PROVINCE OF MANITOBA

BEFORE THE PUBLIC UTILITY BOARD

Manitoba Hydro 2011/12 & 2012/13)
General Rate Application)

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

GREEN ACTION CENTRE

Resource Insight, Inc.

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I. Identification and Qualifications

Q: Mr. Chernick, please state your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honour society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, integrated resource planning, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit GAC-PC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than two hundred and fifty times on utility issues before regulators in thirty U.S. jurisdictions and five Canadian provinces. My previous testimony is listed in my resume.

Q: Have you testified previously before this Board?

A: Yes. I testified in the 2008/09 General Rate application ("GRA") of Manitoba Hydro ("MH," "the Company" or "Hydro"), Hydro's 2008 Energy-Intensive Industrial Rate proceeding, and Hydro's 2010–2012 GRA.

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by Green Action Centre ("GAC").

Q: What is the purpose of your direct testimony?

A: My sponsors have asked me to review two areas of Hydro's filings: marginal costs and the fuel-switching report (Appendix 26). I review Hydro's estimates of marginal costs in the context of their use in rate design, the analysis of fuel switching, and the planning and evaluation of demand-side management ("DSM"), including Hydro's methods for screening DSM options. My review of these issues is consistent with the Public Utility Board's concern about inefficient pricing and environmental emissions:

> The Board seeks to assure itself that MH's rate design and rates are consistent with the pursuit of the environmental objectives of The Sustainable Development Act (SDA). Energy efficiency presents the potential for a virtuous circle, wherein lower domestic consumption results in reduced customer bills, higher MH aggregate net export revenue and net income, and lower carbon emissions by MH's American export customers. (PUB Order 117/06, p. 3)

In connection with these topics, I also testify on the shortcomings in Hydro's documentation of its analyses and on the information available about Hydro's marginal costs.

I prepared draft testimony on time-of-use rates and other rate-design issues, but the Board, in a letter of November 6 2012, moved all rate-design issues to a "separate process in 2013 when Cost of Service Study matters will be reviewed" following an opportunity for Hydro to discuss its approaches with the parties, provide information, and possibly reach consensus on some issues. In various places within this testimony, I discuss issues that overlap with that combined allocation and rate-design proceeding, such as marginal costs (which affect rate design, as well as DSM and fuel-switching) and Hydro's failure to provide data, documentation and spreadsheets (which affect the review of all of Hydro's proposals).

The marginal costs for DSM, fuel-switching, and rate-design analysis are closely linked and cannot be meaningfully divided between the phases of the review.

Q: Which DSM issues do you discuss?

A: My testimony on DSM issues is limited to estimates of marginal costs, the tests that Hydro uses in screening of DSM opportunities, and the potential connection of those factors to Hydro's projected DSM performance. My clients have cosponsored the testimony of Philippe Dunsky, who discusses Hydro's DSM savings targets and other aspects of Hydro's DSM plan.

III. Reviewability of Manitoba Hydro's Proposals and Analyses

Q: Has the Company provided adequate documentation of its rate design proposals, fuel switching report, and DSM plans?

A: No. Hydro's filing was deficient in the following respects:

- The filing lacked essential information. The parties were put in the position of having to use discovery to obtain information that should have been provided with the filing. The result was an inefficient and inadequate discovery process.
- The final rate proposals were not provided with the initial GRA filing. The Company filed its 2012/2013 rate design proposals, including a time-of-use rate for large general service customers, on October 3 2012. That date was full three months into the GRA proceeding and too late in the Board's judgment for the Company's proposals to be considered in this proceeding. The final revised 2012/2013 rate schedules, proof of revenue, and bill comparisons were filed on November 7 2012, leaving no opportunity for discovery.
- The fuel-switching report was filed on September 11 2014, two months after the initial GRA filing and three years late.
- Hydro refused to provide analyses and calculations in Excel-readable form, including the electronic spreadsheets used to calculate the Proof of Revenue and Bill Comparisons.
- The Company refused to provide its marginal cost estimates and supporting analyses. This information is essential to evaluating Hydro's fuel switching report, and its rate design and DSM program proposals.

Q: What sorts of essential information is missing from Hydro's filings on rate levels, fuel-switching, and DSM?

A: Hydro did not document the assumptions, marginal cost estimates, and calculations that would allow independent review. For example, Hydro's so-called proof-of-revenue tables (Appendices 10.1 and 10.12) provide only total revenues by rate class, and therefore, prove nothing. Even with discovery, Hydro provided only PDF tables of billing data and unit charges, but no calculations.

Q: How did the late filing of rates and of the fuel-switching report affect their reviewability?

A: The lateness of the filing and the inadequacy of the accompanying documentation limited the opportunity for review, discovery, and evaluation. The schedule permitted only one round of discovery. Hydro provided a partial set of responses on October 26, leaving intervenors little time to address the proposals in testimony. As of November 15 2012, GAC had still not received responses to all of its requests.

Q: Why is access to electronic spreadsheets essential to regulatory review?

A: When data, calculations, and models are provided in Excel format, intervenors are able to check the Company's calculations, confirm their understanding of its methodologies, and gauge the effect of alternative inputs and assumptions on the results. Hydro's proof-of-revenue and bill-comparison spreadsheets, for example, could be used to develop alternative rate designs and evaluate the bill impacts.

Q: Can PDF tables be translated into Excel?

A: Yes, but at an inordinate cost to intervenors and only if all of the necessary information is provided. The analyst must not only copy the PDF tables into Excel—usually a tedious manual process—but also reproduce the formulas, which typically requires considerable trial and error. If Hydro neglects to provide any data in the visible portion of the spreadsheet that it converted to PDF format, reproducing the original computation will be impossible.

Q: What is Manitoba Hydro's explanation for its refusal to provide calculations and models in Excel-readable form?

A: Hydro contends that limiting intervenor access to Company data and models provides the following benefits:

- promoting regulatory efficiency,
- allowing the Company to protect its work product,
- preventing the release of information that "may" be confidential.

The Company explains its position in detail in response to GAC/MH I-3a (also cited in the response to GAC/MH I-7):

> First, certain models used by the Corporation are large and complex. Manitoba Hydro expects that an independent analyst, untrained with Manitoba Hydro's models, would need to invest a significant amount of time and effort to be capable of operating the model correctly. Allowing other parties to work in and modify spreadsheets and pose questions in Information Requests and on cross-examination based on the modified schedules, will also require Manitoba Hydro to invest a significant amount of time analyzing the changes made to the spreadsheets and to understanding their potential impacts. This approach is inefficient, would require additional time to be provided within the regulatory process and would make the regulatory process more cumbersome.
>
> Second, spreadsheets contain metadata, which includes working notes and references made by the staff responsible for the files which cannot be disclosed for confidentially or other reasons. In order to remove metadata, the file must be converted to an Adobe Acrobat portable document format (pdf) file.…
>
> Third, Manitoba Hydro notes that some of the Corporation's models may be subject to intellectual property rights reserved by third parties and are not available to be shared in the regulatory process. In addition, some spreadsheets may contain competitive or commercially sensitive information which is not appropriate to be disclosed.

Q: Do Hydro's arguments justify its refusal to provide its calculations and models?

A: No. First, numbers on pages cannot be evaluated or independently verified. These numbers are based on calculations, projections and judgments on which qualified participants may reasonably disagree. Even in the case of a proof-of-revenue table, a relatively simple calculation, independent reviewers cannot confirm that Hydro accurately designed its proposed rates to collect the proposed revenues without the inputs and calculations. Nevertheless, Hydro appears to take the position that intervenor review of the Company's rate studies is not worth the time and effort of the Company or of the Board.

Second, failure to provide essential information impedes the regulatory process; it does not increase its efficiency.

Third, the Company bases its refusal to provide spreadsheets and models on an unsupported concern about the complexity of "certain" unspecified models. The revenue proof and bill comparison calculations are not complex. They are a simple matter of addition and multiplication.

Finally, Hydro's response raises only the *possibility* of confidentiality problems. It does not identify any actual problems.

Q: Does Hydro propose an alternative to providing Excel spreadsheets, with or without formulas?

A: Yes. It proposes to rerun its models in response to Intervenor requests:

> it is preferable for Intervenors to propose, through the interrogatory process, that Manitoba Hydro run specific scenarios using its models, changing the assumptions as requested, and providing updated results for all parties to examine. Manitoba Hydro is of the view that this is the most appropriate and efficient approach to test new scenarios. (GAC/MH I-3a)

Q: Will Hydro's proposal provide an adequate substitute for intervenor access to the Company's data, calculations and models?

A: No. Hydro's offer to run its models with intervenor inputs is not an adequate solution.

A proof-of-revenue spreadsheet, which Hydro refuses to provide, includes the assumptions and calculations that are essential to a rate case. Some of Hydro's changes require usage data and assumptions that are not available from bills under current rates. These changes include, for instance, merging the Small and Medium General Service Classes and creating time-of-use rates for Large General Service Customers and doubling their ratchets. In these cases, proof of revenue is even less transparent. Without access to the underlying spreadsheets, the Board cannot confirm that the rates it approves are actually designed to collect the allowed revenues.

In addition, the proof-of-revenue spreadsheet is required for developing alternative rate designs. Relying on Hydro to recalculate its spreadsheets with alternative inputs and rate designs is not an adequate solution, for the following reasons:

- The data needed to develop alternative designs are not readily accessible to third parties.
- The discovery process creates long lead times between intervenor requests for modifications and receipt of spreadsheet results, thereby limiting development of alternative designs.
- It would be time-consuming, if not impossible, to make sure from PDF documents that Hydro correctly understood and made the desired modifications.
- If the results seem counter-intuitive or incorrect, intervenors would not be able to check the spreadsheet for a possible explanation.
- Intervenors would still have to divulge their work product.

Q: In your experience, do other utilities make their Proof of Revenue and Bill Comparison Tables available in Excel spreadsheets?

A: Yes. I cannot recall *any* other utility company that has refused to make its proof-of-revenues and bill-comparison calculations available.

In addition, many utilities are willing to provide access to its more complex models. For example, in the following projects, the companies provided their cost-of-service-study data and work papers in Excel spreadsheets either with their filing or on request:

- In Alberta EB Application No. 1500878, ATCO Electric provided COSS-related files and other requested information in Excel spreadsheets (with formulas intact).
- Nova Scotia Power, in NSUARB NSPI P-893 (2012) provided a working copy of its COSS in response to discovery.
- In its most recent four rate cases before the Utah PSC (Dockets Nos. 07-035-93, 08-035-38, 09-035-23, 11-035-200), Rocky Mountain Power (the Utah subsidiary of PacifiCorp) provided a working copy of its COSS model (both interstate and intrastate), training sessions, and all other exhibits and information responses in Word and Excel.
- Berkshire Gas Company, in Massachusetts DTE Docket No. 01-56 (2001), and Columbia Gas, in Maryland PSC Case No. 9159 (2008/2009), also provided a working copy of the COSS, exhibits, tables and information responses in Excel.
- Baltimore Gas & Electric, in Maryland PSC Case No. 9036 (2005), provided its COS study in Excel format, but without formulas. In its most recent rate proceeding, BG&E provided multiple gas and electric COS studies with all functions operating, including macros.

Q: What was the basis of Manitoba Hydro's refusal to provide marginal-cost documentation?

A: Hydro refused to provide document its marginal-cost estimates on the following grounds:

- The estimates were based on commercially sensitive information, in particular, the expected value of electricity exports (CAC-GAC I-4b, PUB/MH I-107),
- Marginal-cost estimates are relevant only to the Cost-of-Service Study (responses to GAC/MH I-1(a-j), I-2(a-c) and I-2(f-g)).

Q: Do utilities generally release the derivation of their estimates of marginal (or avoided) costs?

A: Yes. I cannot recall a similar situation in which a utility has so broadly refused to document its estimates of avoided costs.[1]

In New England, the regional avoided costs (excluding losses and T&D, which are added by individual utilities) are derived in a collaborative process (for which I have been one of the consultants in three of the five biennial rounds) of the electric and gas utilities, consumer representatives, environmental advocates, and regulators.[2] This work shows detailed avoided-cost projections.

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[1]In some cases, utilities will request protected status for certain inputs, such as detailed forecasts of market prices, releasing that information only to parties who are not engaged in power trading. In more than 20 years of reviewing avoided-cost estimates, I cannot recall a situation in which the utility has refused to even break out generation energy and capacity costs, transmission costs, distribution costs, and losses.

[2]Most recently: Hornby, Rick, Paul Chernick, Carl Swanson, David White, Ian Goodman, Bob Grace, Bruce Biewald, Chris James, Ben Warfield, Jason Gifford, and Max Chang. 2009. "Avoided Energy Supply Costs in New England: 2009 Report." Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid. This report provides detailed avoided-cost projections.

Similar details on the derivation of avoided costs in California, developed through a public process of comments and workshops, are described at www.ethree.com/cpuc_avoidedcosts.html.

Forecasts of avoided costs, and their derivation, have been publicly available since the early 1980s, when they were used to value non-utility generation.

Q: Are marginal costs exclusively or primarily relevant to the COSS?

A: No. The COSS allocates embedded costs. Other than the use of market-based prices in the allocation of energy costs across time periods, the COSS does not appear to use any marginal-cost data.

In contrast, marginal costs are integral and vital to the evaluation of DSM, including fuel-switching, and in rate design.

IV. Estimate of Marginal Costs for Rate Design, Demand-Side Management, and Fuel-Switching

Q: Why are marginal costs important for Hydro's planning and ratemaking?

A: Marginal costs indicate the value of load reductions and the cost of load increases. Those values are important in both the evaluation of DSM and fuel-switching options and the design of rates (e.g., using marginal costs to set the tail block of an inclining block rate).

Q: Would marginal generation cost estimates based on projected MISO spot prices be a reasonable basis for planning and ratemaking?

A: No. MISO spot prices are for opportunity (or interruptible) energy only. Opportunity cost does not generally cover the cost of generation plant investment, let alone transmission, distribution, and environmental costs.

Domestic customers, on the other hand, receive firm service. The marginal generation cost of firm service includes firm capacity and other costs of firming supply.

A. *Estimate of Marginal Generation and Transmission & Distribution Costs*

Q: Has Hydro provided its estimate of long-run marginal cost?

A: Yes. For evaluation of DSM, Hydro estimates long-run marginal cost to be 8.52 cents per kWh (in 2011 dollars). This estimate consists of the following cost components, all in 2011 dollars:

- a 30-year levelized cost of 7.11 cents per kWh at the distribution level (CAC-GAC/MH I-4b).
- a marginal transmission cost of 0.69 cents per kWh (based on a marginal value of $60.46/kW/year divided over 8,766 hours) (GAC/MH II-23c).
- a marginal distribution cost of 0.73 cents per kWh (based on a marginal value of $63.83/kW/year divided over 8,766 hours (GAC/MH II-23c).[3]

Q: How did Manitoba Hydro derive this estimate of marginal generation cost?

A: In the 2010/11 GRA, Hydro explained that it used a production-costing model "to simulate the operation of its reservoir and generating facilities" (2010/11 GRA RCM/TREE/MH II-4b(iii)). It ran this model under 94 possible flow conditions

[3] Hydro's conversion of the marginal transmission and distribution costs into cents-per-kWh terms implicitly assumes a flat load, with a 100% load factor. That load shape is not representative of most end uses, and certainly not of the average end uses for which Hydro's load forecast projects a 62% load factor (Appendix 8.1, Table 25). The average load factor for the classes using distribution is probably still lower. Computing the avoided costs for the average system load factor produces avoided transmission costs of 1.11¢/kWh and avoided distribution costs of 1.18¢/kWh.

> to determine the value of the small increment of energy and capacity. This value is dependent on the mix of thermal and import energy and the quantity of export energy associated with each of the flow conditions. In low flow conditions, the marginal benefit is derived from the displacement of high-cost thermal and import energy, while in median to high flow conditions the benefit is derived primarily from new export sales. Benefits may be very small or even nonexistent in extremely high flows when tie-lines may be saturated and reservoirs filled to capacity.

In other words, the estimate of marginal generation costs largely depends on Hydro's forecast of future export sales, for which Hydro has refused to provide any detailed documentation:

> The detailed spreadsheets used in deriving the marginal cost contain the expected value of electricity exports which is commercially sensitive. Therefore, Manitoba Hydro respectfully declines to provide the requested information. (GAC/MH II-25a)

Q: Can you review Hydro's rates and its evaluation of DSM measures and fuel switching without this information?

A: No.

Q: What was the basis of the marginal T&D cost estimates?

A: According to Manitoba Hydro, the estimates were "based on the same methodology" used in the September 23, 2004 analysis entitled "Marginal Transmission and Distribution Cost Estimates. SPD 04/05" (GAC/MH II-23a; Appendix 35). In this 2004 analysis, Hydro applied a One-Year Deferral Method to the most recent (at the time of the report) ten-year forecast of capital expenditures for the period 2003/04 through 2013/14.

Q: Did you identify problems with the 2004 methodology?

A: Yes. I identified the following four flaws in the analysis of costs per kW-year:

- It eliminated the costs of the transmission and subtransmission projects that were already underway or committed, but did not subtract out the load growth served by these investments.
- It excluded overhead transformers as customer-related and unavoidable by DSM (Appendix 35 at 17, fn. 8). This treatment is inconsistent with the Company's classification of this equipment in its COS Study.
- It excluded operation and maintenance costs, failing to recognize that the O&M associated with load-related projects is also load-related (GAC/MH II-23b).
- The analysis incorrectly considered the Roblin South Station 230-KV Reactor project to be 0% demand-related (Appendix 35, Table B.4). Reactors should be included as 100% load-related, because they are required to prevent the overloading of lines by the combination of real and reactive power.

In the 2004 analysis, there may have been other projects that Hydro classified as 100% customer-related, which were due to the overloading or premature aging of existing equipment, and therefore demand-related. However, there was not enough detail in the 2004 report to identify the cause of "poor conditions," "operating and maintenance concerns," and "deficiencies."

Q: Were you able to check whether your criticisms still applied to Hydro's current estimate of marginal T&D costs?

A: No. Manitoba Hydro provided no documentation other than the 2004 report. However, since Hydro claims to have used the same "methodology," it is reasonable to expect that its analysis has the same sort of problems.

B. Estimate of Transmission & Distribution Losses

Q: Did Manitoba Hydro apply marginal loss factors in computing all marginal cost components?

A: No. The transmission and distribution marginal cost estimates do not include line losses. The Company included line losses only in the marginal generation cost component. (GAC/MH II-27b).

Q: What is Hydro's estimate of the distribution loss factors for various classes?

A: Manitoba Hydro (PCOSS13, Appendix 13.1 at 64, 65) makes the following assumptions:

- average distribution energy losses of 5.56%,
- peak distribution losses of 7.01%,
- peak transmission losses of 8.8%,[4]
- average transmission energy losses of 9.6%.[5]

Hydro further disaggregates the distribution energy and peak demand losses as shown in Table 1. The sales-weighted average of these losses matches Hydro's estimate of average losses.

[4] I computed this loss factor as the difference between generation and common bus losses.

[5] Peak percentage losses are usually greater at peak than for energy over the year (at a lower average load), since losses in conductors vary with the square of current. Hydro's percentage transmission losses may be lower at peak loads than for energy due to the fixed losses of the AC-DC converter stations, which are spread over more load at peak than in the average hour. Alternatively, some of Hydro's loss estimates may be inconsistent or incorrect.

Table 1: Manitoba Hydro Estimates of Distribution Losses

Class	Distribution Energy Losses	Distribution Peak Losses
Residential	6.7%	8.1%
GS Small—Single Phase	6.7%	8.1%
GS Small—Three Phase	5.0%	6.0%
GS Medium	5.0%	6.0%
GS Large (less than 30 kV)	4.1%	4.8%
GS Large 30–100 kV	1.5%	1.9%
GS Large (greater than 100 kV)	—%	—%

Source: PCOSS13 Appendix 13.1 at 68

Note that all of these loss estimates are for average, rather than marginal, deliveries. In other words, they represent Hydro's estimate of total losses in an hour, divided by total deliveries in the hour, rather than the marginal losses of the marginal megawatt-hour delivered. Marginal distribution losses would be considerably greater than these average losses.[6]

C. *Estimate of Marginal Cost by Rate Class*

Q: Has Hydro provided estimates of total marginal cost for each rate class?

A: No.

Q: What are your best estimates of marginal costs, including firm generation supply?

A: I used the sum of the following marginal costs:

- Hydro's estimate of marginal generation costs of 6.2 cents per kWh at the generation level, plus transmission energy losses of 9.6% and distribution energy losses for the class from Table 1,

[6] The situation for transmission is more complex, and depends on the mix of fixed losses (from transformer cores and AC-DC converters) and variable losses (from lines), as well as the differing generation patterns at various load levels.

- a marginal transmission cost of 1.11 cents per kWh, plus peak transmission losses of 8.8% and peak distribution losses for the class from Table 1,
- a marginal distribution cost of 1.18 cents per kWh, plus peak losses as for transmission.[7]

The results of these computations are set forth in Table 2.

Table 2: Marginal Cost (in cents per kWh) by Rate Schedule

Rate Schedule	Generation	Transmission	Distribution	Total
Residential	7.3	1.3	1.4	9.9
GS Small, Non-Demand	7.3	1.3	1.4	9.9
GS Small, Demand-metered	7.1	1.3	1.0	9.4
GS Medium	7.1	1.3	1.0	9.4
GS Large (less than 30Kv)	7.1	1.3	0.8	9.2
GS Large (30–100Kv)	6.9	1.2	0.3	8.4
GS Large (more than 100kV)	6.8	1.2	—	8.0

Marginal costs vary among classes, end uses (like electric space heating and water heating) and DSM measures, depending particularly on energy load shapes and load factors.[8] Since Hydro estimates the marginal energy cost for a constant load over all hours, rather than for a typical retail load shape, the marginal energy costs provided in Table 2 are somewhat understated for rate-design purposes.

[7] The marginal T&D costs at an average system load factor are derived in footnote 3.

[8] Unlike marginal costs for rate-design purposes, which end at the customer meter, avoided resource costs include costs all the way to the end use, which is almost always at secondary voltage. Customers metered at primary or transmission voltage will pay the energy rate for their actual usage plus losses on their side of the meter. In other words, the rate-design marginal utility costs include losses to the meter, but the system-wide (or society-wide) avoided costs include the losses to end use. Hence, even for customers metered at primary or transmission voltage, losses and avoided T&D should be computed to secondary distribution.

Q: Do these direct costs include all the costs of domestic consumption of electricity?

A: No. Reducing domestic sales either increases exports, reduces purchases, or reduces Manitoba Hydro's thermal generation. Any of these effects will reduce emissions of conventional pollutants—various combinations of particulates, SO_2, and NO_X, depending on the thermal units turned down—and CO_2. The costs of some of the conventional pollutants are internalized for U.S. utilities through cap-and-trade systems, but the costs of greenhouse gases are currently not internalized. The total social cost of domestic consumption of electricity is thus greater than the direct costs above.

Q: What is the significance of these results for rate design?

A: Hydro's marginal costs exceed proposed tail-block energy rates for all classes, even without including any environmental costs; see Table 3.

Table 3: Comparison of Energy Rates to Hydro's Estimates of Marginal Costs

	Tail-Block Charges (cents per kWh)		**Marginal Cost**
	Interim	*2013/14*	
Residential	6.94	7.202	9.9
GS Small, Non-Demand	3.34	3.538	9.9
GS Small, Demand	3.34	3.538	9.4
GS Medium	3.34	3.538	9.4
GS Large, Greater Than 30 kV	3.14	3.311	9.2
GS Large, 30–100 kV	2.92	3.068	8.4
GS Large, Less Than 100 kV	2.83	2.963	8.0

Thus, inclining-block rates and reduced demand and customer charges are needed to provide customers with appropriate marginal price signals.

D. *Estimate of Environmental Costs*

Q: How did Manitoba Hydro treat environmental costs in its DSM valuation?

A: Hydro includes "the value of reduced greenhouse gas emissions (GHGs)" for conservation of natural gas, but does not include any environmental value for conservation of electricity. (Appendix 7.1, Appendix F, at 4) As Hydro explained in the 2010 GRA proceeding, the Company assumes that emissions costs are reflected in the export prices on which its marginal cost estimates are based:

> The avoided GHG and other emissions are implicitly valued in the determination of marginal cost because the forecast of export prices includes consideration of potential environmental costs that may be associated with electricity production in Manitoba Hydro's export markets. (2010 GRA, RCM/TREE/MH II-4 (b)(vii))

Q: Is it reasonable to assume that the sales prices for Hydro's exports reflect the value of carbon emissions?

A: No. Hydro notes (Appendix 26 at 22) that in a 2010 report the "Western Climate Initiative (WCI) projects carbon market abatement costs to reach $33/tonne CO_2e by 2020." Since Hydro's major export customers in Minnesota and Wisconsin are not covered by the WCI (which currently includes only California and four provinces, and never included any state in the Eastern Interconnection that would be a potential customer for Hydro's exports), it is not reasonable to assume that the projected WCI price is embedded in the prices paid by utilities in the Eastern Interconnection.

Q: How did Manitoba Hydro treat environmental costs in its fuel-switching analysis?

A: Hydro estimated the effect of fuel-switching on greenhouse gas emissions, but excluded that effect from its cost-benefit analyses.

> The value of reduced greenhouse gas emissions (GHGs) is not included in this analysis. At this time, there is no monetary value resulting from reduced greenhouse gas emissions under existing policies. (Appendix 26 at 19)

In other words, the fuel-switching analysis is entirely a financial analysis, without any valuation of environmental effects.

Q: Has Hydro provided an estimate of the value of reducing CO_2 emissions?

A: Not explicitly. The reference to the \$33/tonne CO_2e by 2020 in the fuel-switching report (Appendix 26 at 22) may be a hint as to the value that Hydro would apply in some situations.[9]

Q: What generation source does Hydro assume its exports to MISO will displace?

A: In the fuel-switching report, Hydro says:

> The marginal generation in MISO is fossil fuel based (primarily coal). The average of emission factors for additional units of generation needed or avoided due to changing Manitoba electricity exports has been conservatively estimated at approximately 750 kg CO_2e/MWh. (Appendix 26 at 21)

Q: Is this a reasonable estimate?

A: Yes. The major sources of marginal energy in MISO are coal (at about 900 kg CO_2e/MWh), combined-cycle gas (at about 350 kg/MWh) and gas-fired combustion turbines (about 500 kg/MWh).

Even in 2011, with very low gas prices, the combined-cycle plants in MISO mostly operated at capacity factors in the 30%–50% range. Consequently some gas would have been at the margin about half the time. Since some of the gas plants would operate to provide local support in load pockets, Hydro's exports may back down a rural coal plant even when an urban combined-cycle plant is

[9] Reviewing Hydro's analysis, for both intervenors and the Board, would be easier if we had clear statements of Hydro's positions and did not need to rely on hints.

operating. Over time, rising gas prices will tend to reduce the share of marginal energy that comes from the gas plants, while retirement of coal plants will tend to increase the marginal gas percentage. Overall, Hydro's estimate of 750-kg of CO_2 per MWh is reasonable for baseload, around-the-clock sales.

Sales limited to the peak periods (e.g., 16 hours daily) would tend to avoid more gas and less coal. Without knowing anything about the terms of the pending sales contracts, I cannot provide any additional information on the mix associated with the contracts.

Q: You have discussed the avoided emissions from existing MISO generation. Would the avoided emissions be similar if Hydro's export contracts avoid new generation?

A: The avoided emissions would be similar, but a little lower. New generation in Minnesota or Wisconsin would be primarily gas combined-cycle or combustion turbine. Those new units would operate similarly to the existing ones, and the mix of energy avoided by the contracts would be similar. For example, suppose that a Minnesota utility purchases 300 MW at a 70% capacity factor from Manitoba Hydro and defers a 300-MW combined-cycle plant that would otherwise have operated at a 40% capacity factor. The 1,850 GWh of annual hydro energy would result in the combined-cycle not being built or run, reducing generation from that unit by about 1,050 GWh. In the 30% of the year in which (1) Hydro provides 700 GWh but (2) the combined-cycle would not have run, the marginal resource would be primarily coal. Thus, the avoided energy mix would be about 57% gas (1,050 ÷ 1,850) and 43% coal, for an avoided emission rate of about 600 kg of CO_2 per MWh.

The mix avoided would vary with the future system mix in MISO, and the relative prices of gas and coal. The effect of Hydro exports avoiding a new gas-fired plant would be essentially the same, whether the gas-fired plant is being added to meet load growth or to replace retiring coal capacity.

Q: Would the emission effects be similar if the contract facilitates the retirement of an existing coal unit?

A: No. In that case, the avoided output would be essentially all coal, and the avoided emissions would be on the order of 900 kg of CO_2 per MWh.

E. Hydro's Utilization of Marginal Costs

Q: In what areas does Hydro use marginal costs?

A: Hydro employs some version of marginal costs to some extent in rate design, DSM planning and evaluation, and analysis of fuel-switching options. The Board has deferred the utilization of marginal costs in rate design to a subsequent process. I discuss the results of Hydro's application of marginal costs to evaluation of fuel-switching in §V. While Hydro does not provide enough detail to allow for a full review of its fuel-switching analysis, corrections to Hydro's marginal costs are likely to increase the estimated advantages of natural-gas over electric end uses.

Q: How does Hydro use marginal costs in screening DSM options?

A: Hydro says that it considers a range of metrics, many of which have no relevance to cost-effectiveness. Hydro describes its approach as follows:

> Manitoba Hydro uses a number of tests to assess energy-efficiency opportunities. The results of these tests are used to determine whether to pursue an opportunity, how aggressively to pursue an opportunity, the effectiveness of program design options and the relative investment between ratepayers (via utility incentives and other costs) and participants. In addition to quantitative assessments, Manitoba Hydro also considers various qualitative factors, including equity (i.e. reasonable participation by various ratepayer sectors such as lower income) and overall contribution toward having a balanced energy conservation strategy and plan. (CAC-GAC/MH I-6a)

In other words, Hydro makes its decisions based on a set of contradictory and often irrelevant tests. The same response references Appendix F of the 2011 Power Smart Plan (Appendix 7.1) "for details of the cost effectiveness tests used to assess opportunities." That document lists the following tests:

- Marginal Resource Cost ("MRC") test (a rough cut at the Total Resource Cost Test, without program costs),
- Total Resource Cost ("TRC") test,
- Societal Cost Test ("SC") test,
- Rate Impact Measure ("RIM") test;
- Levelized Utility Cost ("LUC") test,
- Simple Customer Payback calculation.

The RIM, LUC, and customer-payback calculation are not cost-benefit tests and should not be considered in making any of the choices that Hydro lists in CAC-GAC/MH I-6a. To make matters worse, Hydro explains that it does not even give equal weighting to the real cost-benefit tests, as follows:

> Manitoba Hydro prefers using the Levelized Utility Cost as it provides a specific cost on a per unit of energy basis; however, all tests are used in aggregate in determining which opportunities to pursue and which program design is best suited to meeting the Corporation's energy conservation efforts. (CAC-GAC/MH I-6a)

The Levelized Utility Cost test is the ratio of Hydro's expenditures to the energy savings. Consequently this test

- treats incentives paid to customers as costs, but ignores both the benefit of those incentives to customers and the other costs incurred by customers;
- ignores marginal generation, transmission and distribution costs;
- ignores all benefits to participating customers;
- ignores avoided gas and water costs;

- ignores the timing and shape of the savings (e.g., on-peak versus off-peak, shoulder months versus the peak winter and high-priced summer months);
- ignores all externalities;
- computes a ratio of utility costs to energy savings, rather than the net benefit, so saving a little energy for 1¢/kWh looks better than saving twenty times as much for 2¢/kWh.

Thus, using Hydro's preferred test will bias choices towards low-cost superficial measures, away from comprehensive high-value savings.

Q: How should Hydro be screening DSM?

A: Hydro should be maximizing the net benefits to its power consumers and the Province in general. This calculation would include all of the following benefits:

- avoided utility generation, transmission and distribution costs,
- revenues from off-system sales,
- capital and operating cost savings to participating customers (or to the Province, where prices do not equal cost, such as for regulated gas and water supply),
- quantifiable non-financial benefits to participants (e.g., reduced illness, noise pollution),

and all of the following costs:

- quantifiable externalities, especially environmental effects,
- the costs of the measures and program implementation.

Depending on the range of benefits included, this approach is referred to as the Total Resource Cost (TRC) Test or the Societal Test.

Q: How do Hydro's estimates of marginal costs and its choice of screening tests affect its planned DSM savings?

A: Since Hydro does not explain its decisions regarding DSM in any detail, it is impossible to determine exactly how these factors influence Hydro's planning. From its projections, Hydro appears to be reluctant to pursue efficiency opportunities aggressively. However, planning DSM based on minimizing total costs and using full marginal costs would almost certainly produce much greater savings and lower total costs to Manitoba power consumers.

Q: What did you conclude in your review of Hydro's DSM plans in the 2010–2012 rate proceeding?

A: I noted that Hydro was projecting steep declines in its energy-efficiency achievements, for which it had no adequate explanation. In addition, it appeared that Hydro was not pursuing energy-efficiency opportunities that it knew met the Total Resource Cost test, due to implicit non-TRC screens.

Q: Did the Board comment on that issue in the order in that proceeding?

A: Yes. The final order included the following language:

> The Board shares the view that the current screening process may be resulting in some opportunities being missed. The Board would like to see expanded program delivery to assist in conservation. (PUB Order 5/12, p. 163)

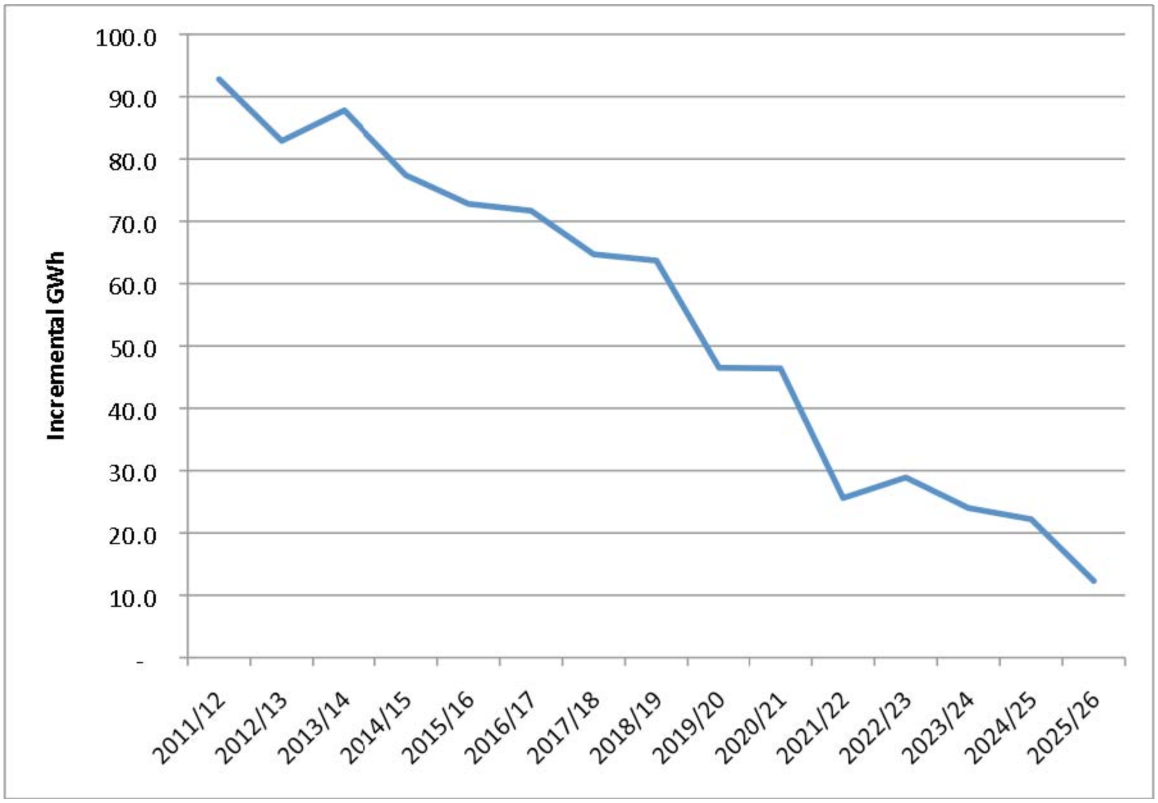
Q: Has Hydro committed to increased DSM efforts?

A: No. Hydro once again projects precipitous declines in its DSM efforts and annual incremental savings.

Q: What are Manitoba's projected energy savings?

A: According to Hydro's 2011 PowerSmart Plan (Appendix 7.1), Hydro expects to reduce its annual energy savings by about 85% from 2011/12 to 2025/26. See Figure 1 below.

Figure 1: Manitoba Hydro's Planned DSM Conservation Savings



Source: 2011 Power Smart Plan, Appendix 7.1, Appendix A.3

Q: How do the Company's savings compare to those of other energy-efficiency programs in North America?

A: Even in the near term, Hydro's savings plans are modest compared to those of many other North American jurisdictions. Philippe Dunsky compares Hydro's performance with that of other DSM programs in his testimony on behalf of the Green Action Centre and CAC Manitoba.

Hydro's low DSM savings are directly related to its low spending levels. For its size, Hydro spends much less on DSM than about 20 North American jurisdictions, including many (e.g., all six New England states, California, New York, New Jersey, Hawaii, and Nova Scotia) with much higher retail rates. Manitoba's low retail rates would generally require higher utility incentives to achieve paybacks attractive to participants. Hydro's projected spending rates would put it much lower in the rankings.

Q: Would Hydro's screening of DSM tend to lead to the spending and savings trends in Hydro's plans?

A: Yes. The RIM test and Hydro's preferred LUC test would both discourage Hydro from spending on DSM, resulting in low savings projections.

Q: What are the benefits of implementation of enhanced DSM programs?

A: Enhancing DSM programs would reduce bills for Manitoba consumers, increase export revenues, reduce greenhouse gas emissions and other pollution, and reduce the drought risk to Manitoba Hydro.

V. Hydro's Fuel-Switching Report

Q: What specific issues does your testimony address concerning Hydro's fuel-switching study?

A: I address the adequacy of the documentation of Hydro's analysis and the implications of the study for Hydro's system: its load growth, environmental emissions, supply and DSM planning, and rate-design policies.

Q: What is the scope of the fuel-switching study?

A: The study examines only the economics of fuel choice in single-family residential homes. Hydro defines fuel switching as including

> Customers in existing homes who replace their natural gas space and water heating equipment with electric equipment when it reaches the end of its life; [and] Customers (or homebuilders) building new homes who build where natural gas service is available, but instead choose to install electric heating equipment. (Appendix 26 at 13)

The analysis considers (in various levels of detail) choices among four options for space heating—electric resistance (furnace or baseboard), ground-source heat pump with a 2.5 seasonal coefficient of performance, or a high-efficiency gas furnace—and five options for water heating—electric resistance and desuperheater units and natural-gas side vent, natural-vent, and tankless units.[10]

Q: What are the conclusions of Manitoba Hydro's fuel-switching report?

A: The study concludes that switching to electricity for space and water heating has consistently adverse impacts from the perspective of customer, utility, provincial leakage, and global environment. Specifically, Hydro finds that choosing electric resistance or geothermal heat pump over a gas furnace, or an electric water heater over a gas water heater, increases the costs to the customer, to electric customers as a whole, to other gas customers. The Company further concludes that such fuel switching increases carbon emissions and (with the possible exception of the heat pump), the net cash flow out of Manitoba (Appendix 26 at 37). Selecting electricity over gas, at least for the applications considered by Hydro, would be undesirable by every measure.

Despite these negative results, the study forecasts significant replacement of gas water heat and space heat with electricity.

> Virtually 100% of the new home market is installing electric water heaters. A small shift towards the increased use of electricity for space heating is expected…. (Appendix 26 at 4)

By 2030/31, the "small shift" consists of 48,000 residential space-heating switches (about 9% of residential customers), 146,000 residential water-heating switches (about 26% of residential customers).[11] Hydro forecasts that 874 GWh, or about 11% of the 8,000 GWh growth in Net Firm Energy requirements from 2011/12 to 2020/31, will be due to fuel switching from natural gas to electricity (Appendix 26 at 27).

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[10]The report mentions hydronic heating once, but provides no analysis.

[11]Hydro also projects 920 switches of both space and water heating by commercial customers, although the projected size of the switched loads are not clear.

Q: What is Hydro's explanation for its prediction that customers would select electricity in so many situations in which it is uneconomic?

A: Hydro does not explain that pattern in any detail, but does suggest that, for new homes, developers have adverse incentives to install electric space and water heating, because (1) electric equipment is less expensive and (2) the developer can charge buyers the same price for the cheaper, inferior electric system or the superior gas system (GAC/MH II-6(c)).

Hydro lists the market distortions that may lead customers to the globally worse and more expensive solution as follows:

> Customer choice may be influenced by a variety of factors which may impact a customer's decision on fuel use for water/space heating, including the customer's expectations with regards to future prices for electricity and natural gas, estimated or quoted capital cost of implementing the options, expected maintenance costs, and a customer's values related to the environmental impacts of the decision. Further, a customer may not make a decision based on an economic assessment over the life of the system (e.g. the customer may be considering moving and therefore may not expect to realize the payback of an investment). (GAC/MH II-16a)

In other words, the customer may not have adequate information on price forecasts, maintenance costs, effect on resale value, or the environmental effects of the fuel choice. He or she may face financial constraints; be gouged or misled by vendors or contractors; and have a short planning horizon.

Q: What is your response to Hydro's fuel-switching report?

A: My review of the report has been limited by the limited level of detail in Appendix 26 and the fact that Hydro has not yet provided its computations supporting the report (e.g., Hydro has not responded to GAC/MH II-3). On its face, the report clearly indicates a serious market problem, which should be addressed through a combination of rate design, DSM programing, and terms and conditions for new and expanded service.

Q: How could rate design address the market failure in space- and water-heating fuel choice?

A: The tendency for customers to make choices that increase emissions as well as costs to the Province as a whole can be reduced by implementation of inclining block rates, especially in the winter heating season. That issue should be taken up in the subsequent rate-design process, which should also consider options for mitigating the burden on low-income customers, providing interim protection for existing heating customers, and ensuring that programs are available to facilitate switching from electricity to natural gas as customers come to recognize that gas heating and water heating are preferable.

Q: How could DSM programs address the market failure in space- and water-heating fuel choice?

A: All of the market problems that Hydro identified as contributing to sub-optimal customer choices can be substantially overcome by utility programs that provide better information, rely on trustworthy vendors with appropriate incentives, pay an adequate share of capital cost and offer low-cost on-bill financing transferable to future residents.

Q: How could Hydro's terms and conditions address the market failure in space- and water-heating fuel choice?

A: To the extent possible, developers of electrically heated homes should pay connection fees that reflect the costs imposed by the installation of electric heat on homebuyers and the province. Higher connection fees would discourage developers from selecting electric heat.

Lower charges to developers for gas connections might have a similar effect.

Hydro's terms and conditions should be reviewed as part of the rate-design phase of this proceeding, to identify opportunities for discouraging uneconomic fuel choice by developers.

VI. Recommendations

Q: What are your recommendations to the Board on the reviewability issue?

A: I recommend the following:

- First, the Board should request comments from Hydro and intervenors on additional documents that should be included in GRA filing requirements.
- The Board should require that the final rates and all studies and reports to be reviewed in the GRA proceeding be filed at the time of the Company's GRA request, so that these components of the case are subject to full review.
- The Board should require that Hydro file its proof-of-revenue tables, bill comparisons, COS studies and marginal cost studies as Excel spreadsheets with all formulas intact.
- The Board should set up a procedure to make confidential information accessible to intervenors.
- The Board should instruct the Company to provide responses to requests for data, assumptions, and calculations.

Q: Please summarize your recommendations to the Board on the estimation and application of marginal costs.

A: I recommend that the Board require that Hydro improve the transparency and reviewability of its estimates of generation, transmission and distribution costs, including the time-differentiation of costs. In addition, Hydro should prepare a new analysis of marginal distribution costs, including all load-related avoidable costs.

I also recommend that the Board order Hydro to document exactly how it applies its estimates of marginal costs in its DSM screening tests, to use the TRC test as the primary cost-effectiveness test, and to justify any DSM programming decisions that deviate from the TRC results.

Q: Please summarize your recommendations to the Board on fuel-switching issues.

A: Hydro's fuel-switching report indicates a serious market problem, which should be addressed through a combination of rate design, DSM programing and terms and conditions for new and expanded service.

Q: Does this conclude your testimony?

A: Yes, at this time. Since Hydro filed portions of its direct case late and provided late responses to so much discovery, I have not reviewed all the responses fully and may need to supplement this testimony at a later date.