | | 50 | 50 | 50 | 50 | 50 |
| subtotal | 277 | 272 | 272 | 295 | 295 | 278 | 309 | 290 | 290 | 290 | 290 |
| Capacity surplus ( shortfall ) | 50 | 32 | 29 | 48 | 42 | 19 | 44 | 18 | 9 | 1 | (7) |

The 21 MW ELCC for wind is 23 % of the 92 MW of wind generation under contract to MECL, based on a probablistic analysis.

**Schedule 3**

**New Brunswick Transmission System Single Line Diagram**

**Cost of Capital and General Escalation Rate**

The following assumptions were made regarding Maritime Electric's cost of capital for the economic analysis:

- Financing based on 58.5 % debt and 41.5 % equity
- Long term debt interest rate of 4.25 %
- Return on equity of 9.75 %
- Corporate income tax rate of 31 %

The resulting weighted average cost of capital is 6.54 %.

The weighted average cost of capital was used as the discount rate in the present value calculations.

Two alternatives to the 50 MW combustion turbine were considered in the analysis – a life extension refurbishment of the CTGS and a 100 MW combustion turbine. The refurbishment of the CTGS is assumed to extend its life for 15 years, and combustion turbines are assumed to have a service life of 50 years. The corresponding amortization rates and levelizing factors are shown in the table below.

| | **Amortization Rate (%)** | **Capital Cost Allowance (%)** | **Capital Recovery Factor (%)** | **Fixed Charges Rate (%)** |
|---|---|---|---|---|
| | | | | |
| Life extension refurbishment | 6.67 | 8.0 | 10.66 | 12.08 |
| Combustion turbine | 2.0 | 8.0 | 6.83 | 7.48 |

The capital recovery factor is calculated using the same levelizing formula as is used to calculate the fixed payments for a house mortgage or an automobile loan, but with the weighted average cost of capital used instead of the interest rate. The difference between the fixed charges rate and the capital recovery factor is the corporate income taxes associated with the return on the equity component of the investment. The capital recovery factor and the fixed charges rate are both levelizing factors, so the difference between them is the levelized income taxes. Thus the present value of owning an asset is the initial capital investment plus the present value of the income taxes associated with the return on equity over the life of the asset.

The fixed charges rate calculations for the CTGS life extension and new combustion turbines are shown in Schedules 6 and 7, respectively.

A general escalation rate of 2 % was used in the economic analysis.

Present value factors were used to calculate the present value of costs, such as O&M costs, incurred each year over the life of the asset. The first year cost multiplied by the present value factor gives the present value. The present value factors shown in the table below were used in the economic analysis.

| Number of years | Discount rate (%) | Present value factors | |
|---|---|---|---|
| | | No escalation | 2 % escalation |
| | | | |
| 15 | 6.54 | 9.38 | 10.78 |
| 50 | 6.54 | 14.65 | 19.92 |

The present value factors are based on the formula for the sum of a geometric progression, which is a sequence of numbers in which each number bears a constant ratio, called the common ratio, to the previous number. If "$a_1$" is the first term, "$a_n$" the nth term, "r" the common ratio, "n" the number of terms and "$s_n$" the sum of n terms, then

$a_n = a_1 r^{n-1}$ and $s_n = a_1 \text{ x } (1-r_n) / (1-r)$

In the application here, $r = (1 + e) / (1 + i)$ where "e" is the escalation rate and "i" is the discount rate. Since "e" and "i" apply to the first year

$s_n = a_1 \text{ x } ((1 + e) / (1 + i)) \text{ x } ((1 + i)^n - (1 + e)^n) / ((I - e)(1 + i)^{n-1})$

## Notes for Table 4 - Present Value Calculations for Comparison of Alternatives

### For the CTGS Life Extension

1. The present value of the income taxes associated with the life extension refurbishment is equal to: $41.0 million x (0.1208 - 0.1066) x 9.38 = $5.5 million. The fixed charges rate (0.1208), capital recovery factor (0.1066) and present value factor (9.38) are explained in Schedule 4.

2. The annual fixed O&M expense for the CTGS after refurbishment is estimated at $4.28 million annually. This is assumed to escalate at 2% annually. The present value of fixed O&M expenses over the 15 year extended life of the CTGS is $4.28 million x 10.78 = $46.1 million. The present value factor (10.78) is explained in Schedule 4.

3. To put the costs for a 15 year life extension of the CTGS on a comparable basis to a combustion turbine with a 50 year service life, the present value cost of installing a 50 MW combustion turbine in year 16 has been added to the life extension costs.

### For the 50 MW Combustion Turbine

1. The present value of the income taxes associated with the combustion turbine is equal to: $68.0 million x (0.0748 - 0.0683) x 14.65 = $6.5 million. The fixed charges rate (0.0748), capital recovery factor (0.0683) and present value factor (14.65) are explained in Schedule 4.

2. The annual fixed O&M expense for the combustion turbine is estimated at $ 0.69 million annually. This is assumed to escalate at 2% annually. The present value of fixed O&M expenses over the 50 year life of the combustion turbine is $0.69 million x 19.92 = $13.7 million. The present value factor (19.92) is explained in Schedule 4.

3. After the CTGS boilers and steam turbines are retired, some of the CTGS assets, such as the land and a portion of the building, will continue to be used for CT3 and CT4. The annual fixed O&M expense for these assets is estimated at $0.56 million. This is assumed to escalate at 2 % annually. The corresponding present value for the 50 year life of the combustion turbine is $0.56 million x 19.92 = $11.2 million.

### For the 100 MW Combustion Turbine

1. The present value of the income taxes associated with the combustion turbine is equal to: $114.1 million x (0.0748 - 0.0683) x 14.65 = $10.9 million. The fixed charges rate (0.0748), capital recovery factor (0.0683) and present value factor (14.65) are explained in Schedule 4.

2. The annual fixed O&M expense for the combustion turbine is estimated at $1.22 million annually. This is assumed to escalate at 2% annually. The present value of fixed O&M expenses over the 50 year life of the combustion turbine is $1.22 million x 19.92 = $24.3 million. The present value factor (19.92) is explained in Schedule 4.

3. After the CTGS boilers and steam turbines are retired, some of the CTGS assets, such as the land and a portion of the building, will continue to be used for CT3 and CT4. The annual fixed O&M expense for these assets is estimated at $ 0.56 million. This is assumed to escalate at 2% annually. The corresponding present value for the 50 year life of the combustion turbine is $0.56 million x 19.92 = $11.2 million.

4. To put the costs for a 100 MW combustion turbine on a comparable basis to a life extended CTGS (50 MW) and a 50 MW combustion turbine, the cost of purchased capacity that would be displaced during 2018 to 2024 by a portion of the 100 MW unit's capacity in excess of 50 MW that would be counted as accredited capacity has been shown as a credit. The calculation of the displaced purchased capacity cost is shown on Page 3 of Schedule 5.

5. Schedule 2 shows that with the installation of a 50 MW CT4, additional capacity will be required in 2024. With the installation of a 100 MW unit, this additional capacity would not be needed. Therefore, the 100 MW unit is credited with avoiding the need for installation of an additional 50 MW combustion turbine in 2024.

AVOIDED CAPACITY PURCHASES WITH A 100 MW COMBUSTION TURBINE

Escalation rate 2.00%
Discount rate 6.54%

| | | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Maritime Electric peak load (Feb 2015 forecast) | MW | 240 | 243 | 247 | 253 | 259 | 265 | 273 | 281 | 289 | 297 |
| Less interruptible load | MW | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 |
| Maritime Electric firm peak load | MW | 226 | 229 | 233 | 239 | 245 | 251 | 259 | 267 | 275 | 283 |
| 30 % of firm peak load | MW | 68 | 69 | 70 | 72 | 73 | 75 | 78 | 80 | 82 | 85 |
| 100 MW CT4 accredited capacity | MW | | | | 72 | 73 | 75 | 78 | 80 | 82 | 85 |
| 50 MW CT4 accredited capacity | MW | | | | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Difference (to be purchased) | MW | | | | 22 | 23 | 25 | 28 | 30 | 32 | 35 |
| Price of purchased capacity | $/kW/yr | 100 | 102 | 104 | 106 | 108 | 110 | 113 | 115 | 117 | 120 |
| Cost of capacity purchases | $ millions | | | - | 2.3 | 2.5 | 2.8 | 3.1 | 3.4 | 3.8 | 4.2 |
| PV in 2018 of capacity purchases | 16.9 $ millions | | | - | 2.2 | 2.2 | 2.3 | 2.4 | 2.5 | 2.6 | 2.7 |

**Schedule 6**
**FIXED CHARGES RATE FOR CTGS LIFE EXTENSION**

1. Capitalization:

| | | | | | | |
|---|---|---|---|---|---|---|
| - | Debt | 58.50% | @ | 4.25% | = | 2.49 |
| - | Common equity | 41.50% | @ | 9.75% | = | 4.05 |
| - | Weighted average cost of capital ( r ) | | | | | 6.54 |

2. Capital recovery factor ( f ): 15 years @ 6.54%

$$\frac{r(1 + r)^n}{(1 + r)^n - 1} = 10.66$$

3. Levelized capital cost allowance: @ i = 8.00%

$$\frac{f \times 100 \times i}{r + i} = 5.87$$

4. Future income tax: @ 31.00 % tax rate

| | | | | | |
|---|---|---|---|---|---|
| - | Levelized capital cost allowance | | 5.87 | | |
| - | Less str line amortization @ | 15 years | 6.67 | | |
| | | 0.31 x | -0.80 | = | -0.25 |

5. Levelized cost of debt:

| | | |
|---|---|---|
| - | Capital recovery factor | 10.66 |
| - | Less straight line amortization | 6.67 |
| - | Less future income tax | -0.25 |
| | | 4.24 |

- Levelized cost of debt = $\frac{2.49}{6.54} \times 4.24 = 1.62$

6. Levelized current income tax:

| | | |
|---|---|---|
| - | Capital recovery factor | 10.66 |
| - | Less levelized capital cost allowance | 5.87 |
| - | Less levelized cost of debt | 1.62 |
| | | 3.17 |

- Income tax payable $\frac{3.17}{1 - 0.31} \times 0.31 = 1.42$

7. Annual fixed charges rate:

| | | |
|---|---|---|
| - | Capital recovery factor | 10.66 |
| - | Plus current income taxes payable | 1.42 |
| - | Total | 12.08 |

## Schedule 7
## FIXED CHARGES RATE FOR COMBUSTION TURBINES

1. Capitalization:

| | | | | | | |
|---|---|---|---|---|---|---|
| - | Debt | 58.50% | @ | 4.25% | = | 2.49 |
| - | Common equity | 41.50% | @ | 9.75% | = | <u>4.05</u> |
| - | Weighted average cost of capital ( r ) | | | | | 6.54 |

2. Capital recovery factor ( f ): 50 years @ 6.54%

$$\frac{r(1 + r)^n}{(1 + r)^n - 1} = 6.83$$

3. Levelized capital cost allowance: @ i = 8.00%

$$\frac{f \times 100 \times i}{r + i} = 3.76$$

4. Future income tax: @ 31.00 % tax rate

| | | | | | |
|---|---|---|---|---|---|
| - | Levelized capital cost allowance | | 3.76 | | |
| - | Less str line amortization @ | 50 years | <u>2.00</u> | | |
| | | 0.31 x | 1.76 | = | 0.55 |

5. Levelized cost of debt:

| | | |
|---|---|---|
| - | Capital recovery factor | 6.83 |
| - | Less straight line amortization | 2.00 |
| - | Less future income tax | <u>-0.55</u> |
| | | 4.28 |

- Levelized cost of debt = $\dfrac{2.49}{6.54}$ x 4.28 = 1.63

6. Levelized current income tax:

| | | |
|---|---|---|
| - | Capital recovery factor | 6.83 |
| - | Less levelized capital cost allowance | 3.76 |
| - | Less levelized cost of debt | <u>1.63</u> |
| | | 1.44 |

- Income tax payable $\dfrac{1.44}{1 - 0.31}$ x 0.31 = 0.65

7. Annual fixed charges rate:

| | | |
|---|---|---|
| - | Capital recovery factor | 6.83 |
| - | Plus current income taxes payable | <u>0.65</u> |
| - | Total | 7.48 |