Evaluation Of The
Maritime Electric Company Limited
Proposed
Energy Cost Adjustment Mechanism

Prepared for the

Island Regulatory and Appeals Commission

John Murphy MBA, P. Eng.
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Overview

Energy Cost Adjustment Mechanisms (ECAMs) have been around for at least 50 years. Fuel Adjustment Clauses, the most common ECAM, became widely used in the 1970s when Oil Price shocks caused utilities and regulators alike to find ways to pass along the uncontrollable fuel cost increases to utility customers without the need for frequent and expensive hearings. Fuel adjustment clauses normally allow utilities to pass along, to customers, increases (or decreases) in costs resulting from price-level changes in both fuel and purchased power on a dollar-for-dollar basis. Changes in costs relating to the volume of sales are normally not considered as eligible as part of an adjustment mechanism because the associated change in revenue is expected to adequately offset sales volume related changes.

By the mid 1980s about 85% of the US State Public Utility Commissions (PUCs) had approved some type of Fuel Adjustment Clause, and many remain in use today. Even in states which have been open to retail competition an automatic price adjustment mechanism is often approved for distribution utilities in order for them to pass along the uncontrollable changes in purchased power costs. Cost adjustment mechanisms have withstood the test of time because they offer a reasonable trade-off between regulatory costs and fairness for both utilities and customers. Supporters of an ECAM consider the benefits to be:

1. Time and cost savings relating to fewer and/or shorter rate hearings.
2. A lower cost of capital for the utility as lower risk should reduce the cost of debt.
3. Customers receive the benefit of lower fuel cost earlier.
4. More timely price signals should encourage conservation during high-price periods.

Weaknesses of an ECAM are generally considered to be:

1. May deter utilities from making efficient investments to change its fuel mix, and may bias investment decisions toward those with lower capital costs and higher fuel costs.
2. May reduce the utility's incentive to bargain aggressively and efficiently in an attempt to minimize all costs, and thus shift risk from shareholders to utility customers.
3. May allow utilities excess returns as increases in net energy costs are passed through while offsetting savings in other areas are not accounted for.
4. May create an additional level of regulation with significant monitoring/auditing efforts.
5. May reduce a customer's understanding of the potential benefits of energy conservation.

MECL's Past and Proposed Future Use of ECAMs

Prior to 1994, when regulated by the Island Regulatory and Appeals Commission (IRAC), MECL had an approved Fuel Adjustment Mechanism whereby changes in the price level[1] for fuel and purchased power were charged to customers as a separate component of their bill. The average amount of the price-level change for the previous twelve months was divided by the forecast sales for the billing (current) month to determine a ¢/kWh hour adjustment. The ¢/kWh charge was multiplied by each customer's kWh usage for the billing month to arrive at the fuel adjustment charge on that month's bill. This approach was intended to spread the collection/pay-out over any subsequent 12 month period.

For the period 2001 to 2003, MECL was permitted to make a rate adjustment once per year that would recover from customers (during the following April 1 to March 31 period) 90% of all designated ECAM costs incurred (above a recognized base level of 5¢/kWh) during the previous calendar year. During 2001-2003 the ECAM included costs for MECL self generation (fuel, operations and maintenance) plus all costs relating to the purchase of energy from both the mainland and on-Island sources including wind.

MECL proposes that it accumulate ECAM costs[2] beginning January 1, 2004, and recover these costs from customers beginning on February 1, 2005. It proposes that 1/18th of the previous month's ECAM balance be divided by the forecast kWh sales for the billing (current) month and noted as a separate ECAM related (¢/kWh) charge on customers' bills.

Use of Rate Adjustment Mechanisms in Canada

The use of rate adjustment mechanisms has not been as widespread in Canada as in the United States and many other parts of the World. This is often explained by the more prominent role crown corporations have played in the Canadian electric utility industry and by a high proportion of hydro-based generation which helps to moderate price changes. A recent study commissioned by Nova Scotia Power Inc. (relating to its application for approval of a Fuel Adjustment Clause beginning in 2005) showed that all eight investor-owned utilities reviewed (2-electric, 6-natural gas) have some mechanism that allows for a true-up of historical actual to forecast fuel costs. Of the eleven government-owned utilities reviewed (9-electric, 2-natural gas) four have a Rate Adjustment Mechanism. Most Fuel Adjustment Clauses in Canada allow only price-level changes, although some do recognize fluctuations in load.

[1] Above the price-level previously set within a PUB Order.
[2] Using ECAM costs as defined for the 2001-2003 period, above a base level calculated as 6.73 cents/kWh.

Use of Automatic Adjustment Clauses in the United States

In the late 1970s The Federal Energy Regulatory Commission issued rules requiring:

1) A through review of automatic adjustment clauses in public utility rate schedules at lease every four years so as to ensure that each such clause contains only costs that are subject to periodic fluctuations and not susceptible to precise determination during rate cases prior to such costs being incurred; and
2) A review of utility practices every two years to ensure such automatic adjustment clauses provide incentives for efficient use of resources.

At the state level, adjustment mechanisms approved by the regulators normally were worded in a way similar to that for New Mexico, which can be summarized as follows:

1) The cost of fuel and purchased power is a "significant percentage of the total cost of service";
2) The cost "periodically fluctuates and cannot be precisely determined in a rate case";
3) The utility's policies and practices assure that electricity is generated and purchased "at the lowest reasonable cost"; and,
4) The utility must show that the proposed adjustment clause is consistent with the goals of "adequate regulatory review", "stability of utility earnings" when costs rise and "prompt credits" to customers when costs decline.

The following words from Bill No. 1100 of the Missouri Legislature further provide a concise definition and a guide as to what costs would normally be included in an ECAM:

> "…any electrical corporation… shall be allowed to recover all of its reasonably and prudently incurred costs for fuel delivered to its generating stations and all of its reasonably and prudently incurred costs for the variable cost component of purchased electrical energy for its retail customers through energy cost adjustment schedules designed to specifically recover such costs."

In some jurisdictions, ECAMs include fuel costs associated with meeting environmental emissions standards (Illinois), price hedging fuel and purchased power related financial instruments (North Dakota), certain demand side initiatives aimed at reducing fuel usage, and coal research and development costs (Ohio).

Although it is not necessary that IRAC adopt the definition of any other jurisdiction, the adjustment mechanisms currently in use have evolved over many years following substantial debate, and should prove instructive in reviewing the ECAM request by MECL.

Sharing of ECAM Costs and Approval of Rate Adjustments

Sharing of ECAM costs between customers and shareholders may appear to be consistent with the concept of performance-based regulation and the belief that a utility should have a financial incentive to try and manage all costs, including those that they cannot directly control. However, some believe that unless the adjustment is done on a dollar-for-dollar basis, it weakens the test for "just and reasonable" rates, as the utility could achieve a return on rate base that was above the level approved in a rate case merely through the incentive portion of the ECAM. Periodic audits of efficiency are more widely used than sharing mechanisms.

Provided that an ECAM is properly defined there is no need for the regulator to approve the new ECAM charge each time there is a change in the ECAM portion of the customers' bills. The utility is responsible to ensure that the principle of dollar-for-dollar pass through is followed. At the time a periodic audit is done, necessary adjustments can be made to ensure that customers have paid no more than the appropriate level of charges.

Analysis of MECL's ECAM Proposed to Commence January 1, 2004

MECL provided a spreadsheet containing selected cost components of its proposed ECAM over a seven year historical and three year forecast period 1997 to 2006, (See Appendix 1). During this timeframe MECL will purchase more than 95% of the energy it sells. While all the price-level changes in fuel and purchased power would be considered eligible components of an ECAM, the following three categories of costs do not fit the normally accepted definition of ECAM costs.

<u>Volume-Level Changes</u>

It is forecast that during 2004, MECL's total volume of energy will be 9,995,000 kWh above the level that was predicted when the budget for 2004 was prepared. A normal test for ECAM related expenses is that they be limited to price-level changes in fuel and purchased power costs. The cost of the volume increases will be recovered from the associated increase in sales. Thus MECL's proposed ECAM costs must be reduced by the amount of the average incremental purchased energy cost of 6.71 cents/kWh times the increased volume, an amount of $670,665.

<u>Ancillary Services, Short-Term Capacity and Payments to NB Power Associated with PEI Tie</u>

A generally accepted definition for ECAM-suitable costs is that they should be only the variable cost component of purchased electrical energy and should be costs that periodically fluctuate and which cannot be precisely determined in a rate case. None of the costs relating to Ancillary Services, Short-Term Capacity and Payments to NB Power associated with the submarine transmission link to PEI fit within these definitions. Such costs are open for reasonable determination in advance and only a small portion of such costs would be considered variable.

MECL Generating Plant Operations and Maintenance (O&M) and the Energy Control Center

Although a higher volume of production by MECL's own generating plants results in a higher amount of plant O&M costs, analysis of the information did not reveal any direct relationship between price-level changes in fuel and purchased power costs and price-level (i.e. unit cost) changes in either generating plant O&M costs or Energy Control Center costs. Therefore there appears to be insufficient justification to include these costs within the ECAM category.

Conclusions

Energy Cost Adjustment Mechanisms are widely approved for use by electric utilities to reduce regulatory burden and reduce the long-term cost of power to customers by reducing utilities' financial risk and thereby the cost of borrowing. In the long history of ECAMs, the positives seem to substantially outweigh the negatives. In principle MECL's proposal to adopt an ECAM is reasonable, however, any ECAM approved by IRAC should recognize the general theory base of ECAMs elsewhere and should contain only changes in price-level relating to prudently incurred costs for fuel delivered to its generating stations and for the variable cost component of purchased electrical energy.

To be consistent with most ECAMs elsewhere, the following expenses should not be included:

1. Costs for the volume of energy above the budget level (which has offsetting revenue).
2. Costs associated with ancillary services and short term capacity payments.
3. Payments to NB Power relating to assets dedicated to the PEI transmission link.
4. O&M costs relating to MECL generating stations and the Energy Control Center.
5. The amortization of the Point Lepreau Write-down.

The first of these items has already been offset by revenue received from the increased volume. However, all of the other items are categories of costs that would normally be recovered from customers. If it is decided to deem such expenses to be within the ECAM category of costs during this period of transition to regulation (perhaps because MECL was allowed to include them under ECAM during the 2001-2003 period), it should be done only as a temporary measure until the non-ECAM portion of the utility's rate can be adjusted to recover such costs.

The 18 month true-up period for the ECAM account balance proposed by MECL is longer than what exists in most jurisdictions. Although one example was found where a 20 month period was used due to the need to "soften" the rate impact following a rapid increase in fuel costs, many jurisdictions utilize three-month, and twelve month true-ups. MECL's proposed monthly adjustment to rates appears to provide a reasonable trade-off between achieving the true-up and moderating large rate changes during times that fuel prices are changing rapidly.

Reduced regulatory cost has always been cited as one of the principal benefits of an ECAM. It is important to ensure that the reduction in hearing time is not replaced by unnecessarily aggressive oversight effort relating to the operation of the ECAM. A properly structured ECAM will assure that customers will not pay more than the justified level of costs, hence there is no need for the regulator to issue an order each time the rate changes as a result of the formula driven automatic adjustment mechanism.

There is a tradeoff between costs associated with required periodic audits (such costs are a function of the frequency) and the wish of a utility to be relieved of liability associated with outstanding ECAM balances. The time between audits could vary considerably without reducing the integrity of the ECAM, but should be performed no less frequently than once every 2-3 years.

It is generally recognized that an ECAM reduces the financial risk of a utility and thus its cost of capital. Therefore, the existence of an ECAM should be factored into the allowed rate of return.

Appendix 2 shows an estimate by MECL that the sales volume in 2004 was expected to be 9,995,000 kilowatt hours above the budgeted amount. At an incremental cost of energy purchases of 6.71 ¢/kWh this amounts to $670,665 that has been collected through above-budget sales revenues, and thus should not be included in an ECAM account balance at the end of 2004. Appendix 3 highlights an additional one million dollars relating to categories of expenses that do not fall within the generally accepted definition of an ECAM, these costs would normally be approved by a regulator as part of the cost of service as non-ECAM costs. All remaining costs appear to meet the generally accepted definition for ECAM categories of costs. If IRAC approves an ECAM, following any necessary period of transition, it would be appropriate to work towards shortening the true-up period to not longer than 12 months.

Introduction to Energy Cost Adjustment Mechanisms (ECAMs)

Overview

Throughout North America[3], utility regulators have sought ways to most efficiently deal with changes in the revenue requirement of electric utilities that directly results from changing fuel prices. The most universal response by regulators has been to approve a Fuel Adjustment Clause (FAC) as a method whereby utilities could pass-through to customers, on a dollar-for-dollar basis, changes in fuel costs and fuel-price-associated changes in purchased power costs. The difference in the price level between the budgeted cost for fuel and the actual cost for fuel would be recovered from customers by altering the amount collected though the Fuel Cost Adjustment portion of the rate which could be changed as necessary (monthly, quarterly, semi-annually or annually) without the need of a hearing process.

Although Fuel Adjustments were not uncommon in the mid sixties, events like the oil price shocks of 1973 and 1979 reinforced the need for such mechanisms. By the mid 1980s about 85% of the US State PUCs had approved some type of a fuel adjustment clause allowing all or part of the fuel cost increase to be recouped immediately or with a specific time lag. Today, the majority of the states without retail competition have a Fuel Adjustment Mechanism in place.[4]

Perceived Strengths and Weaknesses of ECAMs

Strengths associated with a Energy Cost Adjustment Mechanisms are considered to be[5]:

1. Time and cost savings relating to fewer and/or shorter rate hearings.
2. A lower cost of capital for the utility as lower risk should reduce the cost of debt.[6]
3. Customers receive the benefit of lower fuel cost earlier.
4. More timely price signals are sent to customers to encourage conservation during high-price periods.

[3] In many other parts of the World as diverse as Barbados, Cyprus, Thailand Pakistan and Kenya, utility regulators have also implemented fuel adjustment clauses as a way to meet the same objectives.

[4] Several states with retail competition allow the distribution utilities to pass through fuel related cost changes.

[5] Portions of this information taken from pages 15-16 of the Direct Testimony of Douglas Smith on behalf of the Arizona Corporation Commission, February 3, 2004. http://www.cc.state.az.us/utility/electric/DCS.pdf

[6] In response to information request number 18 of the NSPI 2005 rate case, Dr. Morin stated that a Fuel Adjustment Clause should lower cost of debt to NSPI by 30 to 50 basis points.

Weaknesses associated with Energy Cost Adjustment Mechanisms are considered to be:

1. May deter utilities from making efficient investments to change its fuel mix, and may potentially bias investment decisions toward those with lower capital costs and higher fuel costs.

2. May reduce the utility's incentive to bargain aggressively and efficiently in an attempt to minimize all costs, and can shift risk from shareholders to utility customers.

3. May allow utilities excess returns as increases in net energy costs are passed through while offsetting savings in other areas are not accounted for.

4. If not properly structured, adjustors may create an additional level of regulation and require significant efforts relating to monitoring and auditing.

5. Under an adjustor rates may change frequently lowering a customer's understanding of the rates and creating confusion regarding the potential benefits of energy conservation.

MECL and Cost Adjustment Mechanisms

MECL used Fuel Adjustment Mechanism for many years prior to 1994 while regulated by the Island Regulatory and Appeals Commission. And the Provincial Government provided in legislation, an Energy Cost Adjustment Mechanism that was available to MECL during the period 2001-2003.

The Fuel Cost Adjustment Mechanism Available to MECL Prior to 1994

Prior to 1994 there was a fuel cost adjustment mechanism used when the cost of fuel used to produce electricity in the Company's generating plants and the cost of purchased energy increases or decreases from the base cost. The base costs for fuel used in generating electricity and for purchased electricity was 4.043 cents per kilowatt hour (net purchased and produced).

For the purposes of this mechanism, costs included payments made to NB Power for the purchase of energy (capacity purchases were excluded). It included a portion of the costs associated with MECL's entitlement agreement for energy from Point Lepreau[7], and the fuel and fuel inventory charges associated with the Dalhousie Unit #2 participation agreement. It also included the fuel component of energy generated at both the Charlottetown and Borden plants.

[7] Both the Point Lepreau and Dalhousie contracts with NB Power were negotiated as a fixed portion of the plants over their useful lives. At Point Lepreau the ECAM included the fuel cost, fuel inventory cost plus 2/3 of all other costs which, according to MECL, were put into the ECAM to avoid frequent rate hearings.

The cents/kWh adjustment was applied each month was calculated as follows:

[Actual Cost Fuel & Purchased Power – 4.043 ¢/kWh +/- Over-collection] / Billing Month's Projected kWh Sales
[*average during the previous 12 months* for the Previous Months]

The average amount of the price-level change for the previous twelve months was divided by the forecast sales for the billing (current) month to determine a cent per kilowatt hour adjustment, which was multiplied by each customer's kWh usage for the billing month to arrive at the fuel adjustment charge on that month's bill. This approach was intended to spread the collection/pay-out over any subsequent 12 month period.

<u>The Energy Cost Adjustment Mechanism Available to MECL in 2001-2003</u>

In 2001 the Government of PEI approved an Energy Cost Adjustment Mechanism which was designed to allow the true-up of costs above (or below) the base charge by making a rate adjustment once each year. A percentage ECAM adjustment was calculated as follows:

[Actual Costs – Total kWh X 5.0 Cents] X 90% / Total Revenue from Basic Rates
For the previous Calendar Year

The base costs for a calendar year (calculated as the total kWh for the year times the base rate of 5¢/kWh.[8]) was subtracted from the total actual cost during the calendar year for energy purchases (including transmission charges and ancillary services[9]) along with the cost of self generated energy (fuel, plant operations, plant maintenance, plant superintendence and the energy control center operations). The difference was multiplied by .9 as it was agreed that MECL would recover only 90% of the ECAM category of costs. This amount was divided by the total revenue from basic rates to arrive at a percentage adjustment which was applied evenly to customers' rates for bills covering the following April 1 to March 31 period.

During this period (2001 – 2003) the PEI Government also approved a cost of capital adjustment mechanism whereby MECL would calculate its return on equity for the previous calendar year, and to the extent that it varied from the approved rate of 11%, MECL was to adjust the bills so as to recover/reimburse 75% of the difference over the next 12 month (April 1st to March 31st) period. Research relating to cost of capital adjustment mechanisms is outside the scope of this report,

[8] The base rate of 5 cents per kWh was agreed upon between MECL and government.
[9] Ancillary services include: Spinning Reserve, Regulation and Load Following. Also included were O&M costs and rental payment on some NB Power facilities dedicated to serving Island load as well as short term capacity payments for generation.

however it is worth noting that such mechanisms are in use in several jurisdictions and when the interest rate on selected “low risk” bonds moves up or down, the utility’s allowed rate of return on common equity may be adjusted by formula, (usually on an annual basis), without the need for a hearing.

MECL’s Proposed ECAM for Expenses Beginning January 1, 2004

The ECAM currently proposed by MECL is similar to that in place during 2001-2003, but calculated monthly rather than on an annual basis. Another difference is that it uses an 18 month true-up calculation rather than the previously used 12 month collection period. It is proposed that the monthly adjustment be re-calculated on an on-going basis so as to avoid the need to account for each month’s adjustment separately.

It is proposed that beginning with the outstanding 2004 ECAM balance, that the initial ECAM charge would appear on customers’ bills for February 2005, and the amount charged for that month would be $1/18^{th}$ of the ECAM outstanding balance calculated to the end of calendar year 2004. On a monthly go-forward basis (using March 2005 as the billing month) calculation of the balance in the ECAM account at end of the month would be determined as follows:

Outstanding Balance January 2005	**-**	**$1/18^{th}$ of the Outstanding Balance collected in February 2005**	**+/-**	**Difference Between Actual Energy costs for Feb 2005 And the amount included in the Base Rate**

(For March, $1/18^{th}$ of the February balance would be charged to customers.)

The amount charged to each customer in any month would be determined by dividing $1/18^{th}$ of the ECAM account balance for the previous month-end by the total number of kilowatt hours forecast to be sold in the billing month. The ECAM portion of the bill would be a formula derived cents per kilowatt hour charge times the customers’ kWh usage for the month.

Canadian Examples of Fuel Adjustment Charges

Nova Scotia Power Inc. (NSPI) applied to the Nova Scotia Utility and Review Board to introduce a Fuel Adjustment Charge as part of its 2005 rate filing. On August 26, 2004, NSPI held a Fuel and Purchased Power Technical Conference which contained a presentation entitled "Review of Canadian Energy Utility Fuel Cost Pass-Through Mechanisms"[10].

The paper reviewed 11 Electric Utilities (2 investor-owned) and 8 Natural Gas Utilities (6 investor-owned) and found that all eight investor-owned utilities have some mechanism that allows for a true-up of historical actual to forecast fuel costs. Of the eleven government-owned utilities, five have a true-up mechanism and four of those have a Rate Adjustment Mechanism.[11] Time periods for rate adjustments and clearing of true-up mechanisms were 1 month, 3 months, 12 months and variable. Some companies used the Fuel Adjustment Clause (FAC) to stabilize fuel costs resulting from load fluctuations, while in other cases only the price change was allowed in the FAC and companies were still at risk for load variability.

The paper highlights the incentives that would remain for the utility to properly manage fuel procurement even while under the FAC as: (1) Energy procurement activities would remain under prudence review scrutiny which would evaluate the structure of the underlying portfolio and the use of optimization strategies. (2) The utility would wish to avoid negative publicity that would result form any sub-optimal procurement strategy, and (3) Competitive pressure from alternative energy sources.

The Canadian information, although interesting, does not provide in-depth experience because neither sample size nor timeframe of application is sufficient to provide a great insight into automatic adjustment mechanisms. The next section will highlight information from the United States where there has been extensive use of adjustment mechanisms for decades, and changes are being made with the intent to continually improve the workings of ECAMs so that they will better meet the underlying objectives.

[10] "Review of Canadian Energy Utility Fuel Cost Pass-Through Mechanisms" by Tim J. Simard. Slides 16-46 of the NSPI – 2005 Fuel and Purchased Power Technical Conference, August 26, 2004. http://www.nspower.ca/AboutUs/RegulatoryAffairs/RateCase2005/DOCS/TC_PRESAug262004.PDF

[11] It was noted that BC Hydro, Hydro Quebec and NB Power are considering these mechanisms.

Use of Automatic Adjustment Clauses in the United States

The Federal Energy Regulatory Commission (FERC)

In the late 1970s The Federal Energy Regulatory Commission made the following rules regarding review of Automatic Adjustment Clauses:

"**(1)** Not later than 2 years after November 9, 1978 and not less often than every 4 years thereafter, the Commission shall make a through review of automatic adjustment clauses in public utility rate schedules to examine –

(A) whether or not each such clause effectively provides incentives for efficient use of resources (including economical purchase and use of fuel and electric energy), and

(B) whether any such clause reflects any costs other than costs which are –

(i) subject to periodic fluctuations and

(ii) not susceptible to precise determinations in rate cases prior to the time such costs are incurred.

Such review may take place in individual rate proceedings or in generic or other separate proceedings applicable to one or more utilities.

(2) Not less frequently than every 2 years, in rate proceedings or in generic or other separate proceedings, the Commission shall review, with respect to each public utility, practices under any automatic adjustment clauses of such utility to insure efficient use of resources (including economical use of fuel and electric energy) under such clauses. …"[12]

Example of Generic Criteria at the State Level – New Mexico

The following criteria used in New Mexico to determine the appropriateness of adjustment mechanisms are indicative of the tests that have been considered in most jurisdictions:

"When making an initial application for a fuel and purchased power adjustment clause, a utility must show that:

(1) the cost of fuel and purchased power is a "significant percentage of the total cost of service"

(2) the cost "periodically fluctuates and cannot be precisely determined in a rate case"; and

(3) the utility's policies and practices are designed to assure electricity is generated and purchased "at the lowest reasonable cost" In addition

(4) the utility must show that the proposed adjustment clause is consistent with the goals of "adequate regulatory review", "stability of utility earnings" when costs rise and "prompt credits" to customers when costs decline …"

[12] Chapter 12 Federal Regulation and Development of Power, Sub-Chapter II Regulation of Electric Utility Companies engaged in Interstate Commerce, Section 824 d(f) Automatic Adjustment Clauses. http://caselaw.lp.findlaw.com/casecode/uscodes/16/chapters/12/subchapters/ii/sections/section_824d.html

After approval of an adjustment clause, the utility must file every two years for continuation of the adjustment clause. The adjustment clause is deemed approved 30 days after the continuation filing unless the adjustment clause is suspended by the NMPRC."[13]

A Bill Recently Introduced in Missouri

The words in Bill No. 1100 before the Missouri Legislature states:

> "…any electrical corporation… shall be allowed to recover all of its reasonably and prudently incurred costs for fuel delivered to its generating stations and all of its reasonably and prudently incurred costs for the variable cost component of purchased electrical energy for its retail customers through energy cost adjustment schedules designed to specifically recover such costs."[14]

This very recent definition (the Bill received first reading in January of 2004) concisely defines the intent of most energy cost adjustment mechanisms in use today. What is also captured is the essence of the responsibility of all regulators that have a mandate for general supervisory oversight of a utility.

Other States

The cost elements that are contained within Energy Cost Adjustment Mechanisms vary by jurisdiction. The most basic are fuel cost and purchased power costs, and most often it is a combination of the two. However, in some jurisdictions ECAMs include: fuel costs associated with meeting environmental emissions standards (Illinois); certain costs associated with transporting, handling and sampling of fuel (Mississippi); biomass, wood and refuse derived fuel and price hedging purchased-power-related financial instruments (North Dakota); certain demand side initiatives aimed at reducing fuel usage, and coal research and development costs (Ohio). In Vermont, a Bill (H.726) is currently before the House proposing the inclusion of costs relating to hedging practices from third parties for both fuel and purchased power.[15]

The scope of emission related expenses allowed in the fuel adjustment mechanism for Illinois is as follows:

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13 Current electricity Regulatory Systems in Specific States. http://bcsia.ksg.harvard.edu/BCSIA_content/documents/IGCC%20Financing%20Chapter%208.pdf

14 Summary of the Committee version of Missouri House Bill No. 1100. http://www.house.state.mo.us/bills041/bilsum/commit/sHB1100C.htm

15 Vermont House Bill H.726. An Act Relating to the Reform of the Regulation of Electric and Gas Companies. http://www.leg.state.vt.us/docs/legdoc.cfm?URL=/docs/2004/bills/intro/H-726.htm

> "…the Commission may authorize the increase or decrease of rates and charges based upon changes in the cost of fuel used in the generation or production of electric power, changes in the cost of purchased power, or changes in the cost of purchased gas through the application of fuel adjustment clauses or purchased gas adjustment clauses. In addition, the Commission may also authorize the increase or decrease of rates and charges based upon expenditures or revenues resulting from the purchase or sale of emission allowances created under the federal Clean Air Act Amendments of 1990, through such fuel adjustment clauses, as a cost of fuel. For the purposes of this paragraph, cost of fuel used in the generation or production of electric power shall include the amount of fees paid by the utility for the implementation and operation of a process for the desulphurization of the flue gas when burning high sulfur coal at any location within the State of Illinois irrespective of the attainment status designation of such location; but shall not include transportation costs coal (i) except to the extent that …"[16]

A very recent regulatory proceeding in Wyoming ended in an Order by its Commission dated June 21, 2004[17], denying the application by PacifiCorp requesting approval of a Power Cost Adjustment Mechanism. It is the completeness and recentness of the arguments and not the ruling itself that should be considered as instructive for two reasons… (1) for PacifiCorp the portion of its total costs represented by purchased power and fuel is much less than that of MECL, and (2) there appears to be legislative constraints which does not give the Wyoming Commission the same level of flexibility to approve an ECAM as exists with IRAC.

Sharing ECAM Adjustments - Customers/Shareholders

Sharing of ECAM costs between customers and shareholders has been discussed and approved in some jurisdictions, where only a portion (e.g. 80%) of the difference between budget and actual net power cost is charged/reimbursed to customers. It is believed that such an approach fits within the concept of Performance-Based Ratemaking (PBR) and a belief that a utility should have a direct financial incentive to try and manage all costs, including those that they cannot directly control. One would assume that a consequence of such a sharing mechanism is that there would be an incentive for the utility to seek adjustment to the base cost more often, so as to minimize its exposure when

[16] Amendment to the Public Utilities Act by the State of Illinois 92nd General Assembly, 1997 http://www.legis.state.il.us/legislation/legisnet92/hbgroups/hb/920HB1888LV.html

[17] Order by the Public Service Commission of Wyoming IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR AUTHORITY TO IMPLEMENT A POWER COST ADJUSTMENT MECHANISM. June 21, 2004. Docket No. 20000-ET-03-205 This order contains a detailed summary of the evidence, and provides an excellent source of information on the decision process regarding the approval of an ECAM.
http://psc.state.wy.us/htdocs/orders/20000-205-11890.htm

energy costs are increasing. On the down-side, it is believed that unless the adjustment is done on a dollar-for-dollar basis, it weakens the test for "just and reasonable" rates, as the utility could achieve a return on rate base that was above the level approved in a rate case merely through the incentive portion of the ECAM.

Regulatory Oversight and Frequency of True-Up

It is interesting that in Missouri where it was proposed that changes in rates under the adjustment clause would be allowed quarterly, it is expected that each adjustment would be reviewed by the regulator prior to implementation. It was estimated that regulators workload (for the three electric utilities involved) would require seven additional staff to deal with 18 additional filings per year. In Vermont, Bill H.726 proposes that the regulator pre-approve each rate change even though item (f) of the proposed bill states:

> "Whenever the board approves a fuel adjustment clause or purchased power adjustment clause, or both, pursuant to this section, the board shall continually monitor and oversee the application of the adjustment clause. If the board finds that the charges or credits are not based upon the actual cost paid for fuel or net cost of purchased wholesale power, or are not properly computed in accordance with the applicable adjustment clause, it shall re-compute the charges or credits and shall direct the company to take such action as may be required to ensure that the charges or credits properly reflect the actual prices paid for fuel or purchased wholesale power and are properly computed in accordance with the applicable adjustment clause for the applicable period."[18]

Such wording assures appropriate protection for customers regardless of when a true-up audit is done, even if such true-up is done only once every three years. In any case where there is sufficient reason for the regulator to suspect a problem, it has the power to undertake an investigation on its own initiative.

Good enforcement does not require frequent audits or investigation, and it is difficult to understand why some jurisdictions require the regulator to review and approve any ECAM rate change prior to it being implemented. This adds considerably to the cost of regulation without offering any greater control than what would be attainable through much longer investigative cycles. Utility regulation

[18] Vermont House Bill No. 726, 2004.
http://www.leg.state.vt.us/DOCS/2004/BILLS/INTRO/H-726.DOC

includes many examples of deferred expenses and related adjustments and amortization schedules. What is important is to ensure the adjustment mechanism is properly defined and that the process for periodic true-up is clearly stated.

A regulator is expected to allow prudently incurred costs plus a reasonable return… but to accomplish this objective need not require frequent hearings, rather generic issues need to be examined and a set of procedures established that ensure appropriate checks and balances are in place. For instance, large capital expenditures are reviewed at the time of construction, but the appropriate methodology for the associated depreciation expense is reviewed normally on a 3 or 5 year cycle. If there have been some changes in expected asset lives, the necessary adjustments in accounting procedures will be made at the time of the periodic depreciation study, and over the long term, customers will pay no more than the appropriate level of depreciation. Similarly, as long as the Energy Cost Adjustment Mechanism is properly defined there is no need for the regulator to approve the rate level each time there is a change in fuel or purchased power costs. The utility is responsible to ensure that the principle of dollar-for-dollar pass through is followed, and at the time a periodic audit is done, adjustments will be made to ensure that both the customers and the utility have received the appropriate charges.

There is a wide variation in the frequency of true up of actual costs to budgeted costs including monthly, quarterly, bi-annually and annually. Only one instance was observed where more than twelve months was allowed, and that followed rapid increases in fuel prices and an extended period was chosen to soften the rate impacts by spreading it out over a longer period. If MECL were to be allowed eighteen months initially due to rate impact considerations, there should be a plan to progressively shorten it to no more than twelve months so as to be more in line with what is generally accepted as reasonable.

Identification of Expense Categories Qualifying Within an ECAM

A concise definition of ECAM expenses, as noted above, is a utility's reasonably and prudently incurred costs for fuel delivered to its generating stations and all of its reasonably and prudently incurred costs for the variable cost component of purchased electrical energy for its retail customers.[19] The other principal test is that such costs are subject to periodic fluctuations and are not susceptible to precise determinations in rate cases prior to the time such costs are incurred.[20] Both of these tests should be satisfied when deciding what belongs in ECAM, however, it needs to be recognized that the first one is the principal test and the second represents a secondary level of screening.

In addition to ancillary services, capacity charges and Lepreau amortization which will be discussed later, MECL included within its proposed ECAM operations and maintenance (O&M) and superintendence costs relating to its generating plants along with operating costs for the Energy Control Center. Although such O&M expenses would not normally fit within the definition of an ECAM, it is important to test the extent to which such expenses vary directly with price-level changes in fuel and purchased power. If such relationship exists, there might be justification to include such expenses within ECAM. The fact that such expenses are "subject to periodic fluctuations and not susceptible to precise determinations in rate cases prior to the time such costs are incurred" is not a sufficient reason for them to be classified as ECAM expenses.

The response to the first information request issued to MECL for this investigation included cost data for selected components of its proposed ECAM over a seven year historical and three year forecast period. Using this data, analysis was done to identify year over year price level changes in fuel and purchased power, and to see there is any associated price level change in the unit costs in O&M expenses for MECL's own generation and the Energy Control Center.

Page 3 of Appendix 1 shows the calculation of various ratios some of which appear in the summary tables below. The first summary table reflects actual data from 1998 to 2003, and thus provides empirical evidence during that historic period. Historical data for the second table is only available for two years, thus it includes 3 years of forecasts.

[19] See for example Missouri Bill No. 1100, 2004.
[20] FERC Criteria, and adopted by many States.

Own Generation Plant Operations and Maintenance

Table 1-A shows year-over-year percentage changes in: the quantity of electricity generated; level and percentage change in O&M costs (including superintendence); and price-level changes in fuel and purchased power costs.

Own Generation Costs (Excluding Fuel) Table 1-A
Relationship with Volume and Unit Price of Fuel and Purchased Power

	1998	1999	2000	2001	2002	2003
Self Generated MWH	2,408	7,963	45,673	41,587	18,819	30,768
Change Year/Year (%)	-88%	231%	474%	-9%	-55%	63%
Plant O&M Costs ($)	1,613,725	1,780,368	2,120,541	2,791,619	1,562,516	1,482,950
Change Year/Year ($)	-12,527	148,643	340,173	671,078	-1,229,103	-79,566
Change Year/Year (%)	- 0.8%	9.1%	19.1%	31.7%	-44.0%	-5.1%
Unit Cost Change Yr/Yr	- 3.3%	3.6%	14.7%	28.1%	-29.2%	-4.9%
Fuel & Purch. Power						
Price Level Change from Previous Year	-4.5%	-1.6%	24.1%	-4.0%	11.7%	0.1%

If there were a close relationship between changes in the price-level of fuel and purchased power and either the overall cost or price level change of self generation it should be evident in the shaded boxes of Table 1-A. A direct relationship between the price level changes (the lower two shaded boxes in the table) might be cause for additional investigation regarding the possible inclusion of these costs with an ECAM. However, in four of the six years even the direction of the change is in opposite directions, suggesting that no direct relationship exists.

Energy Control Center Operations

Operations costs for the ECC were separately identified beginning in 2002. Table 1-B shows: actual costs for 2002-2003, forecast costs for 2004-2006, year over year percentage change and the year-over year price level change in fuel and purchased power. The only year of actual data is 2003 and no direct association can be seen between the percentage change in costs and the price-level change in fuel/purchased power. They also differ considerably in forecast years.

Energy Control Center Costs Table 1-B

	2002	2003	2004	2005	2006
Costs	327,814	350,437	361,146	353,598	362,120
Year/Year Change %	n/a	6.9%	3.1%	-2.1%	2.4%
Price- Level Change Fuel & Purchased Power	11.7%	0.1%	4.1%	-5.9%	3.2%

Analysis of MECL's ECAM Proposed to Commence January 1, 2004

Review of the cost categories MECL proposes to include in its ECAM include: Price-level changes in fuel and purchased power for energy on a cents per kilowatt hour basis, volume-level changes in fuel and purchased power based on the volume of energy sales, and other categories of costs relating to capacity payments, ancillary services and generating plant O&M that does not vary directly with price level changes in fuel and purchased power. The volume related changes translates into an additional $670,665 of Purchased Power cost that should not be included in the ECAM calculation, while the other non-price-level changes total approximately $1 million of costs that do not fit the generally accepted definition to be included in an ECAM. These will be discussed in detail below.

<u>Purchased Power</u>

(1) Price-Level Change in the Energy Component of Purchases from Emera

The quantity of energy purchased by MECL from Emera was down considerably from the budgeted level, and because the terms of the agreement had certain take-or-pay components, the unit cost was above budget. However, by purchasing energy from alternate sources, MECL was able to secure a small overall energy price-level reduction by purchasing this energy from NB Power. This price-level change is properly identified as an ECAM allowed item.

(2) Price-Level Change in Energy Component of General Purchases from NB Power

During 2004 MECL was able buy energy from NB Power energy under the category of "General Purchases", at an average price-level below what had been estimated in the budget. Because the savings was a result of a price-level change, it fits within the definition of ECAM.

(3) Price-Level Change in the Dalhousie (NB Power) Contract

The fuel cost for the Dalhousie plant was up significantly, and there were minor increases in O&M. Offsetting savings in Cost of Capital and Transmission charges netted an overall increase of 10% above budget. To the extent that energy produced by the Dalhousie plant was below budget level, incremental cost for replacement energy would also be considered as a price-level change. These costs are outside the control of MECL and such an increase fits within the definition of ECAM.

(4) Price-Level Change in the Point Lepreau (NB Power) Contract

Outages beyond the budgeted level at the Point Lepreau plant resulted in its energy production being down by approximately 7%, which resulted in MECL needing to purchase an equivalent amount of replacement energy at a higher cost. The outages also increased O&M costs by more than 20%. These increased costs are price-level changes that fit within the definition of an ECAM.

(5) (Price-Level) Foreign Exchange Level Changes Relating to NB Power Contracts

Any fluctuations in foreign exchange levels relating to payments to NB Power in US Dollars would be considered a price-level change and become part of an ECAM.

(6) Price-Level Change in Energy Component of Purchases from other Sources

During 2004, the amount of Wind Energy available for purchase was about 15% below the budget level. The timing of the purchases was such that the price (based on a percentage of avoided cost) was slightly below budget. Both the reduction in the purchase price and the cost of make-up energy fit within the definition of what would qualify under an ECAM.

(7) Cost Due to Volume-Level Change in Total Purchased Power

Overall, the energy purchased by MECL in 2004 is forecast to be 9,995,000 kWh above the amount budgeted (See Appendix 2). At an average purchase price of 6.71 ¢/kWh, this amounts to a volume related cost increase of $670,665. Because this is a volume-based increase and not a price-level change, it does not fit within the definition of an ECAM. MECL recovers its costs for this additional by additional sales at its tariff rates. Allowing such costs as part of an ECAM would mean that MECL would be recovering these costs twice.

(8) Ancillary Services

Ancillary Services purchased by MECL include Regulation and Load Following, and Spinning Reserve. (Any short-term capacity purchased will be discussed below.) The needs for Ancillary Services are often determined by reliability requirements agreed to by the electric utilities sharing the power grid, in the case of MECL a significant portion of its required Ancillary Services is purchased. The requirements for Ancillary Services are identified well in advance as part of the planning process, and therefore would not fit within the normal definition of an ECAM.

(9) Capacity Purchases

In its participation agreements with NB Power for Dalhousie and Point Lepreau, MECL obtains a fixed amount of capacity, and although the amount of energy produced in any give year may fluctuate due to forced outages at these plants, the capacity available for planning purposes is a standard amount based on the anticipated availability factor for the plant. For planning purposes, MECL uses this capacity in the same way as its own plant capacity. Based on its needs, MECL may purchase additional capacity (on a long-term or often on a short-term basis). During 2004 MECL made capacity payments to Slemon Park, Emera and NB Power. It appears that some of expense for capacity was initially budgeted within the energy component for purchases from Emera and NB Power. Because capacity requirements can normally be determined in advance, the majority of jurisdictions specifically exclude payments for capacity from ECAM costs. Capacity payments were excluded from the Fuel Adjustment Clause used by MECL prior to 1994.

(10) Fees & Rental to NB Power Relating to Maritime Interconnection - Submarine Cable

These charges include: (1) Costs incurred in the maintenance of Government owned facilities associated with the Maritime Interconnection including submarine cable inspections; (2) Monthly O&M charges from NB Power for the use of dedicated transmission line facilities constructed by NB Power to serve the Island load; and (3) Monthly rental charge to NB Power associated with breakers dedicated to serving the Island load, where the submarine cables integrate with the NB Power system at Murray Corner. Changes in these costs are not related to price-level fluctuations in fuel or purchase power costs, and furthermore are open for reasonable determination in advance. Therefore, they do not fit within the definition of an ECAM eligible cost.

(11) Amortization of the Point Lepreau Write-Down

The amortization of the Point Lepreau write-down is a fixed amount known in advance and in no way related to price-level changes in fuel or purchased power. It does not fit the definition of an ECAM allowed expense.

MECL Own Generation

(12) Fuel Cost

During 2004 there have been price-level changes in the price of both Bunker C and diesel fuel. This is the most fundamental of all categories eligible under an ECAM.

(13) Generating Plant Operations, Maintenance and Superintendence

Although a higher volume of production by MECL's own generating plants results in a higher amount of plant O&M costs, an analysis has not shown any direct relationship between price-level changes in fuel and purchased power costs and price-level (i.e. unit cost) changes in generating plant O&M costs. These costs do not fit within the definition of ECAM costs.

(14) The Energy Control Center

There is little variation year to year in these costs and, similarly to Plant O&M, no connection was found between the price-level changes in fuel and purchased power and these costs. These costs do not fit the definition of ECAM allowable costs.

Summary

Energy Cost Adjustment Mechanisms are widely approved for use by electric utilities to reduce regulatory burden and reduce the long-term cost of power to customers by reducing utilities' financial risk and thereby the cost of borrowing. In the long history of ECAMs, the positives seem to substantially outweigh the negatives. In principle MECL's proposal to adopt an ECAM is reasonable, however, any ECAM approved by IRAC should recognize the general theory base of ECAMs elsewhere and should contain only changes in price-level relating to prudently incurred costs for fuel delivered to its generating stations and for the variable cost component of purchased electrical energy.

The 18 month true-up period for the ECAM account balance proposed by MECL is longer than what exists in most jurisdictions. Although one example was found where a 20 month period was used due to the need to "soften" the rate impact following a rapid increase in fuel costs, many jurisdictions utilize three-month, and twelve month true-ups. MECL's proposed monthly adjustment to rates appears to provide a reasonable trade-off between achieving the true-up and moderating huge rate changes during times that fuel prices are changing rapidly.

Reduced regulatory cost has always been cited as one of the principle benefits of an ECAM. It is important to ensure that reduction in hearing time is not replaced by an unnecessarily aggressive oversight effort relating to the operation of the ECAM. A properly structured ECAM will assure that customers will not pay more than the justified level of cost, hence there is no need for the regulator to issue an order each time the rate changes as a result of the formula driven automatic adjustment mechanism.

There is a tradeoff between costs associated with required periodic audits (such costs are a function of the frequency) and the wish of a utility to be relieved of liability associated with outstanding ECAM balances. The time between audits could vary considerably without reducing the integrity of the ECAM, but should be performed no less frequently than once every 2-3 years.

It is generally recognized that an ECAM reduces the financial risk of a utility and thus its cost of capital. Therefore, the existence of an ECAM should be factored into the allowed rate of return.

The following table provides a summary of the cost categories that "do" and "do not" appear to meet the definition to be included in the Energy Cost Adjustment Mechanism. On a year-end forecast basis for 2004, volume change (item #7) is about $670,000. The total of all others that do not fit the definition of ECAM is approximately $1 million. Actual amounts can be quickly calculated once the year-end 2004 accounting information is available from MECL.

Suitability for Including in ECAM Costs Beginning January 1, 2004

Item of Cost	**ECAM Cost**	
Purchases	**Yes**	**No**
(1) Price-Level Change in the Energy Component of Purchases from Emera	√	
(2) Price-Level Change in Energy under General Purchases from NB Power	√	
(3) Price-Level Change in Energy from the Dalhousie Contract - NB Power	√	
(4) Price-Level Change in Energy from the Lepreau Contract - NB Power	√	
(5) (Price-Level) Changes in Foreign Exchange on NB Power Payments in USD	√	
(6) Price-Level Change in Energy Purchased from Other Sources	√	
(7) Volume-Level Change in Total Purchased Power		X
(8) Ancillary Services - Purchased		X
(9) Capacity Purchases		X
(10) Fees & Rental Paid to NB Power Relating to PEI Interconnection		X
(11) Amortization of the Point Lepreau Write-Down		X
MECL Own Generation		
(12) Price-Level Change in the Cost of Fuel	√	
(13) Generating Plant Operations, Maintenance and Superintendence		X
(14) The Energy Control Center Operations		X

It is important to re-emphasize that only the cost of purchased power for the above-budget volume of sales (item #7 above) falls into the category where revenues from additional power sold would recover those costs in full. Although it is recognized that during the 2001-2003 timeframe MECL was allowed to include all of the other costs within the ECAM, it would be inconsistent with other jurisdictions to allow such costs to form part of the ECAM in the long term. The regulator has many options regarding how it might make the change from the previous practice to a more theoretically correct future.

All other expenses identified as non-ECAM costs are recoverable from customers and should be discussed in the context of a rate application as costs to be included in the base charge. The downside of allowing non-traditional ECAM costs to remain within that category is that it removes the direct financial incentive for the utility to optimize its decision process regarding the management of those costs, and leaves the regulator in a situation where it must continually pass judgment as to the prudence of such expenditures, after the fact.

Appendices

Maritime Electric Company, Limited
ECAM Costs and Volumes - Historical and Forecast

	NOTE	1997	1998	1999	2000	2001	2002	2003	2004 (Forecast)	2005 (Forecast)	2006 (Forecast)	Ten Year Period
1 Purchased Power												
MWH		905,591	947,103	991,977	992,347	1,025,299	1,001,137	1,009,177	1,046,606	1,079,325	1,090,984	10,089,546
Cost		45,736,886	45,775,996	48,706,295	59,003,245	58,202,505	65,116,483	64,619,633	70,602,635	69,703,373	72,759,661	600,226,711
Cents / kWh		5.05	4.83	4.91	5.95	5.68	6.50	6.40	6.75	6.46	6.67	5.95
2 Self Generated												
Charlottetown Plant												
MWH		18,553	2,475	7,601	39,501	35,181	18,827	30,252	12,204	2,000	2,000	168,595
Fuel Cost		1,330,062	470,762	739,857	3,918,350	3,695,244	2,029,827	3,847,969	1,903,000	191,244	198,379	18,324,695
Operations	1	-	-	-	-	-	432,215	589,288	547,772	335,044	342,849	2,247,168
Maintenance	1	1,414,110	1,411,859	1,576,755	1,824,265	2,537,023	1,354,514	1,301,370	1,143,522	1,612,466	1,602,695	15,778,579
Superintendence		73,322	82,686	69,068	43,530	45,430	57,978	70,276	60,400	44,898	71,331	618,919
Other	2	53,906	103,784	103,380	78,515	211	-	-	-	-	-	339,796
Total Cost		2,871,400	2,069,091	2,489,060	5,864,660	6,277,908	3,874,534	5,808,903	3,654,694	2,183,652	2,215,254	37,309,157
Cents / kWh		15.48	83.60	32.75	14.85	17.84	20.58	19.20	29.95	109.18	110.76	22.13
Borden Plant												
MWH		1,270	(67)	361	6,172	6,406	(8)	517	928	500	500	16,579
Fuel Cost		169,078	53,587	80,724	863,501	1,049,981	73,282	163,389	270,000	51,737	53,813	2,829,091
Operations	1	-	-	-	-	-	17,513	10,972	13,200	27,749	28,389	97,823
Maintenance	1	102,914	33,396	31,165	174,231	208,955	132,511	100,332	128,017	89,065	87,012	1,087,598
Superintendence		-	-	-	-	-	-	-	-	-	-	-
Other	3	-	-	-	-	-	-	-	-	14,474	29,928	44,402
Total Cost		271,992	86,983	111,889	1,037,732	1,258,936	223,306	274,693	411,217	183,025	199,142	4,058,914
Cents / kWh		21.41	-129.63	30.96	16.81	19.65	-2938.24	53.18	44.31	36.61	39.83	0.2448
Charlottetown New CT												
MWH		-	-	-	-	-	-	-	-	2,000	12,005	14,005
Fuel Cost		-	-	-	-	-	-	-	-	126,000	758,205	884,205
Operations		-	-	-	-	-	-	-	-	32,734	58,760	91,494
Maintenance		-	-	-	-	-	-	-	-	35,985	105,225	141,210
Superintendence		-	-	-	-	-	-	-	-	2,000	2,030	4,030
Other		-	-	-	-	-	-	-	-	4,124	4,203	8,327
Total Cost		-	-	-	-	-	-	-	-	200,843	928,423	1,129,266
Cents / kWh										10.04	7.73	8.06
Subtotal Self Generation												
MWH		19,824	2,408	7,963	45,673	41,587	18,819	30,768	13,132	4,500	14,505	199,180
Cost		3,143,392	2,156,074	2,600,949	6,902,392	7,536,844	4,097,840	6,083,596	4,065,911	2,567,520	3,342,819	42,497,337
Cents / kWh		15.86	89.54	32.66	15.11	18.12	21.77	19.77	30.96	57.06	23.05	21.34

Maritime Electric Company, Limited
ECAM Costs and Volumes - Historical and Forecast

	NOTE	1997	1998	1999	2000	2001	2002	2003	Forecast 2004	2005	2006	Ten Year Period
3 Energy Control Center												(5 Yr. Subtotal)
Total System MWH		925,414	949,511	999,940	1,038,020	1,066,887	1,019,957	1,039,945	1,059,738	1,083,825	1,105,489	5,308,954
Operations	4	-	-	-	-	-	327,814	350,437	361,146	353,598	362,120	1,755,115
Maintenance		-	-	-	-	-	-	-	-	-	-	-
Superintendence		-	-	-	-	-	-	-	-	-	-	-
Other		-	-	-	-	-	-	-	-	-	-	-
Total Cost		-	-	-	-	-	327,814	350,437	361,146	353,598	362,120	1,755,115
Cents / Total kWh		-	-	-	-	-	0.032	0.034	0.034	0.033	0.033	0.033
4 Ancillary Services												
Total System MWH		925,414	949,511	999,940	1,038,020	1,066,887	1,019,957	1,039,945	1,059,738	1,083,825	1,105,489	10,288,726
Cost for Purchases		1,250,004	1,250,004	1,293,841	1,527,109	1,745,630	551,813	286,268	586,687	661,583	674,829	9,827,768
Cents / Total kWh		0.135	0.132	0.129	0.147	0.164	0.054	0.028	0.055	0.061	0.061	0.096
Total Energy Costs		50,130,282	49,182,074	52,601,085	67,432,746	67,484,979	70,093,950	71,339,934	75,616,379	73,286,074	77,139,429	654,306,931
Net Purchased &Produced (MWh)		925,414	949,511	999,940	1,038,020	1,066,887	1,019,957	1,039,945	1,059,738	1,083,825	1,105,489	10,288,726
Cents / Total kWh		5.42	5.18	5.26	6.50	6.33	6.87	6.86	7.14	6.76	6.98	6.36

Notes

1 During 1997 - 2000, the Company operated under a form of price cap regulation. Legislative changes proclaimed in October 2001 introduced an Energy Cost Adjustment Mechanism subject to review by the Island Regulatory and Appeals Commission. In order to assist the Commission in performing its duties under the ECAM, the Company began, in 2002, to budget separately and segregate within the accounts, its operating and maintenance costs.

2 This represents the costs associated with the Bunker C storage tank that was leased from Imperial Oil during these years. The lease was terminated at the end of 2000.

3 This represents building and services costs associated with the Borden Generating Station. With the return to traditional cost of service regulation the Company has begun to identify and segregate these costs within its accounts beginning in 2005.

4 Prior to 2002, the costs associated with the operation of the Company's Energy Control Centre were included in the accounts for the Charlottetown Plant. It was decided, beginning in 2002, to capture these costs in separate accounts with their own cost centre.

Maritime Electric Company, Limited

ECAM Costs and Volumes - Historical and Forecast
Calculation Of Year Over Year Changes

								Forecast			Ten Year
	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	Period
Cost - Fuel & Purchases											
Purchased Power Costs	45,736,886	45,775,996	48,706,295	59,003,245	58,202,505	65,116,483	64,619,633	70,602,635	69,703,373	72,759,661	
Fuel Cost Ch'town Thermal	1,330,062	470,762	739,857	3,918,350	3,695,244	2,029,827	3,847,969	1,903,000	191,244	198,379	
Fuel Cost Borden Plant	169,078	53,587	80,724	863,501	1,049,981	73,282	163,389	270,000	51,737	53,813	
Fuel Cost Ch'town CT	-	-	-	-	-	-	-	-	126,000	758,205	
Total Fuel + Purchased Power	47,236,026	46,300,345	49,526,876	63,785,096	62,947,730	67,219,592	68,630,991	72,775,635	70,072,354	73,770,058	622,264,72
Quantity of Power MWH											
Purchased Power	905,591	947,103	991,977	992,347	1,025,299	1,001,137	1,009,177	1,046,606	1,079,325	1,090,984	
Charlottetown Thermal	18,553	2,475	7,601	39,501	35,181	18,827	30,252	12,204	2,000	2,000	
Borden Plant	1,270	(67)	361	6,172	6,406	(8)	517	928	500	500	
New Charlottetown CT	-	-	-	-	-	-	-	-	2,000	12,005	
Total MWH	925,414	949,511	999,940	1,038,020	1,066,887	1,019,957	1,039,945	1,059,738	1,083,825	1,105,489	10,288,726
Total Fuel + PP Cents/kWh	5.10	4.88	4.95	6.14	5.90	6.59	6.60	6.87	6.47	6.67	6.05
Yr./Yr. Change in Unit Cost		-4.47%	1.57%	24.06%	-3.98%	11.70%	0.14%	4.06%	-5.85%	3.21%	
Aggregate Percentage Change		-4.47%	-2.96%	20.39%	15.59%	29.12%	29.29%	34.54%	26.66%	30.73%	
Select Site Costs											
Ch'town Thermal Excl. Fuel	1,541,338	1,598,329	1,749,203	1,946,310	2,582,664	1,412,492	1,371,646	1,203,922	1,657,364	1,674,026	
Year/Year Change in Cost		3.70%	9.44%	11.27%	32.70%	-45.31%	-2.89%	-12.23%	37.66%	1.01%	
Borden Thermal Excl. Fuel	102,914	33,396	31,165	174,231	208,955	150,024	111,304	141,217	131,288	145,329	
Year/Year Change in Cost		-67.55%	-6.68%	459.06%	19.93%	-28.20%	-25.81%	26.88%	-7.03%	10.69%	
New Ch'town CT Excl. Fuel	-	-	-	-	-	-	-	-	74,843	170,218	
Year/Year Change in Cost										127.43%	
Energy Control Center	-	-	-	-	-	327,814	350,437	361,146	353,598	362,120	
Year/Year Change in Cost							6.90%	3.06%	-2.09%	2.41%	
Ch'town Thermal + ECC	1,541,338	1,598,329	1,749,203	1,946,310	2,582,664	1,740,306	1,722,083	1,565,068	2,010,962	2,036,146	
Year/Year Change in Cost		3.70%	9.44%	11.27%	32.70%	-32.62%	-1.05%	-9.12%	28.49%	1.25%	
All Generators + ECC	1,644,252	1,631,725	1,780,368	2,120,541	2,791,619	1,890,330	1,833,387	,706,285	2,217,093	2,351,693	19,967,293
Year/Year Change in Cost		-0.76%	9.11%	19.11%	31.65%	-32.29%	-3.01%	-6.93%	29.94%	6.07%	
Aggregate Percentage Change		-0.76%	8.28%	28.97%	69.78%	14.97%	11.50%	3.77%	34.84%	43.03%	
Costs Per kWh	0.18	0.17	0.18	0.20	0.26	0.19	0.18	0.16	0.20	0.21	0.19
Year/Year Change in Cost		-3.28%	3.61%	14.74%	28.08%	-29.17%	-4.88%	-8.67%	27.05%	3.99%	
Aggregate Percentage Change		-3.28%	0.21%	14.98%	47.27%	4.31%	-0.78%	-9.38%	15.13%	19.73%	

Appendix 2
Maritime Electric Company Limited
Energy Summary

	11 months to Date Nov. 30, 2004 Energy kWh			Forecast 2004 Energy kWh		
	Actuals	**Budget**	**Difference**	**Forecast (1)**	**Budget**	**Difference**
Purchased Energy						
Energy Purchase Contracts	604,700,000	579,902,000	24,798,000	660,767,000	634,244,000	26,523,000
Point Lepreau	174,677,000	190,342,500	(15,665,500)	193,355,000	209,621,500	(16,266,500)
Dalhousie	138,083,000	139,232,500	(1,149,500)	152,725,000	152,833,500	(108,500)
Wind and Other	34,441,300	42,336,000	(7,894,700)	39,759,000	47,544,000	(7,785,000)
Total Purchases	951,901,300	951,813,000	88,300	1,046,606,000	1,044,243,000	2,363,000
	-	-	-	-	-	-
Self Generation						
Charlottetown Plant	8,033,649	-	8,033,649	12,204,000	5,000,000	7,204,000
Borden Plant	390,227	-	390,227	928,000	500,000	428,000
Total Self Generation	8,423,876	-	8,423,876	13,132,000	5,500,000	7,632,000
Total	960,325,176	951,813,000	8,512,176	1,059,738,000	1,049,743,000	9,995,000

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(1) Based on October 2004 sales forecast

The above table was provided by MECL in Response to Information Request #2 and Modified Slightly as this Appendix

The total energy for the year is forecast to be 9.995.000 kWh above the budget level.
The cost of this energy is included in MECL's calculation of ECAM eligible costs, but increased sales will recover this amount. Thus MECL's ECAM amount must be reduced by the increased volume times 6.71 cents/kWh average cost or $670,665

Appendix 3
Maritime Electric Company Limited
Line by Line Identification of 2004 ECAM Costs

	11 Months Ending November 30, 2004			12 Months Ending December 31, 2004			
	Budget	Actual	Difference	Budget	Forecast **(2)**	Difference	Discussion
Purchased Power							
Lepreau **(1)**	9,732,288	11,012,779	1,280,491	10,644,658	11,799,008	1,154,350	
Dalhousie	8,234,786	9,092,621	857,835	9,004,257	9,869,511	865,254	
Other	44,240,018	44,624,057	384,039	48,604,715	48,934,116	329,401 (a)	411,376
Sub Total	62,207,092	64,729,457	2,522,365	68,253,630	70,602,635	2,349,005	
Fuel							
Charlottetown	-	1,422,674	1,422,674	672,742	1,903,000	1,230,258	
Borden	47,322	150,903	103,581	51,645	270,000	218,355	
Sub Total	47,322	1,573,577	1,526,255	724,387	2,173,000	1,448,613	
MECL Generators							
Operations	386,521	495,612	109,091	423,796	560,972	137,176	137,176
Maintenance	736,329	939,461	203,132	807,004	1,271,539	464,535	464,535
Superintendence	54,043	47,956	(6,087)	58,981	60,400	1,419	1,419
Other	-	-	-	-	-	-	
Sub Total	1,176,893	1,483,029	306,136	1,289,781	1,892,911	603,130	
Energy Control Center	337,689	375,890	38,201	374,667	361,146	(13,521)	(13,521)
Ancillary Services	536,925	328,580	(208,345)	586,693	586,687	(6)	(6)
Total	64,305,921	68,490,533	4,184,612	71,229,158	75,616,379	4,387,221	1,000,979

(1) Includes the amortization of the Point Lepreau write down settlement.
(2) Based on the latest forecast, dated October 2004.

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The above table was provided by MECL in Response to Information Request #2 The two right-hand columns have been added.

(a) Within "Purchased Power - Other" are payments for capacity and costs associated with the cable interconnection.
Any for capacity above the budget level to Emera or Slemon Park, that should also be shown here.)
The net amount of MECL's identified ECAM portion of these are shown in the right hand column
The cost of volume-related increase shown in Appendix 2 is a reduction to ECAM in addition to what is shown here

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