CAC # 8

Manitoba Hydro 2012/13 & 2013/14 General Rate Application

Supporting Materials

CAC Manitoba

January 8, 2013

Public Interest Law Centre
of Legal Aid Manitoba
3rd floor – 287 Broadway
Winnipeg, MB R3C 0R9

finalize all interim Diesel Zone rates since 2004 – including those approved on an interim basis by Orders 17/04; 46/04; 159/04 and 176/06.

vi/ Pre-2004 Accumulated Deficit of $16.9 Million

Back in 2004, and as an apparent concession to the Government accounts that would otherwise have responsibility for payment, the Tentative Settlement Agreement provided payment of the $16.9 million of the then-accumulated deficit, plus interest, over 10-years, from an allocation of Net Export Revenues, calculated using the same methodology as the Net Export Revenue Credit for grid connected customer classes.

Since 2004, and in 2006 and 2007, the Board conducted a comprehensive review of MH's Cost of Service and directed changes in the methodology – including the creation of an Export Customer class and a determination of costs to be allocated to the Export class.

The result of the Board's directed changes in methodology reduced the Net Export Credit available to be applied to the Diesel Zone, such that it is now expected that only approximately 25% of the pre-2004 accumulated deficit (plus interest) will be retired by 2014.

While the Board understands the impact of the post-2007 Cost of Service Study methodology on the Tentative Settlement Agreement, that impact would have been unknown to MH, INAC, MKO and the four First Nations in 2004. As a result, the Grid Customers, who have already been assigned responsibility for the full amount of the $16.9 million, will not "see" significant net export credits go to the Diesel Zone to notionally reduce the Grid customers' contribution to the Settlement.

Rather than look backwards, and perhaps put the finalization of the Settlement Agreement in jeopardy, the Board is prepared to accept that after 2014 there will be no further Net Export Credit applied to the pre-2004 accumulated deficit.

In essence, the remaining notional balance will be "written off", just as it has already been fully expensed in MH's audited and published financial accounts.

vii/ Allocation of Revenue Shortfall

MH has calculated and applied the Surcharge consistent with past practices. (That is – the Residential and General Service class Revenue Requirement minus class rate revenue results in the quantification of the $5.0 million of 'Revenue Shortfall' in this Application.) MH proposed dividing that shortfall among government accounts on the basis of energy usage.

Mr. Hildebrand recommended, as an alternative allocation methodology, the use of the same ratios as those used for capital contributions shared in the Tentative Settlement Agreement (i.e. INAC 69%; Other Federal Government 6%; Provincial 4%; MH 21%).

MH contends the ratio of capital contributions and the ratio of Surcharge responsibility have different underlying purposes. Whereas the Surcharge arises from only Residential and General Service accounts, the Capital Contributions are for all users – Government as well as affiliated Residential and General Service accounts.

Notwithstanding the recommendation and cogent rationale advanced by Mr. Hildebrand, and the intuitive position of MH, the actual sharing of the Revenue

CAC/MH (DIESEL) I-13

Subject: **Settlement Agreement and Interim Rates**
Reference: **Application, Attachment 5, page 2**
Order 159/04, pages 7-8
2010DA, INAC/MH I-16 a)

b) Please confirm that, for any payments received after July 7, 2005, the amounts received included a provision for accrued interest in accordance with the description on page 7 of Order 159/04.

ANSWER:

The following payments were received after July 7, 2005:

INAC	$19,871,870 plus interest
Other Federal	$622,348
Other Provincial	$451,756

The Settlement Agreement required INAC (now AANDC) to pay interest on payments after July 7, 2005. Interest was not charged in respect of other government agencies that paid after this date.

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Costs to serve the Diesel Communities are much higher than costs to serve customers from the grid due to isolation of the communities, small population served, and cost of facilities and fuel. For 2011/12 the total cost (excluding capital cost) to provide service in these communities based on PDCOSS12 is estimated at 53.53¢ per kWh (Schedule 1).

The PUB last approved interim rates in the Diesel Rate Zone effective January 1, 2011 (PUB Order 134/10 and 1/11) which was followed by Order 148/11 (October 20, 2011) which approved the elimination of the higher tail rate for residential customers (November 1, 2011).

3.0 DESCRIPTION OF RATES AND RATE SETTING METHODOLOGY

For indicative rates effective April 1, 2012, Manitoba Hydro is proposing the following changes to the Diesel Zone Revenue Requirement. These changes are:

1. The Revenue Requirement per kWh is calculated based on the 2011/12 Prospective Diesel Cost of Service Study (PDCOSS12) and forecast consumption for 2012/13. The Revenue Requirement per kWh as derived in Schedule 1 of the PDCOSS12 is set at 59.16¢ per kWh which includes a provision for capital recovery.

2. This Application also reflects the provisions from the Settlement Agreement between Manitoba Hydro, Her Majesty the Queen in Right of Canada as represented by the Minister of INAC (now referred to as Aboriginal Affairs and Northern Development Canada (AANDC)), the four Diesel Communities and Manitoba Keewatinowi Okimakanak Inc. (MKO). This agreement contemplates the funding of capital costs through customer contributions rather than rates. Manitoba Hydro will thus only seek to have capital expenditures included in rates in situations where customer contributions are not forthcoming. Post 2004, AANDC has made separate payments: in 2006 a payment of $1.2 million was received for the Tadoule Lake genset replacement, and in March 2011 a $2.3 million payment for several other of the capital items incurred during that time period. AANDC has declined to make any Contribution related to Brochet soil remediation. As a result Manitoba Hydro is proposing to include the Brochet Soil Remediation and outstanding interest and depreciation expense based on capital costs incurred

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4. Manitoba Hydro's Requested Changes to Rates: and Manitoba Hydro's Requested Changes to Rate Setting Methodology:

In its current 2010 Diesel Zone Rate Application, MH proposes a number of changes to a) Diesel Zone rate-setting; b) the derivation of the annual Diesel Zone Revenue Requirement; and, c) Diesel Zone rates:

i) MH proposes to implement a "Tail Block" rate for Residential and General Service customers, to apply to monthly consumption in excess of 2,000 kWh (being a lesser rate than the calculated "Full Cost Rate" that is based on MH's calculated annual Revenue Requirement for the Diesel Zone);

ii) MH proposes that the "new" Tail Block rate be 45¢ per kWh, compared to the 2007 "Full Cost" rate of 41.27¢ per kWh; and

iii) MH's proposed Tail Block rate for Residential and General Service consumption (in excess of 2,000 kWh) would represent an increase of 8%, or approximately 2.9 % per year since the current rate was implemented in 2007, but it would fall "far short" of MH's proposed revised Full Cost Rate of 59 ¢ per kWh.

MH also proposed a revised annual Revenue Requirement for the Diesel Zone, one calculated based on MH's 2009/10 Prospective Diesel Cost of Service Study.

As indicated earlier, the Tentative Settlement Agreement (involving MH, INAC, and MKO for the four First Nations) contemplates the funding of capital expenditure and related annual fixed costs through customer contributions, rather than rates. 1

CAC/MH II-32

Subject: **Diesel Rates**
Reference: **CAC/MH I-94**

e) **With respect to part (g), contrary to the response, there are several projects where MH provides a share of the funding but there are no depreciation charges. Please reconcile.**

ANSWER:

Manitoba Hydro has never asked the Government customers to assume all funding responsibility for capital expenditures. AANDC is asked for Contributions proportional to the usage of diesel generated energy by First Nation Residential, General Service and Government accounts. Other government customers are asked for Contributions proportional to their own usage. The notional share of usage by other customers, principally commercial General Service and non-First Nation Residential is borne by Manitoba Hydro. Over all four diesel communities, this share is approximately 21%.

Manitoba Hydro does not add depreciation or interest to diesel cost of service in respect of facilities where it has received or reasonably expects to receive Contributions from the government customers proportionate to their shares as described above. Manitoba Hydro has incorporated depreciation and interest into the diesel cost of service in respect of facilities for which no Contribution has been received or is reasonably expected to be received from Government customers.

Schedule 3 (Appendix 11.1 Attachment 3 of application) reflects this at the time of its preparation. Subsequently, with its April 2012 Contribution, AANDC did fund some of the items listed in the Schedule – these changes are reflected in the table attached to response to CAC/MH I-94(i).

(with the noted exception of funding capital costs by both levels of governments since 2004) through a Government Rate that includes a Surcharge to fund the revenue shortfall arising from Residential and General Service customers paying grid equivalent rates for the first 2,000 kWh per month.

Again, no compelling evidence was provided to justify the transferring of the Provincial Government financial responsibilities to MH's Grid ratepayers.

While the Board will deny MH's request to transfer Provincial Government accounts to the General Service class, it will remain open to MH to provide further and better evidence to support its now denied proposal at a subsequent proceeding, should the Utility make the same or any similar request.

iv/ Post-2004 Accumulated Operating Cost Deficit in the Diesel Zone

The calculated post-2004 accumulated deficit is $7.0 million to the end of March 2010. This accumulated operating cost deficit is calculated to arise from two components:

a) The full cost Revenue Requirement, net of the Revenue Cost Coverage (RCC) subsidy and also net of class revenues; and
b) The Full Cost Rate variance.

The sum of these two components, less the surcharge revenues to be charged to the Government customers, is the annual deficit.

Based on MH's Application and its calculation of the $8 million cost of service to the Diesel Zone for 2010, only $4.8 million (or 60%) of the Revenue Requirement would be recovered from current existing rates, leaving an annual subsidy of $3.2

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million to be added to the growing accumulated deficit. The rate increases sought by MH would not recover the new annual subsidy, but would reduce the annual deficit to $2.1 million (from $3.2 million).

Included in the annual deficit is the Revenue to Cost Coverage Ratio Subsidy of 18% provided to the Residential class and the 11% provided to the General Service class. By defining the Residential class revenue requirement at 82% of total Full Cost (100% less the Revenue to Cost Coverage Ratio Subsidy of 18%), and General Service class revenues at 89% of total Full Cost (100% less the Revenue to Cost Coverage Ratio Subsidy of 11%), MH seeks to recognize that a similar 'under-recovery' of revenue relative to costs should exist as it does with grid customers living in rural and/or other remote parts of the Province.

What MH does not do in its current Application is to update the RCC subsidy based on the Uniform Rates that now exist in Manitoba to reflect current RCC levels of Residential and General Service customers. The impact of MH's policy approach is to reduce the Government subsidy by a total of $1.07 million (comprised of $841,827.00 of relief related to Residential customers and $228,216.00 of relief related to General Service customers).

MH proposes that the $1.07 million RCC subsidy (together with the Provincial Government Subsidies, as set out above) should be funded by MH's Grid customers.

In prior Applications, MH included, in the Revenue Requirement for the Diesel Zone, 20% of the accumulated deficit. In Order 1/10 (at page 13) the Board questioned whether MH's practice of only including 20% of the accumulated deficit in new rates was sufficient, in light of MH not filing regular annual rate

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reviews for the Diesel Zone – a practice that has contributed significantly to the development of a large accumulated deficit.

In this Application, MH advanced a new position - that being no more 'backwards looking'; i.e., MH is not seeking that Government rates include any amount on account of prior operating deficits.

Accepting this proposal will transfer a significant financial cost to grid customers, a transfer that has largely taken place in the audited accounts of Manitoba Hydro but one that has only been carried on a notional basis for rate setting purposes.

The Board will accept MH's new approach, recognizing that the Government accounts will be the major beneficiary of not including any percentage of prior deficits in the Revenue Requirement for the Diesel Zone.

The prior deficits will fall to MH's Grid customers, who share financial responsibility with the two senior levels of government for the high costs of serving fellow Manitobans in remote areas of the Province not connected to the grid.

In adopting this view, the Board senses a new spirit of cooperation in addressing Diesel Zone electricity costs among MH, INAC, MKO and the four First Nations. This is evidenced by progress to finalize the Tentative Settlement Agreement, the post-2004 capital cost consultations, and expected funding commitments.

By not including prior accumulated operating deficits in the Diesel Zone Revenue Requirement (and even with the removal of the requested interest and depreciation expenses), there is greater flexibility for MH, INAC, and the First

Nations to resolve all outstanding issues related to costs in the Diesel Zone. As well, there will be less pressure on the Full Cost Rate in the future.

CAC/MH (DIESEL) I-14

Subject: **Settlement Agreement and Interim Rates**
Reference: **Order 134/10. pages 33-36**
DA2010, PUB/MH I-31 a) & b)

a) What is the post-2004 accumulated deficit for the Diesel Zone as of March 31, 2011?

ANSWER:

As Manitoba Hydro does not intend to recover previous deficits in rates, the post-2004 accumulated deficit is not relevant to this Application. Nevertheless, it is Manitoba Hydro's intention to internally track actual deficits and surpluses with the objective of minimizing net deficits over the longer term.

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CAC/MH (DIESEL) I-14

Subject: **Settlement Agreement and Interim Rates**
Reference: **Order 134/10. pages 33-36**
DA2010, PUB/MH I-31 a) & b)

d) **Please confirm that Manitoba Hydro currently has no plans to "recover" this accumulated deficit from Diesel Zone customers and that the shortfall is effectively absorbed in MH's net income.**

ANSWER:

Confirmed.

CAC/MH (DIESEL) I-12

Subject: Settlement Agreement and Interim Rates
Reference: Application, Attachment 5, page 2
DA2010, PUB/MH I-16 a)
DA2010, PUB/MH I-11 a)

g) Please confirm that Manitoba Hydro absorbs the impact of its "capital contributions" by not including the associated depreciation and interest in the Diesel COSS, which effectively reduces Manitoba Hydro's net income by a corresponding amount.

ANSWER:

Confirmed.

CAC/MH (DIESEL) I-12

Subject: Settlement Agreement and Interim Rates
Reference: Application, Attachment 5, page 2
DA2010, PUB/MH I-16 a)
DA2010, PUB/MH I-11 a)

e) **During the 2010 Diesel Application review, Manitoba Hydro indicated that it had not approached other federal and provincial departments for their share of the capital funding for post March 31, 2004 projects (PUB/MH I-11 a)).**

1. **Has Manitoba Hydro approached the other government customers in the Diesel Zone for their share of the capital costs incurred since March 31, 2004? If not, why not? If yes, what (if any) capital contributions have been received and from whom?**
2. **Please provide a calculation (based on the responses to parts (a) and (c)) of the capital contributions attributable to other federal and provincial government departments for capital spending up to March 31, 2011.**
3. **Please indicate separately any accrued interest associated with these contributions, whether paid or unpaid.**
4. **If there are expected contributions from these parties that are still outstanding, how does Manitoba Hydro propose to address the shortfall?**

ANSWER:

1. Manitoba Hydro has not approached other government customers at this time due to uncertainty as to the form of payment by AANDC. Now that AANDC has made Contributions in respect of much the outstanding capital items, Manitoba Hydro will take steps to recover payment in respect of those capital costs from other government customers.

2. See attached table. Note that interest was to March 2011 the date contribution payment was received from AANDC.

3. Please see Schedule 3 of PDCOSS12 included as part of Manitoba Hydro's application.

ALLOCATION OF $2.3 MILLION CONTRIBUTION RECEIVED FROM INAC March 31, 2011

	ISD	Actual Cost	Interest Inservice	Implied Interest	FN/INAC Share	Other Fed	Prov	INAC	Other Fed	Prov	MB Hydro
Capital Projects in Service Since March 31, 2004											
		%'age	6.10%								
Brochet											
Soil Remediation	2005-08	2,871,924	3,914,648	1,042,723	45.1%	5.3%	10.9%	1,765,506	207,476	426,697	1,514,969
Well Monitoring Installation	2008	27,687	33,562	5,875	45.1%	5.3%	10.9%	15,136	1,779	3,658	12,988
Engine Failures	2009	85,837	98,069	12,232	45.1%	5.3%	10.9%	44,229	5,198	10,690	37,953
Fall Arrest	2005	454,770	562,594	107,824	45.1%	5.3%	10.9%	253,730	29,817	61,323	217,724
Misc. Small Capital	2009	11,530	13,173	1,643	45.1%	5.3%	10.9%	5,941	698	1,436	5,098
Total Brochet		3,451,747	4,622,045	1,170,298				2,084,542	244,968	503,803	1,788,732
Lac Brochet											
Fall Arrest	2005-08	513,184	629,576	116,393	85.0%	3.5%	1.0%	535,140	22,035	6,296	66,106
Well Monitoring Installation	2008	31,326	37,973	6,647	85.0%	3.5%	1.0%	32,277	1,329	380	3,987
Engine Failures	2010	138,000	148,602	10,602	85.0%	3.5%	1.0%	126,311	5,201	1,486	15,603
Miscellaneous Small Capital	2009	53,391	60,999	7,609	85.0%	3.5%	1.0%	51,849	2,135	610	6,405
Total Lac Brochet		735,900	877,151	141,251				745,578	30,700	8,772	92,101
Shamattawa											
Powerhouse Modifications	2005-07	304,858	414,698	109,840	74.1%	9.0%	1.2%	307,291	37,323	4,976	65,108
Potable Water Supply	2009	96,550	110,309	13,759	74.1%	9.0%	1.2%	81,739	9,928	1,324	17,319
Engine Failures	2009	601,931	687,712	85,781	74.1%	9.0%	1.2%	509,595	61,894	8,253	107,971
Fall Arrest	2005-08	401,359	497,847	96,488	74.1%	9.0%	1.2%	368,905	44,806	5,974	78,162
Minor Overhaul	2010	170,125	183,194			9.0%	1.2%		16,488	2,198	164,509
Miscellaneous Small Capital	2009	39,160	44,741	5,581	74.1%	9.0%	1.2%	33,153	4,027	537	7,024
Total Shamattawa		1,613,984	1,938,502	311,449				1,300,683	174,465	23,262	440,092
Tadoule Lake											
Major Overhaul	2010	232,626									
Fall Arrest	2005-08	441,115	542,971	101,855	79.3%	6.2%	1.7%	430,576	33,664	9,231	69,500
Well Monitoring Installation	2008	33,047	40,060	7,013	79.3%	6.2%	1.7%	31,767	2,484	681	5,128
Engine Failures (added)	2010	150,000	161,523	11,523	79.3%	6.2%	1.7%	128,088	10,014	2,746	20,675
Miscellaneous Small Capital	2009	20,283	23,173	2,890	79.3%	6.2%	1.7%	18,377	1,437	394	2,966
Total Tadoule Lake		877,072	767,727	123,282				608,808	47,599	13,051	98,269
Total All Diesel Sites		6,678,703	8,205,425	1,746,279				4,739,611	497,733	548,888	2,419,193

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CAC/MH I-94

Subject: **Diesel Rates**
Reference: **Tab 11, Appendix 11.1, Attachment 3, Schedule 3**
Response to CAC/MH (Diesel) I-12 a) (December 22, 2011)

f) Please indicate why, in Attachment 3, there appear to be no contributions from "Other Governments" (i.e., the Capital to Revenue Requirement equals this amount in many cases).

ANSWER:

To date Manitoba Hydro has not received Contributions from any Government agency other than AANDC in respect of capital expenditures incurred since April 1, 2004. Letters were sent to these customers requesting such Contributions on August 10, 2012.

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CAC/MH I-94

Subject: **Diesel Rates**
Reference: **Tab 11, Appendix 11.1, Attachment 3, Schedule 3**
Response to CAC/MH (Diesel) I-12 a) (December 22, 2011)

c) **For each of the capital projects listed in CAC/MH Diesel) I-12 please indicate the capital contributions received to-date from AANDC and Other Government Parties (show Federal and Provincial separately).**

ANSWER:

See attached schedule which shows the total capital cost of the projects, as well as Contributions made by AANDC. No other contributions have been received to date from these other government agencies.

There is one item (Tadoule Lake major overhaul) for which funding has not been received, but which is anticipated to be received; final costs for this item had not yet been confirmed at the time AANDC approved and forwarded its April 2012 Contribution.

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Item	Year	Cap Cost	AANDC Paid	Other Gov Share	MH Share
Brochet					
Fall Arrest Protection	2005-08	454,770	(205,101)	73,673	175,996
Soil Remediation	2007	2,871,924	-	-	
Well Monitoring Installation	2008	27,687	(12,487)	4,485	10,715
Engine Failures	2009	85,837	(38,712)	13,906	33,219
Misc Small Capital	2009-10	11,530	(5,200)	1,868	4,462
Minor Overhaul	2009-10	147,793	(66,655)	23,942	57,196
Major Overhaul	2009-10	336,421	(151,726)	54,500	130,195
Misc Small Capital	2009-10	150,472	(67,863)	24,376	58,233
Total Brochet		4,086,433	(547,744)	196,751	470,015
Lac Brochet					
Fall Arrest Protection	2005-08	513,184	(436,206)	23,093	53,884
Corp Fire Protection	2011	1,208,861	(1,027,532)	54,399	126,930
Well Monitoring Instal	2008	31,326	(26,627)	1,410	3,289
Engine Failures	2010	138,000	(117,300)	6,210	14,490
Misc Small Capital	2009-10	53,391	(45,382)	2,403	5,606
Major Overhaul	2011	490,009	(416,508)	22,050	51,451
Misc Small Capital	2011	35,339	(30,038)	1,590	3,711
Total Lac Brochet		2,470,109	(2,099,593)	111,155	259,361
Shamattawa					
Fall Arrest Protection	2005-08	401,359	(297,407)	40,939	63,013
Heat Recovery System	2010	61,420	(45,512)	6,265	9,643
Potable Water Supply	2009	96,550	(71,544)	9,848	15,158
Engine Failures	2009-11	601,931	(446,031)	61,397	94,503
Powerhouse Mods	2005-07	304,858	(225,900)	31,096	47,863
Misc Small Capital	2009-10	39,160	(29,018)	3,994	6,148
Minor Overhaul Contrib	2010	(25,615)	(18,981)	(2,613)	(3,842)
Minor Overhaul	2010	187,981	(120,313)	19,174	48,494
Hilco Fume Extraction	2011	102,848	(76,210)	10,490	16,148
Engine Failures	2010	545,668	(404,340)	55,658	85,670
Minor Overhaul	2011	190,085	(140,853)	19,389	29,843
Misc Small Capital	2010	25,513	(18,905)	2,602	4,006
Total Shamattawa		2,531,758	(1,895,014)	258,239	416,646
Tadoule Lake					
Fall Arrest Protection	2005-08	441,115	(349,805)	34,848	56,463
Heat Recovery System	2005	43,343	(34,371)	3,424	5,548
Corp Fire Protection	2011	1,789,411	(1,419,003)	141,363	229,045
Well Monitoring Install	2008	33,047	(26,206)	2,611	4,230
Engine Failures	2010	150,000	(118,950)	11,850	19,050
Misc Small Capital	2009-11	57,296	(45,436)	4,526	7,334
Major Overhaul Gen Set	2010	232,626	-	18,377	29,544
Minor Overhaul	2010	244,339	(193,761)	19,303	31,031
Major Overhaul	2011	290,234	(230,156)	22,928	36,860
Total Tadoule Lake		3,281,411	(2,417,688)	259,231	419,103
Total All Diesel Sites		12,369,712	(6,960,039)	825,376	1,565,125

CAC/MH I-94

Subject: **Diesel Rates**
Reference: **Tab 11, Appendix 11.1, Attachment 3, Schedule 3**
Response to CAC/MH (Diesel) I-12 a) (December 22, 2011)

i) Please update Schedule 3 to show the current status of all capital spent up to March 31st 2011 (per CAC/MH (Diesel) I-12 a)) and the associated Depreciation and Interest expense.

ANSWER:

Please see the attached table.

Please note the changes in the table from CAC/MH (Diesel) I-12 (a) representing the elimination of depreciation expense for items subsequently funded by AANDC in their April 2012 payment for the following:

- Shamattawa Potable Water
- Shamattawa Minor Overhaul
- Tadoule Lake Heat Recovery
- Tadoule Lake Engine Failure
- Tadoule Lake Major Overhaul

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Item	Year	Cap Cost	AANDC Paid	Depn Exp	Interest Exp
Brochet					
Fall Arrest Protection	2005-08	454,770	(205,101)	-	14,527
Soil Remediation	2007	2,871,924	-	409,241	131,028
Well Monitoring Installat	2008	27,687	(12,487)	-	785
Engine Failures	2009	85,837	(38,712)	-	1,575
Misc Small Capital	2009-10	11,530	(5,200)	-	212
Minor Overhaul	2009-10	147,793	(66,655)	-	1,316
Major Overhaul	2009-10	336,421	(151,726)	-	2,995
Misc Small Capital	2009-10	150,472	(67,863)	-	1,339
Total Brochet		4,086,433	(547,744)	409,241	153,776
Lac Brochet					
Fall Arrest Protection	2005-08	513,184	(436,206)	-	22,826
Corp Fire Protection	2011	1,208,861	(1,027,532)	-	15,710
Well Monitoring Instal	2008	31,326	(26,627)	-	1,297
Engine Failures	2010	138,000	(117,300)	-	1,793
Misc Small Capital	2009-10	53,391	(45,382)	-	1,430
Major Overhaul	2011	490,009	(416,508)	-	6,368
Misc Small Capital	2011	35,339	(30,038)	-	459
Total Lac Brochet		2,470,109	(2,099,593)	-	49,885
Shamattawa					
Fall Arrest Protection	2005-08	401,359	(297,407)	-	17,406
Heat Recovery System	2010	61,420	(45,512)	-	731
Potable Water Supply*	2009	96,550	(71,544)	-	3,663
Engine Failures	2009-11	601,931	(446,031)	-	14,771
Powerhouse Mods	2005-07	304,858	(225,900)	-	20,251
Misc Small Capital	2009-10	39,160	(29,018)	-	961
Minor Overhaul Contrib	2010	(25,615)	(18,981)	-	(38)
Minor Overhaul	2010	187,981	(120,313)	-	2,238
Hilco Fume Extraction	2011	102,848	(76,210)	-	1,225
Engine Failures	2010	545,668	(404,340)	-	6,497
Minor Overhaul	2011	190,085	(140,853)	-	2,263
Misc Small Capital	2010	25,513	(18,905)	-	304
Total Shamattawa		2,531,758	(1,895,014)	-	70,273
Tadoule Lake					
Fall Arrest Protection	2005-08	441,115	(349,805)	-	20,000
Heat Recovery System	2005	43,343	(34,371)	-	4,743
Corp Fire Protection	2011	1,789,411	(1,419,003)	-	23,255
Well Monitoring Install	2008	33,047	(26,206)	-	1,369
Engine Failures	2010	150,000	(118,950)	21,107	4,018
Misc Small Capital	2009-11	57,296	(45,436)	-	1,024
Major Overhaul Gen Set	2010	232,626	-	32,734	5,521
Minor Overhaul	2010	244,339	(193,761)	-	3,175
Major Overhaul	2011	290,234	(230,156)	-	3,772
Total Tadoule Lake		3,281,411	(2,417,688)	53,841	66,876

CAC/MH I-94

Subject: **Diesel Rates**
Reference: **Tab 11, Appendix 11.1, Attachment 3, Schedule 3**
Response to CAC/MH (Diesel) I-12 a) (December 22, 2011)

d) For those projects where to total contribution received to date differs from what Manitoba Hydro has previously indicated it expects to receive, please provide an explanation and indicate where discussions are still ongoing regarding the amounts to be paid.

ANSWER:

All payments made by AANDC were as requested by Manitoba Hydro with the following exceptions.

1) Brochet Soil Remediation and accrued interest on all capital, which AANDC to date has not agreed to fund;
2) Situations where the original amount reported and agreed upon was based on a forecast value and was subsequently updated with actual data;
3) Amounts which, as noted in CAC/MH I-94(a), were subsequently added to an item to be funded;

Currently Manitoba Hydro continues to meet regularly with First Nation and AANDC representatives to inform them of ongoing capital activity in the Diesel Zone. To date AANDC has made contributions in respect of capital expenditures up to March 2011, with the exception of two items: Brochet Soil Remediation and accrued interest.

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This represents a modest decrease from the 2009/10 PDCOSS unit cost of 54.7¢ per kWh.

In the last full diesel proceeding in 2010 Manitoba Hydro proposed to recover not only the set variable or operating costs, but also a provision to recover the carrying cost (interest and depreciation) of the unrecovered capital costs incurred since March 31, 2004 to March 31, 2011. The PUB previously denied Manitoba Hydro's request for this provision in its Order 134/10 based on its "expectation that the parties have removed the impasse" regarding the funding of interest and depreciation (see Order 134/10, page 30). Anticipated payments were not in fact received for all outstanding items. In this Application an amount of $747,607 has been added into the Revenue Requirement which represents the annual interest and depreciation expense on the unfunded capital expenditures made by Manitoba Hydro since March 31, 2004 - the effective date of the Settlement Agreement. The identification of these costs and the mechanisms for their recovery are described in the PDCOSS12 included as Attachment 3.

Manitoba Hydro's Diesel Revenue Requirement is based on the calculated full cost rate multiplied by forecasted consumption for the period (2012/13). The full cost rate was determined based on the period ending 2011/12 as outlined in the PDCOSS12 included as Attachment 3. The 2011/12 PDCOSS incorporates the same RCC requirements from the 2004/05 study of 82% for the Residential class and 89% for the General Service class. These were based on the Zone 3 RCC in the 2002 Prospective Study which was reviewed by the PUB at the Status Update Proceeding. As zonal distinctions are no longer maintained by Manitoba Hydro since the advent of the Uniform Rates legislation, Manitoba Hydro is currently fixing the Diesel Communities RCC on the basis of percentages used in the 2004/05 study.

A derivation of the Revenue Requirement using these RCC's for the Residential and General Service classes is outlined in Attachment 3 – Prospective Diesel Cost of Service Study for 2011/12.

The PDCOSS12 shows the development of the total costs of service after incorporating the effects of the Settlement Agreement.

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SCHEDULE 3

Summary of Interest & Depn Expense on Post 2004 Capital

Item	Year	Cap Cost	AANDC Paid	Other Gov Share	MH Share	Capital to Rev Req	Accrued Interest	Depn Exp	Interest Exp
Brochet									
Fall Arrest Protection	2005-08	454,770	(205,101)	73,673	175,996	73,673	61,028	-	14,527
Soil Remediation	2007	2,871,924	-	-		1,295,238	550,439	409,241	131,028
Well Monitoring Installat	2008	27,687	(12,487)	4,485	10,715	4,485	3,299	-	785
Engine Failures	2009	85,837	(38,712)	13,906	33,219	13,906	6,615	-	1,575
Misc Small Capital	2009-10	11,530	(5,200)	1,868	4,462	1,868	889	-	212
Total Brochet		3,451,747	(261,500)	93,931	224,392	1,389,169	622,271	409,241	148,127
Lac Brochet									
Fall Arrest Protection	2005-08	513,184	(436,206)	23,093	53,884	23,093	95,892	-	22,826
Well Monitoring Instal	2008	31,326	(26,627)	1,410	3,289	1,410	5,450	-	1,297
Engine Failures	2010	138,000	(117,300)	6,210	14,490	6,210	7,534	-	1,793
Misc Small Capital	2009-10	53,391	(45,382)	2,403	5,606	2,403	6,008	-	1,430
Total Lac Brochet		735,900	(625,515)	33,116	77,270	33,116	114,884	-	27,347
Shamattawa									
Fall Arrest Protection	2005-08	401,359	(297,407)	31,707	72,245	31,707	73,121	-	17,406
Potable Water Supply	2009	96,550	-	-		71,544	13,907	7,688	3,311
Engine Failures	2009-11	601,931	(446,031)	47,553	108,348	47,553	62,054	-	14,771
Powerhouse Mods	2005-07	304,858	(225,900)	24,084	54,874	24,084	85,072	-	20,251
Misc Small Capital	2009-10	39,160	(29,018)	3,094	7,049	3,094	4,037	-	961
Minor Overhaul Contrib	2010	(25,615)	(18,981)	6,634	-	6,634	405	-	96
Minor Overhaul	2010	118,895	(18,981)	9,393	90,521	9,393	28,233	4,055	6,721
Total Shamattawa		1,418,243	(1,017,336)	113,072	242,515	184,615	238,597	7,688	56,796
Tadoule Lake									
Fall Arrest Protection	2005-08	441,115	(349,805)	44,994	46,317	44,994	84,020	-	20,000
Heat Recovery System	2005	43,343	-	-		34,371	17,652	9,372	4,202
Well Monitoring Install	2008	33,047	(26,206)	3,371	3,470	3,371	5,750	-	1,369
Engine Failures	2010	33,047	-	-		118,950	14,955	21,107	3,560
Misc Small Capital	2009-11	150,000	(16,084)	2,069	131,847	2,069	2,282	-	543
Major Overhaul Gen Set	2010	20,283	-	-		184,472	23,192	32,734	5,521
Total Tadoule Lake		720,835	(392,095)	50,433	181,634	388,227	147,851	63,213	35,195
Total All Diesel Sites		6,326,726	(2,296,447)	290,552	725,811	1,995,126	1,123,602	**480,142**	**267,465**
				Total Capital Revenue Requirement Addition					**747,607**

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PUB/MH I-152

Reference: Appendix 11.1, Diesel Rate Application

e) Please refile the schedules in appendix 11.1 and 11.2 where necessary, removing the $747,607 in interest and depreciation expense included and comment on the difference between the indicative rate and proposed rates in this application.

ANSWER:

Schedule 1 of Appendix 3 in 11.1 shows unit costs both with the capital portion 59.2¢/kWh), and without the capital portion (53.5¢/kWh).

The Indicative Rate Schedules filed on December 22, 2011, show rates and revenue assuming that:

1) The General Service tail block rate was not increased and remained at the 35¢/ kWh that was in place prior to the recent September 1, 2012, rate change.

2) The Government rate was calculated to incorporate all of the shortfall between the costs to serve the Residential and General Service classes and the revenues resulting from rates to those classes plus the explicit RCC subsidy provided by Manitoba Hydro. The Indicative Government rate was $2.54 per kWh.

The diesel rate schedules filed in the current proceeding and approved for implementation September 1, 2012 in Order 117/12 differed from the December 22 Indicative Rates in that the tail block rate for General Service and the Government Rate were both set by increasing the then current rates by 6.5% reflecting the increases to customers served by the grid since the then-current diesel rates were put in place. This resulted in a rate higher than the Indicative Rate for General Service (37.3¢/ kWh vs. 35¢/ kWh) and a rate lower than the Indicative Rate for Government ($2.27/ kWh vs. $2.54/ kWh).

The table below illustrates the difference in the Indicative rates and Sept 1 rates with and without the capital portion included in the full costs rate (59.16¢/kWh vs. 53.48¢/kWh):

	With Capital Included		With No Capital Included	
	Indicative Rates	Sept 2012 Rates	Indicative Rates	Sept 2012 Rates
Revenue Requirement	$7,964,651	$7,964,651	$7,202,651	$7,202,651
Revenue	$6,904,058	$6,402,110	$6,239,273	$6,402,110
Shortfall	$1,060,593	$1,562,541	$963,378	$800,541
	Difference	$501,948		($162,837)
Revenue per kWh	$0.513	$0.476	$0.464	$0.476
Cost per kWh	$0.592	$0.592	$0.535	$0.535

CAC/MH II-33

Subject: **Diesel Rates**
Reference: **CAC/MH I-95 a) and c)**

a) **Please explain why the actual Diesel cost for 2011/12 are not available. If they are please provide.**

ANSWER:

The Diesel Zone actual costs are only accumulated and prepared in the course of compiling the next prospective diesel cost of service (DCOSS). This is done primarily to reflect: (1) any rate changes that may have occurred since the last DCOSS preparation and/or application, and (2) the most current accumulated deficit from one year to the next. As noted in CAC/MH I-88(a) a more recent PDCOSS has not yet been prepared.

SCHEDULE 4.4

DIESEL SERVED COMMUNITIES
PROJECTED STATEMENT OF INCOME (LOSS)
FOR YEAR ENDING MARCH 31, 2013
(in thousands of dollars)

Revenue (at proposed rates)

	Residential	General Service	Government	Total
Brochet	$ 134	$ 153	$ 896	$ 1,182
Lac Brochet	148	213	1,603	1,963
Shamattawa	226	311	1,894	2,431
Tadoule Lake	91	220	514	825
Total	$ 599	$ 896	$ 4,907	$ 6,402

Expense

Fuel Cost (incl delivery & fees)	$ 4,424
Operating Expense (Labour & Mtce)	2,680
Finance Expense	267
Depreciation	480
Total	$ 7,851
Net Income (Loss)	$ (1,449)

SCHEDULE 1 28

PROSPECTIVE DIESEL COST OF SERVICE STUDY
CALCULATION OF FULL COST RATE
FOR FISCAL YEAR ENDING MARCH 31,2012

		VARIABLE COSTS				
Community	kW.h Consumption	Oper Costs Distrib	Int on Fuel Inventory	Oper Costs Generation	Total Var. Costs	Variable ¢/kW.h
Brochet	2,788,738	$ 161,398	$ 90,347	$ 1,279,481	$ 1,531,226	54.9
Lac Brochet	3,372,500	117,709	94,457	1,517,656	1,729,822	51.3
Shamattawa	4,845,500	160,532	145,718	1,997,476	2,303,726	47.5
Tadoule Lake	2,265,300	144,276	62,632	1,332,411	1,539,319	68.0
Total Cost	13,272,038	$ 583,915	$ 393,154	$ 6,127,024	$ 7,104,093	53.5

Add: Provision for unrecovered capital	747,607
Revised Revenue Requirement	$ 7,851,700
Total forecast conumption for 2011/12	13,272,038
Full Cost Rate	**0.5916**

CAC/MH I-93

Subject: **Diesel Rates**
Reference: **Tab 11, Appendix 11.2**

f) Are the Expenses shown in Schedule 4.4 based on 2012/13 forecast costs or on the 2011/12 costs from Appendix 11.1? If the latter, please update for 2012/13 forecast costs.

ANSWER:

The costs are based on the 2011/12 costs. Below is the full cost calculation based on preliminary 2012/13 forecast. Note that these are preliminary costs as a full analysis will not be done until a full PDCOSS can be completed.

PROSPECTIVE DIESEL COST OF SERVICE STUDY
CALCULATION OF FULL COST RATE (PRELIMINARY)
FOR FISCAL YEAR ENDING MARCH 31,2013

		VARIABLE COSTS				
Community	kW.h Consumption	Oper Costs Distrib	Int on Fuel Inventory	Oper Costs Generation	Total Var. Costs	Variable ¢/kW.h
Brochet	2,788,738	$ 94,130	$ 90,347	$ 1,292,578	$ 1,477,055	53.0
Lac Brochet	3,372,500	76,000	$ 94,457	1,558,675	1,729,132	51.3
Shamattawa	4,845,500	116,430	$ 145,718	2,030,559	2,292,707	47.3
Tadoule Lake	2,265,300	195,750	$ 62,632	1,212,255	1,470,637	64.9
Total Cost	13,272,038	$ 482,310	$ 393,154	$ 6,094,067	$ 6,969,531	52.5

Add: Provision for unrecovered capital	803,892
Revised Revenue Requirement	$ 7,773,423
Total forecast conumption for 2011/12	13,272,038
Full Cost Rate	**0.5857**

CAC/MH I-95

Subject: **Diesel Rates**
Reference: **Tab 11, Appendix 11.1, Attachment 3, Schedules 1 and 2**

a) Please update Schedule 2 to include 2012 actual revenues and costs and extend the Schedule back to the year 2004/05.

ANSWER:

As noted in CAC/MH I-88(a) an updated D COS has not been prepared. However, actual revenues for 2011/12 are $5,984,826 rather than $6,318,962 as found in Schedule 2 of Appendix 11.1, page 39 of 40..

Please see Manitoba Hydro's response to PUB/MH I-150(b).

CAC/MH I-93

Subject: **Diesel Rates**
Reference: **Tab 11, Appendix 11.2**

c) Please provide a schedule that sets out the total Diesel Community deficit based on Schedules 4.2 and 4.3.

ANSWER:

Please see the table below.

RECONCILIATION OF CLASS REVENUE REQUIREMENT AND CLASS REVENUE EFFECTIVE SEPTEMBER 1, 2013

	Residential	General Service	Government	Total	
Revenue Deficiency:					
Class Revenue Requirement	$4,706,071	$1,983,682	$1,274,898	$7,964,651	
Class Revenue at Proposed Rates	$598,810	$896,362	$4,906,542	$6,401,714	
Revenue Deficiency	$4,107,261	$1,087,320	($3,631,644)	$1,562,937	
Funding of Revenue Deficiency by Manitoba Hydro					
RCC Subsidy to Residential			$847,093		
RCC Subsidy to General Service			$218,205		$1,065,298
Government Rate Deficit (Calculated vs. MHEB Rate)					$497,639
Total Manitoba Hydro subsidies					$1,562,937
Overall Diesel Zone Revenue Cost Coverage at Proposed Rates					80.4%

CAC/MH I-93

Subject: **Diesel Rates**
Reference: **Tab 11, Appendix 11.2**

e) **If not, please re-do Schedule 4.4 so as reflect the anticipated revenues based on the April 1, 2012 rates and the September 1, 2012 rates.**

ANSWER:

The first column in the following table reflects the revenues for rates effective September 1, 2012 on an annualized basis. The second column of the table reflects the revenues for the rate increase effective April 1, 2012 to August 31, 2012 to the grid-portion of the diesel rates, as well the rate increase effective September 1, 2012 for the remainder of the fiscal year.

	Revenue (in filing)	Revenue*	Difference
Residential	$ 598,810	$ 593,325	$ (5,485)
General Service	896,362	878,267	(18,095)
Federal Government	4,036,246	3,931,621	(104,625)
Provincial Government	870,691	845,736	(24,955)
Total Revenue	$ 6,402,109	$6,248,949	$ (153,160)

* Annual revenue based on April 1, 2012 rates in effect to the end of August.

the concept of doubling the grid equivalent rates over a four year period. While, in theory, this concept may have some merit, it is not so for the Diesel Zone.

The ability to send price signals is dependent on the circumstances, such as the extent to which the individual customer is financially responsible for the energy bill. With Income Assistance (including a portion for electricity costs) being funded by INAC to the First Nations governments (to support approximately 85% of the residents in the Diesel Zone), rather than Income Assistance being directly paid to the individuals consuming the electricity and responsible for the bill payment, it is likely that any price signal would be distorted – if received at all by those individual residents.

Doubling energy rates for Residential customers would also negatively impact those who do pay their own electricity bill – as well as likely increasing the cost of basic amenities (including food). It also runs counter intuitive to the reduction in the Full Cost rate by introduction of a Tail Block rate for those same customers.

To credit Mr. Hildebrand's candour, he acknowledged that his recommendation was an attempt "to do something" to reduce energy costs, rather than "doing nothing". The Board finds that such a recommendation is fraught with problems, and it will not be implemented.

The Board believes it is preferable for all Parties to strive co-operatively to enhance consumer education, leading to tangible energy savings opportunities being accepted by the leaders and residents in the Diesel Zone communities.

Finally, with respect to the potential for reductions in electricity consumption in the four communities, the Board notes that while assuming that upgraded residences and other buildings with adequate building envelopes and reasonably

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As even the existing Full Cost Rate of 41.27¢ per kWh is a contributor to the high price of groceries and other items in the Diesel Zone communities, simply limiting the increase to 45¢ would still push such prices upwards, although clearly by not as much as without a Tail Block that is lower than the Full Cost Rate.

In directing that the Tail Block rate for residential and General Service accounts will be $0.35/kWh, the Board views this as a first step towards bringing down the cost of electricity for the residents and non-government customers of the four communities. The Board recognizes that it is invoking its discretionary exercise of judgement, based on the Board's determination of what represents just and reasonable rates in the context of economic, social and environmental factors.

On one hand, MH attempts to recover a greater percentage of those costs from the non-First Nations parties responsible for such costs (whether based on a legal, moral, ethical or policy based responsibility). On the other hand, both MH and the Board recognize that the Full Cost Rate of $0.59/kWh is so high that negative consequences to the residents in the Diesel Zone would be brought about with its imposition (by way of increased prices of groceries, other goods and services or, quite possibly, through reduced funding by INAC of non-electricity based existing programs, which could be cut to facilitate INAC meeting its higher cost responsibility without increasing its overall fund transfers to the First Nations).

As to the prospects of initiatives designed to reduce electricity consumption in the Diesel Zone, the Board does not believe that major cost and usage decreases would result. All Parties appeared to accept that demand for electricity, at least for residential accounts, was inelastic in nature.

Canada's participation in funding the extension of the grid to the four communities would (if Canada does not provide its share of the required funding "up front") be through an allocation based on "full cost rates", and an attendant Government Subsidy.

In considering the approach to funding its fair share, Canada's involvement could involve other departments as well as INAC. There is merit to exploring funding availability (up-front and annual), through other Federal Government agencies, given the wide range of benefits (health, education, environmental, industry) expected to be realized for the four communities through grid service.

The Province of Manitoba, too, has a role to play in funding the grid extension. There has been ongoing recognition for Manitoba to contribute to costs incurred in the Diesel Zone.

All parties need to realize that the grid customers of MH are now currently contributing to the diesel costs, even though there is a strong rationale that 100% of the stand-alone diesel generation costs should be borne by the customers in the Diesel Zone and the senior levels of government responsible for those customers.

As an example, in the current Application MH is seeking approval for grid customers to accept responsibility for over $2 million of the $8 million collectible revenue requirement for the 2010 operations of the Diesel Zone.

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REVIEW OF TIME-OF-USE AND INVERTED ELECTRIC RATE STRUCTURES FOR APPLICATION IN MANITOBA

Prepared by

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July 28, 2005

Scenario 4: Rates for Large GS Customers

Large Demand <30 kV

	Demand Charges ($/kVA)	Energy Charges Peak (cents/kWh)	Shoulder (cents/kWh)	Off-Peak (cents/kWh)
Spring	$ 2.65	3.88	2.86	0.95
Summer	$ 4.00	4.98	3.10	0.41
Fall	$ 2.65	3.42	2.29	0.76
Winter	$ 5.30	5.96	3.00	2.10

Large Demand 30-100 kV

	Demand Charges ($/kVA)	Energy Charges Peak (cents/kWh)	Shoulder (cents/kWh)	Off-Peak (cents/kWh)
Spring	$ 2.25	3.75	2.77	0.75
Summer	$ 3.40	4.84	3.01	0.23
Fall	$ 2.25	3.29	2.20	0.55
Winter	$ 4.50	5.71	2.87	2.01

Large Demand >100 kV

	Demand Charges ($/kVA)	Energy Charges Peak (cents/kWh)	Shoulder (cents/kWh)	Off-Peak (cents/kWh)
Spring	$ 2.00	3.57	2.60	0.64
Summer	$ 3.00	4.65	2.85	0.13
Fall	$ 2.00	3.11	2.03	0.45
Winter	$ 4.00	5.47	2.68	1.84

VII. Analysis of Illustrative Rates

A. Changes in Consumption Based on Elasticity Estimates and Feedback to Illustrative Rates

A key factor in the evaluation of TOU and inverted rates is the likely response of customers to the new rate structures. This responsiveness, or "price elasticity," is quantified as the percent change in quantity demanded divided by the percent change in price. Own-price elasticity measures the responsiveness of quantity demanded to changes in the price of that product. It is normally a negative number, as price and quantity are inversely related. Own-price elasticity can vary by TOU period (time-of-day, season) and by rate component (per-kWh charge, per-kW charge). Some elasticity studies derive cross-price elasticity estimates, such as the responsiveness of demand in one period to changes in the price of another period within the day.

NERA identified illustrative short-run own-price elasticities of demand for each customer class and rate structure to be tested, based upon results from controlled experiments on inverted block and TOU rates in other jurisdictions. In the US, much of the elasticity work was done in the late seventies and early eighties. Because the electricity prices, rate designs, market and utility structures have changed significantly since then, the results of those studies must be interpreted cautiously.[43] The price elasticities used in our rate exercise are shown below. The elasticity estimates are not used to *predict* changes in demand, but rather to evaluate the *relative* shifts that might occur with implementation of the various tariff structures.

OWN-PRICE ELASTICITIES BY TOD PERIOD AND SEASON

	Winter, Spring & Fall			Summer		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
Residential and Farm						
(<200 Amp)	-0.056	-0.056	-0.056	-0.028	-0.028	-0.028
General Service - Small						
Non-Demand	-0.060	-0.060	-0.060	-0.060	-0.060	-0.060
Demand	-0.080	-0.065	-0.050	-0.080	-0.065	-0.050
General Service - Medium	-0.080	-0.065	-0.050	-0.080	-0.065	-0.050
General Service - Large						
0.750 < KV <30	-0.080	-0.065	-0.050	-0.080	-0.065	-0.050
30 < KV <100	-0.150	-0.125	-0.100	-0.150	-0.125	-0.100
KV > 100	-0.150	-0.125	-0.100	-0.150	-0.125	-0.100

In order to calculate the likely impact of new TOU or inverted rates on customer loads, it is necessary to identify the relevant price differentials to which we will apply the elasticity estimates. This requires carefully defining the per-kWh "effective prices" by class and periods. The preliminary effective prices by class were calculated for each of the time-of-day periods (for those customers with TOD rates), and on a seasonal basis for customers under inverted (non-TOD) block rates.

The effective price for a customer under a TOU rate will equal the sum of the per-kWh charge for a specific daily period within a season, plus the per-kVA revenues converted into a per-kVA charge as corresponds for each period. In the TOU rates proposed for Manitoba Hydro, the demand charges apply to the maximum demand in the combined peak and shoulder periods. Therefore, the effective price took into account the kWh charge plus the kW revenues divided by the kWh consumed by the customer in the combined peak and shoulder period.

[43] We also reviewed the latest residential TOU experiments in California (summer of 2003), as an additional input to estimate a set of elasticity estimates for residential customers.

In the case of seasonal-only (non-TOD) block rates, the effective price will be the kWh charge of the last block in which the user's consumption falls, plus the demand revenues in the season divided by the sum of kWh in the combined peak and shoulder periods. One complication to estimate the effective price under the new tariffs in the case of inverted block rates has to do with assuming where the marginal consumption would take place:

- For customers whose marginal consumption currently falls in the second block, an increase in the price on the second block will tend to reduce their consumption, possibly enough to move them back to the first block. However, once there, the lower price on the new rates' first block will provide an incentive to increase usage.
- Similarly, for customers with consumption initially ending in the first block, the reduction in the first block price will tend to increase their consumption, possibly enough to move them back to the second block where the higher price on the new rates will provide incentives to reduce usage.[44]

As a simplifying measure, our analysis assumed that if the calculated load response for a customer drove the usage back into the first block, the resulting marginal use would end up at the beginning of the run off block (just above the breakpoint in the block structure). This approach would understate the response in those cases where the new effective per-kWh price is greater than the current effective charge. In practice, however, the effect of our simplifying assumption proved to be quite small, so that we retained the simple correction.

The elasticity estimates were applied to typical customers (with average usage and average load pattern) within each class. This was later grossed up to represent population impacts by multiplying by total customers in the class.[45] In the case of residential, four typical customer sub-groups were defined:

- Customers with "standard" electric use (non-space heating), whose consumption falls into the current first block only;
- Customers with "standard" electric use (non-space heating), whose consumption falls into the current second block;
- Customers with electric space-heating ("All electric"), whose consumption falls into the current first block only;

[44] There is also an income effect of the reduction in the first block price for customers whose consumption is on the second block. The income effect shifts the demand curve to the right. Given the limited data available for the analysis, we did not address this effect.

[45] Future refinements of this analysis would require using a distribution of usage and elasticities within the population, calculate the distribution of load and welfare impacts within the class, and aggregate the results. This refinement would take into account the diversity of load factors and usage patterns within the class, as well as other factors such as the lower elasticity of demand of customers without access to gas as compared to those customers with access.

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- Customers with electric space-heating ("All electric"), whose consumption falls into the current second block.

In the case of SGS-ND, six sub-groups were defined for purposes of the load response analysis, differentiating between those whose marginal consumption falls into the first, second or third blocks of the current rates, and whether they use electric space heating or not.

Based upon the results of this analysis, new billing determinants (both energy and demand) were developed for each class. New class revenue requirements were also computed for each class by adding/subtracting the marginal cost of any increase/decrease in consumption. This approach to the class revenue requirement is not consistent with the current use of embedded costs to set class revenue requirements; however, with so many rate structure alternatives being evaluated, this simplifying assumption kept the analyses manageable. The preliminary illustrative rates were then adjusted to produce the new revenue requirement when applied to the adjusted billing determinants. Ideally the elasticity effects should be re-estimated based on the revised prices and the process repeated one or more times. However, for the purpose of evaluating several generic rate designs, no further iterations were performed.

B. Effect of TOD and Inverted Rates on Manitoba Hydro's Revenue Requirement

One measure of the effectiveness of TOD and inverted rate structures is the effect on the utility's revenue requirement (based on the 2005/06 Revenue Requirement using rates effective August 1, 2004). The table below shows the effect on class revenue requirements of each of the rate structures evaluated.

Residential

	Revenue Requirement	Change in Revenue Requirement After Load Response	
	(000 $)	(000 $)	(%)
Current	$377,421		
Scenario 1 (Two rates, two-blocks, seasonal)	$369,977	-$7,444	-2.0%
Scenario 2 (One rate, two blocks, seasonal)	$370,001	-$7,420	-2.0%

PUB/MH II-101

Reference: PUB/MH I-149 Inverted Rates Alternative

a) Please provide an outline of the alternative residential rate strategies that MH is considering with respect to customers whose primary heat source (no access to natural gas) is electrical.

ANSWER:

Manitoba Hydro reviews potential residential rate strategies from time to time, including inverted rate strategies. Manitoba Hydro's Residential energy rate proposed for implementation April 1, 2013 is 7.2 cents per kW.h which is 85% of the marginal cost value (8.52 cents per kW.h) in the current Power Smart plan and higher than current short run marginal cost.

Other jurisdictions, such as BC Hydro, have recently introduced inclining block rates to replace the single rate schedule for residential customers with the objective of encouraging conservation by reflecting the legacy cost of energy in the first block and the marginal cost of new energy in the second. Price elasticity for electricity in the residential sector is traditionally low therefore requiring a substantial differential to effect a marginal change.

While not under active consideration by Manitoba Hydro at this time, if it were desired to implement inverted rates to the Residential class and to differentiate application of such rates between customers with electric heat and customers with other sources of space heating, the following alternatives may be considered:

- Seasonal differentiation of first block size such that more energy would be billed at a lower rate during the winter heating months
- Differentiating application of Residential rates between electrically heated customers and those with other space heating fuels.
- Special rates for customers where natural gas is not available.

The main goal of any strategy to re-design electricity rates for the Residential class is to balance the competing objectives of sending an appropriate price signal to encourage efficient choices by customers and mitigating impact of future rate increases on specifically electric heat customers. Revenue neutrality, customer acceptability, administrative cost and burden, gradualism and conformity to Uniform Rate Legislation are other factors to be considered.

1) Seasonal Differentiation of First Block Size

This method increases the size of the first block for the winter months (November through April inclusive) and reduces the block size for the summer months (May through October). For example, the summer season inversion could be set at 500 kWh per month while the winter season could be set at 1000 to 1500 kWh per month.

The advantage of a seasonally differentiated first block size is mitigation of impacts on winter bills for those who have no choice but to use electricity to heat their homes. This method does not distinguish between residential customers who are coded as standard (non-electric) or all-electric and so avoids the administrative difficulties inherent in maintaining a separate classification of residential customers based on their heating fuel.

In terms of customer impacts, the winter bill advantage may be offset, at least in part, by higher summer bills. Further, because the larger winter first block shelters a larger portion of residential energy from the second block price, the second block price may have to be higher in order to capture the same revenue as a rate design which is not seasonally differentiated.

From a billing administration perspective, this is the easiest strategy (other than the status quo or a similar approach) to implement and perhaps the easiest for customers to understand. All residential services would be affected with two rate changes a year. Billing issues through a rate change month would, however, be magnified as customers would look more closely at bills and would therefore be more apt to contact the Customer Contact Centre and/or their district office with inquiries. The major complaint would be unfairness of estimated bills and proration.

A more complex variant would be to add one or two additional seasons with first block size set mid way between the winter and summer rate structure; these would apply during the shoulder months of March, April, May, September, October and November.

2) Different application of Rates for Standard and All-Electric Customers

This method is similar to 1) above except that only those customers coded on the Billing System as all-electric would be eligible for the seasonal block rate. Standard customers would not have any seasonal differentiation. Expanding on this method, monthly block sizes could be based on monthly heating degree days. For example, the monthly block could rise gradually starting in October with each month increasing until the maximum block size is reached in January/ February, decreasing gradually thereafter.

The major advantage of this method is that it will expose a larger number of customers and kWh to the higher second block price, than the method which does not distinguish between standard and all-electric customers. However, differentiating rates solely upon heating source may encourage customers to make less optimal heating fuel choices.

Should this method be considered, new billing/customer codes would need to be created to more accurately identify electrically heated customers. Identifying customers with electric heat has been done, but it is a manual process and is primarily based upon customers self-declaring their heating fuel choice or where available evidence demonstrates the heating fuel source (e.g. permit information). Variable blocks, based on heating degree days, are likely to lead to considerable customer confusion and increased calls to the Contact Centre and district offices, especially with estimated billings. Varying monthly blocks would also complicate adjusted billings for periods greater than one month.

One important factor to note is that this method may be perceived as not conforming to the principles of uniform rates, even though the separate electric versus standard heating rate classes would apply across the province. Customers would be discriminated against based on the type of heating they chose to use to heat their homes. More seriously, there is also the potential for customers to choose electric heating in order to benefit from the better rate, thereby increasing demand on the system, which in turn will result in higher rate increases to all customers.

3) Different Rates Based on Fuel Availability.

Similar to the second method above, this method would apply seasonal blocked rates based on availability of alternate heating fuels. Only those customers who do not have access to gas service would be eligible for a larger seasonal block. Customers in areas served by natural gas either would not get a seasonal block charge or would have a lower block kWh amount per month. This method also has the advantage of exposing a larger number of customers and kWh to the higher second block price, particularly during the winter, than the method which does not distinguish between standard and all-electric customers.

Notwithstanding these advantages, this method is judged to be the least appropriate approach to recognizing electric heat requirements. It is administratively difficult to specifically identify areas served and not served by gas, as boundaries and proximity to natural gas are continually changing. Further, the costs associated with conversion to natural gas heating even in areas where natural gas is available can be a significant burden for customers. Alternatively, one could distinguish between existing and new electrically heated homes within areas served by natural gas, although this could add significantly to administrative complexity. This method would also require legislative change, as it would clearly violate existing uniform rates legislation.

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CAC/MH I-58

Subject: **Electric Load Forecast and Load Research**
Reference: **Tab 8, Appendix 8.1, page 7**

a) Why aren't future increases in electricity prices considered to have an impact on the sales to General Service customers?

ANSWER:

Sales to General Service customers are forecast using econometric models. Electricity prices from 1990-91 to present were not found to have a significant relationship to sales for General Service customers. The number of General Service customers has been found to be more closely related to the number of residential customers and Manitoba GDP than to changes in electricity prices.

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Manitoba Hydro Undertaking #88

Show the equations for how PUB/MH I-83 (COALITION Ex. 29) was calculated.

The original question: Please explain how marginal costing at current levels would reduce domestic loads in each of the customer classes:

- Residential
- General Service Small
- General Service Medium
- General Service Large <30 kV
- General Service Large 30 - 100 kV
- General Service Large > 100 kV

Own price elasticity of demand describes the relationship between change in price and change in quantity demanded. The equation is:

$$E = \frac{\Delta Q}{\Delta P}$$

Where E = own price elasticity of demand
ΔQ = percent change in price
ΔP = percent change in price

Transposing $\Delta Q = E * \Delta P$

Short-run own-price elasticities from NERA report, page 44, for winter shoulder season:

Residential	-0.056
General Service Small, Non-Demand	-0.060
General Service Small, Demand	-0.065
General Service Medium	-0.065
General Service Large <30 kV	-0.065
General Service > 30 kV	-0.125

Changes in price to move to marginal cost:

	CURRENT RATES ¢ / kW.h	MARGINAL COST BASED RATE ¢ / kW.h	PERCENT CHANGE IN PRICE ¢ / kW.h
Residential	5.8	7.6	31
General Service Small Non-Demand	6.2	7.6	23
General Service Small Demand Average	5.1	7.6	49
General Service Medium	5.1	7.6	49
General Service Large <30 kV	4.1	7.2	76
General Service Large >30 kV	3.2	6.8	112

Short-term load reduction if marginal cost applied:

Residential	31% x 5.6% = 1.7%
General Service Small, Non-Demand	23% x 6% = 1.4%
General Service Small, Demand	49% x 6.5% = 3.2%
General Service Medium	49% x 6.5% = 3.2%
General Service Large <30 kV	76% x 6.5% = 4.9%
General Service Large > 30 kV	112% x 12.5% = 14.0%