Index – MIPUG Book of Documents

2014/15 and 2015/16 Manitoba Hydro GRA
As of June 1, 2015

Tab	Description	Reference
Manitoba Hydro Planning & Operations Panel		
1	A) Capital project justification for Keeyask	A) PUB/MH-I-24b – Attachment 1 from 2015/16 GRA
2	A) Cumulative Rate Increases under Reference Scenario B) DSM Level 2 Financial Evaluation C) Financial statements for K19/Gas/750MW (Plan 5) – Level 2 DSM under 3 rate methodologies	A) Exhibit MH-111 from the NFAT hearing B) Exhibit MH-104-12-5 from the NFAT hearing C) Exhibit MH-104-12-4 from the NFAT hearing
3	A) Curtailable Rate Program Options B) Curtailable Rate Program Report for April 1, 2013 – March 31, 2014	A) Appendix 6.10, page 16 of 16, January 23, 2015 from 2015/16 GRA B) Appendix 6.11 from 2015/16 GRA
4	A) BC Hydro Service Plan, 2014/15 – 2016/17 B) Saskatchewan Rate Review Panel Report to Minister Responsible for Crown Investments Corporation of Saskatchewan regarding SaskPower Rate application, Effective January 1, 2014 (Submitted April 28, 2014) C) Ontario Energy Board, Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements, March 28, 2013	A) Accessed online: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/service-plans/bchydro-service-plan-2014-15-2016-17.pdf B) Accessed online: http://www.saskratereview.ca/images/docs/SaskPower2013/saskpower-rate-application-report.pdf C) Accessed online: http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/Filing_Reqs_Dx_Applications_ch_1.2.3.5_20130717.pdf

TAB 1

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1505.07
DATE: 2014 11 04
Financial Planning

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Keeyask Generating Station

Addendum #4

REVIEWED BY:
(Owning Dept Manager)

NOTED BY:
(if applicable)

Coordinating Division: Dave Bowen

Constructing Division: Dave Bowen

Financial Department: Doreen Perez
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: OCT. 28, 2014

Business Unit V.P.: Bruce A Barrett 31 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$6,220,088,000
REVISED BUDGET $: (Total Net Cost)	$6,496,061,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2020 12
REVISED ISD: (Last Major In-service Date)	2020 12
RISK MATRIX/ BUSINESS CASE TIER:	n/a
INVESTMENT REASON:	CL04 Future Power Generation

OWNING DIVISION: New Generation Construction

I.M. NODE NUMBER: 1.5.1.6

W.B.S. NUMBERs: P:05866/P:14539/P:14621/P:14622/ P:15264/P:15955/P:16020/P:16021/ P:16022/P:16024/P:16895/P:18568/ P:14625/P:14703/P:16892/P:16897/ P:17448/P:21087/P:21089

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: J.D. Bowen

DATE PREPARED: 2014 10 21

REPORT NUMBER:

FILE NUMBER (Optional):

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
4	2014 03 20	Revision to budget	J.D. Bowen	
3	2012 09 06	Sensitivity Analysis Review	G.P.F. Schick	E.C. Minute 1418.04
2	2010 09 15	Re-estimate	G.P.F. Schick	E.C. Minute 1324.05
1	2009 03 06	Revision to budget	C. Michaluk/D. Magnusson	Board Minute # 797-09 06
	2008 10 15	CPJ	C. Michaluk	Board Minute # 796-08 04

Project Name (This section is required for all Addendums).
Keeyask Generating Station

Recommendation (This section is required for all Addendums).
That the project estimate be increased by $276 million to a revised total of $6,496 million.

Project Scope (This section is be filled out only if there is a change to the scope).
No Change

Background (This section is be filled out only if there is information relevant to the recommendation).

This CPJA reflects the control budget prepared as part of the NFAT and a detailed summary is provided below.

The Keeyask Project control budget was updated in March 2014. The last detailed project estimate was completed in 2009 with a detailed sensitivity analysis conducted in Summer of 2012. The control budget includes bid prices from the major contractors including the General Civil Contract and current budget of the Keeyask Infrastructure Project.

<u>P50 Estimate:</u>
The following changes were made to the P50 Estimate:

- Increase for actual escalation to bring the estimate to 2014$ with a subsequent decrease to future escalation resulting in no net change
- Increase for the difference between awarded value and estimate for the General Civil Works, plus the addition of a performance bonus
- Increase for post-construction adverse effects due to signed agreement
- Increase for site staffing due to partial augmentation through an external consultant
- Decrease to contingency based on an updated risk model

<u>Reserves:</u>
The following changes were made to the Management Reserves:

- Decrease to the labour & escalation reserves as a result of re-calculation using current information from the General Civil Contract

<u>In-Service Costs:</u>
The overall increase to the in-service cost of the project is $276M (5%). The increase to the in-service cost is due to increases to the P50 estimate and corresponding increase to interest offset by a decrease to management reserves and escalation.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Capital Project Justification Addendum

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to some aspect of the recommended alternative).
No change.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**

Other Alternatives Considered	**NPV Benefits/(Costs)**

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

The Labour and Escalation risks previously identified remain unchanged; however the reserve amounts have been re-calculated.

Labour:
The Labour Reserve was re-calculated using the methodology followed in 2012 but with new information as a result of awarding the General Civil Contract. Both the successful and the highest bidder, in combination with lessons learned, including the Wuskwatim project, were used as a basis of deriving the new reserve with an additional consideration of the successful bidder's contracting strategy.

Escalation:
The Escalation Reserve was re-calculated using the revised total project capital costs and associated cashflows.

Interest:
Interest has the potential to change the control budget significantly. Recent updates to interest may cause an increase to the control budget and in-service costs. This will be continuously evaluated over the life of the project.

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

No change.

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 502,072	$ 502,072	$ -
2012/13	$ 201,778	$ 137,778	$ (64,001)
2013/14	$ 339,036	$ 277,396	$ (61,640)
2014/15	$ 405,137	$ 776,272	$ 371,135
2015/16	$ 636,463	$ 676,333	$ 39,870
2016/17	$ 883,863	$ 962,189	$ 78,326
2017/18	$ 1,132,127	$ 1,351,297	$ 219,170
2018/19	$ 955,395	$ 927,908	$ (27,487)
2019/20	$ 804,135	$ 616,472	$ (187,663)
2020/21	$ 288,155	$ 208,578	$ (79,577)
2021/22	$ 71,926	$ 55,193	$ (16,733)
2022/23	$ -	$ 4,470	$ 4,470
2023/24	$ -	$ 103	$ 103
Total	$ 6,220,088	$ 6,496,061	$ 275,973

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change.

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).

2014 Public Utilities Board Report on the Needs for and Alternatives To
K-C NFAT Submission – Original NFAT submission
March 2014 Update - Presentation & Undertakings
2013/14 Power Resource Plan
CPJ dated October 15, 2008 - Keeyask Generating Station
CPJ Addendum #1 dated March 6, 2009
CPJ Addendum #2 dated September 09, 2010
CPJ Addendum #3 dated September 6, 2012

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1418.04

DATE: 2012 10 30
Financial Planning

CAPITAL PROJECT JUSTIFICA FOR

Keeyask Generating Station

Addendum #3

REVIEWED BY:
(Owning Dept Manager)

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:

Business Unit V.P.:

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$5,636,949,000
REVISED BUDGET $: (Total Net Cost)	$6,220,088,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2020 08
REVISED ISD: (Last Major In-service Date)	2020 12
RISK MATRIX/ BUSINESS CASE TIER:	n/a
INVESTMENT REASON:	CL04 Future Power Generation

OWNING DIVISION: New Generation Construction

I.M. NODE NUMBER: 1.5.1.6

W.B.S. NUMBERs: P:05866/P:14539/P:14621/P:14622/P:15264/P:15955/P:16021/P:16022/P:16895/P:18568/P:14625/P:14703/P:16892/P:16897/P:17448

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: G.P.F Schick

DATE PREPARED: 2012 09 06

REPORT NUMBER:

FILE NUMBER (Optional):

2	2010 09 15	Re-estimate	G.P.F. Schick	E.C. Minute 1324.05
1	2009 03 06	Revision to budget	C. Michaluk/D. Magnusson	Board Minute # 797-09 06
	2008 10 15	CPJ	C. Michaluk	Board Minute # 796-08 04
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Keeyask Generating Station

Recommendation (This section is required for all Addendums).
That the project estimate be increased by $583 million to a revised total of $6,220 million.

Project Scope (This section is be filled out only if there is a change to the scope).
No Change

Background (This section is be filled out only if there is information relevant to the recommendation).

The last detailed project estimate was completed in 2009 with a detailed sensitivity analysis conducted in the Summer of 2012. This review incorporated up-to-date experiences and recent market information. The results of the review showed the need to adjust estimate to better address uncertainty related to future costs. As such, the recommended budget is based on a P50 estimate that includes all base costs and contingency at a 50% confidence level and management reserves for labour and escalation risks.

P50 Estimate:

Since the last estimate was developed in 2009 it was necessary to bring the estimate to 2012$ and several items in the point estimate had to be adjusted to match the increased level of detail that has been identified within the current scope. This resulted in the following changes to the P50 Estimate:

- $187M increase for actual escalation that has occurred to bring the estimate to 2012$.
- $34M increase to Planning & Licensing for additional adverse affects, regulatory and environmental costs related to Sturgeon activities, First Nation Activities and EIS preparation
- $60M increase toTransmission costs due to increased detail of scope to include tower type and numbers, additional lines from GS to Switching Stn, additional bank addition and breaker replacments
- $17M increase to infrastructure costs to upgrade camp for labour attraction and retention

Reserves:

A Management Reserve has been established to address significant risks related to labour ($384M) & escalation ($116M). See Risk Analysis section.

In-Service Costs:

The overall increase to the in-service cost of the project is $583M (10%). This increase to the in-service cost is due to the addition of the Management Reserve and base estimate increases offset by reduced interest costs from reduced forecasted interest rates ($215M).

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to some aspect of the recommended alternative).
An additional dependable energy source is required in 2019/20 to meet forecast Manitoba loads and export commitments consistent with the recommended development plan of the 2012/13 Power Resource Plan.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**

Other Alternatives Considered	**NPV Benefits/(Costs)**

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

Keeyask risks related to labour productivity & escalation are addressed through use of management reserves due to the magnitude of the cost variation they may cause. Keeyask estimates include both a labour reserve and an escalation reserve:

The labour reserve represents the potential additional costs associated with labour productivity and cumulative impacts. The labour reserve is derived by applying outcomes of the Wuskwatim process reviews to the labour components of the Keeyask estimates including:

- Increases to the number of labour hours required per work activity and the resulting number of workers due to reduced labour productivity;
- Additional costs for extended construction duration due to lower productivity;
- Increases to collective agreement wages to attract and retain workers; Increases to the size of the camp to accommodate the additional workers required due to lower productivity;
- Increases to the service contracts to accommodate the additional workers required;
- Increases to project management costs related to additional supervisory staff to monitor less experienced and less productive workers; and
- Additional costs for 7-12 work schedule (7 days per week, 12 hours per day).

The Corporation expects to utilize the labour reserve if there are restrictions in our ability to address the current and expected state of the Canadian construction labour market (demand/supply), specifically labour availability and productivity. Examples include (a) restrictions on the ability to modify wage rates, hours

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

of work per day, and turnaround schedules in the Burntwood Nelson Agreement, and (b) constraints on the project using labour outside of Manitoba and Canada.

The escalation reserve represents the potential additional costs to the project associated with cost escalation greater than Canadian CPI. The escalation reserve is derived by projecting the total project capital costs utilizing rates of inflation comprised of components directly related to major hydro project construction, such as copper, cement, concrete reinforcing bar, and diesel fuel price increases, rather than the broadly defined components comprising Canadian CPI. The Corporation expects that it will utilize the escalation reserve.

Considering the uncertainties in heavy construction escalation, labour productivity and project construction conditions, there is a greater likelihood that the actual costs to construct Keeyask will be less than the updated cost estimates than more. This is provided that the in-service dates, interest rates, escalation and major scope items are consistent with the estimate assumptions.

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

No changes to the resource requirements.

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$365,409	$365,409	$0
2010/11	$71,140	$56,434	($14,706)
2011/12	$152,465	$80,229	($72,236)
2012/13	$179,137	$201,778	$22,641
2013/14	$316,097	$339,036	$22,939
2014/15	$381,566	$405,137	$23,571
2015/16	$684,346	$636,463	($47,883)
2016/17	$750,677	$883,863	$133,186
2017/18	$1,082,934	$1,132,127	$49,193
2018/19	$813,264	$955,395	$142,131
2019/20	$631,995	$804,135	$172,140
2020/21	$207,919	$288,155	$80,236
2021/22		$71,926	$71,926
Total	$5,636,949	$6,220,088	$583,139

Capital Project Justification Addendum

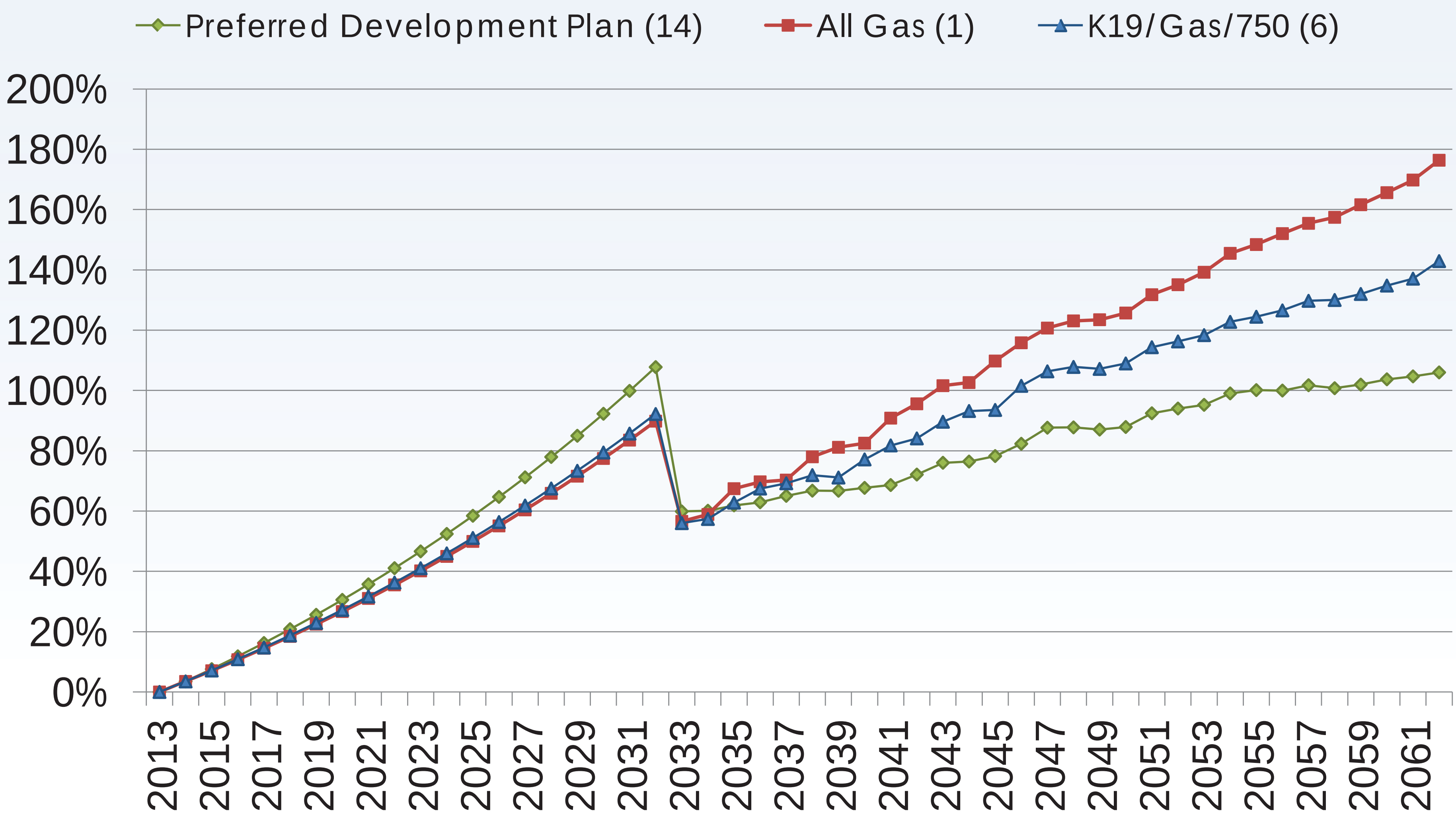
Proposed Schedule (This section is be filled out only if there is a change to the project schedule).
The PR 280 Upgrades started in October 2010 as outlined in CPJA#2 The Infrastructure started in December 2011 which is 6 months later than the date outline in CPJA#2 The first unit In-Service-Date is November of 2019 (unchanged from CPJA#2) and the last unit In-Service Date is December of 2020 (4 months later than CPJA#2).

Related Projects (This section is be filled out only if changed).
Conawapa Generating Station Transmission Lines related to Export Sales to Minnesota Power and Wisconsin Public Service Bipole III Transmission and Converters

Reference Documents (This section is be filled out only if changed).
2012 Keeyask & Conawapa Recommended Budgets 2012 Keeyask & Conawapa Sensitivity Analysis Summary 2012 EC Recommendation – Keeyask Budget Basis - August 28, 2012 Minute 1409.02 2012 Power Resource Plan Report

TAB 2

Cumulative Rate Increases (Nominal) Reference Scenario



May 2, 2014

ADDENDUM TO DSM FINANCIAL EVALUATION OVERVIEW

On April 23, 2014, the PUB Chairperson requested that the following financial evaluations be prepared in addition to Manitoba Hydro's April 11, 2014 submission of the DSM financial evaluation found in Manitoba Hydro Exhibit 104-12-1:

1. Plan 2 DSM Level 2
2. Plan 6 DSM Level 2
3. Plan 4 DSM Level 2
4. Plan 12 DSM Level 2
5. Plan 1 DSM Level 2 with the potential pipeline load
6. Plan 5 DSM Level 2 with the potential pipeline load
7. Plan 14 DSM Level 2 with the potential pipeline load

This overview along with the attached summary sheets and the sets of pro forma financial statements together form the addendum to the DSM Financial Evaluation filed with the PUB on April 11, 2014.

Similarly to the information filed on April 11, 2014, each of the seven (7) scenarios outlined above were prepared under three (3) different rate setting methodologies (as described in Manitoba Hydro Exhibit 104-12-1) resulting in twenty-one (21) distinct sets of pro forma financial statements.

Table 1 outlines the potential timing of new resources at DSM Level 2 required for domestic load for the purposes of this evaluation.

TABLE 1	
DEVELOPMENT PLAN	**DSM LEVEL 2**
WITHOUT POTENTIAL PIPELINE LOAD	
KEEYASK 2031/GAS (2)	1-CCGT: 2042, 4-SCGTs: 2031-2042
KEEYASK 2019/GAS/250MW (4)	3-SCGTs: 2040-2047
KEEYASK 2019/GAS/750MW (6)	3-SCGTs: 2040-2047
KEEYASK 2019/CONAWAPA 2040/750MW (12)	N/A
WITH POTENTIAL PIPELINE LOAD	
ALL GAS (1)	2-CCGTs:2039-2044, 3-SCGTs: 2024-2035, 1-LM6000: 2048
KEEYASK 2019/GAS/750MW (5)	1-CCGT: 2047, 3-SCGTs: 2030-2044
PDP (14)	CONAWAPA:2030

Table 2 provides the in-service capital costs for Keeyask, Conawapa, the 750 MW Interconnection and the DSM utility costs at DSM Level 2.

TABLE 2	
(Billions of Nominal Dollars)	
	DSM LEVEL 2
KEEYASK 2019	$6.3
KEEYASK 2031 *	$8.6
250 MW Interconnection (MB)	$0.1
750 MW Interconnection (MB)	$0.3
750 MW Interconnection (US)	$0.3
CONAWAPA 2030	$11.8
CONAWAPA 2040 *	$12.2
DSM UTILITY COSTS	$1.1

* Given the extended deferral of the in-service date of Keeyask in Plan 2 and the in-service date of Conawapa in Plan 12, interest during construction (for the purposes of this evaluation) was not capitalized during the periods when the active development to these projects are suspended. As the construction start date approaches and the annual capital expenditures become more substantial, interest is once again capitalized to the projects.

Figure 1 compares the cumulative rate increases of the development plans without the potential pipeline load at **DSM Level 2** under Alternative Rate Methodology #2.

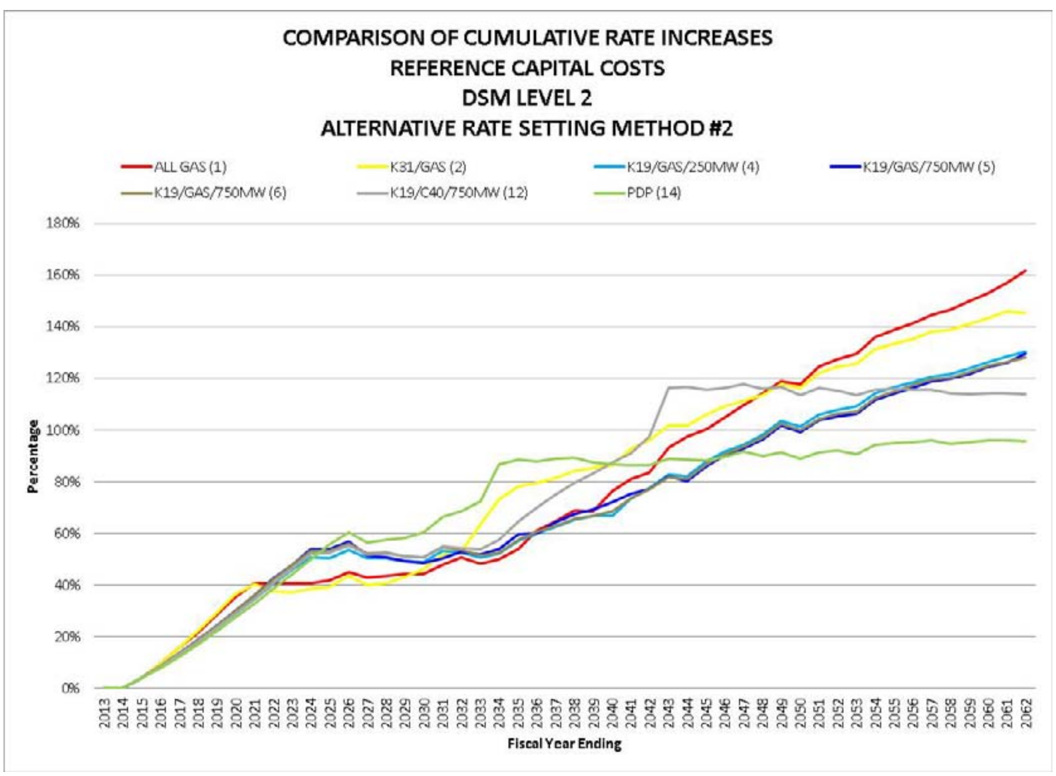


Figure 2 compares the cumulative rate increases (relative to All Gas) of the development plans without the potential pipeline load at **DSM Level 2** under Alternative Rate Methodology #2.

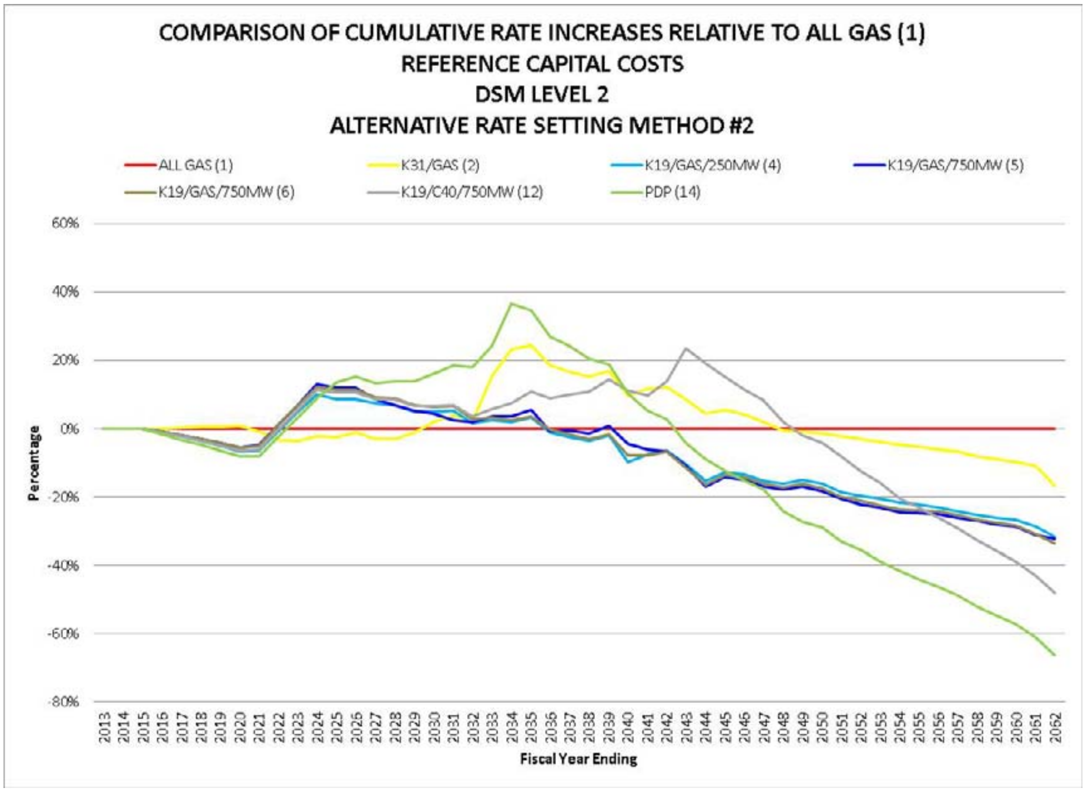


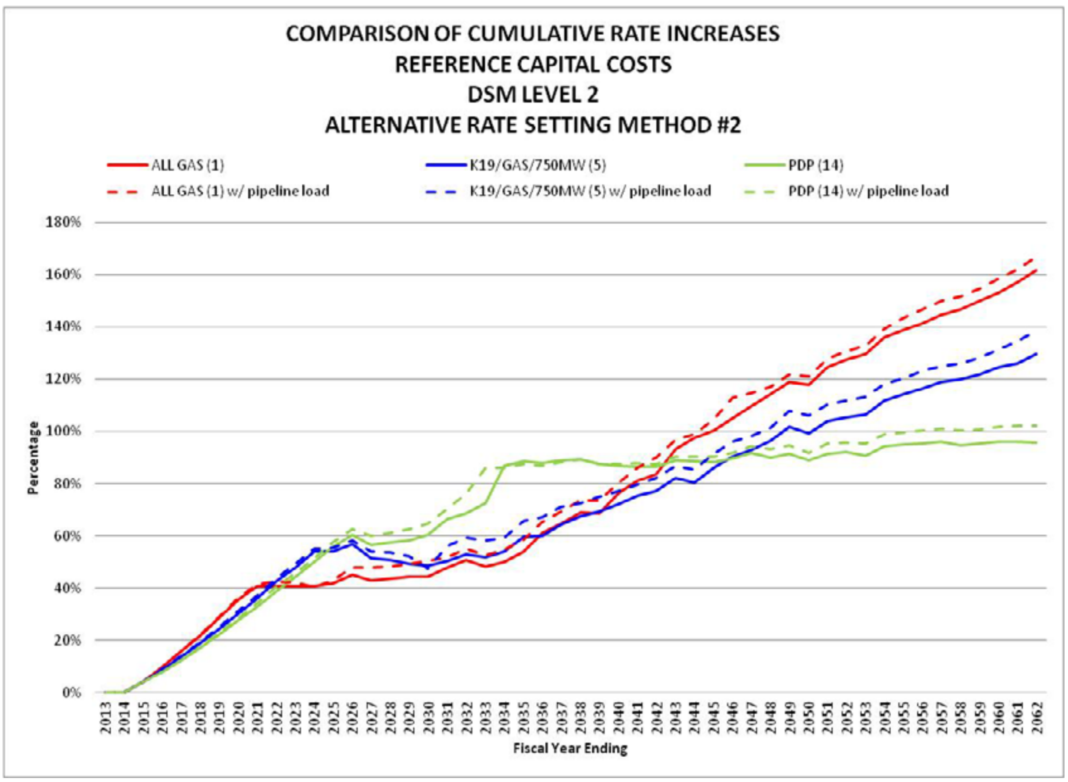
Table 3 outlines the cumulative rate increases.

TABLE 3 CUMULATIVE RATE INCREASES AT DSM LEVEL 2 USING ALTERNATIVE METHODOLOGY #2 AND REFERENCE CAPITAL COSTS		
	2031/32	**2061/62**
ALL GAS (1)	**51%**	**162%**
K31/GAS (2)	**53%**	**145%**
K19/GAS/250 MW (4)	**52%**	**130%**
K19/GAS/750 MW (5)	**53%**	**130%**
K19/GAS/750 MW (6)	**53%**	**128%**
K19/C40/750 MW (12)	**54%**	**114%**
PDP (14)	**69%**	**96%**

Table 4 outlines the cumulative present value of total general consumers' revenue.

TABLE 4 CUMULATIVE PV OF CONSUMERS REVENUE AT DSM LEVEL 2 USING ALTERNATIVE METHODOLOGY #2 AND REFERENCE CAPITAL COSTS DISCOUNTED AT 1.86% REAL (In Billions)		
	2031/32	**2061/62**
ALL GAS (1)	**$26.9**	**$57.6**
K31/GAS (2)	**$26.8**	**$58.5**
K19/GAS/250 MW (4)	**$27.2**	**$56.1**
K19/GAS/750 MW (5)	**$27.4**	**$56.2**
K19/GAS/750 MW (6)	**$27.5**	**$56.3**
K19/C40/750 MW (12)	**$27.4**	**$58.0**
PDP (14)	**$27.7**	**$57.0**

Figure 3 compares the cumulative rate increases of plans 1, 5 and 14 with and without the potential pipeline load at **DSM Level 2** under Alternative Rate Methodology #2 with Reference capital costs.



Manitoba Hydro has summarized the rate increases and key financial metrics in the three attachments to this document in a similar format to Table 4 of the Needs For and Alternatives To Executive Summary (Business Case, page 29) and Table 11.1 found in PUB/MH I-149(a).

The pro forma financial statements for all development plans and scenarios evaluated under the three rate setting methodologies are available electronically.

Development Plan K19/GAS/750MW (5) - LEVEL 2 DSM - MAIN SUBMISSION RATE METHODOLOGY
ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
REVENUES																									
General Consumers Revenue at approved rates	1,331	1,396	1,401	1,408	1,404	1,409	1,413	1,426	1,440	1,455	1,470	1,486	1,501	1,517	1,532	1,548	1,566	1,583	1,601	1,618	1,636	1,649	1,668	1,686	1,704
Additional General Consumers Revenue	-	-	55	110	167	226	288	355	426	501	580	664	752	845	943	1,046	1,156	1,272	1,394	1,522	762	795	887	910	991
Extraprovincial	357	408	383	373	430	491	522	571	853	964	993	1,005	1,005	939	1,000	987	991	996	1,030	1,035	1,020	1,008	998	988	899
Other	14	15	15	15	15	16	16	16	17	17	17	18	18	18	19	19	19	20	20	21	21	21	22	22	23
Total Revenue	1,702	1,819	1,854	1,906	2,017	2,142	2,240	2,368	2,735	2,938	3,060	3,172	3,276	3,320	3,494	3,599	3,732	3,872	4,045	4,196	3,439	3,473	3,574	3,606	3,617
EXPENSES																									
Operating and Administrative	455	471	516	532	543	567	580	597	659	671	685	697	711	724	738	752	768	780	793	815	832	852	870	887	907
Finance Expense	454	462	511	542	611	693	815	839	1,098	1,201	1,199	1,215	1,214	1,209	1,185	1,168	1,131	1,094	1,107	1,070	1,037	1,035	1,073	1,088	1,100
Depreciation and Amortization	408	439	433	463	476	505	543	553	622	662	670	671	675	684	689	682	680	682	704	717	700	695	716	718	721
Water Rentals and Assessments	117	125	122	111	111	112	111	113	124	127	127	127	127	127	128	128	128	129	132	131	131	131	131	132	132
Fuel and Power Purchased	143	144	142	177	193	203	212	213	217	232	240	249	266	259	273	275	287	295	284	313	325	344	360	350	319
Capital and Other Taxes	87	95	103	112	121	129	135	139	142	142	143	145	146	148	149	151	154	157	164	165	167	169	171	173	175
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	7	7	7	7	7	7	7
Total Expenses	1,673	1,746	1,835	1,944	2,064	2,218	2,404	2,461	2,869	3,044	3,073	3,112	3,146	3,159	3,170	3,165	3,157	3,145	3,191	3,217	3,198	3,231	3,328	3,354	3,361
Non-Controlling Interest	(14)	(24)	(22)	(17)	(15)	(13)	(9)	(8)	(7)	0	2	7	9	8	12	14	16	19	21	23	25	27	29	30	32
Net Income	43	97	41	(21)	(32)	(64)	(155)	(85)	(127)	(107)	(16)	53	122	152	312	420	559	707	833	956	215	215	217	221	224
Additional General Consumers Revenue Percent Increase	0.00%	0.00%	3.95%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	-24.47%	1.08%	3.38%	0.50%	2.74%
Cumulative General Consumers Revenue Percent Increase	0.00%	0.00%	3.95%	7.84%	11.87%	16.06%	20.40%	24.90%	29.58%	34.42%	39.45%	44.67%	50.08%	55.70%	61.52%	67.56%	73.83%	80.34%	87.08%	94.08%	46.59%	48.18%	53.19%	53.95%	58.17%
Debt Ratio	76	78	83	85	87	88	89	90	91	92	92	91	91	90	89	87	85	82	79	75	74	73	73	72	71
Interest Coverage Ratio	1.07	1.16	1.06	0.97	0.96	0.94	0.86	0.93	0.89	0.91	0.99	1.04	1.10	1.12	1.26	1.35	1.47	1.60	1.72	1.87	1.20	1.20	1.20	1.20	1.20
Capital Coverage Ratio	1.04	0.97	0.84	0.85	1.11	1.26	0.97	1.39	1.22	1.25	1.30	1.42	1.57	1.74	2.31	2.20	2.27	2.40	2.51	3.18	1.56	1.36	1.32	1.27	1.22

Development Plan K19/GAS/750MW (5) - LEVEL 2 DSM - MAIN SUBMISSION RATE METHODOLOGY
ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

For the year ended March 31	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**	**2055**	**2056**	**2057**	**2058**	**2059**	**2060**	**2061**	**2062**
REVENUES																									
General Consumers Revenue at approved rates	1,723	1,742	1,762	1,782	1,802	1,822	1,844	1,866	1,888	1,910	1,932	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954
Additional General Consumers Revenue	1,064	1,106	1,171	1,243	1,290	1,400	1,387	1,512	1,609	1,676	1,770	1,899	1,857	1,961	2,000	2,012	2,109	2,154	2,199	2,244	2,264	2,304	2,357	2,388	2,463
Extraprovincial	871	847	817	802	795	788	819	791	774	785	783	740	799	814	830	846	862	878	895	912	929	947	965	983	1,002
Other	23	24	24	24	25	25	26	26	27	27	28	29	29	30	30	31	31	32	33	33	34	35	35	36	37
Total Revenue	3,682	3,719	3,775	3,852	3,912	4,035	4,076	4,195	4,298	4,399	4,512	4,622	4,639	4,760	4,815	4,843	4,956	5,019	5,081	5,143	5,181	5,240	5,312	5,362	5,456
EXPENSES																									
Operating and Administrative	927	948	970	993	1,016	1,040	1,063	1,096	1,123	1,149	1,186	1,216	1,244	1,275	1,306	1,326	1,358	1,377	1,397	1,417	1,438	1,459	1,480	1,494	1,516
Finance Expense	1,101	1,098	1,095	1,110	1,111	1,111	1,110	1,121	1,118	1,146	1,142	1,143	1,138	1,124	1,106	1,102	1,086	1,072	1,062	1,042	1,020	1,000	983	954	959
Depreciation and Amortization	751	752	758	770	778	844	852	870	913	931	956	981	997	1,085	1,111	1,106	1,186	1,226	1,264	1,311	1,334	1,375	1,424	1,471	1,517
Water Rentals and Assessments	132	132	132	131	132	132	134	133	134	135	135	134	142	145	148	151	154	156	159	162	166	169	172	175	179
Fuel and Power Purchased	327	341	368	389	412	437	435	489	518	536	590	642	611	623	635	647	659	672	685	698	711	724	738	752	766
Capital and Other Taxes	177	179	182	185	188	192	195	198	202	207	209	212	213	214	216	219	222	225	226	228	230	232	235	237	239
Corporate Allocation	7	7	7	7	7	7	7	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Total Expenses	3,423	3,458	3,512	3,586	3,643	3,761	3,797	3,913	4,014	4,110	4,225	4,334	4,352	4,471	4,528	4,556	4,670	4,734	4,799	4,864	4,904	4,964	5,037	5,088	5,182
Non-Controlling Interest	34	36	38	40	43	46	48	49	51	54	55	55	57	58	59	60	61	62	64	66	68	70	72	74	77
Net Income	225	225	226	225	227	228	231	232	233	235	233	232	231	231	228	227	225	222	218	213	209	205	203	200	198
Additional General Consumers Revenue Percent Increase	2.27%	1.06%	1.84%	1.97%	1.09%	3.07%	-0.94%	3.30%	2.32%	1.37%	2.05%	2.91%	-1.09%	2.74%	1.00%	0.29%	2.44%	1.12%	1.10%	1.07%	0.48%	0.95%	1.25%	0.72%	1.74%
Cumulative General Consumers Revenue Percent Increase	61.76%	63.47%	66.48%	69.76%	71.61%	76.87%	75.22%	81.01%	85.20%	87.73%	91.58%	97.16%	95.00%	100.36%	102.35%	102.95%	107.90%	110.23%	112.54%	114.81%	115.84%	117.89%	120.62%	122.20%	126.06%
Debt Ratio	70	69	69	68	68	67	67	66	66	65	65	64	63	62	61	61	60	59	58	57	56	55	55	54	53
Interest Coverage Ratio	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Capital Coverage Ratio	1.21	1.16	1.11	1.05	1.06	1.14	1.19	1.17	1.06	1.29	1.32	1.33	1.36	1.32	1.33	1.30	1.34	1.36	1.35	1.37	1.35	1.35	1.36	1.36	1.38

Development Plan K19/GAS/750MW (5) - LEVEL 2 DSM - MAIN SUBMISSION RATE METHODOLOGY
ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
In Millions of Dollars

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
ASSETS																									
Plant in Service	15,374	16,434	17,553	18,705	19,265	22,808	23,239	26,188	30,472	31,006	31,538	32,103	32,792	33,394	34,057	34,545	35,293	35,852	37,859	38,869	39,554	40,909	41,432	41,974	43,309
Accumulated Depreciation	(5,173)	(5,536)	(5,869)	(6,254)	(6,662)	(7,096)	(7,566)	(8,040)	(8,575)	(9,147)	(9,726)	(10,306)	(10,890)	(11,484)	(12,085)	(12,687)	(13,291)	(13,902)	(14,541)	(15,196)	(15,838)	(16,477)	(17,141)	(17,809)	(18,483)
Net Plant in Service	10,201	10,898	11,684	12,450	12,604	15,712	15,672	18,149	21,898	21,860	21,812	21,797	21,903	21,909	21,972	21,858	22,002	21,950	23,318	23,672	23,716	24,432	24,291	24,165	24,826
Construction in Progress	2,019	2,805	3,948	4,895	6,338	4,763	5,719	3,761	112	201	293	370	330	410	415	748	1,082	1,628	729	550	648	106	398	710	271
Current and Other Assets	1,869	1,740	1,388	1,573	1,792	2,014	1,847	1,982	2,059	1,731	1,795	2,058	2,254	2,155	2,726	2,951	3,018	3,025	2,922	3,927	3,800	2,866	2,961	2,925	2,948
Goodwill and Intangible Assets	180	165	153	140	130	121	187	212	408	398	388	381	373	366	359	351	344	337	330	322	315	308	301	293	286
Regulated Assets	231	233	259	293	370	399	428	436	428	410	389	368	348	329	311	302	267	237	214	194	178	165	155	148	145
Total Assets	14,500	15,841	17,433	19,352	21,233	23,010	23,854	24,541	24,905	24,599	24,677	24,974	25,209	25,170	25,784	26,210	26,713	27,178	27,511	28,665	28,656	27,877	28,106	28,242	28,476
LIABILITIES AND EQUITY																									
Long Term Debt	9,272	11,144	12,818	14,842	16,563	18,140	19,637	20,205	20,735	20,687	21,289	21,492	21,245	21,447	21,849	21,790	21,540	20,843	21,033	21,006	19,009	18,010	17,319	17,521	16,973
Current and Other Liabilities	2,183	1,647	1,926	1,847	2,106	2,398	1,918	2,140	2,124	2,000	1,507	1,545	1,902	1,506	1,404	1,466	1,658	2,109	1,419	1,641	3,412	3,413	4,113	3,823	4,379
Contributions in Aid of Construction	314	314	315	315	316	322	324	327	330	333	336	339	341	344	346	348	351	353	356	358	361	364	366	369	372
Retained Earnings	2,432	2,529	2,531	2,510	2,478	2,414	2,259	2,174	2,047	1,940	1,925	1,978	2,099	2,252	2,564	2,984	3,543	4,251	5,083	6,039	6,254	6,469	6,686	6,907	7,131
Accumulated Other Comprehensive Income	299	207	(157)	(162)	(230)	(263)	(284)	(306)	(331)	(362)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)
Total Liabilities and Equity	14,500	15,841	17,433	19,352	21,233	23,010	23,854	24,541	24,905	24,599	24,677	24,974	25,209	25,170	25,784	26,210	26,713	27,178	27,511	28,665	28,656	27,877	28,106	28,242	28,476

Development Plan — K19/GAS/750MW (5) - LEVEL 2 DSM - MAIN SUBMISSION RATE METHODOLOGY

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
In Millions of Dollars

For the year ended March 31	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062
ASSETS																									
Plant in Service	43,895	44,501	45,506	46,172	48,543	49,223	49,932	51,997	53,267	54,077	55,514	56,214	58,960	60,197	61,573	62,957	64,375	65,913	67,585	68,973	70,350	71,793	73,234	74,735	76,857
Accumulated Depreciation	(19,189)	(19,900)	(20,617)	(21,347)	(22,085)	(22,891)	(23,706)	(24,539)	(25,417)	(26,314)	(27,237)	(28,186)	(29,151)	(30,203)	(31,281)	(32,365)	(33,528)	(34,729)	(35,967)	(37,248)	(38,552)	(39,894)	(41,284)	(42,718)	(44,198)
Net Plant in Service	24,705	24,601	24,889	24,826	26,458	26,331	26,226	27,458	27,850	27,764	28,277	28,028	29,810	29,994	30,292	30,592	30,847	31,183	31,618	31,724	31,798	31,899	31,950	32,017	32,659
Construction in Progress	628	1,009	1,053	1,512	275	865	1,465	574	760	1,475	1,239	1,690	139	160	168	215	304	241	26	29	31	34	222	496	(89)
Current and Other Assets	2,814	2,791	2,816	2,828	2,837	2,933	2,819	3,133	3,014	3,021	3,397	3,434	3,322	3,149	2,874	2,719	1,840	1,612	1,385	1,316	1,042	943	788	646	786
Goodwill and Intangible Assets	279	272	264	257	250	243	235	228	221	214	207	199	192	185	178	171	163	156	149	142	134	127	120	113	106
Regulated Assets	138	127	116	107	99	92	87	83	81	80	81	82	83	85	86	99	111	121	131	138	145	150	153	154	156
Total Assets	28,564	28,799	29,139	29,530	29,918	30,464	30,832	31,476	31,927	32,554	33,201	33,434	33,546	33,573	33,598	33,795	33,266	33,314	33,309	33,349	33,151	33,153	33,233	33,426	33,617
LIABILITIES AND EQUITY																									
Long Term Debt	17,575	18,277	18,429	19,179	19,278	20,227	20,425	20,824	20,822	21,620	22,019	21,692	21,690	21,490	21,439	20,439	18,638	17,838	17,837	17,229	17,429	17,703	17,702	18,302	18,052
Current and Other Liabilities	3,636	2,942	2,901	2,313	2,373	1,739	1,674	1,684	1,900	1,490	1,502	1,827	1,706	1,699	1,543	2,514	3,560	4,187	3,964	4,398	3,792	3,314	3,192	2,585	2,829
Contributions in Aid of Construction	375	378	381	384	387	390	393	396	400	403	407	410	414	418	421	421	421	421	421	421	421	421	421	421	421
Retained Earnings	7,356	7,581	7,807	8,033	8,259	8,487	8,718	8,951	9,184	9,419	9,652	9,884	10,115	10,345	10,573	10,800	11,025	11,247	11,465	11,679	11,888	12,093	12,296	12,496	12,694
Accumulated Other Comprehensive Income	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)
Total Liabilities and Equity	28,564	28,799	29,139	29,530	29,918	30,464	30,832	31,476	31,927	32,554	33,201	33,434	33,546	33,573	33,598	33,795	33,266	33,314	33,309	33,349	33,151	33,153	33,233	33,426	33,617

Development Plan K19/GAS/750MW (5) - LEVEL 2 DSM - MAIN SUBMISSION RATE METHODOLOGY
ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
In Millions of Dollars

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
OPERATING ACTIVITIES																									
Cash Receipts from Customers	1,692	1,819	1,854	1,906	2,017	2,142	2,240	2,368	2,735	2,938	3,060	3,172	3,276	3,320	3,494	3,599	3,732	3,872	4,045	4,196	3,439	3,473	3,574	3,606	3,617
Cash Paid to Suppliers and Employees	(782)	(810)	(857)	(904)	(939)	(980)	(1,005)	(1,027)	(1,104)	(1,133)	(1,154)	(1,174)	(1,202)	(1,208)	(1,236)	(1,251)	(1,278)	(1,299)	(1,307)	(1,354)	(1,382)	(1,415)	(1,446)	(1,452)	(1,437)
Interest Paid	(467)	(483)	(527)	(570)	(633)	(733)	(866)	(878)	(1,154)	(1,265)	(1,235)	(1,235)	(1,242)	(1,244)	(1,224)	(1,231)	(1,209)	(1,174)	(1,198)	(1,125)	(1,111)	(1,111)	(1,146)	(1,163)	(1,188)
Interest Received	28	17	24	25	30	37	40	38	35	32	18	18	27	30	40	53	66	69	77	51	64	67	70	68	81
Cash from Operating Activities	471	542	495	457	475	466	409	502	512	572	688	782	859	898	1,073	1,170	1,310	1,469	1,616	1,767	1,011	1,013	1,051	1,059	1,073
FINANCING ACTIVITIES																									
Proceeds from Long Term Debt	836	1,970	1,960	2,390	2,180	2,390	1,780	1,190	1,190	390	560	190	190	180	390	(10)	(10)	(40)	190	190	(40)	930	1,920	2,580	2,310
Sinking Fund Withdrawals	129	410	103	22	-	20	412	188	267	670	155	-	-	338	-	-	60	250	700	13	230	200	200	101	200
Retirement of Long Term Debt	(119)	(825)	(177)	(312)	(347)	(530)	(825)	(305)	(633)	(673)	(431)	-	-	(450)	-	-	(60)	(220)	(700)	(13)	(200)	(1,950)	(1,930)	(2,682)	(2,330)
Other Financing Activities	(42)	(7)	(20)	(22)	(20)	(17)	(28)	(17)	(39)	(14)	(5)	(5)	(5)	(5)	(5)	(4)	(3)	(3)	(2)	(21)	(21)	(22)	(22)	(23)	(20)
Cash from Financing Activities	804	1,548	1,866	2,078	1,813	1,863	1,339	1,056	786	373	279	185	185	62	385	(14)	(13)	(13)	188	169	(31)	(842)	168	(24)	160
INVESTING ACTIVITIES																									
Property Plant and Equipment net of contributions	(1,311)	(1,964)	(2,279)	(2,189)	(2,132)	(2,050)	(1,547)	(1,190)	(1,019)	(673)	(672)	(692)	(702)	(732)	(719)	(872)	(1,104)	(1,128)	(1,129)	(853)	(805)	(837)	(838)	(877)	(920)
Sinking Fund Payment	(107)	(218)	(121)	(184)	(169)	(225)	(220)	(223)	(246)	(339)	(221)	(225)	(237)	(247)	(242)	(254)	(264)	(272)	(271)	(248)	(259)	(257)	(251)	(252)	(258)
Other Investing Activities	(17)	(16)	(21)	(20)	(32)	(42)	(28)	(28)	(33)	(38)	(29)	(32)	(25)	(25)	(28)	(26)	(26)	(26)	(26)	(26)	(27)	(27)	(27)	(27)	(27)
Cash from Investing Activities	(1,436)	(2,198)	(2,422)	(2,394)	(2,334)	(2,317)	(1,795)	(1,441)	(1,298)	(1,050)	(922)	(949)	(964)	(1,005)	(989)	(1,152)	(1,394)	(1,425)	(1,425)	(1,127)	(1,090)	(1,121)	(1,116)	(1,156)	(1,205)
Net Increase (Decrease) in Cash	(160)	(108)	(61)	142	(46)	12	(47)	117	(0)	(105)	45	18	80	(45)	470	3	(97)	30	379	809	(111)	(949)	103	(122)	28
Cash at Beginning of Year	43	(118)	(225)	(286)	(144)	(190)	(178)	(225)	(108)	(108)	(213)	(168)	(150)	(70)	(114)	355	359	262	292	671	1,480	1,369	421	524	402
Cash at End of Year	(118)	(225)	(286)	(144)	(190)	(178)	(225)	(108)	(108)	(213)	(168)	(150)	(70)	(114)	355	359	262	292	671	1,480	1,369	421	524	402	429

Needs For and Alternatives To
DSM Evaluation - 2013 Electric Load Forecast
Pro Forma Financial Statements

Development Plan K19/GAS/750MW (5) - LEVEL 2 DSM - MAIN SUBMISSION RATE METHODOLOGY
ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
In Millions of Dollars

For the year ended March 31	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**	**2055**	**2056**	**2057**	**2058**	**2059**	**2060**	**2061**	**2062**
OPERATING ACTIVITIES																									
Cash Receipts from Customers	3,682	3,719	3,775	3,852	3,912	4,035	4,076	4,195	4,298	4,399	4,512	4,622	4,639	4,760	4,815	4,843	4,956	5,019	5,081	5,143	5,181	5,240	5,312	5,362	5,456
Cash Paid to Suppliers and Employees	(1,463)	(1,495)	(1,540)	(1,580)	(1,623)	(1,668)	(1,688)	(1,769)	(1,821)	(1,863)	(1,947)	(2,021)	(2,018)	(2,052)	(2,090)	(2,128)	(2,165)	(2,203)	(2,240)	(2,278)	(2,317)	(2,357)	(2,398)	(2,431)	(2,474)
Interest Paid	(1,187)	(1,190)	(1,190)	(1,208)	(1,219)	(1,221)	(1,237)	(1,257)	(1,270)	(1,305)	(1,312)	(1,333)	(1,332)	(1,316)	(1,294)	(1,291)	(1,292)	(1,234)	(1,233)	(1,201)	(1,180)	(1,162)	(1,142)	(1,119)	(1,119)
Interest Received	82	85	94	99	106	113	121	134	146	153	171	180	190	180	177	186	187	166	165	164	162	161	165	161	169
Cash from Operating Activities	1,113	1,119	1,139	1,161	1,176	1,260	1,271	1,303	1,353	1,385	1,424	1,448	1,480	1,571	1,608	1,609	1,687	1,748	1,774	1,828	1,846	1,882	1,936	1,973	2,033
FINANCING ACTIVITIES																									
Proceeds from Long Term Debt	2,750	2,160	1,550	1,570	980	1,120	370	570	360	760	370	(30)	130	(30)	(40)	(60)	110	1,690	2,360	2,080	2,330	1,930	1,530	1,550	950
Sinking Fund Withdrawals	246	100	188	144	145	147	50	-	100	200	-	-	325	100	200	50	542	198	200	186	207	167	298	-	344
Retirement of Long Term Debt	(2,910)	(2,180)	(1,460)	(1,440)	(840)	(840)	(240)	(190)	(180)	(390)	10	10	(285)	(190)	(190)	(10)	(930)	(1,920)	(2,580)	(2,310)	(2,757)	(2,160)	(1,675)	(1,570)	(980)
Other Financing Activities	(21)	(21)	(22)	(23)	(32)	(33)	(54)	(34)	(35)	(39)	(35)	(36)	(36)	(37)	(38)	(39)	(39)	(40)	(41)	(42)	(76)	(84)	(86)	(88)	(104)
Cash from Financing Activities	66	59	256	250	254	394	126	346	245	531	345	(56)	134	(157)	(68)	(59)	(317)	(73)	(61)	(86)	(296)	(146)	67	(108)	210
INVESTING ACTIVITIES																									
Property Plant and Equipment net of contributions	(960)	(998)	(1,060)	(1,136)	(1,143)	(1,280)	(1,320)	(1,185)	(1,467)	(1,537)	(1,212)	(1,163)	(1,207)	(1,271)	(1,396)	(1,443)	(1,520)	(1,488)	(1,471)	(1,404)	(1,394)	(1,460)	(1,643)	(1,789)	(1,552)
Sinking Fund Payment	(260)	(259)	(266)	(270)	(276)	(283)	(290)	(304)	(318)	(330)	(172)	(183)	(190)	(186)	(191)	(189)	(194)	(173)	(171)	(168)	(164)	(160)	(158)	(150)	(158)
Other Investing Activities	(28)	(28)	(28)	(28)	(28)	(29)	(29)	(29)	(29)	(30)	(30)	(30)	(30)	(31)	(30)	(15)	(15)	(14)	(14)	(13)	(37)	(37)	(37)	(38)	(38)
Cash from Investing Activities	(1,248)	(1,285)	(1,354)	(1,434)	(1,448)	(1,592)	(1,639)	(1,518)	(1,815)	(1,897)	(1,414)	(1,376)	(1,428)	(1,487)	(1,618)	(1,647)	(1,728)	(1,675)	(1,655)	(1,585)	(1,595)	(1,657)	(1,838)	(1,977)	(1,748)
Net Increase (Decrease) in Cash	(68)	(106)	41	(22)	(18)	62	(242)	131	(216)	18	355	17	186	(73)	(77)	(97)	(358)	1	58	157	(45)	79	165	(112)	495
Cash at Beginning of Year	429	361	255	296	274	255	317	75	206	(10)	8	363	379	565	492	415	318	(40)	(39)	18	175	130	209	374	262
Cash at End of Year	361	255	296	274	255	317	75	206	(10)	8	363	379	565	492	415	318	(40)	(39)	18	175	130	209	374	262	757

Development Plan K19/GAS/750MW (5) - LEVEL 2 DSM - ALT. RATE METHOD 1
ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
REVENUES																									
General Consumers Revenue at approved rates	1,331	1,396	1,401	1,408	1,404	1,409	1,413	1,426	1,440	1,455	1,470	1,486	1,501	1,517	1,532	1,548	1,566	1,583	1,601	1,618	1,636	1,649	1,668	1,686	1,704
Additional General Consumers Revenue	-	-	55	113	173	236	302	373	449	529	613	703	798	898	848	845	830	825	860	903	895	938	1,044	1,064	1,144
Extraprovincial	357	408	383	373	430	491	522	571	853	964	993	1,005	1,005	939	1,000	987	991	996	1,030	1,035	1,020	1,008	998	988	899
Other	14	15	15	15	15	16	16	16	17	17	17	18	18	18	19	19	19	20	20	21	21	21	22	22	23
Total Revenue	1,702	1,819	1,854	1,909	2,023	2,152	2,254	2,386	2,758	2,965	3,093	3,212	3,322	3,373	3,399	3,398	3,405	3,425	3,511	3,577	3,571	3,616	3,730	3,760	3,770
EXPENSES																									
Operating and Administrative	455	471	516	532	543	567	580	597	659	671	685	697	711	724	738	752	768	780	793	815	832	852	870	887	907
Finance Expense	454	462	511	542	611	692	813	836	1,094	1,196	1,193	1,205	1,199	1,192	1,163	1,150	1,126	1,115	1,163	1,167	1,147	1,154	1,204	1,216	1,228
Depreciation and Amortization	408	439	433	463	476	505	543	553	622	662	670	671	675	684	689	682	680	682	704	717	700	695	716	718	721
Water Rentals and Assessments	117	125	122	111	111	112	111	113	124	127	127	127	127	127	128	128	128	129	132	131	131	131	131	132	132
Fuel and Power Purchased	143	144	142	177	193	203	212	213	217	232	240	249	266	259	273	275	287	295	284	313	325	344	360	350	319
Capital and Other Taxes	87	95	103	112	121	129	135	139	142	142	143	145	146	148	149	151	154	157	164	165	167	169	171	173	175
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	7	7	7	7	7	7	7
Total Expenses	1,673	1,746	1,835	1,944	2,064	2,217	2,402	2,459	2,865	3,039	3,067	3,102	3,131	3,142	3,148	3,146	3,151	3,165	3,247	3,314	3,309	3,351	3,458	3,483	3,488
Non-Controlling Interest	(14)	(24)	(22)	(17)	(15)	(13)	(9)	(8)	(7)	0	2	7	9	8	12	14	16	19	21	23	25	27	29	30	32
Net Income	43	97	41	(18)	(25)	(53)	(139)	(65)	(101)	(74)	24	103	182	222	240	238	238	240	242	240	238	239	243	247	250
Additional General Consumers Revenue Percent Increase	0.00%	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	-2.40%	-0.50%	-1.04%	-0.57%	1.06%	1.37%	-0.73%	1.41%	3.64%	0.32%	2.48%
Cumulative General Consumers Revenue Percent Increase	0.00%	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%	47.31%	53.13%	59.18%	55.36%	54.58%	52.98%	52.11%	53.72%	55.83%	54.69%	56.88%	62.58%	63.10%	67.14%
Debt Ratio	76	78	83	85	86	88	89	90	91	91	91	91	90	89	88	87	86	85	84	83	82	81	80	80	79
Interest Coverage Ratio	1.07	1.16	1.06	0.98	0.97	0.95	0.87	0.94	0.92	0.94	1.02	1.08	1.15	1.18	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Capital Coverage Ratio	1.04	0.97	0.84	0.85	1.13	1.28	1.00	1.44	1.30	1.34	1.38	1.50	1.68	1.87	2.14	1.86	1.72	1.65	1.60	1.89	1.60	1.40	1.35	1.31	1.25

Needs For and Alternatives To
DSM Evaluation - 2013 Electric Load Forecast
Pro Forma Financial Statements

Development Plan K19/GAS/750MW (5) - LEVEL 2 DSM - ALT. RATE METHOD 1
ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

For the year ended March 31	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**	**2055**	**2056**	**2057**	**2058**	**2059**	**2060**	**2061**	**2062**
REVENUES																									
General Consumers Revenue at approved rates	1,723	1,742	1,762	1,782	1,802	1,822	1,844	1,866	1,888	1,910	1,932	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954
Additional General Consumers Revenue	1,213	1,254	1,318	1,387	1,433	1,542	1,527	1,649	1,743	1,811	1,900	2,032	1,987	2,073	2,103	2,122	2,220	2,269	2,313	2,358	2,376	2,416	2,469	2,497	2,572
Extraprovincial	871	847	817	802	795	788	819	791	774	785	783	740	799	814	830	846	862	878	895	912	929	947	965	983	1,002
Other	23	24	24	24	25	25	26	26	27	27	28	29	29	30	30	31	31	32	33	33	34	35	35	36	37
Total Revenue	3,830	3,867	3,921	3,996	4,055	4,177	4,216	4,332	4,432	4,534	4,643	4,755	4,770	4,872	4,917	4,953	5,067	5,134	5,195	5,258	5,293	5,351	5,423	5,470	5,565
EXPENSES																									
Operating and Administrative	927	948	970	993	1,016	1,040	1,063	1,096	1,123	1,149	1,186	1,216	1,244	1,275	1,306	1,326	1,358	1,377	1,397	1,417	1,438	1,459	1,480	1,494	1,516
Finance Expense	1,225	1,221	1,217	1,231	1,230	1,229	1,227	1,235	1,230	1,258	1,251	1,255	1,247	1,218	1,191	1,194	1,179	1,169	1,157	1,138	1,114	1,093	1,076	1,044	1,049
Depreciation and Amortization	751	752	758	770	778	844	852	870	913	931	956	981	997	1,085	1,111	1,106	1,186	1,226	1,264	1,311	1,334	1,375	1,424	1,471	1,517
Water Rentals and Assessments	132	132	132	131	132	132	134	133	134	135	135	134	142	145	148	151	154	156	159	162	166	169	172	175	179
Fuel and Power Purchased	327	341	368	389	412	437	435	489	518	536	590	642	611	623	635	647	659	672	685	698	711	724	738	752	766
Capital and Other Taxes	177	179	182	185	188	192	195	198	202	207	209	212	213	213	216	219	222	224	226	228	230	232	235	237	239
Corporate Allocation	7	7	7	7	7	7	7	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Total Expenses	3,547	3,581	3,633	3,706	3,762	3,879	3,914	4,027	4,125	4,222	4,334	4,446	4,461	4,564	4,613	4,648	4,763	4,830	4,893	4,959	4,997	5,057	5,130	5,179	5,272
Non-Controlling Interest	34	36	38	40	43	46	48	49	51	54	55	55	57	58	59	60	61	62	64	66	68	70	72	74	77
Net Income	250	250	250	250	250	252	254	255	255	258	254	254	253	249	245	245	244	241	237	233	228	224	221	218	216
Additional General Consumers Revenue Percent Increase	1.93%	0.95%	1.62%	1.76%	0.95%	2.83%	-0.99%	3.03%	2.10%	1.29%	1.83%	2.84%	-1.13%	2.18%	0.73%	0.47%	2.40%	1.18%	1.03%	1.06%	0.40%	0.92%	1.22%	0.64%	1.69%
Cumulative General Consumers Revenue Percent Increase	70.36%	71.98%	74.77%	77.85%	79.55%	84.64%	82.81%	88.35%	92.31%	94.79%	98.35%	103.99%	101.69%	106.09%	107.59%	108.57%	113.59%	116.12%	118.34%	120.67%	121.56%	123.60%	126.32%	127.77%	131.61%
Debt Ratio	78	77	76	75	75	74	73	72	72	71	71	70	69	68	67	66	65	65	64	63	62	61	60	59	58
Interest Coverage Ratio	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Capital Coverage Ratio	1.23	1.19	1.13	1.07	1.07	1.16	1.22	1.18	1.07	1.31	1.34	1.36	1.37	1.33	1.35	1.32	1.36	1.38	1.37	1.38	1.38	1.37	1.38	1.38	1.39

Development Plan K19/GAS/750MW (5) - LEVEL 2 DSM - ALT. RATE METHOD 1

ELECTRIC OPERATIONS

PROJECTED BALANCE SHEET

In Millions of Dollars

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
ASSETS																									
Plant in Service	15,374	16,434	17,553	18,705	19,265	22,808	23,239	26,188	30,472	31,006	31,538	32,103	32,792	33,394	34,057	34,545	35,293	35,852	37,859	38,869	39,554	40,909	41,432	41,974	43,309
Accumulated Depreciation	(5,173)	(5,536)	(5,869)	(6,254)	(6,662)	(7,096)	(7,566)	(8,040)	(8,575)	(9,147)	(9,726)	(10,306)	(10,890)	(11,484)	(12,085)	(12,687)	(13,291)	(13,902)	(14,541)	(15,196)	(15,838)	(16,477)	(17,141)	(17,809)	(18,483)
Net Plant in Service	10,201	10,898	11,684	12,450	12,604	15,712	15,672	18,149	21,898	21,860	21,812	21,797	21,903	21,909	21,972	21,858	22,002	21,950	23,318	23,672	23,716	24,432	24,291	24,165	24,826
Construction in Progress	2,019	2,805	3,948	4,895	6,338	4,763	5,719	3,761	112	201	293	370	330	410	415	748	1,082	1,628	729	550	648	106	398	710	271
Current and Other Assets	1,869	1,740	1,388	1,573	1,792	2,014	1,847	1,982	2,059	1,731	1,794	2,056	2,250	2,175	2,583	2,625	2,742	2,725	2,838	3,127	3,023	2,917	2,838	3,034	2,879
Goodwill and Intangible Assets	180	165	153	140	130	121	187	212	408	398	388	381	373	366	359	351	344	337	330	322	315	308	301	293	286
Regulated Assets	231	233	259	293	370	399	428	436	428	410	389	368	348	329	311	302	267	237	214	194	178	165	155	148	145
Total Assets	14,500	15,841	17,433	19,352	21,233	23,010	23,854	24,540	24,905	24,599	24,676	24,972	25,205	25,190	25,641	25,884	26,437	26,878	27,428	27,866	27,879	27,928	27,983	28,351	28,407
LIABILITIES AND EQUITY																									
Long Term Debt	9,272	11,144	12,818	14,842	16,563	18,140	19,637	20,205	20,735	20,687	21,289	21,292	21,045	21,247	21,449	21,390	21,340	21,243	22,233	22,206	20,209	20,010	19,119	19,521	18,773
Current and Other Liabilities	2,183	1,647	1,926	1,844	2,096	2,377	1,881	2,083	2,041	1,884	1,350	1,537	1,832	1,390	1,397	1,460	1,822	2,117	1,433	1,656	3,426	3,432	4,132	3,849	4,400
Contributions in Aid of Construction	314	314	315	315	316	322	324	327	330	333	336	339	341	344	346	348	351	353	356	358	361	364	366	369	372
Retained Earnings	2,432	2,529	2,531	2,513	2,487	2,435	2,295	2,231	2,130	2,056	2,080	2,183	2,365	2,588	2,827	3,065	3,303	3,543	3,785	4,025	4,262	4,501	4,744	4,991	5,240
Accumulated Other Comprehensive Income	299	207	(157)	(162)	(230)	(263)	(284)	(306)	(331)	(362)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)
Total Liabilities and Equity	14,500	15,841	17,433	19,352	21,233	23,010	23,854	24,540	24,905	24,599	24,676	24,972	25,205	25,190	25,641	25,884	26,437	26,878	27,428	27,866	27,879	27,928	27,983	28,351	28,407

Development Plan K19/GAS/750MW (5) - LEVEL 2 DSM - ALT. RATE METHOD 1
ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
In Millions of Dollars

For the year ended March 31	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**	**2055**	**2056**	**2057**	**2058**	**2059**	**2060**	**2061**	**2062**
ASSETS																									
Plant in Service	43,895	44,501	45,506	46,172	48,543	49,223	49,932	51,997	53,267	54,077	55,514	56,214	58,960	60,197	61,573	62,957	64,375	65,913	67,585	68,973	70,350	71,793	73,234	74,735	76,857
Accumulated Depreciation	(19,189)	(19,900)	(20,617)	(21,347)	(22,085)	(22,891)	(23,706)	(24,539)	(25,417)	(26,314)	(27,237)	(28,186)	(29,151)	(30,203)	(31,281)	(32,365)	(33,528)	(34,729)	(35,967)	(37,248)	(38,552)	(39,894)	(41,284)	(42,718)	(44,198)
Net Plant in Service	24,705	24,601	24,889	24,826	26,458	26,331	26,226	27,458	27,850	27,764	28,277	28,028	29,810	29,994	30,292	30,592	30,847	31,183	31,618	31,724	31,798	31,899	31,950	32,017	32,659
Construction in Progress	628	1,009	1,053	1,512	275	865	1,465	574	760	1,475	1,239	1,690	139	160	168	215	304	241	26	29	31	34	222	496	(89)
Current and Other Assets	2,764	2,970	2,815	2,851	2,879	2,799	2,913	3,045	2,963	3,076	3,381	3,645	2,945	2,178	2,340	2,203	1,542	1,314	1,269	1,098	1,054	974	638	516	879
Goodwill and Intangible Assets	279	272	264	257	250	243	235	228	221	214	207	199	192	185	178	171	163	156	149	142	134	127	120	113	106
Regulated Assets	138	127	116	107	99	92	87	83	81	80	81	82	83	85	86	99	111	121	131	138	145	150	153	154	156
Total Assets	28,514	28,978	29,138	29,553	29,961	30,330	30,926	31,388	31,876	32,609	33,184	33,644	33,169	32,602	33,064	33,279	32,967	33,016	33,193	33,131	33,162	33,184	33,083	33,296	33,711
LIABILITIES AND EQUITY																									
Long Term Debt	19,375	20,277	20,229	20,979	21,078	22,027	22,225	22,424	22,622	23,220	23,419	22,892	22,090	21,890	22,439	20,639	20,038	18,838	19,237	18,429	18,629	19,303	18,902	19,502	19,652
Current and Other Liabilities	3,653	2,962	2,917	2,329	2,385	1,550	1,691	1,696	1,726	1,600	1,719	2,447	2,517	1,898	1,562	3,332	3,377	4,385	3,926	4,439	4,043	3,166	3,245	2,640	2,689
Contributions in Aid of Construction	375	378	381	384	387	390	393	396	400	403	407	410	414	418	421	421	421	421	421	421	421	421	421	421	421
Retained Earnings	5,490	5,740	5,990	6,240	6,490	6,742	6,996	7,251	7,507	7,765	8,019	8,273	8,526	8,776	9,020	9,266	9,510	9,751	9,988	10,220	10,448	10,672	10,893	11,111	11,327
Accumulated Other Comprehensive Income	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)
Total Liabilities and Equity	28,514	28,978	29,138	29,553	29,961	30,330	30,926	31,388	31,876	32,609	33,184	33,644	33,169	32,602	33,064	33,279	32,967	33,016	33,193	33,131	33,162	33,184	33,083	33,296	33,711

Needs For and Alternatives To
DSM Evaluation - 2013 Electric Load Forecast
Pro Forma Financial Statements

Development Plan K19/GAS/750MW (5) - LEVEL 2 DSM - ALT. RATE METHOD 1
ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
In Millions of Dollars

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
OPERATING ACTIVITIES																									
Cash Receipts from Customers	1,692	1,819	1,854	1,909	2,023	2,152	2,254	2,386	2,758	2,965	3,093	3,212	3,322	3,373	3,399	3,398	3,405	3,425	3,511	3,577	3,571	3,616	3,730	3,760	3,770
Cash Paid to Suppliers and Employees	(782)	(810)	(857)	(904)	(939)	(980)	(1,005)	(1,027)	(1,104)	(1,133)	(1,154)	(1,174)	(1,202)	(1,208)	(1,236)	(1,251)	(1,278)	(1,299)	(1,307)	(1,354)	(1,381)	(1,415)	(1,446)	(1,452)	(1,437)
Interest Paid	(467)	(483)	(527)	(570)	(633)	(733)	(867)	(877)	(1,146)	(1,255)	(1,229)	(1,229)	(1,227)	(1,227)	(1,207)	(1,213)	(1,198)	(1,184)	(1,247)	(1,222)	(1,221)	(1,217)	(1,278)	(1,285)	(1,313)
Interest Received	28	17	24	25	30	37	40	38	35	32	18	18	26	30	40	52	65	69	76	51	64	57	71	68	74
Cash from Operating Activities	471	542	495	461	481	475	422	521	542	610	728	827	919	968	996	987	994	1,011	1,033	1,051	1,033	1,042	1,077	1,091	1,094
FINANCING ACTIVITIES																									
Proceeds from Long Term Debt	836	1,970	1,960	2,390	2,180	2,390	1,780	1,190	1,190	390	560	(10)	190	180	190	(10)	190	560	990	190	(40)	1,730	1,720	2,780	2,110
Sinking Fund Withdrawals	129	410	103	22	-	20	412	187	267	670	155	-	-	334	-	-	60	250	700	13	230	200	200	147	340
Retirement of Long Term Debt	(119)	(825)	(177)	(312)	(347)	(530)	(825)	(305)	(633)	(673)	(431)	-	-	(450)	-	-	(60)	(220)	(700)	(13)	(200)	(1,950)	(1,930)	(2,682)	(2,330)
Other Financing Activities	(42)	(7)	(20)	(22)	(20)	(17)	(28)	(17)	(39)	(14)	(5)	(5)	(5)	(5)	(5)	(4)	(3)	(3)	(2)	(21)	(21)	(22)	(22)	(23)	(20)
Cash from Financing Activities	804	1,548	1,866	2,078	1,813	1,863	1,339	1,056	786	373	279	(15)	185	58	185	(14)	187	587	988	169	(31)	(42)	(32)	222	100
INVESTING ACTIVITIES																									
Property Plant and Equipment net of contributions	(1,311)	(1,964)	(2,279)	(2,189)	(2,132)	(2,050)	(1,547)	(1,190)	(1,019)	(673)	(672)	(692)	(702)	(732)	(719)	(872)	(1,104)	(1,128)	(1,129)	(853)	(805)	(837)	(838)	(877)	(920)
Sinking Fund Payment	(107)	(218)	(121)	(184)	(169)	(225)	(220)	(222)	(246)	(339)	(220)	(225)	(235)	(245)	(238)	(250)	(260)	(271)	(274)	(260)	(271)	(270)	(272)	(273)	(278)
Other Investing Activities	(17)	(16)	(21)	(20)	(32)	(42)	(28)	(28)	(33)	(38)	(29)	(32)	(25)	(25)	(28)	(26)	(26)	(26)	(26)	(26)	(27)	(27)	(27)	(27)	(27)
Cash from Investing Activities	(1,436)	(2,198)	(2,422)	(2,394)	(2,334)	(2,317)	(1,795)	(1,441)	(1,298)	(1,050)	(921)	(949)	(962)	(1,002)	(985)	(1,148)	(1,390)	(1,425)	(1,429)	(1,140)	(1,102)	(1,133)	(1,137)	(1,178)	(1,225)
Net Increase (Decrease) in Cash	(160)	(108)	(61)	145	(40)	22	(34)	136	30	(67)	86	(136)	143	24	196	(175)	(209)	173	592	81	(100)	(133)	(92)	135	(31)
Cash at Beginning of Year	43	(118)	(225)	(286)	(141)	(181)	(159)	(193)	(57)	(27)	(94)	(8)	(144)	(1)	22	218	43	(166)	7	599	680	579	446	355	490
Cash at End of Year	(118)	(225)	(286)	(141)	(181)	(159)	(193)	(57)	(27)	(94)	(8)	(144)	(1)	22	218	43	(166)	7	599	680	579	446	355	490	458

Development Plan K19/GAS/750MW (5) - LEVEL 2 DSM - ALT. RATE METHOD 1

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
In Millions of Dollars

For the year ended March 31	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**
OPERATING ACTIVITIES												
Cash Receipts from Customers	3,830	3,867	3,921	3,996	4,055	4,177	4,216	4,332	4,432	4,534	4,643	4,755
Cash Paid to Suppliers and Employees	(1,463)	(1,495)	(1,540)	(1,580)	(1,623)	(1,668)	(1,688)	(1,769)	(1,821)	(1,863)	(1,947)	(2,021)
Interest Paid	(1,313)	(1,310)	(1,317)	(1,329)	(1,343)	(1,339)	(1,349)	(1,371)	(1,378)	(1,414)	(1,424)	(1,439)
Interest Received	79	85	95	99	106	113	121	130	142	155	174	180
Cash from Operating Activities	1,133	1,148	1,160	1,185	1,195	1,283	1,299	1,321	1,375	1,412	1,446	1,475
FINANCING ACTIVITIES												
Proceeds from Long Term Debt	2,750	2,360	1,350	1,570	980	920	370	370	360	560	370	370
Sinking Fund Withdrawals	161	100	226	162	163	164	50	100	100	100	-	100
Retirement of Long Term Debt	(2,910)	(2,180)	(1,460)	(1,440)	(840)	(840)	(40)	(190)	(180)	(190)	10	(190)
Other Financing Activities	(21)	(21)	(22)	(23)	(32)	(33)	(54)	(34)	(35)	(39)	(35)	(36)
Cash from Financing Activities	(19)	259	93	268	271	211	326	246	245	431	345	244
INVESTING ACTIVITIES												
Property Plant and Equipment net of contributions	(960)	(998)	(1,060)	(1,136)	(1,143)	(1,280)	(1,320)	(1,185)	(1,467)	(1,537)	(1,212)	(1,163)
Sinking Fund Payment	(274)	(278)	(286)	(288)	(294)	(301)	(308)	(322)	(332)	(345)	(192)	(202)
Other Investing Activities	(28)	(28)	(28)	(28)	(28)	(29)	(29)	(29)	(29)	(30)	(30)	(30)
Cash from Investing Activities	(1,261)	(1,303)	(1,373)	(1,452)	(1,466)	(1,609)	(1,657)	(1,536)	(1,829)	(1,911)	(1,434)	(1,395)
Net Increase (Decrease) in Cash	(147)	104	(120)	2	1	(115)	(32)	32	(208)	(69)	357	324
Cash at Beginning of Year	458	311	415	295	297	298	183	151	183	(25)	(94)	264
Cash at End of Year	311	415	295	297	298	183	151	183	(25)	(94)	264	588

For the year ended March 31	**2050**	**2051**	**2052**	**2053**	**2054**	**2055**	**2056**	**2057**	**2058**	**2059**	**2060**	**2061**	**2062**
OPERATING ACTIVITIES													
Cash Receipts from Customers	4,770	4,872	4,917	4,953	5,067	5,134	5,195	5,258	5,293	5,351	5,423	5,470	5,565
Cash Paid to Suppliers and Employees	(2,018)	(2,052)	(2,090)	(2,128)	(2,165)	(2,202)	(2,240)	(2,278)	(2,317)	(2,356)	(2,397)	(2,431)	(2,473)
Interest Paid	(1,440)	(1,396)	(1,349)	(1,366)	(1,351)	(1,319)	(1,317)	(1,288)	(1,257)	(1,253)	(1,231)	(1,204)	(1,202)
Interest Received	180	159	161	169	167	159	157	157	157	160	161	157	166
Cash from Operating Activities	1,492	1,583	1,639	1,628	1,718	1,771	1,795	1,850	1,876	1,901	1,956	1,993	2,056
FINANCING ACTIVITIES													
Proceeds from Long Term Debt	130	(30)	560	(60)	1,110	1,490	2,560	1,880	2,530	2,130	1,130	1,550	1,150
Sinking Fund Withdrawals	625	300	-	50	542	198	-	186	207	167	298	-	344
Retirement of Long Term Debt	(885)	(990)	(190)	(10)	(1,730)	(1,720)	(2,780)	(2,110)	(2,757)	(2,360)	(1,475)	(1,570)	(980)
Other Financing Activities	(36)	(37)	(38)	(39)	(39)	(40)	(41)	(42)	(76)	(84)	(86)	(88)	(104)
Cash from Financing Activities	(166)	(757)	332	(59)	(117)	(73)	(261)	(86)	(96)	(146)	(133)	(108)	410
INVESTING ACTIVITIES													
Property Plant and Equipment net of contributions	(1,207)	(1,271)	(1,396)	(1,443)	(1,520)	(1,488)	(1,471)	(1,404)	(1,394)	(1,460)	(1,643)	(1,789)	(1,552)
Sinking Fund Payment	(208)	(186)	(176)	(187)	(192)	(173)	(170)	(177)	(174)	(170)	(168)	(161)	(169)
Other Investing Activities	(30)	(31)	(30)	(15)	(15)	(14)	(14)	(13)	(37)	(37)	(37)	(38)	(38)
Cash from Investing Activities	(1,446)	(1,488)	(1,603)	(1,645)	(1,726)	(1,675)	(1,655)	(1,594)	(1,605)	(1,667)	(1,849)	(1,987)	(1,759)
Net Increase (Decrease) in Cash	(120)	(662)	369	(76)	(126)	24	(120)	169	176	89	(26)	(103)	707
Cash at Beginning of Year	588	468	(194)	175	99	(27)	(3)	(124)	45	221	309	284	181
Cash at End of Year	468	(194)	175	99	(27)	(3)	(124)	45	221	309	284	181	888

Development Plan K19/GAS/750MW (5) - LEVEL 2 DSM - ALT. RATE METHOD 2
ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
REVENUES																									
General Consumers Revenue at approved rates	1,331	1,396	1,401	1,408	1,404	1,409	1,413	1,426	1,440	1,455	1,470	1,486	1,501	1,517	1,532	1,548	1,566	1,583	1,601	1,618	1,636	1,649	1,668	1,686	1,704
Additional General Consumers Revenue	-	-	55	123	193	267	345	430	520	617	706	801	811	864	791	787	773	770	808	853	846	888	992	1,014	1,096
Extraprovincial	357	408	383	373	430	491	522	571	853	964	993	1,005	1,005	939	1,000	987	991	996	1,030	1,035	1,020	1,008	998	988	899
Other	14	15	15	15	15	16	16	16	17	17	17	18	18	18	19	19	19	20	20	21	21	21	22	22	23
Total Revenue	1,702	1,819	1,854	1,918	2,043	2,183	2,297	2,443	2,830	3,054	3,186	3,309	3,335	3,338	3,342	3,340	3,349	3,369	3,458	3,527	3,523	3,566	3,679	3,710	3,721
EXPENSES																									
Operating and Administrative	455	471	516	532	543	567	580	597	659	671	685	697	711	724	738	752	768	780	793	815	832	852	870	887	907
Finance Expense	454	462	511	542	610	690	808	827	1,079	1,174	1,164	1,166	1,157	1,145	1,115	1,101	1,079	1,069	1,119	1,125	1,107	1,112	1,161	1,175	1,187
Depreciation and Amortization	408	439	433	463	476	505	543	553	622	662	670	671	675	684	689	682	680	682	704	717	700	695	716	718	721
Water Rentals and Assessments	117	125	122	111	111	112	111	113	124	127	127	127	127	127	128	128	128	129	132	131	131	131	131	132	132
Fuel and Power Purchased	143	144	142	177	193	203	212	213	217	232	240	249	266	259	273	275	287	295	284	313	325	344	360	350	319
Capital and Other Taxes	87	95	103	112	121	129	135	139	142	143	143	145	146	148	149	151	154	157	164	165	167	169	171	173	175
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	7	7	7	7	7	7	7
Total Expenses	1,673	1,746	1,835	1,944	2,062	2,215	2,398	2,450	2,850	3,017	3,038	3,064	3,089	3,095	3,100	3,098	3,104	3,119	3,203	3,272	3,268	3,309	3,415	3,441	3,448
Non-Controlling Interest	(14)	(24)	(22)	(17)	(15)	(13)	(9)	(8)	(7)	0	2	7	9	8	12	14	16	19	21	23	25	27	29	30	32
Net Income	43	97	41	(9)	(4)	(19)	(92)	1	(13)	36	146	239	237	235	230	228	228	231	233	231	229	230	235	238	241
Additional General Consumers Revenue Percent Increase	0.00%	0.00%	3.95%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	3.95%	3.95%	0.08%	1.90%	-3.39%	-0.52%	-0.95%	-0.51%	1.23%	1.52%	-0.66%	1.39%	3.69%	0.40%	2.58%
Cumulative General Consumers Revenue Percent Increase	0.00%	0.00%	3.95%	8.73%	13.73%	18.96%	24.43%	30.16%	36.14%	42.40%	48.03%	53.88%	54.00%	56.92%	51.60%	50.82%	49.38%	48.61%	50.44%	52.73%	51.72%	53.84%	59.52%	60.15%	64.29%
Debt Ratio	76	78	83	85	86	88	89	89	89	89	89	88	87	86	85	84	83	82	82	81	80	79	78	77	76
Interest Coverage Ratio	1.07	1.16	1.06	0.99	1.00	0.98	0.92	1.00	0.99	1.03	1.12	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Capital Coverage Ratio	1.04	0.97	0.84	0.87	1.17	1.37	1.12	1.62	1.50	1.57	1.61	1.75	1.78	1.89	2.12	1.84	1.71	1.63	1.59	1.88	1.58	1.39	1.33	1.29	1.24

Needs For and Alternatives To
DSM Evaluation - 2013 Electric Load Forecast
Pro Forma Financial Statements

Development Plan K19/GAS/750MW (5) - LEVEL 2 DSM - ALT. RATE METHOD 2

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

For the year ended March 31	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062
REVENUES																									
General Consumers Revenue at approved rates	1,723	1,742	1,762	1,782	1,802	1,822	1,844	1,866	1,888	1,910	1,932	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954
Additional General Consumers Revenue	1,165	1,208	1,271	1,342	1,388	1,498	1,483	1,609	1,703	1,772	1,862	1,990	1,944	2,033	2,062	2,082	2,183	2,231	2,279	2,321	2,343	2,383	2,438	2,466	2,536
Extraprovincial	871	847	817	802	795	788	819	791	774	785	783	740	799	814	830	846	862	878	895	912	929	947	965	983	1,002
Other	23	24	24	24	25	25	26	26	27	27	28	29	29	30	30	31	31	32	33	33	34	35	35	36	37
Total Revenue	3,783	3,821	3,874	3,950	4,010	4,133	4,172	4,293	4,393	4,495	4,605	4,713	4,727	4,832	4,876	4,913	5,031	5,096	5,161	5,221	5,261	5,319	5,393	5,439	5,529
EXPENSES																									
Operating and Administrative	927	948	970	993	1,016	1,040	1,063	1,096	1,123	1,149	1,186	1,216	1,244	1,275	1,306	1,326	1,358	1,377	1,397	1,417	1,438	1,459	1,480	1,494	1,516
Finance Expense	1,185	1,183	1,177	1,192	1,192	1,192	1,191	1,202	1,197	1,226	1,219	1,219	1,211	1,184	1,157	1,161	1,148	1,136	1,129	1,107	1,086	1,066	1,050	1,018	1,019
Depreciation and Amortization	751	752	758	770	778	844	852	870	913	931	956	981	997	1,085	1,111	1,106	1,186	1,226	1,264	1,311	1,334	1,375	1,424	1,471	1,517
Water Rentals and Assessments	132	132	132	131	132	132	134	133	134	135	135	134	142	145	148	151	154	156	159	162	166	169	172	175	179
Fuel and Power Purchased	327	341	368	389	412	437	435	489	518	536	590	642	611	623	635	647	659	672	685	698	711	724	738	752	766
Capital and Other Taxes	177	180	182	185	188	192	196	198	202	207	209	212	213	214	216	219	222	225	226	228	230	232	235	237	239
Corporate Allocation	7	7	7	7	7	7	7	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Total Expenses	3,507	3,543	3,594	3,668	3,725	3,843	3,878	3,995	4,092	4,190	4,302	4,411	4,425	4,531	4,579	4,614	4,732	4,799	4,865	4,928	4,970	5,030	5,104	5,153	5,242
Non-Controlling Interest	34	36	38	40	43	46	48	49	51	54	55	55	57	58	59	60	61	62	64	66	68	70	72	74	77
Net Income	242	242	242	242	243	244	247	248	249	251	248	247	246	243	238	239	238	235	231	226	222	218	216	213	210
Additional General Consumers Revenue Percent Increase	2.02%	1.02%	1.64%	1.85%	0.99%	2.93%	-0.97%	3.21%	2.13%	1.33%	1.87%	2.80%	-1.17%	2.29%	0.71%	0.50%	2.50%	1.16%	1.15%	0.99%	0.51%	0.92%	1.28%	0.63%	1.58%
Cumulative General Consumers Revenue Percent Increase	67.61%	69.32%	72.10%	75.29%	77.03%	82.21%	80.45%	86.25%	90.22%	92.75%	96.35%	101.84%	99.48%	104.05%	105.50%	106.54%	111.71%	114.16%	116.62%	118.77%	119.89%	121.92%	124.75%	126.18%	129.76%
Debt Ratio	75	74	74	73	72	72	71	70	70	69	69	68	67	66	65	64	64	63	62	61	60	59	58	58	57
Interest Coverage Ratio	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Capital Coverage Ratio	1.22	1.18	1.12	1.07	1.07	1.15	1.21	1.18	1.07	1.30	1.33	1.35	1.37	1.32	1.34	1.32	1.36	1.38	1.36	1.38	1.37	1.36	1.37	1.37	1.38

Development Plan K19/GAS/750MW (5) - LEVEL 2 DSM - ALT. RATE METHOD 2
ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
In Millions of Dollars

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
ASSETS																									
Plant in Service	15,374	16,434	17,553	18,705	19,265	22,808	23,239	26,188	30,472	31,006	31,538	32,103	32,792	33,394	34,057	34,545	35,293	35,852	37,859	38,869	39,554	40,909	41,432	41,974	43,309
Accumulated Depreciation	(5,173)	(5,536)	(5,869)	(6,254)	(6,662)	(7,096)	(7,566)	(8,040)	(8,575)	(9,147)	(9,726)	(10,306)	(10,890)	(11,484)	(12,085)	(12,687)	(13,291)	(13,902)	(14,541)	(15,196)	(15,838)	(16,477)	(17,141)	(17,809)	(18,483)
Net Plant in Service	10,201	10,898	11,684	12,450	12,604	15,712	15,672	18,149	21,898	21,860	21,812	21,797	21,903	21,909	21,972	21,858	22,002	21,950	23,318	23,672	23,716	24,432	24,291	24,165	24,826
Construction in Progress	2,019	2,805	3,948	4,895	6,338	4,763	5,719	3,761	112	201	293	370	330	410	415	748	1,082	1,628	729	550	648	106	398	710	271
Current and Other Assets	1,869	1,740	1,388	1,573	1,791	2,014	1,847	1,981	2,059	1,731	1,790	2,046	2,325	2,146	2,458	2,560	2,712	2,680	2,872	3,153	3,040	2,925	2,831	3,012	2,846
Goodwill and Intangible Assets	180	165	153	140	130	121	187	212	408	398	388	381	373	366	359	351	344	337	330	322	315	308	301	293	286
Regulated Assets	231	233	259	293	370	399	428	436	428	410	389	368	348	329	311	302	267	237	214	194	178	165	155	148	145
Total Assets	14,500	15,841	17,433	19,352	21,233	23,010	23,853	24,539	24,905	24,599	24,672	24,962	25,280	25,161	25,515	25,819	26,407	26,833	27,461	27,891	27,896	27,936	27,975	28,328	28,374
LIABILITIES AND EQUITY																									
Long Term Debt	9,272	11,144	12,818	14,842	16,563	18,140	19,637	20,005	20,335	20,287	20,689	20,692	20,445	20,447	20,649	20,590	20,740	20,443	21,633	21,606	19,609	19,410	18,519	18,921	18,173
Current and Other Liabilities	2,183	1,647	1,926	1,834	2,065	2,313	1,769	2,104	2,176	1,910	1,450	1,495	1,820	1,461	1,381	1,514	1,721	2,210	1,413	1,636	3,406	3,412	4,104	3,814	4,364
Contributions in Aid of Construction	314	314	315	315	316	322	324	327	330	333	336	339	341	344	346	348	351	353	356	358	361	364	366	369	372
Retained Earnings	2,432	2,529	2,531	2,522	2,518	2,499	2,407	2,408	2,395	2,431	2,577	2,816	3,053	3,288	3,518	3,746	3,974	4,205	4,438	4,670	4,899	5,129	5,364	5,602	5,844
Accumulated Other Comprehensive Income	299	207	(157)	(162)	(230)	(263)	(284)	(306)	(331)	(362)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)
Total Liabilities and Equity	14,500	15,841	17,433	19,352	21,233	23,010	23,853	24,539	24,905	24,599	24,672	24,962	25,280	25,161	25,515	25,819	26,407	26,833	27,461	27,891	27,896	27,936	27,975	28,328	28,374

Development Plan K19/GAS/750MW (5) - LEVEL 2 DSM - ALT. RATE METHOD 2
ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
In Millions of Dollars

For the year ended March 31	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
ASSETS													
Plant in Service	43,895	44,501	45,506	46,172	48,543	49,223	49,932	51,997	53,267	54,077	55,514	56,214	58,960
Accumulated Depreciation	(19,189)	(19,900)	(20,617)	(21,347)	(22,085)	(22,891)	(23,706)	(24,539)	(25,417)	(26,314)	(27,237)	(28,186)	(29,151)
Net Plant in Service	24,705	24,601	24,889	24,826	26,458	26,331	26,226	27,458	27,850	27,764	28,277	28,028	29,810
Construction in Progress	628	1,009	1,053	1,512	275	865	1,465	574	760	1,475	1,239	1,690	139
Current and Other Assets	2,923	2,917	2,753	2,781	2,807	2,914	3,017	3,142	3,048	3,160	3,458	3,311	3,013
Goodwill and Intangible Assets	279	272	264	257	250	243	235	228	221	214	207	199	192
Regulated Assets	138	127	116	107	99	92	87	83	81	80	81	82	83
Total Assets	28,673	28,926	29,076	29,483	29,888	30,445	31,030	31,486	31,961	32,694	33,262	33,310	33,237
LIABILITIES AND EQUITY													
Long Term Debt	18,975	19,877	19,829	20,379	20,678	21,627	21,825	22,224	22,222	22,820	22,819	22,292	21,490
Current and Other Liabilities	3,616	2,722	2,675	2,287	2,147	1,508	1,644	1,449	1,674	1,554	1,872	2,196	2,676
Contributions in Aid of Construction	375	378	381	384	387	390	393	396	400	403	407	410	414
Retained Earnings	6,086	6,328	6,570	6,812	7,055	7,299	7,546	7,795	8,044	8,295	8,543	8,790	9,036
Accumulated Other Comprehensive Income	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)
Total Liabilities and Equity	28,673	28,926	29,076	29,483	29,888	30,445	31,030	31,486	31,961	32,694	33,262	33,310	33,237

For the year ended March 31	**2051**	**2052**	**2053**	**2054**	**2055**	**2056**	**2057**	**2058**	**2059**	**2060**	**2061**	**2062**
ASSETS												
Plant in Service	60,197	61,573	62,957	64,375	65,913	67,585	68,973	70,350	71,793	73,234	74,735	76,857
Accumulated Depreciation	(30,203)	(31,281)	(32,365)	(33,528)	(34,729)	(35,967)	(37,248)	(38,552)	(39,894)	(41,284)	(42,718)	(44,198)
Net Plant in Service	29,994	30,292	30,592	30,847	31,183	31,618	31,724	31,798	31,899	31,950	32,017	32,659
Construction in Progress	160	168	215	304	241	26	29	31	34	222	496	(89)
Current and Other Assets	2,251	2,237	2,250	1,502	1,549	1,223	1,327	1,075	1,190	843	512	664
Goodwill and Intangible Assets	185	178	171	163	156	149	142	134	127	120	113	106
Regulated Assets	85	86	99	111	121	131	138	145	150	153	154	156
Total Assets	32,675	32,961	33,326	32,927	33,252	33,147	33,359	33,184	33,400	33,289	33,292	33,495
LIABILITIES AND EQUITY												
Long Term Debt	21,490	21,839	20,239	19,438	18,638	18,837	18,029	18,429	19,303	18,902	19,102	19,052
Current and Other Liabilities	1,868	1,563	3,290	3,454	4,344	3,808	4,602	3,805	2,928	3,002	2,592	2,636
Contributions in Aid of Construction	418	421	421	421	421	421	421	421	421	421	421	421
Retained Earnings	9,279	9,517	9,755	9,993	10,228	10,459	10,685	10,908	11,126	11,342	11,555	11,765
Accumulated Other Comprehensive Income	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)
Total Liabilities and Equity	32,675	32,961	33,326	32,927	33,252	33,147	33,359	33,184	33,400	33,289	33,292	33,495

Development Plan K19/GAS/750MW (5) - LEVEL 2 DSM - ALT. RATE METHOD 2
ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
In Millions of Dollars

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
OPERATING ACTIVITIES													
Cash Receipts from Customers	1,692	1,819	1,854	1,918	2,043	2,183	2,297	2,443	2,830	3,054	3,186	3,309	3,335
Cash Paid to Suppliers and Employees	(782)	(810)	(857)	(904)	(939)	(980)	(1,005)	(1,027)	(1,104)	(1,133)	(1,154)	(1,174)	(1,202)
Interest Paid	(467)	(483)	(527)	(570)	(633)	(733)	(858)	(870)	(1,136)	(1,238)	(1,200)	(1,191)	(1,184)
Interest Received	28	17	24	25	30	37	40	38	35	32	18	18	26
Cash from Operating Activities	471	542	495	470	501	507	473	585	625	715	850	963	975
FINANCING ACTIVITIES													
Proceeds from Long Term Debt	836	1,970	1,960	2,390	2,180	2,390	1,780	990	990	390	360	(10)	190
Sinking Fund Withdrawals	129	410	103	22	-	20	412	187	266	670	155	-	-
Retirement of Long Term Debt	(119)	(825)	(177)	(312)	(347)	(530)	(825)	(305)	(633)	(673)	(431)	-	-
Other Financing Activities	(42)	(7)	(20)	(22)	(20)	(17)	(28)	(17)	(39)	(14)	(5)	(5)	(5)
Cash from Financing Activities	804	1,548	1,866	2,078	1,813	1,863	1,339	855	584	373	79	(15)	185
INVESTING ACTIVITIES													
Property Plant and Equipment net of contributions	(1,311)	(1,964)	(2,279)	(2,189)	(2,132)	(2,050)	(1,547)	(1,190)	(1,019)	(673)	(672)	(692)	(702)
Sinking Fund Payment	(107)	(218)	(121)	(184)	(169)	(225)	(219)	(221)	(246)	(339)	(217)	(218)	(228)
Other Investing Activities	(17)	(16)	(21)	(20)	(32)	(42)	(28)	(28)	(33)	(38)	(29)	(32)	(25)
Cash from Investing Activities	(1,436)	(2,198)	(2,422)	(2,394)	(2,334)	(2,317)	(1,794)	(1,439)	(1,298)	(1,050)	(917)	(943)	(955)
Net Increase (Decrease) in Cash	(160)	(108)	(61)	155	(20)	53	18	0	(88)	38	12	6	205
Cash at Beginning of Year	43	(118)	(225)	(286)	(132)	(152)	(98)	(80)	(80)	(168)	(130)	(119)	(113)
Cash at End of Year	(118)	(225)	(286)	(132)	(152)	(98)	(80)	(80)	(168)	(130)	(119)	(113)	92

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
OPERATING ACTIVITIES												
Cash Receipts from Customers	3,338	3,342	3,340	3,349	3,369	3,458	3,527	3,523	3,566	3,679	3,710	3,721
Cash Paid to Suppliers and Employees	(1,208)	(1,236)	(1,251)	(1,278)	(1,299)	(1,307)	(1,354)	(1,381)	(1,415)	(1,446)	(1,452)	(1,437)
Interest Paid	(1,185)	(1,159)	(1,164)	(1,150)	(1,141)	(1,200)	(1,177)	(1,178)	(1,183)	(1,239)	(1,250)	(1,274)
Interest Received	30	40	52	64	67	74	48	61	64	67	67	74
Cash from Operating Activities	975	987	977	984	997	1,025	1,043	1,025	1,033	1,061	1,076	1,084
FINANCING ACTIVITIES												
Proceeds from Long Term Debt	(20)	190	(10)	390	360	1,190	190	(40)	1,730	1,720	2,780	2,110
Sinking Fund Withdrawals	317	-	-	60	250	700	13	230	200	200	66	324
Retirement of Long Term Debt	(450)	-	-	(60)	(220)	(700)	(13)	(200)	(1,950)	(1,930)	(2,682)	(2,330)
Other Financing Activities	(5)	(5)	(4)	(3)	(3)	(2)	(21)	(21)	(22)	(22)	(23)	(20)
Cash from Financing Activities	(158)	185	(14)	387	387	1,188	169	(31)	(42)	(32)	140	84
INVESTING ACTIVITIES												
Property Plant and Equipment net of contributions	(732)	(719)	(872)	(1,104)	(1,128)	(1,129)	(853)	(805)	(837)	(838)	(877)	(920)
Sinking Fund Payment	(239)	(231)	(241)	(252)	(263)	(266)	(251)	(262)	(261)	(262)	(263)	(272)
Other Investing Activities	(25)	(28)	(26)	(26)	(26)	(26)	(26)	(27)	(27)	(27)	(27)	(27)
Cash from Investing Activities	(996)	(978)	(1,139)	(1,382)	(1,417)	(1,420)	(1,131)	(1,094)	(1,125)	(1,127)	(1,168)	(1,219)
Net Increase (Decrease) in Cash	(179)	193	(176)	(10)	(33)	792	81	(100)	(134)	(98)	48	(51)
Cash at Beginning of Year	92	(87)	106	(70)	(80)	(113)	679	761	660	527	429	477
Cash at End of Year	(87)	106	(70)	(80)	(113)	679	761	660	527	429	477	426

Development Plan K19/GAS/750MW (5) - LEVEL 2 DSM - ALT. RATE METHOD 2
ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
In Millions of Dollars

For the year ended March 31	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
OPERATING ACTIVITIES													
Cash Receipts from Customers	3,783	3,821	3,874	3,950	4,010	4,133	4,172	4,293	4,393	4,495	4,605	4,713	4,727
Cash Paid to Suppliers and Employees	(1,463)	(1,495)	(1,540)	(1,580)	(1,623)	(1,668)	(1,689)	(1,769)	(1,821)	(1,863)	(1,947)	(2,021)	(2,018)
Interest Paid	(1,273)	(1,275)	(1,279)	(1,290)	(1,300)	(1,306)	(1,317)	(1,338)	(1,350)	(1,387)	(1,397)	(1,413)	(1,399)
Interest Received	79	85	95	99	106	113	121	130	147	160	179	184	184
Cash from Operating Activities	1,125	1,136	1,150	1,178	1,193	1,271	1,288	1,315	1,369	1,405	1,440	1,463	1,494
FINANCING ACTIVITIES													
Proceeds from Long Term Debt	2,950	2,160	1,150	1,370	980	920	370	370	160	560	370	170	330
Sinking Fund Withdrawals	156	100	214	156	158	159	50	100	-	100	-	200	525
Retirement of Long Term Debt	(2,910)	(2,180)	(1,260)	(1,240)	(840)	(640)	(40)	(190)	20	(190)	10	(390)	(685)
Other Financing Activities	(21)	(21)	(22)	(23)	(32)	(33)	(54)	(34)	(35)	(39)	(35)	(36)	(36)
Cash from Financing Activities	175	59	82	263	266	406	326	246	145	431	345	(56)	134
INVESTING ACTIVITIES													
Property Plant and Equipment net of contributions	(960)	(998)	(1,060)	(1,136)	(1,143)	(1,280)	(1,320)	(1,185)	(1,467)	(1,537)	(1,212)	(1,163)	(1,207)
Sinking Fund Payment	(268)	(272)	(280)	(283)	(289)	(295)	(303)	(316)	(327)	(344)	(191)	(201)	(200)
Other Investing Activities	(28)	(28)	(28)	(28)	(28)	(29)	(29)	(29)	(29)	(30)	(30)	(30)	(30)
Cash from Investing Activities	(1,256)	(1,298)	(1,367)	(1,446)	(1,461)	(1,604)	(1,652)	(1,531)	(1,824)	(1,911)	(1,433)	(1,394)	(1,437)
Net Increase (Decrease) in Cash	45	(102)	(135)	(6)	(2)	73	(38)	30	(309)	(75)	351	13	191
Cash at Beginning of Year	426	471	368	233	227	225	298	260	290	(19)	(94)	258	271
Cash at End of Year	471	368	233	227	225	298	260	290	(19)	(94)	258	271	462

For the year ended March 31	**2051**	**2052**	**2053**	**2054**	**2055**	**2056**	**2057**	**2058**	**2059**	**2060**	**2061**	**2062**
OPERATING ACTIVITIES												
Cash Receipts from Customers	4,832	4,876	4,913	5,031	5,096	5,161	5,221	5,261	5,319	5,393	5,439	5,529
Cash Paid to Suppliers and Employees	(2,052)	(2,090)	(2,128)	(2,165)	(2,203)	(2,240)	(2,278)	(2,317)	(2,357)	(2,398)	(2,431)	(2,474)
Interest Paid	(1,367)	(1,323)	(1,333)	(1,319)	(1,281)	(1,290)	(1,261)	(1,240)	(1,238)	(1,214)	(1,183)	(1,174)
Interest Received	163	165	173	166	156	157	164	165	172	164	157	164
Cash from Operating Activities	1,576	1,628	1,626	1,713	1,768	1,789	1,846	1,869	1,896	1,945	1,983	2,045
FINANCING ACTIVITIES												
Proceeds from Long Term Debt	170	360	140	910	1,890	2,360	2,080	2,530	2,130	930	1,150	950
Sinking Fund Withdrawals	300	-	50	651	-	200	-	207	-	471	198	-
Retirement of Long Term Debt	(1,190)	(190)	(10)	(1,730)	(1,720)	(2,780)	(2,110)	(2,957)	(2,160)	(1,275)	(1,370)	(980)
Other Financing Activities	(37)	(38)	(39)	(39)	(40)	(41)	(42)	(76)	(84)	(86)	(88)	(104)
Cash from Financing Activities	(757)	132	141	(209)	130	(261)	(72)	(296)	(114)	40	(110)	(134)
INVESTING ACTIVITIES												
Property Plant and Equipment net of contributions	(1,271)	(1,396)	(1,443)	(1,520)	(1,488)	(1,471)	(1,404)	(1,394)	(1,460)	(1,643)	(1,789)	(1,552)
Sinking Fund Payment	(185)	(175)	(184)	(191)	(166)	(174)	(171)	(176)	(173)	(179)	(164)	(162)
Other Investing Activities	(31)	(30)	(15)	(15)	(14)	(14)	(13)	(37)	(37)	(37)	(38)	(38)
Cash from Investing Activities	(1,487)	(1,602)	(1,642)	(1,725)	(1,668)	(1,658)	(1,588)	(1,607)	(1,669)	(1,860)	(1,991)	(1,752)
Net Increase (Decrease) in Cash	(668)	158	125	(221)	230	(130)	186	(34)	113	126	(118)	159
Cash at Beginning of Year	462	(207)	(48)	76	(145)	85	(45)	141	106	220	345	227
Cash at End of Year	(207)	(48)	76	(145)	85	(45)	141	106	220	345	227	386

TAB 3

CURTAILABLE RATE PROGRAM OPTIONS
AS OF APRIL 1, 2014
UNLESS SUPERCEDED BY FURTHER ORDER OF THE PUB

Discount to Demand Charge Expressed as Percentage of Reference Discount per kW/month.

OPTIONS	TERMS AND CONDITIONS					
	Minimum Notice to Curtail	Maximum Duration Per Curtailment	Maximum Daily Hours of Curtailment	Maximum Number Curtailments Per Year	Maximum Annual Hours of Curtailment	Discount as Percentage of Reference Discount
A	5 minutes	4-1/4 Hours	6 Hours (Oct 1 - Apr 30) 10 Hours (May 1 - Sep 30)	15 Curtailments	63.75 Hours	70%
C*	1 Hour	4 Hours	8 Hours	15 Curtailments	60.00 Hours	40%
E	48 Hours	10 Days	24 Hours	3 Curtailments	720.00 Hours	35%
R	5 minutes	4-1/4 Hours	10 Hours (Apr 1 – Mar 31)	25 Curtailments	106.25 Hours	70% + Reserve Discount
A & E	Combination	Combination	Combination	18 Curtailments	783.75 Hours	100%
C & E*	Combination	Combination	Combination	18 Curtailments	780.00 Hours	70%
R & E	Combination	Combination	Combination	28 Curtailments	826.25 Hours	100% + Reserve Discount

* Options 'C' and 'CE' will no longer be available as of the sunset date.

The Monthly Reference Discount shall equal A, and shall be adjusted on April 1st of each fiscal year by the annual inflation factor, where:

A = the amount of the Reference Discount which is related to the marginal value of capacity, expressed in Canadian Dollars. The Reference Discount of $3.36 per kW/month as of April 1, 2014 shall be adjusted each year by the Inflation Factor as defined below.

Inflation Factor = at the end of each fiscal year of Manitoba Hydro, the percentage change in the Consumer Price Index for Manitoba as recorded for the most recent set of 12 month periods for which data are available.

Reserve Discount: The fixed price to be paid for energy during curtailment under Option 'R' has been set at $0.04 per kW.h.

REPORT TO
THE PUBLIC UTILITIES BOARD

CURTAILABLE RATE PROGRAM

APRIL 1, 2013 – MARCH 31, 2014

September 2014

Appendix 6.11
January 23, 2015
2015/16 & 2016/17 General Rate Application

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REPORT TO PUBLIC UTILITIES BOARD
CURTAILABLE RATE PROGRAM
APRIL 1, 2013 – MARCH 31, 2014

SUMMARY

This Curtailable Rate Program ("CRP") annual report covers the period from April 1, 2013 to March 31, 2014. During this period three customers participated in the program and 14 Option R curtailments were successfully initiated.

The Public Utilities Board ("PUB") Order 42/13 dated April 26, 2013 approved, on an interim basis, the CRP Reference Discount of $3.28/kW for fiscal 2013/14. Customers received monthly credits on their electrical bill for their participation in the program totaling $5,965,689 during this time.

Manitoba Hydro's 2012/13 & 2013/14 General Rate Application ("GRA") included proposed revisions to the Terms and Conditions of the Curtailable Rate Program. The main revisions included a reduction in the amount of Option A and Option R load available to customers, the elimination of curtailment Options C and CE; and a change to the hours defined as Peak and Off-Peak to correspond to a potential time-of-use rate offering.

In Order 43/13, the PUB accepted, on an interim basis, Manitoba Hydro's proposed changes to the Terms and Conditions of the CRP. As two of the changes proposed by Manitoba Hydro could not be easily reversed if final approval of the rate setting process was not granted given the proposed changes to the Terms and Conditions, Manitoba Hydro requested to defer implementation of the change in the defined hours for Peak and Off-Peak periods, and the elimination of Curtailment Options C and CE until such time as the PUB grants final approval. Manitoba Hydro also advised that it would implement the other changes to the CRP accepted by Order 43/13, including reducing the global subscription cap on Option A, but only to the extent that Option C load can still be accommodated. By letter dated June 25, 2013, the PUB accepted Manitoba Hydro's proposal.

BACKGROUND

The CRP Terms and Conditions applicable during the reporting period from April 1, 2013 to March 31, 2014 took effect on April 1, 2013.

The Terms and Conditions allow Manitoba Hydro to reserve the right to limit the amount of total curtailable load used for maintaining operating and contingency reserves[1]. Manitoba Hydro's application to revise the CRP Terms and Conditions included a reduction to available Option A and C load from 230 MW to 178 MW and available Option R load from 100 MW to 50 MW. There is no limit for Option E load. The revised caps do not affect current CRP customers. Upon final approval of the changes to the Terms and Conditions, the Option C customer will have one year to decide if they wish to convert their load to Option A or to firm service. The caps have been beneficial to both Manitoba Hydro and curtailable customers by ensuring the value of curtailable load does not depreciate. A decreased value would result in lower discounts paid to customers making the program less attractive to them.

Manitoba Hydro uses curtailable load, among other measures, to maintain operating and contingency reserves as a means of minimizing disruption to firm customers in the event of loss of generation or transmission.

Curtailable load provides value to Manitoba Hydro all year round, as curtailments for system emergencies can occur at any time of the year. However, it has the greatest value during peak times as it is during the peak periods that Manitoba Hydro's capacity surplus is the most vulnerable. Options A and C curtailable load in these hours increases the amount of capacity for sale in the export markets while Option R load can allow Manitoba Hydro to meet its contingency reserve obligations at a lower cost.

Curtailable load provides risk mitigation benefits to the power system. Curtailable load can be used to avoid shedding firm load and/or breach of North American Electric Reliability Council (NERC) standard(s) by Manitoba Hydro or the Midwest Independent System Operator-Manitoba Hydro Contingency Reserve Sharing Group (MISO-MBHydro CRSG)[2]. Option R curtailable load allows Manitoba Hydro to meet reserve obligations thereby freeing

[1] Per North American Electric Reliability Council (NERC) Glossary of Terms, Operating Reserves: The reserves needed to protect Manitoba Hydro and its obligations to the Midwest Independent System Operator power system against Contingencies or Disturbances. These events are typically a result of loss of supply caused by sudden generating or transmission outages. Operating Reserves consist of various types including Contingency Reserves. Contingency Reserves: a component of Operating Reserves which are sufficient in magnitude and response to meet NERC Disturbance Control Standards. Contingency Reserves are comprised of Operating Reserves-Spinning and Operating Reserves-Supplemental. Curtailable load (also referred to as Interruptible Load) can be a source of Operating Reserves-Supplemental.

[2] The MISO-MBHydro CRSG is a NERC registered Contingency Reserve Sharing Group that has operated since January 1, 2010. The CRSG was established under the terms of the Amended MISO-Manitoba Hydro Coordination Agreement and executed on October 9, 2009.

up hydro generation for market transactions in the short-term opportunity energy market[3]. In this circumstance the benefits of having Option R available are dependent on Manitoba Hydro's water supply conditions as follows:

- High Water Supply - the generating capacity freed up for commercial use allows for increased hydraulic generation for export as idle generating units can be run to capture additional sales. Without Option R capacity in place energy would be spilled. With Option R load, the additional energy generated can be sold at on-peak prices.

- Average Water Supply - allows for additional hydraulic generation during on-peak hours that would otherwise be produced during off-peak hours (due to limited on-peak generating capability). In this case Manitoba Hydro captures the benefit of the price differential between on and off-peak periods.

- Low Water Supply - does not provide any significant benefits because Manitoba Hydro has sufficient shut down generating units that could be run temporarily for operating reserves purposes without relying on Option R load reductions.

Manitoba Hydro will not initiate load curtailments in order to facilitate an opportunity spot market sale[4].

PERFORMANCE FOR 2013/14

Curtailment Options:

The Curtailable Rate Program consists of four base curtailment options and three combinations. Options vary dependent on: minimum notice to curtail, maximum duration per curtailment, maximum daily hours of curtailment, maximum number of curtailments per year, and maximum annual hours of curtailment.

[3] Opportunity export sales are sales of capacity and/or energy that are not backed by dependable energy and are incremental exports that arise from time to time as a result of water conditions that are better than the lowest historic levels.

[4] Spot market sales are sales that occur on a day ahead or real time basis. They are not considered to be a capacity sale.

The three customers that participated in the Curtailable Rate Program during the April 1, 2013 to March 31, 2014 period designated a total of 228 MW to Manitoba Hydro's reserves, allocated as 80 MW Option AE, 67 MW Option A, 31 MW Option C and 50 MW Option R. The amount each customer designated as curtailable load in relation to their total load varies, and therefore, impacts their curtailable credit, as shown on the following table:

Summary of Curtailment Credit Data April 1, 2013 to March 31, 2014					
Customer	Option(s)	CRP Load as % of Total Load	Average On-Peak MW	Average On-Peak LF	Average Monthly Cr.
1	A, R, E	87%	194.0	94.3%	$447,671
2	A	94%	24.5	93.6%	$49,469
3	C	0%	7.1	60.2%	$0

Customer 1: 87% of total load represents 41% Option AE, 26% Option R and 20% Option A for 2013/14.

Customer 3: this customer was operating below their protected firm load and therefore had no load available for curtailment.

Load designated under Option R must be nominated as a Guaranteed Curtailment. That is, the customer must agree to shed a specified number of MW in order to be compliant with the curtailment request. Under all the other curtailment options, customers can nominate curtailable load as Guaranteed Curtailment or Curtail to Protected Firm Load.

Dependent on the curtailment option selected, Manitoba Hydro will curtail customers to meet reliability obligations only. Options A, C and R curtailments assist in securing operating and contingency reserves whereas Option E curtailments are initiated to meet firm energy requirements in the event that Manitoba Hydro expects to be short of firm energy supplies.

Implementation and Size of Curtailments:

There were 14 Option R curtailments during the April 1, 2013 to March 31, 2014 period, all of which were initiated in response to a contingency or disturbance event requiring deployment of Manitoba Hydro's supplemental reserves. The following table summarizes the duration and load in MW of each curtailment.

April 2013 to March 2014	Option 'R'	
	Hrs	MW
April 18, 2013	0.63	50
April 19, 2013	0.25	50
April 25, 2013	0.77	50
May 27, 2013	1.77	50
June 6, 2013	0.70	50
June 21, 2013	1.37	50
July 3, 2013	0.93	50
July 3, 2013	1.55	50
July 7, 2013	1.43	50
July 17, 2013	0.73	50
August 19, 2013	1.72	50
September 3, 2013	0.23	50
February 5, 2014	3.05	50
March 27, 2014	0.75	50
Total	**15.88**	**N/A**
Average	**1.13**	**50**

All curtailments occurred during peak hours. The customer did not use an alternative power source to supply their load during the curtailments.

Manitoba Hydro continues to use telephone to communicate curtailment requirements to customers on the program. This procedure is manageable and provides the additional security that curtailment(s) will be initiated by confirmation from an agent of the customer. Manitoba Hydro experienced no difficulties in communicating the 14 curtailments during this reporting period.

Reference and Reserve Discounts:

The maximum discount available to a participating customer is called the "Reference Discount." The Reference Discount is related to the marginal value of capacity, and is adjusted on April 1 of each year by the inflation factor. The Reference Discount in effect for the reporting period April 1, 2013 to March 31, 2014 was $3.28 per kW/month, as approved by the PUB, on an interim basis, in Order 42/13 dated April 26, 2013. Option AE customers receive 100% of the discount, while Option A and R customers receive 70% of the discount or $2.30 per kW/month. Option C customers receive 40% of the discount or $1.31 per kW/month.

For curtailable load nominated as 'Protect to Firm Load' the Reference Discount is calculated and credited to customers' bill each month as (A - B) x C x D where:

A = On-Peak Period Demand (kW)
B = Protected Firm Load (kW)
C = On-Peak Period Load Factor
D = Discount Amount

For curtailable load designated as a 'Guaranteed Curtailment' the Reference Discount is calculated and credited to customers' bill each month as GC x D where,

GC = the customer's guaranteed curtailable load
D = Discount Amount

Customers selecting Curtailment Option R receive, in addition to the Reference Discount, a Reserve Discount for each curtailment initiated and successfully completed. The Reserve Discount represents the value of carrying contingency reserves and is calculated and credited to customers' bill for each successful curtailment as LR x Du x FD where,

LR = amount of load reduction (in kW) requested by Manitoba Hydro's System Control to the customer at the time of an Option R curtailment
Du = duration of the curtailment (in hours)
FD[5] = fixed discount amount, currently set at $0.04 per kWh

The table below illustrates the amount of the monthly Reference Discount Credit that each customer received from April 1, 2013 to March 31, 2014, as well as their monthly On-Peak Demand and On-Peak Load Factor.

Monthly Reference Discount Credit									
2013 to 2014	Customer 1 Options AE, R, A			Customer 2 Option A			Customer 3 Option C		
	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $
Apr	208.8	92.6%	$439,020	24.6	97.6%	$51,875	31.7	59.4%	$0
May	207.8	83.9%	$408,342	24.9	93.7%	$50,388	28.6	39.5%	$0
June	175.5	93.8%	$443,042	24.6	92.5%	$49,159	19.0	6.1%	$0
Jul	175.5	97.7%	$456,860	24.6	94.7%	$50,350	0.7	70.1%	$0

[5] The Fixed Discount amount is based on the value of carrying contingency reserves on Manitoba Hydro units.

Monthly Reference Discount Credit									
2013 to 2014	Customer 1 Options AE, R, A			Customer 2 Option A			Customer 3 Option C		
	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $
Aug	175.5	97.4%	$455,635	24.8	98.1%	$52,438	0.7	69.9%	$0
Sep	175.5	95.7%	$449,584	24.7	67.8%	$36,131	0.7	74.4%	$0
Oct	175.5	95.7%	$449,654	24.3	95.8%	$50,310	0.8	56.5%	$0
Nov	209.3	93.9%	$443,462	24.1	99.5%	$51,754	0.8	68.1%	$0
Dec	205.9	92.8%	$439,684	24.4	97.7%	$51,475	0.9	76.7%	$0
Jan	207.0	97.6%	$456,335	24.3	95.6%	$50,168	0.9	46.0%	$0
Feb	205.9	96.4%	$452,137	24.1	96.1%	$50,011	0.4	78.2%	$0
Mar	205.9	94.8%	$446,540	24.3	94.4%	$49,575	0.4	78.1%	$0
Total	**2,328.0**	**94.3%**	**$5,340,296**	**293.8**	**93.6%**	**$593,633**	**85.5**	**60.2%**	**$0**

The discounts shown for Customer 1 do not include the $31,760 credited in respect of the Option R Reserve Discount.

<u>Adequacy of Terms and Conditions</u>:

Manitoba Hydro proposed revisions to the Terms and Conditions of the Curtailable Rate Program as part of its 2012/13 & 2013/14 GRA. The revisions included:

- a reduction in the amount of Option A and Option R load available to customers;
- elimination of curtailment Options C and CE;
- change in hours defined as Peak and Off-Peak to correspond to a potential time-of-use rate offering;
- removal of the monthly variation to nominate curtailable or firm load; and
- exclusion from the program after a customer's 2nd failure to curtail in a 12 month period.

In Order 43/13, dated April 26, 2013, the PUB accepted the proposed revisions as noted above, on an interim basis. Subsequent to the receipt of that Order, Manitoba Hydro, in its letter dated May 15, 2013, informed the PUB of the difficulty in implementing a change in the defined Peak and Off-Peak hours, and elimination of Option C and CE on an interim basis, and proposed that these changes be deferred until such matters can be finalized. The PUB, in its letter dated June 25, 2013, confirmed Manitoba Hydro's proposed approach.

The Terms and Conditions have protected Manitoba Hydro's contingency reserves and provided operating reserves that satisfy the requirements of NERC and the MISO-MB Hydro CRSG.

CONCLUSION

The Curtailable Rate Program facilitates fulfilling Manitoba Hydro's commitment of carrying, deploying, and re-establishing contingency reserves to meet its obligations with the MISO-MBHydro CRSG and to maintain compliance to NERC Standards. The program also assists in minimizing disruption to Manitoba Hydro's firm customers.

CRP continues to fulfill Manitoba Hydro's obligations, and with the above mentioned changes to the Terms and Conditions, will preserve the value of the program to both Manitoba Hydro and its customers.

ATTACHMENT 1

ESTIMATE OF THE VALUE OF CURTAILABLE LOAD TO MANITOBA HYDRO

The value of curtailable load to Manitoba Hydro is related to an estimate of the marginal cost of firm, long-term capacity. Over the long term, a representative value for capacity can be developed by estimating the annual carrying cost (includes finance and depreciation costs but not operating/fuel costs) of the lowest cost resource required to provide capacity to Manitoba Hydro, which is a simple cycle combustion turbine (SCCT). In 2005 the annual carrying cost of a SCCT was estimated to be $78 per kW per year, or $6.50 per kW per month, evaluated at load. It was proposed that this cost would escalate at the rate of inflation. This cost was reviewed in 2012 and was found to be appropriate going forward. This approach has the advantage of providing a clear transparent value, which is also stable over time and is consistent with the approach that is utilized to evaluate the benefits of other resource options such as DSM that may have a capacity component.

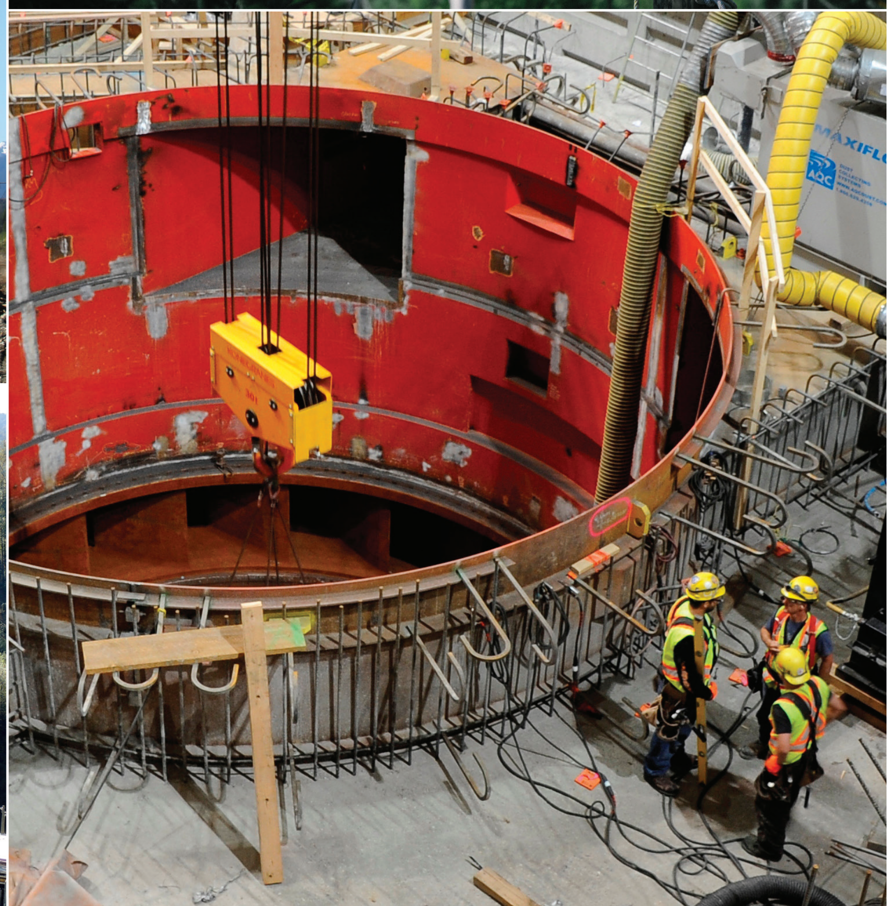
Curtailable load is less valuable than a generation resource such as a SCCT. The SCCT can provide more flexibility in dispatch and also has the capability to deliver for longer time periods during extended emergency situations. Once in place, a SCCT can be relied upon as a permanent, long-term resource, unlike curtailable load which can be terminated with a notice period of one year. Curtailable load normally has more value in the summer months, when it can assist in supporting seasonal capacity exports, and in the peak winter months, when it may add reliability to the Manitoba Hydro system. Curtailable load will provide more winter reliability benefits in years in which there is little capacity surplus on the system. When there is a significant capacity surplus on the Manitoba Hydro system, curtailable load provides less winter value than it would, for example, in the period around the 2023/24 time period, when the requirement to add generation to serve domestic customers may be expected to occur with 2013 planning assumptions and base demand side management program assumptions. The value of reliability benefits in a single year is not easily determined, which is why longer-term levelized values are used to infer the benefits of curtailable load.

The economic benefits of curtailable load can vary considerably year to year for a number of reasons. In the case of Option R CRP, the economic benefits derived from this option will vary depending on water conditions. Export market conditions can also impact the value of curtailable load to Manitoba Hydro. In the MISO market, current supply and demand conditions for capacity resources can cause variability in the near term value of capacity resources. Use of a longer-term levelized value maintains stability in CRP pricing, therefore sheltering the CRP customer from these sources of variability.

As described above curtailable load is less valuable than a SCCT because it has limited dispatchability, is not sustainable in reducing load over longer periods, and is not guaranteed to exist in the long term. Therefore in order to reflect these factors, curtailable load is assigned a long-term levelized value that is 42% of the annual carrying cost of a SCCT. After consideration of inflation subsequent to the 2011 base year, this yields an estimate of benefits for the year beginning April 1, 2013 of $3.28 per kW/month, which is referred to as the "Reference Discount". This value would apply to the curtailable rate option that provides the most value to Manitoba Hydro, that being Options AE and RE, for which the discount is set to return 100% of the estimated value of curtailable load to the customer. Other options provide less flexibility and are accordingly worth less to Manitoba Hydro. These have been priced to reflect their lesser value to Manitoba Hydro but still to return the full estimated value of that option to the customer.

TAB 4

BC HYDRO SERVICE PLAN
2014/15–2016/17



BC hydro

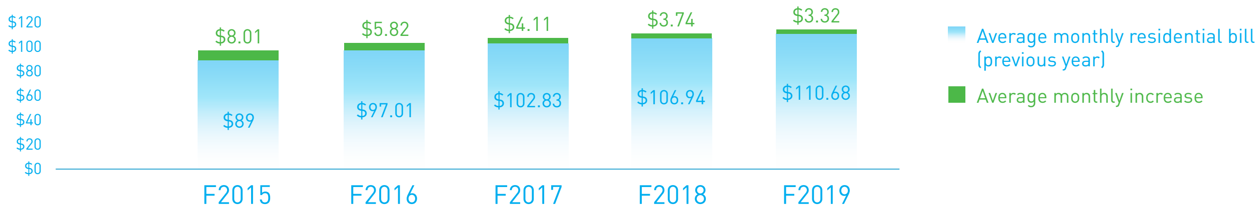
FOR GENERATIONS

THE 10 YEAR PLAN FOR KEEPING RATES COMPETITIVE

The Province and BC Hydro have worked together to reduce pressure on rates. The 10 year plan will keep electricity rates as low as possible while BC Hydro makes investments in aging assets and new infrastructure to support British Columbia's growing population and economy.

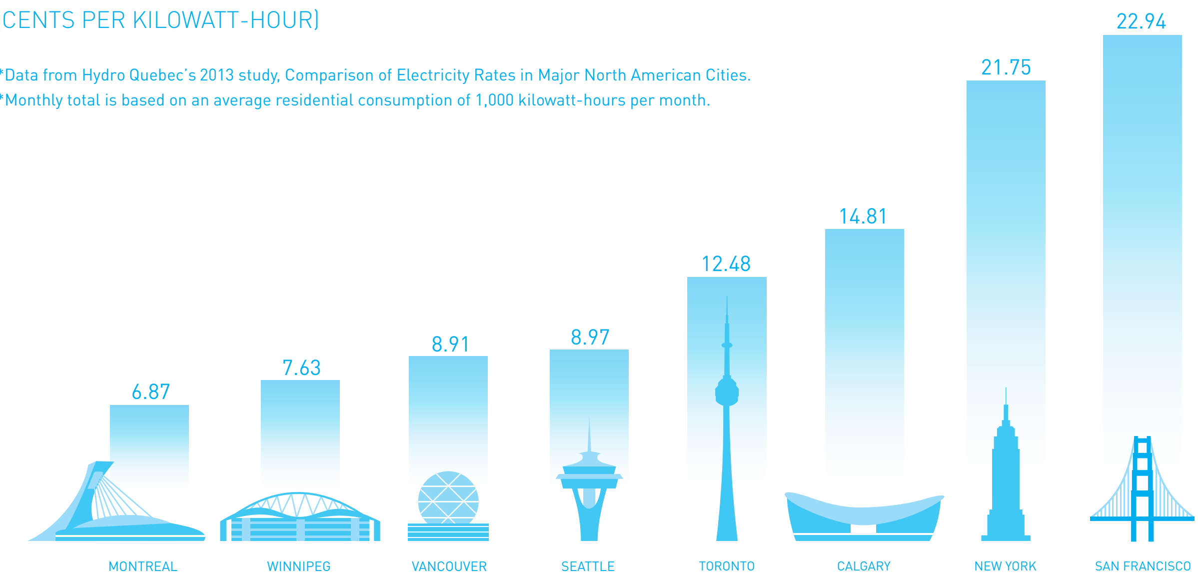
This Plan builds on the 2011 Government Review. New measures in the 10 year plan will reduce the amount of money that the Province takes from the utility, free up additional cash to support investments in infrastructure and limit BC Hydro's operating costs.

AVERAGE RESIDENTIAL RATES AND INCREASES



BC HYDRO'S RATES ARE AMONG THE LOWEST IN NORTH AMERICA.
According to an independent study by Hydro-Quebec, BC Hydro's residential rates are the third lowest in North America. Rates for industrial business customers are the fifth lowest.

SAMPLE OF RESIDENTIAL ELECTRICITY RATES ACROSS NORTH AMERICA
(CENTS PER KILOWATT-HOUR)



*Data from Hydro Quebec's 2013 study, Comparison of Electricity Rates in Major North American Cities.
*Monthly total is based on an average residential consumption of 1,000 kilowatt-hours per month.

MAINTAIN COMPETITIVE RATES

Deliver value for British Columbia and maintain competitive rates by efficiently and responsibly managing our business.

With a 10 year plan in place, BC Hydro's goal is to keep electricity rates as low as possible while making investments in aging assets and new infrastructure to support British Columbia's growing population and economy.

This effort builds on the 2011 Government Review that identified over $391 million in savings. New measures in the 10 year plan will reduce the amount of money that the Province receives from BC Hydro, free up additional cash to support investments in infrastructure and limit operating costs.

To keep rates predictable while funding investments in aging and new infrastructure:

- the Province will set rate increases for the initial two years (F15 and F16) of the 10 year plan at nine per cent and six per cent;
- the BC Utilities Commission (BCUC) will set increases for the following three years within caps of four per cent, 3.5 per cent and three per cent; and,
- in the final five years of the plan, rates will be set by the BCUC. Actions by the Province and BC Hydro will ensure increases remain low and predictable.

In addition, BC Hydro will carefully manage costs; operate in a lean and efficient manner; and strive to ensure that projects deliver benefits on-time. Operating costs are forecast to increase at less than the rate of inflation over the F2015 to F2017 period.

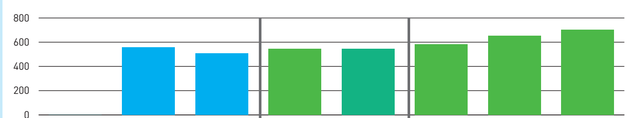
STRATEGIES

- Continue to focus on management and control of our cost structure in order to realize cost-savings and efficiencies.
- Prudently implement our capital plan and continue to deliver on BC Hydro's capital investment program, including process and procurement improvements.
- Improve operational excellence, safety and reliability in the Transmission & Distribution business group by improving work delivery methods, resourcing strategies, integrated planning, as well as technology platforms.
- Continue to implement category and materials management strategies to deliver improved supply chain operational efficiencies; meet cost control and other business objectives through improved sourcing of products and services; and build strong supplier relationships.
- Manage the cost of energy by: implementing a DSM plan; ensuring new electricity supply is the most cost-effective available; making prudent short-term generate and buy decisions; and, optimizing BC Hydro's ability to use the flexibility of our heritage assets.
- Optimize BC Hydro's balance sheet and cost of capital.

PERFORMANCE MEASURES

(Please see Appendix A for Performance Measure definitions, rationales and benchmarking information.)

NET INCOME *($ millions)*



FOUR YEAR AVG.	ACTUAL F2012	ACTUAL F2013	**TARGET F2014**	**FORECAST F2014**	TARGET F2015[2]	TARGET F2016[2]	TARGET F2017
N/A[1]	558	509	545	545	582	652	701

OPERATING COSTS *($ millions)*

FOUR YEAR AVG.	ACTUAL F2012	ACTUAL F2013	**TARGET F2014**	**FORECAST F2014**	TARGET F2015	TARGET F2016	TARGET F2017
N/A[1]	665	705	699	699	706	713	730

COMPETITIVE RATES

1st Quartile

- FOUR YEAR AVERAGE
- ACTUAL F2012 & F2013
- FORECAST F2014
- TARGET F2014, F2015, F2016, F2017

[1] As a result of reintegration of BCTC in July 2010 and changes to the presentation of certain financial statement items, previous year numbers are not comparable.

[2] As described in the Financial Outlook section of the Service Plan, BC Hydro's allowed net income is calculated by multiplying its deemed equity (which is essentially 30% of its assets in service and DSM expenditures) by its allowed return on equity which is currently 11.84%. The reduction in the net income forecast from the last Service Plan is due to the reduction in our capital expenditure and DSM forecasts.

NOTE: The Province, as part of the 10 year plan will restrict the amount of dividends received from BC Hydro starting in F2018 until such time as the Debt:Equity ratio reaches 60:40. BC Hydro does not anticipate reaching the Debt:Equity ratio of 60:40 during the 10-year period. As a result of this change the Debt:Equity ratio has been removed as a performance measure.

BC Hydro's financial performance considers the financial return to the Province of British Columbia and the electricity rates paid by customers.

In fiscal 2013, BC Hydro's return to government was $1,083 million. This amount includes water rental fees (royalties paid for the use of provincial water resources), provincial and municipal property taxes and grants-in-lieu of taxes, and BC Hydro's net income (return on equity). BC Hydro's dividend payment to the Province was $215 million in fiscal 2013.

BC Hydro is projecting its return to government will average approximately $1,265 million per year for the fiscal 2015 to fiscal 2017 plan period and its dividend payment will average approximately $410 million[1] per year over the same period.

CAPITAL AND REGULATORY STRUCTURE

BC Hydro is regulated by the British Columbia Utilities Commission (BCUC) and both entities are subject to general or special directives and directions issued by the Province. BC Hydro operates primarily under a cost of service regulation as prescribed by the BCUC. Orders in Council from the Province establish the basis for determining BC Hydro's equity for regulatory purposes, as well as its allowed return on deemed equity and the annual dividend to the Province.

BC Hydro's deemed equity for regulatory and rate setting purposes is 30 per cent of the company's rate base, comprised largely of BC Hydro's property, plant and equipment in service.

BC Hydro's allowed return on its deemed equity will be set at 11.84% for the F2014 to F2017 period. BC Hydro's allowed net income for F2014 to F2017 is therefore calculated by multiplying its deemed equity and allowed rate of return.

The Government, as part of the 10 Year Plan, has announced that the allowed net income for F2018 and future years will increase by inflation and therefore the concepts of deemed equity and the allowed return on its deemed equity will no longer be relevant after F2017.

BC Hydro is required to make an annual dividend to the Province on or before June 30 each year. The dividend is equal to 85 per cent of BC Hydro's net income assuming that the actual debt to equity ratio, after deducting the dividend, is not greater than 80:20. If the dividend would result in a debt to equity ratio exceeding 80:20, then the dividend will be based on the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. As part of the 10 Year Plan, the Government has announced that the dividend will be reduced over five years starting in F2018 and then be restricted if the dividend would result in a debt to equity ratio exceeding 60:40.

COST INFLUENCES

BC Hydro's costs are driven by capital investment costs, cost of energy, recovery of its regulatory account balances, and costs required to operate and maintain its utility business.

- Capital investment costs relate to costs associated with capital expenditures and additions including amortization, finance charges, and return on equity. Many large capital projects to refurbish and maintain the system to ensure ongoing reliability of our assets and to build new assets to meet growing demand are planned or underway, with annual expenditures of approximately $2.0 billion (excluding Site C) over the next several years. An average of approximately 40 per cent of BC Hydro's total cost structure over the fiscal 2015 to fiscal 2017 period relates to capital investment costs.
- Cost of energy includes water rental charges, purchase costs from Independent Power Producers (IPPs), market electricity purchases and purchases of gas for thermal generation. New sources of energy supply are more expensive than

[1] The Financial Outlook excludes the construction costs related to the Site C project which will require an environmental certification, other regulatory approvals and permits, as well as a final decision before it can proceed to construction. If Site C construction costs and corresponding debt were included the dividend would average $100 million per year lower over the F2015 to F2017 period due to the debt:equity cap described above.

CAPITAL EXPENDITURES

BC Hydro is investing in its heritage assets to ensure system reliability and it's undertaking new projects to meet future electricity demand in B.C. These projects span the entire system, and provide economic and business development opportunities in different communities and regions across the province.

BC Hydro's forecast capital expenditures are developed using a risk-based Enterprise-Wide Capital Prioritization Framework, with consideration given to economic benefits, cost effectiveness and efficient project implementation. BC Hydro classifies capital expenditures as either sustaining capital or growth capital:

- Many of BC Hydro's assets were built before 1970—over 40 years ago. Investments in these aging assets are required to meet targeted levels of customer and supply reliability. Sustaining capital includes expenditures to ensure the continued availability and reliability of generation, transmission and distribution facilities. It also includes expenditures to support the business, such as vehicles and information technology. Large sustaining capital projects include the John Hart Generating Station Replacement and Ruskin Dam and Powerhouse Upgrade projects.
- Growth capital is required to meet customer load growth and other business investments. B.C.'s electricity demand is expected to increase significantly over the next 20 years due to economic expansion, population growth and the increased use of, or conversion to, electricity. Growth capital expenditures relate to the expansion of existing generation assets as well as expansion and reinforcement of the transmission and distribution system. Projects include the Northwest Transmission Line, the Interior to Lower Mainland Transmission Project, and the addition of generating capacity by adding a fifth and sixth unit at Mica.

CAPITAL EXPENDITURES[1] ($ MILLIONS)	ACTUAL F2013	FORECAST F2014	FORECAST F2015	FORECAST F2016	FORECAST F2017
Sustaining	1,009	981	1,170	1,194	1,224
Growth	920	1,014	1,091	754	597
TOTAL CAPITAL PLAN	**1,929**	**1,995**	**2,262**	**1,949**	**1,821**
Generation	421	491	633	607	602
Transmission and Distribution	1,325	1,288	1,391	1,101	965
Properties, Technology and Other	183	216	238	241	254
TOTAL BC HYDRO CAPITAL FORECAST	**1,929**	**1,995**	**2,262**	**1,949**	**1,821**

[1] Table may not add due to minor rounding.

Capital expenditures in the above table do not include construction costs related to the Site C project. Site C is undergoing a cooperative environmental assessment process by federal and provincial regulatory agencies and is currently in the joint review panel stage. The Site C project will require an environmental certification, other regulatory approvals and permits, as well as a final decision from the Province before it can proceed to construction. In addition, the Crown has a duty to consult and, where appropriate, accommodate Aboriginal groups. The completion of the environmental assessment process is expected to be in the fall of 2014. Construction costs of $1,365 million are expected for the F2015 to F2017 period assuming the project proceeds to construction. The estimate is subject to change as planning and implementation of procurement for Site C progresses. Site C costs prior to construction are captured within the Site C Regulatory Account.

Saskatchewan Rate Review Panel

Report to the Minister Responsible for Crown Investments Corporation of Saskatchewan

regarding the

SaskPower Rate Application Effective date January 1, 2014

Report submitted April 28, 2014

5.0 Panel Observations

The Panel offers the following observations arising from its deliberations during this review.

5.1 Capital Projects

The Panel acknowledges that the capital projects plan and its execution are givens in its Terms of Reference, but there were numerous public comments on this issue. Since capital projects are a main driver of this Application, the Panel suggests that a public dialogue be developed to further educate the stakeholders and general public on the need for the capital projects in order to supply a safe, reliable and effective electricity service. SaskPower plans to invest $3 billion over the next 3 years (2014-16) as part of its efforts to renew and modernize its system. This plan includes:

- new power generation capacity;
- reinforcing its transmission and distribution system through projects such as new transmission lines and wood pole replacements;
- a new operations centre, new building construction and existing building renovations;
- investments in new information technology;
- and adding new forms of low or non-emitting forms of generation.

The following table outlines SaskPower's capital spending program from 2012-16:

SaskPower Capital Spending for 2012 to 2016

(in $ millions)	2012	2013	2014	2015	2016
Power Production					
Capacity sustainment	$123	$118	$140	$140	$140
QE repowering	26	94	225	118	25
Tazi Twe (Elizabeth Falls)	0	14	40	80	100
ICCS	357	510	21	0	0
Total Power	**$506**	**$736**	**$426**	**$338**	**$265**
Transmission & Distribution					
Capacity increase/sustainment	$167	$260	$235	$235	$235
Customer Connects	226	189	248	241	232
I1K line	0	0	120	116	0
Total T&D	**$393**	**$449**	**$603**	**$592**	**$467**
Other Capital					
Operations Centre	$0	$0	$12	$50	$80
Buildings/Furniture/Land	26	62	35	35	35
Service Delivery Renewal	25	70	70	11	0
Information Technology & Security	31	33	54	47	50
Total Other	**$82**	**$165**	**$171**	**$143**	**$165**
Total Capital Program	**$981**	**$1,350**	**$1,200**	**$1,073**	**$897**

[23]

The Panel noted there are parts of the capital projects that are essential and must be completed to ensure that the province's power needs are met in a safe and reliable manner. However, some stakeholders have indicated that while justifiable, there may be less essential projects within the capital plan. For example, it was suggested that some of the projects associated with Other Capital projects in the foregoing table may be able to be deferred to the future to mitigate rate increases. A public dialogue with the Panel and stakeholders will help to demonstrate the need

[23] 2014 Forkast Consulting Report, P. 103

for and the transparency of the current plans and to ensure that the plans are implemented in the most least cost and effective manner at the most appropriate time.

5.2 Dividends

As previously mentioned, SaskPower's capital program and rising fuel and purchased power costs are the main reasons behind this Application. These costs are driving up the Corporation's long-term debt, which is expected to reach $7.572 billion by the end of 2016. This rising debt level has an impact on the Corporation's net operating income and the ROE. SaskPower is expected to achieve an operating income for 2014 of $66 million, and is forecasting 2015 net income to be $57.9 million and 2016 to be $46.4 million. This means that the return on equity (ROE) for 2014 will be 2.9%; 2015 will be 2.6%; and 2016 will be 2.1%. These amounts are well below SaskPower's long-term target of 8.5%.

The Panel commends the Government of Saskatchewan for refraining from taking a dividend from the corporation in all years except one since 2008. No dividend payments are anticipated during the 2014-16 time period covered by this Application. This decision allows SaskPower to have lower debt levels, lower finance charges and a stronger equity position, which in turn helps to mitigate or reduce what would otherwise be required higher future rate increases.

5.3 Public Education

SaskPower rate increases are likely to become more commonplace in the future. The Panel recognizes that there is public concern about rising rates, but there has been limited public education and discussion on why this is occurring. The reality is that SaskPower's debt will continue to increase over the next few years as significant spending is required to replace existing transmission and distribution infrastructure and aging generating facilities. Although the Application does not include any dividends being paid by SaskPower, the Corporation's ROE is expected to be well below its target of 8.5% for the next several years.

However, SaskPower's situation is similar to many other publicly-owned utilities. The infrastructure deficit has accumulated over several decades and decisions today are made on the basis that reflect economics, technology, public opinion and concern for the environment. Almost half of SaskPower's electrical generation currently comes from its coal-fired plants and with the province having an abundant supply of coal, which is a low cost and reliable fuel source, the preference is to continue to use this resource. There is concern about the realized costs of the continued use of coal, whether it be in conjunction with the clean coal technology being developed or otherwise.

After coal, natural gas is the second highest fuel source in SaskPower's fuel mix and it will become even more dominant as the bulk of SaskPower's new generation will be natural gas. It is considered a greener fuel source than coal. It is used in natural gas generating stations and co-generating facilities. The price of this generation is less stable as it is dependent upon the market price of natural gas. Coal, on the other hand, is a more price stable fuel source. Hydraulic generation is the most cost-effective source of electrical generation, but SaskPower currently has limited capacity in this area. This capacity is impacted by weather conditions and water flow, which can change significantly from year to year.

Ontario Energy Board **Commission de l'énergie de l'Ontario**

Ontario

Ontario Energy Board

Filing Requirements for Electricity Transmission and Distribution Applications

Chapter 5

Consolidated Distribution System Plan Filing Requirements

March 28, 2013

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CHAPTER 5 CONSOLIDATED DISTRIBUTION SYSTEM PLAN FILING REQUIREMENTS

Glossary

Where applicable, definitions set out in the Distribution System Code (DSC) apply to terms used in these filing requirements. Certain other terms used here are explained below.

Distribution System Plan duration is the duration of a distributor's *Distribution System Plan*, which is a minimum of ten (10) years in total and comprised of an *historical period* and a *forecast period*

Forecast period is the last five (5) years of the *Distribution System Plan duration*, consisting of five (5) forecast years, beginning with the Test year

General plant investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities

Historical period is the first five (5) years of the *Distribution System Plan duration*, consisting of five (5) historical years, ending with the Bridge year

REG investments accommodate the connection of renewable energy generation (including connection assets, expansions and/or renewable enabling improvements) the costs of which are the responsibility of the distributor as set out in the DSC. REG investments can be stand-alone or integrated into a project/activity; and are to be categorized for the purposes of section 5.4 in the same way as any other investment

Regional Infrastructure Plan is a document issued by the transmitter leading a Regional Planning Process that identifies forecast regional electricity service requirements, and describes and justifies the optimal infrastructure investments planned to meet those requirements

Regional Planning Process is a consultation involving distributors, transmitter(s), and the Ontario Power Authority convened for the purpose of exchanging information related to system planning, coordinating the modification of a regional electricity transmission system, and preparing and issuing a Regional Infrastructure Plan

System access investments are modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system

System O&M are routine operations and maintenance activities carried out to sustain required distribution system performance to the end of the subject asset's service life

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.

System service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements

5.0 Introduction

These filing requirements set out the information required by the Board under the renewed regulatory framework for electricity to assess distributor applications involving planned expenditures on distribution system and other infrastructure.[1] For the purposes of these filing requirements, a *Distribution System Plan* ("DS Plan") consolidates documentation of a distributor's asset management process and capital expenditure plan, where:

- an *Asset Management Process* is the systematic approach a distributor uses to collect, tabulate and assess information on physical assets, current and future system operating conditions and the distributor's business and customer service goals and objectives to plan, prioritize and optimize expenditures on system-related modifications, renewal and operations and maintenance, and on general plant facilities, systems and apparatus; and
- a *Capital Expenditure Plan* sets out and robustly justifies according to the Board's standard requirements for evaluation a distributor's proposed expenditures on its distribution system and (non-system) general plant over a five-year planning period, including investment and asset-related maintenance expenditures.

Filing DS Plans consistent with these requirements will ensure that the Board's expectations for a distributor's planning are met; namely, that the DS Plan optimizes investments and reflects regional and smart grid considerations; serves present and future customers; places a greater focus on delivering value for money; aligns the interests of the distributor with those of customers; and supports the achievement of public policy objectives.[2]

Good distributor planning is an essential pre-requisite to the performance-based rate-setting approaches established under the renewed regulatory framework for electricity[3], and necessary to ensure that the performance outcomes the Board has established for electricity distributors are being achieved:

Customer Focus: services are provided in a manner that responds to identified customer preferences;

Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

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1 The renewed regulatory framework for electricity is a comprehensive, performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers. See *Report of the Board – A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*; (the "*RRFE Report*"); p. 2.

2 *RRFE Report*; p. 1.

4 *RRFE Report*; p. 36.

Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and

Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

DS Plan filings must enable the Board to assess whether and how a distributor has planned to deliver value to customers. One of the primary goals of DS Plans and by extension, hallmarks of good planning, is pacing and prioritizing capital investments in a manner that considers rate impacts. To facilitate the achievement of this goal, these filing requirements focus on the qualitative and quantitative information distributors can use to support their investment proposals that will best enable the Board to assess how a distributor has sought to control the costs and related rate impacts of proposed investments.[4]

5.0.1 Purpose of filing a Distribution System Plan

Good distributor planning is an essential pre-requisite to the performance-based rate-setting approaches established under the renewed regulatory framework for electricity. Filing a DS Plan with an application to the Board will provide information to the Board and interested stakeholders including but not necessarily limited to a distributor's:

- asset related performance objectives and approach to evaluating its performance relative to those objectives;
- approach to lifecycle asset management planning and the management of asset-related operational and financial risk; and
- plan for capital-related expenditures over the five-year forecast period.

5.0.2 Application and scope

These filing requirements apply to licenced, rate regulated electricity distribution utilities in Ontario when filing DS Plans as required by the Board as set out in section 5.1.3 of these requirements.

5.0.3 Framework for distribution system plans

The content of these filing requirements has been informed by the Board's expectations for distribution system planning under the renewed regulatory framework for electricity.

[4] *RRFE Report*; p. 36.

5.0.3.1 Integrated planning

An integrated approach to planning, whereby investments for system renewal and expansion, renewable generation connections, smart grid development and implementation, and regionally planned infrastructure are planned and optimized together, will provide the necessary foundation for distribution rate-setting under the renewed regulatory framework; help distributors to pace and prioritize projects; and support the achievement of the four outcomes for electricity distributors.[5]

5.0.3.2 Longer term planning horizon

Under the renewed regulatory framework, a planning horizon of five years is required to support integrated planning and better align distributor planning cycles with rate-setting cycles, which are a minimum of five-years in expected duration.[6] This longer term approach should:

- enhance the predictability necessary to facilitate planning – including regional planning – and decision-making by customers and distributors;
- facilitate the cost-effective and efficient implementation of distributor DS Plans and thereby the achievement of customer service and cost performance outcomes; and
- help distributors to manage consumer rate impacts.[7]

5.0.3.3 Regional considerations

Planning the distribution system infrastructure in a regional context will help promote the cost effective development of electricity infrastructure in Ontario. Regional issues and requirements are to be considered in individual distributor system planning processes.[8] Accordingly, these filing requirements provide that where applicable, a distributor file information on the Regional Planning Process(s) in which it was a participant; on the Regional Infrastructure Plan provided by the transmitter; and information demonstrating that the Regional Infrastructure Plan has been appropriately considered and addressed in the development of the distributor's DS Plan.

5.0.3.4 Smart grid development and implementation

Under the renewed regulatory framework, smart grid development is expected to be integral to distribution system plans, a central focus of grid-enhancing innovation, and implemented on a coordinated regional basis to achieve economies of scope and

[5] *RRFE Report*; p. 31.
[6] *RRFE Report*; p. 31.
[7] *RRFE Report*; p. 10.
[8] *RRFE Report*; p. 39.

scale.[9] These filing requirements therefore include DS Plan information regarding, where appropriate:

- the activities a distributor has undertaken in order to understand their customers' preferences (e.g., data access and visibility, participating in distributed generation, and load management) and how they have addressed those preferences;
- the options a distributor has considered for facilitating customer access to consumption data in an electronic format;
- the mechanisms that facilitate "real-time" data access and "behind the meter" services and applications that a distributor has considered for the purpose of providing customers with the ability to make decisions affecting their electricity costs;
- the consideration a distributor has given to the investments necessary to facilitate the integration of distributed generation and more complex loads (e.g., customers with self-generation and/or storage capability);
- the technology-enabling opportunities a distributor has considered regarding operational efficiencies and improved asset management; and
- the distributor's awareness and adoption of innovative processes, services, business models, and technologies.[10]

5.0.4 The Board's evaluation of DS Plans

DS Plan filings must support the Board's assessment as to whether a distributor has and will continue to achieve the four performance outcomes the Board has established for electricity distributors as explained below. Section 5.4.5 explains the specific criteria the Board will use to evaluate whether a DS Plan and in particular the material[11] projects/activities proposed for cost recovery in a DS Plan address these four outcomes.[12]

Customer Focus

A DS Plan filing must demonstrate that distribution services are provided in a manner that responds to identified customer preferences. As indicated in the provisions that follow, this is accomplished by providing information on customer engagement to identify preferences; the value proposition the DS Plan represents for customers (economic efficiency and cost-effectiveness); and on the factors relating to customer preferences or input from customers and participants in a Regional Planning Process that were considered in the course of planning investment projects and activities.

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[9] See *Report of the Board - Supplemental Report on Smart Grid* (EB 2011-0004); February 11, 2013 (the "*Smart Grid Report*"); pp. 4 – 5.
[10] *Smart Grid Report*; pp. 9 – 16.
[11] A project or activity is "material" if the materiality threshold set out in Chapter 2 of the *Filing Requirements for Electricity Transmission and Distribution Applications* is met.
[12] For details on the evaluation criteria and how the Board will use them to evaluate investments, see the *Smart Grid Report*; pp. 17 – 21.

Operational Effectiveness

DS Plans must show that a distributor's asset management and capital expenditure planning processes are designed to identify and take advantage of opportunities for continuous improvements in productivity and cost performance, while delivering on a distributor's explicitly stated system reliability and quality objectives.

Public Policy Responsiveness

A distributor's DS Plan must explain how the expenditure planning process has been integrated and rationalized so as to permit timely and appropriate expenditures in relation to a distributor's government-mandated obligations (e.g., in legislation or regulatory requirements imposed further to Ministerial directives to the Board).

Financial Performance

DS Plans must show that a distributor's financial viability and operational effectiveness will endure over the long term including by sustaining efficiencies gained through prudent capital-related expenditure planning and DS Plan execution.

5.0.5 Form of these filing requirements

To implement the policy objectives of the renewed regulatory framework, filing requirements related to Distribution System Plans, including information on planned investments related to investments to accommodate the connection of renewable energy generation (REG) and/or smart grid development activities and expenditures (see sections 5.1.2 and 5.0.3.4 respectively), have been consolidated in this Chapter 5 of the Board's *Filing Requirements for Electricity Transmission and Distribution Applications* (*CoS FRs*) Accordingly, these filing requirements replace the Board's *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence*.

5.1 General & Administrative Matters

The form and the content of these filing requirements reflect the Board's conclusions in relation to distribution infrastructure planning. These filing requirements introduce a standard approach to a distributor's filings of asset management and capital expenditure plan information in support of a rate application.[13] As detailed in section 5.2, distributors filing a corporate 'Asset Management Plan' are expected to include and

[13] *RRFE Report*; p. 35.

clearly identify in their filings the information set out in these filing requirements, and to use the terminology and formats set out in these filing requirements.[14]

5.1.1 Investment Categories

A distributor's investment projects and activities should be grouped for filing purposes into one of the four investment categories listed below, based on the 'trigger' driver of the expenditure, examples of which are provided on Table 1.

Table 1 – Investment Categories & Example Drivers and Projects/Activities

	Example Drivers	Example Projects / Activities
system access	customer service requests	– new customer connections – modifications to existing customer connections – expansions for customer connections or property development
system access	other 3rd party infrastructure development requirements	– system modifications for property or infrastructure development (e.g. relocating pole lines for road widening)
system access	mandated service obligations (DSC; Cond. of Serv.; etc.)	– metering – Long term load transfer
system renewal	assets/asset systems at end of service life due to: – failure – failure risk – substandard performance – high performance risk – functional obsolescence	– programs to refurbish/replace assets or asset systems; e.g: batteries; cable (by type); cable splices; civil works; conductor; elbows & inserts; insulators; poles (by type); physical plant; relays; switchgear; transformers (by type); other equipment (by type)
system service	expected changes in load that will constrain the ability of the system to provide consistent service delivery	– property acquisition – capacity upgrade (by type); e.g. phases; circuits; conductor; voltage; transformation; regulation – line extensions
system service	system operational objectives: – safety – reliability – power quality – system efficiency – other performance/functionality	– protection & control upgrade; e.g. reclosers; tap changer controls/relays; transfer trip – automation (new/upgrades) by device type/function – SCADA – distribution loss reduction
general plant[1]	– system capital investment support – system maintenance support – business operations efficiency – non-system physical plant	– land acquisition – structures & depreciable improvements – equipment and tools – supplies – finance/admin/billing software & systems – rolling stock – intangibles (e.g. land rights; capital contributions to other utilities)

Note: 1. Includes only 19## series accounts.

[14] For the Board's conclusions in relation to consolidating and harmonizing its planning-related filing requirements see *RRFE Report*; p. 31.

- ***System access*** investments are modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system
- ***System renewal*** investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.
- ***System service*** investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements
- ***General plant*** investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities

A project or activity involving two or more 'drivers' associated with different categories should be placed in the category corresponding to the 'trigger' driver. For example, a project triggered by the need to replace end of service life components in a distribution station should be considered a 'system renewal investment, even if in anticipation of future system requirements (a 'system service' driver) the project includes assets rated for a higher voltage and/or capable of handling reverse flows. Note, however (as detailed in section 5.4.5), information on all drivers of a given project or activity should be used to justify proposed capital investments.

5.1.2 Investments related to renewable energy generation

Under the renewed regulatory framework, a distributor's investments to accommodate and connect renewable energy generation (i.e. REG investments) are integral to its DS Plan, which includes all costs to connect renewable generation facilities that will be the responsibility of the distributor under the DSC, and are therefore eligible for recovery through the provincial cost recovery mechanism set out in section 79.1 of the *OEB Act*.

5.1.3 Time of filing

All distributors are required to file a DS Plan as specified here when filing a cost of service application for the rebasing of their rates under the 4th Generation IR or a Custom IR application. Distributors proposing to use the 'Annual IR Index' method for 2014 rates are not required to use Chapter 5 when filing an application. However, any distributor using the 'Annual IR Index' method must make a Chapter 5 filing within five years of the date of the most recent Board decision approving their rates in a cost of service proceeding; and is required to do so at five year intervals thereafter while using the Annual IR Index method. The Board may also require a DS Plan to be filed in relation to leave to construct, Incremental Capital Module or Z-factor applications.

5.1.4 Planning in consultation with third parties

5.1.4.1 Regional planning and consultations

Prior to filing a DS Plan and at a time and in a manner to be determined in consultation with the participants in a Regional Planning Process, a distributor must:

1. Provide regionally interconnected distributors (including host and/or embedded where applicable), the transmitter to which the distributor is connected and the OPA (where applicable) with information on:
   - forecast load at existing (and proposed, if any) points of interconnection;
   - forecast renewable generation connections and any planned network investments to accommodate the connections;
   - investments involving smart grid equipment and/or systems that could have an impact on the operation of assets serving the regionally interconnected utilities; and
   - the results of projects or activities involving the study or demonstration of innovative processes, services, business models, or technologies; and on the projects or activities of this nature planned by the distributor over the forecast period.
2. Consult with regionally interconnected distributors (including host and embedded where applicable) and transmitter(s) to which the distributor is connected in preparing their DS Plan.

5.1.4.2 Renewable energy generation investments

Prior to filing a DS Plan, a distributor must:

1. Not less than 60 days (where REG investments are contemplated; 30 days otherwise) in advance of the date the distributor needs to receive the OPA letter for inclusion in an application, a distributor must submit information to the OPA in relation to the REG investments identified in their DS Plan and request in writing that the OPA provide a letter commenting on the information by a date that conforms to the distributor’s filing timetable.
2. The Board expects that the OPA comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

The Board may postpone processing an application where a comment letter from the OPA has not been filed in accordance with this requirement.

5.1.5 Performance reporting

A distributor is to provide information on its performance in relation to its DS Plan as set out in section 5.2.3, including information on the achievement of the operational or other objectives targeted by investments the costs for which were approved in a previous application(s). Through its RRR filing, a distributor is also required to report annually on its performance, including in relation to reliability and any Performance Scorecard metrics established by the Board, including metrics related to asset management and capital expenditure planning as applicable.

5.2 Distribution System Plans

Distributors are encouraged to organize the required information using the section headings indicated. If a distributor's application uses alternative section headings and/or arranges the information in a different order, the distributor shall demonstrate that these requirements are met by providing a table that clearly cross-references the headings/subheadings used in the application as filed to the section headings/subheadings indicated below.

5.2.1 Distribution System Plan overview

This section provides the Board and stakeholders with a high level overview of the information filed in the DS Plan, including but not limited to

a) key elements of the DS Plan that affect its rates proposal, especially prospective business conditions driving the size and mix of capital investments needed to achieve planning objectives

b) the sources of cost savings expected to be achieved over the forecast period through good planning and DS Plan execution

c) the period covered by the DS Plan (historical and forecast years);

d) an indication of the vintage of the information on investment ‘drivers’ used to justify investments identified in the application (i.e. the information should be considered “current” as of what date?);

e) where applicable, an indication of important changes to the distributor’s asset management process (e.g. enhanced asset data quality or scope; improved analytic tools; process refinements; etc.) since the last DS Plan filing; and

f) aspects of the DS Plan that relate to or are contingent upon the outcome of ongoing activities or future events, the nature of the activity (e.g. Regional Planning Process) or event (Board decision on LTLT) and the expected dates by which such outcomes are expected or will be known.

Prior to filing, care should be taken to ensure that summary information is consistent with the detailed information filed in the following sections and elsewhere in the application.

5.2.2 Coordinated planning with third parties

To demonstrate that a distributor has met the Board’s expectations in relation to coordinating infrastructure planning with customers, the transmitter, other distributors and/or the OPA or other third parties where appropriate, a distributor must provide:

a) a description of the consultation(s), including
   - the purpose of the consultation (e.g. Regional Planning Process);
   - whether the distributor initiated the consultation or was invited to participate in it;
   - the other participants in the consultation process (e.g. customers; transmitter; OPA);
   - the nature and prospective timing of the final deliverables (if any) that are expected to result from or otherwise be informed by the consultation(s) (e.g. Regional Infrastructure Plan; Integrated Regional Resource Plan); and
   - an indication of whether the consultation(s) have or are expected to affect the distributor’s DS Plan as filed and if so, a brief explanation as to how.

b) where a final deliverable of the Regional Planning Process is available, the final deliverable; where a final deliverable is expected but not available at the time of filing, information indicating:
   - the role of the distributor in the consultation;
   - the status of the consultation process; and

- where applicable the expected date(s) on which final deliverables are expected to be issued.

c) the comment letter provided by the OPA in relation to REG investments included in the distributor's DS Plan (see 5.2.4.2), along with any written response to the letter from the distributor, if applicable.

5.2.3 Performance measurement for continuous improvement

As mentioned in section 5.0, good distributor planning is an essential element of the Board's performance-based rate-setting approaches. The Board understands that distributors often use certain qualitative assessments and/or quantitative metrics to monitor the quality of their planning process, the efficiency with which their plans are implemented, and/or the extent to which their planning objectives are met. The Board expects that this information is used to improve continuously a distributor's asset management and capital expenditure planning processes.

a) identify and define the methods and measures (metrics) used to monitor distribution system planning process performance, providing for each a brief description of its purpose, form (e.g. formula if quantitative metric) and motivation (e.g. consumer, legislative, regulatory, corporate). These measures and metrics are expected to address, but need not be limited to:

    - customer oriented performance (e.g. consumer bill impacts; reliability; power quality);
    - cost efficiency and effectiveness with respect to planning quality and DS Plan implementation (e.g. physical and financial progress vs. plan; actual vs. planned cost of work completed); and
    - asset and/or system operations performance.

b) provide a summary of performance and performance trends over the historical period using the methods and measures (metrics/targets) identified and described above. This summary must include historical period data on: 1) all interruptions; and 2) all interruptions excluding loss of supply' for a) the distribution system average interruption frequency index; b) system average interruption duration index; and c) customer average interruption duration index.[15]

    Where performance assessments indicate marked adverse deviations from trend or targets (including any established in a previously filed DS Plan), provide a brief explanation and refer to these instances individually when responding to provision 'c)' below.

c) explain how this information has affected the DS Plan (e.g. objectives; investment priorities; expected outcomes) and has been used to continuously improve the asset management and capital expenditure planning process.

[15] The data should be calculated as stipulated in section 2.1.4.2 of the Board's Reporting and Record Keeping Requirements.

5.3 Asset Management Process

As noted in the Introduction, a distributor's asset management process is the systematic approach used to plan and optimize ongoing capital and operating and maintenance expenditures on its distribution system and general plant. The purpose of the information requirements set out in this section 5.3 is to provide the Board and stakeholders with an understanding of the distributor's asset management process, and the direct links between the process and the expenditure decisions that comprise the distributor's capital investment plan.

5.3.1 Asset management process overview

This section provides the Board and stakeholders with a high level overview of the information filed on a distributor's asset management process, including key elements of the process that have informed the preparation of the distributor's capital expenditure plan and therefore are referred to in response to requirements for more detailed information supporting the overall capital expenditure plan, budget allocations to categories of investments, or material projects/activities proposed for recovery in rates. The information provided should include but need not be limited to:

a) a description of the distributor's asset management objectives and related corporate goals, and the relationships between them; where applicable, show and explain how the distributor ranks asset management objectives for the purpose of prioritizing investments;

b) information regarding the components (inputs/outputs) of the asset management process used to prepare a capital expenditure plan, identify and briefly explain the data sets, primary process steps, and information flows used by the distributor to identify, select, prioritize and/or pace investments; e.g.

- asset register
- asset condition assessment
- asset capacity utilization/constraint assessment
- historical period data on customer interruptions caused by equipment failure
- reliability-based ‘worst performing feeder’ information and analysis
- reliability risk/consequence of failure analyses.

Use of a flowchart illustration accompanied by explanatory text is recommended.

5.3.2 Overview of assets managed

Appropriate regulatory assessment of DS Plans requires an understanding of the scope and depth of the assets managed by a distributor. Distributors vary in terms of the types of assets managed (e.g. some own high voltage equipment; others do not). Detailed characteristics and data on the assets covered by the asset management process are to be filed, including but not necessarily limited to

a) a description and explanation of the features of the distribution service area (e.g. urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth) pertinent for asset management purposes, highlighting where applicable expectations for the evolution of these features over the forecast period that have affected elements of the DS Plan;

b) a summary description of the system configuration, including length (km) of underground and overhead systems; number and length of circuits by voltage level; number and capacity of transformer stations;

c) information (in tables and/or figures) by asset type (where available) on the quantity/years in service profile and condition of the distributor's system assets, including the date(s) the data was compiled; and

d) an assessment of the degree to which the capacity of existing system assets is utilized relative to planning criteria, referencing the distributor's asset related objectives and targets

    - where cited as a 'driver' of a material investment(s) included in the capital expenditure plan, provide a level of detail sufficient to understand the influence of this factor on the scope and value of the investment.

5.3.3 Asset lifecycle optimization policies and practices

An understanding of a distributor's asset lifecycle optimization policies and practices will support the regulatory assessment of system renewal investments and decisions to refurbish rather than replace system assets. Information provided should be sufficient to show the trade-off between spending on new capital (i.e. replacement) and life-extending refurbishment, and should include but need not be limited to:

a) A description of asset lifecycle optimization policies and practices, including but not necessarily limited to:

    - a description of asset replacement and refurbishment policies, including an explanation of how (e.g. processes; tools) system renewal program spending is optimized, prioritized and scheduled to align with budget envelopes; and how the impact of system renewal investments on routine system O&M is assessed;
    - a description of maintenance planning criteria and assumptions; and

- a description of routine and preventative inspection and maintenance policies, practices and programmes (can include references to the DSC).

b) A description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation, including but not necessarily limited to the methods used; types of information inputs and outputs; and how conclusions of risk analyses are used to select and prioritize capital expenditures.

5.4 Capital Expenditure Plan

A distributor's DS Plan details the programme of system investment decisions developed on the basis of information derived from its asset management and capital expenditure planning process. It is critical that investments, whether identified by category or by specific project, be justified in whole or in part by reference to specific aspects of that process.

As noted above, a DS Plan must include information on prospective investments over a minimum five year forecast period, beginning with the test year (or initial test year if Customer IR filing), as well as information on investments – planned and actual – over the five year period prior to the initial year of the forecast period.

5.4.1 Summary

This section elicits key information about a distributor's capital expenditure plan including, by category (see section 5.1.1), significant projects and activities to be undertaken and their respective key drivers; the relationship between investments in each category and a distributor's objectives and targets; and the primary factors affecting the timing of investment in each category (or of projects within each category, if significant).

The following information should be provided:

a) information on the capability of the distributor's system to connect new load or generation customers in sufficient detail to convey the basis for the scope and quantum of investments related to this 'driver';

b) total annual capital expenditures over the forecast period, by investment category (see section 5.4);

c) a brief description of how for each category of investment, the outputs of the distributor's asset management and capital expenditure planning process have affected capital expenditures in that category and the allocation of the capital budget among categories;

d) a list and brief description including total capital cost (table format recommended) of material capital expenditure projects/activities, sorted by category;

e) information related to a Regional Planning Process or contained in a Regional Infrastructure Plan that had a material impact on the distributor's capital expenditure plan, with a brief explanation as to how the information is reflected in the plan;

f) a brief description of customer engagement activities to obtain information on their preferences and how the results of assessing this information are reflected in the plan;

g) a brief description of how the distributor expects its system to develop over the next five years, including in relation to load and customer growth, smart grid development and/or the accommodation of forecasted renewable energy generation projects;

h) a list and brief description including where applicable total capital cost (table format recommended) of projects/activities planned:

- in response to customer preferences (e.g., data access and visibility; participation in distributed generation; load management);
- to take advantage of technology-based opportunities to improve operational efficiency, asset management and the integration of distributed generation and complex loads; and
- to study or demonstrate innovative processes, services, business models, or technologies.

5.4.2 Capital expenditure planning process overview

The information a distributor should provide includes, but need not be restricted to:

a) a description of the distributor's capital expenditure planning objectives, planning criteria and assumptions used, explaining relationships with asset management objectives, and including where applicable its outlook and objectives for accommodating the connection of renewable generation facilities;

b) if not otherwise specified in (a), the distributor's policy on and procedure whereby non-distribution system alternatives to relieving system capacity or operational constraints are considered, including the role of Regional Planning Processes in identifying and assessing alternatives;

c) a description of the process(es), tools and methods (including where relevant linkages to the distributor's asset management process) used to identify, select, prioritise and pace the execution of projects in each investment category (e.g. analysis of impact of planned capital expenditures on customer bills);

d) if not otherwise included in c) above, details of the mechanisms used by the distributor to engage customers for the purpose of identifying their needs, priorities and preferences (e.g. surveys, system data analytics, and analyses – by rate class – of customer feedback, inquiries, and complaints); the stages of the planning process at which this information is used; and the aspects of the DS Plan that have been particularly affected by consideration of this information; and

e) if different from that described above, the method and criteria used to prioritise REG investments in accordance with the planned development of the system, including the impact if any of the distributor's plans to connect distributor-owned renewable generation project(s).

5.4.3 System capability assessment for renewable energy generation

This section provides information on the capability of a distributor's distribution system to accommodate REG, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); and information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity.

In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable) includes:

a) applications from renewable generators over 10kW for connection in the distributor's service area;

b) the number and the capacity (in MW) of renewable generation connections anticipated over the forecast period based on existing connection applications, information available from the OPA and any other information the distributor has about the potential for renewable generation in its service area (where a distributor has a large service area, or two or more non-contiguous regions included in its service area, a regional breakdown should be provided);

c) the capacity (MW) of the distributor's distribution system to connect renewable energy generation located within the distributor's service area;

d) constraints related to the connection of renewable generation, either within the distributor's system or upstream system (host distributor and/or transmitter); and

e) constraints for an embedded distributor that may result from the connections.

5.4.4 Capital expenditure summary

The purpose of the information filed under this section is to provide the Board and stakeholders with a 'snapshot' of a distributor's capital expenditures over a 10 year period, including five historical years and five forecast years. Note that where a distributor's internal investment planning framework does not align with the investment categories defined here, best efforts are expected to 'map' investments to these categories.

Despite the 'multi-purpose' character of a project or activity, for 'summary' purposes the entire costs of individual projects or activities are to be allocated to one of the four investment categories on the basis of the primary (i.e. initial or 'trigger') driver of the investment. Note, however, that for material projects, a distributor must estimate and allocate costs to the relevant investment categories when providing information to justify the investment, as this assists in understanding the relationship between the costs and benefits attributable to each driver underlying the investment. In any event, the categorization of an individual project or activity for the purposes of these filing requirements should not in any way affect the proper apportionment of project costs as per the DSC.

Table 2 illustrates how information filed under this section includes a distributor's actual and forecast (i.e. proposed) capital expenditures over the historical and forecast periods. System operations and maintenance (O&M) costs are also shown to reflect the potential impact, if any, of capital expenditures on routine system O&M. Note that 'Plan' expenditures over the historical period refer to a distributor's previous plan for capital expenditures *after* adjustments (if any) occasioned by the Board's decision on the relevant prior application.

Brief explanatory notes should be provided to explain the factor(s) and/or circumstances underlying marked changes in the share of total investment represented by a given investment category over the forecast period relative to 'actual' spending over the historical period. For example, a large expenditure over a relatively short period for a 'one-off' project (e.g. a distribution station) can cause a temporary 'step change' in category C spending compared to the trend in actual expenditures over the historical period.

While year over year 'Plan vs. Actual' variances for individual investment categories are expected, explanatory notes should be provided where

- for any given year "Total" 'Plan' vs. 'Actual' variances over the historical period are markedly positive or negative; or
- a trend for variances in a given investment category is markedly positive or negative over the historical period.

Table 2 – Capital Expenditure Summary

CATEGORY	Historical (previous plan[1] & actual)															Forecast (planned)				
	Test-5			Test-4			Test-3			Test-2			Test-1[2]			Test	Test+1	Test+2	Test+3	Test+4
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000	$ '000	$ '000	$ '000	$ '000
System Access																				
System Renewal																				
System Service																				
General Plant																				
Total																				
System O&M																				

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in year 'Test-1' (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category
Notes on year over year Plan vs. Actual variances for Total Expenditures
Notes on Plan vs. Actual variance trends for individual expenditure categories

5.4.5 Justifying capital expenditures

As indicated in Chapter 1, the onus is on a distributor to provide the data, information and analyses necessary to support the capital-related costs upon which the distributor's rate proposal is based. Filings must enable the Board to assess whether and how a distributor's DS Plan delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate optimization, prioritization and pacing of capital-related expenditures.

5.4.5.1 Overall plan

The Board's assessment of DS Plans includes the costs of material projects/activities included in the DS Plan, as well as the costs represented by the respective shares of the overall DS Plan budget allocated to each of the four investment categories. Information to be provided in this section pertains to the latter; the former is addressed in section 5.4.5.2.

To support the overall quantum of investments included in a DS Plan by category, a distributor should include information on:

- comparative expenditures by category over the historical period;
- the forecast impact of system investment on system O&M costs, including on the direction and timing of expected impacts;
- the 'drivers' of investments by category (referencing information provided in response to sections 5.3 and 5.4), including historical trend and expected evolution of each driver over the forecast period (e.g. information on the distributor's asset-related performance and performance targets relevant for each category, referencing information provided in section 5.2.3);
- information related to the distributor's system capability assessment (see section 5.4.3)

5.4.5.2 Material investments

The focus of this section is on projects/activities that meet the materiality threshold set out in Chapter 2 of the *Filing Requirements for Electricity Transmission and Distribution Applications*. However, distributors are encouraged in all instances to consider the applicability of these requirements to ensure that all investments proposed for recovery in rates, including those deemed by the applicant to be distinct for any other reason (e.g. unique characteristics; marked divergence from previous trend) are supported by evidence that enables the Board's assessment according to the evaluation criteria set out below. The level of detail characterizing the evidence filed by a distributor to support a given investment project/activity should be proportional to the materiality of the investment.

A. General Information on the Project/Activity

The following information is to be provided for any material project in order to facilitate and understanding of the quantum of the expenditure, timing, and contingencies associated with the project:

- total capital and where applicable, (non-capitalized) O&M costs proposed for recovery in rates
- related customer attachments and load, as applicable
- start date, in-service date and expenditure timing over the planning horizon
- the risks to the completion of the project or activity as planned and the manner in which such risks will be mitigated
- if not evident from Table 2, comparative information on expenditures for equivalent projects/activities over the historical period, where available
- information on total capital and OM&A costs associated with REG investment, if any, included in a project/activity; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities
- where a proposed project requires Leave to Construct approval under Section 92 of the OEB Act, with construction commencing in the test year, the applicant must provide a summary of the evidence for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular)

B. Evaluation criteria and information requirements for each project/activity

The Board's evaluation of material investments aligns with the outcomes set out in section 5.0.4. Efficiency, customer value, reliability and safety are the primary criteria for evaluating any material investment; other criteria pertaining specifically to grid modernization will be applied where applicable.

The Board's investment evaluation criteria and the qualitative or quantitative evidence that a distributor can use to demonstrate that an investment is consistent with these criteria are set out below.

1. *Efficiency, Customer Value, Reliability*
    a) identify the main 'driver' ('trigger') of the project/activity, and where applicable any secondary 'drivers'; related objectives and/or performance targets; and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment
    b) indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.2(c)

c) using, where applicable, quantitative and/or qualitative analyses of the project and project alternatives involving design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties)

   – explain the effect of the investment on system operation efficiency and cost-effectiveness
   – the net benefits accruing to customers as a result of the investment
   – the impact of the investment on reliability performance including on the frequency and duration of outages

   Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the imputed value of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.

   Where a distributor's choices as to technical design, component characteristics, how the work is carried out, etc. have been affected by a decision to configure a project to meet both a 'trigger' driver and one or more other drivers in a manner that affects cost as well as benefits, these effects should be highlighted.

2. *Safety*

   Provide information on the effect of the investment on health and safety protections and performance

3. *Cyber-security, Privacy*

   Where applicable, provide information showing that the investment conforms to all applicable laws, standards and best utility practices pertaining to customer privacy, cyber-security and grid protection

4. *Co-ordination, Interoperability*

   a) where applicable, explain how the investment applies recognized standards, referencing co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.

   b) describe how the investment potentially enables future technological functionality and/or addresses future operational requirements

5. *Economic Development*

   Where applicable, describe the effect of the investment on Ontario economic growth and job creation

6. *Environmental Benefits*:

   Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies

C. Category-specific requirements for each project/activity

As set out below, category-specific information and analyses should also be used to support a project/activity (or elements thereof as applicable).

a) *System access* – projects/activities in this category are driven by statutory, regulatory or other obligations on the part of the distributor to provide customers with access to their distribution system. Most frequently, investments relate to requests by customers for connections or connection modifications, but also include requests from municipal authorities for a distributor to relocate system assets in order to accommodate infrastructure development or modifications. Consequently, investment budgets for this category can vary from one DS Plan to the next depending on business conditions.

   In the event that the project involves replacing a distributor's system assets, there may also be asset life-cycle related considerations to the extent that infrastructure is taken out of service prior to the end of its service life and new infrastructure is commissioned.

   Information bearing on these issues should therefore be included in a distributor's justification of a project/activity in this category, including (where applicable) but not restricted to:

   - factors affecting the timing/priority of implementing the project
   - factors relating to customer preferences or input from customers and other third parties
   - factors affecting the final cost of the project
   - how controllable costs have been minimized
   - whether other planning objectives are met by the project or have intentionally been combined into the project and if so, which objectives and why
   - whether technically feasible project design and/or implementation options exist, whether these options were considered and if not, why not
   - where such options were considered and project decision support tools and methods described in response to section 5.4.2 (c) were used to help identify the proposed option, provide a summary of the results of the analysis, including where applicable:
     – the least cost option: a comparison of the life cycle cost of all options considered (including the proposed project) – over the service life of the proposed project
     – the cost efficient option: a comparison of net project benefits and costs over the service life of the proposed project including:
       i. a project configured solely to meet the obligation; and

ii. the proposed project and where considered, technically feasible options to the proposed project that meet the same objectives.

- where applicable, the results of the 'final economic evaluation' carried out as per section 3.2 of the DSC
- where applicable (e.g. REG investment), information on the nature and magnitude of the system impacts of the project, the costs of any system modifications required to accommodate these impacts and the means by which these costs are to be recovered

b) *System renewal* – projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure"). Generally, the lower the former and/or higher the latter, the more important it becomes to replace or refurbish the asset(s) sooner rather than later.

Hence, a distributor's discretion over the timing and priority of projects in this category may lessen over time, such as where assets with high consequence of failure are consistently operating outside applicable operating limits. On the other hand, a distributor may have considerable discretion over timing and priority where deteriorating asset condition has little or no impact on performance and the consequences in terms of the number of customers and criticality of service potentially affected by an asset failure are relatively low.

Information bearing on these issues should therefore be included in a distributor's justification of each sustainment project/activity, including (where applicable) but not restricted to:

- a description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to
  - the distributor's asset performance-related operational targets and asset lifecycle optimization policies and practices (i.e. filings in relation to sections 5.2.3 and 5.3.3)
  - information on the condition of the assets relative to their typical life-cycle; and performance record of the assets targeted by the project
  - the number of customers in each customer class potentially affected by a failure of the assets included in the project
  - quantitative customer impacts (e.g. frequency or duration of interruptions or number of customers affected) with associated risk level(s)
  - qualitative customer impacts (e.g. customer satisfaction; customer migration) with associated risk level(s)

  - the value of customer impact (e.g. high, medium, low) in terms of the characteristics of customers potentially affected by failure that have a bearing on the criticality and/or cost of failure (e.g. customer classes; customer access to backup service)
- other factors that may affect the timing of the proposed project, including the rate at which assets are replaced over the forecast period (i.e. investment intensity), where applicable; priority relative to other projects (this and other categories)
- identify the consequences for system O&M costs, including the implications for system O&M of not implementing the project
- identification of reliability and or safety factors that may have played a role
- where applicable and reasonable variation and/or uncertainty in the above factors exists, provide – using the tools and methods described in response to section 5.4.2 (c) – an analysis of project benefits and costs comparing alternatives to the timing of the proposed project, highlighting the trade-offs between rate of expenditure and mitigation of the consequences of asset performance deterioration. Where the ranking of the proposed project relative to the alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.
- where the proposed project meets the requirement for 'like for like' renewal and has been configured at extra cost to address other distributor planning objectives (e.g. development related objectives), provide – using the tools and methods described in response to section 5.4.2 (c) – an analysis of project benefits and costs comparing a) a project configured solely to meet the requirement; b) the proposed project; and c) technically feasible alternatives to the proposed project that meet the same objectives as the proposed project. Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.

c) *System service* – projects/activities in this category are driven by the distributor's expectations that evolving customer use of the system may occasion the creation of system capacity constraints or otherwise adversely impact operations in a manner that challenges the distributor's service delivery standards or objectives. Distributor discretion in relation to investments in this category can be relatively high in terms of both initiating a project and determining the priority and timing of project-related expenditures.

   Information used by a distributor to justify projects/activities in this category should include, but need not be restricted to:

- where measurable, an assessment of the benefits of the project for customers in relation to the achievement of the objectives of the investment; express the result (including where value is in the form of an avoided cost) in terms of cost impact to customers where practicable

- where applicable, information on regional electricity infrastructure requirements identified in a regional planning process that affected the initiation or final configuration of the project; and on the corresponding distribution of the benefits and responsibility for project costs
- description of how advanced technology has been incorporated into the project (if applicable) and including how standards relating to interoperability and cybersecurity have been met.
- identification of any reliability, efficiency, safety and coordination benefits or affects the project will have on the distributor's system
- identifying and explaining the factors affecting implementation timing/priority
- providing, where applicable and using the tools and methods described in response to section 5.4.2 (c), an analysis of project benefits and costs comparing the proposed project to a) doing nothing; and b) technically feasible alternatives to the proposed project considered that meet the same objectives as the proposed project.

  Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, information should be provided that describes these 'qualitative' factors in relation to the proposed project and all alternatives, and that explains whether and how these factors affected the selection of the proposed project.

d) ***General plant*** – projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities. Distributor discretion in relation to investments in this category can be relatively high in terms of both initiating a project and determining the priority and timing of project-related expenditures.

   Information used by a distributor to justify material projects/activities in this category should include but need not be restricted to:

   - the results of quantitative and qualitative analyses (using the tools and methods described in response to section 5.4.2 (c) where applicable) of the proposed project/activity, including assessments of financially feasible options to the proposed project (including the 'do nothing option' where applicable), identifying the (net) benefits of the proposed investment in monetary terms where practicable;
   - For projects the capital cost of which substantially exceed the materiality threshold, (e.g. CIS, GIS, new office building) the distributor shall file a thorough business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).