Exhibit JFW-1

Qualifications of

JONATHAN F. WALLACH

Resource Insight, Inc.
5 Water Street
Arlington, Massachusetts 02476

SUMMARY OF PROFESSIONAL EXPERIENCE

1990–Present **Vice President, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, regulation, and restructuring. Designs and assesses resource-planning strategies for regulated and competitive markets, including estimation of market prices and utility-plant stranded investment; negotiates restructuring strategies and implementation plans; assists in procurement of retail power supply.

1989–90 **Senior Analyst, Komanoff Energy Associates.** Conducted comprehensive cost-benefit assessments of electric-utility power-supply and demand-side conservation resources, economic and financial analyses of independent power facilities, and analyses of utility-system excess capacity and reliability. Provided expert testimony on statistical analysis of U.S. nuclear plant operating costs and performance. Co-wrote *The Power Analyst*, software developed under contract to the New York Energy Research and Development Authority for screening the economic and financial performance of non-utility power projects.

1987–88 **Independent Consultant.** Provided consulting services for Komanoff Energy Associates (New York, New York), Schlissel Engineering Associates (Belmont, Massachusetts), and Energy Systems Research Group (Boston, Massachusetts).

1981–86 **Research Associate, Energy Systems Research Group.** Performed analyses of electric utility power supply planning scenarios. Involved in analysis and design of electric and water utility conservation programs. Developed statistical analysis of U.S. nuclear plant operating costs and performance.

EDUCATION

BA, Political Science with honors and Phi Beta Kappa, University of California, Berkeley, 1980.

Massachusetts Institute of Technology, Cambridge, Massachusetts. Physics and Political Science, 1976–1979.

PUBLICATIONS

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distributed Utilities" (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (460–469). Cleveland, Ohio: USAEE. 1996.

"The Price is Right: Restructuring Gain from Market Valuation of Utility Generating Assets" (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (345–352). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distribution Utilities" (with Paul Chernick), *1996 Summer Study on Energy Efficiency in Buildings* 7(7.47–7.55). Washington: American Council for an Energy-Efficient Economy, 1996.

"Retrofit Economics 201: Correcting Common Errors in Demand-Side-Management Cost-Benefit Analysis" (with John Plunkett and Rachael Brailove). In proceedings of "Energy Modeling: Adapting to the New Competitive Operating Environment," conference sponsored by the Institute for Gas Technology in Atlanta in April of 1995. Des Plaines, Ill.: IGT, 1995.

"The Transfer Loss is All Transfer, No Loss" (with Paul Chernick), *Electricity Journal* 6:6 (July, 1993).

"Benefit-Cost Ratios Ignore Interclass Equity" (with Paul Chernick et al.), *DSM Quarterly*, Spring 1992.

"Consider Plant Heat Rate Fluctuations," *Independent Energy*, July/August 1991.

"Demand-Side Bidding: A Viable Least-Cost Resource Strategy" (with Paul Chernick and John Plunkett), *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

"New Tools on the Block: Evaluating Non-Utility Supply Opportunities With *The Power Analyst*, (with John Plunkett), *Proceedings of the Fourth National Conference on Micro-computer Applications in Energy*, April 1990.

REPORTS

"Green Resource Portfolios: Development, Integration, and Evaluation" (with Paul Chernick and Richard Mazzini) report to the Green Energy Coalition presented as evidence in Ontario EB 2007-0707.

"Risk Analysis of Procurement Strategies for Residential Standard Offer Service" (with Paul Chernick, David White, and Rick Hornby) report to Maryland Office of People's Counsel. 2008. Baltimore: Maryland Office of People's Counsel.

"Integrated Portfolio Management in a Restructured Supply Market" (with Paul Chernick, William Steinhurst, Tim Woolf, Anna Sommers, and Kenji Takahashi). 2006. Columbus, Ohio: Office of the Ohio Consumers' Counsel.

"First Year of SOS Procurement." 2004. Prepared for the Maryland Office of People's Counsel.

"Energy Plan for the City of New York" (with Paul Chernick, Susan Geller, Brian Tracey, Adam Auster, and Peter Lanzalotta). 2003. New York: New York City Economic Development Corporation.

"Peak-Shaving–Demand-Response Analysis: Load Shifting by Residential Customers" (with Brian Tracey). 2003. Barnstable, Mass.: Cape Light Compact.

"Electricity Market Design: Incentives for Efficient Bidding; Opportunities for Gaming." 2002. Silver Spring, Maryland: National Association of State Consumer Advocates.

"Best Practices in Market Monitoring: A Survey of Current ISO Activities and Recommendations for Effective Market Monitoring and Mitigation in Wholesale Electricity Markets" (with Paul Peterson, Bruce Biewald, Lucy Johnston, and Etienne Gonin). 2001. Prepared for the Maryland Office of People's Counsel, Pennsylvania Office of Consumer Advocate, Delaware Division of the Public Advocate, New Jersey Division of the Ratepayer Advocate, Office of the People's Counsel of the District of Columbia.

"Comments Regarding Retail Electricity Competition." 2001. Filed by the Maryland Office of People's Counsel in U.S. FTC Docket No. V010003.

"Final Comments of the City of New York on Con Edison's Generation Divestiture Plans and Petition." 1998. Filed by the City of New York in PSC Case No. 96-E-0897.

"Response Comments of the City of New York on Vertical Market Power." 1998. Filed by the City of New York in PSC Case Nos. 96-E-0900, 96-E-0098, 96-E-0099, 96-E-0891, 96-E-0897, 96-E-0909, and 96-E-0898.

"Preliminary Comments of the City of New York on Con Edison's Generation Divestiture Plan and Petition." 1998. Filed by the City of New York in PSC Case No. 96-E-0897.

"Maryland Office of People's Counsel's Comments in Response to the Applicants' June 5, 1998 Letter." 1998. Filed by the Maryland Office of People's Counsel in PSC Docket No. EC97-46-000.

"Economic Feasibility Analysis and Preliminary Business Plan for a Pennsylvania Consumer's Energy Cooperative" (with John Plunkett et al.). 1997. 3 vols. Philadelphia, Penn.: Energy Coordinating Agency of Philadelphia.

"Good Money After Bad" (with Charles Komanoff and Rachel Brailove). 1997. White Plains, N.Y.: Pace University School of Law Center for Environmental Studies.

"Maryland Office of People's Counsel's Comments on Staff Restructuring Report: Case No. 8738." 1997. Filed by the Maryland Office of People's Counsel in PSC Case No. 8738.

"Protest and Request for Hearing of Maryland Office of People's Counsel." 1997. Filed by the Maryland Office of People's Counsel in PSC Docket Nos. EC97-46-000, ER97-4050-000, and ER97-4051-000.

"Restructuring the Electric Utilities of Maryland: Protecting and Advancing Consumer Interests" (with Paul Chernick, Susan Geller, John Plunkett, Roger Colton, Peter Bradford, Bruce Biewald, and David Wise). 1997. Baltimore, Maryland: Maryland Office of People's Counsel.

"Comments of the New Hampshire Office of Consumer Advocate on Restructuring New Hampshire's Electric-Utility Industry" (with Bruce Biewald and Paul Chernick). 1996. Concord, N.H.: NH OCA.

"Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities" (with Paul Chernick, Susan Geller, Rachel Brailove, and Adam Auster). 1996. On behalf of the Massachusetts Attorney General (Boston).

"Report on Entergy's 1995 Integrated Resource Plan." 1996. On behalf of the Alliance for Affordable Energy (New Orleans).

"Preliminary Review of Entergy's 1995 Integrated Resource Plan." 1995. On behalf of the Alliance for Affordable Energy (New Orleans).

"Comments on NOPSI and LP&L's Motion to Modify Certain DSM Programs." 1995. On behalf of the Alliance for Affordable Energy (New Orleans).

"Demand-Side Management Technical Market Potential Progress Report." 1993. On behalf of the Legal Environmental Assistance Foundation (Tallahassee)

"Technical Information." 1993. Appendix to "Energy Efficiency Down to Details: A Response to the Director General of Electricity Supply's Request for Comments on Energy Efficiency Performance Standards" (UK). On behalf of the Foundation for International Environmental Law and Development and the Conservation Law Foundation (Boston).

"Integrating Demand Management into Utility Resource Planning: An Overview." 1993. Vol. 1 of "From Here to Efficiency: Securing Demand-Management Resources" (with Paul Chernick and John Plunkett). Harrisburg, Pa.:Pennsylvania Energy Office

"Making Efficient Markets." 1993. Vol. 2 of "From Here to Efficiency: Securing Demand-Management Resources" (with Paul Chernick and John Plunkett). Harrisburg, Pa.: Pennsylvania Energy Office.

"Analysis Findings, Conclusions, and Recommendations." 1992. Vol. 1 of "Correcting the Imbalance of Power: Report on Integrated Resource Planning for Ontario Hydro" (with Paul Chernick and John Plunkett).

"Demand-Management Programs: Targets and Strategies." 1992. Vol. 1 of "Building Ontario Hydro's Conservation Power Plant" (with John Plunkett, James Peters, and Blair Hamilton).

"Review of the Elizabethtown Gas Company's 1992 DSM Plan and the Demand-Side Management Rules" (with Paul Chernick, John Plunkett, James Peters, Susan Geller, Blair Hamilton, and Andrew Shapiro). 1992. Report to the New Jersey Department of Public Advocate.

"Comments of Public Interest Intervenors on the 1993–1994 Annual and Long-Range Demand-Side Management and Integrated Resource Plans of New York Electric Utilities" (with Ken Keating et al.) 1992.

"Review of Jersey Central Power & Light's 1992 DSM Plan and the Demand-Side Management Rules" (with Paul Chernick et al.). 1992. Report to the New Jersey Department of Public Advocate.

"Review of Rockland Electric Company's 1992 DSM Plan and the Demand-Side Management Rules" (with Paul Chernick et al.). 1992.

"Initial Review of Ontario Hydro's Demand-Supply Plan Update" (with David Argue et al.). 1992.

"Comments on the Utility Responses to Commission's November 27, 1990 Order and Proposed Revisions to the 1991–1992 Annual and Long Range Demand Side Management Plans" (with John Plunkett et al.). 1991.

"Comments on the 1991–1992 Annual and Long Range Demand-Side-Management Plans of the Major Electric Utilities" (with John Plunkett et al.). Filed in NY PSC Case No. 28223 in re New York utilities' DSM plans. 1990.

"Profitability Assessment of Packaged Cogeneration Systems in the New York City Area." 1989. Principal investigator.

"Statistical Analysis of U.S. Nuclear Plant Capacity Factors, Operation and Maintenance Costs, and Capital Additions." 1989.

"The Economics of Completing and Operating the Vogtle Generating Facility." 1985. ESRG Study No. 85-51A.

"Generating Plant Operating Performance Standards Report No. 2: Review of Nuclear Plant Capacity Factor Performance and Projections for the Palo Verde Nuclear Generating Facility." 1985. ESRG Study No. 85-22/2.

"Cost-Benefit Analysis of the Cancellation of Commonwealth Edison Company's Braidwood Nuclear Generating Station." 1984. ESRG Study No. 83-87.

"The Economics of Seabrook 1 from the Perspective of the Three Maine Co-owners." 1984. ESRG Study No. 84-38.

"An Evaluation of the Testimony and Exhibit (RCB-2) of Dr. Robert C. Bushnell Concerning the Capital Cost of Fermi 2." 1984. ESRG Study No. 84-30.

"Electric Rate Consequences of Cancellation of the Midland Nuclear Power Plant." 1984. ESRG Study No. 83-81.

"Power Planning in Kentucky: Assessing Issues and Choices—Project Summary Report to the Public Service Commission." 1984. ESRG Study No. 83-51.

"Electric Rate Consequences of Retiring the Robinson 2 Nuclear Plant." 1984. ESRG Study No. 83-10.

"Power Planning in Kentucky: Assessing Issues and Choices—Conservation as a Planning Option." 1983. ESRG Study No. 83-51/TR III.

"Electricity and Gas Savings from Expanded Public Service Electric and Gas Company Conservation Programs." 1983. ESRG Study No. 82-43/2.

"Long Island Without the Shoreham Power Plant: Electricity Cost and System Planning Consequences; Summary of Findings." 1983. ESRG Study No. 83-14S.

"Long Island Without the Shoreham Power Plant: Electricity Cost and System Planning Consequences; Technical Report B—Shoreham Operations and Costs." 1983. ESRG Study No. 83-14B.

"Customer Programs to Moderate Demand Growth on the Arizona Public Service Company System: Identifying Additional Cost-Effective Program Options." 1982. ESRG Study No. 82-14C.

"The Economics of Alternative Space and Water Heating Systems in New Construction in the Jersey Central Power and Light Service Area, A Report to the Public Advocate." 1982. ESRG Study No. 82-31.

"Review of the Kentucky-American Water Company Capacity Expansion Program, A Report to the Kentucky Public Service Commission." 1982. ESRG Study No. 82-45.

"Long Range Forecast of Sierra Pacific Power Company Electric Energy Requirements and Peak Demands, A Report to the Public Service Commission of Nevada." 1982. ESRG Study No. 81-42B.

"Utility Promotion of Residential Customer Conservation, A Report to Massachusetts Public Interest Research Group." 1981. ESRG Study No. 81-47

PRESENTATIONS

"Office of People's Counsel Case No. 9117" (with William Fields). Presentation to the Maryland Public Utilities Commission in Case No. 9117, December 2008.

"Electricity Market Design: Incentives for Efficient Bidding, Opportunities for Gaming." NASUCA Northeast Market Seminar, Albany, N.Y., February 2001.

"Direct Access Implementation: The California Experience." Presentation to the Maryland Restructuring Technical Implementation Group on behalf of the Maryland Office of People's Counsel. June 1998.

"Reflecting Market Expectations in Estimates of Stranded Costs," speaker, and workshop moderator of "Effectively Valuing Assets and Calculating Stranded Costs." Conference sponsored by International Business Communications, Washington, D.C., June 1997.

EXPERT TESTIMONY

1989 **Mass. DPU** on behalf of the Massachusetts Executive Office of Energy Resources. Docket No. 89-100. Joint testimony with Paul Chernick relating to statistical analysis of U.S. nuclear-plant capacity factors, operation and maintenance costs, and capital additions; and to projections of capacity factor, O&M, and capital additions for the Pilgrim nuclear plant.

1994 **NY PSC** on behalf of the Pace Energy Project, Natural Resources Defense Council, and Citizen's Advisory Panel. Case No. 93-E-1123. Joint testimony with John Plunkett critiques proposed modifications to Long Island Lighting Company's DSM programs from the perspective of least-cost-planning principles.

1994 **Vt. PSB** on behalf of the Vermont Department of Public Service. Docket No. 5270-CV-1 and 5270-CV-3. Testimony and rebuttal testimony discusses rate and bill effects from DSM spending and sponsors load shapes for measure- and program-screening analyses.

1996 **New Orleans City Council** on behalf of the Alliance for Affordable Energy. Docket Nos. UD-92-2A, UD-92-2B, and UD-95-1. Rates, charges, and integrated resource planning for Louisiana Power & Lights and New Orleans Public Service, Inc.

1996 **New Orleans City Council** Docket Nos. UD-92-2A, UD-92-2B, and UD-95-1. Rates, charges, and integrated resource planning for Louisiana Power & Lights and New Orleans Public Service, Inc.; Alliance for Affordable Energy. April, 1996.

Prudence of utilities' IRP decisions; costs of utilities' failure to follow City Council directives; possible cost disallowances and penalties; survey of penalties for similar failures in other jurisdictions.

1998 **Massachusetts Department of Telecommunications and Energy** Docket No. 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Paul Chernick, January, 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

Massachusetts Department of Telecommunications and Energy Docket No. 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Paul Chernick, October, 1998. Joint surrebuttal with Paul Chernick, January, 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

1999 **Maryland PSC** Case No. 8795, Delmarva Power & Light comprehensive restructuring agreement, Maryland Office of People's Counsel. July 1999.

Support of proposed comprehensive restructuring settlement agreement

Maryland PSC Case Nos. 8794 and 8808, Baltimore Gas & Electric Company comprehensive restructuring agreement, Maryland Office of People's Counsel. Initial Testimony July 1999; Reply Testimony August 1999; Surrebuttal Testimony August 1999.

Support of proposed comprehensive restructuring settlement agreement

Maryland PSC Case No. 8797, comprehensive restructuring agreement for Potomac Edison Company, Maryland Office of People's Counsel. October 1999.

Support of proposed comprehensive restructuring settlement agreement

Connecticut DPUC Docket No. 99-03-35, United Illuminating standard offer, Connecticut Office of Consumer Counsel. November 1999.

Reasonableness of proposed revisions to standard-offer-supply energy costs. Implications of revisions for other elements of proposed settlement.

2000 **U.S. FERC** Docket No. RT01-02-000, Order No. 2000 compliance filing, Joint Consumer Advocates intervenors. Affidavit, November 2000.

Evaluation of innovative rate proposal by PJM transmission owners.

2001 **Maryland PSC** Case No. 8852, Charges for electricity-supplier services for Potomac Electric Power Company, Maryland Office of People's Counsel. March 2001.

Reasonableness of proposed fees for electricity-supplier services.

Maryland PSC Case No. 8890, Merger of Potomac Electric Power Company and Delmarva Power and Light Company, Maryland Office of People's Counsel. September 2001; surrebuttal, October 2001. In support of settlement: Supplemental, December 2001; rejoinder, January 2002.

Costs and benefits to ratepayers. Assessment of public interest.

Maryland PSC Case No. 8796, Potomac Electric Power Company stranded costs and rates, Maryland Office of People's Counsel. December 2001; surrebuttal, February 2002.

Allocation of benefits from sale of generation assets and power-purchase contracts.

2002 **Maryland PSC** Case No. 8908, Maryland electric utilities' standard offer and supply procurement, Maryland Office of People's Counsel. Direct, November 2002; Rebuttal December 2002.

Benefits of proposed settlement to ratepayers. Standard-offer service. Procurement of supply.

2003 **Maryland PSC** Case No. 8980, adequacy of capacity in restructured electricity markets; Maryland Office of People's Counsel. Direct, December 2003; Reply December 2003.

Purpose of capacity-adequacy requirements. PJM capacity rules and practices. Implications of various restructuring proposals for system reliability.

2004 **Maryland PSC** Case No. 8995, Potomac Electric Power Company recovery of generation-related uncollectibles; Maryland Office of People's Counsel. Direct, March 2004; Supplemental March 2004, Surrebuttal April 2004.

Calculation and allocation of costs. Effect on administrative charge pursuant to settlement.

Maryland PSC Case No. 8994, Delmarva Power & Light recovery of generation-related uncollectibles; Maryland Office of People's Counsel. Direct, March 2004; Supplemental April 2004.

Calculation and allocation of costs. Effect on administrative charge pursuant to settlement.

Maryland PSC Case No. 8985, Southern Maryland Electric Coop standard-offer service; Maryland Office of People's Counsel. Direct, July 2004.

Reasonableness and risks of resource-procurement plan.

2005 **FERC** Docket No. ER05-428-000, revisions to ICAP demand curves; City of New York. Statement, March 2005.

Net-revenue offset to cost of new capacity. Winter-summer adjustment factor. Market power and in-City ICAP price trends.

FERC Docket No. PL05-7-000, capacity markets in PJM; Maryland Office of People's Counsel. Statement, June 2005.

Inefficiencies and risks associated with use of administratively determined demand curve. Incompatibility of four-year procurement plan with Maryland standard-offer service.

FERC Dockets Nos. ER05-1410-000 & EL05-148-000, proposed market-clearing mechanism for capacity markets in PJM; Coalition of Consumers for Reliability, Affidavit October 2005, Supplemental Affidavit October 2006.

Inefficiencies and risks associated with use of administratively determined demand curve. Effect of proposed reliability-pricing model on capacity costs.

2006 **Maryland PSC** Case No. 9052, Baltimore Gas & Electric rates and market-transition plan; Maryland Office of People's Counsel, February 2006.

Transition to market-based residential rates. Price volatility, bill complexity, and cost-deferral mechanisms.

Maryland PSC Case No. 9056, default service for commercial and industrial customers; Maryland Office of People's Counsel, April 2006.

Assessment of proposals to modify default service for commercial and industrial customers.

Maryland PSC Case No. 9054, merger of Constellation Energy Group and FPL Group; Maryland Office of People's Counsel, June 2006.

Assessment of effects and risks of proposed merger on ratepayers.

Illinois Commerce Commission Docket No. 06-0411, Commonwealth Edison Company residential rate plan; Citizens Utility Board, Cook County State's Attorney's Office, and City of Chicago, Direct July 2006, Reply August 2006.

Transition to market-based rates. Securitization of power costs. Rate of return on deferred assets.

Maryland PSC Case No. 9064, default service for residential and small commercial customers; Maryland Office of People's Counsel, Rebuttal Testimony, September 2006.

Procurement of standard-offer power. Structure and format of bidding. Risk and cost recovery.

FERC Dockets Nos. ER05-1410-000 & EL05-148-000, proposed market-clearing mechanism for capacity markets in PJM; Maryland Office of the People's Counsel, Supplemental Affidavit October 2006.

Distorting effects of proposed reliability-pricing model on clearing prices. Economically efficient alternative treatment.

Maryland PSC Case No. 9063, optimal structure of electric industry; Maryland Office of People's Counsel, Direct Testimony, October 2006; Rebuttal November 2006; surrebuttal November 2006.

Procurement of standard-offer power. Risk and gas-price volatility, and their effect on prices and market performance. Alternative procurement strategies.

Maryland PSC Case No. 9073, stranded costs from electric-industry restructuring; Maryland Office of People's Counsel, Direct Testimony, December 2006.

Review of estimates of stranded costs for Baltimore Gas & Electric.

2007 **Maryland PSC** Case No. 9091, rate-stabilization and market-transition plan for the Potomac Edison Company; Maryland Office of People's Counsel, Direct Testimony, March 2007.

Rate-stabilization plan.

Maryland PSC Case No. 9092, rates and rate mechanisms for the Potomac Electric Power Company; Maryland Office of People's Counsel, Direct Testimony, March 2007.

Cost allocation and rate design. Revenue decoupling mechanism.

Maryland PSC Case No. 9093, rates and rate mechanisms for Delmarva Power & Light; Maryland Office of People's Counsel, Direct Testimony, March 2007.

Cost allocation and rate design. Revenue decoupling mechanism.

Maryland PSC Case No. 9099, rate-stabilization plan for Baltimore Gas & Electric; Maryland Office of People's Counsel, Direct, March 2007; Surrebuttal April 2007.

Review of standard-offer-service-procurement plan. Rate stabilization plan.

Connecticut DPUC Docket No. 07-04-24, review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel, Joint Direct Testimony June 2007.

Assessment of proposed capacity contracts.

Maryland PSC Case No. 9117, residential and small-commercial standard-offer service; Maryland Office of People's Counsel. Direct and Reply, September 2007; Supplemental Reply, November 2007; Additional Reply, December 2007; presentation, December 2008.

Benefits of long-term planning and procurement. Proposed aggregation of customers.

Maryland PSC Case No. 9117, Phase II, residential and small-commercial standard-offer service; Maryland Office of People's Counsel. Direct, October 2007.

Energy efficiency as part of standard-offer-service planning and procurement. Procurement of generation or long-term contracts to meet reliability needs.

2008 **Connecticut DPUC 08-01-01**, peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Paul Chernick), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

Ontario EB-2007-0707, Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Paul Chernick and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

2009 **Maryland PSC** Case No. 9192, Delmarva Power & Lights rates; Maryland Office of People's Counsel. Direct, August 2009; Rebuttal, Surrebuttal, September 2009.

Cost allocation and rate design.

Wisconsin PSC Docket No. 6630-CE-302, Glacier Hills Wind Park certificate; Citizens Utility Board of Wisconsin. Direct and Surrebuttal, October 2009.

Reasonableness of proposed wind facility.

PUC of Ohio Case No 09-906-EL-SSO, standard-service-offer bidding for three Ohio electric companies; Office of the Ohio Consumers' Counsel. Direct, December 2009.

Design of auctions for SSO power supply. Implications of migration of First-Energy from MISO to PJM.

2010 **PUC of Ohio** Case No 10-388-EL-SSO, standard-service offer for three Ohio electric companies; Office of the Ohio Consumers' Counsel. Direct, July 2010.

Design of auctions for SSO power supply.

Maryland PSC Case No. 9232, Potomac Electric Power Co. administrative charge for standard-offer service; Maryland Office of People's Counsel. Reply, Rebuttal, August 2010.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Maryland PSC Case No. 9226, Delmarva Power & Light administrative charge for standard-offer service; Maryland Office of People's Counsel. Reply, Rebuttal, August 2010.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Maryland PSC Case No. 9221, Baltimore Gas & Electric cost recovery; Maryland Office of People's Counsel. Reply, August 2010; Rebuttal, September 2010; Surrebuttal, November 2010

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Wisconsin PSC Docket No. 3270-UR-117, Madison Gas & Electric gas and electric rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, Surrebuttal, September 2010.

Standby rate design. Treatment of uneconomic dispatch costs.

Nova Scotia UARB Case No. NSUARB P-887(2), fuel-adjustment mechanism; Nova Scotia Consumer Advocate. Direct, September 2010.

Effectiveness of fuel-adjustment incentive mechanism.

BEFORE THE

MANITOBA PUBLIC UTILITIES BOARD

MANITOBA HYDRO

2010/11 & 2011/12 GENERAL RATE APPLICATION

DIRECT TESTIMONY OF

JONATHAN WALLACH

ON BEHALF OF

RESOURCE CONSERVATION MANITOBA

AND

TIME TO RESPECT EARTH'S ECOSYSTEMS

Resource Insight, Inc.

DECEMBER 13, 2010

TABLE OF CONTENTS

I. Introduction

Q: Please state your name, occupation, and business address.

A: My name is Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Please summarize your professional experience.

A: I have worked as a consultant to the electric-power industry since 1981. From 1981 to 1986, I was a research associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a senior analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since September of 1990.

Over the last twenty-nine years, I have advised clients on a wide range of economic, planning, and policy issues relating to the regulation of electric utilities, including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market-price forecasting; market valuation of generating assets and purchase contracts; power-procurement strategies; risk assessment and mitigation; integrated resource planning; cost allocation and rate design; and energy-efficiency program design and planning.

My resume is attached as Exhibit JFW-1.

Q: Have you testified previously in utility regulatory proceedings?

A: Yes. I have sponsored expert testimony in more than 45 federal, provincial, or state proceedings in the U.S. and Canada. Exhibit JFW-1 includes a detailed list of my previous testimony.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Resource Conservation Manitoba and Time to Respect Earth's Ecosystems (RCM/TREE).

II. Overview and Summary

Q: What is the purpose of your testimony?

A: I have been asked by Resource Conservation Manitoba and Time to Respect Earth's Ecosystems to review and evaluate Manitoba Hydro's ("the Company") assessments of financial risk, as described in the General Rate Application and in the following filings by the Company in this proceeding:

- *Integrated Financial Forecast: 2009/10-2019/20 (IFF09-1)*, dated November, 2009.
- *Analysis of Financial Loss Due to Extended Periods of Drought*, prepared in response to PUB Order 117/06 and undated.
- *Executive Decision Paper*, "Export Power Sales Risk Management in Manitoba Hydro", dated October 18, 2005.
- *Corporate Risk Management Report*, dated October 2008.[1]

In addition, I have been asked by Resource Conservation Manitoba and Time to Respect Earth's Ecosystems to review and evaluate the findings and conclusions of a number of independent studies filed in this proceeding relating to the issue of Manitoba Hydro's exposure to financial risk, including:

[1] I have also reviewed the November, 2010 update to the Integrated Financial Forecast and the October, 2010 update to the Corporate Risk Management Report, both released by the Company on December 2, 2010. These documents were released at too late a date to fully incorporate in this testimony. However, nothing in these documents alters my findings and conclusions in this testimony.

- *Independent Review of Manitoba Hydro Export Power Sales and Associated Risks*, prepared by ICF International on behalf of Manitoba Hydro and dated September 11, 2009 ("ICF Report").
- *Manitoba Hydro External Quality Review*, prepared by KPMG LLP on behalf of Manitoba Hydro and dated April 15, 2010 ("KPMG Report").
- *Manitoba Hydro Risks: An Independent Review*, prepared by Drs. Atif Kubursi and Lonnie Magee on behalf of the Public Utilities Board and dated November 15, 2010 ("KM Report").[2]

This testimony focuses on Manitoba Hydro's consideration of the long-term costs and financial risks associated with drought conditions, as well as consideration of the effects of long-term contracting on the Company's risk exposure. Specifically, this testimony addresses the following issues with respect to the Company's exposure to drought-related financial risk:

- Quantification of drought-related costs and financial exposure to drought-related risk, in isolation or in combination with other risk factors.
- Assessment of the risk factors associated with export sales under long-term contracts
- Measures for accommodating or mitigating drought-related financial risk.

[2] As part of my assignment for RCM/TREE, I also reviewed the so-called "Public Document" filed in this proceeding by the "New York Consultant." However, this report did not merit further consideration in my direct testimony, since it consists largely of undocumented, unsubstantiated, and ultimately unverifiable assertions.

Q: What do you mean by the term "financial risk"?

A: Generally speaking, *risk* is a measure of adverse outcomes due to *uncertainty* in the key risk factors that give rise to these outcomes. For example, there is always a risk that tomorrow's generation from a wind turbine will be much less than forecast today, due to uncertainty in wind patterns and speed.

I use the term "financial risk" in this case to refer to the risk of financial losses, or more precisely, to the risk that future financial performance will be much worse than expected due to uncertainty in the key factors that drive financial performance.

Q: Why do you focus on drought risk, rather than other risk factors?

A: According to Manitoba Hydro, variability in flow conditions represents the largest financial risk to the Company. The singularly large impact of hydrology risk is due in part to the fact that:

- Hydro-electric facilities account for more than 95% of the annual generation from the Company's resource portfolio.
- Generation from the Company's hydro facilities is strongly correlated with water flow, due to limited storage capacity on major river systems in Manitoba.
- Revenues from exports of surplus hydraulic generation represent more than 30% of total system revenues.

This near-total reliance on hydroelectric generation to serve domestic load and to generate export revenues, in combination with limited storage capability, exposes the Company to significant risk of financial loss from variations in water flows.

Although flow variability poses the greatest financial risk to Manitoba Hydro, other risk factors, such as volatility in export and import prices, also

expose the Company to a significant risk of financial loss, particularly during drought periods. I therefore also address in this testimony the quantification of other risk factors in combination with drought risk.

Q: How does Manitoba Hydro define its exposure to financial risk from drought conditions?

A: According to the Corporate Risk Management Report, the Company defines financial risk in terms of the impact of drought on "the Corporation's ability to maximize net revenue levels and maintain the current rates for Manitoba customers."[3]

Q: How does the Company measure its tolerance for drought-related financial risk?

A: It is not apparent from the various filings in this proceeding that the Company has explicitly established measurable tolerance limits for exposure to drought-related financial risk. However, the Corporate Risk Management Report states that "the Corporation intends to have adequate retained earnings to protect against a repeat of the worst recorded drought."[4] This statement indicates that Manitoba Hydro will not tolerate losses under adverse water conditions in excess of retained earnings.

Q: Were you able to conduct a detailed evaluation of the Company's risk assessments or the risk analyses in the ICF, KPMG, or KM Reports?

A: No. All of these analyses were shrouded in an impenetrable veil of secrecy that stifled even the most cursory review of these analyses' methods, assumptions, or results.

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[3] *Corporate Risk Management Report*, October 2008, p. 32.

[4] *Id.*

Manitoba Hydro's filings and the ICF, KPMG, and KM Reports were so heavily redacted by the Company (and the New York Consultant, to the extent permitted by the Board) that I could not independently confirm or evaluate many of the findings or conclusions regarding the analyses of risk exposure. For example, Manitoba Hydro redacted all results of KPMG's analysis of the financial impacts of a drought under a planning scenario that assumes the alternative resource development plan from the 2009/10 Power Resource Plan. I therefore have no way of independently confirming KPMG's conclusions regarding that analysis, or ascertaining whether the results of that analysis might support alternative or contrary conclusions.

Likewise, the Company denied on the basis of confidentiality all requests by RCM/TREE for model inputs, algorithms, or outputs relied on to derive the cost or financial results reported in the publicly available versions of the Company's filings or the KPMG Report. As a result, I was unable to determine whether model inputs were reasonably estimated or whether model algorithms reasonably represented system conditions and operations.

Finally, the Company redacted from publicly available filings in this proceeding most of the terms and provisions of the binding term sheets with Northern States Power, Wisconsin Public Service, and Minnesota Power. I was therefore unable to verify claims made by the Company and in the ICF and KPMG Reports regarding the risk-mitigating attributes of the provisions regarding curtailment of delivery or transmission expansion and access.

Q: Have you ever experienced such a strict standard of confidentiality or such an extreme restriction on access to confidential material during your professional career?

A: In my three decades of working as a consultant to the electric-power industry in the U.S. and Canada, I cannot recall ever encountering such a broad standard for confidentiality. For example, I cannot recall any proceeding where the publicly available documentation of the utility's resource plan redacted all information regarding the forecasted costs of recommended or alternative resource plans, as is the case for Manitoba Hydro's 2009/10 Power Resource Plan. Nor can I recall any proceeding where parties were completely denied access to any material deemed to be confidential. Instead, standard practice in my experience has been to provide access to confidential material to parties willing to sign a confidentiality agreement, either by direct transmission of confidential material to such parties, by posting such material on a secure, password-restricted website, or, for particularly sensitive material, by depositing such material in a secure data room located at the utility's offices. In proceedings I have been involved in, access to confidential material has typically extended to copies of term sheets and executed agreements for the purchase or sale of power, as well as to inputs, software, and outputs for models relied on in the course of the proceedings.

Q: Please summarize your findings and conclusions.

A: Manitoba Hydro's assessments of planning risks, along with the three independent studies, collectively provide a substantial and detailed review of the potential risks to the Company associated with its hydro-based, export-oriented long-range business strategy. The consensus among these studies is that Manitoba Hydro is exposed to the risk of severe financial loss due to the

Company's almost-sole reliance on hydraulic resources to serve domestic load and firm export commitments. Risk analyses reported in Company filings and in the KPMG and KM Reports consistently find that an extended drought would seriously deplete accumulated retained earnings in a matter of a few years, and that, in the absence of compensating measures, earnings would likely remain depressed for several years after the end of a drought.

As serious as this threat appears, the likely exposure to drought-related risk may be even greater than forecast by Manitoba Hydro or KPMG. According to the KM report, operating costs under drought conditions are "severely understated" in the Company's simulation models. The KPMG Report finds likewise. If operating costs during a drought are under-forecast, then so will be financial losses resulting from that drought.

In addition, risk exposure may be greater than forecast by the Company in IFF09-1, because the IFF09-1 risk analysis did not quantify potential financial losses from an extended drought that coincides with a period of high fuel and market prices. The KPMG Report evaluated a scenario that assumed both recurrence of drought and higher-than-expected natural gas and export prices and found that in this case an extended drought would more than wipe out retained earnings by the end of the drought, and that retained earnings would stay strongly negative for several years thereafter. It is possible that KPMG would have found even greater financial losses if it had evaluated the effect of an extended drought assuming higher-than-expected import prices.

In general, long-term contracts for firm export sales will increase the Company's risk of financial losses under adverse water conditions. However, both Manitoba Hydro's and KPMG's risk analyses indicate that the economic benefits from the proposed new agreements with Northern States Power, Wisconsin Public Service, and Minnesota Power would likely outweigh their

financial risks. While encouraging, the results of these analyses are neither verifiable nor conclusive. As discussed above, I cannot verify the results of these analyses because Manitoba Hydro redacted key results for the KPMG analysis of long-term contracts, and denied access to all model inputs, algorithms, and outputs relied on to derive those results. Furthermore, financial risk may have been underestimated in both the Company's and KPMG's analyses, due to the understatement of drought costs discussed above.

Even if the Company's recommended resource plan with the proposed long-term contracts appears less risky than an alternative plan without those contracts, as indicated by the KPMG analysis, that does not necessarily imply that the financial risk associated with the recommended plan is either tolerable or manageable. The central issue of concern is not whether the recommended plan with long-term contracts is less risky than an alternative with short-term opportunity sales, but whether the near-total reliance on hydraulic resources under the recommended plan threatens the financial stability of the Company and unnecessarily increases the risk to consumers of unreasonable rate increases. From this perspective, the KPMG results are troubling, since, as noted above, they indicate that the Company would likely need to increase borrowings or dramatically increase rates for many years to recover from a drought that is accompanied by high fuel and market prices.

While both the Company's and KPMG's risk analyses show the potential for severe financial losses, they do not indicate how likely such outcomes would be or whether and to what extent losses might be even worse than forecast by these analyses. As discussed in the ICF, KPMG, and KM Reports, decisions about whether and how best to mitigate these potentially adverse outcomes depend not just on the potential severity of the outcomes, but on the likelihood that such outcomes would come to pass. The Company recognizes this

limitation is its current approach to risk modeling and is in the process of developing a new model that will more fully reflect forecast uncertainty, generate a probabilistic distribution of outcomes (rather than a point estimate), and allow for measurement of risk exposure at pre-defined tolerance limits (e.g., earnings loss at 95% confidence level.)

The KM Report recommends consideration of rate increases and other measures to increase retained earnings and build an emergency reserve fund as a buffer against potential drought-related financial losses. It would be premature to adopt any such measures before Manitoba Hydro's new risk model is fully implemented as part of the Company's resource planning and corporate risk management processes. As noted above, before taking such measures and thereby increasing costs to consumers, the Company should determine the likely magnitude of expected financial losses, the likelihood of more severe losses than expected, and the extent to which forecasted losses would fall within tolerance limits. Moreover, to the extent that risks are deemed unsustainable, the Company should examine whether there are opportunities for directly *reducing* risk – such as diversification of the resource portfolio into energy efficiency, renewables, or efficient thermal generation – that are less expensive than measures such as those proposed in the KM Report to *buffer* risks.

III. Quantification of Long-Term Drought Costs

Q: How do drought conditions affect costs on the Manitoba Hydro system?

A: In general, lower-than-average water flows will increase system net costs – i.e., the costs to serve domestic load and exports less export revenues, either by reducing export sales and thus export revenues, by increasing the costs to serve

exports, or both.[5] In other words, low flows will reduce net revenues from export sales, where net revenues are defined as revenues from export sales less the costs to serve those sales.

Depending on the severity of the drought, net export revenues will decline as a result of some combination of reduced revenues from non-firm opportunity export sales, increased costs to serve firm export commitments, and reduced revenues from curtailment of firm export sales. The extent to which each of these three factors contributes to the drop in net export revenues depends in large part on the effect of drought conditions on the availability and cost of "dependable supply."

Manitoba Hydro has adopted planning criteria that define dependable energy supply as the expected energy supply from domestic hydraulic and thermal resources, wind purchases, contracted firm imports, and contracted non-firm imports of reserves from adjacent control areas under the worst flow conditions in the historical record.[6] The Company's planning criteria further stipulate that there must be sufficient dependable supply to meet forecasted domestic demand requirements and anticipated long-term firm export commitments. Thus, so long as water flows exceed the worst drought conditions on record (and domestic load is not higher or availability of import power not lower than expected), dependable energy supply will be adequate to serve both domestic load and firm export commitments. Moreover, to the extent that water

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[5] In reality, a drought may increase costs to serve both domestic load and export commitments. However, for the purposes of this discussion, I treat all such cost increases as a reduction to export net revenues.

[6] "Corporate Policy Statement on Generation Planning (No. G195)", provided in response to RCM/TREE/MH I-30(a). The Company's planning criteria also limit contracted non-firm imports to no more than 10% of domestic demand.

flows exceed the worst drought conditions (with all else equal), there will be an opportunity for non-firm exports of hydraulic energy generation in excess of dependable levels.

Consequently, a decline in river flows will directly reduce opportunities for, and net revenues from, non-firm export sales, but will not affect the adequacy of dependable supply for firm export commitments so long as flows exceed the lowest levels in recorded history. However, while dependable supply may still be adequate in aggregate under these flow conditions, the actual mix of energy resources serving firm export commitments may change as a result of the decline in flows. In particular, if under average flow conditions the Company is serving firm exports with hydraulic generation in excess of dependable levels, then a decline in water flows would require the Company to rely on additional amounts of more-expensive imports or domestic thermal generation to offset the decline in available excess hydraulic generation. If so, the overall cost to serve firm export commitments would increase and the net revenues from firm sales would consequently decline.

Finally, in the event that the system experiences a drought more severe than the worst in recorded history, net export revenues would likely suffer even greater reductions as a result of a shortfall in dependable supply. In this case, net revenues from firm exports would decline as a result of either curtailment of firm deliveries (to the extent allowed under contract) or an increase in costs to continue firm deliveries with replacement power purchased at prevailing market prices.

Q: How does Manitoba Hydro quantify the cost of drought in its long-range resource planning and financial forecasting?

A: My understanding is that the Company reflects the impacts of drought in its long-range cost and financial forecasts in two ways. First, the Company implicitly captures the average impact of drought conditions on total system costs in its simulation modeling of generation expansion scenarios. The Company forecasts long-term system costs and performance for different resource planning scenarios using the Simulation Program for Long Term Analysis of System Hydraulics (SPLASH) software model. According to the KM Report, the SPLASH model forecasts long-term costs for a specific resource plan assuming recurrence of historical monthly water flows over a 94-year period.[7] Since the historical record includes a number of periods of adverse water conditions, SPLASH simulation of annual water conditions – and the accompanying forecast of system costs under those water conditions – will implicitly reflect the impact of drought conditions on long-term system costs.

Second, the Company explicitly models the financial impact of an extended drought as part of its risk analysis for the Integrated Financial

[7] Specifically, the SPLASH model forecasts costs over the planning horizon for 94 separate "flow cases." Each flow case simulates starting conditions for the first year of the planning horizon using water flows from one of the 94 historical flow years, and then simulates water flows over remaining years of the planning horizon using historical flows for the years following the flow year used to set initial conditions. For example, one flow case may use water flows from 1940 to represent flow conditions for the first year of a 40-year planning horizon. In this case, the SPLASH model will use historical water flows from 1941 through 1979 to simulate conditions for the remaining 39 years of the planning horizon.

Forecast.[8] Specifically, for the Integrated Financial Forecast for Fiscal Years 2009 through 2019 (IFF09-1), Manitoba Hydro forecasts the impact on net export revenues and retained earnings from a recurrence of water flows from the worst (measured in terms of the impact of water flows on revenue) five-year drought on record (1987-1992) starting in Fiscal Year 2011. The Company relies on this sensitivity analysis as a measure of its financial exposure to drought-related risk.[9]

Q: Did the ICF, KPMG, or KM studies evaluate the Company's simulation of drought-related costs using the SPLASH model?

A: The KPMG and the KM Reports evaluated the SPLASH model's algorithms for forecasting long-term costs and the model's effectiveness at simulating operating performance and cost under drought conditions. Both studies find that the SPLASH optimization algorithms understate likely system costs, especially at times of adverse water conditions. According to the KPMG Report:

> KPMG has a concern that the assumption of perfect foresight will tend to understate operating costs when the model is used to generate forecasts of future financial results.[10]

[8] Presumably, the Integrated Financial Forecast also implicitly reflects the financial impact of drought conditions, since it incorporates the SPLASH forecast of system costs and performance for the recommended development plan from the resource planning process.

[9] As discussed below, Manitoba Hydro also simulates financial impacts from other risk factors, such as lower-than-expected export prices. However, the Company does not consider risk scenarios that combine the effects of a five-year drought with other risk factors in the risk analysis reported in IFF09-1.

[10] KPMG Report, p. 113.

And according to the KM Report:

> … the cost and implications of the assumption of perfect foresight must be determined…. When water levels in reservoirs are kept at their minimum levels because we know exactly when a drought will begin and end, the actual costs of a drought would be seriously understated.[11]

Q: What is the magnitude of the impact on drought-related costs from the assumption of perfect foresight?

A: The extent to which drought-related costs are understated is unknown at this time, since neither the KPMG nor the KM studies estimated the impact of perfect foresight on the SPLASH model's forecasting of system costs.

The Company should undertake as soon as feasible to estimate and, if necessary, correct for the underestimate of system costs due to the assumption of perfect foresight. This effort should be completed on a timely basis because of the potential implications for the Company's resource planning decisions or risk assessments. Of particular concern is the impact of the assumption of perfect foresight on the forecasts of costs associated with the recommended and alternative resource development plans adopted in the 2009/2010 Power Resource Plan, and the impact on the relative economics of these two plans from any correction to the forecast of costs. Likewise, it is critical that Manitoba Hydro determine the effect of perfect foresight on its estimates of drought-related financial losses in order to assess whether the Company's exposure to financial risk is materially greater than currently estimated.

[11] KM Report, p. 97.

IV. Assessment of Risk Exposure

Q: How does Manitoba Hydro quantify and measure its risk exposure?

A: The Company appears to rely on two quantitative approaches for measuring exposure to risk. First, as part of its Integrated Financial Forecast, the Company subjects the baseline forecast of financial performance to a series of sensitivity analyses, each of which changes model inputs to reflect occurrence of a single risk factor (e.g., extended drought.)[12] Second, although relatively undocumented, the Company apparently also uses the Power Risk System Model (PRISM) to conduct stochastic analyses of the likely distribution of export revenues given uncertainties in key input assumptions (e.g., water flows.) As far as I am aware from my review of publicly available documentation, the Company has not attempted to reconcile the results of these two quantitative analyses of risk exposure.

Q: Please describe the risk analysis in IFF09-1.

A: As part of its risk-management process, the Company identifies a number of key risks to system costs, operations, and financial performance, and then ranks these risk factors on the basis of a qualitative assessment of the likelihood of the risk occurring and the consequences to the Company if the risk were to occur.

Given that export revenues constitute over 30% of total revenues, Manitoba Hydro undertook in IFF09-1 a quantitative analysis of risk exposure from those key risk factors that were considered to have the greatest impact on export revenues. The risk factors selected for analysis in IFF09-1 were:

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[12] The Company also conducted these sensitivity analyses as part of its most recent 20-Year Financial Outlook.

- Extended drought;
- Interest rates;
- Foreign exchange; and
- Export prices.

In IFF09-1, the Company measures risk exposure from each of these risk factors in terms of their impact on the IFF09-1 baseline forecast of financial performance for electric operations. Specifically, the Company simulated the change to the baseline forecast due to each risk factor in isolation by running a series of sensitivities, with each sensitivity changing baseline inputs to reflect occurrence of a single risk factor (e.g., high export prices.) The Company then reported its risk exposure for each risk factor in terms of the differences between the baseline forecast and the sensitivity forecast of cumulative retained earnings.

The IFF09-1 risk analysis confirms expectations that, of the modeled risk factors, an extended drought poses the single largest risk to Manitoba Hydro's financial stability. This analysis found that recurrence of the worst five-year drought in recorded history starting in Fiscal Year 2011 would reduce Fiscal Year 2015 retained earnings by about $2.4 billion, wiping out more than 90% of the cumulative retained earnings from electric operations projected for that year under the baseline forecast.[13] More critically, the effect on retained earnings would extend well beyond the end of the drought. According to the most recent 20-Year Financial Forecast, in the absence of compensating incremental rate increases, consolidated equity ratios would not rise to pre-drought levels until fourteen years after the end of the modeled five-year drought.

[13] The second largest risk factor was low export prices, which were estimated to reduce retained earnings by about $360 million in Fiscal Year 2015 and by $920 million in Fiscal Year 2019.

Q: In IFF09-1, did the Company examine any sensitivities that combined the effects of more than one risk factor?

A: No. As noted above, the Company measured the impact of only one risk factor at a time. However, the Company does acknowledge in IFF09-1 that:

> If a drought of this magnitude (or the even larger 1936-1943 drought) were to coincide with a period of high prices for thermal generation and import purchases the impact would be greater.[14]

Q: Should Manitoba Hydro have examined the financial impact of drought coinciding with a period of high fuel or import prices as part of its risk analysis in IFF09-1?

A: Yes. The Company has identified import- and fuel-price uncertainty as a major contributor to its drought-related risk exposure. As stated in the Corporate Risk Management Report:

> Key to this risk [of drought] is the large degree of uncertainty surrounding the price of imports and fuel purchases required to serve firm demand commitments during an extended drought.[15]

Given the key role played by import- and fuel-price uncertainty, Manitoba Hydro should have examined the extent to which high import or fuel prices would be expected to exacerbate the Company's exposure to financial losses during an extended drought.

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[14] IFF09-1, pp. 21-22. In contrast, Manitoba Hydro quantified the combined effect of an extended drought and high market prices in *Analysis of Financial Loss Due to Extended Periods of Drought*. In that report, the Company found that the reduction to net income from a seven-year drought during a period of high market prices would be about $300 million more than net-income losses in the scenario with a seven-year drought and expected market prices.

[15] *Corporate Risk Management Report*, October 2008, p. 32.

Q: Do the ICF, KPMG, or KM Reports address whether these single-risk-factor sensitivity analyses reasonably quantify Manitoba Hydro's risk exposure?

A: The ICF Report explicitly addresses this issue, finding that the IFF09-1 five-year drought sensitivity was reasonably stressful in terms of the likelihood that financial losses would exceed those estimated in the drought sensitivity. Specifically, the ICF Report finds that it is reasonable to model the recurrence of a five-year drought rather than a seven-year drought, because the probability of a five-year drought, based on the historical record, falls within the 95% confidence interval commonly relied on for stress testing. The ICF Report further finds that the joint probability of a five-year drought and another risk factor such as higher export prices would fall outside the 95% confidence interval, and therefore a sensitivity that combined drought risk with price risk would be unreasonably stressful.

The KM Report does not directly address the reasonableness of the Company's single-factor sensitivities, but does find that ICF underestimated the probability of recurrence of a five-year drought. However, the KM Report does not indicate whether ICF's underestimate of drought probability undermines that report's finding that a sensitivity that combined drought risk with other risk factors would be unreasonably stressful.

The KPMG Report also does not directly address the reasonableness of the Company's approach. Instead, KPMG instructed Manitoba Hydro to conduct a series of sensitivity runs that combined the recurrence of a five-year drought – starting in either 2013, 2019, or 2025 – with low, expected, or high forecasts for natural gas and export prices. The KPMG analysis shows that the Company's financial position would be perilous if it experienced a five-year drought during a period of high natural gas and export prices. For example, the sensitivity run

with drought starting in 2013 and assuming expected values for market prices shows retained earnings by the end of the drought of $190 million. In contrast, the same drought scenario assuming high prices shows retained earnings by the end of the drought of *negative* $1.1 billion.[16] And in this case, cumulative retained earnings would remain largely negative for eight years following the end of the five-year drought.[17]

It is possible that KPMG would have forecast even greater drought-related losses if it had evaluated a sensitivity assuming higher-than-expected import prices, rather than higher-than-expected natural gas and export prices. In KPMG's sensitivity with high natural gas and export prices, the assumption of higher-than-expected prices for the natural gas burned in the Company's thermal resources increases the cost of relying on those resources when needed during times of drought. Thus, the assumption of high gas prices increases drought-related financial losses compared to the scenario that assumes expected gas and export prices. However, the corresponding assumption of higher-than-expected export prices in KPMG's high price sensitivity increases export net revenues at all times (drought or non-drought) compared to the scenario with expected prices and thus offsets some of the losses associated with high natural gas prices.[18] In contrast, a sensitivity that assumes just higher-than-expected import prices would increase the costs to serve firm commitments at all times, without any offsetting gains, and thus could possibly result in greater financial losses than forecast for the sensitivity with high gas and export prices.

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[16] See Exhibit 4-21 of the KPMG Report.

[17] See Exhibit J-3 of the KPMG Report.

[18] Nonetheless, it is reasonable to also assume high export prices in a sensitivity that assumes high natural gas prices. Market prices are strongly correlated with natural gas prices during on-peak periods, when export sales are typically transacted.

Q: Does the KPMG Report provide any indication of the likelihood that losses would approximate those estimated in the KPMG analysis?

A: The KPMG Report does not indicate the likelihood that losses will approach those estimated in the various KPMG sensitivities. More critically, the KPMG analysis does not provide information regarding the extent to which, or the probability that, losses might exceed those forecasted in the various sensitivities. In other words, there is no indication of how much worse Manitoba Hydro's risk exposure might be than forecast in these "worst-case" scenarios.

As the KPMG Report observes, this limitation is not unique to KPMG's (or the Company's) sensitivity analyses of risk exposure:

> Stress tests are scenario exercises to determine financial losses that might occur under unlikely but plausible circumstances. Traditional stress testing is conducted on a stand-alone basis and the stress test results are highly subjective because they depend on scenarios chosen by the stress tester. As a result, the value of stress testing depends on scenario choice and skill of the modeler. A related problem is that stress test results are difficult to interpret because the scenarios are not probabilistic.[19]

Q: Are there alternative approaches to risk quantification that overcome the limitations of stress testing?

A: Yes. In particular, Monte Carlo simulation techniques allow for an explicit quantification of probability distributions around forecasts of expected outcomes (e.g., net revenues, retained earnings.)

As noted above, stress testing involves making substantial, discrete changes to one or more input assumptions (e.g., water flows, market prices) in order to forecast outcomes (e.g., retained earnings) under unlikely conditions that are considered to be "worst-case." In contrast, Monte Carlo simulation represents key inputs not as single, expected values, but as probabilistic

[19] KPMG Report, p. 242.

distributions around expected values.[20] A Monte Carlo simulation model will generate multiple (typically 1,000) forecasts of outcomes, with each forecast relying on a random draw of input values from the probability distribution for each input value. Thus, the Monte Carlo simulation generates a distribution of forecast outcomes, with the expected outcome value reflecting the average over the entire distribution of outcomes and probabilities of extreme outcomes defined by the distribution of outcomes.

Monte Carlo simulation thus offers a number of advantages over sensitivity analysis with respect to the quantification of risk exposure. In particular, Monte Carlo simulation:

- allows for complete specification of uncertainty in input assumptions;
- fully captures the combined impact on forecasted outcomes of uncertainty in multiple independent input variables; and
- allows for measurement of risk exposure at pre-defined tolerance limits (e.g., earnings loss at 95% confidence level; average of 10% worst outcomes.)

Q: Should Manitoba Hydro incorporate Monte Carlo simulation techniques in its analyses of risk exposure?

A: Apparently, the Company already has the capability to undertake Monte Carlo simulations of risk exposure with its PRISM model. Based on what little documentation is publicly available, it appears that PRISM uses Monte Carlo simulation techniques to generate five-year forecasts of expected net revenues, and distributions around expected net revenues, by repeated, random sampling

[20] These input distributions are typically derived based on historical fluctuations in the value of the input parameter.

of probability distributions for key input variables (e.g., water flows, electricity prices.)

However, it is not clear at this time to what extent Manitoba Hydro makes use of PRISM to inform its quantification of risk exposure. The KPMG Report cryptically describes PRISM as a "screening tool" that is "designed to provide an initial estimate rather than a precise analysis, and is used to identify possible outcomes associated with fixed, pre-defined scenarios."[21] The KM Report alludes to a limited role for PRISM, indicating that there is very little if any reconciliation of results from PRISM simulations and the Company's sensitivity analyses:

> There is also a need to contrast and compare @RISK calculations with other quantitative risk calculations. Greater integration and harmonization of the PRISM model with other MH models should be initiated quickly.[22]

I agree that Manitoba Hydro should more fully integrate its PRISM modeling with its sensitivity modeling of risk exposure.[23] At a minimum, the Company should fully reconcile results from the two modeling efforts, and then apply PRISM results to determine whether sensitivity scenarios are reasonably stressful. Ideally, the Company should improve the PRISM representation of system conditions and simulation of system operations, lengthen the planning horizon, expand the roster of input variables subject to stochastic treatment, and otherwise improve model structure, so that it can be relied on as the primary method for quantifying risk exposure.

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[21] KPMG Report, p. 38.

[22] KM Report, p. 128.

[23] I also concur with the recommendations in both the KM and KPMG Reports for improving the model structure (e.g., lengthening the forecast horizon) and for improving the specification of input distributions.

Manitoba Hydro apparently also recognizes the imperative to more fully integrate stochastic modeling into its analyses of risk exposure. In response to PUB/MH/RISK-114, the Company states that:

> Manitoba Hydro is reviewing its current drought stress analytics and is developing a model that use both historical and Monte Carlo simulation in order to analyze the financial loss associated with its drought stress scenarios which will assist in combined event drought risk management.

The Company should incorporate this new risk model not only in its corporate risk management process, as suggested by the response to PUB/MH/RISK-114, but also in its long-range resource planning process. Embedding stochastic modeling in the resource planning process would provide the Company with the capability to evaluate resource portfolios both on the basis of their expected long-term costs and in terms of the risk that long-term costs will be greater than expected. This capability, in turn, would allow the Company to identify the portfolio plan that minimizes long-term costs at a sustainable level of risk.

V. Risk Assessment of Long-Term Export Sales

Q: Please provide an overview of Manitoba Hydro's export sales.

A: By almost any measure, export sales are a major component of the Company's operations. According to the response to RCM/TREE/MH/RISK-22, the Company exported about 29% of its total generation from domestic supply (including wind purchases) in Fiscal Year 2009. According to IFF09-1, net revenues from export sales are projected to account for about 26% of total electric revenues received in Fiscal Year 2009. Also according to IFF09-1, the contribution to total revenues from export sales is expected to increase

substantially over the next ten years, growing to 38% of total electric revenues by Fiscal Year 2019.

Export sales take the form of either long-term firm commitments (either System Participation Sales or Diversity Exchange Agreements) or short-term non-firm opportunity sales. As discussed in Section III, pursuant to the Company's planning criteria, long-term firm commitments are served from dependable energy supply in excess of that required to serve expected domestic load. The Company engages in opportunity sales of generation in excess of domestic load and firm commitments, when economic to do so and to the extent that export transfer capacity is available. The bulk of export sales are into the Midwest Independent System Operator (MISO) market.

Manitoba Hydro is currently party to eight long-term system participation or diversity exchange agreements with utilities in the United States, representing almost 1,200 MW of summer sales.[24] These agreements expire by 2014, with the exception of a 200 MW diversity exchange contract with Northern States Power that expires in 2016.[25]

The Company has executed binding term sheets with Northern States Power (NSP), Wisconsin Public Service (WPS), and Minnesota Power (MP) for the sale or exchange of power starting in 2015.[26] The NSP term sheet has a ten-year term and calls for the sale of 375 MW of firm power starting in 2015, increasing to 500 MW in 2021. In addition, the NSP term sheet provides for 350

[24] ICF Report, Exhibit 3-3.

[25] See "Summary of Long Term Contracts", provided in response to RCM/TREE/MH I-27.

[26] The following summary is based primarily on information provided in the 2009/2010 Power Resource Plan.

MW of diversity exchange starting in 2015.[27] The WPS term sheet extends from 2018 through 2032, with sales ramping up from 150 MW in 2018 to 500 MW in 2020 and then ramping down to 250 MW in 2030.[28] Finally, the MP term sheet calls for the sale of 250 MW of firm power from 2022 to 2035. In total, these term sheets commit Manitoba Hydro to the sale of 1,600 MW of firm power by 2021.

All three term sheets contain a variety of curtailment or call-option provisions in the event of a drought of severity within or outside of the historical record. However, all details regarding these provisions have been redacted from the public versions of all Company filings in this proceeding and the ICF, KPMG, and KM Reports.

The WPS and MP term sheets require Manitoba Hydro to construct 1,800 MW of new hydro capacity and a new interconnection to the U.S. In exchange, these term sheets require WPS and MP to increase long-term transfer capability (for both export from and import into Manitoba) by 750 MW. Again, all details regarding these mutual obligations have been redacted from publicly available documents in this proceeding.

Q: What are some of the benefits to Manitoba Hydro from these proposed new long-term firm contracts?

A: In general, the sale of surplus generation under long-term contracts rather than on a short-term basis offers Manitoba Hydro three potential benefits. First, the

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[27] The System Participation and Diversity Exchange agreements associated with the NSP term sheet have been executed since release of the 2009/2010 Power Resource Plan. See the response to CAC/MSOS/MH/RISK-35.

[28] According to the response to CAC/MSOS/MH/RISK-35, the start date for the WPS term sheet has been pushed back to 2019. This response does not indicate how this one-year delay affects the ramp-up schedule for power deliveries.

sale of excess power under a long-term contract would likely provide greater revenue assurance and stability than if that excess were sold into the wholesale market as an opportunity sale. Market pricing of short-term sales can be extremely volatile, and transmission access on a non-firm basis may not be available at those times when market opportunities for short-term sales arise. Both of these market risks can be avoided, and a stable source of revenues assured, with the sale of surplus power on a firm basis at contractually determined prices.[29]

Second, as discussed in the KPMG report, revenues from long-term contracts provide a stable source of cash flow that would likely match debt-service requirements associated with long-term fixed-rate debt obligations. This matching of cash flows to interest payments could potentially improve earnings stability, and allow for a reduction to the equity ratio in the Company's capital structure.

Finally, the ICF Report argues that a buyer's willingness to pay for power would be greater under a long-term firm sales agreement to the extent that that agreement allows the buyer to defer capital investments in generation or transmission. If so, then presumably the buyer would be willing to pay a higher price for that power than if it were purchased on a short-term basis from the wholesale market.

The WPS and MP term sheets also offer the unique benefit of increased access to the Midwest ISO market associated with the obligation for WPS and MP to provide 750 MW of long-term firm transfer capability into and out of MISO. This additional transfer capability potentially allows not only for

[29] Although firm contract pricing avoids the risk of market-price volatility, it may lead to seller regret if contract prices fall below prevailing market prices.

additional opportunity sales into the Midwest ISO, but also for additional imports of power from the MISO market when economic to do so or when needed to satisfy firm load during droughts.[30]

Q: Will these proposed new long-term contracts increase Manitoba Hydro's exposure to financial risk?

A: In general, there is a greater risk of net losses from the sale of power on a firm basis than on a non-firm basis. Under adverse conditions, non-firm sales are fully curtailable, either because surplus power is inadequate to support the sale or because the sale would not be economic to execute. In either case, no revenues are gained and no costs are incurred. In contrast, and ignoring allowances for partial curtailment, firm sales continue under adverse conditions regardless of the transaction economics. In this case, net losses would be incurred if the costs to serve the firm commitment exceeded the revenues gained from the sale. Any such net losses would necessarily reduce net income and retained earnings.

The WPS and MP term sheets may further increase the risk of financial losses under adverse conditions, because the investment in new hydraulic and transmission capacity required by these contracts will increase fixed plant depreciation expenses and debt-service requirements. The increase in fixed expenses, in turn, increases the risk that revenues would be inadequate to support expenses under adverse conditions.[31]

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[30] Although these term sheets offer greater access to imports from the MISO market during droughts, the Company would be exposed to financial risk associated with volatility in market prices for import power.

[31] Presumably, revenues would be adequate to support expenses under expected conditions.

On the other hand, two aspects of the WPS and MP term sheets could potentially mitigate financial risk under adverse conditions. First, according to the ICF and KPMG Reports, the various curtailment and call-option provisions of these term sheets (and the NSP agreements) would likely reduce the risk of delivering firm power at a loss.[32] Second, the obligation for WPS and MP to increase transfer capability to the border with Manitoba will likely increase the Company's access to imports from MISO, and perhaps allow the Company to serve firm exports with off-peak (and on-peak, if the drought is especially severe) imports rather than more-expensive internal thermal generation during a drought.[33]

Q: Has the Company examined whether the benefits of the proposed long-term contracts outweigh the risks?

A: Manitoba Hydro has quantitatively evaluated this issue from two different perspectives. First, as part of the process to develop the 2009/2010 Power Resource Plan, the Company estimated the expected long-term costs for a resource plan that included the three proposed firm sales (the "recommended plan") and for an alternative plan that excluded the WPS and MP term sheets. According to the KPMG Report, Manitoba Hydro estimated that the net present value of expected costs over the planning horizon was lower for the

[32] I cannot verify this claim independently, since the specific provisions have been deemed confidential material and all descriptions of these provisions have been redacted from publicly available documents in this proceeding.

[33] More precisely, it would provide the opportunity to: (1) rely on off-peak imports to serve off-peak domestic load; (2) store the water that would have been used to serve off-peak domestic load but for the imports; and (3) draw down the stored water during on-peak hours to serve firm export sales.

recommended plan than for the alternative plan.[34] Thus, according to the Company's analysis, the WPS and MP term sheets were economically beneficial, at least on an expected-value basis.

Second, as discussed in Section IV, the Company examined in IFF09-1 the potential for financial losses from the recommended plan in the event of a recurrence of the worst five-year drought on record. That analysis indicated that losses from a five-year drought, though substantial, would not exceed tolerance limits, in the sense that retained earnings were expected to be adequate to sustain such losses.

Taken at face value, these two analyses together indicate that the recommended plan with the proposed long-term firm contracts is expected to provide economic benefits without risking unsustainable losses under adverse water conditions. However, there are two reasons why these results should not be considered conclusive. First, as discussed in Section III, both the KPMG and KM Reports find that operating costs are being understated in the Company's analyses, due to a modeling assumption of perfect foresight when simulating the drawdown of reservoirs during a drought. Although the scale of this underestimate is unknown at this time, the concern is that it is of sufficient magnitude to either overstate the economic benefits of the recommended plan relative to the alternative plan, overstate the extent to which financial losses associated with adverse water conditions under the recommend plan are sustainable, or both.

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[34] According to the KPMG Report, the Company estimated a net-present-value cost of about $5 billion for the recommended plan. (See p. 174) The Company's estimate of the cost for the alternative plan was redacted from the KPMG Report. In addition, requests by RCM/TREE for these results, as well as for underlying assumptions and annual model results were denied by Manitoba Hydro on the basis of confidentiality.

Second, as discussed in Section IV, the IFF09-1 risk analysis did not examine the combined impact of key risk factors, specifically drought and fuel and import prices, even though the Company's risk management process identified uncertainty around fuel and import prices as a key driver of drought-related financial risk. Thus, the IFF09-1 analysis does not provide a complete accounting of the potential for drought-related financial losses under the recommended plan.

Q: Does the KPMG risk analysis described in Section IV provide a more complete accounting of the benefit-risk trade-offs associated with the proposed long-term firm sales?

A: Yes. The KPMG analysis expands on the Company's approach by evaluating economic benefits and financial risks across a range of sensitivities that: (1) assume various combinations of flow conditions and price forecasts for natural gas and opportunity exports; (2) vary the starting year for the onset of an extended drought; and (3)vary the duration of the drought between five, ten, and fifteen years. Moreover, the KPMG analysis differs from the Company's approach, in that the KPMG analysis considers whether the recommended plan is riskier than the alternative plan, not whether the recommended plan is too risky to tolerate as under the Company's approach.[35]

Q: Please summarize the findings of the KPMG analysis.

A: In terms of expected economic benefits, the KPMG Report finds that:

[35] The KPMG analysis also differs from the Company's in that the former uses flow conditions from 1937 to 1941 to represent the five-year drought, while the latter uses conditions from 1987 to 1992. The KPMG Report does not provide the rationale for using a different five-year period.

> Under all of the scenarios analyzed, the NPV of the Sale Scenario [i.e., the recommended plan] remains strongly positive relative to the No Sale Scenario [i.e., the alternative plan.] This means that drought events do not impair the economics of MH's preferred development sequence and associated proposed long-term contracts.[36]

I am unable to verify this finding, since Manitoba Hydro redacted all results relating to the No Sale Scenario from the KPMG Report. In addition, I am unable to ascertain the reasonableness of the results for either the Sale or the No Sale Scenario, because all requests by RCM/TREE for the input data, model algorithms, and model outputs relied on to derive these results were denied on the basis of confidentiality.

In terms of financial risk, the KPMG Report assesses the relative riskiness of the recommended and alternative plans on the basis of the amount of retained earnings at the end of the drought for each plan. Focusing on the results for the five-year drought cases, the KPMG Report concludes that:

> The results demonstrate that the Sale Scenario and the related long-term export contracts do not lead to a significant increase in financial risk for MH from a drought risk perspective. On the contrary, the Sale Scenario appears to reduce the overall risk of a five year drought compared to a No Sale Scenario, since it provides greater Retained Earnings to withstand the financial impact of a five year drought.[37]

Again, I am unable to verify this conclusion or to judge the reasonableness of the underlying modeling, because all results for the No Sale Scenario and all model inputs, algorithms, and outputs relied on to derive the results for both the Sale and No Sale Scenarios were considered to be confidential.

This denial of access to input assumptions and model algorithms is particularly critical with respect to the modeling of export and import pricing

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[36] KPMG Report, p. 176.

[37] KPMG Report, p. 183.

and access, since, according to the KPMG report, the retained-earnings advantage of the Sale Scenario apparently hinges on the model forecasts of export revenues and import costs for each scenario:

> The improved Retained Earnings [of the Sale Scenario versus the No Sale Scenario] are due primarily to the increased surplus export sales associated with the new generation and increased US transmission interconnection capabilities. Moreover, the availability of increased US transmission interconnection capacity (planned in service date of 2018) under a Sale Scenario has an ameliorating effect on Net Income reduction due to droughts. This is due to the increased US transmission interconnection in the Sale Scenario allowing MH to import more power than in the No Sale Scenario with such imports being typically less expensive than MH's domestic thermal production.[38]

Q: Issues of verifiability aside, does the KPMG risk analysis confirm the finding from the Company's analysis that drought-related losses under the recommended plan are sustainable?

A: On the contrary, the KPMG risk analysis shows that, under the scenario that combines a five-year drought starting in 2013 with high natural gas and market prices, retained earnings would go negative by 2018 and remain negative for eight years thereafter. Likewise, the combination of a ten- or fifteen-year drought starting in 2013 and high prices would also result in negative net earnings by the end of the respective drought periods.[39]

In other words, the KPMG Report finds that under certain drought scenarios, drought-related losses would be unsustainable and consumers would

[38] KPMG Report, p. 182.

[39] Unlike for the five-year drought scenarios, the KPMG Report does not report annual values for retained earnings for the ten- and fifteen-year drought scenarios.

be exposed to the risk of dramatic rate increases to compensate for the total depletion of equity.[40]

VI. Risk Protection and Mitigation

Q: What measures does the Company employ to reduce consumers' exposure to the risk of rate shock?

A: As discussed in Sections III, Manitoba Hydro seeks to mitigate drought-related financial risks from its long-term export commitments by requiring that such commitments be served by dependable supply. Moreover, as discussed in Section V, the Company seeks to mitigate risks from its proposed contracts with NSP, WPS, and MP by including provisions that allow curtailment under adverse water conditions and that increase firm access to low-price imports from MISO.

Beyond mitigation measures, Manitoba Hydro seeks to cushion the impact of drought-related financial losses by maximizing export net revenues and accumulating sufficient retained earnings in non-drought years to sustain losses comparable to those experienced in the worst drought on record.

Q: Do the ICF, KPMG, or KM Reports recommend adoption of additional measures for reducing or buffering drought-related risks?

A: The KM Report alone recommends adoption of additional risk-protection measures. The measures recommended in the KM Report are as follows:[41]

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[40] Such increases would be in addition to the 3.5% annual increases forecast in IFF09-1 and assumed for the purposes of KPMG's forecast of net income and retained earnings.

[41] See the KM Report, p. 245.

- Increase the retained-earnings target such that accumulated retained earnings in non-drought years are sufficient to sustain losses of "at least a high percentage of the full cost of a seven year severe drought with high import prices, high interest rates, and an appreciated Canadian dollar."[42]
- Maintain storage levels above minimum levels required for dependable supply.
- Impose a surcharge on domestic rates for the purposes of funding an emergency reserve fund for use in the event of a "drastic drought."

Q: Would it be prudent for the Company to adopt such measures at this time?

A: No. It would be premature to adopt any such measures before Manitoba Hydro's new risk model is fully implemented as part of the Company's resource planning and corporate risk management processes. Before taking such measures and thereby increasing costs to consumers, the Company should determine the likely magnitude of expected financial losses, the likelihood of more-severe losses than expected, and the extent to which forecasted losses would fall within tolerance limits. Moreover, to the extent that risks are deemed unsustainable, the Company should examine whether there are opportunities for directly reducing risk that are less expensive than the measures proposed in the KM Report to cushion such risks. In particular, the Company should examine the long-term cost and risk impacts of increasing its reliance on energy efficiency, wind power, or efficient thermal generation resources. Portfolio diversification would not only reduce exposure to drought-related financial losses, but might also reduce earnings volatility and reduce the Company's overall cost of capital.

[42] KM Report, p. 18.

Q: Does this conclude your testimony?

A: Yes.