Table of Contents

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12 Economic Evaluations – 2013 Update on Selected Development Plans

12.0 Chapter Overview

The NFAT submission has utilized 2012 planning assumptions (with export prices adjusted primarily downward) throughout with the exception of this chapter. Chapter 12 presents an evaluation of the economics of selected development plans using 2013 planning assumptions for load forecast, electricity export prices, natural gas prices, economic parameters and resource timing. A demand side management (DSM) sensitivity and a DSM stress test are also included to demonstrate whether the Preferred Development Plan remains attractive under higher levels of DSM. An economic analysis to evaluate the attractiveness of higher levels of DSM could not be completed in time for this NFAT submission as overall resource costs, including program costs for increased levels of DSM, were not available.

Due to the timing of Manitoba Hydro's annual planning cycle, only a limited scope of development plans and analysis is available to be presented in this chapter.

12.1 2013 Updated Reference Scenario Assumptions

The following updated assumptions have been applied to the reference scenario, i.e. "most likely outcomes", as a basis for the 2013 economic analysis update in this chapter:

- Overall the 2013 Electric Load Forecast has decreased for both energy and peak demand as compared to the 2012 Electric Load Forecast.
- The next generation in-service date requirement for Manitoba load and existing firm commitments has been deferred from 2022/23 to 2023/24.
- With respect to export sales, the Great River Energy (GRE) Diversity Exchange Agreement has been extended, based on the progress of negotiations, to end in 2030/31 as opposed to the end date of 2025/26 used in the 2012 planning assumptions.

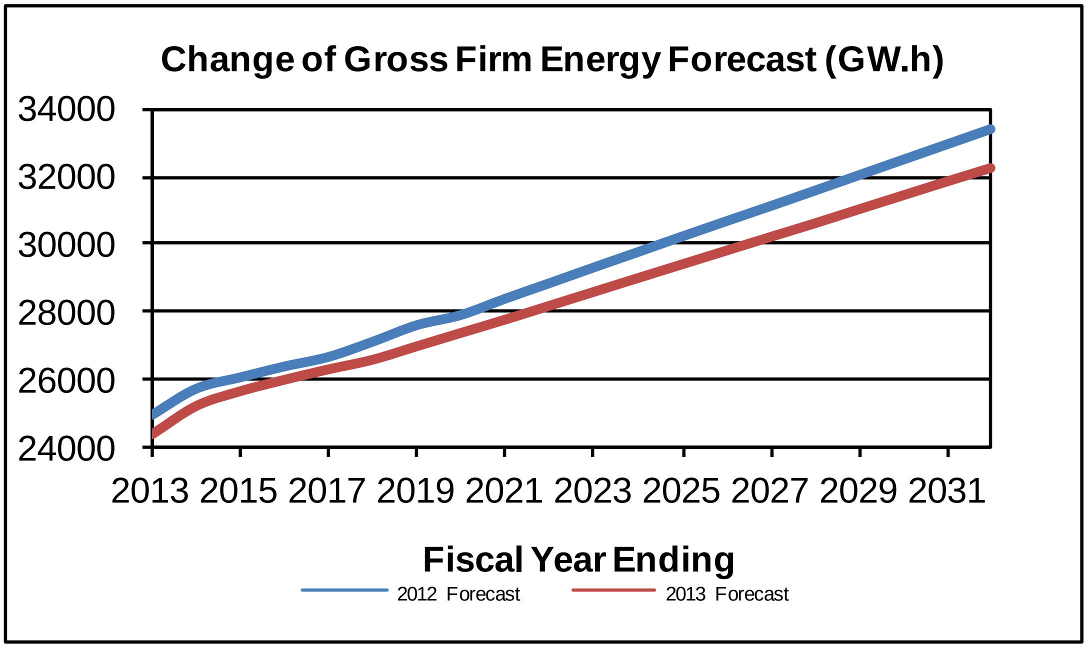
In addition, a new five year 50 MW Term Sheet with Minnesota Power (MP) beginning 2015/16 is included in the 2013 assumptions.

- The 2013 forecast for electricity export prices is higher than the electricity export prices used in the 2012 planning assumptions in the NFAT submission.
- The real discount rate has been increased from 5.05% in the 2012 planning assumptions to 5.40% in the 2013 assumptions.
- The earliest possible in-service date for the Conawapa G.S. is now 2026/27, as opposed to 2025/26 used in the 2012 assumptions.

12.1.1 Changes Between the 2012 and 2013 Electric Load Forecasts

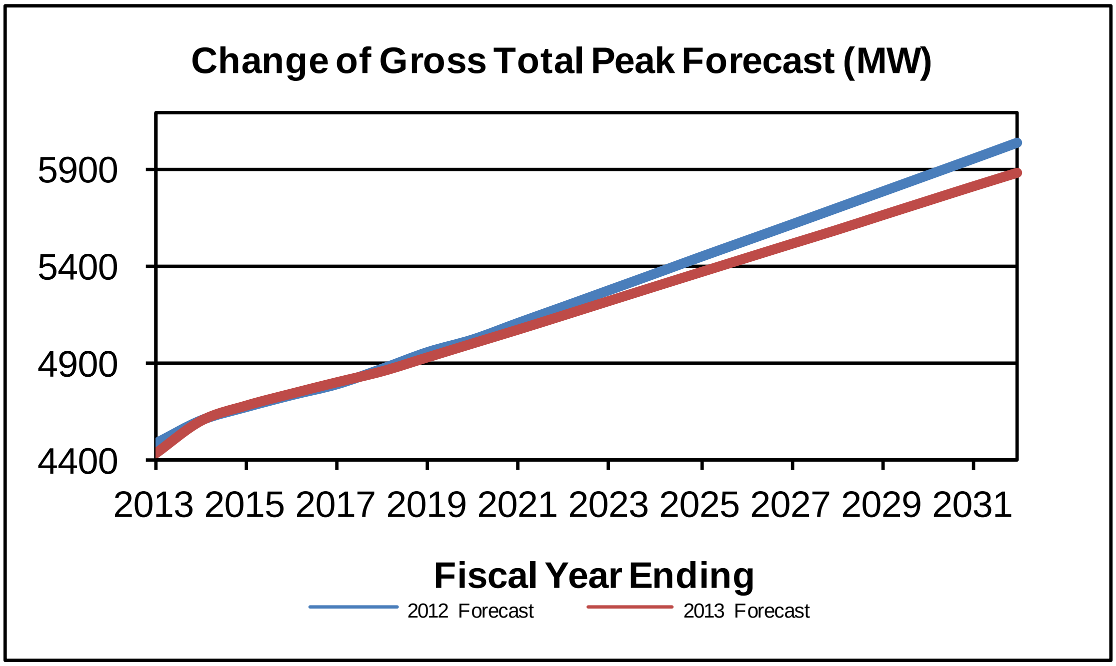
The Gross Firm Energy forecast under the 2013 Electric Load Forecast is 1,159 GWh (3.5%) lower by 2031/32 compared to the 2012 Electric Load Forecast, primarily due to the reduction of the Residential Basic customer forecast and its effect on the Residential and General Service Mass Market forecasts. The reduction in Gross Total Firm Energy in 2022/23 of 717 GWh (2.4%) is equivalent to approximately 1.5 years of load growth (one year = approximately 420 GWh). In 2031/32, the 3.5% decrease in Gross Total Firm Energy is equivalent to a reduction of almost three years of load growth. The 2013 Electric Load forecast for Gross Total Firm Energy compared to 2012 is shown in Figure 12.1 below.

Figure 12.1 GROSS TOTAL FIRM ENERGY FORECAST – COMPARISON OF 2013 TO 2012



The Gross Total Peak (Manitoba peak demand) forecast under the 2013 Electric Load Forecast is 146 MW (2.4 %) lower by 2031/32 compared to the 2012 Electric Load Forecast. The reduction in winter peak demand in 2022/23 amounts to 54 MW, less than one year of load growth (one year = approximately 80 MW). The reduction in winter peak demand in 2031/32, of 146 MW, amounts to a reduction of almost two years of load growth. The forecast of Manitoba peak demand very closely follows the energy forecast, and the reasons for the reduction in winter peak demand are similar to those for energy. The 2013 Electric Load Forecast for Gross Total Peak compared to 2012 is shown in Figure 12.2.

Figure 12.2 GROSS TOTAL PEAK FORECAST – COMPARISON OF 2013 TO 2012



The primary changes between the 2013 Electric Load Forecast and the 2012 Electric Load Forecast are as follows:

- Residential Basic forecast decreased primarily due to the decrease in the forecast growth of Residential Basic customers and to reflect heating fuel choice initiatives being undertaken by Manitoba Hydro.
- General Service Mass Market forecast decreased primarily due to the decrease in the forecast growth of Residential Basic customers.
- General Service Top Consumers forecast decreased, mostly in the Primary Metals sector.

12.1.2 Changes in Demand Side Management Forecast

The update to the 2013-2016 Power Smart Plan (along with the 2013-2016 Power Smart Plan – 15 Year Supplementary Analysis Report) results in a reduction in forecasted DSM savings of

93 GWh and 29 MW by the year 2027/28 based on changes to assumptions related to Manitoba Hydro's Power Smart programs.

12.1.3 **Changes in Need for New Resources**

Based on the 2013 Electric Load Forecast, new generation to meet Manitoba load and existing firm commitments will be required in 2023/24, which is one year later than the requirement using the 2012 planning assumptions. Similarly new capacity resources are required one year later, in 2026/27, as shown in Figure 12.4. Supply and demand tables for the 2013 update are included in ***Appendix 4.2 – Manitoba Hydro Supply and Demand Tables.***

Figure 12.3 shows the dependable energy balance for the next 20 years (2013/14 to 2032/33) as either a surplus or deficit, assuming no further resource additions to system supply.

Figure 12.3 2013 UPDATE – ENERGY BALANCE-DEPENDABLE ENERGY

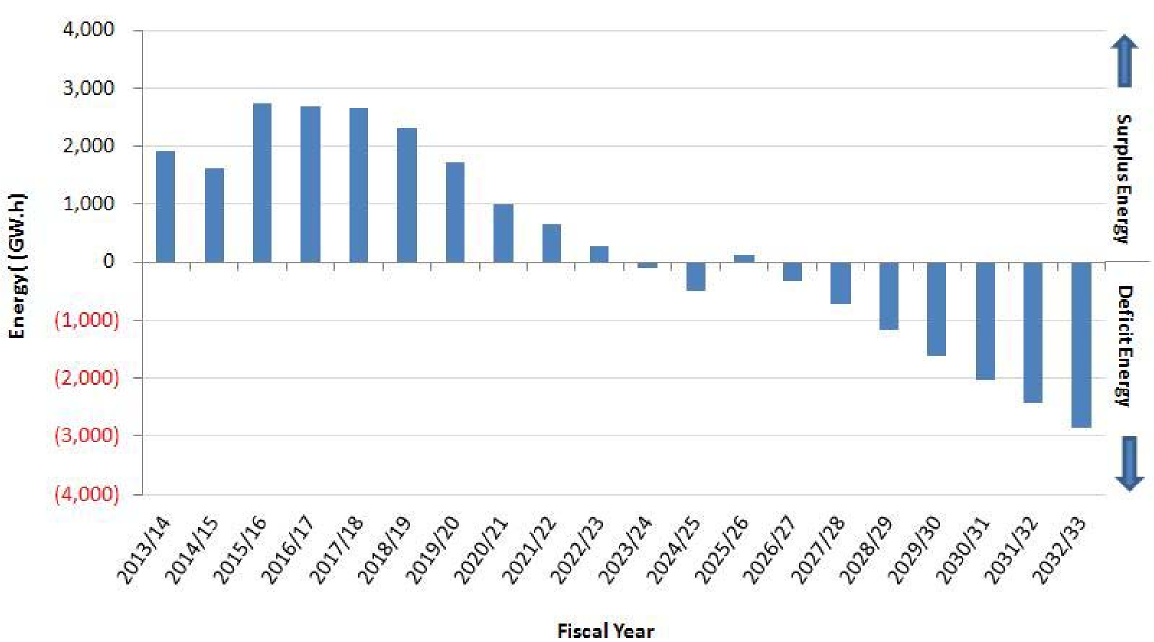
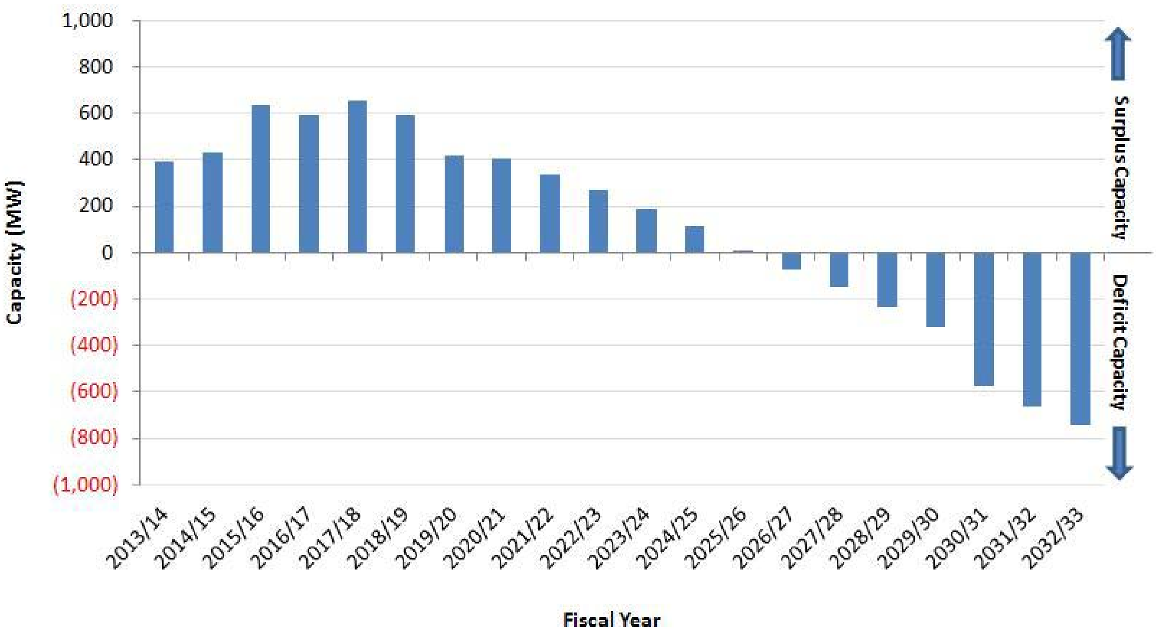


Figure 12.4 shows the capacity balance for the next 20 years (2013/14 to 2032/33) as either a surplus or deficit, assuming no further resource additions to the system.

Figure 12.4 2013 UPDATE CAPACITY BALANCE – WINTER PEAK CAPACITY



As dependable energy deficits begin earlier than capacity deficits, it is the shortfall of dependable energy which drives the need for new resources in the year 2023/24.

Tables 12.1 and 12.2 summarize the supply and demand values for key dates from the 35-year study period to demonstrate whether a surplus or deficit is expected. More detailed versions of these tables showing each year of the study period are included in ***Appendix 4.2 – Manitoba Hydro Supply and Demand Tables.***

Table 12.1 WINTER PEAK CAPACITY BALANCE FOR SELECT YEARS (MW)
@ GENERATION

Winter Peak Capacity, MW				
Fiscal Year	2014/15	2022/23	2023/24	2026/27
Total Base Supply	6,183	6,312	6,312	5,927
Total Peak Demand	5,242	5,436	5,505	5,355
Reserves	510	609	618	643
System Surplus (Deficit)	431	267	189	(71)

Table 12.2 DEPENDABLE ENERGY BALANCE FOR SELECT YEARS (GWH)
@ GENERATION

Dependable Energy, GWh				
Fiscal Year	2014/15	2022/23	2023/24	2026/27
Total Base Supply	30,242	30,018	30,018	29,461
Total Energy Demand	28,628	29,742	30,121	29,785
System Surplus (Deficit)	1,614	276	(103)	(324)

12.1.4 **2013 Electricity Export Price Forecast**

The 2013 Electricity Export Price Forecast was prepared using the consensus forecasting methodology described in ***Appendix 9.3 – Economic Evaluation Documentation***. The 2013/14 electricity export price forecast has resulted in, on average, an approximate increase of 7% to the reference electricity export price forecast relative to the adjusted 2012/13 electricity export price forecast used elsewhere in the NFAT submission.

12.1.5 **Conawapa G.S. Earliest In-Service Date**

For the 2013 update it is assumed the earliest possible in-service date for the Conawapa G.S. is 2026/27, as opposed to 2025/26 used in the 2012 planning assumptions.

12.1.6 Changes to Export Sales Agreement Assumptions

All sales assumptions for the 2013 update remain the same, with the exception of the Great River Energy Diversity Exchange Agreement which starts in 2014/15 and which was extended to end in 2030/31—as opposed to the end date of 2025/26 used in the 2012 planning assumptions. As well, a new five-year 50 MW term sheet with Minnesota Power beginning in 2015/16 is included in the 2013 update.

12.1.7 Discount Rate

As shown in ***Appendix 9.3 Economic Evaluation Documentation***, the real discount rate applied for the economic evaluations in the 2013 update is 5.40%, which has increased from the 5.05% used in the 2012 planning assumptions. The increase in discount rate reflects the update in the consensus forecast used by Manitoba Hydro for economic indicators.

12.2 Demand Side Management Sensitivity and Stress Test Assumptions

As noted in ***Chapter 4 – The Need for New Resources*** (Section 4.2.2) and provided in ***Appendix 4.4 – Demand Side Management Potential Study***, the DSM Potential Study examines the “market potential” (“ideal”) and “achievable potential” of existing energy-efficient technologies which are economic in Manitoba and for those technologies that may be on the horizon.

For the purposes of this submission, a sensitivity analysis for increased DSM was undertaken, including increasing Manitoba Hydro energy and capacity savings through DSM by 1.5 times, and, similarly, a stress test for increased DSM was undertaken for 4.0 times the current planned DSM. This DSM sensitivity and stress test analysis can also be viewed as being representative of a lower load growth sensitivity. As described in ***Chapter 4 – The Need for New Resources*** and ***Chapter 7 – Screening of Manitoba Resource Options***, the results of the market potential study demonstrates that a 1.5 times sensitivity and 4.0 times stress test were reasonable approximations for the “achievable potential” and “ideal” thresholds for energy savings through DSM initiatives, respectively. Assumptions used in the 1.5 times sensitivity and 4.0 times stress test are shown in the ***Appendix 4.2 Manitoba Hydro Supply Demand Tables***.

The DSM sensitivity and stress test demonstrate whether the Preferred Development Plan remains attractive under higher levels of DSM. As discussed in ***Chapter 9 – Economic Evaluation – Reference Scenario***, when evaluating alternative development plans, the incremental costs and benefits associated with one development plan are compared to another development plan. Costs and benefits that are common to all development plans are not included in the analysis as these values are the same in each development plan. As the costs associated with the increased level of DSM for either the DSM sensitivity or stress test analysis would be the same for each development plan, additional program costs will not impact the analysis undertaken in this chapter.

12.3 2013 Update Economic Analysis – Reference Scenario

12.3.1 **2013 Update – Reference Scenario Development Plans**

Table 12.3 provides a brief summary of development plans included in the reference scenario economic evaluation based on 2013 updated planning assumptions. The development plans in this chapter are formulated using the same concepts described in ***Chapter 8 – Determination and Description of Development Plans.*** Development plans selected for the 2013 update incorporate a range of resource options and recognize the opportunity for a 250 MW and/or 750 MW U.S. interconnection.

Table 12.3 LIST OF 2013 REFERENCE SCENARIO DEVELOPMENT PLANS

Order of Capital Investment	Development Plan Short Name	Description of Development Plan
1	All Gas	Natural Gas-Fired Generation starting in 2023/24
2	K23/Gas	Keeyask 2023/24, Natural Gas-Fired Generation starting in 2031/32
4	K19/Gas30/250MW	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2030/31, 250 MW Export/50 MW Import Interconnection 2020/21, 250 MW MP Sale
12	K19/C33/750MW	Keeyask 2019/20, Imports, Conawapa 2033/34, Natural Gas-Fired Generation starting in 2045/46, 750 MW Import/Export Interconnection 2020/21, 250 MW MP Sale
14	K19/C26/750MW (WPS Sale & Inv) Preferred Development Plan	Keeyask 2019/20, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2045/46, 750 MW Import/Export Interconnection 2020/21, 250 MW MP Sale and proposed 300 MW WPS Sale

12.3.2 **2013 Update – Reference Scenario Results**

The economic analysis of the DSM sensitivity provides the net present value (NPV) of the incremental investment associated with each development plan. The incremental investment associated with a more costly development plan is economically preferable if it provides a positive incremental NPV.

Table 12.4 compares the incremental differences in NPV for five developments plans evaluated using 2013 assumptions.

Table 12.4 2013 ECONOMIC ANALYSIS - REFERENCE SCENARIO

Development Plan	Incremental NPV, millions of 2014 Dollars @ 5.40% Discount Rate			
	1 - All Gas	2 - K23/Gas	4 - K19/Gas30/250MW	12 - K19/C33/750MW
1 All Gas				
Lowest Capital Investment Development Plan	-			
2 K23/Gas	2 -1			
	$728			
4 K19/Gas30/250MW	4 -1	4 -2		
MP Sale	$1,133	$405		
12 K19/C33/750MW	12 -1	12 -2	12 -4	
MP Sale	$1,204	$476	$71	
14 K19/C26/750MW	14 -1	14 -2	14 -4	14 -12
MP Sale, WPS Sale & Inv Preferred Development Plan	$1,462	$734	$329	$258

As shown in Table 12.4, a comparison of development plan Plan 2 (K23/Gas) to the All Gas plan demonstrates that Keeyask G.S. as the first resource to meet Manitoba load requirements is an economic option.

A comparison of Plan 4 (K19/Gas30/250MW) to the Plan 2 (K23/Gas) and All Gas development plans shows that the additional capital investment required for this development plan, which includes Keeyask G.S., the 250 MW MP Sale and a new 250 MW U.S. interconnection, is economic.

The Preferred Development Plan, which includes the proposed 300 MW WPS sale and investment, remains the most economic option to meet Manitoba load requirements and existing firm commitments when compared against the development plans with lower capital costs.

Plan 12 (K19/C33/750MW) includes the 250 MW MP sale but does not include the proposed 300 MW WPS sale and investment. Plan 12 demonstrates that deferring Conawapa G.S. in-service date in a plan that has a 750 MW U.S. interconnection remains economic.

12.3.3 **Comparison of 2012 and 2013 Reference Scenario Results**

Table 12.5 provides a comparison of incremental NPVs of development plans relative to the All Gas plan for both the 2012 planning assumptions used elsewhere in the NFAT submission and for 2013 planning assumptions. When the change in discount rate assumptions is excluded, the effect of the changes in assumptions results in an improvement in the relative economics of the more capital intensive plans. Table 12.5 shows the change in economics due to the load and electric market assumptions, first without, and then with the change in discount rate assumption.

Table 12.5 **IMPACT OF 2013 UPDATES TO FORECASTS AND RELATED ASSUMPTIONS**

Development Plan	Incremental NPV Relative to All Gas, millions of 2014 Dollars		
	2012 Assumptions 5.05% Discount Rate	2013 Assumptions 5.05% Discount Rate	2013 Assumptions 5.40% Discount Rate
2 K23/Gas	$887	$960	$728
4 K19/Gas30/250MW MP Sale	$1,346	$1,437	$1,133
12 K19/C33/750MW MP Sale	$1,360	$1,763	$1,204
14 K19/C26/750MW MP Sale, WPS Sale & Inv Preferred Development Plan	$1,696	$2,125	$1,462

It is important to note that the All Gas plan, other than under the 2013 update in this chapter, is based on 2012 planning assumptions (with export prices adjusted primarily downward); while analysis of the All Gas plan within the 2013 update is based on 2013 planning assumptions. When comparing changes to the All Gas plan within a particular set of assumptions (i.e. 2012 or 2013 assumptions), the All Gas plan, as the benchmark for comparison, has experienced an improvement overall between 2012 and 2013 due to the decrease in the load forecast resulting in capital cost savings and additional surplus hydraulic energy for sale in the earlier years at higher export prices.

In the third column, Table 12.5 compares the changes in NPVs relative to the All Gas development plan between 2012 and 2013 forecasts and assumptions using a 5.05% discount rate (i.e., a 2012 planning assumption) in order to show the differences in assumptions other than the discount rate. All development plans here show an increase in incremental benefits between 2012 and 2013 assumptions when compared at the same discount rate. Depending on the development plan, the updates to various assumptions impact a development plan differently in terms of direction (increase or decrease) and magnitude of the change.

Capital costs decrease for each development plan primarily due to the decrease in load forecast resulting in deferral of the need for new resources. The long-term revenues increase for all development plans between the 2012 and 2013 reference scenario forecasts and assumptions, due to the effect of the reduction in load forecast allowing for periods with increased surplus energy for some development plans combined with the overall increase in the forecast of electricity export prices. The magnitude of the increase in revenues is larger with development plans that include a new U.S. interconnection, with the largest increase occurring in the Preferred Development Plan. These changes have the effect of increasing NPVs for all development plans relative to the All Gas plan (Plan 2: $960 million minus $887 million = $73 million, for Plan 4: $91 million, for Plan 12: $403 million, and for the Preferred Plan: $429 million).

As demonstrated in the fourth column of Table 12.5, the change in discount rate from 5.05% to 5.40% significantly decreases the NPVs for all development plans relative to the All Gas plan. The 0.35% increase in discount rate has a greater impact on development plans with higher levels of capital investment, with the Preferred Development Plan experiencing the largest relative decrease to NPV of $663 million ($2,125 million minus $1,462 million). The relative decreases in NPVs for the other development plans are: Plan 2: $232 million; Plan 4: $304 million; and Plan 12: $559 million.

Overall, when comparing the incremental NPVs of development plans relative to the All Gas plan between 2012 reference scenario planning assumptions and the 2013 reference scenario planning assumptions, the incremental economics between all development plans has narrowed, demonstrating that the change in discount rate has had the greatest impact on relative NPVs. Under the 2013 planning assumptions, the economic ranking of the development plans remains the same as the ranking under the 2012 planning assumptions used elsewhere in the NFAT submission.

As a further observation, the probabilistic analysis described in ***Chapter 10 – Economic Uncertainty Analysis – Probabilistic Analysis and Sensitivities*** captures a range of uncertainty around energy prices, discount rate (cost of capital) and capital cost. The 2013 planning assumptions were well within the range of uncertainty analyzed in Chapter 10.

12.4 2013 Update – DSM Sensitivity and DSM Stress Test

The DSM sensitivity and DSM stress test demonstrate the relative impact of higher levels of DSM on selected development plans. As the resource and program costs for increased levels of DSM were not available, an economic analysis to evaluate the attractiveness of higher levels of DSM could not be completed in time for this NFAT submission.

As described in Section 12.2, the results of the market potential study confirmed that a 1.5 times sensitivity and 4.0 times stress test were reasonable approximations for the “achievable potential” and “ideal” thresholds for energy saving through DSM initiatives, respectively.

Tables 12.6 and 12.7 summarize the DSM assumptions for selected dates from the 35-year study period for DSM capacity savings and DSM energy savings respectively.

Table 12.6 DSM Sensitivity and Stress Test - Potential Energy Efficiency Savings (MW)

Winter Peak Capacity, MW				
Fiscal Year	2014/15	2022/23	2027/28	2033/34
2013 Base DSM Forecast	43	144	166	153
1.5x DSM Sensitivity	65	216	249	230
4.0 x DSM Stress Test	174	577	664	612

Table 12.7 DSM Sensitivity and Stress Test - Potential Energy Efficiency Savings (GWH)

Dependable Energy, GWh				
Fiscal Year	2014/15	2022/23	2027/28	2033/34
2013 Base DSM Forecast	204	667	773	665
1.5x DSM Sensitivity	306	1,000	1,159	998
4.0 x DSM Stress Test	815	2,667	3,090	2,661

Table 12.8 provides a brief summary of the development plans used for the DSM sensitivity and DSM stress test evaluations. In order to evaluate the development plans, the in-service dates for new resources were adjusted for Plan 2 (K23/Gas), for Plan 4 (K19/Gas30/250MW) and for the Preferred Development Plan, as applicable, to accommodate the change as a result of

higher levels of DSM. For plans with a new U.S. interconnection, the in-service dates for the Keeyask G.S. and the interconnection were not changed.

Table 12.8 LIST OF 2013 DSM SENSITIVITY DEVELOPMENT PLANS

Order of Capital Investment in 2012 Analysis	Development Plan Short Name	Description of Development Plan
2	K23/Gas 1x DSM	Keeyask 2023/24, Natural Gas-Fired Generation starting in 2031/32
	K24/Gas 1.5x DSM	Keeyask 2024/25, Natural Gas-Fired Generation starting in 2032/33
	K30/Gas 4x DSM	Keeyask 2030/31, Natural Gas-Fired Generation starting in 2036/37
4	K19/Gas30/250MW 1x DSM	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2030/31, 250 MW Export/50 MW Import Interconnection 2020/21, 250 MW MP Sale
	K19/Gas30/250MW 1.5x DSM	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2030/31, 250 MW Export/50 MW Import Interconnection 2020/21, 250 MW MP Sale
	K19/Gas34/250MW 4x DSM	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2034/35, 250 MW Export/50 MW Import Interconnection 2020/21, 250 MW MP Sale
14	K19/C26/750MW (WPS Sale & Inv) 1x DSM	Keeyask 2019/20, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2045/46, 750 MW Import/Export Interconnection 2020/21, 250 MW MP Sale and proposed 300 MW WPS Sale
	K19/C26/750MW (WPS Sale & Inv) 1.5x DSM	Keeyask 2019/20, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2046/47, 750 MW Import/Export Interconnection 2020/21, 250 MW MP Sale and proposed 300 MW WPS Sale
	K19/C26/750MW (WPS Sale & Inv) 4x DSM	Keeyask 2019/20, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2048/49, 750 MW Import/Export Interconnection 2020/21, 250 MW MP Sale and proposed 300 MW WPS Sale
14a	K19/C30/750MW (WPS Sale & Inv) 4x DSM	Keeyask 2019/20, Conawapa 2030/31, Natural Gas-Fired Generation starting in 2048/49, 750 MW Import/Export Interconnection 2020/21, 250 MW MP Sale and proposed 300 MW WPS Sale

12.4.1 2013 – DSM Sensitivity 1.5 Times and 4 Times – Economic Analysis Results

Table 12.9 provides the incremental NPVs for the three plans selected for the 1.5 times DSM sensitivity analysis. There is a one-year change in the in-service date in Keeyask G.S. as a result of increasing the level of DSM by 50% for Plan 2 (K24/Gas 1.5xDSM). Table 12.9 shows the relative economic ranking of the three development plans: when compared to the 2012 and 2013 reference scenario economics in Table 12.5, the economic ranking remains the same.

Table 12.9 2013- 1.5x DSM Sensitivity – Incremental Impact on NPVs

Development Plan	Incremental NPV, millions of 2014 Dollars @ 5.40% Discount Rate	
	2 - K24/Gas 1.5x DSM	4 - K19/Gas30/250MW 1.5x DSM
2 K24/Gas 1.5x DSM	-	
4 K19/Gas30/250MW 1.5x DSM	4 -2	
MP Sale	$429	
14 K19/C26/750MW 1.5x DSM	14 -2	14 -4
MP Sale, WPS Sale & Inv Preferred Development Plan	$771	$342

Table 12.10 provides the incremental NPVs for Plan 2 (K30/Gas 4xDSM), Plan 4 (K19/Gas34/250MW 4xDSM), and the Preferred Plan (Plan 14 and Plan 14a), which were selected for the 4.0 times DSM stress test. The 4.0 times DSM stress test has the effect of deferring the in-service date for Keeyask G.S. in Plan 2 by six years and defers the in-service date of the first natural gas-fired resource in Plan 4 by four years. Plan 14 in Table 12.10 is the Preferred Development Plan with fixed in-service dates for both Keeyask G.S. and Conawapa G.S. Plan 14a is a variant of the Preferred Development Plan in which the in-service date for Conawapa G.S. is deferred four years with 4.0 times DSM. Table 12.10 demonstrates that the relative economic ranking of the three development plans (Plan 2, Plan 4, and Plan 14) remains the same when compared to Table 12.5. Plan 14a, deferring Conawapa G.S. from 2026/27 to 2030/31, shows a net benefit of $11 million when compared to Plan 14, an amount which is small enough to result in indifference between the plans. This indicates that the benefit from

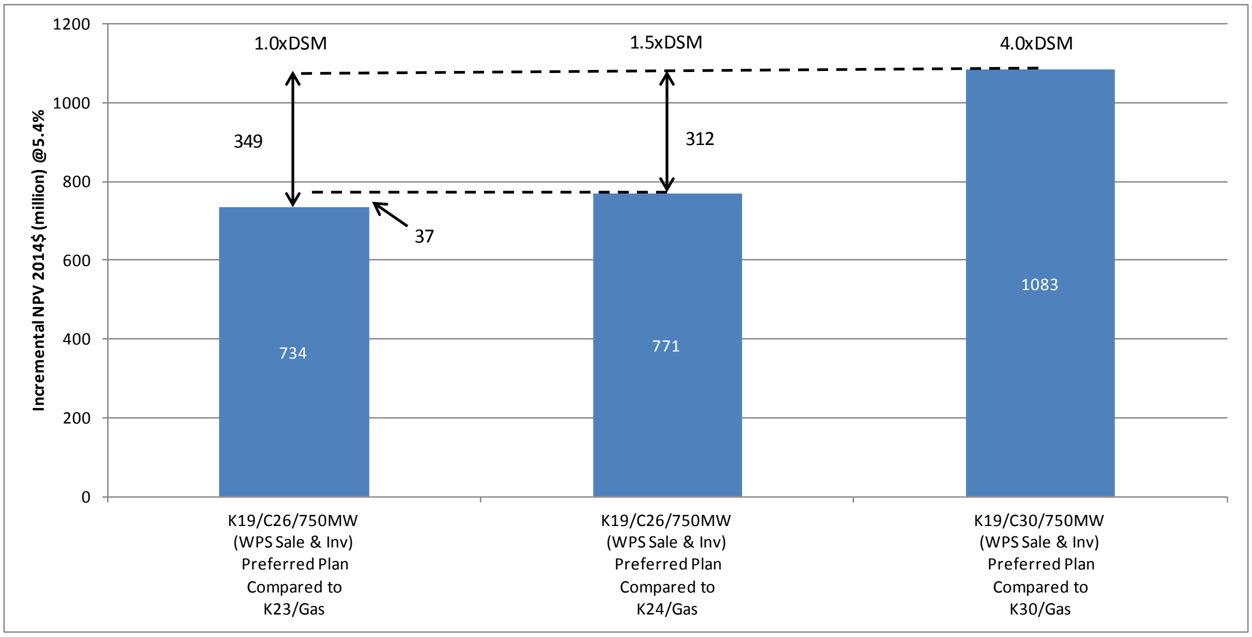
deferring the capital investment in Conawapa G.S. is virtually equal to the lost benefit from surplus power sales.

Table 12.10 2013 4.0X DSM STRESS TEST – INCREMENTAL IMPACT ON NPV

Development Plan	Incremental NPV, millions of 2014 Dollars @ 5.40% Discount Rate		
	2 - K30/Gas 4x DSM	4 - K19/Gas34/250MW 4x DSM	14a - K19/C30/750MW 4x DSM WPS Sale & Inv
2 K30/Gas 4x DSM	-		
4 K19/Gas34/250MW 4x DSM	4 -2		
MP Sale	$887		
14a K19/C30/750MW 4x DSM	14a -2	14a -4	
MP Sale, WPS Sale & Inv Conawapa G.S. Deferred by 4x DSM	$1,083	$196	
14 K19/C26/750MW 4x DSM	14 -2	14 -4	14- 14a
MP Sale, WPS Sale & Inv Preferred Development Plan	$1,072	$185	($11)

Figure 12.5 compares 1.0 times, 1.5 times and 4.0 times DSM between two development plans under reference scenario assumptions: the Preferred Plan and Plan 2. The in-service date for the Keeyask G.S. under Plan 2 varies according to the level of DSM applied: the date is 2023/24 for 1.0 times DSM, 2024/25 for 1.5 times DSM, and 2030/31 for 4.0 times DSM. The in-service date for the Conawapa G.S. under the Preferred Plan remains at 2026/27 for 1.0 and 1.5 times DSM and is 2030/31 for 4.0 times DSM.

Figure 12.5 DSM SENSITIVITY AND STRESS TEST COMPARISON OF PREFERRED PLAN TO K23/GAS



At 1.0 times DSM, the NPV for the Preferred Plan is $734 million greater than the NPV for Plan 2 (K23/Gas). At 1.5 times DSM, the NPV for the Preferred Plan is $771 million greater than the NPV for Plan 2 (K24/Gas). At 4.0 times, the NPV for the Development Plan is $1,083 million greater than the NPV for Plan 2 (K30/Gas). The difference between the NPV at 1.5 times DSM when compared to the NPV at 1.0 times DSM is $37 million ($771 million minus $734 million) and represents the net benefit of the additional DSM to the Preferred Plan. Likewise, at 4.0 times DSM the difference of $349 million represents a net benefit to the Preferred Plan (K19/C30/750MW (WPS Sale & Inv)). In both cases (1.5 times and 4.0 times DSM), the incremental NPV of the Preferred Plan is greater when compared to Plan 2 (K23/Gas). When 4.0 times DSM is applied to Plan 2, there are capital cost savings as a result of deferring Keeyask G.S. from 2024/25 to 2030/31, increased revenues due to additional surplus power available for export, and reduced thermal operating costs due to a lower requirement for thermal generation. When 4.0 times DSM is applied to Plan 14 there are capital cost savings as a result of deferring Conawapa G.S. from 2026/27 to 2030/31, and increased revenues due to

additional surplus power available for export. The difference of $349 million shows that Plan 14 can derive more benefit from 4.0 times DSM than can Plan 2.

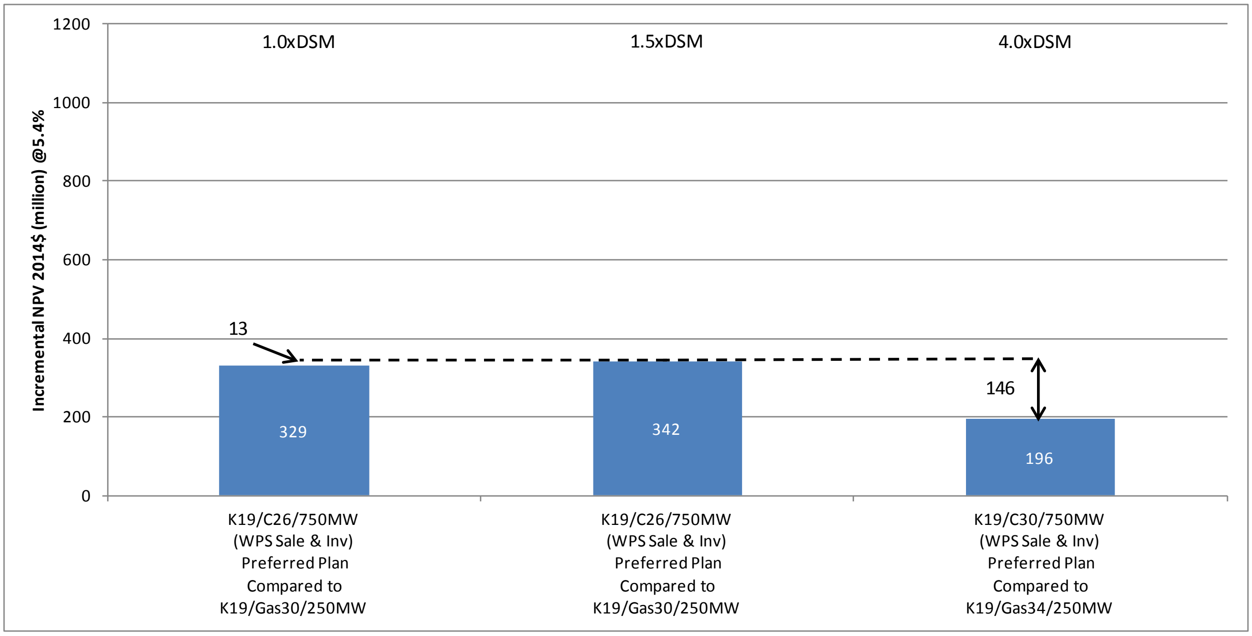
Figure 12.6 compares 1.0 times, 1.5 times and 4.0 times DSM between two development plans under reference scenario assumptions: the Preferred Plan and Plan 4 (K19/Gas30/250MW). The in-service date for the Keeyask G.S. under Plan 4 remains 2019/20 for all levels of DSM as it is required to meet the 250 MW MP Sale and requirements for a new U.S. interconnection. The in-service date for the first natural gas-fired resource under Plan 4 remains at 2030/31 at 1.0 and 1.5 times DSM and is 2034/35 at 4.0 times DSM. The in-service date for the Conawapa G.S. under the Preferred Plan remains at 2026/27 for 1.0 and 1.5 times DSM and is 2030/31 for 4.0 times DSM.

The NPV for the Preferred Plan is $329 million greater than the NPV for Plan 4 at 1.0 times DSM, $342 million greater at 1.5 times DSM, and $196 million greater at 4.0 times DSM. The difference of $13 million between the NPV at 1.5 times DSM when compared to the NPV at 1.0 times DSM ($342 million minus $329 million) means that both the Preferred Plan and Plan 4 benefit similarly at the 1.5 times DSM level. When comparing 1.5 times DSM to 4.0 times DSM the net benefit at 4.0 times DSM is lower by $146 million, showing that the higher level of DSM yields greater benefits to Plan 4 than to the Preferred Plan.

When 4.0 times DSM is applied to Plan 4, there are increased revenues due to additional surplus power available for export, capital cost savings as a result of the deferral of new resources, and reduced thermal operating costs due to a lower requirement for thermal generation. When 4.0 times DSM is applied to Plan 14, there are increased revenues due to additional surplus power available for export and capital cost savings as a result of deferring Conawapa G.S. from 2026/27 to 2030/31. The difference of $133 million shows that Plan 4 can derive more benefit from 4.0 times DSM than can Plan 14.

Figure 12.6 DSM SENSITIVITY AND STRESS TEST

COMPARISON OF PREFERRED PLAN TO PLAN 4 (K19/GAS30/250MW)



An analysis of higher levels of DSM for the All Gas plan was not available in time to be included in the NFAT submission. The low load sensitivity described in ***Chapter 10 – Economic Uncertainty Analysis – Probabilistic Analysis and Sensitivities*** which is based on the 2012 planning assumptions (with export prices adjusted primarily downward), is used as a proxy for comparing the Preferred Plan and Plan 4 to the All Gas plan at 4.0 times DSM. The low load sensitivity represents an amount of energy savings equivalent to over 4.5 times DSM.

Table 12.11 presents the incremental NPVs for the low load sensitivity for each development plan studied as compared to each respective base load development plan under the reference scenario using 2012 planning assumptions (with export prices adjusted primarily downward).

Table 12.11 LOW LOAD SENSITIVITY AS A PROXY FOR 2012 NFAT PLANNING ASSUMPTIONS COMPARISON OF EACH PLAN TO ITS REFERENCE SCENARIO

	Incremental NPV benefit, millions of 2014$ @ 5.05% discount rate	
Development Plan	Reference Scenario	10th percentile Manitoba Load (Low Load)
All Gas	-	$3,470
K22/Gas	-	$3,319
K19/C25/750MW (WPS Sale & Inv) Preferred Plan	-	$3,164

Under low loads the incremental NPV for the All Gas plan increases by $151 million ($3,470 million minus $3,319 million) over Plan 2 (K22/Gas) and $306 million over the Preferred Development Plan. This is due to higher level of capital cost savings resulting from the deferral of a number of natural gas-fired resources throughout the planning horizon for the All Gas plan. The results demonstrate that lower loads yield greater benefits to the All Gas plan than the Plan 2 (K22/Gas) plan and the Preferred Development Plan.

Table 12.11 shows that under the low load sensitivity the incremental NPV for development plans with new hydro resources and a new interconnection decreases relative to the All Gas development plan.

Table 12.12 LOW LOAD SENSITIVITY AS A PROXY 2012 NFAT PLANNING ASSUMPTIONS COMPARISON TO ALL GAS REFERENCE SCENARIO

	Incremental NPV benefit, millions of 2014$ @ 5.05% discount rate	
Development Plan	Reference Scenario	10th percentile Manitoba Load (Low Load)
All Gas	-	-
K22/Gas	$887	$736
K19/C25/750MW (WPS Sale & Inv) Preferred Plan	$1,696	$1,390

Table 12.12 also shows that under the 2012 low load sensitivity the economic ranking of the development plans studied does not change. The Plan 2 (K22/Gas) development plan continues to be more economic than the All Gas development plan and the Preferred Development Plan continues to be the most economic of the three plans studied.

It is judged that the results, based on the 2012 assumptions for the low load sensitivity described in Chapter 10 and used as proxy in this Section 12.4.1, are representative of the results that would be seen for a higher level of DSM (in the order of 4.5 times DSM) under the 2013 planning assumptions. Therefore, the economic ranking of the development plans would not be expected to change if the All Gas plan were included in the analysis.

12.5 Conclusions

An analysis has been undertaken in this chapter to demonstrate the effect of changes in planning assumptions from 2012 to 2013 on selected development plans.

Conclusions for 2013 Reference Economics

Under the 2013 planning assumptions the economic ranking of the development plans remains the same as was shown under the 2012 planning assumptions used elsewhere in the NFAT submission (Table 12.4). When comparing NPVs between 2012 and 2013, the incremental economics between all development plans has narrowed, with the change in discount rate from 5.05% to 5.4% having the greatest impact on relative NPVs.

As a further observation, the 2013 planning assumptions were well within the range of uncertainty analyzed in Chapter 10. (The probabilistic analysis described in Chapter 10 captures a range of uncertainty around energy prices, discount rate (cost of capital) and capital cost.)

Conclusions for the DSM Sensitivity and Stress Test

DSM sensitivity and DSM stress tests were undertaken to demonstrate the relative impact of higher levels of DSM on selected development plans. The results of the market potential study confirmed that a 1.5 times sensitivity and 4.0 times stress test were reasonable representations of the “achievable potential” and “ideal” thresholds for energy saving realized through DSM initiatives, respectively.

In general, the development plans analyzed benefit from increased levels of DSM. The Preferred Plan and Plan 4 (K19/Gas30/250MW) derive greater benefits from higher levels of DSM than the K23/Gas plan.

To demonstrate the relative impact of higher levels of DSM on selected development plans, comparisons were made between the Preferred Plan and Plan 2 (K23/Gas) and between the Preferred Plan and Plan 4 (K19/Gas 30/250 MW) for the 1.5 times DSM sensitivity and the 4.0 times DSM stress test.

Comparing the Preferred Plan to Plan 2 showed that in both cases (i.e., 1.5 times and 4.0 times DSM), the incremental NPV of the Preferred Plan is greater. (Figure 12.5)

Both the Preferred Plan and Plan 4 benefit similarly at the 1.5 times DSM level. At the 4.0 times DSM level Plan 4 can derive more benefit from the higher level of DSM than the Preferred Plan. (Figure 12.6)

An analysis of higher levels of DSM for the All Gas plan was not available to be included in the NFAT submission. The low load sensitivity described in Chapter 10, which is based on 2012 planning assumptions (with export prices adjusted primarily downward), was used as a proxy for comparing the Preferred Plan and Plan 4 (K19/Gas30/250MW) to the All Gas plan at higher levels of DSM. Under the 2012 low load sensitivity the economic ranking of the development plans studied does not change. It is judged that the results are representative of the results that would be seen for a higher level of DSM (in the order of 4.5 times DSM) under the 2013 planning assumptions. With the lower load level used as a proxy for DSM—at an approximately 4.5 times higher level of DSM—the incremental NPV of the Preferred Plan improves relative to Plan 2 (K23/Gas) and decreases relative to All Gas; the economic ranking of the development plans would not be expected to change if the All Gas plan were included in the analysis.

Overall, based on the 2013 planning assumptions, these analyses show that the economic ranking of development plans remains the same under higher levels of DSM.