MANITOBA	**Board Order 7/03**
THE PUBLIC UTILITIES BOARD ACT	
THE MANITOBA HYDRO ACT	
THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT	**February 3, 2003**

Before: G. D. Forrest, Chair
R. A. Mayer, Q.C., Vice Chair
Dr. K. Avery Kinew, Member

A FILING BY MANITOBA HYDRO TO PROVIDE AN INFORMATION UPDATE REGARDING FINANCIAL RESULTS, FORECASTS, METHODOLOGIES, PROCESSES, AND OTHER MATTERS RELATING TO SALES RATES CHARGED BY MANITOBA HYDRO

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Executive Summary

The Manitoba Hydro-Electric Board ("Hydro") filed a status update with The Public Utilities Board ("the Board") on November 30, 2001. The purpose of the filing was to provide the Board and interested parties with an information update on Hydro, including its financial results, forecasts, methodologies, processes, and events that have transformed the electricity industry over the last few years. Hydro was not seeking any general rate changes, stating that for 2002/03, rates will have effectively been frozen for six years for residential customers and for eleven years for large industrial customers, except for the rate reductions to certain consumers as a result of province-wide implementation of Uniform Rates on November 1, 2001.

Hydro last requested a general rate increase in the fall of 1995, followed by a public hearing in early 1996. The Board's decisions from that hearing are set out in Order 51/96. In light of the long passage of time since Hydro's sales rates were last reviewed in a public forum, the Board determined that one of the purposes of this hearing would be to determine whether the existing sales rates continue to be just and reasonable and whether any changes to existing sales rates may be required.

On February 8, 2002, Hydro announced its intention to acquire the assets and business of Winnipeg Hydro, which had approximately 570 employees and served about 94,000 customers in the City of Winnipeg. The acquisition may have a significant impact on the future overall operations of Hydro.

Hydro believes holding rates constant is a more prudent course of action than offering rate reductions because of the robust export markets and favourable water conditions, which underpinned Hydro's strong financial performance, may not continue at present levels. Rates at or near their current levels will assist Hydro in achieving its longer term financial objectives. Hydro also stated domestic rates are less than market prices in nearby interconnected markets. Current rates are, on average, the lowest of any utility in North America. Lower rates may encourage more domestic consumption, which would reduce revenues as profitable export sales are foregone. Hydro agreed, however, that lower rates could attract more energy intensive industry to the Province.

During the course of the public hearing, the Board examined a number of specific areas related to Hydro's operations including operating results and financial projections, financial targets and risk, capital expenditures, extra provincial revenues, payments to the Province of Manitoba, operating, administrative and finance expenses, transmission tariffs, load forecasts and overall revenue requirements. As a result of this review, the Board identified a number of areas of concern, and made a number of recommendations including:

- Hydro limit its capital expenditures not related to new major generation and transmission, where safety and reliability constraints allow, and focus on reducing long-term debt.
- Hydro pursue short-term financing options to expeditiously pay down the debt incurred for the special export profit payment to the Province of Manitoba.
- Hydro continue to monitor and control operating and administrative expenses.
- Hydro consider ways to diversify and supplement its hydraulic generation with an appropriate mix of other forms of energy.

In addition to the above recommendations, the Board directed Hydro to:

- File an updated Integrated Financial Forecast reflecting the integration of Winnipeg Hydro and the in-service dates of all new generation within the eleven-year planning period;
- File a detailed debt management strategy;
- Undertake a study to quantify specific reserve provisions required to cover major risks and contingencies;
- Undertake a study on the merits of implementing an inverted rate structure for all customer classes;

- Undertake a study on the impact of decreasing the demand charge and increasing the tail block of the energy charge;
- Undertake a study which considers time of use rates for General Service classes based on a seasonal, weekly, daily, and hourly basis;
- Identify and specifically account for all export-related capital expenditures in its capital forecasts to ensure that export revenues are appropriately matched against the full cost of production;
- Undertake a study on the methods and impacts with respect to the classification of generation costs in the Cost of Service Study;
- Re-examine the current level of Demand Side Management programs and pricing strategies to encourage conservation, develop a program with more aggressive targets, and report to the Board;
- Consider the use of wind power in remote diesel electric communities and file a report with the Board; and

A considerable amount of time at the hearing was directed towards a review of the various cost of service studies filed by Hydro, and in particular, the proposed changes in methodology from the methodologies previously approved by the Board. The most contentious issue, and the issue with the greatest impact on cost of service results, is the allocation of net export revenues between customer classes. In this Order, the Board has not accepted Hydro's proposed cost of service methodology. The Board has directed Hydro to file an actual cost of service study for the year ended March 31, 2003 by no later than September 30, 2003 and a prospective cost of service study for the year ended March 31, 2004 by no later than September 30, 2003 which reflects a number of specific directives as set out in the Order including the cost treatment of export classes.

Although Hydro is not seeking any change to firm rates currently charged to customers, the Board noted that certain customer classes have consistently paid rates higher than their allocated costs. Therefore, the Board has directed Hydro to file for Board approval a revised schedule of rates to be effective April 1, 2003 that reflects:

(a) A 1% rate decrease for General Service Small customers;

(b) A 2% rate decrease for General Service Large ("GSL") customers greater than 30 kV; and

(c) A decrease in the winter ratchet to 70% and the subsequent elimination of the winter ratchet effective April 1, 2004.

The Board understands that this change will likely bring the General Service Medium class and the GSL <30 kV class closer to unity. Therefore, no further rate adjustment will be ordered for this class.

Given that uniform rates have provided recent rate decreases to some residential customers and the residential class revenue to cost coverage ratio has been consistently below unity (i.e., subsidized by other classes), no further rate changes are ordered for the residential rate class at this time.

The Board also directed Hydro to file a separate application for approval of an open access transmission tariff by no later than June 30, 2003.

The Board approved the Curtailable Rate Program, confirmed as final a number of interim ex parte Orders, and approved extending the Limited Use Billing Demand Rate option to March 31, 2004.

The Board also directed Hydro to establish a more regular schedule for periodic rate reviews, not exceeding three years between hearings even if no rate changes are required. This timeframe will improve the efficiency, effectiveness and timeliness of the regulatory process.

Subject to these and other specific rate directives contained in this Order, the Board has confirmed Hydro's remaining existing rate schedules to be in effect until March 31, 2006, or until otherwise amended by a further Order of the Board.

1.0 Appearances

R. Peters K. Kalinowsky C. McNicol	Counsel for The Manitoba Public Utilities Board (“the Board”)
M. Murphy O. Fernandes P. Ramage	Counsel for the Manitoba Hydro Electric Board (“Hydro”)
J. Feldschmid	Counsel for Canadian Centre for Energy Policy Incorporated (“CCEP”)
B. Williams B. Froese	Counsel for Consumers’ Association of Canada (Manitoba) Inc./Manitoba Society of Seniors Inc. (“CAC/MSOS”)
T. McCaffrey	Counsel for Manitoba Industrial Power Users Group (“MIPUG”)
M. Anderson	Representing Manitoba Keewatinowi Okimakanak Inc. (“MKO”)
E. Fleming	Representing Provincial Council of Women of Manitoba, Inc. (“PCWM”)
M. Buchart	Counsel for Time to Respect Earth’s Ecosystems/Resource Conservation Manitoba (“TREE/RCM”)
C. Henderson	Counsel for Indian and Northern Affairs Canada (“INAC”)

2.0 Witnesses for Hydro

V. Warden	Chief Financial Officer, Vice President, Finance & Administration
L. Wray	Division Manager, Business Analysis & Regulatory Affairs
R. Kirk	Corporate Controller
H. Surminski	Section Head, Resource Planning and Market Analysis
R. Wiens	Manager, Rates Department
B. Poff	Manager, Transmission Services
G. Rose	Vice-President, Customer Service and Marketing

3.0 Intervenors of Record

Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors Inc.

The City of Winnipeg

Manitoba Industrial Power Users Group

Communications, Energy and Paperworkers Union of Canada

Provincial Council of Women of Manitoba Inc.

Canadian Centre for Energy Policy Incorporated

Manitoba Keewatinowi Okimakanak Inc.

Time to Respect Earth's Ecosystems/Resource Conservation Manitoba

Subsequent to the City of Winnipeg registering as an Intervenor, Hydro entered into negotiations with the City of Winnipeg to purchase all of the assets of Winnipeg Hydro. As a result of this transaction, the City of Winnipeg withdrew from active participation as an Intervenor in this hearing.

4.0 Intervenor Witnesses

4.1 CAC/MSOS

J. Todd	President, Econalysis Consulting Services, Inc.
B. Harper	Manager, Econalysis Consulting Services, Inc.

4.2 MIPUG

J. Osler	Principal Consultant & Manager, InterGroup Consultants Ltd.
P. Bowman	Consultant, InterGroup Consultants Ltd.

4.3 TREE/RCM

J. Lazar	Consulting Economist, Micro Design Northwest
P. Miller	Professor, University of Winnipeg
B. Wild	Homesteader, Lake Winnipegosis

4.4 MKO

F. Mills	Manager, Program Planning and Allocation, Funding Services Directorate, INAC

5.0 Presenters

J. Knowles	Chief Financial Officer Hudson Bay Mining and Smelting Co. Ltd. (“HBMS”)
W. Schroeder	Chief Power Engineer, Inco Limited, Thompson “Inco”)
C. Weiss-Bundy	Systems Engineer, Simplot Canada, Brandon Complex (“Simplot”)
B. Turner	Plant Manager, Nexen Chemicals Canada Limited Partnership, Brandon Plant (“Nexen”)
Dr. C. Nicolaou	Member, Canadian Centre for Energy Policy (“CCEP”)

6.0 Background

Hydro filed a status update with the Board on November 30, 2001. The purpose of the filing was to provide the Board and interested parties with an information update on Hydro, including its financial results, forecasts, methodologies, processes, and events that have transformed the electricity industry over the last few years. Hydro was not seeking any general rate changes, stating that for 2002/03, rates will have effectively been frozen for six years for residential customers and for eleven years for large industrial customers, except for the rate reductions to certain consumers as a result of province-wide implementation of Uniform Rates on November 1, 2001. The last time Hydro sought a general rate increase was in the fall of 1995, followed by a public hearing in early 1996. The Board's decisions from that hearing are set out in Order 51/96.

Hydro sought final approval of a new Curtailable Rate Program and numerous interim ex parte Orders dealing mainly with setting the monthly reference discount prices for curtailable service program customers, establishing weekly spot market replacement energy rates under the former dual fuel heating surplus energy to self-generators and industrial surplus energy programs, and establishing weekly spot market replacement energy rates for surplus energy program customers. Hydro also requested final approval extending the Limited Use Billing Demand Rate Option.

A pre-hearing conference was held on January 14, 2002 to define the scope of the hearing, and to establish a timetable for the orderly exchange of information. As a result of the hearing, the Board issued Order 9/02 in which the Board found that, in light of the long passage of time since Hydro's sales rates were last reviewed in a public forum, one purpose of this hearing would be to determine whether the existing sales rates continue to be just and reasonable and whether any changes to existing sales rates may be required.

A public hearing was held on various dates between May 27 and September 30. The Board heard final arguments on June 11, 2002 to deal with the revenue requirement aspects of the application and September 30, 2002 to deal with Cost of Service and Rate Design.

A separate hearing was held to review matters related to the Integration of Centra Gas Manitoba Inc. and Hydro. Order 208/02 dated December 6, 2002 addresses Integration matters.

7.0 Operating Results and Financial Projections

7.1 Comparison of Actual Operating Results with IFF 95-2

The Integrated Financial Forecast ("IFF 95-2") reflected the forecasted financial results of the Board's decisions in Order 51/96. Hydro's actual operating results from 1996 to 2001 and forecast results for 2002 through 2006, as stated in IFF MH 01-1, are compared to IFF 95-2 in the following table:

Statement of Operations & Retained Earnings ($millions)	*Actual*						*Forecast IFF 01-1*				
	1996	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
Revenues											
Domestic	740	756	745	757	748	793	796	802	832	857	885
Export	246	268	297	326	376	480	628	553	528	467	454
	986	1,024	1,042	1,083	1,124	1,273	1,424	1,355	1,360	1,324	1,339
Expenses:											
Finance	426	418	419	411	402	387	496	504	507	493	497
Depreciation	169	178	191	198	215	227	237	256	269	280	286
Operating & Administrative	224	226	214	226	234	245	254	262	266	268	273
Water Rentals	47	51	56	50	51	56	112	101	97	97	97
Tax Expense	36	37	37	39	41	43	40	41	41	42	42
Fuel & Power Purchased	14	13	14	59	33	48	65	81	89	86	75
	916	923	931	983	976	1,006	1,204	1,245	1,269	1,266	1,270
Net Income	70	101	111	100	148	267	220	110	91	58	69
IFF 95-2	59	49	31	11	42	41	60	89	129	126	66
Annual Difference	11	52	80	89	106	226	160	21	(38)	(68)	3
Retained Earnings Balances											
Opening Retained Earnings	284	354	455	566	666	814	1,081	1,151	1,186	1,214	1,272
Net Income	70	101	111	100	148	267	220	110	91	58	69
Special Payment to Province	-	-	-	-	-	-	(150)	(75)	(63)	-	-
Retained Earnings - MH01-1	354	455	566	666	814	1,081	1,151	1,186	1,214	1,272	1,341
Retained Earnings - IFF 95-2	343	392	423	434	475	516	576	665	795	921	987
Culmulative Difference	11	63	143	232	339	565	575	521	419	351	354

Hydro's operating results since 1996 have been substantially better than forecasted in IFF 95-2. Hydro attributed the improvement in financial position to increased export revenues coinciding with periods of above average water flows, and controls over operating and administrative costs relative to inflation. Actual net income for each of the years 1996 through 2001 exceeded that forecast in IFF 95-2, by $11 million in 1996 to $226 million in 2001. The better than expected operating results have provided retained earnings forecast at $1.15 billion at the end of fiscal

2002, compared to the retained earnings forecast for 2002 in IFF 95-2 of $576 million. On an overall basis, Hydro is now forecasting to have $1.341 billion in retained earnings by March 31, 2006 in IFF MH 01-1 compared to the amount forecasted in IFF 95-2 of $987 million at March 31, 2006.

7.2 Integrated Financial Forecast ("IFF MH 01-1")

Hydro filed its most current financial forecast (IFF MH 01-1) for its electric operations, which included a projected operating statement, balance sheet, financing requirements and financial ratios, as well as a capital expenditure forecast (CEF 01-1) for the eleven-year period 2002 to 2012. The purpose of the IFF and CEF was to provide an indication of Hydro's long-term financial direction and for use in future planning. The forecast was revised during the hearing to reflect the impact of a $288 million payment to the Province and accounting policy changes related to foreign currency transactions including the Exposure Management Program.
IFF MH 01-1 and CEF 01-1 are attached as Appendix A and B to this Order.

IFF MH 01-1 reflects no requested rate increases for fiscal 2002 or 2003, but includes a rate increase scenario of 2% annually for fiscal years 2004 to 2009. Hydro is not seeking approval from the Board for any rate changes in this application, but will file a future rate application with the Board for its approval if rate changes are subsequently determined to be required.

On February 8, 2002, Hydro announced its intention to acquire the assets and business of Winnipeg Hydro, which had approximately 570 employees and served about 94,000 customers in the City of Winnipeg. The acquisition will have a significant impact on the future overall operations of Hydro. The impact of this transaction is not reflected in IFF MH 01-1.

8.0 Financial Targets

8.1 Background

In September 1995, Hydro adopted the following financial targets, which were reviewed by the Board at the 1996 General Rate Application ("GRA").

1. To achieve and maintain a minimum debt to equity ratio target of 75:25 by no later than 2005/06.

2. To achieve and maintain an annual gross interest coverage ratio in the range of 1.20 to 1.35 as soon as possible.

3. To fund all capital construction requirements from internal resources, except during periods when major new generation and/or major transmission facilities are being added to the system.

At that time, Hydro stated that in adopting its financial targets, a number of factors were considered including the following:

- A cushion is required to absorb the impact of negative events so as to maintain rate stability for customers;

- Risks faced by Hydro have been increasing in complexity and size, noting that a major drought could cost in the range of $1 billion;

- Credit rating agencies rely on Hydro's status as a self-supporting utility in determining the Provincial credit rating; and

- Hydro's financial targets are not out of line with the financial position and performance of several other Canadian government owned electric utilities.

These financial targets are consistent with the financial targets included in Hydro's Corporate Strategic Plan for 2002.

8.2 Risks

Hydro has identified a number of specific domestic risks that could have serious financial impacts on its operations including:

- Drought;
- Economic downturn;
- Lower than forecast domestic load related to weather;
- Decreased water flows from increased Alberta and Saskatchewan usage;
- Higher interest rates;
- Higher escalation rates; and
- Transmission or generation system outages.

During a drought, some of Hydro's non-firm export sales would be curtailed, and Hydro could be required to import power to satisfy domestic and firm export load requirements. Imported power would be significantly more expensive. An extended five-year drought has happened three times in the last 86 years. It is Hydro's position that the five-year drought scenario is the most substantial risk, with a possible $1.3 billion negative impact on retained earnings. Other risks could increase this financial impact, especially if they occur concurrent with drought. However, other risks may be non-related, and hence not totally additive. In addition to the threats of water flows, weather, economic and market conditions, erosion of domestic load, major equipment failures, and increased government payments, Hydro's financial position could also be seriously impacted by competition and deregulation in the US.

Hydro has identified a number of specific export revenue risks that could also have a serious financial impact including:

- Economic downturn;
- New gas and coal generating stations coming on line in the US;
- Increased protectionism in the US;

- Changing US legislation and regulation;
- Transmission constraints, mainly in export markets;
- Lower export prices; and
- Open access transmission.

Since export revenues are approximately 40% of total revenue, any risks to export revenues must be considered seriously. With a drought, export revenues will be significantly diminished.

In response to the suggestion of CAC/MSOS witnesses that Hydro prepare a quantitative risk analysis, which would indicate an appropriate amount for required reserves, Hydro noted the breadth and complexity of its risks are vast, and to quantify each risk would be a near impossible task. Furthermore, Hydro stated its many risks are already evaluated and managed throughout Hydro on a day-to-day basis.

According to Hydro, the suggested aggregation of risks goes against including a reserve provision only for foreseeable and measurable contingencies. The nature of risk is precisely that it cannot be foreseen and measured perfectly. While the costs of drought are estimated at over $1.3 billion today, the actual costs of a financial downturn may be greater, depending upon other factors such as domestic load, market prices, supply availability and transmission conditions at that time. In addition, other risks may occur simultaneously with the drought and all costs may have to be recovered through future rate increases. According to Hydro, the current financial targets are designed to provide a cushion to absorb the expected costs of foreseeable measurable risks, with some room to cover unforeseeable contingencies.

8.3 Debt to Equity Ratio

Hydro had a debt to equity ratio in 1996 of 91:09. The ratio has improved to 80:20 in 2001. The improvement is attributable to a growth in retained earnings, rather than a reduction in the level of debt. Total debt, net of sinking fund, increased from $4.8 billion in 1996 to $5.5 billion in

2002, while retained earnings increased from $354 million in 1996 to $1.15 billion in 2002, due primarily to increased operating profits over that forecasted in IFF 95-2.

In its credit rating report dated October 21, 2001, Dominion Bond Rating Services stated, "Hydro continues to generate sufficient cash flows to finance capital expenditures, but there's little surplus available for debt reduction. … The challenge is that high debt levels weaken most financial ratios."

Hydro attributed the high-debt level to its significant capital program and that internally generated funds first pay operating costs and then are allocated towards the capital construction program. Furthermore, the acquisition of Centra Gas Manitoba Inc. ("Centra") and the construction of the Brandon combustion turbine increased debt by $748 million during this period.

Hydro has achieved and exceeded the debt equity ratio forecasted in IFF 95-2 as illustrated in the following table:

	Actual						**Forecast**				
Fiscal Year	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
Actual/IFF MH 01-1	91:09	88:12	86:14	84:16	83:17	80:20	77:23	78:22	78:22	77:23	77:23
IFF 95-1	91:09	91:09	90:10	89:11	88:12	87:13	86:14	85:15	82:18	80:20	79:21

In IFF MH 01-1, Hydro originally forecasted to achieve its target debt equity ratio of 75:25 by fiscal 2006 with a 74:26 debt equity ratio. After reflecting the $288 million special payment to be made to the Province, the debt equity ratio in fiscal 2006 is now forecasted to be 77:23, and Hydro will not achieve a 75:25 ratio until 2008. Hydro stated that the current target is not attainable and that there would likely be a recommendation presented to its Board of Directors to establish a new target when the IFF is updated in the fall of 2002.

8.4 Interest Coverage

The Hydro Board of Directors revised the interest coverage target in 2001 from "a range of 1.20 to 1.35" to "maintaining a minimum gross interest coverage level greater than 1.20." Hydro stated that it was important that it operated with a gross interest coverage ratio of 1.20, noting that if it operated at break even, with no margin for adverse events, losses or unexpected costs, Hydro would be required to undertake additional borrowing for interest payments. According to Hydro, capital markets would not have a positive view of an interest coverage lower than 1.20, and operating at a break-even could have a negative impact on rate stability.

Hydro achieved its interest coverage ratio target of 1.20 in fiscal years 1997 to 2000, and exceeded the target in 2001 with an interest coverage ratio of 1.66. The actual results for fiscal 1996 to fiscal 2001 were significantly better than that projected in IFF 95-2 as illustrated in the table below:

	Actual						**Forecast**				
Fiscal Year	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
Actual IFF MH 01-1	1.16	1.23	1.25	1.23	1.35	1.66	1.41	1.21	1.18	1.12	1.13
IFF 95-2	1.13	1.10	1.06	1.02	1.08	1.08	1.12	1.18	1.27	1.27	1.14

The interest coverage ratio is projected to fall below the 1.2 target in 2004 for the remainder of the forecast period as a result of the additional financing costs related to the $288 million special payment to the Province. The gross interest coverage ratio over the 11-year period 2002 to 2012 in IFF MH 01-1 ranges from a high of 1.41 forecast for fiscal 2002 to a low of 1.12 in fiscal 2005, ending at 1.13 in fiscal 2012.

8.5 Capital Coverage

Hydro's target is to fund all capital construction requirements from internal cash resources, except during periods when major new generation or major transmission facilities are being added to the system.

Since 1996, Hydro has funded all capital expenditure from internally generated funds. However, at the end of fiscal 2001, its overall debt had increased by approximately $750 million. Hydro noted that its goal was to fund all capital construction, except major generation and transmission, from internally generated funds. However, there were other expenditures that fall outside the definition of capital construction expenditures that required financing such as inventory, mitigation expenses, vehicle purchases and the acquisition of Centra.

9.0 Capital Expenditures

9.1 Comparison of CEF 01-1 to CEF 95-1

Hydro's Capital Expenditure Forecast CEF 01-1 summarizes an eleven-year program of capital expenditures totalling $3.75 billion, ranging from $425 million in 2002 and declining to $239 million in 2012. This compares with CEF 95-1 total program forecast expenditures of $2.7 billion over the eleven-year period from 1996 to 2006. Over the same eleven-year period, Hydro's actual capital expenditures for 1996 to 2001 and projected expenditures for 2002 through 2006 is $3.6 billion, approximately $848 million greater than that forecast in CEF 95-1, as illustrated in the following table:

Capital Expenditures ($ millions)	**Actual**						**Forecast/Projected**					
For the years ended March 31	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**Total**
Actual/ CEF 01-1 Capital Expenditures	256	297	252	308	310	335	425	367	376	338	330	3,594
CEF 95-1	314	297	285	239	222	207	204	207	220	229	322	2,746
Difference	(58)	0	(33)	69	88	128	221	160	156	109	8	848

At the 1996 GRA, capital expenditures averaged approximately $250 million per year. In CEF 01-1, capital expenditures average approximately $350 million per year.

In CEF 01-1 capital expenditure estimates in later years are less than in earlier years since future capital projects have not yet been identified. Hydro believes that in the absence of fortuitous events, capital expenditures in the later years of the forecast period will be significantly higher than forecast since new projects will be identified. According to Hydro, the higher level of annual expenditures has been, and will continue to be driven, in large part, by distribution system expansions and upgrades, and the repair and replacement of an ageing distribution system.

The capital expenditures forecast in CEF 01-1 do not include Wuskwatim, Gull or Notigi generating stations which are expected to come into service over the next 8-20 years. Hydro has already incurred approximately $367 million in expenditures related to these future capital projects. These expenditures and related financing costs are deferred and will not be depreciated or amortized until the plant or facility is put into service.

9.2 Major Expenditures

Included in Hydro's current capital forecast are the following major projects:

Project	**Total Costs ($ million)**
Brandon Combustion Turbine	183
Brandon Unit #5 Life Extension for Coal	23
Selkirk Conversion to Natural Gas	32
Selkirk Life Extension	29
Interconnection to Rugby ND	25
Radisson-Riel HVDC Line	352
Riel Station	98
Microwave Radio Replacements	141
Planning Studies (2002-2012)	130

Hydro has installed a new 260 MW natural gas combustion turbine at the existing Brandon generating station site. Hydro also plans to upgrade the coal-fired generator to extend its useful life to 2019, beyond its scheduled closing date. Whereas the coal facilities will assist in servicing the domestic load in Southwestern Manitoba, the new natural gas combustion turbines are largely to provide necessary reserve power to facilitate extra provincial sales. The investment in the Brandon combustion turbine is primarily based on increasing the value of Hydro's surplus hydraulic energy that would have otherwise been exported into the short-term opportunity market as interruptible power. After firming up this energy, it can be sold into the more lucrative forward market. The primary benefit of the Brandon combustion turbine is to provide backup power when hydraulic generating capability is reduced during drought or equipment outages. It is expected to operate only 10-16% of the time, while hydraulic generation operates 65-80% of the time.

Citing environmental reasons, Hydro is converting the Selkirk generating station from a coal-fired to a natural gas-fired source of generation, in addition to extending its operating life. Selkirk is also scheduled to operate approximately 16% of the time.

Hydro is also embarking upon an ambitious transmission project which, when totally completed, will result in an additional HVDC line and converter stations on the east side of Lake Winnipeg. The new HVDC line ($352 million) will stretch from the Radisson Converter Station to the proposed Riel Station ($98 million) located outside Winnipeg. An HVDC paralleling line will be constructed to the existing Dorsey HVDC converter station. This will increase reliability and provide an additional 78 MW of capacity due to decreased line losses. This additional power may be sold on the export market. Ultimately two new converter stations will be added at an estimated costs of $400-$500 million each. These are not included in CEF 01-1 since their in-service date is beyond 2012. The total estimated costs for Bipole III are approximately $1.35 billion.

Hydro has forecast spending $130 million from 2002 to 2012 on planning studies for major new generation and transmission projects. In cross-examination, Hydro acknowledged paying for planning study costs commissioned by First Nations communities which will have an equity interest in the future generating stations. Planning studies are capitalized and attract carrying costs that may be significant since these studies are typically undertaken several years in advance of the planned in-service date of the project.

Costs associated with mitigation of environmental and social impacts are not included in the capital forecasts, but are included as a separate expense line item. To ameliorate the adverse effects of hydro-electric projects on the Churchill River Diversion and the Lake Winnipeg Regulation, Hydro has incurred approximately $471 million in mitigation costs. Four of the five First Nations have signed final agreements for compensation under the Northern Flood Agreement, and negotiations for settlement with Cross Lake First Nation are ongoing.

9.3 Justification and Prioritization

Hydro justified its capital expenditures within the following categories:

Justification Category	**% of Capital Costs**
Capacity	3.5
Load/Reliability	26.5
Safety	0.5
Reliability/Rehabilitation	10.0
Service	2.0
Efficiency	4.5
Other	4.0
Domestic Items*	48.7
	100.0

* Domestic items are non-specific domestic consumer-related expenditures.

Hydro has not attempted to specifically allocate capital costs associated with servicing the export market. Many of the existing capacity and load reliability items (i.e., connection to Rugby, North Dakota) may have an export component and future new generation may be built primarily for the export market. To date however, only the Brandon Combustion Turbine has specifically been justified solely for export purposes. Hydro stated that the majority of capital expenditures in CEF 01-1 have benefits associated with both export and domestic markets.

10.0 Extra-Provincial Revenues

10.1 Industry Changes Impact on Hydro

Over the past six years the North American electricity industry has changed significantly with the introduction of competition at the wholesale level. In response to the issuance of Orders 888 and 889 by the US Federal Energy Regulatory Commission ("FERC") in 1996, open access conditions were made mandatory for transmission carriers, along with a non-discriminatory wholesale tariff, which enabled wholesale competition in the electric industry in the US. By Order 2000, FERC mandated utilities to join Regional Transmission Operators ("RTOs").

The restructuring of the electricity industry in the US resulted in significant opportunities for Hydro, which prompted changes in Hydro's operations to better respond to increased deregulation. In 1996 Hydro reorganized its operations into three business units (Power Supply, Transmission and Distribution, and Customer Service and Marketing) and two support groups (Finance and Administration, and Corporate.)

Hydro's governing legislation was also changed by statutory amendments in 1997, expanding the mandate to include the marketing and supply of power outside the Province. Previously, Hydro's mandate was limited to supplying power adequate for the needs of the Province and promoting economy and efficiency in the generation, distribution, supply and use of electricity.

In response to the new opportunities, Hydro became an active member of the Mid-Continent Area Power Pool ("MAPP"), an electric reliability region and power marketing pool based in St. Paul, Minnesota. With MAPP unable to successfully transform into an RTO, Hydro then joined the Midwest Independent System Operator ("MISO"), which has become an RTO, serving 35 states.

The main consequences to Hydro resulting from electricity restructuring in the US include the following:

- Hydro now sells its transmission service under an open access transmission tariff;
- Significant increases in both the price and quantity of electricity exported;
- Annual export revenues have increased significantly;
- US customers have increased to more than 50 from 5;
- The operation of the main transmission grid is under the oversight of MISO which is responsible for operational reliability; and
- Standards of conduct limit the free flow of transmission information between the transmission operations with Hydro and the wholesale marketers within Hydro.

10.2 Extra-Provincial Revenues - 1996 to 2001

For the fiscal year ended 1996, extra-provincial revenues accounted for $246 million or 25% of total revenues. For the fiscal year ended 2001, extra-provincial revenues were $480 million representing over 40% of total revenue. The major increase in extra-provincial revenues since 1996 was primarily due to the changes in the electric industry with the evolution of competitive wholesale electricity markets discussed above. In addition, the shortage of generation supply caused spikes in prices during the high demand summer periods. This created the opportunity for Hydro to enter into forward contracts for export sales at higher prices. High natural gas prices also added to the volatility of the electricity prices.

Hydro maintains a mixed portfolio of export sales to reduce risk. These export products include long-term firm contracts and short-term opportunity sales. The opportunity sales are dependant upon water flows and can vary greatly from year-to-year.

The table below summarizes export revenues from 1996 to 2001:

	Export Revenues ($ Millions)		
Year	**Opportunity Export Revenues**	**Long-Term Firm Export Revenues**	**Total Export Revenues**
1996	105	141	246
1997	126	142	268
1998	149	148	297
1999	146	180	326
2000	146	230	376
2001	219	261	480

The export revenues, GW.h exported and average sales price per kW.h for the years 1996 to 2001 are as follows:

For the years ended March 31	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**
Revenue $ million(s)	246	268	297	326	376	480
GW.h	10,496	12,531	14,341	10,694	10,776	12,082
Average sale price ¢/kW.h	2.34	2.14	2.07	3.05	3.49	3.97

10.3 Extra-Provincial Revenues - Future Outlook

Hydro stated that price volatility in the MAPP marketplace decreased significantly in 2001 due to the addition of new generation. In addition, the spike in natural gas prices subsided as a result of a downturn in the US economy. With much of the new electricity generated by natural gas combustion turbines, the resulting forward price of electricity decreased significantly in the last months of fiscal 2002. Hydro noted that with a continuance of the downturn in the US economy and lower natural gas prices, it is expected export prices will remain at lower levels in the near term. However, export prices are expected to increase gradually in the long term because of the greater reliance on generation from natural gas-fired combustion turbines in MAPP, rather than generation from coal fired plants with lower fuel costs. In addition, the price of natural gas is forecast to increase in the long term due to high projected demand for natural gas, particularly in the electricity generation sector.

Extra-provincial revenues are forecast to increase to $628 million in fiscal 2002. The major increase forecast for 2002 over 2001 was due primarily to a change in the exchange rate used for translating US extra-provincial revenues, discussed later in this Order. Of the $148 million increase in 2002 over 2001, approximately $110 million relates to the change in the accounting for US export sales. The remainder, approximately $38 million, is due to forecast increases in volumes.

Longer-term sales volumes are forecasted at average levels with revenues of $400 to $500 million/year. Hydro did not provide a breakdown of its future export revenues forecast nor GW.h information for fiscal years 2002 through 2012, since it considers the information to be commercially sensitive.

11.0 Payments to the Province

As a Crown Corporation, Hydro does not pay income tax, provincial sales tax or the Goods and Services Tax. Hydro does, however, pay the Provincial Corporations Capital Tax, similar to other privately held corporations employing capital in the Province. The Province of Manitoba also levies a number of other fees to be paid by Hydro. At the 1996 GRA, annual payments made to the Province from Hydro were in the range of $96 million. Payments to the Province have now increased to $128 million in 2001 and are forecasted to be $354 million in 2002.

The total payments to the Province from 1996 through 2004 are summarized as follows:

For the year ended March 31	Actual ($ millions)						Forecast ($ millions)		
	1996	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**
Debt Guarantee Fee	25	26	29	31	40	49	65	62*	61*
Water Rental Rates	46	50	53	46	46	50	107	96	92
Corporations' Capital Tax	25	26	26	27	29	29	31	31	32
Sinking Fund Service Charge	0	0	0	0	0	0	1	1	1
Special Export Profit Payment ($288 million)	0	0	0	0	0	0	150**	75**	63**
Total	96	102	108	104	115	128	354	265	249

* The impact of the required borrowings related to $288 million special payment to the Province is not reflected.

**Subsequent to the hearing, Hydro's 2002 financial statements indicated that the special export profit payment will be paid out in 2003 and 2004. The first instalment will be $150 million plus an additional amount not to exceed 75% of net income for 2003. The remaining instalment in 2004 will not exceed 75% of net income for that year. In accordance with the legislation, the total distribution to the Province of Manitoba over the two-year period will not exceed $288 million.

11.1 Special Export Profit Payment

In the April 2002 Provincial budget, the Province announced a special export profit payment by Hydro to the Province of $288 million, payable in the amount of $150 million in 2002, $75 million in 2003 and $63 million in 2004. These payments are to be funded from the high export profits Hydro is experiencing and is forecast to continue experiencing. Hydro indicated that general rates would not increase as a result of these payments.

Hydro intends to finance the $288 million payment to the Province since its cash on hand is insufficient to make the payments. The interest costs to finance the payments are estimated to be an additional $276 million during the eleven-year forecast period from 2002 to 2012. As a result of the special payment and additional finance charges, retained earnings is forecast to be over $534 million less in 2012 than that originally forecast prior to the payment. When questioned as to whether Hydro had considered alternatives to financing these payments, Hydro responded it had only considered removing monies from its sinking fund. Hydro had not considered reductions to its capital expenditures nor revisions to its operations, maintenance and administration budgets.

The effect of the special export profit payment on the financial targets is to delay achieving the 75:25 debt equity ratio from 2006 to 2010, and to not achieve the interest coverage ratio target of 1.20 after fiscal 2003 through the remainder of the forecast period to 2012. Subsequent to the completion of the hearing the Hydro annual report for fiscal 2002 indicates that the $288 million will now be taken out in fiscal 2003 and 2004. The first instalment will be $150 million plus an additional amount not to exceed 75% of net income for 2003. The remaining instalment in 2004 will not exceed 75% of net income. Total distributions to the Province are limited to $288 million, under the legislation.

11.2 Water Rental Payment

Hydro pays water rental rates to the Province for the use of water resources in the operation of its hydroelectric generating stations. Under *The Water Power Act* water rental rates increased by over 105% from $1.6285/MW.h to $3.34/MW.h effective April 1, 2001. The effect of this increase was to more than double the water rental fees from $50 million in 2001 to $107 million in 2002.

Hydro had previously negotiated an agreement with the Province whereby water rental rates would be frozen from 1989 to 2001 in exchange for Hydro undertaking a number of northern development initiatives. The total costs to Hydro of such initiatives were $154 million over the 12 years. While Hydro noted the freezing of water rental rates was beneficial to Hydro, it did not plan to negotiate a similar agreement in the future.

11.3 Debt Guarantee Fee

Hydro pays the Province a debt guarantee fee in return for the Province guaranteeing Hydro's long-term debt. Previously set at 0.5% of the outstanding debt guaranteed by the Province, the fee was increased to 0.65% effective April 1, 2000 and 0.95% effective April 1, 2001. This increases the debt guarantee fee from $25 million in 1996 at the last GRA to $65 million in 2002.

Hydro stated that it receives a benefit of 15 basis points in Canadian capital markets and 75 basis points in US capital markets by financing with the backing of the provincial guarantee. All credit rating agency reports point to the provincial debt guarantee as a favourable factor in the credit rating of Hydro.

11.4 Sinking Fund

A sinking fund service charge of 0.075% of the sinking fund is paid to the Province for managing and servicing Hydro's sinking fund balance. This amounts to approximately $1 million per year.

12.0 Finance Expenses

Finance expenses were $426 million in 1996 representing over 46% of total operating expenses. Finance expenses declined to $387 million in fiscal 2001. For the fiscal years 1996 through 2001 actual finance expenses were over $226 million lower than that forecast in IFF 95-2 a result of declining long-term interest rates during the period.

Hydro has forecast finance expenses to increase in fiscal 2002 by $109 million to $496 million or 41% of annual operating expenses. The increase is attributable to an accounting policy change related to the Exposure Management Program ("EMP"), discussed below, additional debt related to the payment of the special payment to the Province, as well as an increase in the debt guarantee fee paid to the Province.

12.1 Exposure Management Program ("EMP")

Hydro employs an EMP which acts as a hedging program intended to limit the Corporation's net US dollar exposure within defined policy limits. Debt denominated in US currency is not subject to foreign exchange fluctuations as the exchange rate used has been fixed in accordance with the EMP. The program is necessary since $2.9 billion or 45% of the Corporation's $6.5 billion in long-term debt at March 31, 2001 is payable in US dollars.

As a result of the EMP, Hydro does not recognize gains or losses related to changes in the US currency exchange rate on its long-term debt or sinking fund. The EMP limits Hydro's exposure to foreign currency changes, and the sinking fund and export revenues act as a natural hedge for the retirement of the US denominated debt. Hydro has estimated that its US cash inflows will exceed the cumulative US cash outflows for interest, thermal fuel and sinking fund payments and will be sufficient to retire the existing US debt by March 31, 2023.

As a result of the program, the long-term debt and sinking fund were recorded at a designated exchange rate of ($1.00 US = $1.17 Cdn), rather than a year-end rate of ($1.00 US = $1.56 Cdn) at March 31,2001. If long-term debt had been recorded at the year-end rate it would have been approximately $1 billion greater than that reflected in Hydro's financial statements. The balance of the sinking fund would have been approximately $200 million greater. US extra-provincial revenues and finance expenses were also recorded at the lower designated rate rather than current exchange rates.

Hydro revised its EMP to reflect a new accounting policy whereby revenues and expenditures resulting from transactions in foreign currencies are translated into Canadian dollar equivalents at exchange rates in effect at the transaction dates except to the extent revenues are used to hedge future long-term foreign debt obligations. Revenues used as formal hedges are firm US revenues which are translated at the embedded exchange rates of the respective US debt obligations to which the firm revenues are linked and for which they, together, form an effective hedge.

Previously, the US based transactions including net export revenues, interest revenues on US sinking fund investments, finance expenses on US debt and fuel purchases were translated at a designated exchange rate of $1.00 US to $1.17 Cdn, an exchange rate significantly lower than the rate of exchange prevailing during the year.

As a result of these changes, Hydro's export revenues increased from $480 million in 2001 to $628 million in 2002. Approximately $110 million of the $148 million increase was due to the change in accounting policy and the remainder, $38 million was due to a forecast increase in the volume of extra provincial sales. In addition, net long-term debt increased by over $403 million in 2003 and finance expenses also increased during the forecast period.

13.0 Operating and Administration Expenses

Operating and administration expenses include the costs associated with operating, maintaining and administering Hydro. Over 72% of these costs relate to labour costs including employee benefits. Hydro reorganized its operations into a business unit structure effective April 1, 1997, resulting in no practical means of comparing individual operating and administrative expense items for fiscal 1996 and 1997 to current expenses. The operating and administrative expenses for fiscal years 1998 to 2002 are as follows:

Operating & Administrative Expenses
($ thousands)

For the years ending March 31,	1998	1999	2000	2001	2002
Wages, salaries and overtime	205,299	213,732	219,702	259,162	274,079
Employee benefits	46,516	46,782	44,145	49,664	53,963
	251,815	260,514	263,847	308,826	328,042
Travel	18,301	19,992	20,327	22,146	23,302
Material & tools	18,089	18,280	18,674	22,135	22,212
Building and property services	13,967	13,393	13,410	17,221	17,493
Motor vehicle	11,045	12,050	13,048	15,052	12,785
Office and administration	8,358	9,299	9,858	13,604	12,624
Consulting and professional fees	8,151	9,515	8,413	9,229	9,290
Construction and maintenance services	7,765	10,691	8,482	10,242	10,797
Computer services	5,868	5,471	3,920	4,513	4,234
Purchased services	3,897	4,176	6,321	6,794	6,588
Customer and public relations	3,211	4,731	2,436	2,970	3,272
Equipment maintenance	2,761	2,870	3,730	5,096	5,760
Communication systems	1,545	1,586	2,133	2,211	2,242
Consumer services	1,109	1,203	1,339	5,533	5,656
Collections	1,054	1,329	1,445	3,260	2,757
Contingency	-	-	-	-	(1,632)
Operating expense recovery	(11,833)	(5,722)	(7,723)	(11,415)	(11,583)
	345,103	369,378	369,660	437,417	453,839
Less: Capital order activities	(87,280)	(91,617)	(88,065)	(99,660)	(107,814)
Centra costs of operations	-	-	-	(44,000)	(44,900)
Electric costs of operations	257,823	277,761	281,595	293,757	301,125
Less: Capitalized overhead	(45,209)	(54,846)	(53,373)	(50,758)	(46,805)
Total	212,614	222,915	228,222	242,999	254,320

Total operating and administration expenses have increased from $213 million in 1998 to $254 million in 2002. Over the same period of time, Hydro's workforce has increased by 911 equivalent full-time ("EFT") employees, and labour costs have increased by $76 million. This increase in staffing levels and related gross labour costs was largely due to the acquisition of Centra by Hydro and the integration of Centra's employees into Hydro's operations.

13.1 Operating and Administration Costs Per Customer

In the 2002 Corporate Strategic Plan, one of Hydro's stated goals is to improve corporate financial strength. One measure of this goal is to achieve an operating and administration cost per customer (electric) of $600 by March 2003. Hydro stated that the target is a stretch target, calculated based on the average costs per customer in the proceeding five years. By relying on the average of the proceeding five years in calculating the target, productivity increases are automatically built in and accounted for in the target.

IFF MH 01-1 indicates that over the eleven-year forecast period 2002 to 2012, operating and administration expenses per customer are projected to increase from $584/customer to $664/customer. Hydro has stated that to meet the target set out in the 2002 Corporate Strategic Plan, the operating budgets of the various divisions will be scrutinized on an overall basis to ensure the target is met.

13.2 Staffing Levels

Hydro indicated that between 1998 through 2003, staffing levels are projected to increase by 887 effective full time ("EFT") employees, from 4,030 to 4,917 EFT employees. The largest increase in EFT employees occurred in 2001 when staffing levels increased by 704 EFT employees, largely attributable to the acquisition of Centra and the integration of approximately 650 Centra employees.

According to Hydro, the projected level of EFT employees in 2002 and 2003 is optimistic and the actual increase projected for these years may be less. Hydro indicated that the number of EFT positions is closely monitored to maximize efficiency within the Corporation. Hydro stated that any new position has to be approved by the President and is subject to a rigorous process to make sure the position is justified.

13.3 Cost Control Process

According to Hydro, cost control measures are continuous through the utilization of a formalized cost control process that includes planning, budgeting, monthly reporting and variance analyses, which ensures costs and resource allocations are consistent and in line with operating and capital plans. Hydro uses this process to allow management to prioritize programs and projects; manage changing conditions; provide changes in corporate direction; establish communication regarding performance; and react to unforeseen conditions on a timely basis.

13.4 Capitalization of Operating and Administration Expenditures

Hydro segregates costs between operating activities, which are a direct charge against the operating income for the year, and capital activities, which are charged to future periods and amortized over the future life of a respective project. Hydro indicated that employees timecard their activities to specific capital projects. This amount, combined with other related costs, is charged to a capital order. In addition, Hydro also capitalizes overhead by applying the predetermined overhead rates to all capital projects.

Operating and administrative expenses were approximately $454 million in 2002 before capitalized activities and overhead. Hydro indicated that approximately 25% or $107 million would be charged to capital order activities and approximately 10% or $46 million to capitalized overhead. Hydro stated that capitalizing approximately 35% of the total operating and administration expenses was reasonable and was the norm within the industry.

14.0 Transmission Tariffs

14.1 Hydro Transmission Tariff

To ensure access to the lucrative American export market, Hydro complies with certain FERC initiated demands, including reciprocity. Just as Hydro is able to obtain open access to other utilities' transmission systems in the US, Hydro now offers an open access transmission service and levies a transmission tariff to provide for the movement of electricity through Manitoba on its transmission grid. Offered as a service since 1997, the Transmission Tariff has been utilized, on occasion, by other entities and Hydro itself. Under Hydro's standards of conduct, the transmission function is separated from other functions and bills the other business units for use of the transmission facilities. Revenues have been received from use of this Transmission Tariff.

Hydro's Open Access Transmission Tariff has never been submitted for approval by the Board or the National Energy Board, but its associated rate schedules have been filed with FERC in the US. This tariff is based on the FERC pro forma Open Access Transmission Tariff. Approval of this tariff varies across other jurisdictions. Some provincial regulators, such as the British Columbia Utilities Commission, have approved open access transmission tariffs. In the restructured Alberta and Ontario marketplaces, provincial regulators approve provincial based open access transmission tariffs.

14.2 MISO Transmission Tariff

MISO also has its own open access transmission tariff to provide for the movement of electricity from Manitoba into, through, and from a MISO destination. Based on licence plate pricing, whereby the rate charged is that of the destination load zone, this tariff is also a FERC pro forma tariff. The MISO tariff does not apply to the Hydro transmission facilities – rather, it applies south of the border.

This MISO tariff has been approved by FERC, but has not been filed with either the Board or National Energy Board for approval.

14.3 Hydro's Position on Jurisdiction

Hydro noted the legislation is silent as to explicit approvals of transmission tariffs. Hydro argued the MISO tariff was beyond the provincial realm of constitutional division of powers. With respect to the Hydro Open Access Transmission Tariff, the only users are Hydro and parties outside of Manitoba. To retain the flexibility Hydro stated it must respond to rapid changes in the US markets, therefore the tariff should not be subject to direct PUB approval. Instead, the Board would review the tariff at a GRA to the extent that the tariff may affect domestic rates.

15.0 Load Forecasts and Power Resources

15.1 System Load

Hydro's domestic system load forecast is estimated at approximately 3,700 MW net peak demand, and 21,000 GW.h energy for 2003. This is forecast to increase to approximately 4,100 MW peak demand and 24,000 GW.h energy for 2012. Hydro's system load forecast has projected an increase of approximately 18% for energy and 13% for demand for the next 10 years. Over the last 16 years, actual domestic loads have been significantly below base forecasts in 13 of the last 16 years. In the other three years, actual loads have marginally exceeded base forecasts.

With relatively low generating costs and favourable export markets, Hydro is in a relatively advantageous situation to compete on the open market for the sale of power. Therefore, firm contracts negotiated by Hydro provide additional system load demands over and above domestic loads. Available power not required by domestic or firm contract export customers can also potentially be sold in the export market as opportunity sales.

15.2 System Capacity

Hydro currently has approximately 5,400 MW (winter demand) and 25,000 GW.h (annual energy) capability within its hydraulic generation and thermal plants. Hydro has sufficient resources to supply domestic loads and existing firm export sales to the year 2019 under expected load growth conditions.

The capacity criterion for the Hydro system requires that planned generation capacity must not be less than forecast annual firm peak demand plus a reserve requirement of 12% of forecast firm loads. The energy criterion requires that the Hydro system be capable of a dependable supply of energy to meet forecast firm load demands. Specifically, there must be sufficient firm energy sources to meet firm energy demand in the event of a repeat of the lowest historic water flows.

Even with a 12% demand reserve requirement, the demand capability will not be exceeded until after 2020 for domestic load and energy capability will not be exceeded until 2014. Firm exports impose only a modest (100 to 200 MW in demand and 500 to 1,000 GW.h in energy) addition to system capacity and energy demand because the nature of Hydro's firm export contracts (often involving an off-setting import commitment).

15.3 New Power Resources

In accordance with its mandate to pursue sales in the export market, Hydro is bringing new capacity online in 2003 including the Brandon Combustion Turbine. This facility will provide a total installed capacity of 260 MW.

As mentioned in the capital expenditures section of this Order, Hydro intends to embark upon an ambitious construction program over the next two decades with construction of several new generating stations: Wuskwatim (200 MW), Gull (650 MW), Notigi (100 MW), and possibly Conawapa (1,230 MW) which Hydro indicates will be subject to a separate hearing. It is Hydro's contention that new hydraulic generation should be viewed as "green" energy since it produces little or no greenhouse gases. As such, their new hydraulic facilities will contribute significantly to greenhouse gas reductions as contemplated in the Kyoto Protocol. Hydro is committed to maintaining the cumulative average net greenhouse gas emissions since 1990 at 6% below 1990 levels.

Hydro did not distribute its Power Resource Plan citing confidentiality due to the increased competitive nature of electricity trading in the US. Hydro has no wind generation in its current power resources nor plans to install any over the next decade. Witnesses for Hydro agreed the efficiencies and reliability of wind generation have increased substantially while costs have dropped simultaneously over the past few years. However, as yet, wind generation is more costly than Hydro's hydraulic generation, although there may be some other additional environmental and social benefits.

16.0 Revenue Requirement and Current Rates

16.1 Current Level of Rates

Hydro believes holding rates constant is a more prudent course of action than offering rate reductions because the robust export markets and favourable water conditions, which underpinned the strong financial performance, may not continue at present levels. Rates at or near their current levels will assist Hydro in achieving its financial objectives.

Hydro also believes domestic rates are less than market prices in nearby interconnected markets. Current rates are, on average, the lowest of any utility in North America. Lower rates may encourage more domestic consumption, which would reduce revenue as profitable export sales are foregone. Hydro agreed, however, that lower rates could attract more energy intensive industry to the Province.

In IFF 01-1 Hydro has forecast a 2% rate increases in 2004 and each year thereafter until 2009. Hydro indicated these future actual rate increases are at risk of being higher than those projected in the long range forecast in the absence of fortuitous events, such as higher export revenues or higher water flows. Furthermore, according to Hydro, a short-term decrease in rates may simply have to be recovered in future years, potentially leading to rate instability for customers. As rate stability was one of the overriding parameters, reducing and then subsequently increasing rates was not desirable. In response to the suggestion that rates should be set at a break-even level, Hydro stated domestic rates would have followed a widely fluctuating pattern with large rate decreases in 2001 during the windfall years followed by huge rate increases in the subsequent years. As such, it would be neither stable nor predictable.

17.0 Cost of Service Study

17.1 Purpose of a Cost of Service Study

A cost of service or cost allocation study is a tool used to assist in setting appropriate rates to be charged to each class of customer. The Cost of Service Study analyzes the components of Hydro's costs and assigns them to the various customer classes. The purpose of this analysis is to compare assigned costs to revenue by customer classes. The relationship of the revenues from a particular customer class to the assigned costs for that class is the revenue to cost ratio. A customer class where the revenues are equal to the assigned costs, would have a revenue to cost ratio of one. In Order 51/96, the Board stated in part that Hydro "should assume a revised zone of reasonableness target of 0.95 to 1.05" for all class revenue to cost coverage ratios. The results are used to provide guidance in establishing the rate levels and designing the rate structures for each customer class so that each customer class pays its fair share of costs incurred by Hydro to deliver service.

17.2 Methodology

Fully embedded cost of service studies generally employ a three-step process of cost analysis as follows:

(a) Functionalization of costs according to services (or functions) performed by the utility. The major functions by which costs are assigned are generation, transmission, distribution and ancillary services.

(b) Classification of each function's costs according to the system design or operating characteristics that caused those costs to be incurred. In the case of electric utilities, costs are generally classified as one of the following:

- Demand-related costs - Allocated among the customer classes on the basis of demand imposed on the system during specific peak hours, and the maximum size (capacity) of facilities required to service the demand of customers.

- Energy-related costs - Allocated among the customer classes on the basis of energy which the system must supply to serve the customers.

- Customer-related costs – Allocated among the customer classes on the basis of the number of customers, the weighted number of customers, or costs per customer.

(c) Allocation of each functional and classified cost component to specific customer classes based on each class's contribution to the specific cost driver selected.

17.3 1997 Cost of Service Study

Hydro's 1997 Cost of Service Study generally follows the standard three-step process of functionalization, classification and allocation of costs to customer classes. The methodology was last reviewed in conjunction with Hydro's Application for 1996 and 1997 rates. In the resulting Order 51/96, the Board directed Hydro to make some methodology changes, to review a number of other matters, and to report to the Board by no later than the next GRA on a number of issues including the following:

(a) An alternate method of solving the persistent problem of certain subclasses (e.g. Zone 3 Residential and General Service Large ("GSL") being outside of the zone of reasonableness.

(b) The merit of considering GSL customers (over 100 kV) as a separate customer class for cost of service purposes.

(c) An actual cost of service study for 1996/97 on Area and Roadway Lighting to determine actual conditions including the real coincident peak ("CP") factor.

(d) The implications of using incremental versus embedded costs as they would apply to Hydro's rate design, including the impact on various customer classes.

(e) Directly assign DSM costs for General Service Small ("GSS") and General Service Medium ("GSM") customers in future cost of service studies.

(f) Continue with the present net export revenue allocation for cost of service purposes.

(g) Develop a comprehensive rate policy which gives full consideration to all issues related to implementing time of use rates, including off-peak and seasonable rates. The study was also to include the implication of the phase out of the winter ratchet.

17.4 November 2001 Cost of Service Study

Hydro revised its cost of service methodology in the Cost of Service Study filed in November 2001 to:

- Recognize the changes in export energy markets that have taken place in the last several years;
- Recognize the significance of Hydro's participation in these markets to the pricing of its energy and transmission resources;
- Recognize the unique circumstances of Hydro's wholesale customer – The City of Winnipeg; and
- Address issues arising out of Orders 51/96 and 91/00.

17.5 March 2002 Cost of Service Study

Prior to the commencement of the hearing, Hydro indicated it was unable, for reasons of commercial sensitivity, to provide the information necessary to support its November 2001 proposed cost of service methodology. Also, subsequent to the original filing, Hydro and the City of Winnipeg entered into negotiations for Hydro to purchase the net assets of Winnipeg Hydro. Completion of this transaction would eliminate Winnipeg Hydro as a separate customer class and impact the cost of service analysis. As result, on March 27, 2002, and in accordance with Order 52/02, Hydro filed a revised cost of service study that included a number of modifications to its November 2001 filing. The Revenue Cost Average Analysis is attached as Appendix C and the Revenue Cost Variance Analysis is attached as Appendix D.

17.6 Functional Changes

17.6.1 Transmission Assets

In Hydro's 1996 cost of service methodology, all transmission lines and stations (including HVDC facilities) were included in the transmission function and, subsequently, allocated on the basis of both demand and energy. In the March 2002 Cost of Service Study, Hydro proposed a number of changes in the functionalization of transmission assets:

- Hydro's HVDC facilities (with the exception of the Dorsey Converter Station which is considered transmission) are functionalized as generation;
- Only transmission facilities recognized for inclusion in Hydro's Transmission Tariff are included in the transmission function;
- Four sets of AC transmission lines that serve as part of the HVDC collection system in the north to bring the power to the converter stations at Henday and Radisson are functionalized as generation;
- Radial (one way) transmission facilities, including those with voltages greater than 100 kV, are treated as sub transmission and included as part of distribution assets; and
- Local power lines and stations are treated as distribution.

The transmission lines and stations excluded from the transmission function continue to be treated as generation.

17.6.2 Ancillary Services

In its proposed cost of service methodology, Hydro has introduced a new function to capture the facilities and costs associated with providing the following ancillary services:

- Scheduling, System Control and Dispatch
- Reactive Supply and Voltage Control from Generation Sources
- Regulation and Frequency Response
- Energy Imbalance
- Operating Reserve-Spinning Reserve
- Operating Reserve-Supplemental Reserve

In previous studies the costs associated with these services were "bundled" as part of generation and transmission costs. To determine the costs of ancillary function, the assets and expenses associated with providing each of the above services were identified.

17.7 Classification Changes

17.7.1 Generation

Hydro's pre-2001 cost of service methodology classified generation and transmission between energy and demand on the basis of system load factor. The methodology proposed in Hydro's November 2001 study classified generation, transmission and ancillary service separately. Generation costs were classified into four categories: winter energy, winter capacity, summer energy and summer capacity. The classification ratios were to be derived by multiplying the domestic energy and demand forecast by a five-year levelized forecast of Hydro's marginal costs, which, in turn, reflected the export value of capacity and energy.

In its March 2002 revised cost of service methodology, Hydro generally returned to the pre-2001 approach and classified total generation and transmission (along with ancillary services) costs on the basis of system load factor. However, in the revised Cost of Service Study, transmission and ancillary services are classified wholly as demand-related. The balance of the demand-related costs is assigned to generation and all other generation costs are classified as energy related. The result is that 21.2% of generation costs are classified as demand-related.

17.7.2 Transmission

Both the November 2001 and March 2002 cost of service studies classified all transmission costs as demand-related as opposed to classifying then on the basis of system load factor, as previously done by Hydro.

17.7.3 Ancillary Services

Hydro proposes to classify these costs on the same basis as transmission function costs - entirely demand-related.

17.8 Allocation Changes

17.8.1 Generation, Transmission and Ancillary Services Costs

Hydro's pre-2001 cost of service methodology allocated energy-related generation and transmission costs on the basis of annual energy use, including losses between the meter and the generators. Demand-related generation and transmission costs were allocated on the basis of each customer class' contribution to the coincident peak (where coincident peak was defined as the average load during the highest 50 hours of the year). Ancillary services were not separately identified in the previous Cost of Service Study.

In Hydro's March 2002 cost of service methodology:

- Energy-related generation costs are allocated to customer classes based on their share of the overall annual energy requirements (Non-Coincident Peak Methodology);
- Demand-related generation costs are allocated to customer classes on the basis of each customer class' share of the average of the top 50 coincident load hours during the months of December, January and February and June, July and August (2 Coincident Peak Methodology);
- Transmission costs are all classified as demand-related and allocated to customer classes based upon their monthly demands at the time of the system's monthly peaks, with all months given an equal weighting (12 Coincident Peak Methodology);
- Ancillary services costs (all considered to be demand-related) are allocated on the same basis as transmission costs (12 Coincident Peak Methodology).

17.8.2 Export Revenues

Hydro's net export revenues have grown from 17% of total revenues in 1993 to 43% of total revenues as forecast for 2002. As a result, the Cost of Service Study treatment of net export revenues now plays a significant role in the determination of revenue to cost coverage ratios for the various customer classes. For example, the revenue to cost ratio of the "GSL" customer class, based on the proposed methodology in the March 2002 Cost of Service Study, is 1.00, and allocated export revenues are approximately 39% of allocated costs. Alternatively, if export revenues are allocated to the GSL customer class using the methodology consistent with the Board's decision in Order 51/96, the revenue to cost ratio is approximately 1.12, and the allocated export revenues are approximately 49% of allocated costs. Different methodologies for allocation of export revenues can significantly impact customer class revenue to cost coverage ratios.

The previous cost of service methodology employed by Hydro in 1996, and approved by this Board, allocated export revenues as a credit to the various customer classes, based on the generation and transmission costs allocated to each customer class. The previous methodology was based on the premise that it was only the generation and transmission functions which support the export of Hydro's surplus capacity and energy. The revised cost allocation study proposed by Hydro allocates net export revenues on the basis of each class of customer's share of all allocated costs (generation, transmission and distribution).

There was much discussion and debate during the hearing concerning the merits or otherwise of creating a separate export revenue customer class. While acknowledging that creation of an "Export Class" is theoretically possible, Hydro has not fully studied the matter and indicated there were issues, such as the identification of embedded costs, that would need to be determined and whether it is appropriate to include only long-term sales, all firm sales or all export sales in an "Export Class".

Hydro suggests its proposed change in the allocation of net export revenue yields results that:

- Are less distorting of the economic price signals for generation and transmission; and
- Address the Board's concerns as expressed in Order 51/96, including the concerns about class revenue to cost ratios falling outside of the "zone of reasonableness."

17.8.3 Winnipeg Hydro

The November 2001 cost of service filing by Hydro had proposed a number of modifications to the way generation and transmission costs were allocated to Winnipeg Hydro. However, as a result of the acquisition of Winnipeg Hydro, the revised cost of service methodology filed with the Board in March 2002 resulted in the following changes:

- Removal of Winnipeg Hydro as a class of service from the Cost of Service Study;
- Allocation of the costs formerly allocated to Winnipeg Hydro to all the retail classes on the basis of the appropriate allocators; and
- Allocation of the revenues anticipated from Winnipeg Hydro to all the retail classes on the same basis as export revenues.

Hydro's interim adjustment, to the Cost of Service Methodology, for costs and revenues associated with Winnipeg Hydro, was in recognition that the retail customers of Winnipeg Hydro will be incorporated into Hydro's retail classes in future cost of service studies. However, the load and cost data from Winnipeg Hydro was not available to permit such treatment in the March 27, 2002 amended methodology.

Both CAC/MSOS's and MIPUG's pre-filed evidence criticized Hydro's March 27, 2002 amended methodology for the treatment of Winnipeg Hydro as being inconsistent in its treatment of costs and revenues.

In its rebuttal evidence, Hydro acknowledged the inconsistency and suggested that a more appropriate interim cost of service methodology to exclude Winnipeg Hydro as a customer class, would be to subtract all costs expected to have been billed directly by Hydro to Winnipeg Hydro, from generation and transmission costs. Hydro also suggests it would be consistent with the balance of all costs incurred by Hydro's current customer classes.

Hydro has indicated that there is sufficient information available to revise the most recent Cost of Service Study and roughly assign Winnipeg Hydro data to the appropriate classes with a view to illustrating, on a directional basis, the impacts of the Winnipeg Hydro acquisition. A more precise prospective cost of service study for 2003/04 will be prepared.

17.8.4 Implications of Proposed Cost of Service Methodology

The March 2002 proposed Cost of Service Study includes the above-mentioned methodology changes. The results are at considerable variance from the results obtained under the methodology previously approved by the Board. The Revenue to Cost Coverage ("RCC") results under the proposed methodology are significantly affected by the proposed treatment of export revenues and the acquisition of Winnipeg Hydro. The RCC results by overall major customer class are shown in the following table:

Class	RCC Using Previous Methodology (51/96) For Year Ended March 31, 2002	RCC Using Proposed Methodology (March 2002) For Year Ended March 31, 2002
Residential	.884	.965
General Service Small (non-demand)	1.058	1.095
General Service Small (demand)	1.061	1.047
General Service Medium	1.073	1.044
Winnipeg Hydro	1.173	not applicable
Area and Roadway Lighting	.976	1.019
General Service Large	1.108	1.000

17.8.5 Zone of Reasonableness

One product of a cost of service study is a revenue to cost ratio by customer class, where unity, or revenue to cost ratio of 1, indicates that the costs allocated to a class is equal to the revenue earned from that class. The "zone of reasonableness" refers to the revenue to cost ratio range above and below unity that is acceptable. That is, the degree to which each customer class either underpays or overpays their share of allocated costs. Prior to 1996, the zone of reasonableness target was initially 0.85 to 1.15, then 0.90 to 1.10. In Order 51/96, the Board Findings stated in part that Hydro "should assume a revised zone of reasonableness target of 0.95 to 1.05."

The attached table summarizes revenue to cost ratios by major customer classes over the ten year period 1992 to 2002, and highlights certain customer subclasses that have consistently been outside of the zone of reasonableness for a considerable period of time.

Revenue to Cost Coverage – Various Customer Classes
1992 to 2002

PCOSS	1992	1993	1994	1995	1996	1997	1999	2000	2001	*2002
Res Z1	93.2	90.9	92.5	96.5	100.5	102.5	96.3	97.0	92.4	100.6
Res Z2	96.2	93.7	93.7	95.2	96.6	96.0	99.9	101.0	98.6	102.1
Res Z3	85.5	83.0	82.6	82.7	81.8	81.6	83.7	83.1	83.9	89.0
GSS	103.8	103.2	105.6	105.3	106.2	104.5	107.7	105.8	105.4	107.1
GSM	109.3	110.5	110.1	106.1	102.4	102.4	105.5	108.4	109.4	104.4
GSL<30kV	109.0	109.7	109.5	105.2	98.5	100.9	101.4	101.2	102.6	96.8
GSL 30-100kV	122.5	117.5	114.8	111.8	109.4	108.1	110.3	112.0	118.8	109.4
GSL>100kV	110.9	111.8	111.6	110.9	109.5	111.1	110.8	111.0	116.7	100.1
GS Curtail	_	_	_	_	_	_	107.5	110.3	114.5	99.2

* Hydro's March 2002 proposed Cost of Service Study includes some methodologies, which have not been accepted by the Board.

18.0 Rate Design

18.1 Background

As part of its Status Update filing, Hydro is not seeking any change to firm rates currently charged to customers. Hydro's position is that any Board directed changes and modifications to the Cost of Service Study may impact rate design, and accordingly, the issue of rates should be deferred for future discussions at another hearing. However, Hydro agreed that this regulatory review was a good time to examine rate design issues on a purely principled basis, because Hydro was not requesting any rate changes.

In Order 51/96 the Board directed Hydro to "undertake a study and report to the Board by no later than the next GRA to develop a comprehensive rate policy which gives full consideration to all issues related to implementing time of use rates, including off peak and seasonal rates. This study should include consultation with interested parties and consideration of implications of the phase out of the winter ratchet." It was Hydro's position that matters relating to the problems of subclasses being outside the zone of reasonableness requires regulatory resolution before any other issues related to rate policy and strategy are considered. Hydro also indicated it has no intention of planning any major rate design changes over the next five years.

18.2 Uniform Rates

With the introduction of uniform rates by way of legislation in November 2001, rate zone distinctions for customers on the inter-connected grid were eliminated and all rates in the previous zones 2 and 3 were reduced to be the same as the rate charged in zone 1, which includes the City of Winnipeg. The financial impact of uniform rates is a decrease in revenues of approximately $14.8 million in 2003, the first full year of implementation.

18.3 Residential Rates

The residential rate has a declining block structure which includes a higher energy charge for the initial 175 kW.h and a lower charge for the remaining block. Additionally a basic monthly charge of $6.25 is intended to partially recover costs which do not vary with either demand or energy but which are incurred merely by being a customer on the system. These costs include those associated with billing, customer service, metering, meter service reading, and some portion of the distribution system. Currently the basic monthly charge recovers less than half of these actual costs, the balance of such costs being recovered by way of the energy charge.

18.4 General Service Small Demand and Non-Demand

These customers are the least homogenous of all rate groups. GSS customers are generally small retail and commercial operations. The basic monthly charge of $14.00 for single-phase power or $20.86 for three-phase power recovers substantially more customer related costs than does the residential basic monthly charge. The energy charge is also a declining block rate structure. GSS customers that exceed 50 kV.A are also subject to a demand charge.

18.5 General Service Medium

These rates contain a basic monthly charge, in addition to both demand and energy charges.

18.6 General Service Large

This customer class is broken into three different rate groups, depending upon consumption levels. There are no basic monthly charges for customers in this class. Those customers with the highest consumption levels are charged the lowest rates, because the largest consumers are served off the main transmission system, thereby not using sub-transmission or distribution facilities.

18.7 Time of Use Rates

A time of use rate varies according to the time in which the consumption occurs. During peak periods, customers are charged higher rates and are charged lower rates during off-peak periods. Time of use rates vary seasonally, weekly, daily, or hourly, and even extend to real time pricing. These rates provide a signal to customers of the variable costs of power.

In Order 51/96 the Board directed Hydro to undertake a comprehensive rate design study and include consideration of time of use rates, amongst other things. No such report has been prepared and no movement towards time of use rates is planned by Hydro in the near future. Hydro indicated it is planning to attach specialized meter reading equipment on more customers below the 1,000 kV.A threshold, namely the 250-1,000 kV.A level, of GSL and GSM, which will enable these customers to access time of use rates should Hydro develop such rates in the future. In doing so, this will remove a practical impediment to implementing time of use rates.

18.8 Winter Ratchet

As part of the demand billing process, the monthly billing demand for general service customers is based on actual demand, with a minimum demand equal to 80% of maximum previous winter monthly demand measured in December, January or February. The rationale for the winter ratchet is to signal to customers the high costs of winter capacity and to ensure full winter demand costs are recovered. This issue is problematic for those customers with low off-peak energy usage relative to maximum demand.

The Board is aware that certain customers have been pressing Hydro for a waiver of demand charges during scheduled maintenance shutdowns. Their argument focuses on Hydro’s ability to sell this available power on the opportunity export market. Under appropriate constraints with respect to timing and pricing, there could be merit in Hydro offering such a waiver to certain customers.

A report prepared by Hydro investigated alternatives to the winter ratchet including:

- Elimination or substantial reduction of the winter ratchet;
- Gradual reduction of the winter ratchet;
- Replacement of the winter ratchet with higher seasonal and/or peak prices; and
- Waive of the winter ratchet during selected periods.

If the winter ratchet were to be eliminated, the financial consequences would be approximately $3-4 million less revenue annually for Hydro.

18.9 Limited Use Billing Demand

In seeking to address some issues with the winter ratchet, Hydro introduced the Limited Use Billing Demand ("LUBD") rate option in 2000. This allows eligible customers with low energy use relative to demand use to choose an alternate billing process. Under the LUBD program, customers may opt for a lower demand charge in exchange for a higher energy charge. The energy rate for a GSM firm customer is 2.12¢/kW.h whereas a LUBD customer pays 6.92¢/kW.h. The demand rate for that same firm customer is 8.32¢/kV.A whereas a LUBD customer pays 2.08¢/kV.A.

Originally approved for two years commencing June 30, 2000, Order 118/02 extended the LUBD on an interim ex parte basis so it could be considered in this hearing before the Board. Hydro is seeking final approval of Order 118/02 and to make the LUBD rate option a permanent rate offering.

The LUBD rate option is utilized by approximately 120 customers.

18.10 Surplus Energy Program

The Surplus Energy Program ("SEP") replaced the Dual Fuel Heating ("DFH") and Industrial Surplus Energy Programs ("ISE") in 2000. The rationale for those programs was that as a predominantly hydraulic utility, Hydro must plan to have sufficient energy capability to meet the demand of firm customers under the most adverse water conditions. As droughts occur intermittently, Hydro normally has surplus energy available most years. Hydro markets this surplus energy to Manitoba eligible consumers at rates comparable to export prices for similar energy services to enhance pricing options.

The ISE program permitted customers to obtain an alternate supply of energy through spot market energy when Hydro interrupted their supply. The spot market price was based on market conditions considering such factors as import and thermal costs, foregoing export revenues, transmission losses, a margin to account for overhead and administration, and a contribution to retained earnings. A minimum spot market replacement energy rate was in place, in addition to a varying weekly Energy Cost Adjustment and when the Energy Cost Adjustment was required Hydro would file such an application with the Board, on a weekly basis for interim ex parte approval.

The prices for the SEP are based on a forecast of the expected source of energy and associated costs. These are submitted to the Board on a weekly basis for interim ex parte approval, with rates broken into peak, shoulder, and off-peak hours.

At the time of closing arguments, a total of 116 interim ex parte weekly orders had been approved for the DFH and ISE programs, and 96 orders had been approved on an interim ex parte basis for the SEP. Hydro requested final approval of all orders issued on an interim ex parte basis prior to the Board issuing this order. No Intervenors addressed these orders in the hearing. A list of all ex parte orders relating to these programs is attached as Appendix E to this Order.

18.11 Curtailable Rates

Hydro has applied for approval of a new Curtailable Rate Program ("CRP") to supercede the existing Curtailable Service Program ("CSP"). The existing program, originally set to expire November 30, 2001, was extended to February 28, 2002 by Order 150/01 and then again by ex parte Order 55/02, until this Order was released. Hydro proposes the new CRP have a relatively short duration of until November 30, 2003 because the unknown impact of MISO's requirement for and value of reserves.

The CRP allows Hydro to curtail a portion of a large industrial customer's peak load in exchange for reduced rates on that same portion of the load when it was not curtailed. The objective of the CRP is to cut back on the electrical loads during specific periods when the overall electrical system was being taxed to its maximum capacity. As part of the Demand Side Management Program, the CRP reduces Hydro's peak load and assists in maintaining the essential power capacity reserves required for domestic and export operations.

Currently, nine curtailable rate options exist for customers, based on duration and notice for curtailment, in addition to price. Three customers now subscribe to the program, with a total subscribed load of approximately 100 MW. In 2001, the two customers who subscribed to the curtailable rates program saved $1.96 million and $380,000 respectively. Under the proposed CRP, five curtailable rates options will be offered to customers.

Under the proposed CRP, the rationale for curtailments will be altered to only instances required to meet reliability of the system and obligations to maintain operating reserves. There will be no curtailments to enable Hydro to make a high value opportunity sale; curtailments may, however, be made for firm export sales. Additionally, curtailments could occur for forecast errors, loss of facility, and restoring the operating reserve. Curtailments will not be conducted for peak shaving. In 2001, the overwhelming majority of curtailments (26 of 29) were for peak shaving and reducing imports. Since neither of those will be reasons for curtailment in the future, Hydro expects only two to three curtailments per year under the new program, although there will be a maximum ceiling of 3 to 18 curtailments per year depending upon the option chosen.

The financial case for the CRP is based upon an expectation of 150 MW subscribed annually, for a $4.3 million revenue savings to customers. With approximately $1 million attributable to benefits easily quantifiable, the remaining $3.3 million is attributable to reliability benefits not easily quantifiable according to Hydro witnesses. In 1998 (Order 153/98) Hydro presented an application to the Board to alter and extend the Curtailable Service Program. At that time, Hydro indicated there would be $10.4 million in savings to ratepayers if the CRP were extended for a decade. With compounding effects, this would increase to $26 million over that 10 year period. At this hearing, Hydro was unable to provide any tangible evidence whether part of this benefit had been achieved since 1998, noting that by their very nature, these benefits are difficult to quantify and reconstructing decisions made based upon existing circumstances at that time is nearly impossible with intervening events.

The proposed CRP has a reference discount which varies by percentage for each program option. Previously, the benefits had been calculated using the marginal cost values of capacity. The benefit of capacity curtailed over the winter peak was estimated to result from the ability to improve reliability and thus defer the timing of resource requirements. For summer, the benefit of capacity curtailed was estimated to result in increased revenues corresponding to short-term firm capacity sales. Previously the reference discount varied monthly, based on the US – Canadian dollar exchange rate.

In this application, Hydro has applied for a fixed reference discount of $2.75/kW per month, to be adjusted annually for the Consumer Price Index. Hydro has also changed the calculation of the reference discount since Hydro now believes marginal costs are commercially sensitive information and the determination of a value was difficult. Now, Hydro is attempting to use reasonable judgment to balance the lowest value Hydro judges to be necessary to attract sufficient curtailable load to make the CRP work, with the expectation that the load will be available in the long term where the capacity values to Hydro are expected to be higher. Accordingly, Hydro proposes the reference discount be ascribed a value of a reasonable relationship to an alternative least cost resource of capacity, namely a natural gas combustion turbine. In this instance, at $2.75/kW, it is approximately 42% of the levelized cost of the combustion turbine.

With the reference discount previously subject to monthly fluctuations in currency exchange rates, Hydro had filed a number of interim ex parte applications for the CSP. In this application Hydro seeks final approval of the ex parte Orders listed in Appendix E of this Order.

18.12 Diesel Rates

There are approximately 800 customers in the four remote communities of Shamattawa, Tadoule Lake, Brochet and Lac Brochet, who are provided electrical service by diesel generation. These customers are not connected to the main grid due to remoteness of location. In 1997 nine other remote communities previously on diesel service were connected to the main grid. Recent upgrades have permitted the four remaining diesel communities to have similar residential service to those on the main grid with the exception of a prohibition of space and hot water heating.

The current full cost rate for providing diesel service was estimated at 35.9¢/kW.h. Residential diesel customers are charged the same rates as residential grid customers, thereby creating a shortfall of approximately 29¢/kW.h sold. Non-government General Service customers are charged the same rate as grid customers for the first 3,000 kW.h consumed per month and the full cost rate thereafter. Government customers pay the full cost rate. In addition to these full cost rates, all government customers pay a government surcharge intended to recover the deficit incurred by providing grid based rates to non-government diesel customers. The surcharge has been in effect since 1984 and has escalated dramatically to 44.8¢/kW.h. This surcharge is in addition to the full cost rate of 35.9¢/kW.h.

Notwithstanding the government surcharge, a shortfall of $250,000/month is accumulating since the costs of providing service greatly exceed the revenues generated. Up until 2001, the total revenue shortfall was $7.4 million, with a $3.2 million shortfall in 2001 alone.

Since November 2000, in response to a request by MKO, Hydro has billed all First Nations accounts, including government surcharges, directly to Indian and Northern Affairs Canada. In response, Indian and Northern Affairs Canada maintains it provides funding through a formula to the Bands to assist in paying their electricity bills, and returned the unpaid bills to Hydro.

Hydro filed an application for rates for diesel service dated December 2, 2002 and a public hearing is scheduled to commence on March 3, 2003.

19.0 Intervenors' Positions

19.1 CAC/MSOS

19.1.1 Financial Targets

CAC/MSOS questioned the need for Hydro to attain a 75:25 debt equity target to acquire capital at reasonable rates. CAC/MSOS stated the evidence presented by its witnesses, Mr. Todd and Mr. Harper, had confirmed that neither the debt equity ratio nor interest coverage ratios are determinative of Hydro's ability to access capital at reasonable rates. Rather, the key factor in establishing the credit rating is the health of the Provincial finances coupled with the sufficiency of the actual potential revenue streams. Mr. Todd stated neither the interest coverage ratio nor the debt equity ratio should impact Hydro's debt rating nor change Hydro's ability to issue debt, since Hydro's rating is primarily based on the existing Provincial debt guarantee. Mr. Todd noted Hydro's capacity to raise rates, if circumstances warrant, is the key indicator of its ability to meet its obligations in the event of a catastrophe, without posing a burden on the Province.

Further, as confirmed by Standard & Poors, "the existence of a strong and supportive Government and regulatory environment, including a debt guarantee fee, can outweigh somewhat weaker financial indicators." CAC/MSOS noted this was supported by the fact that Hydro's debt rating had remained unchanged, while its debt equity ratio has consistently improved, noting Manitoba still benefits from the same "A" rating now as in 1995 when its debt equity ratio was substantially weaker at 92:8.

Mr. Todd stated there was an inconsistency in Hydro setting an interest coverage ratio of 1.20 to collect an additional $100 million cushion each year, when current reserves of over $1 billion give Hydro sufficient financial protection from a drought. Mr. Todd further stated Hydro need not keep earning net income of $100 million or more annually to be fiscally responsible and that instead of maintaining an interest coverage ratio of 1.20, building reserves even further, Hydro could establish an interest coverage ratio of 1.0, resulting in lower rates set roughly in line with break even over the long run.

19.1.2 Risks

Mr. Todd stated that with more than $1 billion in retained earnings, and 400,000 customers, each customer on average had contributed $2,500 towards that retained earning. As a form of rate stabilization insurance, this was rather expensive according to Mr. Todd, and Hydro is seeking to increase the amount by another 50% to $1.5 billion by fiscal 2008.

Mr. Todd stated it was not sufficient to justify seeking reserves of over $1.5 billion on the basis of a cursory listing of risks. To determine analytically the extent to which it is appropriate to build financial reserves by setting rates that recover more than the normally allowed costs, it is necessary to define clearly the risks being mitigated. Defining the risks involves not only identifying them, but also quantifying the range of possible financial impacts of the relevant risk factors and the likelihood of different possible outcomes. In addition, it is necessary to understand clearly the purpose of mitigating the risk, so an assessment can be made of the appropriate risk tolerance to be adopted for purposes of establishing appropriate financial targets. According to Mr. Todd, risks which cannot be anticipated and built into the forecast should be the only risks requiring reserves.

CAC/MSOS suggested that Hydro's risk analysis consisted of identifying the financial impact of drought at $1.3 billion and then merely listing other risks with no indication as to their impact or likelihood of occurring. Accordingly, such a superficial approach should be rejected in favour of a more vigorous quantitative risk analysis. CAC/MSOS supported its witnesses' recommendations on examining the risks to set an adequate reserve provision by undertaking the following:

1. Determine which risks require reserves – namely unanticipated and therefore not built into the forecast;

2. Consider the magnitude and probability of that risk occurring and recognize the relationship between the risks;

3. Consider the tolerable rate increase should the risks be realized; and

4. Ensure the risk analysis can justify the reserve provision.

19.1.3 Capital Expenditures

CAC/MSOS further suggested the current levels of reserves encourage higher than necessary capital expenditures and that Hydro could operate with a 5% lower capital budget without seriously impacting system capacity and reliability. Furthermore, Hydro's response to a worsening financial situation should be a decrease in capital expenditures rather than merely a requested rate increase.

19.1.4 Operating and Administrative Expenses

The evidence of Mr. Harper, on behalf of CAC/MSOS, suggested Hydro be encouraged to pursue aggressive cost control through productivity improvements to control operating and administration expenses. CAC/MSOS adopted the position of Mr. Harper in closing argument and advocated that Hydro should be evaluated on whether it could achieve annual productivity improvements of 1.5%. CAC/MSOS also suggested there exists opportunities for Hydro to reduce the operating and administration costs per customer.

Mr. Todd and Mr. Harper stated in their evidence that the target level for operating and administration cost per customer for rate setting purposes for the years 2000 to 2012 should be set at $620/customer. Mr. Harper stated the $620 benchmark would reflect a level of productivity typically expected of other regulated activities. Mr. Harper acknowledged Hydro has built in a productivity factor in setting the operating and administration cost per customer target, but suggested that the bar be set higher, more in line with general industry expectations.

CAC/MSOS witnesses stated Hydro's performance in terms of operating costs per customer was in the middle to upper end of the cost range when compared to Hydro Quebec and BC Hydro. They also examined the operating and administration costs in IFF MH 99-1 and IFF MH 01-1, and suggested Hydro has room for improvement.

19.1.5 Load Forecast and Power Resources

CAC/MSOS witnesses highlighted that Hydro has adopted as an energy supply planning criteria that its system be capable of supplying sufficient energy from its thermal and hydraulic stations, under low flow conditions, to meet firm load demands (including firm exports). CAC/MSOS noted forecast export prices should be reflective of the price of natural gas. The cost of gas-fired generation is expected to increase with resulting increased opportunities for Hydro to export power, according to CAC/MSOS witnesses.

19.1.6 Revenue Requirement and Rates

CAC/MSOS argued that although a rate decrease would have been justified prior to the announcement of the special export profit payment, it would now be difficult to recommend one taking into consideration the impact of the payment on the net income of Hydro. CAC/MSOS suggested the Board consider a modest one-time only dividend of approximately 4% to reduce the net income forecasted for 2003.

19.1.7 Cost of Service

CAC/MSOS argued that one of the key questions in the proceedings is whether the Board should accept the narrow view of cost causation supported by MIPUG, or a broader view adopted by Hydro and supported by CAC/MSOS and CCEP. CAC/MSOS pointed out that historically, export revenues were small relative to domestic revenues and costs, and at that time, export prices were less than domestic rates. Under that scenario, applying the principle of cost causality, efficiency, stability and public acceptability made some sense, as did the allocation of export revenues to generation and transmission only. Given the relatively low level of export revenues, this methodology was not distorting and was reasonably reflective of total costs.

CAC/MSOS pointed out that in the recent past, the export market has changed considerably, both in terms of the magnitude of sales, access to the market and Hydro's planning perspective. Net export revenues now offset over 52% of total generation and transmission costs. Mr. Harper stated the costs of generation and transmission allocated to customers have been increasingly underwritten by export revenues, causing an increasing disparity between costs allocated to high-voltage customers served off the transmission system and lower-voltage customers served off distribution.

Export sales now play a more prominent role in the planning and installation of generation and transmission resources, and rates from export sales are now higher than domestic rates in terms of dollars per megawatt hour. As a consequence, all things being equal, an increase in domestic loads will result in required increases in rates to the extent that export sales are reduced. This change in circumstance raises a fundamental question as to the fairness of the cost allocation process, and in the view of CAC/MSOS, a cost allocation methodology conceived in a far different time cannot endure. Mr. Harper stated since all customer classes contribute to the costs of covering risks associated with export revenues, it would be appropriate that all customer classes share in the benefit from net export revenues. Mr. Harper further noted Hydro's proposed methodology accomplishes this and eliminates the significant distortion the previous methodology created between the costs of generation and transmission versus distribution.

CAC/MSOS recommended not pursuing a separate export class at this point of time, suggesting two fundamental problems. The first problem was an analytical weakness, being that the export rates are set by the market, and since the Board has no jurisdiction over these rates, there is a disconnect between the purpose of cost allocation, which is ultimately connected to the setting of rates based on embedded costs. The second problem was a technical weakness, being the difficulties and issues around the question of how to identify and allocate costs between export and domestic customers. This issue is further complicated by issues around commercial sensitivity of certain data related to export revenues and costs. CAC/MSOS acknowledged that although the concept of an export class of customer did not appear feasible or analytically defensible at the present time, that may change when future generation is built for export purposes.

Mr. Harper agreed with Hydro that capacity is the primary factor in determining the overall investment in transmission facilities and agreed that it was appropriate to classify transmission costs as 100% demand related.

CAC/MSOS also supported the allocation of demand related generation costs on a two CP method, which, in their view, is a major improvement in terms of cost causality. Given concerns regarding confidentiality to eliminate the need to rely on marginal costs and export prices to support the Cost of Service Study, Mr. Harper stated that it might also be appropriate to consider using the 12 CP method to allocate demand related generation costs.

CAC/MSOS also supported its witnesses recommendations for the Board to:

- Approve separating the costs of ancillary services from those associated with generation and transmission;
- Direct Hydro to study and report on whether these are alternative approaches to classifying and allocating generation costs that are more reflective of cost causation; and
- Accept the classification of ancillary services as 100% demand related and their allocation on the basis of 12 CP.

Mr. Harper further stated given the materiality of generation in the overall Cost of Service Study and the changes required with the integration of Winnipeg Hydro, it would be appropriate for Hydro to address the allocation of generation before the next GRA. Mr. Harper urged the Board to direct Hydro to study and report whether there are alternative approaches to classifying and allocating generation that are more reflective of cost causation. Mr. Harper further noted it would be inadvisable to adjust the relative rates of the retail customers based on the RCC results presented in the current Cost of Service Study.

19.1.8 Rate Design

With respect to the Curtailable Rates Program, CAC/MSOS adopted the four concerns of its witness:

1. The current reference discount price cannot be justified over the short, intermediate or long term, in terms of net benefit to firm customers;

2. The process for studying the reference discount price is excessively judgmental, which leads to issues of transparency;

3. The application of the load factor is overly generous and overcompensates customers, especially in light of the potential for new customers whose current patterns of usage may differ and diverge materially from the current customers; and

4. Given the uncertainty with MISO, it would be a more prudent regulatory course to continue with the current program until the position of MISO is more apparent.

CAC/MSOS recommended that the reference discount level be set such that it provides real financial benefits to firm customers over a defined period of not more than 10 years, that the reference discount should be benchmarked relative to a publicly available cross-reference that allows the continuing value of the program to be objectively monitored. Mr. Harper urged the Board to direct Hydro change its methodology for calculating the load factor adjustment basing it strictly on the load factor of the curtailable load. Mr. Harper further urged the Board to direct

Hydro to clarify the implications its association with MISO will have on the value of reserves and required terms and conditions, and file a proposal that reflects the anticipated value of the CRP program. CAC/MSOS further recommended that the current CRP should be extended to November 30, 2003, and no further.

On the subject of Uniform Rates, CAC/MSOS recommended that subclasses within the residential and general service categories be maintained, and there be a specific allocation of export revenues to the residential and general service classes to address the class revenue shortfalls arising from the implementation of uniform rates, sufficient to equate the revenue to cost ratios for zone 2 and zone 3 to zone 1.

Dealing with inverted rates, CAC/MSOS acknowledged that although an interesting concept whose time might come, the debate for inverted rates raises more questions than it resolves, and the time for inverted rates has not come yet. CAC/MSOS therefore recommended that the Board should direct Hydro to report back on the feasibility of adopting alternative rate designs, including inverted rates, for all customer classes that would encourage the efficient use of electrical energy, including an implementation plan for those alternatives considered appropriate.

19.2 CCEP

19.2.1 Capital Expenditures

CCEP agreed with the evidence of witnesses of CAC/MSOS that there appears to be less discipline being exercised over the level of capital expenditure as the overall financial position of Hydro improves. CCEP argued that when constrained by increased payments to the province and wanting to maintain financial targets, one option Hydro could explore, other than increasing rates, would be to control the level of capital expenditures. CCEP argued Hydro’s capital budgetary requirements could be lowered if targets for export revenues were lowered and environmental initiatives such as the Selkirk fuel switching to natural gas project were deferred until required by legislation. The justification for certain projects was not rigorous enough and as such, some other justifiable projects might be dropped.

Given the potential savings in operating and administrative expenses and capital expenditures and the potential for better than forecast export revenues, CCEP stated there is a possibility that there would be more funds available to provide rate relief to ratepayers.

19.2.2 Extra Provincial Revenues/Operating and Administrative Expenses

CCEP stated Hydro, since the last GRA, consistently underestimated export revenues citing evidence of CAC/MSOS that export revenue projections are likely conservative and Hydro will likely outperform its current financial forecast. CCEP also stated that Hydro could fare better than forecast and realize some $100 million in savings if operating and administrative expenses were held to a benchmark of target $620 per customer in 2012 as proposed by the witness for CAC/MSOS, rather than $664 per customer currently forecast by Hydro.

19.2.3 Payments to the Province

Although outside the Board's jurisdiction, CCEP urged the Board to consider the financial effects of the increased payments to the Province. At $354 million, just over 25% of Hydro's gross revenues are paid to the Province of Manitoba – amongst the highest in Canada. CCEP further stated the Province, as the shareholder of Hydro, has a role to play in assisting Hydro in reaching its appropriate targets without unduly or adversely affecting ratepayers.

19.2.4 Revenue Requirement And Rates

CCEP argued if the Province and Hydro are confident increased payments to the Province are sustainable, then a modest rate decrease of 1% to 2% to the benefit of ratepayers should also be included. This small rate reduction will still provide Hydro with sufficient reserves to face its greatest risk, the possibility of a five-year drought.

19.2.5 Transmission Tariff

In assessing the Board's jurisdiction over the wholesale Transmission Tariff, CCEP urged the Board to view the legislation broadly, and argued that the provision of power should include a transmission tariff as a necessary component of electrical power.

19.2.6 Cost of Service

CCEP stated that they have taken on the mandate of representing the interests of the GSS customer class, a non-residential customer class, whose demand and energy profiles are often similar to residential customers. CCEP also has a mandate to promote better energy policy and understanding of relevant energy issues. Accordingly, although CCEP advocated on behalf of the GSS customer class, it does not do so to the exclusion of improved energy policy.

In CCEP's view, the principles of equity and improved energy policy, in particular the principle that customer classes should pay rates in accordance with the costs of serving that class, require some redress at the earliest opportunity in favour of the GSS class. CCEP pointed out that the revenue to cost "zone of reasonableness" for Hydro customers has been established by the Board between 0.95 and 1.05, and the different cost of service studies reviewed show the GSS customers to be above the zone of reasonableness. The revenue to cost ratio for the GSS customer class, as a whole, is 1.07, and the non-demand sub-class, representing in excess of 40,000 customers, is 1.09. Since the GSS customer class has been outside the zone of reasonableness for some time, and is the only major customer class that remains outside the zone of reasonableness in accordance with the March 2002 study, CCEP strongly advocates immediate redress.

CCEP accepted Hydro's position that the entire Hydro system, including those portions of the system built to support export sales, are built at the risk of all Hydro domestic customers. It is therefore appropriate to allocate export revenues to all functions of the Cost of Service Study, even though the position of the GSS class is nearly unaffected by the methodological change. Accordingly, CCEP disagrees with the MIPUG argument that the GSL customer class pays rates which are even greater than the GSS class, relative to cost of service, since this argument by MIPUG is based on the former methodology of allocating export revenues. CCEP also discounted the argument by certain MIPUG members that electricity costs comprises a large portion of their costs, arguing that issues of economic development and employment policy should not be an issue for cost of service and rate design proceedings.

CCEP argued that if the Board accepts the position of Hydro, supported by CAC/MSOS and CCEP, that Hydro's proposed COS methodology changes, including allocation of export revenues, are appropriate, then the only class continuing to pay more than their cost of service is the GSS class. CCEP further argued that Hydro's proposal to rebalance rates at the next GRA was unacceptable because the ultimate timing of that application was uncertain. Therefore, CCEP requested the Board to direct Hydro to institute a rate decrease to the GSS class at the conclusion of this proceeding of $5.3 million, or 3.8%, in order to bring the GSS class to the top of the zone of reasonableness of 1.05. Alternatively, a rate reduction in the range of $17.7 million or 12.5% would be required to bring the GSS class to unity. CCEP argued that such a rate decrease could be implemented without changing the rates of other customer classes, and with no adverse effects on other revenue to cost ratios.

19.3 MIPUG

19.3.1 Financial Targets

In MIPUG's view, achieving a 75:25 debt to equity ratio and an interest coverage target of 1.20 were laudable goals from an internal corporate perspective. However, they were not appropriate from a cost of service regulatory perspective. The issue to be considered is whether domestic ratepayers should contribute towards achieving Hydro's internal goals beyond that required to enable Hydro to provide safe and reliable electrical service. MIPUG further noted although existing reserves exceed $1 billion, the debt equity ratio would be impacted by the additional debt related to the purchase of Centra, and as a result, rate increases may be required to maintain the debt equity target.

19.3.2 Risks

MIPUG argued that evidence presented by its witnesses demonstrated the existing reserves are more than adequate to achieve the regulatory goals of running the utility and providing a safe and reliable electrical service, and agreed with the witnesses of CAC/MSOS that the existing reserves are beyond what is necessary to protect against the material risks faced by Hydro and are now more than adequate to deal with the risk of drought.

19.3.3 Capital Expenditures

MIPUG argued Hydro's capital program mirrors the rise in export revenues, and capital expenditures increase when export profits are high. MIPUG stated Hydro's capital expenditures have exceeded their 1996 forecast and are now expected to result in $1 billion more in capital assets by 2006 than was expected at the time of the last GRA. MIPUG argued that given the strong export markets, the trend towards acquiring more and more capital assets is likely to continue, and there is not the same level of restraint in controlling capital expenditures that would be required in lean years. MIPUG stated Hydro's decisions about the amount of capital spending increases the burden on domestic ratepayers due to increased interest costs and depreciation in future years.

19.3.4 Operating and Administrative Expenses

The witnesses for MIPUG noted Hydro has been diligent in operating cost control through most of the period under review and that there have not been any increased operating costs, with the exception of fuel expenses, to parallel the increases in revenues. Mr. Osler and Mr. Bowman indicated throughout most of the period since the last GRA, Hydro has functioned with less operating expenses than in the IFF H 95-2 forecast. The witnesses indicated the forecast future increase in fuel expenses is related to exports because the large amount of fuel to be used by the Brandon Combustion Turbine and the Selkirk Generating Station is used to produce power for export purposes.

19.3.5 Load Forecasts and Power Resources

MIPUG expressed concerned about the potential shift in prioritization within Hydro from a domestic supply-oriented utility to an export sales-oriented utility, which discourages domestic use. MIPUG further stated Hydro is first and foremost here to serve Manitobans and low electrical rates can have the benefit of attracting more industry and associated job opportunities to Manitoba. MIPUG urged the Board to be vigilant, noting Hydro has signalled a shift away from a domestic focus, discouraging the use of power in Manitoba in favour of selling into the more lucrative extra-Provincial markets.

19.3.6 Payments to the Province

MIPUG agreed with CAC/MSOS that Hydro’s risks are somewhat overstated and Hydro likely will continue to exceed its current revenue targets. MIPUG noted Hydro is nowhere near becoming a risk to the Province. Mr. Osler, who presented evidence on behalf MIPUG, stated that there has been a substantial improvement in Hydro’s forecast revenues and financial situation, compared to the forecasts that were provided in the last GRA. Hydro had exceeded its 1996 forecast export revenues over the 10-year period 1996 to 2006 by some $1.63 billion. MIPUG noted the biggest beneficiary from this improved financial position continues to be the Government of Manitoba rather than domestic ratepayers. MIPUG noted that payments to the Province have increased by $800 million over the 10-year period 1996 to 2006, approximately half of the additional $1.6 billion in export revenues, of which only 11% had actually gone to the general benefit of customers through foregone rate increases.

MIPUG suggested increasing payments to the Province is another risk faced by Hydro and that given the increased payments, the Province does not appear overly concerned with the current progress Hydro makes towards reaching its financial targets. MIPUG is satisfied Hydro could adequately address its risks, even with these increased payments to the Province, and further noted that increased equity levels would likely benefit the Province and not the ratepayers - something MIPUG urged the Board to consider in setting rates that may contribute to increased equity levels.

19.3.7 Revenue Requirement and Rates

MIPUG argued when forecasts are scrutinized, it is apparent that rates should not be increased. In addition, MIPUG argued there is some room for a rate decrease based on the fact that the future outlook suggests that the financial expectations of Hydro will be surpassed and that the current reserves are sufficient to protect customers without requiring them to contribute unnecessarily to the achievement of financial targets. Further, MIPUG argued Hydro has not discharged their onus of establishing that the overall level of rates are just and reasonable.

MIPUG argued that the revenue requirement was overstated by Hydro, the existing level of reserves are more than adequate, and rate decrease in the amount of approximately $15 million could be achieved without increasing rates to other customer classes.

19.3.8 Transmission Tariff

MIPUG argued that since power was not part of the transmission service, the Board’s jurisdiction over the tariff did not exist because the Board’s jurisdiction was confined to reviewing rates for service for the provision of power.

19.3.9 Cost of Service

MIPUG asserted that Hydro's sales rates have long been set based on the principle of cost causation, and the Board, in fulfilling its responsibility to determine whether the rates charged by Hydro are just and reasonable, must consider the evidence in support of Hydro's revenue requirement and Cost of Service Study. MIPUG further stated that the principle of cost causation has long been used in this jurisdiction because it works, and because it satisfies the ratemaking principles of rate stability, predictability, transparency and public acceptability. MIPUG further argued that the cost causation principle has been refined over the years, has stood the test of time, and there is no reason to depart from that principle today.

With historic revenue to cost ratios generally exceeding 1.05, MIPUG argued for a rate reduction of $15 million to comply with Order 51/96 and to bring the "GSL greater than 100 kV sub-class into the zone of reasonableness. MIPUG argued that a rate freeze does not address the problem of a sub-class paying rates that chronically exceed costs. The witnesses for MIPUG stated there is a demonstrable need and opportunity to provide substantive rate relief to industrial customers who have been paying rates above costs for more than a decade. MIPUG believes the time for solution is now, not only because rate relief for the sub-class is overdue, but also because Hydro's favourable financial situation at the present time creates an opportunity to make progress in bringing the sub-class towards the zone of reasonableness without negatively impacting other customer classes. MIPUG argued that there should be no further delay in rate relief.

MIPUG supported its witnesses' position that some changes to Hydro's Cost of Service Study have departed from cost causation, most notably the treatment of export revenues. The change in the methodology to allocate export revenues is also based on the premise that domestic rates in Manitoba are already as low as they need be, which in MIPUG's view, is a premise that has not been tested or accepted by the Board. MIPUG further argued that no other regulated jurisdiction sets rates other than on cost based principles, and that cost based principles are resilient enough to apply to a range of changing circumstances, including a large increase or decrease in export revenues, and the future construction of Wuskwatim for export purposes. The witnesses for MIPUG stated that it is apparent that the revised methodology has mathematically achieved what Hydro has been unable to achieve through rate revisions over the past decade. MIPUG believes that a primary motivation for Hydro to depart from a cost based allocation methodology is Hydro's desire to bring the revenue to cost ratios for all subclasses closer to unity without having to reduce rates.

In MIPUG's view, the established practice of allocating net export revenues to generation and transmission is consistent with the costs of getting those export sales in the first place. Since generation and transmission are the only functions responsible for supplying the power to the export market, the revenues earned from the export market should be used to offset those costs. In addition, since all Hydro customers use the generation and transmission assets, all customers do receive a benefit from the export revenue allocation, in proportion to each customer classes use of those assets.

MIPUG stated that the non export revenues related changes to Hydro's cost of service methodologies have a relatively minimal impact on the revenue to cost ratios of the subclasses in comparison to the changes in allocation of the net export revenues. The witnesses for MIPUG stated the proposed changes to the Cost of Service Study methodology dramatically redefines the measurement of costs to service customer classes and serves to shift material net costs away from residential customer classes onto industrial customer classes.

MIPUG does not support the creation of a separate export customer class, noting the difficulty in identifying the embedded costs associated with earning the export revenues. MIPUG suggested that the Board could direct Hydro to study further the issue of embedded costs for export revenues, but noted that Hydro was directed to do this in 1999 and did not do so. MIPUG requested that the Boards decision on this matter should not delay the issue of immediate rate relief.

The witnesses for MIPUG noted there is a minimum basis to adopt any of the proposed changes to the Cost of Service Study methodology and that the past cost of service practice remains suitable for the present domestic situation, and therefore recommended retaining the previously approved cost of service approach. The witnesses further stated that the classification of transmission costs on a basis of 100% demand (based on a continued allocation using a 1 CP methodology) may have merit. In addition, they recommended the assignment of some level of "system dividends" to all customers limited to net export revenues net of all embedded costs to serve these loads. However, MIPUG stated the proposed changes to not functionalising HVDC to generation, changes are perhaps not necessary, they can be supported by cost causation, and therefore, MIPUG is not opposing the proposed change. MIPUG also believes that the previous method of classifying each of transmission and generation on the basis of system load factor is preferable over the complicated and unprecedented two-step classification approach proposed by Hydro.

MIPUG also argued that there is only one key time of the year which drives the costs on the Manitoba system, and that is winter. Therefore, under the cost causation principle, the only approach that relies on established principled rationale is the retention of the 1 CP method, based on winter peak load, for both transmission and generation.

With respect to the treatment of Winnipeg Hydro costs and revenues as export sales, MIPUG's witnesses stated this ignores that Winnipeg Hydro's costs and revenues are matched with both entirely related to generation and transmission. Instead, Hydro's proposal results in the costs previously allocated to Winnipeg Hydro's being reallocated back to other customers on the basis of generation and transmission, while the revenues are reallocated back to other customers on the basis of generation, transmission and distribution. This fails to maintain the matching of costs and revenues and fails to reflect cost causation. Accordingly, there is no basis to adopting this interim approach.

19.3.10 Rate Design

With respect to the CRP, the witnesses for MIPUG stated the CRP continues to be the most substantial capacity related Demand Side Management program offered by Hydro and continues to provide value to the utility and its customers in terms of reliability and support of increased high-value firm export sales. MIPUG argued that although the program is relatively small program compared to Hydro's firm rate offerings, it is none the less an important program for certain large industrial customers and strongly supported approval of the Curtailable Rates Program on a permanent basis, subject to the reference discount being adjusted to remove the 12% reduction, to revert to an 80% equivalency factor, and to re-introduce the U.S. exchange rate for the summer generation portion of the benefits.

19.4 TREE/RCM

19.4.1 Capital Expenditures

TREE/RCM argued that Hydro's capital requirements could be lowered if appropriate incentives for reduced energy usage were put in place. With enhanced energy efficiency major new transmission and generation would be unnecessary.

19.4.2 Extra Provincial Revenues

TREE/RCM commended Hydro for its efforts in expanding export sales and stated Hydro had been successful in exploiting opportunities in the North American energy market through their initiative and would like to see Hydro apply such similar talents and skills to an aggressive demand side management policy. TREE/RCM noted that an aggressive demand side management policy and the inverted rate structure may be unduly harsh on the 35% of households in Manitoba reliant on electric heat and that some revenues would be required to mitigate these effects in the short run. Accordingly, some revenues from the export market should be used to enhance energy efficient installations in Manitoba homes.

19.4.3 Load Forecast and Power Resources/Revenue Requirement and Rates

TREE/RCM argued the Board should consider the conservation interest and sustainable development in its rate-setting, and realize that low rates are not necessarily the only or even prime consideration in determining rates. TREE/RCM argued for an overall rate increase to enhance the revenue requirement such that the additional monies could be used for conservation purposes, to enhance DSM programs for residential customers, and, in particular, to finance the transition to the inverted rate structure, especially for residential customers reliant upon electric heat.

19.4.4 Rate Design

The intervention by TREE and RCM was to examine Hydro's operations and rates for their impact on energy conservation and consequent impacts on local and global eco-systems. TREE/RCM stated that Hydro has sales rates that are amongst the lowest in the world, and generally speaking, low rates have a negative impact on energy efficiency because it is affordable to waste energy. Peter Miller, a witness appearing on behalf of TREE/RCM, noted because of the low rates, it is more cost effective, or at least affordable, for the consumer to waste energy than to spend money on energy conservation. TREE/RCM's objective is to get Hydro to adopt policies that better promote principles of sustainability, emphasizing energy conservation and environmental impact reduction and mitigation. Peter Miller, on behalf of TREE/RCM, stated in setting rates Hydro should interpret its mandate as being to secure the best possible "triple-bottom-line" including social, environmental and economic outcomes in its operations. TREE/RCM argued that despite well-expressed intentions, Hydro has not been aggressive in their DSM efforts and in promoting conservation and efficiency.

TREE/RCM brought forward Mr. James Lazar, a regulatory consulting economist, as a witness to address the benefits of adopting an inverted rate structure for residential customers. This would have an initial rate inversion based on the low cost power on the older Winnipeg River System which has no high cost lengthy HVDC transmission lines. It would then be enhanced by an additional rate inversion based on the relative load factors of different size residential customers, which consumes higher cost more modern Northern generation with associated lengthy transmission facilities.

Mr. Lazar, appearing on behalf of TREE/RCM, proposed the adoption of an inverted rate structure. The structure provides each customer a limited amount of power at one lower price per kilowatt hour and additional usage provided at a higher price per kilowatt hour. This contrasts with the current rate structure utilized by Hydro; a declining block structure, where larger customers pay a lower rate per kilowatt hour than smaller customers. Mr. Lazar noted that an inverted rate structure would be appropriate in Manitoba because it communicates the fact that the utility has only a limited supply of low-cost power and distributes the benefit of low-cost hydro resources uniformly among customers while the current declining block rate structure gives the largest users the largest share of the benefit.

Mr. Lazar further stated the inverted rate structure was most appropriate for Hydro, because it has two very different sources of power supply, including the older system on the Winnipeg River that provided a limited supply of low-cost power that could be recovered by the lower block rate and newer more expensive facilities in the north which provide a larger supply of power at higher debt service costs on dams and transmission, that could be recovered at a higher block rate.

Mr. Lazar recommended the following changes be made to implement an inverted rate structure:

- Flatten the customer demand charge to $6.25/month regardless of the connected average.
- Provide each customer an initial block of 250 kW.h/month at a rate of $0.02/kW.h lower than the rate for additional usage. Any further revision could await cost studies on the amount of low cost power and how to distribute export profit.
- Hydro undertake a stratified load research study of its customers and their respective end use electricity to determine if large use customers have a diversified load factor that is different from small customers to develop de-averaged distribution rates.

Mr. Lazar stated the impact on residential customers would result in those using less than 250 kW.h/month realizing a rate decrease of 32%. Large use residential customers (3,000 kW.h/month) would receive an increase of 8% noting further that very few customers would see large changes to their bills. However, as a result, all consumers would have a greater incentive to conserve electricity. Mr. Lazar stated the benefit of such a structure would be approximately a 4-5% less usage per customer than the current residential rate design.

Citing the principles of the Sustainable Development Act which TREE/RCM argued was applicable to Board decisions, TREE/RCM made nine recommendations as follows:

1. An explicit goal be added to the Power Smart program to increase the eco-efficiency of the energy supplied by Hydro.
2. Adopt methods for measuring absolute and relative efficiency performance for different customers and end use classes.
3. Consider for adoption comparative efficiency performance measures.
4. Adopt a more aggressive conservation program for the residential sector.
5. Create a rate regime in which each customer faces tail-block rates that are much closer to the marginal costs of electrical demand and energy.

6. Hydro be directed to file an inverted rate for residential customers holding the customer charge to \$6.25, providing the first 250 kW.h block of power at a rate of \$0.038/kW.h and additional power at the level needed to make Hydro revenue neutral, estimated to be approximately \$0.059/kW.h. Alternatively, the Board could direct Hydro to file an inverted rate structure to give a larger low-cost block to all electric residential customers. A third alternative would be to have a minimum bill to replace the basic charge.

7. Hydro be directed to prepare load research on the relative load shape and load factor of large versus small use residential customers on the generation, transmission and distribution system.

8. Hydro be directed to study options for general service rate design changes to improve the efficiency of pricing information to customers.

9. Hydro be directed to implement an energy efficiency grant program funded from initially up to one quarter of the net export revenues.

TREE/RCM believes that adoption of their recommendations will strengthen the economy of Manitoba and reduce the adverse environmental impacts of energy production and consumption in the region and globally.

19.5 MKO

19.5.1 Rate Design

MKO stated that with the exception of the hydroelectric operations on the Winnipeg River, all of the existing and planned hydroelectric stations of Hydro are within the MKO region and directly affect the rights, interests, communities and traditional territories of the 12 MKO First Nations. MKO generally supports the basic principle of uniform rates established by legislation effective November 1, 2001. MKO further stated that, in respect of the rate rebalancing proposed by some interveners, as long as rates are less than those approved to be effective November 1, 2001, it appears doubtful the Board can alter the rates that went into effect after November 1, 2001 until Hydro applies by way of a GRA to change rates.

With respect to diesel rates, MKO argued that the First Nations communities do not have the financial resources to pay their electricity bills that are being assessed, which creates a circumstance that must be addressed. Although all residential customers in the diesel communities do pay the equivalent zone 1 rate, all consumption over 3,000 kW.h for non-government customers and First Nations facilities are assessed a surcharge, which in the view of MKO, is not consistent with the legislation. Therefore, the intent of uniform rates should be extended to all remaining customers in the diesel communities and all ratepayers, regardless of geography to pay the same rates. MKO further argued that Hydro has not exercised its duty to diesel community customers to promote economy and efficiency in the use of electricity. On that basis, customers have been exposed to substantial costs, and Hydro should assume the costs to the remaining customers in the diesel communities, and provide benefits to those customers that are being shared by other Manitobans.

MKO also suggested that Hydro should aggressively promote demand side management initiatives in the diesel communities, as well as seek alternative sources of supply to serve the communities in a more cost effective way.

MKO issued a subpoena to Mr. Fred Mills of Indian and Northern Affairs Canada to discuss the nature of the funding provided by Indian and Northern Affairs Canada to First Nations in respect of electricity costs. Mr. Mills testified that a formula pays for what is, in essence, a nominal amount of the electricity bills incurred by all First Nations government accounts, which could include schools, police stations, band offices, social services offices, etc. Mr. Mills also testified that Hydro and Indian and Northern Affairs Canada are really not involved in trying to resolve issues arising out of diesel rates.

19.6 PCW

19.6.1 Rate Design

PCW did not speak to the specifics of the status update, but expressed particular interest in the future regulation and public accountability of Hydro. PCW expressed concern for the increasing instances where the Government of Manitoba has denied Manitobans the opportunity for public scrutiny, and referred specifically to the implementation of Uniform Rates, the increases in government charges to Hydro, and the acquisition of Winnipeg Hydro, all done outside of the scrutiny and review of the Board. PCW argued that by far the most effective oversight of Hydro is by public process directed by the Board, and expressed concern that it took over six years for Hydro to apply to the Board for this Status Update hearing. PCW also expressed concern as to what future legislation the government might introduce to further diminish the Board's oversight role.

PCW endorsed the Board's role as a proxy for competition, and stated that Manitobans need regular review of Hydro by an informed watchdog, looking out for the public interest. PCW requested the Board to consider the timing of future reviews of Hydro.

20.0 Presenters' Positions

20.1 HBMS

HBMS is a base metal mining, smelting, and refining business in northern Manitoba. Together with the Mining Association of Manitoba, in 1999 HBMS proposed a variable rate structure that would strengthen its operation in low price periods and share the benefit of high price periods with Hydro. Applying this approach to multiple industries would diversify the utility's risk while ensuring continued strength of the Province's major economic drivers and Hydro customers.

HBMS argued that large power users in this Province have paid a disproportionate portion of the rates charged to Hydro customers over the last decade Hydro's industrial rates should more closely reflect the costs of producing and delivering electricity. A 10% reduction of GSL (over 100 kV) rates, to reflect more closely Hydro's actual cost of service, would have significant beneficial effect on any decision for future energy-intensive capital projects and improve the allocation of rates in the Province and enhance the long-term strength of significant customers and economic drivers of the Manitoba economy.

20.2 Inco

Inco, is a nickel mining company in Thompson. Inco stated increased debt guarantee charges, water use rates, and other cash extractions have resulted in a net transfer to the Manitoba Government. Inco stated that short-term export profits or long-term direct employment in Manitoba is a government policy choice. The 1,400 direct jobs, the support services jobs, and the revenues that they create for Hydro, as well as the taxes this employment generates affects Inco's competitive position. Inco believes that leveraging electricity rates to create and maintain jobs is paramount to protect the ratepayers from volatile energy markets.

Inco pays a demand charge winter ratchet for unused electricity in their scheduled summer shutdown. However, this electricity is sold again on the spot market. Inco suggested that Hydro stop charging twice for the same products.

20.3 Simplot

Simplot is an integrated fertilizer plant which manufactures nitrogen and sulphur based fertilizers as well as a limited range of industrial nitrogen products. Simplot submitted that Hydro costs and rates must remain subject to rigorous examination by the Board. Simplot is concerned that, while Hydro is not requesting a rate increase with this submission, it appears to be positioning itself for a series of rate increases over the immediate future. Simplot was disturbed that the provincial government continues to increase its revenues through special levies on Hydro.

The apparent shift in Hydro's priorities, away from its domestic customers to its export sales is of concern to Simplot. This shift has resulted in Hydro's stated position, in this filing, that domestic electricity rates are "as low as they need to be", and the further assertion that failure to recognize the real value of electricity (i.e., export value) could result in the diversion of energy from profitable export sales to energy intensive domestic industries.

Simplot, together with other members of MIPUG, have maintained that Hydro's rate structures impose an unfair burden on the GSL (over 100 kV) rate class. Hydro's response to the Board's Order, as evidenced by its Prospective Cost of Service Study, has been to develop a new method of service calculation to bring all rate classes with the zone of reasonableness, rather than to adjust the rate structure itself. Reducing firm power costs by 11% would significantly improve the competitive position of all large industrial power users in Manitoba.

Simplot optimistic that Hydro will be able to agree on a proposal that would provide Simplot and other large industrial customers some relief from the demand charge winter ratchet during scheduled plant maintenance shutdowns.

20.4 Nexen

Nexen uses an electrolytic process to produce sodium chlorate, which is used to bleach wood pulp. Nexen requested that the Board consider the presentations made by MIPUG in light of the competitive challenges faced by Nexen, and other energy intensive industries in Manitoba, and help them retain their competitive positions Nexen is currently a curtailable rate program customer. In 1998-2000, Nexen participated in the Industrial Surplus Energy program. However, as export power prices continued to rise, Nexen could not justify participating in the program. The introduction of Curtailable and Industrial Surplus Energy programs in the latter years has also been a positive factor in convincing Nexen's Board of Directors that expansions should occur in Manitoba. Dedication to providing reliable firm power at fair and reasonable rates that reflect cost of service and commitment to innovative rate options that benefit both industry and Hydro are important for the future growth of large industry in Manitoba.

Competitive power rates encourage new growth in the industrial sector. In 1994, the Board's direction to move firm industrial rates as close to cost as possible, and the subsequent 1994 reductions in provincial taxes on manufacturing energy purchases have both had significant positive impacts on Nexen's production in Manitoba, and in Nexen's commitments to capital expansion in this province.

20.5 Presentation of C. Nicolaou

Dr. Nicolaou, a Professor of Economics at the University of Manitoba, stated that the GSS class needs serious attention by the Board. Rates for the GSS class require modification to relieve the sector from a long-term burden.

Growth prospects of the Province rest squarely upon the small business sector. The typical small business is often, by its nature, ill-prepared to deal with adverse conditions. Without pressure from the unrepresented small business sector, and without representations to the Board, the small business sector has the highest revenue cost coverage above the Board's zone of reasonableness. Small business over pays $15-17 million annually.

The simplest, most direct and immediate redress of this long-term disadvantage imposed on small business is for Hydro to be ordered to lower rates for GSS, to bring the RCC to unity. The current and long-standing overpayment by the small business sector must end immediately. However, even this measure would not return past overpayments. Relief should be given to the class which is not only crucial for Manitoba's economic development but is also in need for even the smallest amount of assistance.

21.0 Board Findings

21.1 Operating Results and Financial Forecasts

The Board notes that for the fiscal years 1996 to 2001, Hydro has experienced actual financial results that are dramatically better than the results forecasted in IFF 95-2. The improvement in Hydro's financial results is due primarily to favourable water levels and market conditions, and the successful implementation of a strategy to develop extra-provincial sales opportunities. The Board commends Hydro for its proactive approach and effective execution of a strategy to capitalize on and adapt to the changes in the export market, brought on in part by the introduction of competition in the wholesale export market. Through membership and participation in MAPP, MISO and other key committees and organizations, and proactive marketing efforts, Hydro has been able to represent its interests and more than double the revenues related to extra-provincial sales since 1996. This has resulted in record profits, improved financial strength and stable rate levels for Manitoba consumers. The Board encourages Hydro to continue its active participation in MAPP and MISO and marketing efforts, which have resulted in benefits to Manitoba ratepayers.

Extra-provincial revenues now have a greater prominence within Hydro than in 1996, representing an increasingly significant portion of Hydro's total revenues. Risks related to losing those revenues have also increased substantially since 1996.

The Board notes that IFF MH 01-1 is based upon many assumptions which are beyond the control of Hydro. In the Board's view, IFF MH 01-1 represents a conservative forecast using reasonable assumptions. The IFF assumes a decline in export revenues through 2010 with a subsequent increase in 2011 and 2012. The Board believes Hydro has been conservative in its planning and its projection of future export revenues given historical increases in extra-provincial revenues, the current export market and Hydro's competitive hydraulic power advantage. The Board however recognizes the level of export revenues depends on a number of factors including available water flow, market prices, and a proper balance between demand and supply. Conservative assumptions are, in the Board's view, an appropriate and prudent strategy given the nature and magnitude of the risks involved.

The Board accepts IFF MH 01-1 is a general indication of Hydro's long-term financial direction for decision-making purposes. The Board notes that the IFF does not reflect any future major generation projects within the planning period, nor the impact of the acquisition of Winnipeg Hydro, both of which may significantly impact the financial forecast and plans of Hydro. The Board will direct Hydro to file an updated IFF reflecting new generation in-service dates within the planning period, and the financial consequences of the integration of Winnipeg Hydro's operations by no later than December 31, 2003.

21.2 Financial Targets

The Board has previously stated a debt equity ratio of 85:15 is a reasonable short to medium term financial target and agrees with Hydro that a long-term target ratio of 75:25 is appropriate. The Board notes that the achievement of the 75:25 debt equity target should include a strategy for the reduction of the level of its debt.

The Board remains concerned with the current high level of debt and the additional risk posed to Hydro of incurring higher finance charges due to increases in interest rates and fluctuations in the US exchange rate on its US denominated debt. The Board is particularly concerned with the dramatic increase in long-term debt from $5.17 billion in 1997 to $6.43 billion in 2002, especially during a period of limited major capital expansions in generation or transmission. The Board encourages Hydro to consider appropriate debt minimization strategies. The Board notes the Corporate Strategic Plan includes a reference to reducing debt and improving equity to meet this target. Accordingly, the Board will direct Hydro to file a detailed debt management strategy with the Board by no later than December 31, 2003. This strategy should include the implications of major new generation contemplated within the planning period, and the related financing implications.

The Board is of the view that a gross interest coverage target ratio of 1.20 and the capital coverage target of funding the capital program (with the exception of new generation) from internally generated funds are appropriate financial targets which assist Hydro in achieving its long-term target of 75:25 debt equity ratio. However, the Board is also of the view that once the debt equity target has been reached, the current interest coverage target may, at that time, no longer be required or appropriate, and a lower target should then be considered.

21.3 Risks

In the Board's view a five-year drought represents the greatest threat to Hydro's financial position. It has been estimated that retained earnings reserves of approximately $1.3 billion may be required to withstand the financial impact of such an event. Although the actual amount might be mitigated somewhat by certain strategies, Hydro's net revenues are nevertheless subject to the vagaries of weather and water flows. Establishing an adequate reserve level is an appropriate strategy to mitigate the financial impact of a drought.

If Hydro experiences a drought, most opportunity sales will be foregone, thereby reducing export revenues. The Board generally supports Hydro's conservative approach to forecasting export revenues. The Board notes that although high export revenues have brought positive financial impacts, it has also increased the risk to Hydro. Continued high export revenues may permit Hydro to offset the need for rate increases in the future.

While there may be some risk of an export market collapse due to US legislation, regulatory changes or energy subsidies, amongst other things, there is also a probability of increased market prices, and therefore, increased export revenues. Export revenues on average over the last seven years have been 15% higher than forecast under the mean flow scenario. If this trend continues over the next few years, Hydro will achieve its targeted debt equity ratio earlier than forecasted and a retained earnings level in excess of $1.5 billion. According to Hydro this level of retained earnings should be sufficient to deal with identified risks. As another risk, the Board would agree that higher interest rates could have a modest negative impact on Hydro's financial position, as could higher inflation rate than forecast. Similarly, major system outages could negatively impact Hydro's finances.

21.4 Risk Analysis and Reserve Levels

The Board understands the difficulty of preparing a comprehensive quantitative analysis of all risks facing Hydro, as recommended by Mr. Todd. The Board believes, however, there is merit in quantifying specific reserve provisions required to cover the major contingencies Hydro faces. The specific amounts should be based on a process that identifies and quantifies at least the major risks at a high level. To do otherwise would be tantamount to establishing a reserve provision at an arbitrary amount. Defining specific reserve amounts for contingencies may also help prevent reserve provisions from being depleted for other purposes.

Although each risk has its own financial quantification, one cannot simply consider all risks together as additive, since many of the risks are inter-related. In reviewing risks, Hydro is urged to further examine their inter-relationships.

The Board believes that Hydro should develop a policy to identify a reserve provision amount and, in particular, to set the circumstances under which it can be drawn down or increased, keeping in mind the statutory limitations in *The Manitoba Hydro Act*. The Board expects that Hydro has most, if not all, of the required data in one form or another as part of its ongoing planning and risk management. The Board will therefore direct Hydro to prepare a document to quantify specific reserve provisions required to cover the major risks and contingencies faced by Hydro, and file that document with the Board by no later than December 31, 2003. A more disciplined approach to risk quantification can only be beneficial to the financial planning of

Hydro and assist the Board in its rate setting obligations, particularly with regard to the objective of determining an appropriate rate reserve level.

21.5 Capital Expenditures

Order 51/96 recommended that Hydro "stringently limit its capital expenditures where safety and reliability constraints allow and apply itself to reducing long-term debt with urgency." The Board remains concerned with the progressive growth in capital expenditures, and notes the dramatic increase in capital expenditures from $250 million in 1996 to $425 million in 2002. The Board reiterates its concerns expressed in Order 51/96.

The Board is particularly concerned with planned future capital expenditures that are justified primarily by export revenue opportunities. While very few projects are now justified exclusively for export, many projects nevertheless have a substantial export component. Hydro has indicated that certain future major capital projects will initially be for export purposes. The Board directs Hydro to appropriately identify and specifically account for all export-related capital expenditures in their capital forecasts. This information is required to ensure that export revenues are appropriately matched against the full costs of production and to ensure that Hydro's domestic ratepayers do not subsidize export market costs in the future.

Planning studies attracted substantial review in this hearing. Not only was the total amount spent of some $130 million of concern to the Board, but also the amount spent on particular projects (i.e., $34.1 million on Gull, $22.3 million on Wuskwatim). Hydro has agreed to pay for certain costs of the First Nations' participation in planning for new generation stations. Of concern to the Board is the very real likelihood of Hydro paying for what are, in essence, duplicate studies, by undertaking their own studies on aspects of new generating facilities and then paying for the First Nation partner to conduct a similar study. Given that such payments in 2002 are in the range of $1 million per month for the Wuskwatim generating station, and nearly $2 million per month for Gull, the Board urges Hydro to be diligent in how the ratepayers' monies are being spent and minimize such duplication.

21.6 Payments to the Province of Manitoba

Payments to the Province of Manitoba have increased dramatically, which impacts Hydro's revenue requirements. As many of the increases are legislatively enacted, Hydro has no choice but to make such payments. Nevertheless, such dramatic increases in payments have a negative effect on the ability of Hydro to achieve its financial targets, and may ultimately affect the level of rates paid for electricity. That having been said, the Board recognizes that dividend payments similar to the special export profit payments are not uncommon in publicly owned utilities.

Hydro does not intend to increase its sales rates as a result of the special export profit payment, or the increases in water rental rates or the debt guarantee fee. Hydro will be financing its payments to the Province of Manitoba. The costs of borrowing the $288 million for the special export profit payment over the next ten years is $276 million. Therefore, the total impact of that payment alone is $564 million over the next 10 years. Ultimately, future ratepayers will pay the financing costs. The Board encourages Hydro to pursue short-term financing options to pay down this debt expeditiously and reduce the impact of such charges to future domestic ratepayers.

21.7 Finance Expenses

The Board notes that a significant dollar value of transactions are conducted in US dollars including US extra-provincial sales, US sinking fund investment income and finance expenses. In addition, over $2.9 billion or 45% of the Corporation's debt is denominated in US currency, which exposes Hydro to risks related to the change in US exchange rate. The Board further notes that the exposure management program is in place to act as a hedge in protecting Hydro from the significant foreign currency risk related to the change in the US currency. As a result of the program, prior to the change in accounting policy, Hydro had reflected the balance of the US debt, and sinking fund at a designated US exchange rate, which has been significantly below the rates currently experienced. As a result of this policy, the debt of Hydro at March 31, 2001 was valued at approximately $1 billion less in the financial statements than it would have been if the year-end exchange rate had been used to translate the US denominated debt into Canadian dollar equivalent.

The Board notes that as a result of the accounting policy change, US denominated transactions and balances will better reflect the true economic costs and benefits and more clearly reflect the risks faced by Hydro to US denominated transactions and balances, which in the Board's view, are significant.

21.8 Operating Expenses

Although Hydro's operating and administration expenses appear reasonable, the Board encourages Hydro to continue to control these expenses through aggressive cost control initiatives and management of the labour force. The Board appreciates that some operating and administration expenses, particularly payments to the Province, are beyond Hydro's control. However, it remains necessary for Hydro to continue to be diligent in taking steps to control all such costs and improve efficiencies.

Corporate performance measures such as the operating and administration costs per customer or per kW.h targets are of great assistance in assessing the performance of Hydro's cost control initiatives compared to other utilities. The Board recommends Hydro aggressively pursue meeting its operating and administration costs per customer target while finding ways to increase productivity. The Board also encourages Hydro to continue to participate in benchmarking initiatives to help identify and implement further efficiencies and enhancements in its operations as compared to other utilities. Hydro should actively pursue all possible synergy savings in operating and administration expenses as a result of Hydro's recent acquisition of Winnipeg Hydro.

21.9 Transmission Tariffs

The jurisdiction of the Board over transmission tariffs is an area of concern to the Board and parties were requested to address this issue in their closing argument.

The MISO tariff does not apply to the Hydro transmission grid, but only outside the Province. Therefore, there is no provincial authority over the MISO tariff, and accordingly, no role for the Board.

The Board receives its jurisdiction and obligations for Hydro rates mainly from *The Crown Corporations Public Review and Accountability Act*. Rates for services provided by Hydro shall be approved by the Board, which rates for service means the provision of electrical power. Even though Hydro can issue its own tariff under s. 15 of *The Manitoba Hydro Act*, Hydro is still obligated to have such a tariff as a rate for service for the provision of electrical power approved by the Board. Whether the provision of power is bundled or unbundled between generation, transmission and distribution, the Board retains the jurisdiction to approve rates for service if offered in this province.

Accordingly, the Board will direct Hydro to make a separate application to the Board for approval of the Hydro Open Access Transmission Tariff. Hydro is ordered to file such an application by no later than June 30, 2003. Such an application should contain tariff and rate schedules, and a comprehensive explanation of the pricing and costs included in designing the rates.

21.10 Power Resources

Hydro stated that any periodic failure to meet base domestic plus firm export load is unacceptable. Base domestic load growth and firm export load growth are the primary drivers for new and additional power resources. Therefore a strategy to avoid brown-outs under all normal circumstances will result in substantial energy surpluses in most years. This surplus can then be sold as an opportunity sale on the export market.

If Hydro were to employ a median water flow scenario, instead of mean flow, in its energy forecasts, the amount currently available for export could be increased. By employing relatively conservative forecasting processes for supply and demand, Hydro will continue to enjoy more favourable financial results than forecast, except when droughts actually happen. From 1997 to 2001 there was an additional 10,000 GW.h of export energy due to hydraulic generation being above-median water supply, resulting in incremental annual revenues of approximately $200 million. Nevertheless, the Board considers it appropriate for Hydro to continue employing the conservative mean water flow scenario.

The Board notes the concerns expressed by Intervenors that Hydro may be paying less attention to creating competitive opportunities and developing energy conservation initiatives in the domestic market. While the Board encourages Hydro to pursue export markets and the corresponding revenue opportunities, Hydro's primary purpose continues to be the supply power adequate for the domestic needs of the Province.

The Board urges Hydro to explore ways to diversify and supplement its hydraulic generation capabilities by applying an appropriate mix of other forms of energy, including wind turbines, solar panels, ground source heat exchange, and hydrogen cells. Hydro should give particular consideration to exploring alternatives such as wind turbines for the four remaining diesel generation communities. Here, the back-up diesel power generator is already in place and an alternative energy supply may be justified on either an environmental or cost basis.

Hydro no longer supplies copies of its Power Resource Plan, citing confidentiality due to the increased competitive nature of electricity trading in the US. Should the Board be seized with a needs and justification hearing for major new generating stations, arrangements may need to be made to examine the Power Resource Plan.

21.11 Cost of Service Study

21.11.1 General

A cost of service study is one of the fundamental tools used by utilities in the overall rate design process. Much judgment is applied in completing a cost of service study. The results of a cost of service study are used in designing rates that are fair and equitable to customer classes. Generally, fairness is attained when revenues from each customer class approximates the net allocated costs of serving that class.

Hydro has made numerous changes to its proposed Cost of Service Study since it was last reviewed by the Board in Order 51/96. The Board will direct Hydro to file two cost of service studies; an actual cost of service study for the fiscal year ended March 31, 2003 by no later than September 30, 2003 and a prospective cost of service study for the fiscal year ending March 31, 2004 by no later than September 30, 2003. The following sections contain the Board's comments and directives with respect to changes proposed by Hydro, and requirements for the Cost of Service Studies to be filed with the Board in the future.

21.11.2 Winnipeg Hydro

Hydro has acknowledged that adjustments will be required to the proposed Cost of Service Study to accommodate the recent purchase of Winnipeg Hydro assets by Hydro. Hydro has stated it will have a better understanding of Winnipeg Hydro costs by late 2002. Achieving a precise understanding of detailed customer load and revenue cost information may take longer. Hydro did not rule out that methodological changes to the Cost of Service Study may be required. The

Board expects that the acquisition of Winnipeg Hydro may have a dramatic impact on the RCC's of the various customer classes. The Board also does not accept the methodology applied to Winnipeg Hydro matters in the March 2002 Cost of Service Study. The Board will therefore direct Hydro to treat Winnipeg Hydro customers in the same fashion as current Hydro customers in the March 2003 Actual Cost of Service Study and the March 31, 2004 prospective Cost of Service Study. It is important to know the impact of Winnipeg Hydro on the Cost of Service Study as soon as possible.

21.11.3 Allocation of Export Revenues

A major change to the Cost of Service Study methodology proposed by Hydro is to allocate net export revenues to customer classes on the basis of total allocated costs, being each class's share of generation, transmission and distribution costs.

The Cost of Service methodology approved in Order 51/96 allocates net export revenues to rate classes in proportion to class responsibility for generation and transmission costs. Distribution costs, of which a large percentage is allocated to residential customers, were not part of the allocation formula. It has long been argued by Hydro that it is primarily the generation and transmission assets that create the opportunity for export sales. Therefore, based on accepted cost causation principles, the benefits from export sales in the past were shared by the rate classes in proportion to each rate class' responsibility for generation and transmission costs.

In the public hearing related to Hydro's 1994 GRA, CAC/MSOS submitted that allocation of net export revenues on the basis of total cost responsibility (i.e., generation, transmission and distribution costs) would be more beneficial to the residential class. In 1994 Hydro opposed the CAC/MSOS cost of service methodology that Hydro now proposes in 2002. Hydro's position in 1994 was that export revenues are derived from generation and transmission capacity built to provide firm service to domestic loads, and since the costs of these facilities are allocated totally to domestic rate classes, it is proper to share the export revenues derived from this capacity in proportion to cost responsibility of such classes.

In Order 64/94, the Board stated at page 33, "…Hydro's method of allocating net export revenues is appropriate for Hydro's system, because it proceeds from the principle of cost responsibility rather than mere judgment." The Board further stated "… that it would be inappropriate to allocate any portion of export revenues as an offset to distribution costs within the central system or to costs in the Diesel Zone."

The Board has heard no new evidence at the current hearing to support or justify a departure from the principles of cost causation previously adopted for allocating net export revenues. Because export revenues arise from generation and transmission capacity, the Board believes that it continues to be appropriate to allocate the net export revenues derived from that capacity in proportion to class responsibility for generation and transmission costs.

In the Board's view, many direct and indirect costs related to export power sales are currently not included in Hydro's calculation of net export revenues. The Board notes that this matter was the subject of a recommendation in its March 31, 1988 Report to the Minister, at page 51 and 52, where the Board stated:

> "The Board recommends that revenues and costs related to export sales should be segregated in Hydro's accounting records. Costs include direct costs as well as indirect or allocated costs. The purpose of this segregation is to ensure that the Manitoba ratepayer is not subsidizing export sales.
>
> A possible method would be to treat export sales as a separate customer class in the Cost of Service Study. The result would not be used in designing rates for export sales because of the fact that such sales are open market negotiated sales. The only relevance to the resulting export class revenue/cost ratio would be to ensure that Manitoba customers are not allocated costs related to export."

This Board believes these comments remain appropriate today, and accordingly will direct Hydro to file an actual cost of service study for 2003 and a prospective cost of service study for 2004, that reflects:

(a) The creation of a Firm Export Class. This class should include long-term firm export sales and one-year firm export sales, with costs allocated on a fully embedded basis using a 2 CP allocation as employed for general service customers; and

(b) The creation of an Opportunity Export Class. This class should allocate costs using a similar basis to the domestic interruptible GSL customer class.

These Cost of Service Studies should include the impact of allocating net export revenues determined in accordance with the above directives on the basis of transmission and generation costs. Once these submissions have been filed, the allocation methodologies may require further consideration by the Board.

21.11.4 Functional Changes to the Cost of Service Study

Previously, all transmission lines and stations, including HVDC facilities, were included in the transmission function. In the March 2002 Cost of Service Study, all HVDC assets, with the exception of the Dorsey Converter station, were assigned to the generation function. The Board accepts this methodology and Hydro’s reasoning that the primary function of the HVDC facilities is to move energy from the remote generation sites into the backbone transmission system and therefore serve as an extension of the generating facilities.

The Board, however, has some concerns about the exclusion of the Dorsey Converter Station from the HVDC assets assigned to the generation function. While the assignment of the Dorsey Station to the transmission function has relatively minor impacts to revenue cost coverage ratios under current operating circumstances, the Board has concerns this may change as additional generation and transmission facilities are constructed in the future. The Board will expect Hydro to re-evaluate the continued appropriateness of this treatment in the future.

Hydro has also assigned the AC transmission lines that provide power to the northern converter stations as generation. The Board accepts this methodology since these lines are required to bring generated power to the HVDC converter stations in the north.

The Board also accepts Hydro's proposed assignment of only those transmission facilities, which would be recognized for inclusion in Hydro's Transmission Tariff, to the transmission function. Radial transmission facilities, including those with voltages greater than 100 kV, are included in the sub-transmission function.

The Board accepts Hydro's creation of a new ancillary services function necessary to support the transmission of capacity and energy to the load.

21.11.5 Classification Changes to the Cost of Service Study

Hydro's November 2001 Prospective Cost of Service Study used marginal costing to classify generation costs to energy and demand. For reasons of commercial sensitivity, Hydro was unable to provide information supporting its determination of relative marginal costs. Hydro therefore proposed to revert back to the previous methodology. The Board accepts this approach given the commercial sensitivity of marginal cost information.

In the March 2002 revised Cost of Service Study, Hydro returned to the pre 2001 approach and classified total generation and transmission costs (including ancillary services) on the basis of the system load factor. However, in the March 2002 approach, transmission and ancillary services are classified as 100% demand related. The balance of demand related costs are then assigned to generation. This results in a demand to energy classification division of transmission and generation costs of approximately 36% to 64% respectively. If, however, transmission costs are classified as 100% demand and the system load factor is applied to generation costs only, this approach would result in a demand to energy classification division of generation and transmission costs of approximately 48% to 52%.

The Board accepts the classification of transmission assets at 100% demand related, however, the methodology used to classify generation costs is of concern to the Board. Hydro has stated it is prepared to undertake a further review with respect to the appropriate classification of generation costs. The Board will therefore direct Hydro to complete this review of generation cost classification methodologies by December 31, 2003. This review should critically examine the impacts of the various methods of classifying generation costs, and describe how such classification methods would impact the overall rate design process in terms of setting demand and energy charges.

The Board accepts Hydro's proposed methodology with respect to classifying ancillary services as 100% demand.

21.11.6 Allocation Changes to the Cost of Service Study

The process of allocation takes functionalized and classified costs and assigns the costs to the various customer rate classes and subclasses. Hydro has proposed a number of changes in cost allocation methodologies.

In the November 2001 allocation methodology, energy related generation costs were allocated to each customer class according to the class contribution of the highest integrated 50 hour load during the winter and summer seasons. This treatment was changed in the March 2002 where energy related costs of generation were allocated to customer classes on the basis of their share of overall annual energy requirements, the same methodology used in the Cost of Service Study approved in Order 51/96.

The March 2002 Cost of Service Study proposed to allocate generation demand costs on the basis of each class of customer's share of the average of the top 50 coincident load hours during the months of June, July and August and the top 50 coincident load hours during the months of December, January and February (2 CP Methodology). Hydro stated this treatment recognized the value of energy and capacity during the summer and winter seasons. Although the domestic peak continues to occur in winter, loads can be as high as other times of the year, particularly the summer months. With a strong export market during the summer months, transmission and generation assets can be fully utilized at the time of summer peaks. Based on this reasoning, the Board accepts Hydro's methodology to allocate demand related costs of generation on the basis of the 2 CP method.

Hydro has proposed to allocate transmission and ancillary services related costs to customer classes on the basis of the 12 CP method with each month being given equal weight. Hydro argued that this approach is consistent with the treatment in the Transmission Tariff in which transmission pricing in the open access market is based on the 12 CP method. The Board is of the view that allocation of costs on a 2 CP basis would be a stronger correlation to cost causation. Participation in MISO does not oblige Hydro to adopt similar pricing structures for the domestic market. The Board therefore rejects the allocation of transmission and ancillary service costs on the basis of the 12 CP and directs Hydro to allocate these costs on a 2 CP basis similar to that used for the generation demand costs.

The Board also supports the continued practice to allocating DSM costs to the customer classes that receive the benefit.

21.11.7 Future Cost of Service Studies

Given the above comments, the Board has fundamental concerns with both the November and March Cost of Service Study submissions. Therefore, the Board will direct Hydro to file an actual cost of service study for year ending March 31, 2003 by September 30, 2003 and a prospective cost of service study for the fiscal year ending March 31, 2004 by September 30, 2003 reflecting the following:

(a) The former Winnipeg Hydro revenues and costs are appropriately assigned to the various customer classes in the same fashion as current Hydro customers.

(b) Net export revenues are allocated on the basis of generation and transmission costs only in accordance with Order 51/96.

(c) Transmission costs, including Dorsey, are classified as 100% demand.

(d) Transmission and ancillary services costs are allocated on the basis of the 2 CP.

(e) Generation demand costs are allocated on the basis of the 2 CP.

(f) Energy related costs of generation are allocated on the basis of class annual energy (Non-Coincident Peak).

(g) HVDC costs (other than Dorsey) are functionalized as generation.

(h) Only transmission facilities recognized for inclusion in Hydro's Transmission Tariff are included in the transmission function.

(i) The creation of a Firm Export Class. This class should include long-term firm export sales and one-year firm export sales, with costs allocated on a fully embedded basis using a 2 CP allocation as employed for general service customers; and

(j) The creation of an Opportunity Export Class. This class should allocate costs using a similar basis to the domestic interruptible GSL customer class.

21.12 Rate Design

21.12.1 General

Although Hydro did not apply for any changes in rate design, the Board and the Intervenors considered the issues of rate design to be of considerable importance in this status update filing. As part of the Board's review as to whether the rates charged remain just and reasonable, the Board not only examined the overall revenue requirement, but also the cost of service methodology, and the rate structure itself.

The Board is disappointed with the inaction of Hydro to comply with the spirit of Order 51/96 with regard to undertaking a study and reporting to the Board by no later than the next GRA to develop a comprehensive rate design policy. More than six years have elapsed since that directive was issued, and Hydro stated at this hearing that it has no intention of preparing such a study in the near future. Such inaction is a disservice to the many Hydro customers, particularly those who might benefit from such a comprehensive rate design policy.

Having reviewed rate design issues as part of this status update, the Board believes that certain rates require adjustment.

21.12.2 Rates

After examining the overall revenue requirement of Hydro, the Board finds that there is no need for an overall rate adjustment for all customer classes. However, the Board is of the view that rates for certain customer classes should be adjusted.

Much time was spent at the hearing reviewing the Cost of Service Study. A revenue to cost ratio of 1.0 indicates that costs allocated to a customer class equal the revenues earned from that customer class. While unity may be the desired goal, Order 51/96 sets a zone of reasonableness target at 0.95 to 1.05 for revenue to cost coverage ratios. The Board is of the view that this zone of reasonableness of 0.95 to 1.05 continues to be an appropriate target for rate setting purposes.

As demonstrated in the table in Section 17.8.5, certain customer classes and subclasses have consistently remained outside of this zone of reasonableness for long periods of time, in some cases more than 10 years. Therefore, the Board is convinced that directional rate adjustments are appropriate now to address these inequities. Accordingly, the Board will order a 1% decrease in rates for GSS customers and a 2% decrease in rates for GSL customers in subclasses greater than 30 kV. Such rate decreases are to be effective April 1, 2003. The Board will direct Hydro to file new rate schedules for Board approval reflecting these rate adjustments.

The Board will also eliminate the winter ratchet over the next two years, which will reduce revenues to Hydro by approximately $3 to 4 million. The Board understands that this change will likely bring the GSM class and GSL subclass less than 30 kV closer to unity. Therefore, no further rate adjustment will be ordered for the GSM or GSL less than 30 kV subclass at this time.

The Board is confident that these rate adjustments will not impact the overall financial strength of Hydro, or its ability to achieve its financial targets.

21.12.3 Inverted Rates and Rate Structure

The declining block structure is largely the result of the historical circumstances of electrification throughout the Province and the construction of major generating plants on the Northern rivers. While the Board is not prepared at this time to support an inverted rate structure, the Board accepts that certain concepts of an inverted rate structure for residential customers may have merit for consideration in the future. The Board compliments both Mr. Lazar and Hydro for preparing thoughtful evidence on this matter and raising interesting new approaches. The Board believes that more study is required before an inverted rate structure can be considered for any customer class. The Board will direct Hydro to prepare a study on the merits of an inverted rate structure across all rate classes including transition and implementation issues. As part of this study, Hydro should evaluate the impact of an inverted rate structure on electric heat customers and residential customers with higher than average loads. This study should be filed with the Board by no later than December 31, 2003.

While the issue of inverted rates was largely confined to residential rates, the Board investigated demand and energy charges levied on larger General Service customers as part of the overall rate design. In the Board's opinion, some of Hydro's demand charges are in the mid to high range as compared to other jurisdictions in Canada, while the energy charges are amongst the lowest in Canada.

The Board is of the belief a lower demand charge and higher energy charge may serve as an impetus to further conservation of electricity since the users may become more aware of their consumption and hence, may attempt to minimize usage. Accordingly, the Board will direct Hydro to prepare a study on the impact of decreasing the demand charge and increasing the tail block of the energy charge and include recommendations and a timetable for possible implementation. The study should be filed with the Board by no later than December 31, 2003.

21.12.4 Winter Ratchet and Limited Use Billing Demand

In the 1996 GRA, Hydro sought to eliminate the winter ratchet with the implementation of seasonal rates. However, with little actual evidence and no customer consultation, the Board did not support the implementation of seasonal rates, and directed further study by Hydro. Since then, the LUBD program was introduced to alleviate some irritants posed by the winter ratchet. The Board is of the view that winter ratchet continues to pose problems for customers unable to benefit from the LUBD program.

The traditional rationale for the winter ratchet is that additional winter capacity to meet peak demand requires significant and costly capital expansions. The winter ratchet is designed to recover capacity costs incurred to meet this peak demand. The current system load runs nearly at capacity throughout the year as any additional capacity beyond domestic use is sold on the export market. Therefore, the Board finds that the use of the winter ratchet is not valid in the current circumstances. Accordingly, the Board will order Hydro to phase out the winter ratchet in two steps. On April 1, 2003, the winter ratchet is to be decreased to 70% of the maximum previous winter demand measured in December 2002, and January and February 2003. On April 1, 2004, the winter ratchet is to be eliminated. The Board will order Hydro to file the resulting rate schedules, for Board approval, prior to the above dates.

The Board will order the LUBD be eliminated on April 1, 2004. All LUBD customers will then revert to the billing rate of their appropriate class. Until April 1, 2004 the LUBD rate option will be considered a temporary rate offering. The Board also expects Hydro to inform all LUBD customers of this decision and its implication. The Board will grant final approval of Order 118/02 which extended the LUBD rate option on an interim ex parte basis.

21.12.5 Time of Use Rates

In Order 51/96 the Board directed Hydro to prepare a comprehensive rate policy including time of use rates which remains outstanding. The Board heard testimony that Hydro continues to install specialized metering equipment for certain general service customers with time of use capability. Accordingly, the Board considers it important to proceed with the development of time of use rates and directs Hydro to prepare a study, including a timetable and a plan for implementation, for a time of use rate program. Such study should also consider time of use rates for general service classes based on a seasonal, weekly, daily and hourly basis, including an evaluation of each alternative. The study should be filed with the Board by no later than December 31, 2003.

21.12.6 Diesel Rates

Any determination of whether rates are just and reasonable must include an examination of rates charged to those customers serviced by Hydro's diesel generation. The Board cannot make a determination on which customer should be included in a specific rate class of government versus non-government or whether a customer has sufficient resources to pay the bill, or funding formulas are appropriate.

During the hearing, Hydro stated it would be filing a separate application for diesel rates in December 2002. Such an application has now been filed and the Board will consider diesel rate issues at a future public hearing to review this filing.

21.12.7 Curtailable Rates

Hydro applied for a new CRP which included only minor variations from the existing curtailable service program. The rationale for curtailments has changed and, as stated by Hydro witnesses, the number of curtailments will likely decrease sharply. However, the Board is reasonably satisfied with the rationale used in the calculation of the Reference Discount.

Hydro has applied for the CRP to be a temporary program with an expiry date of November 30, 2003, given the unknown impact of MISO's requirement and the value of reserves. In the interest of rate stability, the Board will approve the CRP on a permanent basis.

21.12.8 Surplus Energy Program and Interim Ex Parte Orders

The Board will approve, on a final basis, all interim ex parte Orders relating to the DFH, ISE, SEP and CSP programs as attached in Appendix E.

21.12.9 Demand Side Management - Energy Conservation

The Board acknowledges that Hydro's initiatives on DSM since 1989 have achieved approximately 50% of targets set for 2012 of 356 MW and 1,272 GW.h. However, it is the Board's view the new DSM programs may not be effective for achieving DSM targets for 2012.

In this period of potential generation expansion the Board is concerned that Hydro may reduce efforts for DSM. It would appear that other utilities are more proactive in pursuing energy conservation measures. A program target for energy use reduction of 3% does not seem to be sufficiently aggressive.

The Board is of the view that, at present, Hydro provides few incentives for either residential or general service customer energy conservation. Financial incentives such as a movement toward lower demand and higher energy charges could encourage more efficient energy usage. Greater energy conservation within Manitoba opens the door for increased power exports with good financial returns. The Board views this as a positive process, particularly if the exported energy displaces coal or other greenhouse gas producing generation within other jurisdictions.

Therefore, the Board directs Hydro to re-examine the current level of DSM programs and pricing strategies to encourage conservation and develop a program with more aggressive targets to be filed with the Board by December 31, 2003.

Wind power offers potential fuel consumption reductions where the primary source of power is coal, natural gas, propane, or diesel. It can be a lower cost supplier of electricity where a primary fuel-based generator already exists and is available as a full back-up when the wind velocities are too low. The Board directs Hydro to consider the use of wind power in remote diesel electric communities where energy costs are high and file a report with the Board by December 31, 2003.

21.12.10 Future Regulation

The Board recognizes the many parties who expressed frustration with Hydro's absence from public review for over six years. The Board reiterates the statement made in Order 208/02 that Hydro establish a more regular schedule, not exceeding three years, for periodic rate reviews. This regular schedule should improve the efficiency, effectiveness and timeliness of the regulatory process, even if no rate changes are requested. Subject to other specific directives contained herein, the Board will approve Hydro's existing rate schedules to be in effect until March 31, 2006 or until otherwise amended by a further Order of the Board. The Board will direct Hydro to file a GRA for rates to be effective April 1, 2006 whether or not rate adjustments are sought. This directive does not preclude Hydro from filing applications for rate adjustments prior to this date.

22.0 It Is Therefore Recommended That:

1. Hydro limit its capital expenditures not related to new major generation and transmission, where safety and reliability constraints allow, and apply itself to reducing its long-term debt.

2. Hydro be diligent in ensuring it does not pay for duplicate planning studies for new generation projects.

3. Hydro pursue short-term financing options to expeditiously pay down the debt incurred for the special export profit payment to the Province of Manitoba, and thereby reduce the impact of such financing charges to future domestic ratepayers.

4. In respect of operating and administration expenses:

   (a) Hydro pursue with vigour meeting the operating and administration cost per customer target of $600 by increasing productivity.

   (b) Hydro continue to participate in benchmarking initiatives.

   (c) Hydro actively pursue all possible synergy savings in operating and administrative expenses as a result of its recent acquisition of Winnipeg Hydro.

5. Hydro consider ways to diversify and supplement its hydraulic generation with an appropriate mix of other forms of energy, including wind turbines, solar panels, ground source heat exchange and hydrogen cells.

23.0 It Is Therefore Ordered That:

1. The interim ex parte Orders listed in Appendix E of this Order BE AND ARE HEREBY CONFIRMED AS FINAL.

2. The Curtailable Rates Program as applied for by Hydro BE AND IS HEREBY APPROVED.

3. Hydro file for Board approval a revised schedule of rates to be effective April 1, 2003 including revenue impacts that reflect:
   (a) A 1% rate decrease for General Service Small customers;
   (b) A 2% rate decrease for General Service Large customers in subclasses greater than 30 kV; and
   (c) A decrease in the winter ratchet to 70% and the subsequent elimination of the winter ratchet effective April 1, 2004.

4. Hydro eliminate the Limited Use Billing Demand Rate option on April 1, 2004 and inform all affected customers of the changes to the winter ratchet and the Limited Use Billing Demand Rate option.

5. Hydro file an application with the Board by no later than June 30, 2003, for approval of Hydro's Open Access Transmission Tariff.

6. Hydro file the following information with the Board by no later than December 31, 2003:
   (a) An updated Integrated Financial Forecast reflecting the integration of Winnipeg Hydro and the in-service dates of all new generation within the eleven-year planning period;
   (b) A detailed debt management strategy;
   (c) A study to quantify specific reserve provisions required to cover the major risks and contingencies faced by Hydro;
   (d) A study on the merits of implementing an inverted rate structure for all customer classes;
   (e) A study on the impact of decreasing the demand charge and increasing the tail block of the energy charge;

(f) A study which considers time of use rates for GS classes based on a seasonable, weekly, daily, and hourly basis;

(g) A review of generation cost classification methodology options;

(h) Re-examine the current level of DSM programs and pricing strategies to encourage conservation, develop a program with more aggressive targets, and report to the Board; and

(i) Consider the use of wind power in remote diesel electric communities and file a report with the Board.

7. Hydro's proposed Cost of Service Study dated March 2002, which includes a number of methodology changes including allocating net export revenues to customer classes on the basis of total allocated costs BE AND IS HEREBY DENIED.

8. Hydro file an actual cost of service study for the year ended March 31, 2003 by no later than September 30, 2003 and a prospective cost of service study for the year ended March 31, 2004 by no later than September 30, 2003 which reflects the following:

(a) The former Winnipeg Hydro revenues and costs are appropriately assigned to the various customer classes in the same fashion as current Hydro customers.

(b) Net export revenues are allocated on the basis of generation and transmission costs only in accordance with Order 51/96.

(c) The creation of a Firm Export Class. This class should include long-term firm export sales and one-year firm export sales, with costs allocated on a fully embedded basis using a 2 CP allocation as is proposed for general service customers; and

(d) The creation of an Opportunity Export Class. This class should allocate costs using a similar basis to the domestic interruptible GSL customer class.

(e) Transmission costs, including Dorsey are classified as 100% demand.

(f) Transmission and ancillary services costs are allocated on the basis of the 2 CP method.

(g) Generation demand costs are allocated on the basis of the 2 CP method.

(h) Energy related generation costs are allocated to customer classes based on their share of the overall annual energy requirements (Non-Coincident Peak).

(i) HVDC costs (other than Dorsey) are functionalized as generation.

(j) Only transmission facilities recognized for inclusion in Hydro's Transmission Tariff are included in the transmission function.

9. Hydro appropriately identify and specifically account for all export-related capital expenditures in their capital forecasts to ensure that export revenues are appropriately matched against the full costs of production.

10. Hydro establish a more regular schedule for periodic rate reviews, not exceeding three years between hearings.

11. Subject to other specific rate directives contained herein, Hydro's existing rate schedules BE AND ARE HEREBY CONFIRMED, to be in effect until March 31, 2006, or until otherwise amended by a further Order of the Board.

12. Hydro file a General Rate Application for rates to be effective no later than April 1, 2006.

The Public Utilities Board

Chairman

Secretary

THE PUBLIC UTILITIES BOARD

"G. D. Forrest"
Chairman

"G. O. Barron"
Secretary

Certified a true copy of
Board Order 7/03 issued by
The Public Utilities Board

Secretary

Appendix A

Integrated Financial Forecast IFF MH 01-1

Appendix A

UNDERTAKING #39
Transcript Page #1679-1680

ELECTRIC OPERATIONS (MH01-1) WITH EXPOSURE MANAGEMENT AND SPECIAL PAYMENT
PROJECTED OPERATING STATEMENT
(x 1,000,000)

For year ending March 31:	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
REVENUES:											
General Consumers Revenue											
at approved rates	743	749	762	770	780	789	798	807	818	829	840
additional*	-	-	15	31	48	65	83	102	103	105	106
Winnipeg Hydro	48	48	50	51	52	53	55	56	57	58	58
Extraprovincial	628	553	528	467	454	448	430	425	404	425	427
Other	5	5	5	5	5	5	5	6	6	5	5
	1,424	1,355	1,360	1,324	1,339	1,360	1,371	1,396	1,388	1,422	1,436
EXPENSES:											
Finance Expense	496	504	507	493	497	490	484	478	475	492	491
Depreciation	237	256	269	280	286	296	303	312	317	322	332
Cost of Operations	254	262	266	268	273	278	284	290	295	301	307
Water Rentals	112	101	97	97	97	97	98	98	98	98	98
Tax Expense	40	41	41	42	42	42	42	42	42	42	42
Fuel & Power Purchased	65	81	89	86	75	80	84	90	94	96	102
	1,204	1,245	1,269	1,266	1,270	1,283	1,295	1,310	1,321	1,351	1,372
Net Income	220	110	91	58	69	77	76	86	67	71	64
Special Payment	150	75	63								
Contribution to Retained Earnings	70	35	28	58	69	77	76	86	67	71	64
*Additional General Consumers Revenue			15	31	48	65	83	102	103	105	106
Percentage Increase			2.0%	2.0%	2.0%	2.0%	2.0%	2.0%			
Cumulative percentage Increase			2.0%	4.0%	6.1%	8.2%	10.4%	12.6%	12.6%	12.6%	12.6%
Financial Ratios											
Debt:Equity	77:23	78:22	78:22	77:23	77:23	76:24	75:25	74:26	74:26	73:27	71:29
Interest Coverage	1.43	1.21	1.18	1.12	1.13	1.15	1.15	1.17	1.13	1.14	1.13
Capital Coverage	1.10	1.05	0.99	1.05	1.06	1.17	0.99	1.20	1.07	1.24	1.61

Appendix A

UNDERTAKING #39
Transcript Page #1679-1680

ELECTRIC OPERATIONS (MH01-1) WITH EXPOSURE MANAGEMENT AND SPECIAL PAYMENT
PROJECTED BALANCE SHEET
(x 1,000,000)

For year ending March 31:	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
ASSETS:											
Plant in Service	8,720	9,267	9,592	9,912	10,206	10,473	10,776	11,110	11,336	11,948	12,221
Accumulated Depreciation	(2,800)	(3,038)	(3,287)	(3,545)	(3,808)	(4,082)	(4,361)	(4,649)	(4,945)	(5,243)	(5,550)
Net Plant in Service	5,920	6,229	6,305	6,367	6,398	6,391	6,415	6,461	6,391	6,705	6,671
Construction in Progress	352	179	218	224	248	294	368	355	472	149	84
Current & Other Assets	2,502	2,456	2,372	2,300	2,272	2,263	2,256	2,267	2,279	2,309	2,363
	8,774	8,864	8,895	8,891	8,918	8,948	9,039	9,083	9,142	9,163	9,118
LIABILITIES:											
Long Term Debt (Net)	4,777	5,486	5,898	5,881	6,179	6,085	5,756	5,224	6,009	5,976	5,731
Current & Other Liabilities	2,577	1,927	1,521	1,479	1,143	1,193	1,542	2,035	1,245	1,231	1,366
Contributions in Aid of Construction	269	265	262	259	255	251	247	244	241	238	240
Retained Earnings	1,151	1,186	1,214	1,272	1,341	1,419	1,494	1,580	1,647	1,718	1,781
	8,774	8,864	8,895	8,891	8,918	8,948	9,039	9,083	9,142	9,163	9,118
Debt:Equity Ratio	77:23	78:22	78:22	77:23	77:23	76:24	75:25	74:26	74:26	73:27	71:29

Appendix A

UNDERTAKING #39
Transcript Page #1679-1680

ELECTRIC OPERATIONS (MH01-1) WITH EXPOSURE MANAGEMENT AND SPECIAL PAYMENT
PROJECTED FINANCING REQUIREMENTS STATEMENT
(x 1,000,000)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
FUNDS FROM OPERATIONS											
Net Income	220	110	91	58	69	77	76	86	67	71	64
Provision for Depreciation	237	256	269	280	286	296	303	312	317	322	332
Other	9	19	13	16	(6)	(2)	(4)	(7)	(5)	(5)	(11)
	466	385	373	354	349	371	375	391	379	388	385
APPLICATION OF FUNDS											
Capital Expenditures	425	367	376	338	330	318	380	325	355	312	239
Refinancing of LTD	627	757	-	211	-	90	107	3	501	-	-
Sinking Fund Deposit	116	123	87	121	139	137	128	128	206	192	205
Other	80	39	36	19	18	20	20	21	20	21	22
	-	225	63	-	-	-	-	-	-	-	-
	1,248	1,511	562	689	487	565	635	477	1,082	525	466
FINANCING REQUIREMENTS	782	1,126	189	335	138	194	260	86	703	137	81

Appendix B

Capital Expenditure Forecast CEF 01-01

Appendix B

MANITOBA HYDRO CAPITAL EXPENDITURE FORECAST (CEF01-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 2001/02 TO 2011/12

	Project Total	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	11 Year Total
POWER SUPPLY													
NEW GENERATION													
BRANDON COMBUSTION TURBINE	183	92	16										108
HVDC FACILITIES													
HVDC BIPOLE RELIABILITY ENHANCEMENTS	56	3		-	-	-	-	-	-	-	-	-	3
BIPOLE 1 MERCURY ARC VALVES STAGE 3	74	0	2	45	27	-	-	-	-	-	-	-	74
HVDC BIPOLE 2 THYRISTOR POLY PIPE REPLACEMENTS	5	1	-	-	-	-	-	-	-	-	-	-	1
CONVERTER TRANSFORMER BUSHING REPLACEMENT	7	1	1	2	-	-	-	-	-	-	-	-	3
DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPLACEMENT	7	1	2	-	-	-	-	-	-	-	-	-	4
BIPOLE 1&2 DC FILTER CAPACITOR REPLACEMENT	5	2	1	-	-	-	-	-	-	-	-	-	3
BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT	9	1	(0)	-	-	-	-	-	-	-	-	-	0
BIPOLE I & 2 ELECTRODE LINE MONITORING	1	-	1										1
HVDC SYSTEM SWITCHGEAR UPGRADE	3	1	1	1	-								3
HVDC AUXILLIARY POWER SUPPLY	2	1	0	1									2
DORSEY SYNCHRONOUS CONDENSER REFURBISHMENT	8		1	-	1	1	1	1	1				8
	-												-
HYDRAULIC REHABILITATION	-												-
GREAT FALLS G.S. REHABILITATION	23	4	9	6	3	0	-	-	-	-	-	-	22
PINE FALLS G.S. REHABILITATION	20	2	2	6	5	1	-	-	-	-	-	-	16
LAURIE RIVER PLANT 1 AND 2 REHABILITATION	17	-	3	1	1	1	-	-	-	-	1	1	6
GRAND RAPIDS G.S. REHABILITATION	96	8		-		-	-	-	-	-	-	-	8
JENPEG G.S. UNIT OVERHAULS (UNITS 1 - 6)	29	0	4	4	0	4	4	4	-	-	-	-	21
POWER SUPPLY DAM SAFETY UPGRADES	15	1	2	2	2	2	-	-	-	-	-	-	10
WINNIPEG RIVER CONTROL SYSTEM	17	2	3	3	-	-	-	-	-	-	-	-	7
LIMESTONE OUTSTANDING WORK	17	0	1	4	-	-	-	-	-	-	-	-	4
WINNIPEG RIVER RIVERBANK PROTECTION PROGRAM	7	1	1	1	1	1	1	-	-	-	-	-	4
KETTLE GS - IMPROVEMENTS & UPGRADES	69	1	1	1	0	-	-	-	-	-	-	0	2
KELSEY G.S. IMPROVEMENTS & UPGRADES	15	-	3	10	1	-	1	-	1	-	-	-	15
KETTLE ANNUNCIATION SYSTEM RENEWAL	2	1											1
NELSON RIVER CONTROL	6		2	2	2								6
													-
THERMAL REHABILITATION	-												-
BRANDON G.S. UNIT 5 LIFE EXTENSION	23			2	1	6	1	2	1	3	1	1	17
SELKIRK GS FUEL SWITCHING PROJECT	32	19	13										32
SELKIRK GS LIFE EXTENSION	29		2	15	12	0							29
													-
OTHER	-												-
200MW ONTARIO HYDRO SALE - SYNC COND CONVERSION	9	0	1	1	2	-	-	-	-	-	-	-	5
SITE REMEDIATION OF CONTAMINATED CORPORATE FACILITIES	13	2	1	1	1	1	1	1	1	1	0	1	10
OIL CONTAINMENT	16	0	1	2	1	1	1	1	1	-	-	-	7
FIRE PROTECTION PROJECTS	8	1	3	-	-	-	-	-	-	-	-	-	4
GENERATION TOWNSITE INFRASTRUCTURE		2	3	-	-	-	-	-	-	-	-	-	4
PLANNING STUDY COSTS		41	12	6	5	4	3	5	7	16	26	10	135
													-
DOMESTIC ITEMS - POWER SUPPLY		11	11	11	11	12	12	12	12	13	13	13	131
													-
PROPOSED POWER SUPPLY		**197**	**100**	**124**	**76**	**33**	**24**	**26**	**25**	**32**	**42**	**26**	**705**

MANITOBA HYDRO CAPITAL EXPENDITURE FORECAST (CEF01-1)

Appendix B

(IN MILLIONS OF DOLLARS)

FOR THE YEARS 2001/02 TO 2011/12

	Project Total	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	11 Year Total
TRANSMISSION AND DISTRIBUTION													
WUSKWATIM TRANSMISSION													
HVDC CONVERSION BIPOLE 3/CONAWAPA TRANSMISSION													
TRANSMISSION FOR GENERATION													
RADISSON - RIEL ± 500kV HVDC LINE	352		3	5	13	14	12	101	76	84	44	-	352
RIEL 230/500kV STATION	98		2	5	6	8	25	31	22				98
													-
INTERCONNECTIONS													-
200MW ONTARIO HYDRO SALE - T/L UPGRADE	5	0	-	-	-	-	-	-	-	-	-	-	0
GLENBORO - RUGBY 230KV LINE	25	13	9	1	1								24
													-
TRANSMISSION													-
NORTHERN AC TRANSMISSION SYSTEM REQUIREMENTS	31	0	2	7	11	9							30
THOMPSON>HERBLET LAKE 230kV TRANSMISSION	53	-	1	1	2	9	22	18	-	-	-	-	53
NORTH CENTRAL MANITOBA PROJECT	18	0		-	-	-	-	-	-	-	-	-	0
FLIN FLON - CLIFF LAKE TRANSFORMER REPLACEMENT	6	0	(1)	-	-	-	-	-	-	-	-	-	(1)
HERBLET LAKE > THE PAS 230kV TRANSMISSION	46	-		0	0	1	1	2	7	20	16	-	46
DORSEY > NEEPAWA > CORNWALLIS 230kV LINE	50	0	(0)	-	-	-	-	-	-	-	-	-	(0)
WINNIPEG > BRANDON TRANSMISSION IMPROVEMENTS	37	-	1	3	5	6	10	8	4	-	-	-	37
FT GARRY - PERIMETER SOUTH BANK REPLACEMENT	5			0	3	2	-	-	-	-	-	-	5
RIDGEWAY TRANSFORMER ADDITION	9	-	-	0	1	1	4	3	-	-	-	-	9
ST. VITAL TRANSFORMER ADDITION	9	7	1		-	-	-	-	-	-	-	-	8
DORSEY-ROSSER 230kV TRANSMISSION IMPROVEMENTS	2	0	0	-	-	-	-	-	-	-	-	-	0
DORSEY > ST. VITAL 230kV AC TRANSMISSION	8	6	1		-	-	-	-	-	-	-	-	7
DORSEY > LAVERENDRYE > ST. VITAL 230kV TRANSMISSION	26	-	-	-	-	-	-	-	-	-	-	-	-
ROSSER > SILVER 230kV TRANSMISSION	30	0	0	3	7	14	-	-	-	-	-	-	24
NEEPAWA 230 -66kV STN	18	-	-	0	1	8	9	-	-	-	-	-	18
ASSINIBOINE - WILKES AVE 115-24 KV BANK 1 ADDITION	15	1	(2)	-	-	-	-	-	-	-	-	-	(1)
ROSSER > MCPHILLIPS 115kV TRANSMISSION IMPROVEMENTS	3	-	0	1	2	-	-	-	-	-	-	-	3
RICHER SOUTH 230-66kV TRANSFORMER ADDITION	5	-	0	0	2	2	-	-	-	-	-	-	5
PINE FALLS > BLOODVEIN 115kV TRANSMISSION LINE	29						0	0	1	2	7	16	26
ST. VITAL > STEINBACH 230kV TRANSMISSION	23	-	-	-	0	0	1	3	4	14	-	-	23
RIDGEWAY > SELKIRK 230kV TRANSMISSION	26	-	1	2	4	5	7	6	-	-	-	-	26
SOURIS > PEMBINA VALLEY 230kV TRANSMISSION	33	-	-	-	-	-	1	1	1	2	12	16	33
WINNIPEG AREA TRANSMISSION REFURBISHMENT	8	2	2	1	-	-	-	-	-	-	-	-	4
DORSEY STATION 230kV BREAKER REPLACEMENT	19	0	0	-	-	-	-	-	-	-	-	-	0
DORSEY > US BORDER D602F 500KV AC T/L INSULATOR REPLACEMENT	8	1	1	-	-	-	-	-	-	-	-	-	2
BIPOLE 1 & 2 LINE SPACER DAMPERS REPLACEMENT	15	4	5	-	-	-	-	-	-	-	-	-	9
DORSEY 230kV BUS ENHANCEMENTS	16	3	4	4	4	2	-	-	-	-	-	-	16
FLIN FLON AREA TRANSMISSION IMPROVEMENTS	22	1	-	3	5	3							12
PINE FALLS-GREAT FALLS 115-66kV SUPPLY	10	2	4	4	0								10
													-
SUBTRANSMISSION	-												-
JENPEG > NORWAY HOUSE 66 kV SUB TRANSMISSION LINE	12	5	6			-	-	-	-	-	-	-	11
RUTTAN > SOUTH INDIAN LAKE 66 kV LINE	16	0	0	0	2	4	-	-	-	-	-	-	7
PIKWITONEI & THICKET PORTAGE SITE REMEDIATION	6	2	1	-	-	-	-	-	-	-	-	-	2
BIRTLE SOUTH > ROSSBURN 66kV LINE	6	-	0	0	4	2	-	-	-	-	-	-	6
ST. BONIFACE PLESSIS Rd 115-25KV STATION	16	0	(2)	-	-	-	-	-	-	-	-	-	(1)
ROSSER - OAK POINT 115-24KV STATION	21	-	-	-	-	-	0	2	2	13	4	-	21

MANITOBA HYDRO CAPITAL EXPENDITURE FORECAST (CEF01-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 2001/02 TO 2011/12

	Project Total	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	11 Year Total
ROSSER - OAK POINT BANK 2 ADDITION	10	-	-	-	-	-	-	-	1	6	3	-	10
ST. BONIFACE PLESSIS Rd BANK 2 ADDITION	3	0	2	0	-	-	-	-	-	-	-	-	2
NEEPAWA 66KV SYSTEM	4	-	-	0	4	-	-	-	-	-	-	-	4
RESTON/GLENBORO CAPACITY INCREASE	6	3	1	-	-	-	-	-	-	-	-	-	4
ST. LEON 230-66KV TRANSFORMER ADD'N AND IPL EXPANSION	6	4	0	0	-								5
BRANDON CROCUS PLAINS 115-24kV BANK ADDITION	8	1	-	-	-	4	2	0	-	-	-	-	8
BRERETON LAKE STATION AREA	7	1	1	2	0	0	1						7
	-												-
DISTRIBUTION	-												-
VIRDEN AREA DISTRIBUTION CHANGES	15	2	1	1	1	-	-	-	-	-	-	-	6
DEFECTIVE RINJ CABLE REPLACEMENT	8	1	2	2	2	1	-	-	-	-	-	-	7
PAINT LAKE FEEDER	2	2	-										2
													-
COMMUNICATIONS, CONTROLS AND INFO TECHNOLOGY	-												-
MICROWAVE RADIO REPLACEMENTS	141	13	41	23	8	28	7	-	-	-	-	-	120
MAPINFO IMPLEMENTATION	33	4	3	-	-	-	-	-	-	-	-	-	6
	-												-
OTHER	-												-
SITE REMEDIATION	10	2	2	1	0	-	-	-	-	-	-	-	5
OIL CONTAINMENT	4	1	1	1	0	-	-	-	-	-	-	-	4
													-
DOMESTIC ITEMS - TRANSMISSION AND DISTRIBUTION		61	68	70	72	73	75	77	79	81	83	84	822
PROPOSED TRANSMISSION AND DISTRIBUTION		**142**	**161**	**142**	**159**	**195**	**177**	**253**	**197**	**221**	**169**	**116**	**1,930**
CUSTOMER SERVICE & MARKETING													
DEMAND SIDE MANAGEMENT CAPITAL COSTS		11	14	22	22	19	16	13	12	12	12	8	162
	-												-
AUTOMATIC METER READING IMPLEMENTATION	31	2	3	3	3	3	3	3	6	2	0	-	31
	-												-
DOMESTIC ITEMS - CUSTOMER SERVICE		44	45	48	49	50	51	52	54	55	56	57	560
													-
													-
PROPOSED CUSTOMER SERVICE & MARKETING		**57**	**62**	**73**	**74**	**72**	**71**	**68**	**72**	**69**	**69**	**64**	**752**
FINANCE & ADMINISTRATION													
	-												-
CORPORATE BUILDING PROGRAM		7	8	8	8	8	22	10	8	8	8	8	100
	-												-
CUSTOMER INFORMATION SYSTEM	11	-	4	7	0	-	-	-	-	-	-	-	10
													-
HUMAN RESOURCE MANAGEMENT SYSTEM	13		12	1									13
													-
DOMESTIC ITEMS - FINANCE & ADMINISTRATION		22	21	21	22	22	23	24	24	25	25	25	253
													-
PROPOSED FINANCE & ADMINISTRATION		**29**	**45**	**37**	**29**	**30**	**45**	**33**	**32**	**32**	**33**	**33**	**377**
PROPOSED CAPITAL EXPENDITURES (ELECTRIC)		**425**	**367**	**376**	**338**	**330**	**318**	**380**	**325**	**355**	**312**	**239**	**3,764**

Appendix C

Revenue Cost Coverage Analysis – Schedule A-1

Manitoba Hydro
Retail Prospective Cost Of Service Study
March 31, 2002
Revenue Cost Coverage Analysis

Appendix C

SUMMARY

Class	Total Cost ($000)	Class Revenue ($000)	Contribution To Reserves ($000)	Revenue Cost Coverage %	Net Export Revenue ($000)	Total Revenue ($000)	Contribution To Reserves ($000)	RCC % Current Rates
Residential	533,184.3	306,544.7	(226,639.5)	57.5%	207,789.6	514,334.4	(18,849.9)	96.5%
General Service - Small	207,096.3	141,827.1	(65,269.2)	68.5%	79,973.3	221,800.4	14,704.1	107.1%
General Service - Medium	117,575.1	77,393.3	(40,181.9)	65.8%	45,402.3	122,795.6	5,220.5	104.4%
General Service - Large	317,203.9	193,745.6	(123,458.2)	61.1%	123,352.9	317,098.5	(105.4)	100.0%
Interruptible	4,237.1	4,115.2	(121.9)	97.1%	-	4,115.2	(121.9)	97.1%
Area & Roadway Lighting	15,589.7	13,769.2	(1,820.5)	88.3%	2,113.4	15,882.6	292.9	101.9%
Total General Consumers	1,194,886.4	737,395.2	(457,491.2)	61.7%	458,631.5	1,196,026.6	1,140.2	100.1%
Winnipeg Hydro	-	-	-	0.0%	-	-	-	0.0%
Net Export Revenue	-	461,413.9	461,413.9	0.0%	(461,413.9)	-	-	0.0%
Total Central System	1,194,886.4	1,198,809.1	3,922.7	100.3%	(2,782.4)	1,196,026.6	1,140.2	100.1%
Diesel	7,118.8	3,196.1	(3,922.7)	44.9%	2,782.4	5,978.6	(1,140.3)	84.0%
Total System	1,202,005.2	1,202,005.2	-	100.0%	-	1,202,005.2	-	100.0%

Appendix D

Revenue Cost Variance Analysis – Table D-1

Prospective Cost of Service Study for 2002
Detailed Variance Analysis
2002 PCOSS vs Final 2002 Alternate Scenario

Appendix D

	Residential	**GSS**	**GSM**	**GSL**	**S/L**	**Wpg Hydro**
2002 Prospective Cost of Service (Previous Methodology)	***88.4%***	***105.8%***	***107.3%***	***110.8%***	***97.6%***	***117.3%***
Impact of Changes on RCCs due to the following variables*:						
(1) HVDC (excl Dorsey) as Generation & Ancillary Services	-0.1%	0.0%	0.1%	0.2%	0.1%	0.1%
(2) Transmission 100% Demand	-1.6%	-0.5%	1.0%	4.2%	1.4%	-2.4%
(3) Transmission - Avg 12 monthly Peaks	1.7%	0.0%	-1.4%	-3.3%	1.6%	-1.1%
(4) Gen reclassification & allocation on seasonal demand	-0.1%	1.2%	2.1%	0.8%	-1.5%	-9.6%
(5) Removal of Winnipeg Hydro as a customer class	0.8%	-0.2%	-0.1%	-0.5%	0.3%	-104.3%
(6) Allocation of export revenue	7.4%	0.8%	-4.6%	-12.2%	2.4%	0.0%
Total Impact on RCCs	8.1%	1.3%	-2.9%	-10.8%	4.3%	-117.3%
2002 Prospective Cost of Service Study - REVISED	*96.5%*	*107.1%*	*104.4%*	*100.0%*	*101.9%*	*0.0%*

Appendix E

Interim Ex Parte Orders

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
09/09/98	120/98	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	Until confirmed or otherwise by a further Order of the Board following a public hearing.
16/09/98	122/98	“ “ “ “	“ “ “ “ “ “	“ “
23/09/98	124/98	“ “ “ “	“ “ “ “ “ “	“ “
30/09/98	129/98	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
07/10/98	131/98	“ “ “ “	“ “ “ “ “ “	“ “
14/10/98	133/98	“ “ “ “	“ “ “ “ “ “	“ “
21/10/98	134/98	“ “ “ “	“ “ “ “ “ “	“ “
28/10/98	135/98	“ “ “ “	“ “ “ “ “ “	“ “
04/11/98	142/98	“ “ “ “	“ “ “ “ “ “	“ “
10/11/98	146/98	“ “ “ “	“ “ “ “ “ “	“ “
18/11/98	150/98	“ “ “ “	“ “ “ “ “ “	“ “
25/11/98	151/98	“ “ “ “	“ “ “ “ “ “	“ “
02/12/98	156/98	“ “ “ “	“ “ “ “ “ “	“ “
09/12/98	157/98	“ “ “ “	“ “ “ “ “ “	“ “
16/12/98	159/98	“ “ “ “	“ “ “ “ “ “	“ “
23/12/98	164/98	“ “ “ “	“ “ “ “ “ “	“ “
24/12/98	167/98	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for December 1998	“ “
30/12/98	168/98	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
06/01/99	2/99	“ “ “ “	“ “ “ “ “ “	“ “
08/01/99	3/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for January 1999	“ “
13/01/99	5/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
20/01/99	10/99	“ “ “ “	“ “ “ “ “ “	“ “
27/01/99	17/99	“ “ “ “	“ “ “ “ “ “	“ “
03/02/99	19/99	“ “ “ “	“ “ “ “ “ ”	“ “
08/02/99	21/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for February 1999	“ “
10/02/99	23/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
17/02/99	25/99	“ “ “ “	“ “ “ “ “ “	“ “
24/02/99	26/99	“ “ “ “	“ “ “ “ “ “	“ “
03/03/99	27/99	“ “ “ “	“ “ “ “ “ “	“ “
10/03/99	28/99	“ “ “ “	“ “ “ “ “ “	“ “
10/03/99	29/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of	“ “

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
			Curtailable Service Program Reference Discount for March 1999	
17/03/99	41/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
24/03/99	54/99	" " " "	" " " " " "	" "
31/03/99	56/99	" " " "	" " " " " "	" "
07/04/99	57/99	" " " "	" " " " " "	" "
12/04/99	60/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for April 1999	" "
14/04/99	63/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
21/04/99	71/99	" " " "	" " " " " "	" "
28/04/99	72/99	" " " "	" " " " " "	" "
28/04/99	73/99	Hydro – Curtailable Rates Program	Interim Curtailable Service Program Order	???????????
05/05/99	83/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
10/05/99	85/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for May 1999	" "
12/05/99	86/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
19/05/99	88/99	" " " "	" " " " " "	" "
26/05/99	89/99	" " " "	" " " " " "	" "
02/06/99	98/99	" " " "	" " " " " "	" "
09/06/99	101/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for June 1999	" "
09/06/99	102/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
16/06/99	111/99	" " " "	" " " " " "	" "
23/06/99	114/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
30/06/99	119/99	" " " "	" " " " " "	" "
07/07/99	122/99	" " " "	" " " " " "	" "
14/07/99	139/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for July 1999	" "
14/07/99	140/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
21/07/99	142/99	" " " "	" " " " " "	" "
28/07/99	145/99	" " " "	" " " " " "	" "
04/08/99	147/99	" " " "	" " " " " "	" "
11/08/99	153/99	" " " "	" " " " " "	" "
11/08/99	154/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of	" "

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
			Curtailable Service Program Reference Discount for August 1999	
18/08/99	155/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
25/08/99	156/99	" " " "	" " " " " "	" "
01/09/99	157/99	" " " "	" " " " " "	" "
07/09/99	160/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for September 1999	" "
08/09/99	161/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
15/09/99	162/99	" " " "	" " " " " "	" "
22/09/99	164/99	" " " "	" " " " " "	" "
29/09/99	165/99	" " " "	" " " " " "	" "
06/10/99	166/99	" " " "	" " " " " "	" "
12/10/99	169/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for October 1999	" "
13/10/99	170/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
20/10/99	171/99	" " " "	" " " " " "	" "
27/10/99	172/99	" " " "	" " " " " "	" "
03/11/99	178/99	" " " "	" " " " " "	" "
08/11/99	184/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for November 1999	" "
10/11/99	185/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
17/11/99	196/99	" " " "	" " " " " "	" "
23/11/99	198/99	" " " "	" " " " " "	" "
01/12/99	201/99	" " " "	" " " " " "	" "
07/12/99	203/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for December 1999	" "
08/12/99	205/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
15/12/99	209/99	" " " "	" " " " " "	" "
22/12/99	216/99	" " " "	" " " " " "	" "
29/12/99	217/99	" " " "	" " " " " "	" "
5/1/00	1/00	" " " "	" " " " " "	" "
7/1/00	2/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for January 2000	" "
12/1/00	3/00	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement	" "

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
			Energy Rate, Schedule B-2	
19/1/00	4/00	" " " " "	" " " " " "	" "
26/1/00	12/00	" " " " "	" " " " " "	" "
2/2/00	15/00		" " " " " "	" "
8/2/00	17/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for February 2000	" "
9/2/00	18/00	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
16/2/00	20/00	" " " " "	" " " " " "	" "
23/2/00	23/00	" " " " "	" " " " " "	" "
1/3/00	35/00	" " " " "	" " " " " "	" "
6/3/00	37/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for March 2000	" "
8/3/00	38/00	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
15/3/00	40/00	" " " " "	" " " " " "	" "
22/3/00	42/00	" " " " "	" " " " " "	" "
29/3/00	50/00	" " " " "	" " " " " "	" "
05/04/00	52/00	" " " " "	" " " " " "	" "
10/04/00	53/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for April 2000	" "
12/04/00	54/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
19/04/00	60/00	" " " " "	" " " " " "	" "
26/04/00	61/00	" " " " "	" " " " " "	" "
03/05/00	63/00	" " " " "	" " " " " "	" "
08/05/00	64/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for May 2000	" "
10/05/00	68/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
17/5/00	70/00	" " " " "	" " " " " "	" "
24/5/00	75/00	" " " " "	" " " " " "	" "
31/5/00	76/00	" " " " "	" " " " " "	" "
2/6/00	77/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for June 2000	" "
7/6/00	78/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
14/6/00	79/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
21/6/00	88/00	" " " " "	" " " " " "	" "

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
28/6/00	89/00	“ “ “ “ “	“ “ “ “ “ “	“ “
5/7/00	96/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
11/7/00	104/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for July 2000	“ “
12/7/00	106/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
19/7/00	111/00	“ “ “ “ “	“ “ “ “ “ “	“ “
26/7/00	113/00	“ “ “ “ “	“ “ “ “ “ “	“ “
2/8/00	116/00	“ “ “ “ “	“ “ “ “ “ “	“ “
8/8/00	117/00	Hydro – Monthly Reference Discount	An application by Manitoba Hydro for Interim Ex parte Approval of Curtailable Service Program Reference Discount for August 2000	“ “
9/8/00	118/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
16/8/00	119/00	“ “ “ “ “	“ “ “ “ “ “	“ “
23/8/00	121/00	“ “ “ “ “	“ “ “ “ “ “	“ “
30/8/00	122/00	“ “ “ “ “	“ “ “ “ “ “	“ “
5/9/00	124/00	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for September 2000	
6/9/00	125/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
13/9/00	126/00	“ “ “ “	“ “ “ “ “ “	“ “
20/9/00	129/00	“ “ “ “	“ “ “ “ “ “	“ “
27/9/00	131/00	“ “ “ “	“ “ “ “ “ “	“ “
4/10/00	133/00	“ “ “ “	“ “ “ “ “ “	“ “
10/10/00	134/00	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for October 2000	“ “
11/10/00	135/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
18/10/00	136/00	“ “ “ “	“ “ “ “ “ “	“ “
25/10/00	139/00	“ “ “ “	“ “ “ “ “ “	“ “
1/11/00	144/00	“ “ “ “	“ “ “ “ “ “	“ “
7/11/00	145/00	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for November 2000	“ “

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
8/11/00	147/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
15/11/00	148/00	" " " "	" " " " " "	" "
22/11/00	149/00	" " " "	" " " " " "	" "
29/11/00	150/00	" " " "	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule SEP-1	" "
6/12/00	155/00	" " " "	" " " " " "	" "
6/12/00	156/00	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for December 2000	
13/12/00	159/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
20/12/00	163/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
27/12/00	164/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
3/1/01	1/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
9/1/01	3/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for January 2001	" "
10/1/01	5/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
17/1/01	9/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
24/1/01	12/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" "
31/1/01	16/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" "
6/02/01	19/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for February 2001	" "
7/02/01	23/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" "
14/02/01	29/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" "
21/02/01	30/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" "
28/02/01	31/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" "
06/03/01	34/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for March 2001	" "

DATE	*BOARD ORDER NO.*	*FILE NAME*	*SUBJECT MATTER*	*TO BE BROUGHT FORWARD*
07/03/01	35/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “
14/03/01	47/01	“ “ “ “	“ “ “ “ “ “	“ “
21/03/01	58/01	“ “ “ “	“ “ “ “ “ “	“ “
28/03/01	60/01	“ “ “ “	“ “ “ “ “ “	“ “
4/4/01	62/01	“ “ “ “	“ “ “ “ “ “	“ “
11/04/01	72/01	“ “ “ “	“ “ “ “ “ “	“ “
12/04/01	73/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for April 2001	“ “
18/04/01	74/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “
25/04/01	76/01	“ “ “ “	“ “ “ “ “ “	“ “
2/5/01	79/01	“ “ “ “	“ “ “ “ “ “	“ “
7/5/01	85/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for May 2001	“ “ “
9/5/01	86/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
16/5/01	88/01	“ “ “ “	“ “ “ “ “ “	“ “ “
23/5/01	89/01	“ “ “ “	“ “ “ “ “ “	“ “ “
30/5/01	90/01	“ “ “ “	“ “ “ “ “ “	“ “ “
04/06/01	92/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for June 2001	“ “ “
06/06/01	93/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
13/06/01	96/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
20/06/01	102/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
27/06/01	103/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
4/7/01	105/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
10/7/01	110/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for July 2001	“ “ “
11/7/01	111/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
18/7/01	112/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
25/7/01	115/01	“ “ “ “	“ “ “ “ “ “	“ “ “
1/8/01	120/01	“ “ “ “	“ “ “ “ “ “	“ “ “
8/8/01	121/01	“ “ “ “	“ “ “ “ “ “	“ “ “
8/8/01	122/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for August 2001	“ “ “
15/8/01	123/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
22/8/01	128/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
29/8/01	131/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ ” “
5/9/01	133/01	“ “ “ “	“ “ “ “ “ “	“ “ “
10/9/01	140/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for September 2001	“ “ “
12/9/01	142/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
19/9/01	144/01	“ “ “ “	“ “ “ “ “ “	“ “ “
26/9/01	146/01	“ “ “ “	“ “ “ “ “ “	“ “ “
03/10/01	148/01	“ “ “ “	“ “ “ “ “ “	“ “ “
10/10/01	151/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for October 2001	“ “ “
10/10/01	152/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
17/10/01	162/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
24/10/01	165/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
31/10/01	169/01	“ “ “ “	“ “ “ “ “ “	“ “ “
5/11/01	171/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for November 2001	“ “ “
7/11/01	175/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
14/11/01	176/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
21/11/01	181/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
28/11/01	183/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
05/12/01	186/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
10/12/01	188/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for December 2001	“ “ “
12/12/01	190/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
19/12/01	191/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
27/12/01	193/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
02/01/02	4/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
07/01/02	5/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for January 2002	“ “ “
09/01/02	6/02	Hydro – ISE, Spot Market Replacement Energy Rate,	Application by Manitoba Hydro for an Interim Ex Parte Order	“ “ “

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
		Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Approving Surplus Energy Program Rates, Schedule Sep-1	
16/01/02	8/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
23/01/02	11/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
30/1/02	13/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
1/02/02	17/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for February 2002	" " "
06/02/02	19/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
13/02/02	29/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
20/02/02	30/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
27/02/02	31/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
4/3/02	32/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for March 2002	" " "
6/3/02	35/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
13/3/02	42/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
20/3/02	51/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
27/3/02	54/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
02/4/02	55/02	Hydro – '02 GRA – Vol. IV & Curtailable Rate Program	Application by Manitoba Hydro for an Interim Ex Parte order Approving the Curtailable Rate Program	" " "
03/4/02	56/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
09/4/02	57/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for April 2002	" " "
10/4/02	58/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
17/4/02	71/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
24/4/02	73/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
1/5/02	74/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
6/5/02	80/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for May 2002	" " "
8/5/02	81/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
15/5/02	83/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
22/5/02	85/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
29/5/02	88/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
5/6/02	89/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
11/6/02	116/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for June 2002	" " "
12/6/02	117/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
12/6/02	118/02	An Application by Manitoba Hydro for Interim Ex Parte Approval of the Limited Use of Billing Demand Rate Option	Hydro -- Application for Interim Ex Parte Approval for Continuation of the Limited Use of Billing Demand Rate	" " "
19/6/02	119/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
26/6/02	121/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
3/7/02	124/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
10/7/02	127/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
10/7/02	128/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for July 2002	" " "
17/7/02	130/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
24/7/02	132/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
31/7/02	137/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
2/8/02	138/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for August 2002	" " "
7/8/02	140/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
14/8/02	153/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
21/8/02	155/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
28/8/02	156/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
4/9/02	157/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
6/9/02	162/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for September 2002	" " "
11/9/02	165/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "

DATE	*BOARD ORDER NO.*	*FILE NAME*	*SUBJECT MATTER*	*TO BE BROUGHT FORWARD*
18/9/02	167/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
25/9/02	169/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
2/10/02	171/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
7/10/02	177/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for October 2002	" " "
9/10/02	178/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
16/10/02	184/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
23/10/02	186/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
30/10/02	187/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
6/11/02	190/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
12/11/02	193/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for November 2002	" " "
13/11/02	194/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
20/11/02	197/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
27/11/02	198/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
4/12/02	204/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
10/12/02	213/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for December 2002	" " "
11/12/02	214/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
18/12/02	220/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
23/12/02	221/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
31/12/02	222/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
8/1/03	1/03	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
8/1/03	2/03	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for January 2003	" " "

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