The Consumer Advocate

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August 5, 2019

Via Courier

Board of Commissions of Public Utilities
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: G. Cheryl Blundon, Director of Corporate Services / Board Secretary

Dear Ms. Blundon:

RE: Newfoundland and Labrador Hydro – Application for Revisions to Cost of Service Methodology – Expert Report

Further to the above-captioned, enclosed please find the original and thirteen (13) copies of the report of C. Douglas Bowman, filed on behalf of the Consumer Advocate.

Yours truly,

Stephen Fitzgerald
Counsel for the Consumer Advocate

/jl
Enclosure

cc

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THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF
the *Electric Power Control Act*, 1994, SNL 1994, Chapter E-5.1 (the "*EPCA*") and the *Public Utilities Act*, RSNL 1990, Chapter P-47 (the "*Act*");

AND

IN THE MATTER OF
an *Application* by Newfoundland and Labrador Hydro ("*Hydro*") for approval of revisions to its Cost of Service Methodology pursuant to Section 3 of the EPCA (the "*Cost of Service Methodology Application*") for use in the determination of test year class revenue requirements reflecting the inclusion of the Muskrat Falls Project costs upon full commissioning.

PRE-FILED EVIDENCE
OF
C. DOUGLAS BOWMAN

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Evidence Outline

List of Exhibits

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PRE-FILED EVIDENCE OF C. DOUGLAS BOWMAN

My name is Doug Bowman. This document was prepared by myself, and is correct to the best of my knowledge and belief. I have been retained by the Government appointed Consumer Advocate to provide expert advice and evidence to the Consumer Advocate in response to Newfoundland and Labrador Hydro's ("Hydro's") Cost of Service Methodology Application (the "Application") submitted to the Board of Commissioners of Public Utilities (the "Board") on November 15, 2018.

A summary of my background and qualifications is provided in ***Exhibit CDB-2***. I have both a B.S. and an M.S. in Electrical Engineering from the State University of New York at Buffalo and 41 years of experience in the electricity services and consulting industry. My primary expertise includes electricity services costing and pricing, and power sector restructuring, regulation and market design. I am an independent Energy Consultant working out of my office located in Warrenton, Virginia.

Prior to becoming an independent consultant, I was employed by KEMA Consulting, Nexant Inc., Pace Global Energy Services, International Resources Group, CSA Energy Consultants and Ontario Hydro. I have taken part in the regulatory process in the Province of Newfoundland and Labrador on behalf of the Consumer Advocate since 1996, and have submitted testimony before this Board 11 times previously as an expert witness on cost of service and rate design at Newfoundland Power's 1996 *Application by Petition for Approval of Certain Revisions to its Rates, Charges and Regulations*, at Newfoundland and Labrador Hydro's 2001 *General Rate Proceeding*, at Newfoundland Power's 2003 *General Rate Application*, at Newfoundland and Labrador Hydro's *2003 General Rate Application*, at Newfoundland and Labrador Hydro's *2006 General Rate Application*, at Newfoundland Power's *2007 General Rate Application*, at Newfoundland and Labrador Hydro's *2009 Application concerning the Rate Stabilization Plan components of the rates to be charged Industrial Customers*, at Newfoundland and Labrador Hydro's *2013 General Rate Application*, at Newfoundland and Labrador Hydro's *Amended 2013 General Rate Application*, at the Board's *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System* and at Newfoundland and Labrador Hydro's 2017 General Rate Application.

Section 1 of my Pre-filed Evidence includes a summary of the key points in the Cost of Service Methodology Application and my position on Hydro's proposals. **Section 2**

includes support for my positions and recommendations, and **Section 3** summarizes my recommendations.

1. Summary of Application

The Settlement Agreement to Hydro's Amended 2013 General Rate Application required Hydro to submit an application for revisions to its cost of service methodology for use in the determination of test year revenue requirement reflecting the inclusion of the Muskrat Falls Project ("MFP") (Hydro's November 15, 2018 report pages 1 and 2 attached to Application, to be referred to hereinafter as "Hydro COS report"). At current estimates, the Muskrat Falls Project will significantly impact the revenue requirement and cost allocation to customers on the Island Interconnected System ("IIS").[1] Hydro states (Hydro COS report, page 20, lines 1 to 3) "*projected 2021 revenue requirement for the Island Interconnected System is approximately $575 million higher (more than double) than that of the projected 2019 Test Year revenue requirement*." Few jurisdictions have had to deal with such a large rate increase brought on by a single project, a problem exacerbated by the very slow rate of demand growth on the IIS which may even go negative depending on the magnitude of the rate increase and corresponding demand response (elasticity).

As noted by Hydro, the inclusion of the MFP in the cost of service and the change brought on in the operating pattern of the Island Interconnected System, specifically the replacement of Holyrood fuel costs with the supply cost payments relating to the MFP

[1] The Province has two primary interconnected systems, the Island Interconnected System (IIS) and the Labrador Interconnected System (LIS). The Province also has a number of "isolated" systems serving remote villages.

creates the need to review the appropriateness of the functionalization, classification and allocation of supply costs among customer classes. As Hydro states (Hydro COS report, page 1, lines 13 to 16) "*At present, fuel costs from Holyrood comprise the largest single portion of the supply costs incurred by Newfoundland and Labrador Hydro ("Hydro"). Prior to the accessibility of off-island purchases, approximately 85% of the test year revenue requirement related to Holyrood was classified as energy-related costs*."

As can be seen in the evidence submitted to date on this Application, there are many views and interpretations about what constitutes fair and equitable treatment of costs in the cost of service study. There is general agreement that customers are treated fairly if costs are allocated to customer classes in the cost of service study on the basis of cost causation. However, there are numerous accepted practices and methodologies for allocating costs to customer classes and the views of the "experts" on how best to reflect cost causation can vary significantly with profound effect on the share of the revenue requirement allocated to each customer class. Cost of service is far from an exact science and will require that the Board exercise a fair amount of judgment in its Order on the Application.

For the most part I agree with the proposals set out in Hydro's Cost of Service Application. Hydro of course should know its electricity system better than anyone else and has received, and generally adopted, proposals made by its consultant, Christensen Associates Energy Consulting ("CA Energy Consulting"). I believe that CA Energy Consulting's recommendations have been well thought out and researched. The primary recommendations made by Hydro in the Application along with my position are summarized in ***Exhibit CDB-1***. As can be seen, I support all but two of Hydro's proposals.

Exhibit CDB-1 – Summary of Hydro's Cost of Service Proposals and My Position

Hydro Proposal	My Position
Systemization	
Separate LIS and IIS cost of service studies now and in the near future	Agree
Functionalization	
Muskrat Falls PPA as generation	Agree
LTA and LIL as generation	Agree
Generation leads/connections as generation	Agree
TL-234 and TL-263 as transmission	Agree
Holyrood Unit 3 as transmission following conversion to synchronous condenser	Agree
Continue to specifically assign transmission connection assets to load customers	Agree
Contribution from customers for new network additions deducted from rate base	Agree
Classification	
Muskrat Falls PPA using equivalent peaker	Agree
LIL and LTA using equivalent peaker	Agree
Existing hydraulic assets and purchases excluding wind using system load factor	Disagree. Classify using equivalent peaker
Holyrood using forecast capacity factor	Agree
Holyrood Unit 3 following conversion to synchronous condenser as demand	Agree
Wind power purchases as 22% demand and 78% energy	Agree
Generation connections/leads classified on same basis as the generator they connect	Agree
Common/network transmission assets as 100% demand	Disagree. Classify on same percentage basis as IIS generation (on average)
LIS and IIS diesel and gas turbine units and variable fuel costs as demand	Agree
Isolated diesel units using system load factor with variable fuel costs as energy	Agree
L'Anse-au-Loup as demand with variable fuel costs as energy	Agree
Allocation	
Demand-related costs using 1-CP allocator for now, but consideration to be given to using 50 highest peaks in future	Agree
Energy-related costs using energy consumed	Agree
Other	

Continue with embedded cost of service	Agree for now, but recommend the Board direct Hydro to develop a marginal cost-based approach for future cost of service studies
Rural deficit allocated using revenue requirement approach	Agree
Continue current CDM classification	Agree for now, but changes should be considered in future applications to reflect changes in CDM programs
Use of indexed asset costs in operating and maintenance cost allocations in the determination of specifically assigned charges until a reasonable alternative is developed	Agree
Newfoundland Power generation credit provided for both hydraulic and thermal generation	Agree for now but going forward, customer-owned generation credits should be based on value to system; i.e., marginal costs
Discontinue CBPP pilot study	Agree. Recommend that customer-owned generation be based on value to system going forward; i.e., marginal costs
Net export revenues to be included in the COS study with variations from forecast to be dealt with through a deferral account mechanism	Agree

2. Discussion and Support for My Positions

As already stated, for the most part I believe that the cost of service proposals made by Hydro and CA Energy Consulting allocate the revenue requirement to customer classes fairly and on the basis of cost causation. Although there are numerous proposals in the Application, the five key proposals in this Application include:

1) Separate cost of service studies for the LIS and IIS now and in the immediate future;

2) Functionalization of the MFP including Muskrat Falls generation, the LTA transmission assets and the LIL transmission assets as generation;
3) Classification of the MFP on the basis of the equivalent peaker methodology;
4) Classification of "other hydro" and "purchases other than wind" on the basis of system load factor; and
5) Classification of common transmission as 100% demand.

The proposals in the Application that I disagree with relate to the classification of "other hydro" and "purchases other than wind" and the classification of "common transmission" (items 4 and 5 in the above list). In this Section 2 of my evidence I provide support for my positions on the main proposals in the Application.

2.1 Systemization

The Labrador Interconnected System is not in need of new generation capacity and energy, and did not have such needs when the MFP was committed. The MFP was committed based on the needs of customers on the Island Interconnected System. Potential sales to Nova Scotia and beyond will be returned to customers on the IIS. As a result, at this time customers on the Labrador Interconnected System ("LIS") will not benefit from the MFP, so should not be responsible for the costs of the MFP.

With respect to the issue of separate cost of service studies Hydro states (Hydro COS report, page 7, lines 22 to 24) "*This approach is consistent with the Government direction exempting customers on the Labrador Interconnected System from paying costs related to the Muskrat Falls Project*." As stated by CA Energy Consulting (Appendix A of Application, hereinafter referred to as "CA COS report", page 7, lines 14 to 19) "*Hydro* *has a number of external institutional influences that suggest continuation of separate treatment. The Muskrat Falls Exemption Order requires that the costs "shall be recovered in full by Newfoundland and Labrador Hydro in Island Interconnected rates charged to the appropriate classes of ratepayers. This obligation enshrines in law the cost causation underlying the decision to invest: least cost planning of new generation capability to serve the island.*" CA Energy Consulting notes (CA COS report, page 7, lines 11 to 12) "*the technical experience does not strongly suggest that the two regions be combined, and the institutional experience in North America is mixed.*"

I share the opinion of Hydro and CA Energy Consulting that separate cost of service studies should continue now and in the near future. I do not see any benefit in combining the two systems into one cost of service study. For the most part the two systems will operate independently, so the separation of costs to supply the two systems is best addressed by conducting separate cost of service studies based on the costs incurred to supply each system. If in the future it becomes evident that the two systems are operating in a meshed, or combined, manner and MFP power is sold to customers on the LIS, the issue of separate cost of service studies should be revisited.

2.2 Design and Operation of Electricity Markets

It has been 27 years since the last review of the cost of service methodology was conducted in this Province. Since 1992 there has been a significant change in the electricity industry in many parts of the world, moving from a vertically-integrated (bundled) and fully-regulated market structure to an unbundled (along functional lines) market structure with competition introduced in the production and supply (procurement) functions. Before embarking on a discussion on the proper functionalization and classification of costs it is important to understand the basics of electricity markets.

As noted, there are generally two types of electricity markets:

1) Fully-regulated markets such as that in NL where all functions are regulated by a regulatory board.
2) Competitive markets like those in New England, New York, PJM (originally the Pennsylvania-New Jersey-Maryland interconnection) and elsewhere in the United States and Canada, and elsewhere in the world such as the European Union. Only certain elements of these markets are competitive, specifically the generation/production function and the supply/procurement function which includes entities that procure energy and other electricity services in the market for themselves or for sale to other customers. The "wires" components remain monopolies and regulated, specifically the transmission and distribution networks.

In any electricity market whether regulated or competitive there are generally two types of market participant, sellers and buyers.[2] There are also a number of market service providers such as a system operator, transmission owners and service providers, distribution operators, owners and service providers, and market operators. In regulated markets such as NL these entities are often bundled into one or a few entities. For example, Hydro and Nalcor provide generation, transmission, system operator, market operator, supplier and distribution services. Newfoundland Power (NP) provides distribution operation, asset management and supplier services on behalf of its retail customers. In a competitive

[2] There may be other market participants who act on behalf of buyers and sellers such as brokers.

market, these functions are unbundled in an effort to promote competition and keep entities from favouring their affiliates in market transactions.

In a competitive market sellers and buyers of electricity services do so in accordance with market, or commercial, rules that have been drafted in a way to promote competition in the competitive components of the market. In the United States such documentation is often referred to as the open-access transmission tariff. In a regulated market sellers and buyers of electricity services do so in accordance with the rules of regulation as set out in legislation and orders by the regulatory board.

In any electricity market, access to the transmission network is paramount. Without open access to the transmission network it is not possible to minimize the cost of production. In the case of competitive markets, it will not be possible to have fair competition without open access to the transmission network. This is why FERC requires the filing of an open-access transmission tariff. The European Union has a similar requirement, and ensures reciprocity in the sense that each country must unbundle its power sector and allow all market participants, domestic or otherwise, to buy and sell power in their countries.[3] Competition is much more effective when there are multiple buyers and sellers.

There are two types of transmission in any electricity market – connection facilities and network facilities. Hydro refers to connections as “specifically-assigned facilities” when they relate to loads and “generator leads” when they relate to generators. Connection facilities are radial in nature and benefit only one or a few customers. Network facilities,

[3] This is where Hydro’s open-access transmission tariff differs. Everyone has access to Hydro’s transmission network, but owing to Hydro’s exclusive right to sell power in the Province, nobody can actually use its access to the transmission network, so effectively there is no reciprocity.

referred to as "common transmission" by Hydro, benefit many customers. Connection facilities include those transmission facilities necessary to connect a market participant to the network. In my experience, most jurisdictions make market participants responsible for the costs of their connection facilities. In many jurisdictions market participants are also responsible for any system upgrades necessary to reliably connect their generator or load to the network. I understand that Hydro proposes in its connection policy for Labrador[4] that new market participants, loads or generators, pay for all connection costs and any necessary system upgrades. The costs for connections to the grid alone are often referred to as shallow connection costs, while costs for connection to the grid and any necessary system upgrades are often referred to as deep connection costs.

Power system costs can generally be categorized as fixed or variable. Fixed costs as the name suggests do not vary with energy production; variable costs on the other hand do vary with energy production. Fixed costs cannot be controlled once spent, while variable costs can be controlled to an extent in two ways: 1) by influencing the type of generating stations that are added to the market (i.e., high capital cost/low operating cost baseload plants, low capital cost/high operating cost peaking plant, and everything in between (medium capital/medium operating cost intermediate plant); and 2) by controlling energy production through the practice of "economic dispatch" (also known as "merit order dispatch").

The demand on a power system varies over the course of a day, week and year. For example, demand tends to be low at night, but then ramps up in the early morning hours

[4] See Hydro's connection policy outlined in the report entitled *Labrador Interconnected System Network Additions Policy Summary Report* dated December 14, 2018.

when people rise to prepare for the working day and commercial and industrial establishments start the day's operations. During low periods of demand, only the most efficient and lowest cost generators are operated. As demand increases during the day operators are forced to bring on less efficient and more costly generation to supply demand. When calculating the operating cost of a generator, fixed costs are ignored because they cannot be controlled. Only a generator's variable costs are considered because these are the only costs over which there is a measure of control. Variable costs include the cost of generation fuel plus any operating and maintenance costs that vary with energy production, referred to as variable operation and maintenance costs (variable O&M costs). A generator's fuel plus variable O&M is referred to as its production cost.

Each day the system operator forecasts the demand in each hour of the next operating day. The operator then forms a stack of generators in order of least production cost to supply the demand in each hour of the operating day. For example, renewable energy generation sources such as hydro are at the bottom of the stack (i.e., they are loaded first) because they have very low production costs; i.e., the cost of fuel is close to zero. Must run generators are also included at the bottom of the stack because the operator has no control over dispatch; i.e., if a contract with an Independent Power Producer has no flexibility of dispatch, or the contract is take-or-pay. Next in the generation stack would be the generator with the lowest production cost, and so on and so forth until the last generator necessary to meet the demand, the generator with the highest production cost at this point in the stack, is dispatched. The production cost of the last generator dispatched to supply demand establishes the marginal production cost for the jurisdiction. In other words, the system marginal cost is the variable cost to supply the next increment of energy on the system.

Formation of the generation stack and dispatching on the basis of lowest production cost to supply demand is known as economic dispatch.

Economic dispatch is the goal of both regulated and competitive markets. Regulated markets promote economic dispatch through centralized control – the system operator directs which generators are to operate, at what output levels and when. The goal of a competitive market is likewise to promote economic dispatch, but through commercial means. For example, PJM, New England and New York all require generators to submit bids that reflect marginal production costs and the system operator dispatches generation to meet demand in each hour of the day on the basis of lowest bids. If a generator bids considerably more than its marginal production costs, and does so regularly without a market response, the generator is abusing its market power position. In such cases the market monitoring group has the authority to take appropriate action including levying penalties and fines, and in extreme cases, terminating the generator from future market participation.

Generation fuel represents a significant portion of the cost of power, often over 35%. The transmission network enables the design of a power system that supplies demand at lowest cost across the entire spectrum of load configurations varying by time of day, day of week and season of year, meaning the optimum development of baseload, intermediate load and peaking generation.[5] Generation projects and transmission network projects may be in competition to meet a defined need. In such cases the projects are modelled to determine

[5] The numerous isolated systems in NL that are for the most part supplied by high production cost diesel units because it is too costly to connect them to the transmission network.

the impact not only on capacity, but also on energy supply costs as each project will affect system losses and the order of economic dispatch.

It is the transmission network that enables economic dispatch across the jurisdiction. When economic dispatch is extended over larger regions through the addition of transmission lines and facilities the benefits increase. This correlation has been recognized in the United States through the formation of Regional Transmission Organizations and in Europe through formation of the Internal Electricity Market. In each case the area over which competition (and via competition, economic dispatch) is practiced has been extended beyond traditional regions; i.e., in the case of Europe, beyond country borders.

Building transmission lines between regions enables the sharing of generation reserves both in the planning and operating time frames, thus reducing the need for generating capacity. The transmission lines also accrue savings by expanding the zone across which economic dispatch is practiced and enable construction of larger, more efficient generating stations with their economies of scale. The higher capital cost of the larger more efficient generators is justified on the basis of energy savings made possible by the transmission network. The savings from energy transfers enabled by new transmission additions are often much greater than the capacity savings.

In summary, market participants, both sellers and buyers, should be, and almost always are, responsible for the cost of their connections to the network. In some cases, they are also responsible for any network upgrades necessary to reliably connect them to the network. Network, or common, transmission benefits many customers and is built to transport power from sellers to buyers. A strong transmission system reduces generation capacity requirements and enables construction of an optimum power system that minimizes the overall cost of supply taking into consideration the cost impacts on both capacity and energy. A strong transmission network enables economic dispatch across a broader region, thus reducing energy costs.

2.3 Functionalization

2.3.1 Functionalization of the MFP

I agree with Hydro's proposal to functionalize as generation all components of the MFP including MF generation, the Labrador Transmission Assets (LTA) and the Labrador-Island Link (LIL) transmission assets.

The MF generation would not have been constructed without the LTA and LIL transmission assets which transport the generation to the market, in this case, the IIS and Nova Scotia and beyond. Neither would the LIL/LTA transmission assets have been constructed without the MF generation assets. The LTA and LIL are connection facilities that benefit only MF generation. As is current practice with all generation leads on the IIS, the MFP including the generation and LIL/LTA transmission leads should be functionalized as generation. This practice is consistent with typical practice in competitive markets where new market participants are responsible for all costs associated with connecting their facility, in this case MF generation, to the network.

As pointed out by CA Energy Consulting (CA COS report, page 36, lines 5 to 8) "*The Order in Council that sets out the Muskrat Falls Exemption Order states that all costs are to be paid by Hydro native load customers, since the LIL and MF are being constructed based on the supply needs of the Island without consideration of export opportunities*." The

LIL/LTA transmission assets should therefore be functionalized as generation since they are in fact generation leads.

In the future if it becomes evident that the LIL is transferring power in both directions to the benefit of many customers, it would be appropriate to reconsider the functionalization of the LIL from generation to transmission.

2.3.2 Functionalization of Connections

I agree with Hydro's proposal to continue to functionalize generation connection facilities (i.e, the transmission that connects a generator to the transmission network), referred to as generation leads in the Application, as generation. These connection facilities benefit only the generator as the generator cannot get its power to market without a connection to the transmission network. Looked at another way, the generator and its connection to the transmission network are one and the same – there is no sense having a transmission line to nowhere and there is no sense having a generator with no means for getting its power to the market. Given that the generator connection, or lead, is an extension of the generator, the generator and the lead should be functionalized on the same basis.

I also agree with Hydro's proposal to continue to specifically assign the costs of load connections. These facilities provide benefits only to the customers (loads) that they connect, so other customers on the system should not be responsible for their costs. To do otherwise would not be consistent with cost causation. This argument is a natural extension of the argument above concerning generator leads. As the costs of specifically-assigned assets are paid directly by the load customers, they are not included in the cost of service study.

In CA-PUB-006, the Board's consultant, the Brattle Group ("Brattle") states with respect to connections (note, the quote refers to connections as interconnections) "*Interconnections are dealt with in ISO/RTO rules. Interconnections costs are borne by the generation resources or loads requesting the interconnection. In addition, those parties requesting interconnection also are responsible for modifications to the transmission system should their interconnection affect the transmission system's transfer capabilities*". This supports the notion that generator leads should be functionalized as generation. If the IIS were unbundled, it would be logical to separate generators and their leads from the transmission network (same as Hydro currently separates loads and their leads, or connections, from the network). From the perspective of cost causation it would not make sense to charge other customers for a generator lead by including the cost in the transmission tariff when they are not benefitting from the lead. Since the lead or interconnection is part of the generating station, it follows that it should be functionalized as generation.

2.4 Use of Marginal Costs for Classification and Allocation

I agree with the CA Energy Consultants that marginal costs should be used for classification and allocation of production/generation costs in the cost of service study. I believe that a marginal cost-based cost of service approach would result in a fairer allocation of costs to customers. I do not share Hydro's concern about the complexity and understandability of marginal cost derivation relative to traditional cost of service approaches. In fact, traditional classification and allocation may be more controversial and complex given the multitude of classification and allocation techniques that are considered "accepted practice" and the wide-ranging views on which techniques should be applied.

However, I agree with Hydro that marginal cost-based approaches are not common in Canada and that the absence of hourly load data for each customer class poses a problem. (Hydro COS report, page 9, lines 16 to 24 summarizes Hydro's position).

For these reasons I agree with Hydro's proposal to continue with the traditional cost of service methodology at this time but recommend that the Board direct Hydro to develop an approach for incorporating marginal cost-based approaches in future cost of service studies.

2.5 Classification

2.5.1 Classification of Generation Component of the MFP

I agree with Hydro's proposal to classify Muskrat Falls generation on the basis of the equivalent peaker approach.

The equivalent peaker approach recognizes that if only capacity were needed on the system a peaking plant with the lowest capital costs would be constructed. Base load (i.e., hydro, nuclear, etc.) and intermediate load generating plants (i.e., simple cycle gas plants, combined cycle gas plants, etc.) with higher capital costs than peaking plants are constructed because the energy savings gained over time via the economic dispatch process exceed the higher capital cost of such generating units. This fact is grounded not only by planners in system expansion studies but also in marginal cost calculations. A planner does not base the marginal value of capacity on the capital cost of a base or intermediate load power plant because this would incorrectly and unfairly skew the results of the evaluation. As stated by CA Energy Consulting (CA COS report, page 16, lines 1 to 7) "*The equivalent peaker method is viewed by some as giving formal recognition to the generation planner's* *selection of a range of plants to serve the system. (The argument is that generation planners must design their system to meet not only peak demand, but also the full range of load durations, and to do so at least cost. Costs not incurred to meet peak load are deemed to be incurred to supply energy. Muskrat Falls is designed to operate as a baseload unit. The equivalent peaker approach would recognize that fact by treating much of its cost as being energy-related*."

CA Energy Consulting notes (CA COS report, page 17, lines 8 to 13) "*The equivalent peaker methodology received serious consideration by the Board in the 1992 COS methodology review. The approach was ultimately rejected for reasons of computational challenge, and plant vintage and valuation issues. However, those issues apply with less force now, since the peaking unit computations pertain to a plant of current vintage. As a result, this approach may deserve renewed consideration for its application to the classification approach for Muskrat Falls."*

In the response to PUB-NLH-037 CA Energy Consulting provides a rebuttal to the five reasons Brattle relies on for its recommendation for classification of MF generation on the basis of system load factor. The CA Energy Consulting rebuttal concludes (page 5) "*Despite greater complexity, the Equivalent Peaker approach arguably has an advantage from the perspective of economic theory*". I agree, and as discussed below, recommend that the equivalent peaker approach be used for "other generation" and "purchases other than wind" as well.

2.5.2 Classification of the LIL and LTA Components of the MFP

I agree with Hydro's proposal to classify the LIL and LTA components of the MFP on the same basis as MF generation using the equivalent peaker approach.

The LTA and LIL transmission facilities are part of the MFP. They would not have been constructed without the generation component of the MFP. I refer once again to Brattle's response to CA-PUB-006 relating to connections (note, the quote refers to connections as interconnections) "*Interconnections are dealt with in ISO/RTO rules. Interconnections costs are borne by the generation resources or loads requesting the interconnection. In addition, those parties requesting interconnection also are responsible for modifications to the transmission system should their interconnection affect the transmission system's transfer capabilities*". For the reasons I gave earlier, the LTA and LIL transmission assets are generation interconnections, or leads. Generation interconnections, or leads, should be considered part of the generator, so should be functionalized as generation and classified on the same basis as the generation. Since I support classification of MF generation using the equivalent peaker approach, I likewise support classifying the LTA and LIL assets using the equivalent peaker approach. Connections/leads for other generators on the system should likewise be classified on the same basis as the generators they connect to the transmission network.

It is anticipated that flow on the LTA and LIL transmission assets for the foreseeable future will be primarily in one direction. If that changes in the future and these assets start to be operated as transmission network facilities providing benefits to many customers, then the functionalization and classification of these assets should be reviewed.

2.5.3 Classification of “Other Hydro” and “Purchases Other than Wind”

I disagree with Hydro’s proposal to classify “other hydro” and “purchases other than wind” using system load factor.[6] Although I disagree with Hydro, it appears I may agree with the CA Energy Consulting proposal as discussed below.

Hydro’s proposal does not reflect how a system planner undertakes system expansion studies, classifying far more cost than is warranted to demand. As stated by CA Energy Consultants (CA COS report, page 14, lines 24 to 28) “*Hydro could try to proceed as it does with its current generation units by selecting an appropriate generator-specific method that would reflect the plant’s baseload role in supplying energy. Alternatively, Hydro could revise its practice for all its units, and bundle them all together into a single allocation mechanism.*” For the same reasons that it makes sense to classify the MFP using the equivalent peaker approach, it makes sense to classify “other hydro” and “purchases other than wind” using the equivalent peaker approach. “Other hydro” and “purchases other than wind” were not constructed to supply system load factor, but rather were constructed to meet capacity requirements and produce system energy savings through the economic dispatch process.

CA Energy Consulting goes on to say (CA COS report, page 17, lines 15 to 18) “*Additionally, if the equivalent peaker approach, with its grounding in system planning, appeals conceptually to Hydro, the utility may wish to consider applying this approach to*

[6] In other words, if the system load factor is 55% (the average amount of energy served over the year divided by the system peak for the year), 55% of the costs of “other hydro” and “purchases other than wind” would be classified as energy and the remaining 45% as demand.

its entire fleet of Interconnected generation. The theoretical advantage is that each unit is judged for its demand and energy components under the same set of assumptions.” In the same paragraph CA Energy Consulting indicates that the challenge of this methodology is to compute the current value of each generation unit according to an index such as Handy-Whitman. In the 1992 cost of service methodology review the Board considered the equivalent peaker approach but ultimately rejected the approach for reasons of computational challenge, and plant vintage and valuation issues. However, the Board has recently approved use of index valuation for specifically-assigned O&M costs which represent a much smaller portion of the asset base than “other hydro” and “purchases other than wind”. The equivalent peaker approach is grounded in system planning so the extra effort required to make the determination is fully justified on the basis of fairness, similar to the justification for changing to an index valuation of specifically-assigned O&M. As noted earlier, CA Energy Consulting states (PUB-NLH-037, page 5) “*Despite greater complexity, the Equivalent Peaker approach arguably has an advantage from the perspective of economic theory.*” In my opinion the additional complexity of the calculation is more than justified by the cost causation and fairness advantages of the equivalent peaker approach.

In CA-NLH-4 Hydro provides a high-level approach for calculating the classification percentages for other hydro using the equivalent peaker approach. Hydro also provides a methodology for determining the capacity value of wind generation in the attachment to CA-NLH-11. It is understood that Mr. Brockman, the expert witness for Newfoundland Power at the 1992 cost of service hearing, also provided a classification methodology for other hydro.[7] Options exist for making such a calculation, or the Board might simply accept the classification percentage for the MFP of 20% capacity and 80% energy (Hydro COS report, page 11, lines 1 to 2) for its entire generation fleet. I note that the study on the classification of wind purchases came up with a similar 22% capacity and 78% energy split (CA-NLH-11, Attachment 1, page 7 of 7). Classification on the basis of a methodology that may appear complicated is still much preferred over a simplistic classification based on a methodology that does not reflect cost causation.

2.5.4 Classification of Holyrood TGS

As noted by Hydro (Hydro COS report, page 12, lines 2 to 7) "*Following the completion of Muskrat Falls Project commissioning, Holyrood's role will change and the plant will cease to perform as a generating unit. The plant may be required to be available for generation for a period of time after Muskrat Falls Project commissioning. In this circumstance, Hydro proposes that Holyrood asset costs be functionalized as generation and classified using a forecast capacity factor. The Holyrood fuel cost is proposed to continue to be classified as an energy cost.*"

Given the transitional nature and uncertainty of Holyrood's role following commissioning of the MFP, I believe that this approach is reasonable and fairly reflects cost causation. I agree with Hydro's proposed cost of service treatment of Holyrood TGS until its future role is more clearly defined.

[7] According to CA-NLH-003, at the 1992 cost of service hearing Mr. Brockman recommended that hydro generation be classified using the equivalent peaker approach with 26% classified as demand and 74% classified as energy.

I also agree with Hydro's proposal that following conversion of Holyrood TGS Unit 3 to synchronous condenser operation, it should be functionalized as transmission. It should be classified on the same basis as network/common transmission.

2.5.5 Classification of Common/Network Transmission

I disagree with Hydro's proposal to classify 100% of common, or network, transmission as demand. The transmission network enables delivery of power and energy to the load. While network transmission clearly provides capacity benefits, it also provides significant energy benefits by enabling optimum system expansion with the proper mix of baseload, intermediate load and peaking generation and expanding the region across which economic dispatch can be practiced. Further, although network transmission costs are mostly fixed, for the same reasons it is appropriate to classify a portion of the fixed costs of baseload generation to energy, it is appropriate to classify a portion of the fixed costs of transmission to energy. As noted by CA Energy Consulting (CA COS report, pages 37 and 38 and Table 3) although it is common practice in the industry to classify 100% of network, or common, transmission to demand, Nova Scotia Power "*has a tradition of treating its common transmission facilities as an extension of its generation facilities*" (page 38, lines 2 to 3). Table 3 shows that Nova Scotia Power classifies its network transmission on the same basis as its generation.

As stated in the report by J.W. Wilson and Associates, the Board's expert witness at Hydro's 2013 GRA (pages 10 and 11),[8]

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[8] See April 25, 2014 report by J.W. Wilson and Associates entitled *Report to The Newfoundland and Labrador Board of Commissioners of Public Utilities on Cost Allocation and Rate Design Issues in the Newfoundland and Labrador Hydro ("Hydro") July 30, 2013 General Rate Application*.

An alternative to allocating all other (non-hydraulic) transmission costs to peak demand would be to allocate transmission costs for connecting other production plant to the network (and possibly network transmission as well) in the same proportions as production plant. The allocation of base load generation plant costs to both demand and energy recognizes the fact that these plants are built and dispatched not just to serve peak loads, but all system loads. Base load generating plants would not be an economical choice if they were intended only for peak loads. The same is true for transmission networks. There is, therefore, a sound rationale for allocating transmission network costs to both demand and energy."[9]

Network transmission provides energy benefits as it enables economic dispatch over a broader region. Further, new network transmission facilities can reduce energy losses. Consider the Avalon Peninsula (see CA-NLH-15). If it were operated in isolation without the transmission connecting it to the rest of the IIS, energy needs on the Avalon would mostly be met with high-cost energy from Holyrood TGS and peaking plants Hardwoods, Holyrood Gas Turbine and Holyrood diesel. This would result in energy costs that are prohibitively expensive. Instead, owing to the network transmission facilities connecting the Avalon Peninsula to the rest of the IIS, less than 34% of the Avalon Peninsula needs (1560.3 GWh production from Holyrood TGS and peaking plants divided by 4622.5 GWh demand on the Peninsula in the 2019 Test Year) are met from these high-cost sources with

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[9] Hydro's reference to "*common transmission*" is often referred to in the industry as "*network transmission*".

the other 66% met from low-cost sources brought in to the Avalon Peninsula over the transmission network. In effect, the network transmission enables the delivery of low-cost hydro generation to the Avalon Peninsula to displace high-cost Holyrood TGS and peaking generation during periods of low system demand; i.e., spring, summer and fall.

Another example of how network transmission provides energy benefits is the connection of the IIS to Nova Scotia (and on to the Northeastern United States). Hydro is no longer as dependent on Holyrood to meet energy demand on the IIS throughout the winter period with the availability of lower cost generation from Nova Scotia and beyond.[10] It is the transmission network on the IIS that enables delivery of this lower cost generation to the Avalon Peninsula.

In its discussion of the new third transmission line from Bay d"Espoir to Western Avalon (TL267) Hydro states (2017 GRA, Volume I, section 3.5.3 page 3.28, line 17) that TL267 "*will enable the delivery of additional capacity to the Avalon Peninsula, relieve congestion, reduce system losses, enhance the resiliency of the current transmission network"*. Hydro further explains in IC-NLH-090 that "*TL267 will enable the delivery of more hydraulic energy to the Avalon Peninsula. This will enable more efficient hydraulic unit operation and decreased spill*". These statements further confirm that network transmission provides energy benefits.

The concept that network transmission reduces energy costs is recognized around the world. The formation of Regional Transmission Organizations in the United States while providing capacity benefits, also provides significant energy benefits by expanding

[10] Energy will be available provided transmission capacity is available between the source of the generation and the IIS.

economic dispatch to a broader region via transmission network facilities. The European Union has made a priority of expanding competitive electricity trade throughout the union, as opposed to on an individual country basis, to gain the benefits of economic dispatch and competition which incentivizes generators to continue to improve reliability and production efficiency to increase profits. As stated by Brattle (LAB-PUB-002) "*compared to systems that are not interconnected, interconnected systems generally achieve efficiencies that would not be possible absent interconnection, such as improvements in overall system load factor and economies of scale. As an example, generation units with different marginal costs can be used more efficiently, and at lower overall costs, in an interconnected system*."

The energy benefits of network transmission are reflected by the nodal pricing, or locational marginal pricing ("LMP"), schemes in places such as PJM. Different prices at different nodes on the system recognize that transmission constraints result in generation dispatch that is not optimum; i.e., not on the basis of economic merit order. Building additional transmission between two nodes to alleviate transmission congestion enables merit order dispatch and reduced energy costs. As stated by CA Energy Consulting (CA COS report, page 34, lines 11 to 15) "*transmission can substitute for local generation, in selected cases. For example, the recent expansion of transmission capability in Southwest Connecticut and along California's Path 15 rather dramatically improved flow capability, thus reducing the costs of generation by significantly lowering congestion costs, specifically costs related to out-of-merit generation dispatch.*" Brattle similarly states (NLH-PUB-001) "*In general, an area with higher LMPs will be import constrained, indicating that congestion exists for power flows into that area and preventing the* *importing of less expensive power*." Clearly, the addition of transmission between constrained nodes would provide energy benefits by alleviating the constraint and enabling economic dispatch across the broader region.

Network transmission not only "can" substitute for local generation, but often "does" substitute for local generation. Consider two isolated systems each with 100 MW loads. Each system has a 100 MW generating unit, but wants backup generation so supply is not interrupted when the main generating unit experiences an outage. Each system could add a new 100 MW generating unit to cover off such outages, or alternatively, a transmission line could be constructed between the two systems and a single 100 MW generating unit might be added to cover off generator outages on both systems. In this case transmission and generation are competing alternatives. The cost of the transmission line and one 100 MW generator would be compared to the cost of two 100 MW generators in the scenario with two isolated systems. Capital costs are not the only consideration in such evaluations. Adding a transmission line enables economic dispatch across the combined systems rather than each individual system and the resulting energy costs can be significantly reduced. In this simple example, the transmission line would reduce generation capacity requirements and the overall cost of energy production. The transmission line would also enable consideration of a broader range of generation alternatives to meet demand at lowest cost as a larger system enables construction of a larger and more diverse range of generating stations.

When developing a system expansion plan, generation and transmission investments are assessed on the basis of overall cost impacts including capital and impacts on system costs such as fuel resulting from changes in losses and economic dispatch. Referring to the new

TL267 transmission line referenced earlier, Hydro states in Volume 1 of the 2017 GRA (page 1.17, lines 1 to 8) "*In 2016, it started the acceleration of TL267 from Bay d'Espoir to Western Avalon, a key project that will allow Hydro to bring more capacity from its generating assets on the island to customers on the Avalon Peninsula where demand is concentrated. This project is currently scheduled to be in service in late 2017 and will result in added stability of the transmission network and a significant improvement to reliability. The increased availability of existing hydraulic generation capacity will reduce the requirement for Holyrood to support the Avalon Peninsula load, and will, in turn, reduce fuel costs.*"

To ensure fairness and reflect cost causality, the cost of service study must recognize the energy benefits provided by the transmission network. As stated in the Wilson and Associates report referenced earlier (page 12) "*In Hydro's case, substantial transmission investment and expense is clearly related to both the transmission and network integration of less costly energy from hydraulic and base load plants rather than to simply meet peak demand. The important network integration and energy cost aspects of these facilities would be better recognized by assigning a significant portion of all transmission plant costs to energy*." As already stated, Table 3 (page 38) of the CA COS report indicates that Nova Scotia Power classifies its network transmission on the same basis as its generation so there is regulatory precedent in Canada. I recommend a similar approach for the IIS cost of service study with network transmission classified to demand and energy on the same percentage basis as generation (on average).

2.6Allocation

Hydro proposes to allocate generation and transmission demand costs on the basis of 1CP (coincident peak) and energy costs according to annual energy consumed (Hydro COS report, pages 14 and 15). This has been a long-standing practice in the Province.

Hydro states (Hydro COS report, page 14, lines 14 to 18) "*Hydro plans to evaluate if it is practical to employ a peak allocation approach based on the percentage of load by class in the highest 50 hours of the winter season. Manitoba Hydro currently uses this approach. This analysis would provide additional information to evaluate the reasonableness of the current 1 CP allocation approach. Hydro plans to report to the Board on the analysis results in its next GRA.*"

I agree with the proposal to allocate energy on the basis of energy consumed and demand on the basis of 1CP. Further, I support Hydro's proposal to evaluate a peak allocation approach over a greater number of peak hours for potential implementation at future GRAs.

2.7 Other

2.7.1 Rural Deficit Allocation

Hydro states (Hydro COS report, page 15, lines 11 to 12) "*CA Energy Consulting also reviewed the Rural Deficit allocation in its report. CA Energy Consulting agreed that Hydro's proposed approach is preferable to the previous method*." Hydro recommends (Hydro COS report, page 15, lines 14 to 17) "*continued use of the revenue requirement method for allocation of the Rural Deficit between Newfoundland Power and the Hydro Rural customers on the Labrador Interconnected System. This recommendation is* *consistent with Hydro's proposal which was approved by the Board in the 2013 GRA Final Order*."

This results in what I believe to be the fairest allocation of this subsidy among customer classes. However, I continue to believe that the subsidy is blatantly unfair to the customers forced to pay the subsidy and that it should instead be paid directly by Government, particularly in light of the substantial rate increases these customers will be facing with the commissioning of the MFP. Following the introduction of the MFP in rates, these customers might be paying rates that are higher than the rates of some of the customers they are being forced to subsidize.

2.7.2 Classification of CDM as Energy

Hydro states (page 15, lines 20 to 21) "*Based on discussions with Newfoundland Power, Hydro is proposing to continue the current approach in recovery of CDM costs among its customer classes.*"

I do not take exception to this treatment of CDM but note that this is an evolving issue so should be reviewed regularly as CDM programs change in response to the value they provide to the system.

2.7.3 Use of Indexed Asset Costs in Specifically-Assigned Charges

Hydro states (Hydro COS report, page 15, lines 24 to 28) "*Consistent with its 2017 GRA filing, Hydro recommends that the use of original asset costs as a basis for the allocation of operating and maintenance costs to specifically assigned assets be discontinued. The use of original assets costs in the allocation of operating and maintenance costs is* *problematic since direct assignment on the basis of original asset costs appears to be poorly correlated with actual expense patterns over time*." Hydro goes on to say (Hydro COS report, page 16, lines 6 to 8) "*Until a reasonable alternative method is developed, Hydro recommends the use of indexed asset costs in operating and maintenance cost allocations in the determination of specifically assigned charges*." Hydro will report to the Board at the next GRA on use of actual operating and maintenance costs is a reasonable and more favourable approach.

I do not take exception with this proposal.

2.7.4 Newfoundland Power Generation Credit

Hydro states (Hydro COS report, page 16, lines 11 to 14) "*Hydro continues to assume that the existing Newfoundland Power hydraulic and thermal generation assets will continue to provide firm capacity to meet system demand requirements. Therefore, Hydro recommends the continuation of the existing approach of providing a generation credit for both the hydraulic and thermal generation of Newfoundland Power*."

I support Hydro's proposal for the time being but note that the treatment of customer-owned generation has been a long-standing issue in the Province. I recommend that the Board direct Hydro to file a report on the treatment of customer-owned generation (specifically Newfoundland Power and CBPP) that fairly compensates such customers on the basis of the value their generation provides to the system. Marginal costs should be the basis for this valuation. If marginal cost-based classification and allocation is introduced in future cost of service studies, Newfoundland Power and CBPP generation credits should be determined in a similar and consistent manner.

2.7.5 CBPP Generation Demand Credit

Hydro states (Hydro COS report, page 18, lines 6 to 10) "*Hydro proposes to discontinue the generation credit agreement between Hydro and CBPP upon full commissioning of the Muskrat Falls Project. However, Hydro believes CBPP should have the opportunity to manage its generation as efficiently as possible and, to that end, proposes to work with CBPP in the rate design review planned for 2019 to develop a proposal to achieve this objective*."

I support discontinuance of this program as it was never shown to provide benefits to customers other than CBPP. As I stated in the previous section, I recommend that the Board direct Hydro to file a report on the treatment of customer-owned generation (specifically Newfoundland Power and CBPP) that fairly compensates such customers on the basis of the value their generation provides to the system; i.e., marginal costs. If marginal cost-based classification and allocation is introduced in future cost of service studies, Newfoundland Power and CBPP generation credits should be determined in a similar and consistent manner.

2.7.6 Treatment of Net Export Revenues

Hydro recommends (Hydro COS report, page 18, lines 14 to 20):

> *"(i) net export revenues be used to reduce the Muskrat Falls supply costs to be recovered through the rates of customers on the Island Interconnected System;*

(ii) net export revenues be classified in the same manner as the classification of the Muskrat Falls Project costs in the cost of service study; and

(iii) net export revenues be included in the test year cost of service study for rate making with variations from forecast net export revenues be dealt with through a deferral account mechanism."

Hydro proposes (Hydro COS report, page 18, lines 22 to 23) to include any revenues from carbon credits in the net revenue calculation. Hydro states that it will provide a detailed proposal on the deferral account mechanism at the next GRA.

I do not take exception with this proposal and look forward to reviewing the detailed deferral account mechanism to be filed by Hydro at the next GRA.

3. Summary of Recommendations

I recommend that the Board accept Hydro's proposals in the Cost of Service Application with the following exceptions:

1. Classify existing hydro assets and purchases other than wind using the equivalent peaker approach.
2. Classify common, or network, transmission on same percentage basis as classification of IIS generation (on average).

Further, I make the following recommendations for the Board's consideration:

1. Continue with embedded cost of service for now, but the Board should direct Hydro to develop an approach for incorporating marginal cost classification and allocation in future cost of service studies.
2. Continue with current practice of providing generation credit to Newfoundland Power hydro and thermal generation but the Board should direct Hydro to file a report on the treatment of customer-owned generation (specifically Newfoundland Power and CBPP) that fairly compensates such customers on the basis of the value their generation provides to the system; i.e., marginal costs. If marginal cost-based classification and allocation is introduced in future cost of service studies, Newfoundland Power and CBPP generation credits should be determined in a similar and consistent manner.

This concludes my pre-filed evidence.

Exhibit CDB-2

C. Douglas Bowman

Background and Qualifications

Profession	*ENERGY CONSULTANT*
Nationality	Canadian Citizen U.S. Resident
Years of Experience	41
Education	M.S./1977/Electrical Engineering/State University of New York, Buffalo, NY B.S./1975/Electrical Engineering/State University of New York, Buffalo, NY
Key Qualifications	Mr. Bowman has 41 years of experience in the power industry both domestically and internationally. His primary areas of expertise include electricity services costing and pricing, and power sector restructuring, regulation and markets. Mr. Bowman has played a leading role in consulting projects in Canada, Armenia, Australia, Central America, China, Colombia, Dutch Antilles, Egypt, Georgia, Ghana, India, Indonesia, Macao SAR, Macedonia, Mexico, the Middle East, Mongolia, Pakistan, the Philippines, Russia, Saudi Arabia, Serbia, South Korea, Taiwan, Thailand, United States and Vietnam.

Expert Testimony at Newfoundland and Labrador Hydro's Rates Submission
Provided expert written testimony on issues related to cost of service, rate design and regulation at Hydro's 2017 General Rate Proceeding.

Expert Testimony at Board of Commissioners of Public Utilities' Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System
Provided written evidence on system planning and regulatory issues pre- and post-Muskrat Falls.

Expert Testimony at Newfoundland and Labrador Hydro's Rates Submission
Provided expert written testimony on issues related to cost of service, rate design and regulation at Hydro's Amended 2013 General Rate Proceeding.

Expert Testimony at Newfoundland and Labrador Hydro's Rates Submission
Provided expert written testimony on issues related to cost of service, rate design and regulation at Hydro's 2013 General Rate Proceeding.

Expert Testimony at Newfoundland and Labrador Hydro's Application Concerning the Rate Stabilization Plan
Provided expert written testimony on issues related to Hydro's 2009 Application on the rate stabilization plan components of the rates to be charged Industrial Customers.

Expert Testimony at Newfoundland Power Inc.'s Rates Submission
Provided expert written and oral testimony on issues related to cost of service, rate design and distribution quality and reliability of service standards at Newfoundland Power's 2008 General Rate Application.

Expert Testimony at Newfoundland and Labrador Hydro's Rates Submission
Provided expert oral and written testimony and participated in negotiation sessions on issues related to cost of service, rate design and regulation at Hydro's 2006 General Rate Proceeding.

Expert Testimony at Newfoundland and Labrador Hydro's Rates Submission
Provided expert oral and written testimony and participated in mediation sessions on issues related to cost of service, rate design and regulation at Hydro's 2003 General Rate Proceeding.

Expert Testimony at Newfoundland Light & Power's Rates Submission
Provided expert written testimony and participated in mediation/technical sessions on issues related to cost of service and rate design at Newfoundland Light & Power's 2003 General Rate Application.

Expert Testimony at Newfoundland and Labrador Hydro's Rates Submission
Provided expert oral and written testimony related to cost of service and rate design issues at Hydro's 2001 General Rate Proceeding.

Expert Testimony at Newfoundland Light & Power's Rates Submission
Provided expert oral and written testimony related to cost of service and rate design issues at Newfoundland Light & Power's 1996 General Rate Proceeding.

Expert Testimony at Nova Scotia Power's Rates Submission
Provided expert oral and written testimony related to cost of service and rate design issues. Recommended and designed time-of-day rates for all customer classes and designed an alternative interruptible rate design for large industrial customers.

Expert Testimony at Nova Scotia Power's Rates Submission
Provided expert oral and written testimony regarding an Industrial Expansion rate design. Recommended approval of rate with modifications and submitted two alternative rate designs for approval including a real-time surplus power rate and a time-of-day expansion rate.

Cost of Service and Cost Reducing Rate Design Study
On behalf of the Nova Scotia Utility and Review Board, reviewed Nova Scotia's cost of service study and developed rate designs consistent with Nova Scotia Power's integrated resource plan for all customer classes.

Report was filed with Board, and reviewed as part of hearing on utility's subsequent rate submission.

Economic Policy Reform and Competitiveness Project – Mongolia
Assisted with the setup and training of the new regulatory commission in Mongolia. Developed tariff reform plan that was accepted by the regulatory commission for implementation. Developed incentive based power purchase agreement for sales of generating company capacity and energy to the transmission company. Developed market rules for governing competitive electricity market.

Electricity Market Reform in Macedonia
Participated in development of competitive electricity market design for Macedonia consistent with European Union market design. Assisted with development of Market Rules to govern operation of the competitive electricity market.

Competitive Electricity Market Design – Taiwan
Developed competitive market design for electricity sector in Taiwan. Drafted market governance documents including Market Rules and Grid Code. Managed market modeling component of project which simulated market operation under wide range of scenarios.

Alberta RTO Evaluation Project
Developed strategy related to preferred business relationship between the Alberta Regional Transmission Organization and RTO West to ensure Alberta's electricity needs are met by a competitive market. The project participants included the Alberta Department of Energy, ESBI Alberta Limited, and the Power Pool of Alberta.

Detailed Market Design and Market Rules Development, Western Australia
Served as project manager providing advice to the Government of Western Australia with regard to detailed market design, market rules development, and market power mitigation. Assisted with the stakeholder process, drafted position papers on various design topics, drafted market rules consistent with a bilateral contracts market, and designed a market power mitigation program.

Market Assessment of Generating Company in Korea
Provided advisory services to a client interested in submitting a bid for the purchase of a large generating company in Korea. Served as Project Manager for the market valuation component of the project.

Expert Testimony in Kansas Civil Case Concerning IPP Development
Provided expert testimony concerning the independent power producer (IPP) programs in India and Colombia. The testimony related to the difficulties and hurdles that must be overcome in order to successfully develop an independent power project in a developing country.

Market Power Mitigation Strategy for Generating Company in Korea
Provided advisory services to a large generating company in Korea relating to a market power mitigation strategy. Served as project manager. The project included market simulation to determine if the generating company would have market power in the new competitive market, and if so, if its market power were any greater than other generating companies participating in the market.

Advisory Services to World Bank on Regional Market Design among Arab Countries: Conducted a review of the status of market reform in the Arab countries and designed a competitive regional electricity market and road map for implementation of the market and ultimately gain access to markets in the surrounding region. Developed governance documentation for the regional electricity market including a General Agreement, Market/Commercial Rules and a Grid Code.

Advisory Services on Transmission Tariff Development in Georgia: Provided advice to Government of Georgia on behalf of USAID on transmission tariff development. The project included a comparison of current practice in Georgia to best practice in the European Union and provided recommendations for bringing current practice up to EU standards.

Advisory Services to World Bank on Regional Energy Integration in Middle East and Surrounding Area: Provided advice to Government of Saudi Arabia on behalf of World Bank on regional energy integration of GCC countries (Saudi Arabia, Kuwait, Bahrain, Qatar, UAE and Oman), as well as a select number of other countries offering trade opportunities for Saudi Arabia including Egypt, Iraq, Jordan, Syria, Lebanon, Iran, Turkey and the EU. Advice included assessments of legal, regulatory and policy relating to international energy trade, energy demand and supply balance, electric transmission interconnection including HVAC and HVDC, and pipeline capacity to support trade.

Advisory Services to World Bank on Potential Egypt – Saudi Electrical Interconnection: On behalf of Government of Saudi Arabia, conducted evaluation of potential HVDC electrical interconnection between Saudi Arabia and Egypt.

Advisory Services on Electricity Market Design in Serbia
Developed a high-level, phased design for the internal Serbian electricity market consistent with the EU Directive. The project intent was to provide institutional support to the Ministry of Mining and Energy to facilitate the phased development of the internal electricity market with competitive bilateral contracts taking into account Serbian Energy Policy, the draft Energy Law, European Union requirements and the Athens Memorandum 2002.

Expert Testimony in California Civil Case Concerning Breach of Contract

Provided expert testimony concerning the value of a company based on revenues generated less costs to manage and operate the business. Revenues were derived from a contract for energy services covering steam and electricity sales to an industrial client and its power purchase agreement covering electricity sales to a utility.

Workshop on Transmission Planning in a Competitive Power Market
Conducted workshop on transmission planning for proposed RTO West in Portland, Oregon. Workshop covered transmission planning responsibilities of Regional Transmission Organizations under FERC Order No. 2000.

Workshop on Transmission Pricing in a Competitive Power Market
Conducted workshop on transmission pricing for proposed RTO West in Portland, Oregon. Workshop covered transmission pricing in Regional Transmission Organizations under FERC Order 2000 and experience with domestic Independent System Operators and international transmission organizations.

Development of Terms and Conditions for Transmission Tariff
Assisted Ontario Hydro Services Company with development of terms and conditions for its new transmission tariff. The terms and conditions were filed with the regulatory authority as part of the utility's application for approval of the new tariff. Also assisted with preparation of responses to various discovery questions related to the tariff.

International Survey of Transmission Rates and Services
Conducted a survey of transmission rates and services provided in various domestic and international jurisdictions. Survey conducted in support of submission by Ontario Hydro Services Company to Ontario Energy Board on its new transmission tariff. Survey topics included: services offered such as network, point-to-point, connection, import and export service; cost recovery such as postage stamp, zonal and nodal pricing; treatment of generation; and transmission planning.

Feasibility Study of Merchant Co-generation Project
Participated with a team of consultants on a feasibility study for development of a merchant co-generation facility to sell power into the wholesale market and steam to the industrial plant. Directed market studies including analyses of forecasts for electricity demand, new generating plant construction, generation costs, market bid strategies, fuel costs, utility avoided costs, etc.

Advice to Mid-west Cooperative Concerning Role in Deregulated Power Market

Provided advice to a mid-west cooperative on positioning itself for a deregulated power market. Advice included the cooperative's future power purchasing strategy, transmission and distribution construction and operations and maintenance strategy and how it should position itself to compete in the future deregulated power market.

Experience

Independent Consultant, Warrenton, VA 2005 to Present

Nexant, Inc., Washington, DC 2004
Executive Consultant

KEMA Consulting, Fairfax, VA 1999 to 2004
Executive Consultant

Pace Global Energy Services, Fairfax, VA 1998 to 1999
Director, Power Services

International Resources Group, Ltd. (IRG), Washington, DC 1995 to 1998
Senior Manager, Energy Group

CSA Energy Consultants, Arlington, VA 1994 to 1995
Vice President (1995); Senior Manager, Power Supply Analysis (1994)

Ontario Hydro, Toronto, Ontario, Canada 1977 to 1993
Industrial Service Advisor, Field Support Services Department, 1992-1993

Senior Rate Economist, Rate Structures Department, 1990-1992

Planning Engineer, Demand/Supply Integration, System Planning Division, 1988-1990

Senior Engineer, Resource Utilization, Power System Operations Division, 1987-1988

Planning Engineer, BES-Resources Planning, System Planning Division, 1981-1987

Assistant Planning Engineer, Transmission System Planning Department, 1979-1981

Engineer-in-Training, 1977-1979