

**Direct Testimony of
Paula D. Zarnett
Filed on Behalf of
Summerside Electric
March 31, 2008**

**CANADA
PRINCE EDWARD ISLAND**

**BEFORE THE ISLAND REGULATORY
AND APPEALS COMMISSION**

IN THE MATTER of Section 20 of
the *Electric Power Act*, R.S.P.E.I.
1988, Cap. E-4, and **IN THE
MATTER** of the Application of
Maritime Electric Company, Limited,
for Approval of an Open Access
Transmission Tariff

**DIRECT TESTIMONY OF
PAULA D. ZARNETT
FILED ON BEHALF OF
SUMMERSIDE ELECTRIC
MARCH 31, 2008**

List of Exhibits

- PDZ-2 Curriculum Vitae of Paula Zarnett
PDZ-3 Questions of the City of Summerside to MECL dated December 7, 2007, with responses dated December 21, 2007 and additional information provided in January, 2008
- PDZ-4 Study by R.J. Rudden Associates, filed by Hydro One with the Ontario Energy Board
- PDZ-5 Decision U98125 of the Alberta Energy and Utilities Board
PDZ-6 EUB Decision 2002-060 July 2, 2002
PDZ-7 Decision 1999-0903 of the British Columbia Utilities Commission
PDZ-8 Bypass Rate Guidelines for BC Hydro, issued by the British Columbia Utilities Commission, as an Attachment to Decision 1999-0903
- PDZ-9 Decision GH-3-2001 approving construction by Petro-Canada of the Medicine Hat Pipeline, National Energy Board
- PDZ-10 Summary of Decision in EBRO 477, re Cardinal Power, of the Ontario Energy Board, taken from the Ontario Energy Board's Web Site.
- PDZ-11 Extract from Ontario Energy Board Decision re Union Gas, under dockets RP-2003-0063, EB-2003-0087, and EB-2003-0097.

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25 **INTRODUCTION**

26 **Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND RELATIONSHIP**
27 **TO THE CITY OF SUMMERSIDE ELECTRIC UTILITY (“SE”).**

28 A. My name is Paula D. Zarnett. I am Vice President with the management consulting firm
29 of BDR NorthAmerica Inc. BDR is headquartered at 34 King Street East, Suite 1000,
30 Toronto, Ontario, M5C 2X8. I have been retained by SE to provide expert testimony in
31 this proceeding.

1 **Q. PLEASE DESCRIBE THE ELEMENTS OF YOUR BACKGROUND THAT ARE**
2 **RELEVANT TO THIS DOCKET.**

3 A. My career specialization has been cost allocation, rate designs and regulatory compliance
4 in Canada. Since 1998, an additional focus has been to assist clients who are utilities,
5 regulators, government agencies, generators and consumers in responding to industry
6 change brought about by open access and re-regulation.

7 During the period from 1981 to 1984, I was employed by ICG Utilities Ltd., a
8 company which then served natural gas distribution territories in Ontario, Manitoba and
9 Alberta, piped propane and natural gas in British Columbia and electricity in the
10 Northwest Territories. My responsibility was to assist regional utility management with
11 guidance and supporting studies in their rate approval applications to the regulators in
12 their jurisdictions. In this capacity I performed cost allocation and working capital
13 (“lead-lag”) studies and bundled rate designs. I appeared as a company witness in three
14 proceedings before the British Columbia regulator during that period.

15 In 1984, I joined Toronto Hydro, a municipal electric distribution utility which then
16 served about 250,000 customers in Toronto. There, I was responsible for electricity rate
17 designs and supporting analysis. In 1985, I led a cross-function team on a one-year
18 assignment to develop the utility’s first fully allocated cost of service study, including
19 load research, class load shape analysis, minimum system and zero intercept analysis, and
20 distribution loss analysis. As a supervisor and later as a manager with Toronto Hydro, I
21 participated in industry working groups on issues of cost allocation and rate design, and I

1 also testified before the Ontario Energy Board on issues related to Ontario Hydro's bulk
2 power rate proposals.

3 After 14 years with Toronto Hydro, and in the midst of Ontario's initiatives to
4 introduce retail open access and re-regulation, I left the utility to enter the field of
5 consulting. As a consultant, I have performed several cost allocation studies for electric
6 utilities and one for a piped steam distribution system. I have testified on behalf on
7 municipal utility intervenors as to methodology issues in a cost allocation study filed by
8 New Brunswick Power Distribution and Customer Service, and participated on behalf of
9 a consumer in the Ontario Energy Board's multi-year stakeholder process to develop a
10 uniform methodology for cost allocation for the province's electric distribution utilities.
11 For the past two years, I have participated as an instructor in CAMPUT's Energy
12 Regulation Course, on the subjects of cost allocation and rate design.

13 In 2003, I was part of a team that advised the Ministry of Energy and Mines of British
14 Columbia with regard to recommendations by the British Columbia Utilities Commission
15 ("BCUC") for implementation of the proposed Heritage Contract arrangements and
16 stepped rates for wholesale and industrial customers of BC Hydro. The following year, I
17 prepared a report to the Ontario Energy Board comparing heritage contracts and similar
18 arrangements in selected jurisdictions within and beyond Canada.

19 In 1999, I participated in a project to unbundle costs of a vertically integrated utility
20 and develop a tariff structure for open access use of the national electric transmission
21 system in Ghana, West Africa. This assignment involved review of issues and precedents
22 in Ontario, the United States and foreign jurisdictions to recommend a simple tariff

1 approach that would meet local needs. In 2005, I advised Shanghai Municipal and four
2 provincial electric power companies in East China in developing their transmission and
3 distribution revenue requirements, and simulating the operation of an unbundled
4 distribution tariff.

5 I also appeared before the Ontario Energy Board as a witness on behalf of Coral
6 Energy, requesting approval of a by-pass competitive rate for gas distribution by Union
7 Gas to Coral's electricity generation plant.

8 A more detailed resume, including relevant experience in other jurisdictions, is
9 contained in Exhibit PDZ-2.

10 **PURPOSE AND ORGANIZATION OF TESTIMONY**

11 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY AND HOW IS IT**
12 **ORGANIZED?**

13 A. The purpose of my testimony is to provide the Island Regulatory and Appeals
14 Commission ("IRAC") with information on three issues associated with the provision of
15 transmission services to SE: (i) the cost allocation study prepared by Foster Associates as a
16 basis for Maritime Electric Company Limited's ("MECL's") proposed network transmission
17 revenue requirement; (ii) regulatory precedents for the approval of by-pass competitive rates
18 in Canada; and (iii) the designation and treatment of specified electricity assets as heritage
19 assets for purposes of ensuring equitable sharing of their benefits among all consumers for
20 whose benefit the assets were constructed.

1 ISSUES RELATED TO THE EVIDENCE

2 Q. BEFORE DISCUSSING THESE ISSUES OF SUBSTANCE, WOULD YOU
3 PLEASE DESCRIBE ANY ISSUES YOU BELIEVE ARE IMPORTANT WITH
4 REGARD TO THE INFORMATION THAT HAS BEEN MADE AVAILABLE BY
5 MECL IN THE STAKEHOLDER PROCESS?

6 A. I have serious concerns about the fact that certain data requested by SE from MECL
7 through the stakeholder process was provided only very late in the process, and in some
8 cases has not been provided at all. MECL has included the questions and answers as of
9 July 17, 2007 in its evidence as Exhibit B. On pages 1-13 of Exhibit B, the June 22, 2007
10 questions with answers to SE are set out. These record a dialogue in which SE has
11 attempted to obtain additional information on several topics, which include substation
12 peaks, estimates of OASIS-related costs, and background data and methodologies of the
13 Foster cost of service study. Additional questions were submitted to MECL by SE on
14 December 7, 2007, and responded to on December 21, 2007. Further responses to these
15 questions were not received until January, 2008. These questions and answers are
16 attached as my Exhibit PDZ-3.

17 I have had more than 25 years' experience in regulatory processes which provide
18 mechanisms for questions to the applicant from participants. The purpose of such
19 questions goes beyond the objective which MECL identifies in its response to SE's
20 questions 1 and 2 dated June 22, 2007, that of assisting the parties in deciding what class
21 of service they will take when the tariff is approved. The purpose of a participant
22 question mechanism is to provide the information that the parties need to clarify the

1 impacts on them of the applicant's proposals, to develop their positions on the matters of
2 substance, to identify feasible alternatives, and to provide the basis of their own analysis
3 and arguments to the regulator either in support of or against the applicant's proposals.
4 Such questions inform the decisions that the regulator will make at the close of the
5 proceeding.

6 Most of the information on which an application for approval of rates is based is
7 information on the applicant's costs and operations. Other parties have no source of such
8 information, other than the applicant. It is thus of concern when requests for data or for
9 clarification of methodologies used by the applicant are refused, or when only a partial
10 response is given.

11 **Q. WHAT IS YOUR CONCERN WITH RESPECT TO SUBSTATION PEAK DATA?**

12 A. SE initially requested data as to the load of each substation at the time of the system
13 coincident peak, and at each station's non-coincident peak for each month over the most
14 recent two years. The purpose of the request was to better understand the load
15 computations underlying the proposed tariff, in which billings are proposed to be based
16 on coincident peak load, and to explore the implications of alternative billing
17 determinants. While the coincident peak approach is widely used, both Nova Scotia and
18 New Brunswick use non-coincident peaks in their OATTs. Data for the substation non-
19 coincident peaks would assist in evaluating the impacts of a non-coincident peak
20 approach for Prince Edward Island. In my opinion, a discussion of this alternative has
21 merits in view of the fact that adopting it would provide consistency with neighbouring
22 jurisdictions.

1 In response to the initial questions in March, 2007, and to the restated questions in
2 June, 2007, MECL provided only aggregate data. At lines 11-13 on page 2 of Exhibit B,
3 they go on to say that "Maritime Electric does not routinely gather peak information from
4 each of its substations and accessing this historical information will require substantial
5 effort therefore COS is requested to provide additional justification for this request." This
6 triggers additional concern. If MECL does not routinely gather load information from
7 each substation, the question is raised as to how MECL proposes to comply with the
8 condition of its own OATT, which SE understands as requiring MECL to schedule all
9 network generation points and all network load points.

10 In order to further clarify, SE in December, 2007 submitted the questions that are in
11 my Exhibit PDZ-3, and received the answers in that exhibit. In Question 6, MECL says
12 that it proposes to schedule its native network loads on an aggregate basis. Furthermore,
13 while substation peak data was provided in January, 2008 in response to Question 5 of
14 that Exhibit, the parts of that question which pertain to metering facilities, data retrieval,
15 and the business processes necessary to implement non-coincident billing as part of the
16 OATT, were never answered.

17 **Q. WHAT IS YOUR CONCERN WITH RESPECT TO OASIS COST DATA?**

18 A. As explained in detail in Mr. Dunn's evidence, an OASIS is an important component of
19 the operation of a transmission system on an open access basis, and I have been advised
20 by SE that access to the functionality of an OASIS has a potential impact on SE's costs
21 under the OATT. As a result SE's March, 2007 question 6 addressed the issue of
22 potential costs for implementation of an OASIS. Although the answer states at line 25 of

1 page 6 of Exhibit B, that these costs are based on the New Brunswick System Operator
2 (“NBSO”) providing the service, it is not clear whether MECL has received a specific
3 quote for such services, and if so, how much of the total costs are for services from the
4 NBSO and how much are MECL’s own costs, and how it is envisaged that the service
5 would be structured. As a result, SE posed Question 4 in June, 2007. The answer simply
6 states that the figures provided include costs for both NBSO and MECL in providing the
7 service.

8 These responses, in my view, provide no assistance in assessing whether potential
9 alternatives exist by which OASIS-type services could be offered to Prince Edward
10 Island transmission customers at an acceptable level of cost.

11 **Q. WHAT IS YOUR CONCERN WITH RESPECT TO THE COST ALLOCATION**
12 **STUDY?**

13 A. In brief, SE attempted in its questions of March, June and December, 2007 to obtain
14 additional detail as to the background computations and functionalization approaches in
15 the cost allocation study, and MECL refused to answer the questions. As a result, I
16 believe information is missing from the record that is necessary to support the
17 transmission revenue requirement. I explain this in more detail in the next section of my
18 testimony.

19
20 **Q. WHAT IS YOUR SUGGESTION, STEMMING FROM THESE CONCERNS?**

21 A. I suggest that IRAC order MECL to file the requested information, specifically with
22 respect to the cost allocation study, with IRAC, and to serve copies on all parties to this

1 proceeding. I would further suggest that IRAC set a date for the filing of the information,
2 such that it can be analyzed, and additional submissions can be made to IRAC based on
3 it, before oral hearing takes place.

4 **PROPOSED TRANSMISSION REVENUE REQUIREMENT AND COST**

5 **ALLOCATION STUDY**

6 **Q. IN YOUR OPINION, IS THE EVIDENCE PRESENTED BY MECL IN SUPPORT**
7 **OF ITS PROPOSED TRANSMISSION REVENUE REQUIREMENT**
8 **ADEQUATE?**

9 A. No.

10 MECL purports to have developed a transmission revenue requirement through the
11 use of a cost allocation study conducted by Foster Associates ("Foster study"). It is
12 important to understand that the usual end product of a cost allocation study is the
13 allocation of the regulator-approved costs of service (i.e., the revenue requirement) to
14 each of the utility's classes of customers.

15 Cost allocation studies typically have three stages: functionalization, classification
16 and allocation, and these are described in the documentation of the Foster study. At the
17 functionalization stage, different cost functions are distinguished, so that for each a
18 suitable allocation factor or cost driver can be identified as a basis for allocation of the
19 costs. If all classes of MECL's customers were receiving fully bundled service, each
20 would typically receive an allocation of generation, transmission, distribution and
21 customer service costs. The functionalization would affect the amount of the total costs

1 that are allocated to each class, because different cost functions are allocated differently,
2 and therefore the accuracy of functionalization should receive close regulatory scrutiny.

3 In contrast to the typical use of a customer cost allocation study, MECL has used the
4 results of the functionalization component of the cost allocation study to define a separate
5 revenue requirement, for recovery on separate basis (i.e., the proposed Open Access
6 Transmission Tariff or "OATT"). Foster Associates has used a series of high-level cost
7 functions which include generation, transmission, several types of distribution assets, and
8 several customer service activities. The costs functionalized as "transmission" in this
9 study are proposed to constitute the transmission revenue requirement for purposes of the
10 OATT. It is my view that the information provided in the Foster study itself, and
11 subsequently by MECL, is not sufficient to provide assurance that the costs to be
12 recovered through charges under the OATT have been correctly determined.

13 **Q. IN WHAT SPECIFIC RESPECTS IS THE INFORMATION PROVIDED WITH**
14 **RESPECT TO THE COST OF SERVICE STUDY INSUFFICIENT?**

15 A. MECL is not proposing to create a separate transmission business unit, and it is
16 reasonable to expect that the loss of operational and administrative synergies if it did so
17 would be costly. Much larger utilities than MECL on implementing a separate
18 transmission tariff have nonetheless continued to operate, for example, transmission and
19 distribution facilities through a single corporate structure, and thereby to benefit
20 customers through synergies in management and administration of "wires" functions, as
21 well as certain design, construction, and maintenance functions, for example tree-
22 trimming. An example of a utility operating on this basis, with separate transmission and

1 distribution pricing and revenue requirements, is Hydro One Networks, an Ontario utility
2 which owns and operates over 95% of Ontario's transmission system and serves
3 approximately 1.2 million customers through its distribution system.

4 The transmission revenue requirement from the bundled costs of service of MECL
5 should consist of specifically identified transmission assets, an allocated portion of any
6 assets shared with distribution functions, related operating and maintenance costs, and an
7 allocation of general costs. In order to determine whether the components are correctly
8 identified and costed, detailed information should be provided. In particular, as far as
9 possible costs which are directly assignable as transmission should be identified and so
10 assigned as part of the study. Except for a single paragraph on page 12 of its report,
11 Foster Associates does not elaborate on the process of separating transmission from
12 distribution assets or provide a cost breakdown by asset class. Shared operating costs
13 are, on page 13, explained to be functionalized on the basis of "(1) gross plant, (2) net
14 plant, and (3) operations maintenance and administrative ("OMA")." However, no
15 information is provided for review by stakeholders or by IRAC as to which basis is used
16 for which costs. No alternative methods, which might more specifically reflect cost
17 drivers (such as, for example, labour recorded to work orders) have been discussed, and
18 therefore can be assumed not to be utilized.

19 Furthermore, it is not apparent that a detailed cost causation approach was undertaken
20 to separate general and administrative costs that support the transmission function.
21 Foster Associates, at page 13 of its report, instead says, "After all such cost items were
22 functionalized, general plant investment and expenses (originally functionalized to the

1 temporary general category for simplicity) then were “refunctionalized” to MECL’s
2 functions utilizing factors according to either management “in support of plant” or “in
3 support of labor.”” Again no detail is provided.

4 **Q. ARE YOU AWARE WHETHER ANY PARTY TO THE STAKEHOLDER**
5 **PROCESS REQUESTED ADDITIONAL INFORMATION FROM MECL?**

6 A. Yes. As shown by Exhibit C, Issue 13 of MECL’s October 3, 2007 information filed
7 with the IRAC, the SE had made requests for additional information and an electronic
8 copy of the cost of service study. The SE also asked in what forum MECL intended to
9 respond to requests for additional data. MECL’s response was: “Maritime Electric will
10 not be providing this information. Maritime Electric contends that the information in the
11 Cost of Service Study is of sufficient detail for the stakeholders to confirm that the
12 methodology used to determine revenue requirements was appropriate.”

13 On December 7, 2007, SE submitted four additional questions, requesting detail as to
14 how non-general and general plant and expenses were functionalized, and received by
15 way of reply in the document I have attached as Exhibit PDZ-3 a reference to Exhibit C,
16 Issue 13, which is in effect, a refusal to provide the requested information.

17 **Q. WHAT EXAMPLES ARE YOU AWARE OF FROM OTHER JURISDICTIONS,**
18 **OF UTILITIES THAT HAVE PERFORMED STUDIES TO ALLOCATE**
19 **SHARED COSTS BETWEEN A TRANSMISSION REVENUE REQUIREMENT**
20 **AND A DISTRIBUTION OR GENERATION FUNCTION?**

21 A. Hydro One Networks Inc. is a transmission and distribution utility in Ontario, regulated
22 by the Ontario Energy Board (“OEB”). Its transmission revenue requirement is collected

1 through an OEB-approved transmission tariff from transmission load customers who
2 include distribution utilities and industrial customers directly connected to the
3 transmission system. Its distribution revenue requirement is collected through an
4 unbundled distribution rate, which is approved in a separate proceeding by the OEB. In
5 Hydro One's initial rate case in preparation for industry restructuring and retail open
6 access, docket RP-1998-0001, the OEB issued a directive stating: "The Board believes
7 that OHSC [the corporate predecessor of Hydro One Networks] should adopt a consistent
8 approach to allocating overhead costs to distribution and transmission in order to ensure
9 that customers of transmission and distribution pay a fair share of the costs associated
10 with the services received by these respective business units. Therefore, in subsequent
11 applications, the Board expects the Company to adopt a consistent allocation
12 methodology to be used by NAM (Network Asset Management) and Network Services.
13 OHSC should also be prepared, in the next rate application, to provide the rationale and
14 justification for the approach selected."

15 Hydro One therefore commissioned a study by R.J. Rudden Associates,
16 recommending a best practice methodology to distribute the cost of providing common
17 corporate functions and services among the business units that use the functions and
18 services. The Rudden study was filed as an appendix to Exhibit C1, Tab 6, Schedule 1
19 under docket number RP-2005-0020/EB-2005-0378. A copy of the study is attached as
20 Exhibit PDZ-4.

21 The methodology of the study was accepted at that time, and was used to develop
22 both the transmission and distribution revenue requirements in more recent applications

1 to the OEB. The methodology involves a detailed breakdown of shared corporate and
2 administrative functions into activities, each of which was first reviewed to determine if
3 it could be directly allocated to a business unit, and otherwise allocated based on a “cost
4 driver” selected on the basis of cost causation. The allocation of asset management,
5 operating and customer care management costs are distributed to the distribution and
6 transmission functions based on a time study.

7 **Q. WHAT IMPACT DO YOU BELIEVE THAT A MORE DETAILED COST**
8 **ALLOCATION APPROACH WOULD HAVE ON THE TOTAL TRANSMISSION**
9 **REVENUE REQUIREMENT?**

10 A. There is no basis to answer this question, as the data are not available. However,
11 whatever the effect might be on the resulting numbers, such analysis would provide
12 IRAC and stakeholders with an opportunity to question and understand the costs that
13 MECL is applying to recover through its OATT.

14 **Q. DO YOU HAVE ANY OTHER COMMENTS AS TO THE COSTS PROPOSED**
15 **TO BE COLLECTED THROUGH TRANSMISSION CHARGES?**

16 A. I support the concerns expressed by William Dunn in his evidence, that certain facilities
17 may be inappropriately included in the transmission tariff. Specifically, Mr. Dunn has
18 concluded that the cost of certain radial lines that provide no general reliability benefits
19 should be excluded from the OATT rates and directly supported by those
20 customers/generators benefitting from those facilities.

21 **Q. WHAT EFFECT WOULD RESULT ON THE TRANSMISSION TARIFF LEVELS**
22 **IF CERTAIN RADIAL LINES WERE EXCLUDED?**

1 A. In order make an accurate determination, it would be necessary to know the net book
2 value of each relevant section of line and related assets, and any operating, maintenance
3 or administrative costs that are directly assignable to those assets. A better
4 understanding of the allocation of dependent non-general and general costs would also be
5 necessary if the Foster Associates methodology were going to be used to compute a fully
6 allocated cost. However, as I explained previously, I would recommend a more
7 transparent, direct and detailed method of functionalization of shared costs.

8 That information is not presently available. However, I believe that it is important to
9 estimate the potential significance to the network revenue requirement if Mr. Dunn's
10 recommendations as to the definition of network assets is accepted by IRAC. SE
11 requested, and MECL provided a line diagram of the system and a spreadsheet showing
12 the length in kilometers of each section. The total length of lines identified by MECL is
13 621.6 km.

14 I first excluded the lengths of the submarine cables and the line from Richmond Cove
15 to Bedeque Station, because, based on information provided by MECL I understand that
16 these assets have no net book value in the proposed transmission rate base. I also
17 excluded lines T12, T23, T25 and T 27, because it is my understanding that the cost of
18 these lines is not intended to be recovered through transmission network charges. I then
19 computed the net length of line in kilometers as 479.7 km, and, based on the proposed
20 transmission revenue requirement of \$6,052,072, computed an average system revenue
21 requirement of \$12, 615 per km.

1 I then subtracted the lengths of the line components identified by Mr. Dunn in his
2 testimony, WHD-1, as apparent generation leads and radial lines to load, to compute a net
3 value of 307.6 km. At an average revenue requirement of \$12,615 per km, the total
4 amount to be recovered from the OATT rates would therefore be \$3,880,040, a reduction
5 from MECL's proposed level of thirty-six percent (36%).

6 Table 1 sets out the computation just described.

7 This computation, as previously explained, is not being proposed as an accurate re-
8 determination of the amounts appropriately collected through the OATT rates. What I do
9 recommend is, if IRAC accepts Mr. Dunn's recommendation that generation leads and
10 radial lines to load be excluded from the OATT rates, that IRAC direct MECL to prepare
11 a re-determination based on its best available information, and file the analysis, with
12 appropriate supporting documentation for review by IRAC and all parties to this
13 proceeding.
14

Table 1
Line Data and Computation

1	2	3	4	5	6	7	8	9	
From Bus Name	To Bus Name	Line Number	Base (kV)	Line Length (km)	Revenue Requirement As Proposed	Apparent Radial Lines to Load	Apparent Generation Leads	Network Lines Revised	
1	Murray Corner	Richmond Cove	138	21.7					
2	Murray Corner	Richmond Cove	138	21.7					
3	Richmond Cove	Bedeque	138	9.5					
4	Richmond Cove	Bedeque	138	9.5					
5	Bedeque	Sherbrooke	138	15.8	15.8			15.8	
6	Borden	Bedeque	138	8.4	8.4			8.4	
7	Bedeque	West Royalty	138	40.9	40.9			40.9	
8	Bedeque	West Royalty	138	40.9	40.9			40.9	
9	Borden	Sherbrooke	138	24.9	24.9			24.9	
10	Sherbrooke	New Annan	69	7.9	7.9			7.9	
11	New Annan	Rattenbury	69	14.8	14.8			14.8	
12	Rattenbury	Hunter River	69	12.6	12.6			12.6	
13	Hunter River	West Royalty	69	19.2	19.2			19.2	
14	Charlottetown	Cross Roads	69	4.8	4.8			4.8	
15	Cross Roads	Summerville	69	24.1	24.1			24.1	
16	Summerville	Lorne Valley 2	69	6.4	6.4			6.4	
17	Borden	McCain Foods	69	4.8	4.8			4.8	
18	McCain Foods	Albany	69	0.5	0.5			0.5	
19	Charlottetown	Scotchfort	69	21.7	21.7			21.7	
20	Scotchfort	Lorne Valley 1	69	21.4	21.4			21.4	
21	Sherbrooke	St Eleanors	69	4.7	4.7		(4.7)	-	
22	St Eleanors	Wellington	69	15.9	15.9		(15.9)	-	
23	Lorne Valley 1	Georgetown	69	14.6	14.6	(14.6)		-	
24	Sherbrooke	Slemon Park	69	4.7	4.7	(4.7)		-	
25	Lorne Valley 1	Dingwells Mills	69	23.7	23.7	(23.7)		-	
26	Dingwells Mills	Souris	69	19.6	19.6		(19.6)	-	
27	Lorne Valley 2	Victoria Cross	69	18.0	18.0	(18.0)		-	
28	Victoria Cross	Dover	69	18.0	18.0	(18.0)		-	
29	Sherbrooke	Summerside	69	4.3	4.3			4.3	
30	Dingwells Mills	Elmira	69	43.1				-	
31	West Royalty	UPEI	69	3.7	3.7			3.7	
32	UPEI	Charlottetown	69	2.6	2.6			2.6	
33	West Royalty	Charlottetown	69	10.1	10.1			10.1	
34	Wellington	O' Leary	69	33.6	33.6		(33.6)	-	
35	O' Leary	Alberton	69	19.3	19.3		(19.3)	-	
36	Alberton	T25, T23 jnc.	69	17.9	17.9			17.9	
37	T25, T23 jnc.	AWTS	69	10.3				-	
38	T25, T23 jnc.	Vestas	69	7.1				-	
39	O'leary	West Cape	69	19.0				-	
40	Total Line Length (km)				621.6	479.7	(79.1)	(93.1)	307.6
41	MECL's proposed Transmission Revenue Requirement				\$	6,052,072			
42	Average Revenue Requirement per km of Line				\$	12,615			
43	Transmission Revenue Requirement based on Exclusions of Radial Lines to Load and Generation Leads (Proportional Estimate)				\$	3,880,040			
44	Reduction in Revenue Requirement from MECL's Proposal					36%			

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PRECEDENTS FOR BY-PASS COMPETITIVE RATES IN CANADA

Q. WHAT IS A BY-PASS COMPETITIVE RATE?

A. Generally, the term refers to a situation in which a customer could reduce its long-run costs by constructing facilities that would by-pass the incumbent utility's transmission or distribution system and thereby avoid paying some or all of the transmission or

1 distribution rate. If the customer proceeds with the construction, it would be financially
2 better off, but the utility, and its other customers, would lose the benefit of a contribution
3 to revenue requirement from this customer. In this situation, the utility may be willing to
4 offer, and the regulator to approve, a reduced rate to the customer for use of the utility's
5 system, which provides sufficient cost savings as compared to standard rates so that the
6 customer with the by-pass opportunity prefers to receive service from the utility instead
7 of building the by-pass facility.

8 If the customer accepts this reduced "by-pass competitive rate", the utility and its
9 other customers are better off than if the customer by-passed, because the customer will
10 contribute some revenue to the revenue requirement, and the customer with the by-pass
11 opportunity would be indifferent financially between the two options. This overall
12 conceptual framework applies whether the potential by-pass customer would otherwise
13 use existing facilities of the incumbent utility, or whether, if the customer accepts the by-
14 pass competitive rate, new facilities would need to be constructed by the utility.

15 There are other terms for the same concept, including "by-pass avoidance rate", "by-
16 pass equivalent rate", "load retention rate" and "duplication avoidance rate".

17 **Q. WHY IS THE CONCEPT OF A BY-PASS COMPETITIVE RATE RELEVANT**
18 **TO THE COMMISSION'S CONSIDERATION OF MECL'S APPLICATION FOR**
19 **TRANSMISSION RATES?**

20 A. Coles Associates has prepared a study which indicates that, based on the transmission
21 costs that SE would incur under MECL's proposed OATT, the SE would have an
22 economic business case to construct a transmission line between Summerside and the

1 Bedeque substation terminal of the connection to New Brunswick to provide the SE with
2 a direct power connection to external provisional sources, if by doing so it could avoid
3 paying charges under the proposed OATT. In my opinion, it is appropriate for IRAC to
4 consider its policy with regard to transmission by-pass and by-pass competitive rates in
5 conjunction with this OATT approval application, because either by-pass of the
6 transmission system by SE, or approval of a by-pass competitive rate, would affect
7 conditions of service under the OATT and the charges to other transmission users.

8 **Q. IS THERE PRECEDENT IN CANADA FOR A REGULATOR TO EITHER**
9 **ALLOW BY-PASS BY CUSTOMERS OR TO APPROVE BY-PASS**
10 **COMPETITIVE RATES?**

11 A. Yes. I found precedents at the National Energy Board, and in British Columbia, Alberta
12 and Ontario that I believe will be helpful to IRAC on this issue. Although some of these
13 precedents relate to natural gas transportation, rather than to electricity, I believe the
14 regulatory principles are transferable to this case and support both the granting of any
15 approvals that might be required for construction of the facilities by SE, and also
16 approval of a by-pass competitive rate by MECL if MECL prefers to offer such a rate
17 rather than have SE build the new facilities. In each case, the details are slightly different
18 as to the specific conditions that would need to be satisfied, because each jurisdiction has
19 different legislation and a different industry structure. However, I believe the clear
20 conclusions to be drawn are that: (1) subject to terms of legislation, a customer can be
21 permitted to construct by-pass facilities if the project is economically viable; and (2) the

1 offer of a by-pass competitive rate by the incumbent utility is in the interest of all parties
2 when faced with a credible by-pass threat.

3 **Q. PLEASE DESCRIBE THE RELEVANT POINTS OF THE ALBERTA**
4 **PRECEDENTS.**

5 A. Decision U98125 of the Alberta Energy and Utilities Board (“EUB”) dated July 24, 1998,
6 resulted from an application for TransAlta Utilities Corporation to provide discounted
7 transmission service to Dow Chemical Canada Inc. I have provided a copy as Exhibit
8 PDZ-5. Under legislation in Alberta at that time, customers were required to purchase
9 from the utility in the service area, unless the electricity was “produced on property of
10 which a person is the owner or a tenant, for use solely by that person and solely on that
11 property”. (Section 2(b) of the *Electric Utilities Act*). Dow intended to generate power
12 for use at its own site, and also to transmit some of the power to another company’s
13 (Praxair) industrial facility located on the adjacent property. Had the exemption from
14 purchasing from the utility been deemed by the EUB to not apply, Dow could not have
15 supplied Praxair, and no by-pass avoidance rate would have been necessary. However,
16 the EUB found that Dow would qualify for the exemption if it purchased the adjacent
17 property, and was committed to do so in order to qualify, and decided that it (the EUB)
18 had discretion not to force such a purchase to satisfy the letter of the law.

19 In proceeding to evaluate the case on its merits, the EUB referred to four criteria
20 established in its earlier Decision in a natural gas case, U97096. These criteria are:

- 21
- The by-pass avoidance rate is required to respond to a credible bypass threat;

- 1 • The bypass avoidance rate must exceed the long run incremental cost of
2 service;
- 3 • The bypass avoidance rate is no more attractive than is reasonably required to
4 avoid duplicate facilities; and
- 5 • The cost of offering the bypass avoidance rate is appropriately shared
6 between other utility customers and the utility shareholders.

7 The EUB proceeded to evaluate the application in accordance with these principles.

8 Evidence that Dow's physical by-pass option was viable economically, technically and
9 physically was necessary to meet the criterion that the by-pass threat is "credible". The
10 EUB noted "the considerable cost savings accruing to Dow if it constructs the proposed
11 by-pass", as well as other economic advantages. With regard to physical and technical
12 viability, the EUB said at page 8 of its Decision:

13 "The Board notes the extensive nature of Dow's existing onsite utility operations
14 and that the construction and operation of the bypass is a relatively
15 straightforward addition to Dow's existing electric operations. The Board
16 observes that none of the intervenors challenged the technical and physical
17 viability of Dow's proposal, nor Dow's ability to construct and operate the
18 bypass."

19
20 The EUB concluded in approving the discount on page 8, saying:

21 "In short, the Board believes Dow is well positioned to meet its own requirements
22 in an effective manner absent a suitable transmission bypass avoidance rate.
23 Should it do so, the costs of TransAlta's underutilised transmission assets would
24 be borne by remaining transmission system users and/or TransAlta's shareholders.
25 Therefore, the Board finds Dow's physical bypass option a credible threat.
26 Accordingly, it believes the development of a suitable bypass avoidance rate is in
27 the public interest."

28
29 The remainder of the Decision focuses on the appropriateness of the specific rate
30 proposal.

1 In a different proceeding, EUB Decision 2002-060 July 2, 2002, which is provided as
2 Exhibit PDZ-6, the EUB determined that a “duplication avoidance tariff” (“DAT”) for
3 Shell Canada’s Scotford Refinery was appropriate. At page 22 of the Decision, the EUB
4 says:

5 “Having considered the evidence, the Board agrees with EAL that the proposed
6 Duplicate Facilities form the basis for a credible bypass threat. In particular, the
7 Board notes that Shell Canada would save approximately \$4.5 million per year
8 should it construct the Duplicate Facilities. The Board also notes that the Shell
9 Canada Scotford facility has been granted ISD [Industrial System Designation]
10 status and believes that the proposed Duplicate Facilities would form the basis for
11 a valid facilities application to the Board.”

12
13 Acknowledging the concerns of remaining system customers, the EUB went on to say at
14 page 24:

15 “The Board shares FIRM’s concern that the approval of DAT applications causes
16 the balance of demand customers to shoulder an increasing portion of system
17 costs. In particular, the Board notes that no real “benefit” accrues to customers
18 other than the potential bypass customer, except for the minimization of potential
19 costs to these customers occasioned by the revenue loss to the TA when the
20 system is bypassed.

21
22 “However, the Board must recognize that the current legislative framework
23 allowing for ISDs creates opportunities for customers such as Shell Canada to
24 bypass the system and realize significant savings. In these circumstances, the best
25 financial outcome for remaining customers is likely the negotiation of business
26 arrangements such as a DAT.

27
28 “The Board considers that it would not be a prudent business decision for Shell
29 Canada to accept a DAT less favourable than building the Duplicate Facilities.”

30
31 **Q. WHAT IS THE PRECEDENT IN BRITISH COLUMBIA?**

32 A. In response to a BCUC Order, BC Hydro filed with the BCUC an application for
33 approval of Bypass Rate Guidelines in 1999. The Order, and BC Hydro’s application,
34 stemmed from an issue with regard to the impacts of rate switching by customers. In its

1 proposed Guidelines BC Hydro provided examples of by-pass facilities, which included
2 on-site generation, and substations built by the customer to by-pass distribution facilities.

3 In the latter case, the customer would then qualify for rates applicable to customers
4 served directly from the transmission system. The BCUC, in approving Guidelines of its
5 own drafting in Decision 1999-0903, restricted consideration to this case, and stated:

6 "The Commission believes that customers with a viable option to construct a
7 substation for the purpose of moving from Rate Schedule 1211 to Rate Schedule
8 1821 should be permitted to do so provided that their all-in cost of construction
9 ("Customer's Cost of Bypass") is less than the Incremental Cost of Service
10 supplied by the Utility. To the extent that the reverse is true – that is, the
11 Customer's Cost of Bypass is greater than the Utility's Incremental Cost of
12 Service – the customer should only be allowed to move to Rate Schedule 1821
13 [for service from the transmission system] if it pays the Utility a sum equal to the
14 Customer's Cost of Bypass."

15
16 Attached to the Decision are the Guidelines implemented by the BCUC, which prescribe
17 the information necessary to be filed by the customer, or jointly by the customer and BC
18 Hydro, with the BCUC in order to obtain approval for the bypass and rate. The Decision
19 is provided as Exhibit PDZ-7, and the Guidelines as Exhibit PDZ-8.

20 **Q. PLEASE DESCRIBE THE PRECEDENT CASE FROM THE NATIONAL**
21 **ENERGY BOARD.**

22 A. In December, 2001, the NEB rendered Decision GH-3-2001 approving construction by
23 Petro-Canada of the Medicine Hat Pipeline. This Decision is provided as Exhibit PDZ-9.

24 The purpose of the new pipeline was to transport natural gas which, at the time of the
25 application, was being transported to market via the facilities of NOVA Gas
26 Transmission Ltd. (NGTL). Petro-Canada supported its application with data as to the
27 cost savings that would accrue to it, and various benefits, including job creation, that

1 would result from the project. Petro-Canada also argued that a reduction in its gas
2 transportation cost would increase the economic viability of the gas resources, and
3 therefore contribute economically on a wider basis. The environmental considerations
4 and requirements were also satisfied.

5 NGTL alone opposed the project, questioning “when it would be in the public interest
6 for a party to construct a physically superfluous bypass pipeline for no other reason than
7 to reduce its own transportation costs on the incumbent pipeline.” NGTL had refused to
8 offer Petro-Canada Load Retention Service (LRS) – essentially a by-pass competitive
9 rate - concerned that too many of its shippers would request the same concessions if
10 criteria for such service became too relaxed. Petro-Canada argued that it had actively
11 pursued negotiation of an LRS rate with NGTL, and also offered to purchase facilities
12 from NGTL at the opportunity cost of the proposed new pipeline.

13 In approving the application, the NEB said at page 17 of the Decision:

14 “The Board recognizes that the Medicine Hat Pipeline is a duplication of facilities
15 in the region. However, the uncontradicted evidence establishes that Petro-
16 Canada diligently explored all available alternatives to constructing the Medicine
17 Hat Pipeline, including trying to negotiate an LRS rate with NGTL, shipping on
18 the AEC South Suffield Pipeline and offering to purchase NGTL facilities. Petro-
19 Canada is also currently involved in a cost study of NGTL’s system which may
20 lead to changes in NGTL’s tolling structure in the future. In the meantime, Petro-
21 Canada concluded that construction and operation of the Medicine Hat Pipeline
22 represents its most economic gas transportation option.

23
24 “The Board agrees that the public interest will be served by the Medicine Hat
25 Pipeline by lowering transportation costs, the benefits of which will not only
26 accrue to Petro-Canada and any third parties selling their gas to the Applicant, but
27 also to the region as a whole. Enhanced recovery of gas resources will be another
28 benefit of the Medicine Hat Pipeline. The Board notes that no party, other than
29 NGTL, raised objections to the Medicine Hat Pipeline project.
30

1 “Based on the preceding views, the evidence that the Medicine Hat Pipeline
2 meets all of the criteria of section 52, and the overall benefit to the public interest,
3 the Board finds that the Medicine Hat Pipeline is and will be required by the
4 present and future public convenience and necessity.”
5

6 **Q. WHAT POSITION HAS THE ONTARIO ENERGY BOARD TAKEN WITH**
7 **REGARD TO BY-PASS AND BY-PASS COMPETITIVE RATES?**

8 A. According to an official summary of the OEB’s Decision in EBRO 477, an application
9 was brought by Cardinal Power in 1993 for approval of a by-pass competitive rate for gas
10 transportation from Centra. Cardinal also applied for the necessary approvals to build its
11 own pipeline. In this case, the OEB did not approve the application. While the OEB
12 accepted that Cardinal was a credible candidate for by-pass, it did not accept that, in the
13 circumstances, the by-pass competitive rate was in the public interest.

14 While the specific request was refused, the OEB acknowledged that three tests had
15 been established by precedent in Ontario:

16 “Q1. Is the applicant for a bypass competitive rate a credible candidate for a
17 bypass?”

18 Q2. Is it in the public interest to grant a bypass competitive rate?
19

20 Q3. Is the proposed rate just and reasonable?”
21

22 The Cardinal case was relied on by Coral Energy in arguing for special rate consideration
23 from Union Gas in 2004 under dockets RP-2003-0063, EB-2003-0087, and EB-2003-
24 0097. The relevant extract from this Decision is provided as Exhibit PDZ-11. Coral had
25 entered into a tolling agreement with the owners of a gas-fired generation facility, under
26 the terms of which Coral was responsible to procure fuel. Coral negotiated with Union
27 for favorable distribution rates and terms, but when the negotiations broke down, Coral
28

1 applied to the OEB for Leave to Construct facilities that would by-pass Union's
2 distribution system. The negotiations between Coral and Union then resumed, and a deal
3 was made. Coral therefore withdrew its application for Leave to Construct the facilities.

4 Unfortunately, the favorable rate treatment which Union had offered Coral relied on a
5 provision of the rates which were subsequently ordered by the OEB to be phased out.
6 Coral therefore intervened in Union's rate approval application to request rate treatment
7 similar in effect to what it had expected under the negotiated agreement.

8 In opposing Coral's proposal, Union argued that the rate incorporated in Coral's
9 supply contract was not a bypass rate, but a standard rate applicable to a class of
10 customers. Union also argued that the public interest arguments of Coral, which
11 revolved mainly around benefits to the electricity, rather than the gas sector, should not
12 be considered by the OEB.

13 Coral argued that it was a credible by-pass candidate, having a positive business case,
14 and, as a subsidiary of Shell, being qualified to build and operate the facilities. Coral
15 said that it had withdrawn its Leave to Construct application only because it was offered
16 a competitive price by Union. Quoting from the OEB's decision in the 1993 Cardinal
17 case, Coral argued that "the question of public interest is not a question of fact, but it was
18 a question of judgment based on the facts and circumstances before the Board. Since the
19 facts and circumstances change from case to case, so will the depiction of the public
20 interest." It argued that in a competitive electricity market with a known need for
21 incremental supplies, the Board should recognize favorable fuel supply conditions for
22 generators as being in the public interest.

1 Although the OEB did not grant Coral's request, the reason was that Coral had
2 entered into a contract, and should not now rely on the OEB to override the terms of that
3 contract on its behalf. I interpret the decision as upholding the key principles that relate
4 to by-pass facility approvals and by-pass competitive rates. At page 173, the OEB
5 acknowledges that Coral, having made application for a Leave to Construct the gas
6 facilities, had taken at least the beginning steps necessarily to establish itself as a credible
7 by-pass candidate. The OEB further acknowledges that the route of application for a by-
8 pass competitive rate is open to customers in Ontario, saying "Prior to the execution of
9 the Contract for Carriage, Coral could have, and perhaps should have, made application
10 to the Board for a bypass competitive rate to govern gas supply for Brighton Beach."
11 Acknowledging the public interest issues raised by Coral, the OEB also ordered Union to
12 undertake a study to review the possibility of a new rate class for customers similar to
13 Coral.

14 **Q. WHAT IS YOUR CONCLUSION FROM THESE PRECEDENTS?**

15 A. I conclude that in Canada, there are numerous regulatory precedents for permitting the
16 construction of facilities by transmission or distribution customers when that customer is
17 qualified to build and operate the facilities and has a positive business case to do so.

18 **Fulfilling these conditions establishes the customer as a credible bypass candidate.**

19 In some cases the result will be that the facilities are actually constructed, especially,
20 as may be the case with the line being considered by SE, redundancy and reliability
21 benefits to the system may be among the benefits, regulators will in other cases prefer a
22 rate solution to the issue rather than the construction of potentially redundant facilities.

1 Several jurisdictions have established criteria by which the customer qualified for a by-
2 pass rate, and by which the “justness” and “reasonableness” of the rate is determined. A
3 rate solution, correctly developed, can offer the by-pass candidate a cost-neutral
4 alternative to the new facilities, while continuing to provide at least some net revenue
5 from the existing facilities to the incumbent utility. I believe that these represent good
6 precedents that could be helpful to IRAC in reviewing an application brought to it for
7 approval of a by-pass competitive transmission rate, or, as was done by the BCUC, in
8 ordering the utility to bring forward an application for such a rate.

9 **Q. BASED ON THESE PRECEDENTS, HOW MIGHT A BY-PASS COMPETITIVE**
10 **RATE BE DEVELOPED FOR SE?**

11 A. The line costs in the Coles Associates study would be used to develop an annualized cost,
12 which would include depreciation, financing costs, operating and maintenance costs, and
13 any incremental administrative and general costs to SE. The cost projections, and
14 assumptions as to the service life of the assets, interest rates, etc. would be subject to
15 approval by IRAC. MECL would also submit for approval information as to costs that it
16 expected to incur related to the new line, if any. However, since any incremental costs to
17 MECL would in this case not be expected to exceed the cost to SE of the new line, the
18 competitive by-pass rate would be set equal to the annualized cost of the physical bypass
19 alternative. This would, as explained previously, make SE neutral financially between
20 the bypass rate and physical bypass, and would provide MECL a revenue stream in
21 excess of any incremental costs it might incur.

1 **HERITAGE CONTRACT ARRANGEMENTS**

2 **Q. WHAT DO YOU MEAN BY A HERITAGE CONTRACT?**

3 A. Generally, a heritage contract is an arrangement by which certain electricity facilities, or
4 their outputs, are specially designated so that despite changing industry, market or
5 pricing structures, the benefits continue to accrue on an equitable basis to the users for
6 whose benefit the facilities were historically constructed.

7 **Q. WHAT ASSETS RELEVANT TO THIS PROCEEDING MIGHT BE**
8 **CONSIDERED AS A PROPER SUBJECT FOR A HERITAGE CONTRACT?**

1 A. The assets relevant to this proceeding which might, with appropriate approvals, be
2 considered as Heritage Assets are the submarine cables which connect the Prince Edward
3 Island electricity transmission system with New Brunswick. These cables have a unique
4 history as compared with the other assets that MECL proposes to include under its
5 OATT. Specifically, they were originally funded in a large part by the Government of
6 Canada, with the remainder funded by MECL's transmission and electric power
7 customers including SE and its customers, and currently have no investment "rate base".
8 The terms of the 1976 lease of the facilities by the Province to MECL states: "AND
9 WHEREAS the parties are agreed that any and all benefits of such interconnection,
10 including the aforementioned grants and loans by the Government of Canada shall accrue
11 to the electric power consumers of the Province of Prince Edward Island". Until today,
12 these cables have in fact provided a benefit to the customers of both MECL and SE
13 through reduced prices and improved supply reliability as compared with the only other
14 option, which would be total reliance on generation resources located on the Island.

15 I have been advised that until 2002, SE purchased electricity supply and transmission
16 services from MECL, and so received the benefits of the submarine cables on a consistent
17 basis with MECL's other customers. SE has advised me that after that date its
18 transmission service from MECL was in all respects equal to the service received by
19 MECL's "native load" customers, in that any curtailments caused by constraints on the
20 cables were allocated proportionately between MECL and SE based on load.

21 These facts demonstrate the three qualities which, based on my research, I believe
22 they have in common with assets designated in other jurisdictions as Heritage Assets:

1 (1) they provide an important benefit, which either could not be provided by other assets
2 or could be provided only at significantly greater cost; (2) they were constructed and put
3 into use with the express purpose of providing that benefit to specified recipients, in this
4 case all of “the electric power consumers of the Province of Prince Edward Island”; and
5 (3) those recipients have been accustomed to the benefit of the asset over time.

6 **Q. WHAT RELEVANCE MIGHT IT HAVE TO THE APPLICATION OF THE**
7 **PROPOSED OATT IF THE SUBMARINE CABLES WERE TREATED AS**
8 **HERITAGE ASSETS?**

9 A. Designation as a Heritage Asset would imply that the submarine cables are separated
10 from MECL’s on-Island transmission system for purposes of both access and pricing. If
11 the Heritage Contract were structured to give SE as well as MECL a right of access to
12 and use of the cables proportionate to their share of customers or load on Prince Edward
13 Island, and to deem that share of the capacity of the cables as part of SE’s and MECL’s
14 systems respectively, then if SE were to build its own transmission line from Summerside
15 to Bedeque, SE would not be using MECL’s system for purposes of imports of power
16 from the mainland and would not be subject to any charges under the OATT for that
17 power. SE would of course have to pay MECL for point to point service to bring on-
18 Island generation to serve customers in Summerside, and, assuming MECL continued as
19 operator of the cables, to reimburse MECL for its proportionate share of those operating
20 costs and associated administrative costs.

21 An alternative approach would be to establish the Heritage Asset cables as a separate
22 system, with a separate revenue requirement and tariff. This would enable SE to contract

1 with MECL separately for service on the cables and the on-Island system, and to
2 designate a different class of service on each. For example, SE might be able to elect
3 firm point to point service on the submarine cables in combination with either network
4 service or hourly point to point service on the on-Island system. As another example, SE
5 might be able to elect firm point to point service on the submarine cables, while receiving
6 a by-pass competitive rate on the on-Island system.

7 **Q. TO WHAT CANADIAN JURISDICTIONS CAN THE COMMISSION LOOK**
8 **FOR EXAMPLES OF HERITAGE CONTRACTS IN OPERATION?**

9 A. British Columbia, Québec and New Brunswick all have explicitly adopted a Heritage
10 Contract model with respect to generation resources of their provincial utilities. Ontario
11 has also, following a short period under a largely market-driven market model, chosen to
12 adopt regulated cost of service pricing for specific (nuclear and base load hydro) plants of
13 Ontario Power Generation. While this is in many respects similar to the Heritage
14 Contract approach adopted by the former three jurisdictions, the Heritage Contract
15 terminology has not been used there.

16 **Q. IF THESE EXAMPLES ALL INVOLVE GENERATION ASSETS, CAN THE**
17 **HERITAGE CONTRACT MODEL BE VALIDLY EXTENDED TO**
18 **TRANSMISSION ASSETS FOR PRINCE EDWARD ISLAND?**

19 A. While that is, in the final analysis, for IRAC and/or the Government of Prince Edward
20 Island to determine, I believe the examples demonstrate that the key concepts and issues
21 involved—namely, protection of the continuing rights of the customers for whose benefit
22 the facilities were built—are the same. In addition, the function of the submarine cables

1 with respect to service to Prince Edward Island is similar to the service provided by
2 generation in the other jurisdictions. In other words, from an Island point of view the
3 submarine cables act like a generator and deliver capacity, energy and ancillary services
4 to the Island.

5 **Q. PLEASE DESCRIBE THE BRITISH COLUMBIA HERITAGE CONTRACT.**

6 A. The British Columbia Heritage Contract is a legislated Heritage Contract between BC
7 Hydro's generation line-of-business (BC Hydro Generation) and BC Hydro's
8 distribution line-of-business (BC Hydro Distribution). Authority for the arrangement is
9 the *BC Hydro Public Power Legacy and Heritage Contract Act*.

10 In November 2002 an Energy Plan was released by the Provincial Government which
11 provided, as part of a wider policy strategy for the province's energy future, for
12 development of a legislated Heritage Contract. During the first six months of 2003, BC
13 Hydro held stakeholder consultations and developed a proposal for implementation of
14 the Heritage Contract, along with a stepped rate structure for customers taking supply
15 directly from the transmission system. In the summer of 2003, hearings were held
16 before the BCUC with regard to the proposals, and in October, 2003 the BCUC issued
17 its report with recommendations to the Government. In November, 2003, a Special
18 Direction was issued by Lieutenant Governor in Council to BC Hydro for
19 implementation of the Heritage Contract.

20 BC Hydro's generation capacity is 90% hydro. Because of the dominance of hydro-
21 electric power in the generation mix, average and high water years currently result in
22 sufficient inexpensive power to meet in-province loads through most hours of the year,

1 and provide a surplus for trade. Imports, when required for peaks and in low water
2 years, are subject to risk of high prices in spot markets of the Pacific northwest. The
3 embedded cost of generation is among the lowest in North America, about 2.5 cents per
4 kWh. However, with load growth in the province, additional imports or new in-
5 province resources are expected to be required, and to involve a significantly higher
6 cost.

7 The purpose of the Heritage Contract was to safeguard the benefits of this low cost
8 generation for BC Hydro's in-province customers, while a stepped rate structure and
9 optional time of use rates were also being implemented to provide pricing incentives to
10 large customers to conserve and self-generate.

11 Under the arrangement, the current generation portfolio of BC Hydro is designated as
12 the Heritage Resources. BC Hydro Generation provides the full capacity of the Heritage
13 Resources to BC Hydro Distribution on a priority call basis. The output capacity of the
14 Heritage Resources is estimated at 49,000 GWh per year under average water
15 conditions; however the obligation is defined as the capability of the Heritage Resources
16 (which are specific, named plants) rather than as a fixed quantity. Pricing of the
17 Heritage Energy to BC Hydro Distribution is determined on a revenue requirement basis
18 by the BCUC.

19 **Q. PLEASE DESCRIBE THE QUÉBEC HERITAGE CONTRACT**

20 A. As in British Columbia, the generation pool in Québec is dominated by hydro-electric
21 resources and as such, is very low cost relative to neighbouring jurisdiction. The Québec
22 government is committed to uniform, low, stable pricing within the province, and

1 particularly for residential customers. The Heritage Pool arrangement ensures that
2 Hydro-Québec continues to make available electricity supply to all customers in Québec
3 at low, stable regulated pricing. While Hydro-Québec is dominant in generation,
4 industrial customers may self-generate.

5 The Heritage Pool arrangement was brought into effect through the December, 1996
6 – Government passes the Act respecting the Régie de l'Énergie, passed in December,
7 1996. This legislation establishes authority of the regulator and sets both the price and
8 the quantity of production in the Heritage Pool. Unlike British Columbia, which
9 specifies as the Heritage Resources a number of generation plants, and their output as the
10 Heritage Energy, and establishes a cost of service basis for pricing, the Québec
11 arrangement establishes a fixed amount of 165 TWh as the Heritage production
12 obligation of Hydro-Québec and sets a fixed price. Since it is possible, in low water
13 years or for other reasons, that Hydro-Québec may have to purchase power to meet its
14 Heritage power obligation, there is a price risk which is borne by the government as
15 Hydro-Québec's shareholder.

16 Since provincial demand now exceeds the Heritage quantity, Hydro-Québec's
17 distribution business unit must procure additional supply. This is done through issuance
18 of a request for proposals from generation resources. The Régie de l'Énergie has the
19 responsibility to approve the tender solicitation and contract award procedure and code of
20 ethics of Hydro-Québec with respect to procurement, since the production business unit
21 is permitted to bid against arms-length generators for the contracts. This arrangement

1 therefore introduces some of the benefits of competition to control costs of incremental
2 supply.

3 **Q. PLEASE DESCRIBE THE HERITAGE CONTRACT ARRANGEMENT IN NEW**
4 **BRUNSWICK.**

5 A. New Brunswick has historically enjoyed modest electricity rates - the lowest in the
6 region except for Québec. Customers benefit from the use of part of the proceeds of
7 export sales, as determined by a formula, to reduce the in-province cost of service. The
8 Heritage contract arrangement was established on the break-up of New Brunswick
9 Power, creating several companies including two generating companies (Nuclearco and
10 Genco) and a distribution company (Disco). Under government direction, Power
11 Purchase Agreements ("PPAs") were developed which establish the basis on which the
12 generation output is sold by Nuclearco and Genco to Disco. The purpose was to provide
13 for the continued benefit of relatively low, cost-based pricing to any New Brunswick
14 customer. The pricing provisions establish the costs that can be passed through to Disco,
15 and include provisions to reflect changes in the cost of generation fuels.

16 The generating companies are obligated to provide to in-province loads energy and
17 capacity on the same basis they did in 1995. The obligation is reduced to the extent that
18 existing plants are either retired or undergo major life-extension projects. The contract is
19 intended to remain in place until all existing plants are removed from the "Heritage
20 Pool".

21 While the restructuring of New Brunswick Power was intended to usher in the
22 development of a bi-lateral market in the province, the market has not developed, and

1 even those customers with the option to purchase elsewhere have not done so, primarily
2 for reasons of relative price.

3 **Q. DOES THIS CONCLUDE YOUR TESTIMONY.**

4 A. Yes it does,