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10 Economic Uncertainty Analysis – Probabilistic Analysis and Sensitivities

10.0 Chapter Overview

Despite efforts to understand and predict the future, it inherently remains uncertain. For decision making, including resource planning decisions, potential outcomes can directly and indirectly affect the impact of the alternatives considered and the choices made. The outcome of a wide range of economic, financial, social, technological and political events in both the near-term and the long-term is unpredictable. It is important to recognize uncertainty and identify the way forward that has the best balance of value and risk given that uncertainty.

Chapter 10 - Economic Uncertainty Analysis – Probabilistic Analysis and Sensitivities Section 1.0 introduces the concept of scenarios and presents extensive probabilistic analysis on 12 of the development plans with and without probabilities on the factors that have a high impact on the economics of the development plans.

While probabilistic analysis considers several key factors at once, sensitivity analysis focuses on a single variable that tests the impact of that variable on selected development plans. Section 2.0 provides sensitivity analysis on drought, climate change, load growth, and in-service delay. Through ***Chapter 10 - Economic Uncertainty Analysis – Probabilistic Analysis and Sensitivities*** it is recognized that there are many factors that are considered in formulating and analyzing development plans and uncertainty and risk associated with these factors.

As it would be a virtually endless task to study the effect of the uncertainty in each of the factors in depth, Section 3.0 provides a matrix which presents a framework in which uncertainties and risks associated with the development of resource options in Manitoba are summarized and are assessed either qualitatively or quantitatively.

Supporting information and additional detail for the analyses presented in this chapter is available in ***Appendix 9.3– Economic Evaluation Documentation.***

10.1 Probabilistic Analysis with Scenarios

10.1.1 Methodology

Probabilistic analysis considers the range of uncertainty defined by reference, high and low values on key factors which are formulated into scenarios. An assessment is done to determine which factors have the highest impact on the economic and financial outcomes. Probabilistic analysis will grow exponentially with each added factor and, therefore, in this submission it is based on three sets of factors. These sets of factors represent 1) the electricity market 2) investment costs and 3) the economy and, when combined, result in 27 individual scenarios for each development plan analyzed. As each combination of these factors does not have the same likelihood of occurring, probabilities for reference, high and low are applied to the factors and subsequently the weighted factors are applied to the development plans. The application of these probabilities results in a probabilistic comparison of development plans.

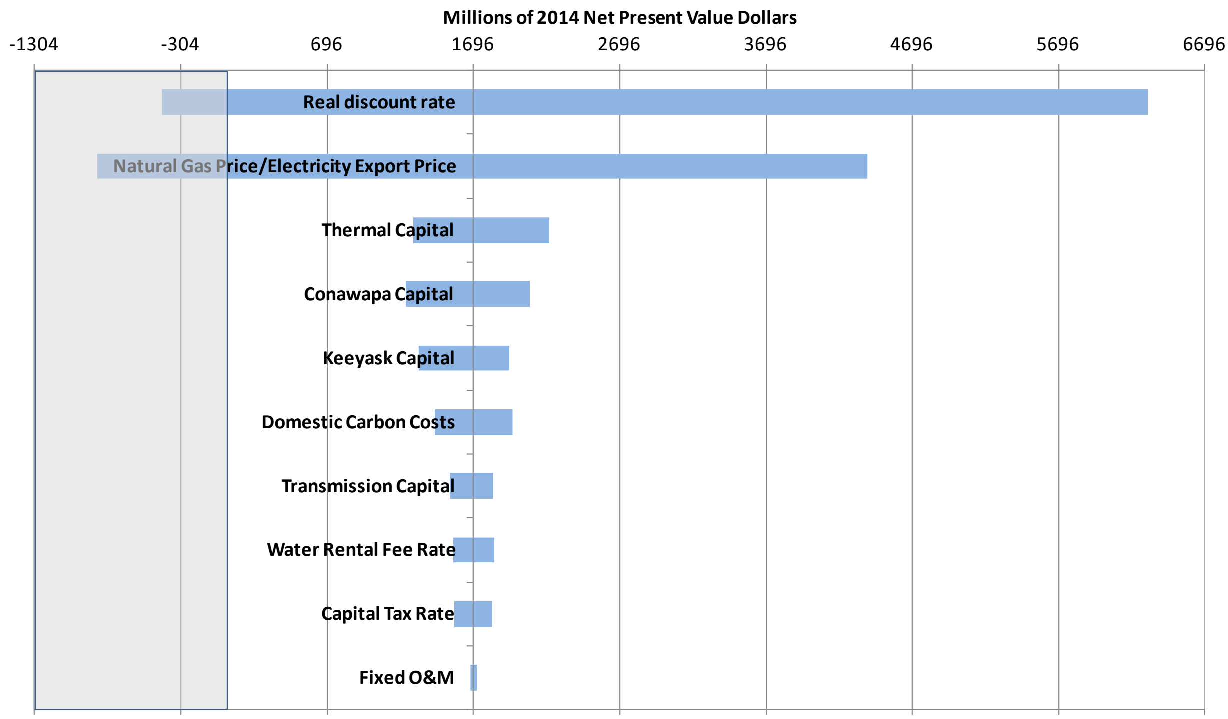
10.1.1.1 Determination of Highest Impact Factors

There are numerous inputs and assumptions that are required to formulate and analyze development plans. It would be an endless task to study the effect of uncertainty in each of the inputs and assumptions in depth and uncertainty in some factors is relatively unimportant. In order to focus attention on matters of significance, analysis was conducted to determine which of these factors have the greatest impact and require the most attention and, in turn, which factors have the least impact and do not require in-depth analysis.

In probabilistic analysis, each individual factor is varied from a plausible low value to a plausible high value. For the Needs For and Alternatives To (NFAT) economic evaluation, the impact of this variation has been measured between the two development plans with the most significant difference in characteristics – the All Gas development plan and the Preferred Development Plan (K19/C25/750MW (WPS Sale & Inv)). One useful way of displaying this sensitivity information is a "tornado diagram."

Figure 10.1 is a tornado diagram which shows the impact of uncertainty in 10 individual factors; the length of each bar shows the impact of varying each factor from low to high. The "high impact" factors are electricity and natural gas prices, discount rate (representative of the cost of capital), and capital costs. "Low impact" factors include operating and maintenance (O&M) costs, and changes in water rental and capital tax rates. It is important to note that impact refers to the uncertainty in each factor not the factor itself. For example, this diagram does not indicate that O&M is itself relatively unimportant, simply that uncertainty within O&M is relatively unimportant. All else being equal, uncertainty analysis should be focused on the "high impact" factors. The grey area in Figure 10.1 indicates factors that can have a significant impact on the net present value (NPV), resulting in a net loss as opposed to a net benefit.

Figure 10.1 Tornado Diagram of Highest Impact Factors



10.1.1.2 Combinations of Highest Impact Factors

The high impact factors are grouped into three sets: Energy Prices, Capital Costs and Economic Indicators.

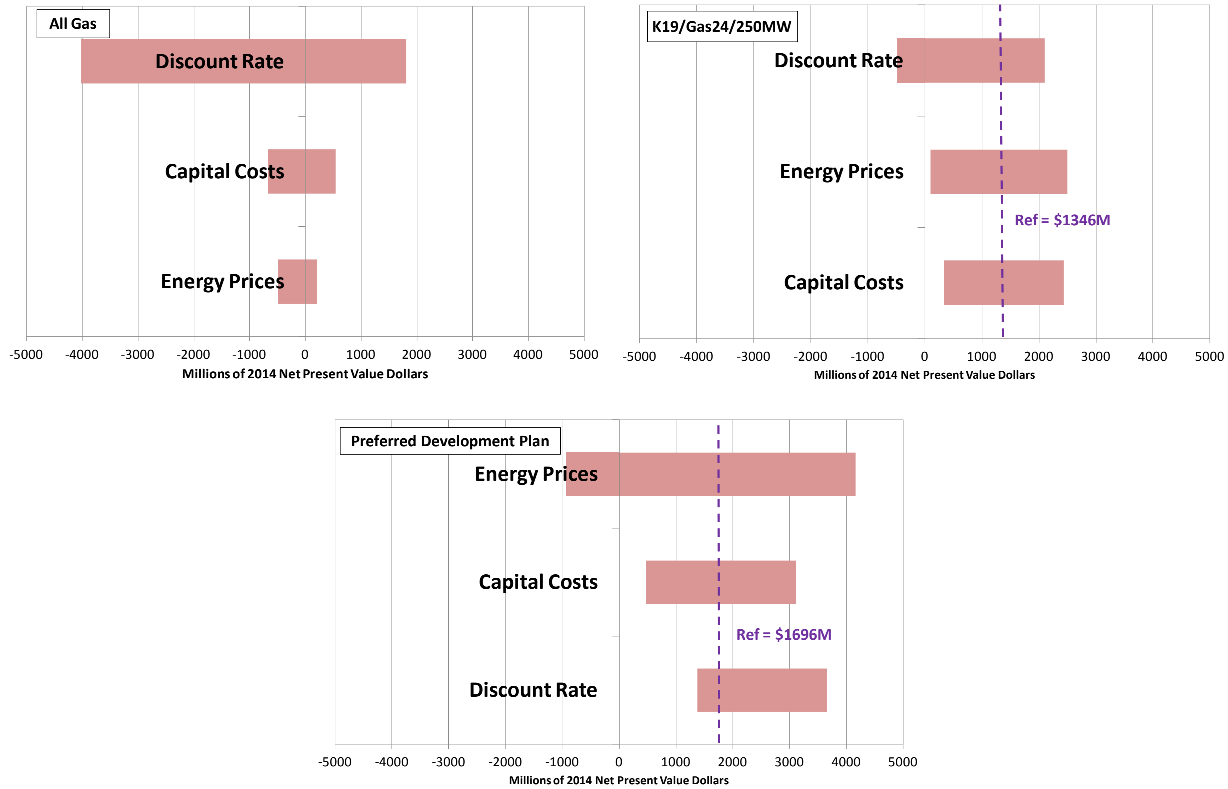
Energy Price factors consist of natural gas, electricity and carbon prices. Electricity export prices are a key factor in evaluating Manitoba Hydro's development plans. As described in ***Chapter 3 – Trends and Factors Influencing North American Electricity Supply***, natural gas is a significant factor in the determination of electricity prices in the North American market. The effect of natural gas prices on electricity export prices is embedded in Energy Prices as is the effect of carbon. Carbon prices are reflected in Energy Prices from two perspectives. One is the impact of carbon policy on electricity export prices in the Midcontinent Independent System Operator, Inc. (MISO) market and the other is the impact of a potential carbon adder on Manitoba based fossil fuel-fired generation.

Capital Cost factors include generation costs for all resource types, transmission costs and applicable real escalation. As more analysis on capital cost estimates is undertaken, the uncertainty range narrows.

Economic Indicators include U.S. and Canadian, short- and long-term interest rates, inflation rates including U.S. gross domestic product implicit price deflator, CAD/USD exchange rate, and Manitoba Hydro's real weighted average cost of capital. For economic uncertainty analysis the relevant Economic Indicator is the real weighted average cost of capital (discount rate).

Figure 10.2 provides a tornado diagram of the highest impact factors for a selection of development plans which are representative of a plan with no new large hydro resources, a plan with one new large hydro resource and a plan with two new large hydro resources. For each set of factors, the length of the bar in Figure 10.2 is indicative of the impact of the range of that factor on NPV.

**Figure 10.2 Probabilistic Analysis – Tornado Diagram
Highest Impact Factors – All Gas, K19/Gas24/250MW
Preferred Development Plans**



For the All Gas development plan, Figure 10.2 illustrates that the Discount Rate is the dominant factor and can result in a significant negative impact on incremental NPV. Over the long-term, the amount of natural gas-fired generation required to meet domestic load requirements increases significantly. These operating costs when combined with a low discount rate result in a significant downside risk and a negative impact on the incremental NPV. For the Preferred Development Plan, on a relative basis, the Discount Rate factor does not result in as significant an impact on incremental NPV. Unlike the All Gas development plan, it is the high discount rate that results in a negative impact on incremental NPV. This is primarily due to the impact of the capital intensive nature of large hydro-electric projects which have high upfront costs and which rely on revenue that occurs over the long-term.

For the Preferred Development Plan, the Energy Prices factor has the most significant impact on the incremental NPV due to the sale of large volumes of surplus power associated with the development of two large hydro-electric generating stations, exposing the Preferred Development Plan to the effect of changes in energy price.

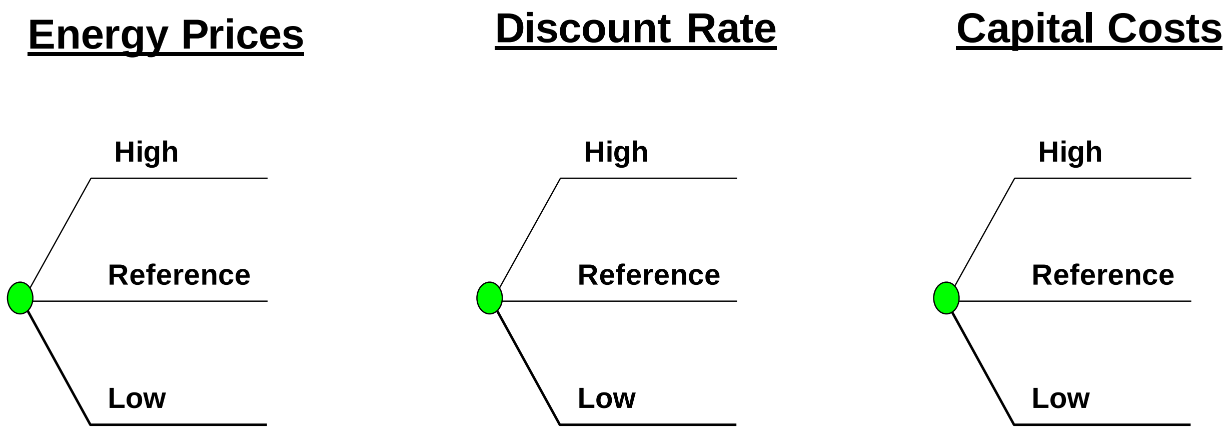
From an overall perspective, the Preferred Development Plan is most affected by the Energy Prices set of factors but still has significant exposure to the Discount Rate and Capital Cost sets of factors. The All Gas plan has exposure to the Discount Rate with narrow ranges of exposure to the Capital Cost and Energy Prices factors. For Plan 4 (K19/Gas24/250MW), because it has a mix of new gas and hydro resources, the impact of the three factors is moderated. The diversity provided by the mix of hydro-electric and natural gas-fired resources in the K19/Gas24/250MW development plan balances the effect of the factors and limits the significance of their effect on incremental NPV.

10.1.1.3 Development of Scenarios

In ***Chapter 9 – Economic Evaluations – Reference Scenario***, the reference scenario was presented as the “most likely” set of assumptions for evaluating development plans. Assumptions higher and lower than the reference assumptions are incorporated into the development of scenarios. The resulting scenarios represent all possible combinations of the high impact factors with the range of high, reference and low assumptions.

When combined, three sets of factors with the high, reference and low assumptions result in 27 discrete scenarios.

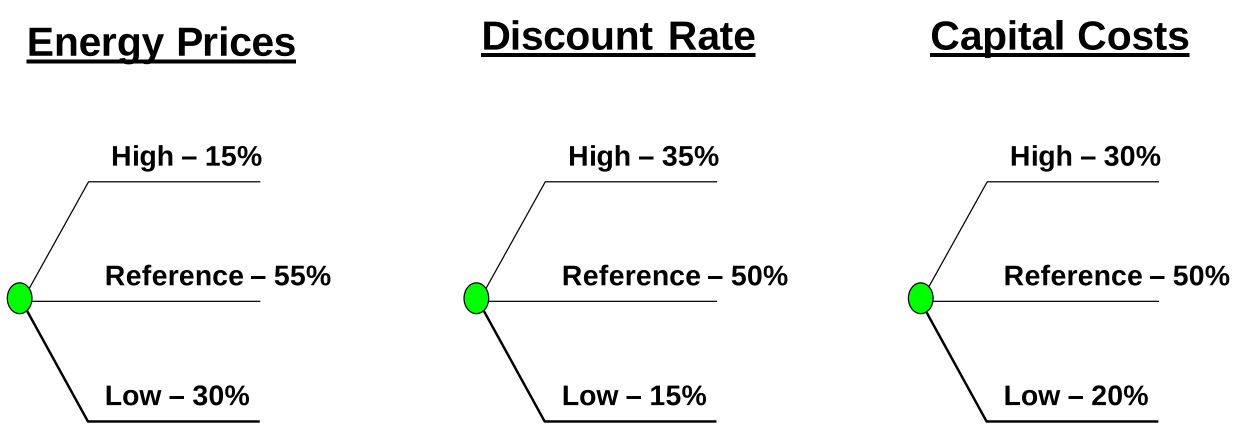
Figure 10.3 Combination of Highest Impact Factors



10.1.1.4 Probabilities for Scenarios

As each of the combinations of the highest impact factors do not have the same likelihood of occurring, probabilities were developed for each set of these factors as explained in ***Appendix 9.3 – Economic Evaluation Documentation***. Figure 10.4 provides the probabilities for each of the highest impact factors.

Figure 10.4 Probabilities for Highest Impact Factors



10.1.2 Inputs for Probabilistic Analysis with Scenarios

Chapter 9 – Economic Evaluations – Reference Scenario provided the economic analysis from the reference scenario perspective and determined which development plans that will be considered in the economic uncertainty analysis documented in this chapter. The reference scenario represents one view of the future. This section builds on the reference scenario economic analysis and considers the impact of uncertainty, using probabilistic analysis to compare the net benefits for the 12 development plans identified in ***Chapter 9 – Economic Evaluations – Reference Scenario***, Section 9.3.4.

The 12 development plans analyzed in this chapter are provided in Table 10.1.

Table 10.1 List of Twelve Development Plans for Probabilistic Analysis

Order of Capital Investment	Development Plan Short- Name	Description of Development Plan	
		U.S. Interconnection	Resources/Sales
1	All Gas	None	Natural Gas-Fired Generation starting in 2022/23
3	Wind/Gas		Wind Generation starting in 2022/23 supported by Natural Gas-Fired Generation starting in 2025/26
7	SCGT/C26		Simple Cycle Gas Turbines in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2038/39
2	K22/Gas		Keeyask 2022/23, Natural Gas-Fired Generation starting in 2029/30
4	K19/Gas24/250MW	250 MW export/50 MW import in 2020/21	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2024/25, 250 MW MP Sale
13	K19/C25/250MW		Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2040/41, 250 MW MP Sale
11	K19/C31/250MW		Keeyask 2019/20, Natural Gas-Fired Generation starting in 2024/25, Conawapa 2031/32, 250 MW MP Sale
6	K19/Gas31/750MW	750 MW import and export in 2020/21	Keeyask 2019/20, Imports, Natural Gas-Fired Generation starting in 2031/32, 250 MW MP Sale
15	K19/C25/750MW		Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2041/42, 250 MW MP Sale
12	K19/C31/750MW		Keeyask 2019/20, Imports, Conawapa 2031/32, Natural Gas-Fired Generation starting in 2041/42, 250 MW MP Sale
5	K19/Gas25/750MW (WPS Sale & Inv[1])		Keeyask 2019/20, Natural Gas-Fired Generation starting in 2025/26, 250 MW MP Sale, proposed 300 MW WPS Sale
14 (Preferred Development Plan)	K19/C25/750MW (WPS Sale & Inv[1])		Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2041/42, 250 MW MP Sale, proposed 300 MW WPS Sale

[1] Inv refers to WPS investment in the U.S. portion of the 750 MW interconnection facilities

Assumptions and forecasts for all of the scenarios were based on adjusted 2012 planning assumptions and are provided in ***Appendix 9.3 – Economic Evaluation Documentation***.

10.1.3 Analysis of Development Plans Using Scenarios

Table 10.2 provides the framework for comparing the 12 development plans under the 27 scenarios. The 12 development plans are listed across the top of the table. The 27 scenarios are shown in the three left-most columns and represent all possible combinations of the three sets of highest impact factors (3 Energy Prices x 3 Discount Rates x 3 Capital Costs = 27 scenarios). The 12 development plans combined with 27 scenarios result in 324 cases (12 development plans x 27 scenarios = 324 cases). The colour red indicates a negative NPV and the colour green indicates a positive NPV when assuming the All Gas Ref-Ref-Ref case is used as a single point base for comparison. The darkest colours of green represent an NPV that is equal to or greater than +$3,000 million and the darkest colours of red represent an NPV that is equal to or less than -$3,000 million. The colours become lighter as the NPV approaches zero. When all 324 cases are populated in the table and assigned a colour, the table resembles a patchwork quilt.

Table 10.2 Probabilistic Analysis - Quilt
Incremental Economics – Reference Scenario

Development Plan			1	3	7	2	4	13	11	6	15	12	5	14
			All Gas	Wind/Gas	SCGT/C26	K22/Gas	K19/Gas24 /250Mw	K19/C25 /250MW	K19/C31 /250MW	K19/Gas31 /750MW	K19/C25 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
													WPS Sale & Investment	
Energy Prices	Discount Rates	Capital Costs	Millions of 2014 NPV dollars											
	Low													
Low	Ref													
	High													
	Low													
Ref	Ref	Ref	0	-775	738	887	1346	1295	1215	1091	1427	1360	1097	1696
	High													
	Low													
High	Ref													
	High													

Colour Legend: < -3000 | 0 | > 3000

The NPVs shown in Table 10.2 and identified as reference assumptions (Ref-Ref-Ref) for all three sets of factors — Energy Prices, Discount Rates, and Capital Costs — are incremental to the All Gas plan under reference assumptions. These reference assumptions are indicated by the "0" NPV for the All Gas Ref-Ref-Ref case. The NPVs shown in Table 10.2 are the same for each development plan as those shown in Table 9.9 in ***Chapter 9 – Economic Evaluations - Reference Scenario.***

The reference scenario (Ref-Ref-Ref) only represents one view of the future, which we know is uncertain. The Ref-Ref-Ref scenario represents the "most likely" future. Table 10.3 introduces two additional scenarios where the range of Energy Prices is shown in the scenarios Low-Ref-Ref (low Energy Prices, reference Discount Rates, and reference Capital Costs) and High-Ref-Ref (high Energy Prices, reference Discount Rates, and reference Capital Costs).

Table 10.3 Probabilistic Analysis – Quilt
Incremental Economics Range of Energy Prices

Development Plan			1	3	7	2	4	13	11	6	15	12	5	14
			All Gas	Wind/Gas	SCGT/C26	K22/Gas	K19/Gas24 /250Mw	K19/C25 /250MW	K19/C31 /250MW	K19/Gas31 /750MW	K19/C25 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
													WPS Sale & Investment	
Energy Prices	Discount Rates	Capital Costs	Millions of 2014 NPV dollars											
Low	Low													
	Ref													
		Ref	208	-1478	-582	-278	95	-1368	-1050	-185	-1559	-1153	257	-929
	High													
Ref	Low													
	Ref													
		Ref	0	-775	738	887	1346	1295	1215	1091	1427	1360	1097	1696
	High													
High	Low													
	Ref													
		Ref	-487	-189	1956	1874	2403	3888	3420	2134	4250	3741	1701	4166
	High													

Colour Legend: < -3000 0 > 3000

Table 10.3 demonstrates how the incremental NPVs for development plans are affected by changes in the Energy Prices set of factors. The All Gas Ref-Ref-Ref case is used as a fixed base for comparing each development plan in the context of each of the 27 scenarios and is indicated by the “0” NPV. An improvement in NPV is reflected by the shade of red becoming lighter or the shade of green becoming darker with a reduction in NPV having the opposite effect. The comparison of the Low-Ref-Ref scenario of all development plans to the All Gas Ref-Ref-Ref case shows the impact on the incremental NPV due to the decrease in the Energy Prices factor. Similarly, the comparison of the High-Ref-Ref scenario for all development plans to the All Gas Ref-Ref-Ref case shows the impact on the incremental NPV due to the increase in the Energy Prices factor. In this way, Table 10.3 provides a measure of relative performance between each of the 12 development plans and the All Gas Ref-Ref-Ref case for the three scenarios identified: Low-Ref-Ref, Ref-Ref-Ref, and High-Ref-Ref.

Table 10.4 Probabilistic Analysis Quilt
Incremental Economics – All Scenarios

Development Plan			1	3	7	2	4	13	11	6	15	12	5	14
			All Gas	Wind/Gas	SCGT/C26	K22/Gas	K19/Gas24 /250Mw	K19/C25 /250MW	K19/C31 /250MW	K19/Gas31 /750MW	K19/C25 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
													WPS Sale & Investment	
Energy Prices	Discount Rates	Capital Costs	Millions of 2014 NPV dollars											
Low	Low	H	-4043	-7769	-3309	-3792	-3190	-3459	-3506	-3418	-3642	-3554	-2855	-2841
		Ref	-3049	-5403	-2401	-2532	-1877	-2124	-2166	-2130	-2177	-2138	-1616	-1410
		L	-2247	-3666	-1655	-1590	-890	-1069	-1099	-1175	-1030	-1022	-703	-292
	Ref	H	-463	-3056	-1297	-1212	-911	-2510	-2161	-1191	-2816	-2323	-730	-2155
		Ref	208	-1478	-582	-278	95	-1368	-1050	-185	-1559	-1153	257	-929
		L	750	-323	6	408	837	-473	-176	548	-585	-243	974	20
	High	H	1204	-796	-284	25	117	-2029	-1413	-182	-2383	-1622	203	-1810
		Ref	1708	384	323	785	963	-994	-434	679	-1243	-592	1060	-698
		L	2114	1245	822	1336	1580	-189	327	1297	-364	201	1674	157
Ref	Low	H	-5014	-7167	-1760	-2511	-1796	206	-334	-2041	498	0	-2103	853
		Ref	-4020	-4802	-852	-1251	-482	1541	1006	-753	1963	1415	-865	2284
		L	-3217	-3064	-107	-309	504	2597	2073	202	3110	2531	49	3402
	Ref	H	-671	-2354	23	-46	341	152	104	85	170	190	109	470
		Ref	0	-775	738	887	1346	1295	1215	1091	1427	1360	1097	1696
		L	542	380	1326	1573	2089	2189	2089	1824	2401	2270	1813	2645
	High	H	1308	-82	879	1091	1258	109	391	998	2	366	1041	268
		Ref	1812	1098	1487	1851	2104	1144	1370	1859	1143	1396	1898	1380
		L	2218	1959	1986	2402	2721	1949	2132	2478	2022	2189	2512	2235
High	Low	H	-6435	-6719	-355	-1499	-692	3819	2796	-1006	4455	3410	-1694	4372
		Ref	-5441	-4353	552	-239	621	5154	4135	282	5921	4826	-456	5803
		L	-4638	-2616	1298	703	1607	6210	5203	1237	7068	5941	458	6922
	Ref	H	-1158	-1767	1241	941	1398	2746	2308	1127	2993	2571	713	2940
		Ref	-487	-189	1956	1874	2403	3888	3420	2134	4250	3741	1701	4166
		L	55	966	2543	2560	3146	4783	4293	2867	5225	4652	2417	5115
	High	H	1210	533	1956	2017	2246	2170	2127	1993	2236	2228	1691	2203
		Ref	1713	1712	2563	2777	3092	3206	3106	2854	3377	3259	2549	3315
		L	2120	2573	3063	3328	3709	4010	3867	3473	4256	4051	3163	4170

Colour Legend < -3000 0 > 3000

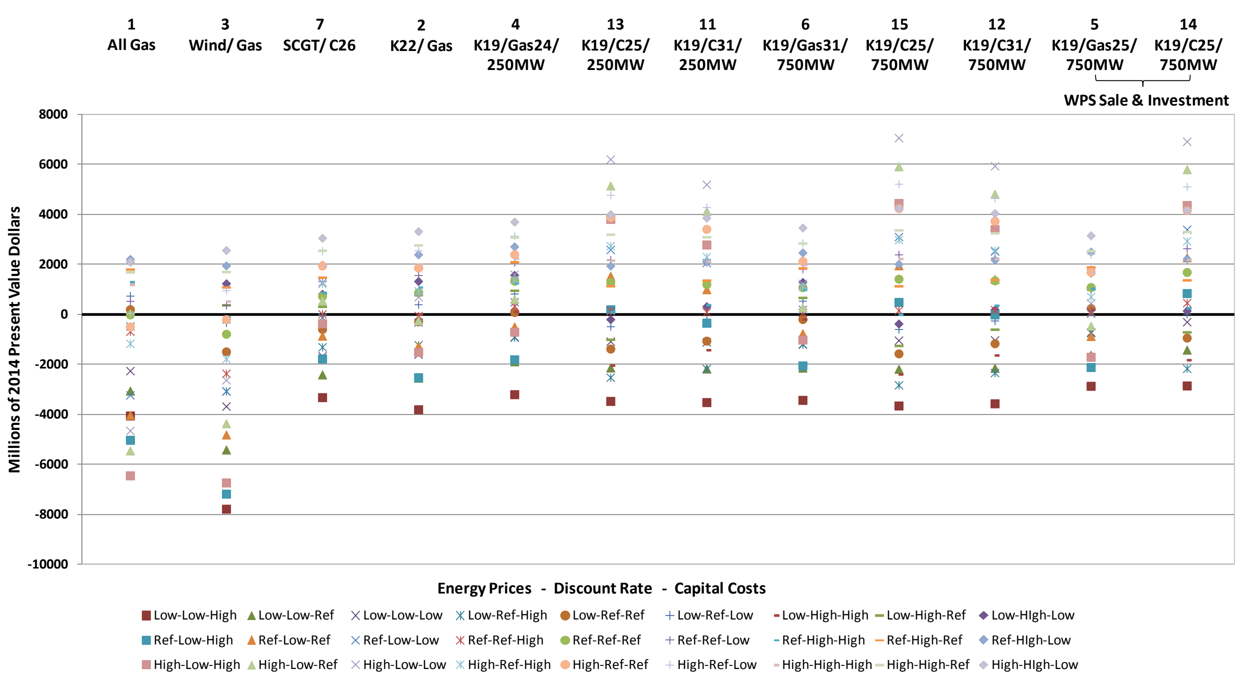
Table 10.4 populates the table with all 324 cases. The purpose of the table is to provide a visual representation of the development plans over the 27 future scenarios. As stated previously, the All Gas Ref-Ref-Ref case is used as a single point base for comparing each development plan in the context of each of the 27 scenarios and is indicated by the "0" NPV for the All Gas Ref-Ref-Ref case. In this type of analysis, NPVs for a development plan provide a measure of the relative performance between that development plan and the All Gas Ref-Ref-Ref case.

The development plan evaluations are categorized as follows:

- development plans with no new U.S. interconnection designed to serve only Manitoba load and existing export commitments
- development plans with a 250 MW U.S. interconnection
- development plans with a 750 MW U.S. interconnection
- comparison of development plans across categories.

Figure 10.5 is a scatter plot that provides the same incremental NPVs as in Table 10.4 but graphically displays the range of incremental NPVs by development plans. It demonstrates that the rank of a particular scenario will not be the same in all development plans. Figure 10.5 confirms the insights drawn from the Table 10.4 quilt. The All Gas plan and the Wind/Gas plan have more downside risk and less upside potential than the other development plans, by hundreds of millions of dollars. The other development plans without an interconnection have modest downside risk and upside potential. The development plans with an interconnection have modest downside risk and varying degrees of upside potential, again, differences of hundreds of millions of dollars.

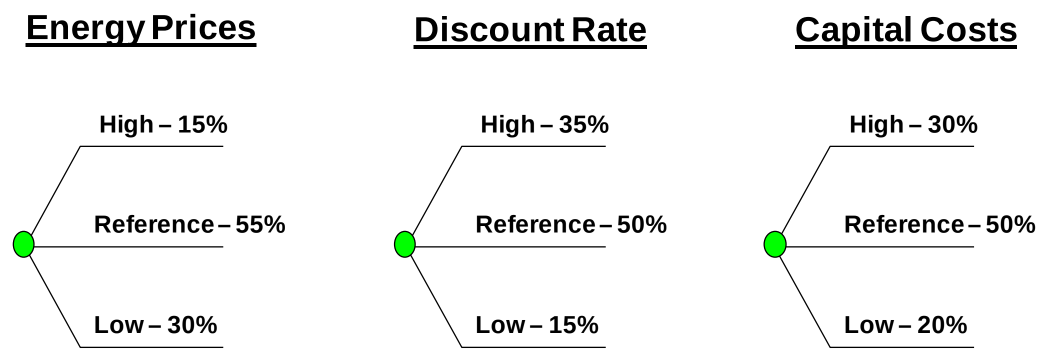
Figure 10.5 Probabilistic Analysis – Scatter Plot
Incremental Economics – All Scenarios



10.1.4 Probabilistic Analysis

As indicated in Section 10.1.1.4, each of the scenarios does not have the same likelihood of occurring and therefore probabilities were developed for each of the sets of these factors. Figure 10.6 repeats the illustration previously introduced in Section 10.1.1.4 and provides the probabilities for each of the highest impact factors.

Figure 10.6 Probabilities for Highest Impact Factors



As Table 10.5 shows, all plans have a substantial range of outcomes which vary from substantially worse than the baseline outcome (All Gas Ref-Ref-Ref case) to substantially better than the baseline outcome. The degree and direction of this variation differs from plan to plan. Both the All Gas and Wind/Gas development plans appear to have the most downside risk as there are more scenarios showing red. Plans with a 250 MW or 750 MW interconnection appear to have the most upside potential as there are more scenarios showing green.

The expected values, provided in Table 10.6, are weighted-average NPVs for each development plan. The information in Table 10.5 is the basis for the determination of the expected value for each development plan when combined with the probabilities provided in Figure 10.6.

Expected value is calculated for each development plan by taking the sum of the NPVs multiplied by their appropriate scenario probabilities listed on the right-most column of the table (see ***Appendix 9.3 - Economic Evaluation Documentation*** for more information on calculating expected value).

Table 10.5 Probabilistic Analysis Quilt – Single Point Base Incremental Economics – All Scenarios

Energy Prices	Discount Rates	Capital Costs	1 All Gas	3 Wind/Gas	7 SCGT/C26	2 K22/Gas	4 K19/Gas24 /250Mw	13 K19/C25 /250MW	11 K19/C31 /250MW	6 K19/Gas31 /750MW	15 K19/C25 /750MW	12 K19/C31 /750MW	5 K19/Gas25 /750MW WPS Sale & Investment	14 K19/C25 /750MW WPS Sale & Investment	Probabilities
			Millions of 2014 NPV dollars												
Low	Low	H	-4043	-7769	-3309	-3792	-3190	-3459	-3506	-3418	-3642	-3554	-2855	-2841	1.35%
		Ref	-3049	-5403	-2401	-2532	-1877	-2124	-2166	-2130	-2177	-2138	-1616	-1410	2.25%
		L	-2247	-3666	-1655	-1590	-890	-1069	-1099	-1175	-1030	-1022	-703	-292	0.90%
	Ref	H	-463	-3056	-1297	-1212	-911	-2510	-2161	-1191	-2816	-2323	-730	-2155	4.50%
		Ref	208	-1478	-582	-278	95	-1368	-1050	-185	-1559	-1153	257	-929	7.50%
		L	750	-323	6	408	837	-473	-176	548	-585	-243	974	20	3.00%
	High	H	1204	-796	-284	25	117	-2029	-1413	-182	-2383	-1622	203	-1810	3.15%
		Ref	1708	384	323	785	963	-994	-434	679	-1243	-592	1060	-698	5.25%
		L	2114	1245	822	1336	1580	-189	327	1297	-364	201	1674	157	2.10%
Ref	Low	H	-5014	-7167	-1760	-2511	-1796	206	-334	-2041	498	0	-2103	853	2.48%
		Ref	-4020	-4802	-852	-1251	-482	1541	1006	-753	1963	1415	-865	2284	4.13%
		L	-3217	-3064	-107	-309	504	2597	2073	202	3110	2531	49	3402	1.65%
	Ref	H	-671	-2354	23	-46	341	152	104	85	170	190	109	470	8.25%
		Ref	0	-775	738	887	1346	1295	1215	1091	1427	1360	1097	1696	13.75%
		L	542	380	1326	1573	2089	2189	2089	1824	2401	2270	1813	2645	5.50%
	High	H	1308	-82	879	1091	1258	109	391	998	2	366	1041	268	5.78%
		Ref	1812	1098	1487	1851	2104	1144	1370	1859	1143	1396	1898	1380	9.63%
		L	2218	1959	1986	2402	2721	1949	2132	2478	2022	2189	2512	2235	3.85%
High	Low	H	-6435	-6719	-355	-1499	-692	3819	2796	-1006	4455	3410	-1694	4372	0.68%
		Ref	-5441	-4353	552	-239	621	5154	4135	282	5921	4826	-456	5803	1.13%
		L	-4638	-2616	1298	703	1607	6210	5203	1237	7068	5941	458	6922	0.45%
	Ref	H	-1158	-1767	1241	941	1398	2746	2308	1127	2993	2571	713	2940	2.25%
		Ref	-487	-189	1956	1874	2403	3888	3420	2134	4250	3741	1701	4166	3.75%
		L	55	966	2543	2560	3146	4783	4293	2867	5225	4652	2417	5115	1.50%
	High	H	1210	533	1956	2017	2246	2170	2127	1993	2236	2228	1691	2203	1.58%
		Ref	1713	1712	2563	2777	3092	3206	3106	2854	3377	3259	2549	3315	2.63%
		L	2120	2573	3063	3328	3709	4010	3867	3473	4256	4051	3163	4170	1.05%

Colour Legend

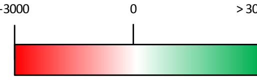


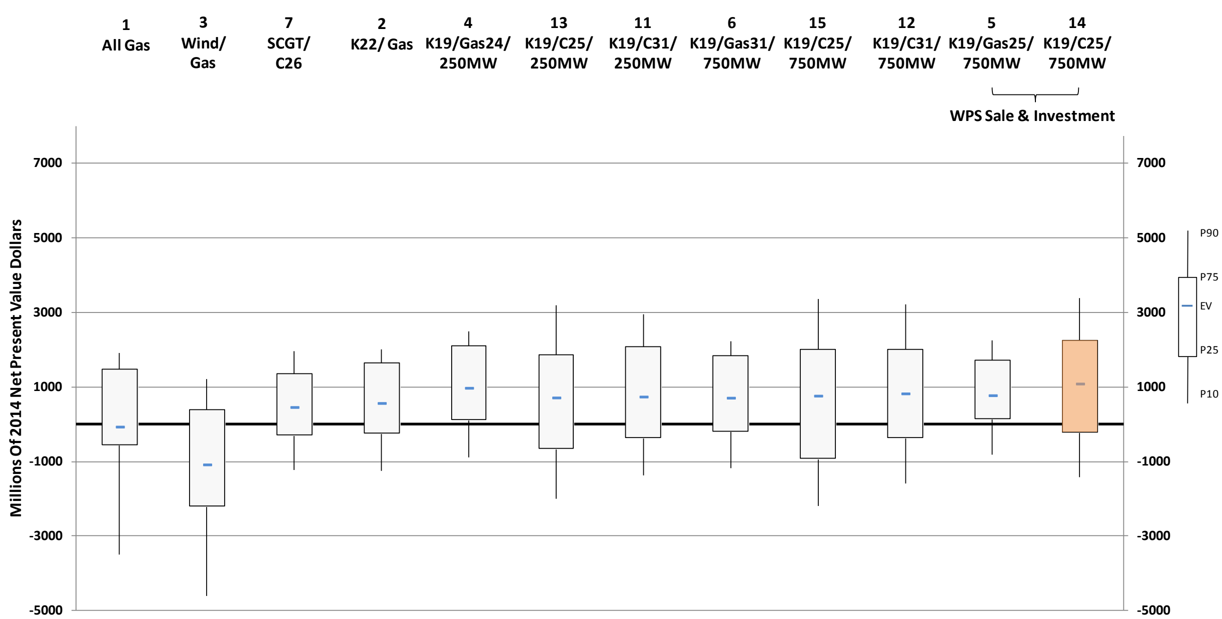
Table 10.6 Probabilistic Analysis – Expected Values Incremental Economics – All Scenarios

Development Plan	1 All Gas	3 Wind/Gas	7 SCGT/C26	2 K22/Gas	4 K19/Gas24 /250Mw	13 K19/C25 /250MW	11 K19/C31 /250MW	6 K19/Gas31 /750MW	15 K19/C25 /750MW	12 K19/C31 /750MW	5 K19/Gas25 /750MW WPS Sale & Investment	14 K19/C25 /750MW WPS Sale & Investment
	Millions of 2014 NPV dollars											
10th Percentile -"Risk"	-3502	-4599	-1217	-1249	-898	-1988	-1362	-1181	-2186	-1594	-828	-1429
25th Percentile	-560	-2200	-297	-248	115	-650	-363	-183	-904	-361	139	-204
75th Percentile	1481	383	1363	1636	2092	1854	2074	1832	2008	2009	1726	2255
90th Percentile - "Reward"	1905	1209	1956	2007	2479	3180	2953	2215	3360	3220	2256	3377
Expected Value	-70	-1084	455	564	971	712	736	706	760	821	772	1085
Ref-Ref-Ref NPV	0	-775	738	887	1346	1295	1215	1091	1427	1360	1097	1696

The expected values, or weighted-average NPVs, incorporate the uncertainty associated with the highest impact factors represented in the scenarios. For example, the reference scenario economics provided in ***Chapter 9 – Economic Evaluations – Reference Scenario*** used a single un-weighted scenario (Ref-Ref-Ref) with a resulting incremental NPV of $1,696 million for the Preferred Development Plan (Plan 14) as compared to the All Gas development plan. For this same comparison using expected value economics, the incremental NPV is $1,155 million ($1,085 minus -$70, as shown in Table 10.6). Table 10.6 shows that the incremental expected value for the Preferred Development Plan (Plan 14) is higher than the expected value for all other development plans.

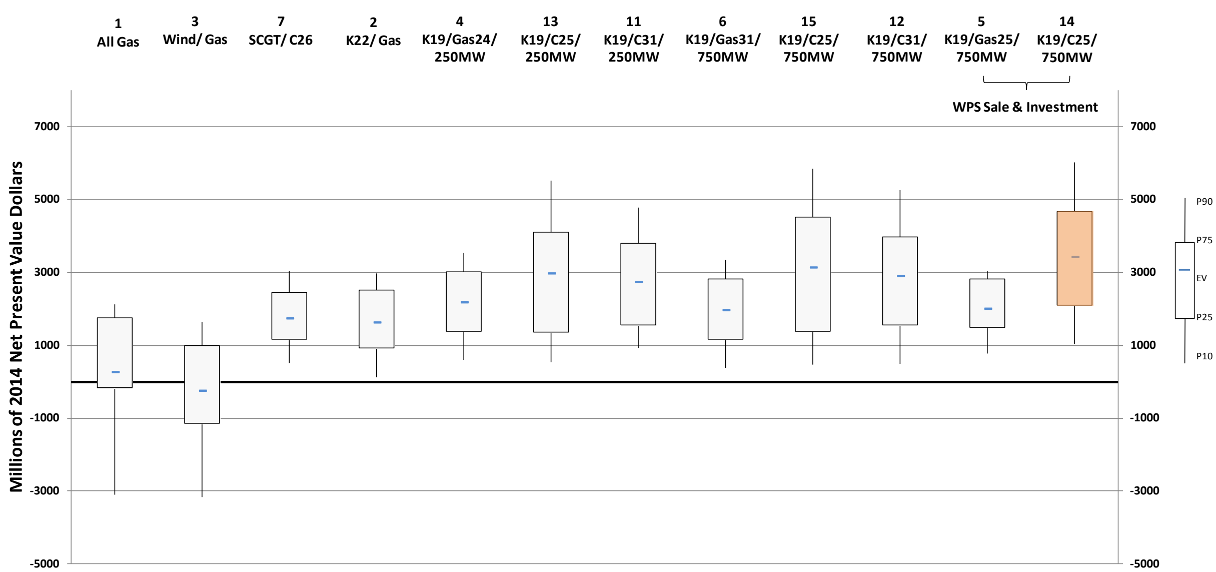
Figure 10.7 provides a box plot which is another method to visualize the range of NPVs for the different development plans being considered. While a scatter plot does not give an indication of the relative likelihood of the NPVs, the box plot is based on the same NPV information used to develop the NPVs presented in Table 10.5, and uses the probabilities provided in Figure 10.6 to produce a probability distribution. The probability distribution is then used to develop the percentiles shown in Table 10.6 and create the "box and whiskers" chart shown in Figure 10.7. The box is defined by the 25th and 75th percentiles and the whiskers are defined by the 10th and 90th percentiles. The expected value is demarked by the dash inside the box. For greater clarity, at the 90th percentile (P90) there is a 10% chance of being greater than the P90 NPV or a 90% chance of being lower than the P90 NPV.

Figure 10.7 Probabilistic Analysis – Box Plot
Incremental Economics – All Scenarios



The "0" on the y-axis is the basis for comparison and represents the All Gas Ref-Ref-Ref case. The smaller the size of the box (between the 25th and 75th percentiles) the less variability a development plan has, and the shorter the "whiskers" the lower the risk and the lower the upside potential. For example, Plan 5 has a smaller box and shorter whiskers than the Preferred Development Plan (Plan 14): this indicates that the Preferred Development Plan has greater variability but has more upside potential. The long whiskers between the 10th and 25th percentiles on the All Gas and Wind/Gas plans indicate a significant downside risk for these plans. Figure 10.7 adds further confirmation to the earlier observations. The All Gas and Wind/Gas plans are relatively low value and high risk. The other plans without an interconnection are low value and low risk. The plans with an interconnection are generally higher value with low to moderate risk, while the ranking among the various interconnection plans represents a value/risk trade-off.

Figure 10.8 Probabilistic Analysis – Box Plot with Transfers to the Province Incremental Economics –All Scenarios

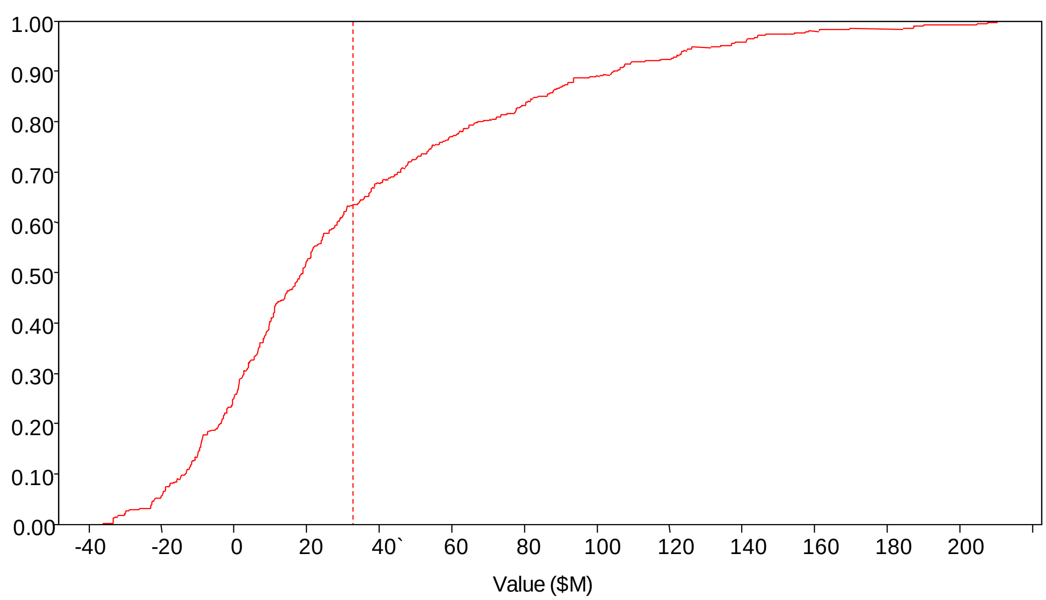


As discussed in ***Chapter 9 – Economic Evaluations – Reference Scenario***, Section 9.3.3, cash transfers to the Province were calculated for each development plan as additional economic benefits. The cash transfers are water rentals, capital taxes and the debt guarantee fee and they benefit the provincial government and indirectly Manitoba taxpayers. The cash transfers to the Province increase the net benefits of all development plans as shown by the higher expected values in Figure 10.8 as compared to similar values without the cash transfers in Figure 10.7. It has been determined that the higher the capital cost of the development plan the greater the cash transfers to the Province. Development plans with one hydro-electric resource will have a greater increase in net benefits than development plans with no hydro-electric resources. As well, the development plans with two hydro-electric resources will have a greater increase in net benefits than development plans with one hydro-electric resource. This reflects the capital intensive nature of hydro project development.

10.1.4.1 Probabilistic Analysis: Understanding S-Curves

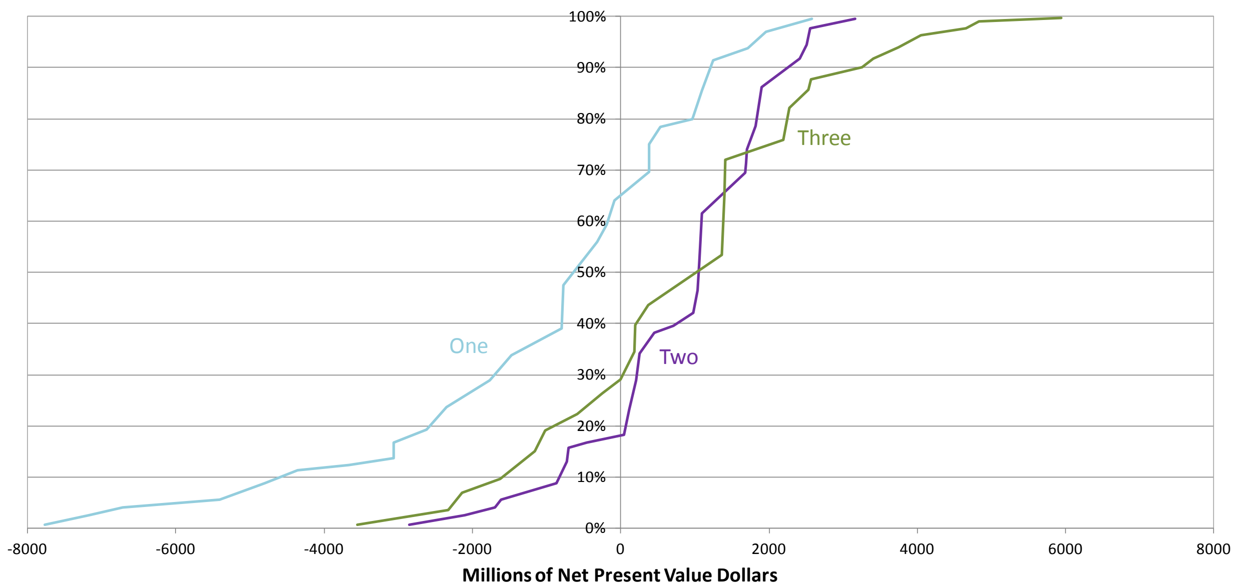
Probabilistic information is often displayed in the form of a cumulative distribution function, called an s-curve or risk profile. The risk profile displays the full range of values associated with an individual alternative in a compact, understandable, graphic format that is suitable for answering a variety of questions about value, risk and opportunity.

Figure 10.9 Sample S-Curve



The risk profile contains a wealth of useful information. Figure 10.9 provides a sample s-curve. The risk profile clearly shows the range of possible outcomes, from a loss of more than $30 million to a gain of more than $200 million. It also shows that there is roughly a 25% chance that the value is less than 0; that is, that the investment results in a loss or failure. There is roughly a 90% chance that the value is less than $100 million, meaning that there is a 10% chance that the value is more than $100 million; indicating that the investment has a 10% probability of being highly successful. Consequently, it can be determined that there is a 65% (90% less 25%) chance that the value lies between $0 million and $100 million, a modest success. At the 50th percentile or median point, there is a 50% chance that the value is less than (or greater than) $20 million. The expected value or mean can also be determined from the risk profile, although it requires additional processing. In Figure 10.9, the expected value is indicated by the dotted line at roughly $35 million—it is the value represented by the line where the roughly triangular areas to the lower left and upper right are equal.

Figure 10.10 Sample S-curve Comparison



Risk profiles are generally most useful for comparing alternatives. Figure 10.10 shows three risk profiles on the same scale. Based on the risk profiles, alternative One is “dominated” by alternatives Two and Three; that is, alternative One is strictly to the left of (or worse than) alternatives Two and Three. Therefore, no matter what target dollar value is selected, it is less likely that alternative One will achieve that target than alternatives Two or Three. Alternative One is also much more likely to result in a loss (roughly an 80% chance) than alternatives Two or Three (roughly a 30% chance). Given these observations, it is difficult to support alternative One.

The choice between alternatives Two and Three is more difficult. Alternative Two has a slightly steeper risk profile than alternative Three; this means that the range of values with alternative Two is smaller than alternative Three. One consequence is that alternative Two has less "downside risk" than alternative Three. Similarly, alternative Two has less "upside opportunity" than alternative Three. Alternative Three has a slightly higher expected value than alternative Two, so the choice is effectively a risk-return trade-off issue. Alternative Two has less risk than alternative Three, but a lower expected value. Alternative Three has higher expected value than alternative Two, but more risk.

10.1.4.2 Probabilistic Analysis: S-Curves

In this section, development plans are compared within each category as described in Section 10.1.3 and across all categories based on economic benefits to Manitoba Hydro using expected value, risk profiles (downside risk and upside opportunity) and the reference (most likely) scenario. In subsequent chapters, further comparisons are made incorporating financial and "multiple-account" impacts.

The comparisons in this section draw out the differences between the plans, as some of the plans have expected values that are within the same order of magnitude but may have different risk profiles. A table which provides the incremental NPV for the Ref-Ref-Ref scenario, the expected value and the 10th and 90th percentile values for each development plan, is included on each s-curve figure.

The development plans being evaluated are categorized as follows:

- development plans with no new U.S. interconnection designed to serve only Manitoba load and existing export commitments
- development plans with a 250 MW U.S. interconnection
- development plans with a 750 MW U.S. interconnection
- comparison of development plans across categories.

Within the comparison of plans across the categories, comparisons were made to demonstrate the difference between pursuing:

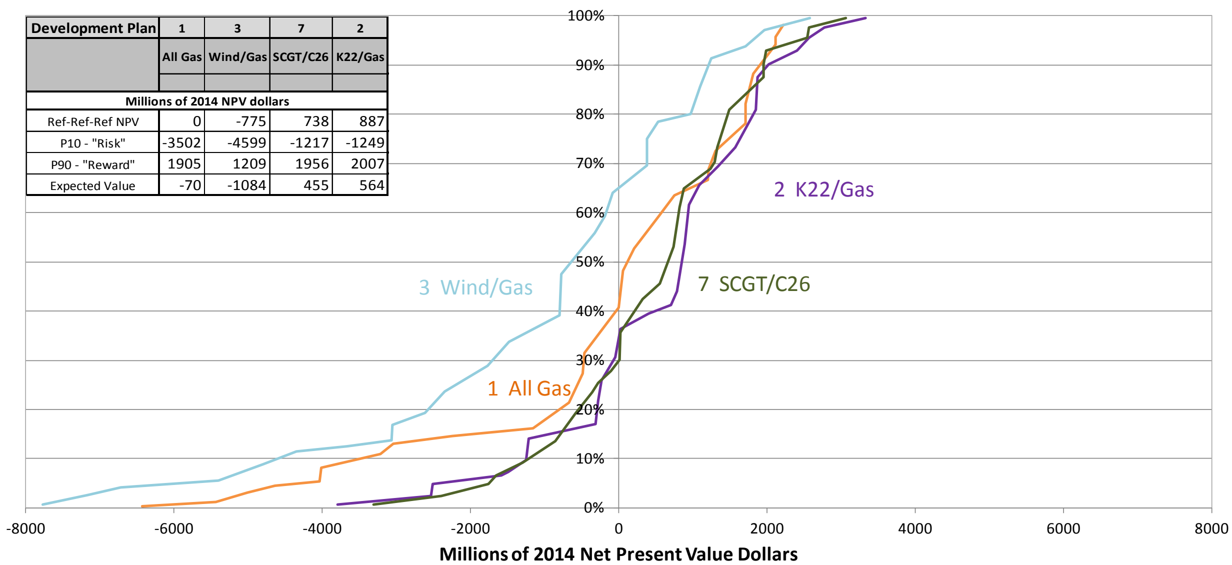
- plans with a 250 MW interconnection or a 750 MW interconnection
- plans with and without the proposed 300 MW WPS sale and related investment in the 750 MW interconnection
- plans with and without Conawapa generating station (G.S.).

Development Plans with No New U.S. Interconnection - Four Plans

Figure 10.11 displays the four plans in the “Manitoba Load” category that were evaluated: All Gas, Wind/Gas, K22/Gas and SCGT/C26. The expected values for the four plans are: $70 million, $1,084 million, $564 million and $455 million, respectively. With the exception of the Wind/Gas Plan, the plans all have similar upside potential above the 60th percentile. The Wind/Gas plan has the greatest downside risk and the least upside potential when compared to the other three plans and results in an expected value that is significantly lower than the other three plans at $1,084 million. The Wind/Gas plan is less economic than that of the All Gas plan due to the greater capital cost of the Wind/Gas plan. Both plans require the same level of natural gas-fired generation to meet increases in system peak loads. The Wind/Gas plan has the additional cost of the wind turbines and the fuel savings associated with the wind generation is not sufficient to offset these increased costs. With the increased capital cost, the Wind/Gas plan is more sensitive to lower discount rates. As shown in Figure 10.11, the All Gas plan lies to the right of the Wind/Gas plan, clearly dominating the Wind/Gas plan.

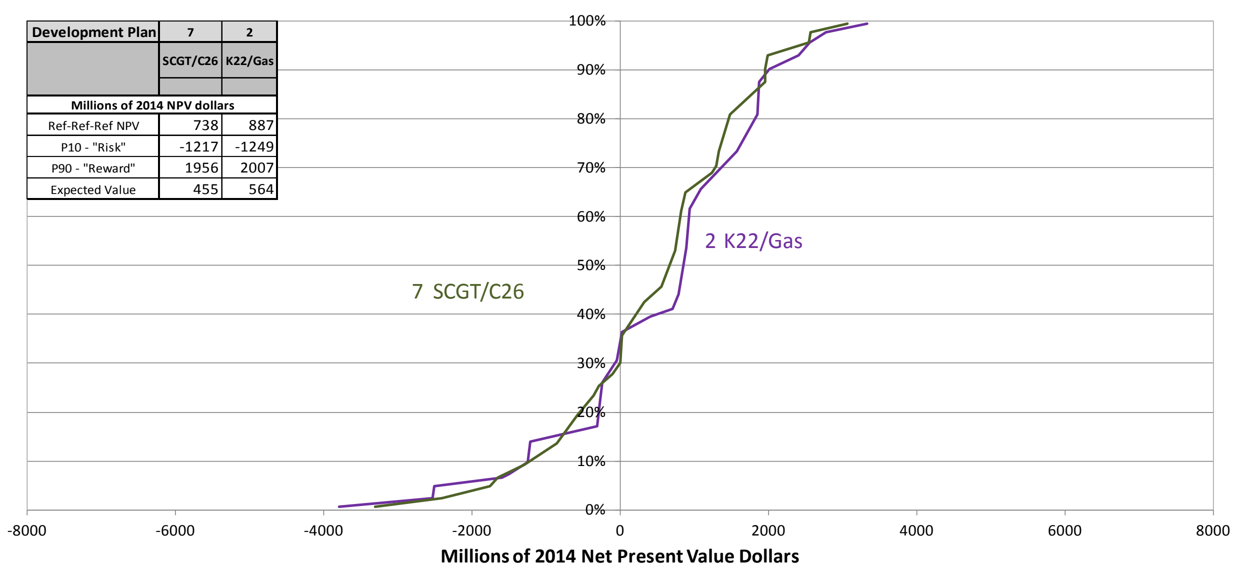
While the All Gas plan dominates the Wind/Gas plan, it has a significantly greater downside potential than the K22/Gas and SCGT/C26 plans due to the greater proportion of thermal generation, particularly under low discount rate scenarios. Therefore, on the basis of the expected values and the risk profile, it can be concluded that the All Gas and Wind/Gas plans are effectively dominated, making both inferior to K22/Gas and SCGT/C26.

Figure 10.11 Probabilistic Analysis: S-Curves
Plans With No New Interconnection



Development Plan	1	3	7	2
	All Gas	Wind/Gas	SCGT/C26	K22/Gas
Millions of 2014 NPV dollars				
Ref-Ref-Ref NPV	0	-775	738	887
P10 - "Risk"	-3502	-4599	-1217	-1249
P90 - "Reward"	1905	1209	1956	2007
Expected Value	-70	-1084	455	564

Figure 10.12 Probabilistic Analysis: S-Curves
K22/Gas and SCGT/C26 Plans



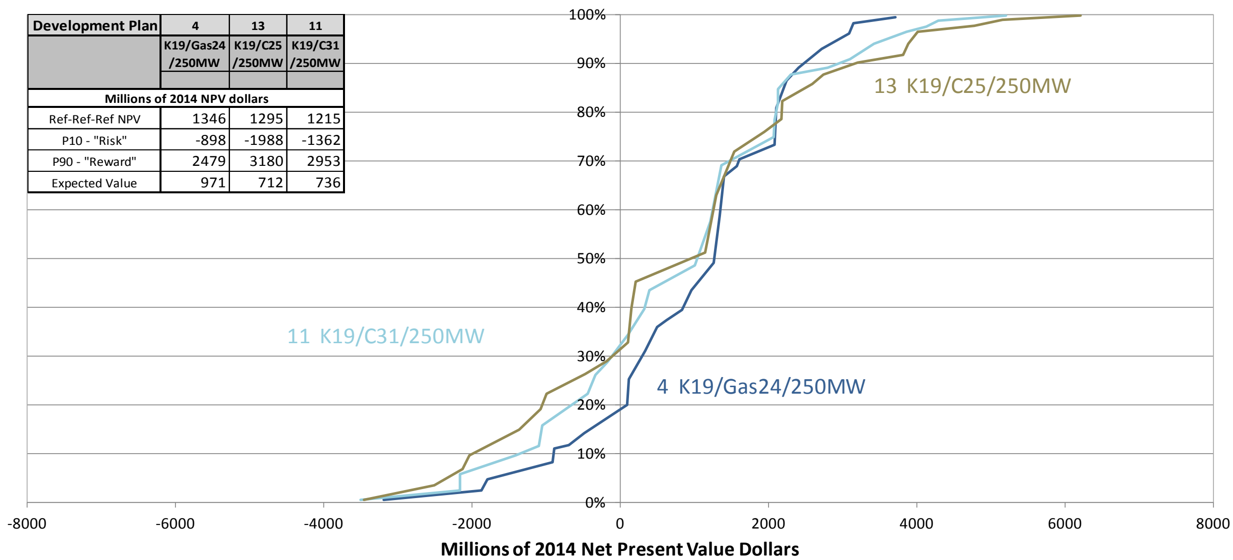
Development Plan	7	2
	SCGT/C26	K22/Gas
Millions of 2014 NPV dollars		
Ref-Ref-Ref NPV	738	887
P10 - "Risk"	-1217	-1249
P90 - "Reward"	1956	2007
Expected Value	455	564

As shown in Figure 10.12, K22/Gas and SCGT/C26 have comparable risk profiles, with the expected value of K22/Gas approximately $100 million greater than the SCGT/C26 plan. On this basis, K22/Gas is preferable to the other three "Manitoba load only" plans. SCGT/C26 is a reasonable second choice.

Development Plans with a 250 MW U.S. Interconnection - Three Plans

Figure 10.13 displays the three plans in the "250 MW interconnection" category.

Figure 10.13 Probabilistic Analysis: S-Curves
Plans With 250 MW U.S. Interconnection



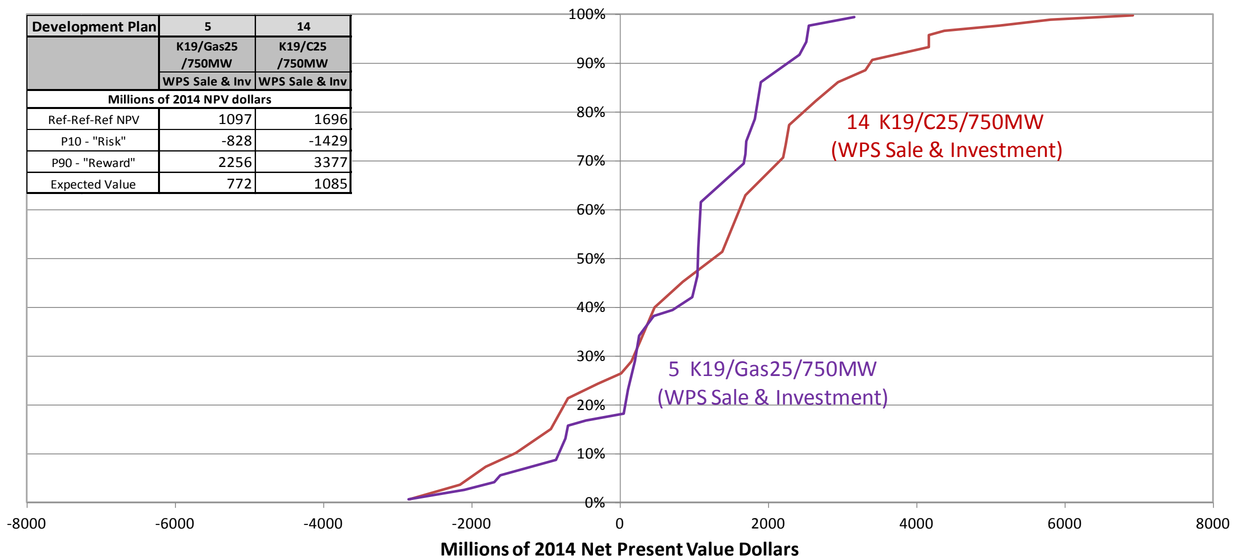
The expected value of Plan 4 (K19/Gas24/250MW) exceeds that of Plan 13 (K19/C25/250MW) and Plan 11 (K19/C31/250MW) by over $230 million. As shown in Figure 10.13, below the 50th percentile, Plan 4 lies to the right of both of the other 250 MW interconnection plans, indicating that Plan 4 has less downside risk. Above the 80th percentile, Plan 4 lies to the left of the other 250 MW interconnection plans, showing less upside potential due to limited surplus power as it does not have the Conawapa G.S. As the two plans with the Conawapa G.S. have greater surplus energy, without fixed-priced surplus power sales they would have more exposure to export price risk when prices are low and greater upside potential when prices are high. The relative risk-reward trade-off between the three plans is reflected in their expected values of $971 million, $712 million and $736 million. From an economic evaluation perspective Plan 4, with an expected value of over $200 million higher than the other two plans, is the most economic of the three plans. Careful consideration must be given to the trade-offs between the plans due to difference in their risk profiles as shown in this economic evaluation. Further analysis of other perspectives (financial, multiple accounts and optionality), which are provided in following chapters, will be an important consideration.

Development Plans with a 750 MW U.S. Interconnection - Five Plans

There are five plans in the "750 MW interconnection" category. Two of the plans, Preferred Development Plan (K19/C25/750MW (WPS Sale & Inv)) and Plan 5 (K19/Gas25/750MW (WPS Sale & Inv)), include the proposed 300 MW WPS sale and related investment in the 750 MW transmission interconnection. The other three plans, Plan 12 (K19/C31/750MW), Plan 6 (K19/Gas31/750MW) and Plan 15 (K19/C25/750MW), reflect the uncertainty in the outcome of the ongoing negotiations with Wisconsin Public Service (WPS) and, therefore, do not include the proposed 300 MW WPS sale and, in addition, in one of the plans the in-service date of Conawapa is deferred to 2031/32.

Figure 10.14 shows the two development plans with the proposed 300 MW WPS sale. As shown in Figure 10.14, when compared with Plan 5 (K19/Gas25/750MW (WPS Sale & Inv)), the Preferred Development Plan (Plan 14) is $300 million higher in expected value. Below the 50th percentile, the risk profile is similar for the two plans but is driven by different factors. The downside risk of Plan 5 is due to a greater proportion of operating costs being related to thermal generation, particularly under low discount rate scenarios. As the Preferred Development Plan, which has Conawapa in 2025/26, has a large volume of surplus power, it is more sensitive to lower energy prices particularly when combined with higher discount rates and higher capital costs. Above the 50th percentile, the Preferred Development Plan lies to the right of Plan 5, reflecting significantly greater value primarily due to the availability of surplus power from the Conawapa G.S. at reference or higher energy prices.

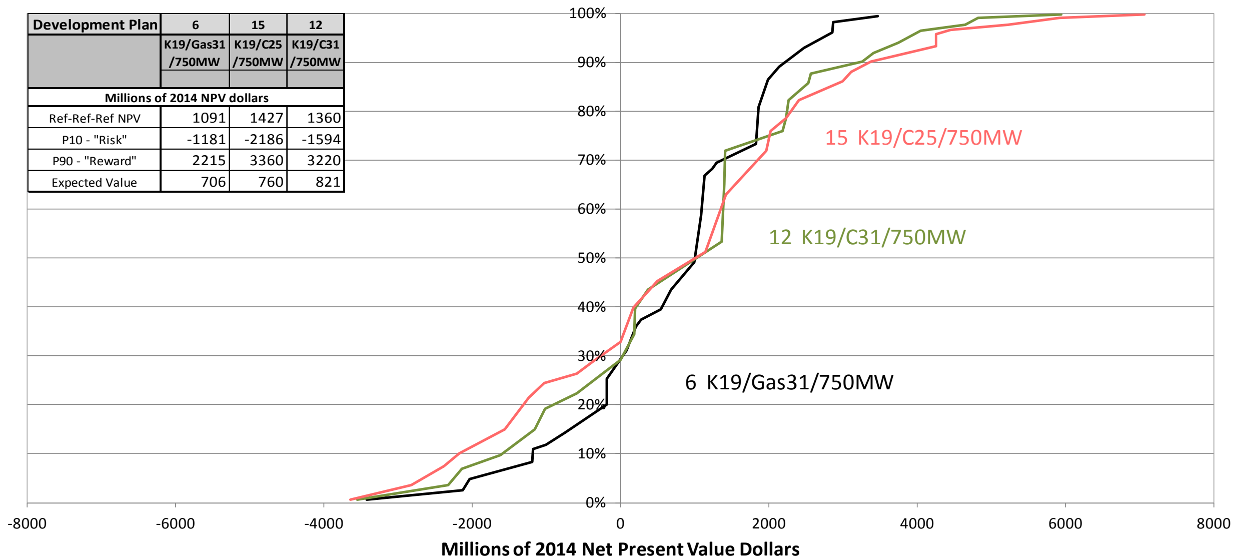
Figure 10.14 Probabilistic Analysis: S-Curves
Plans With 750 MW Interconnection and Proposed WPS Sale



Development Plan	5	14
	K19/Gas25 /750MW	K19/C25 /750MW
	WPS Sale & Inv	WPS Sale & Inv
Millions of 2014 NPV dollars		
Ref-Ref-Ref NPV	1097	1696
P10 - "Risk"	-828	-1429
P90 - "Reward"	2256	3377
Expected Value	772	1085

Figure 10.15 shows the three development plans without the proposed 300 MW WPS sale. As shown in Figure 10.15, when comparing the plans that do not include the proposed 300 MW WPS sale, the range of expected values is in the order of $100 million. Under scenarios where energy prices are low, Plan 12 (K19/C31/750MW) and Plan 15 (K19/C25/750MW) yield lower incremental NPVs than Plan 6 (K19/Gas31/750MW). Plan 12 and Plan 15 have greater upside potential when the energy prices are at reference or high (regardless of whether capital cost is at low, reference or high values and when discount rate is at low or reference values) because in Plans 12 and 15 there is surplus power from the Conawapa G.S. to take advantage of the energy prices. As the two plans with the Conawapa G.S. (Plan 12 and Plan 15) have greater surplus energy without fixed-priced export sales, they have more exposure to export price risk when prices are low and greater upside potential when prices are high. With such a narrow range in the expected values of the three development plans (i.e. within approximately $100 million), careful consideration must be given to the risk/reward trade-offs between the plans.

Figure 10.15 Probabilistic Analysis: S-Curves Plans With 750 MW Interconnection and Without Proposed WPS Sale

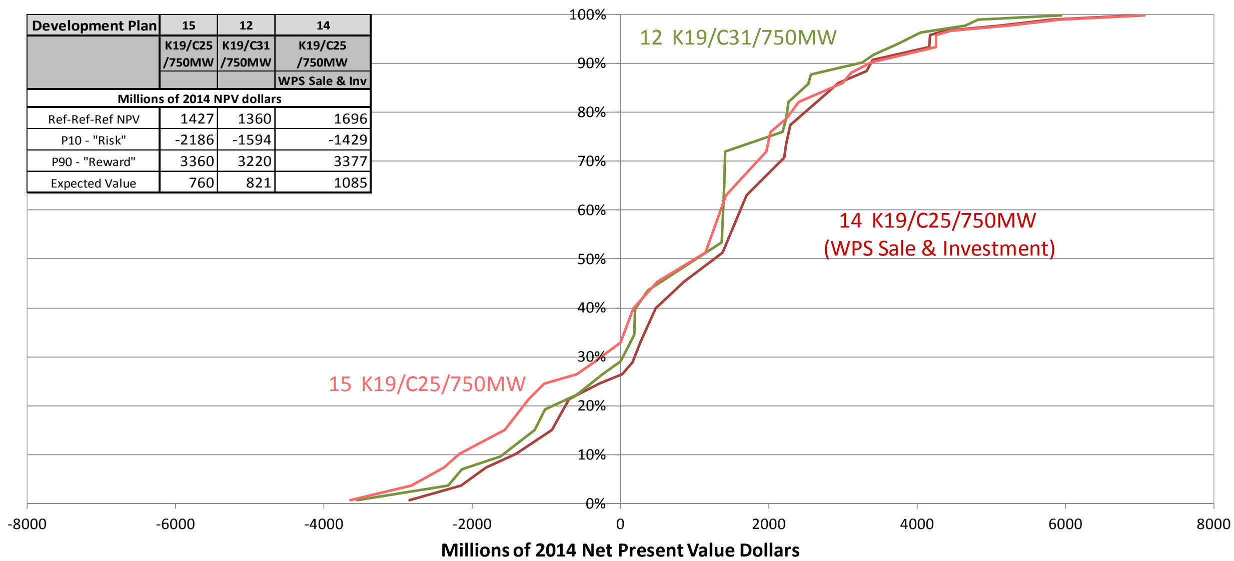


Development Plan	6	15	12
	K19/Gas31 /750MW	K19/C25 /750MW	K19/C31 /750MW
Millions of 2014 NPV dollars			
Ref-Ref-Ref NPV	1091	1427	1360
P10 - "Risk"	-1181	-2186	-1594
P90 - "Reward"	2215	3360	3220
Expected Value	706	760	821

Figure 10.16 displays the three development plans with the 750 MW interconnection and Conawapa G.S.: the Preferred Development Plan (K19/C25/750MW (WPS Sale & Inv)), Plan 12 (K19/C31/750MW), and Plan 15 (K19/C25/750MW). The Preferred Development Plan and Plan 15 both have the Conawapa G.S. in 2025/26, while Plan 15 reflects the uncertainty in the outcome of the ongoing negotiations with WPS by not including this sale and, therefore, provides a direct comparison to the Preferred Development Plan (Plan 14). The two plans without the proposed 300 MW WPS sale include increased costs to Manitoba Hydro associated with the U.S. interconnection as no investment from WPS is assumed.

The expected value of $1,085 million for the Preferred Development Plan is the highest expected value of the development plans evaluated. The other two development plans in Figure 10.16 have expected values that place them in the top three development plans after the Preferred Development Plan.

Figure 10.16 Probabilistic Analysis: S-Curves
Plans with 750 MW Interconnection and Conawapa G.S.



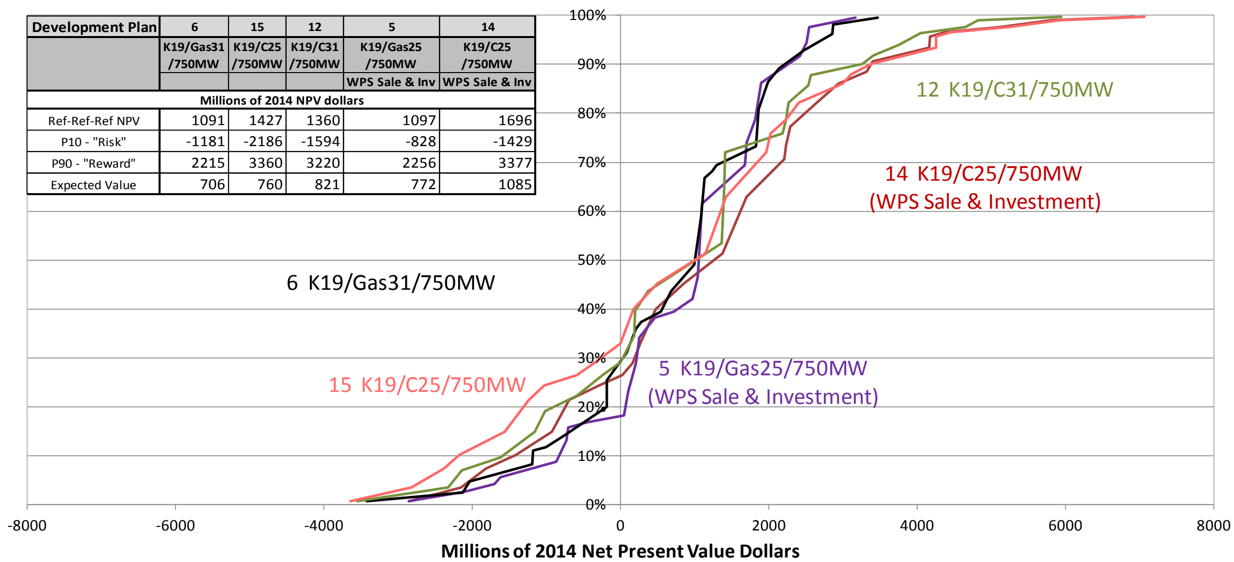
Development Plan	15	12	14
	K19/C25 /750MW	K19/C31 /750MW	K19/C25 /750MW
			WPS Sale & Inv
Millions of 2014 NPV dollars			
Ref-Ref-Ref NPV	1427	1360	1696
P10 - "Risk"	-2186	-1594	-1429
P90 - "Reward"	3360	3220	3377
Expected Value	760	821	1085

Figure 10.16 highlights the difference between plans which have more surplus power at fixed export prices as opposed to plans with surplus capacity and energy evaluated at forecasted long-term electricity export prices. The Preferred Development Plan, which includes the proposed 300 MW WPS Sale, when compared to Plan 15 (without the proposed 300 MW WPS sale) has an expected value that is higher by over $300 million. Plan 15 has slightly more upside potential than the Preferred Development Plan above the 90th percentile—more of the surplus power in the Preferred Development Plan is at fixed prices, which are lower than those in the high end of the range of energy prices being evaluated. The benefit of this upside potential for Plan 15, however, is more than offset by the significant downside risk related to the exposure to low energy prices on surplus power unprotected by fixed prices. Plan 12 benefits from comparatively lower capital costs and less exposure to low energy prices partially offset by lower upside potential all due to the deferral of Conawapa G.S. This is reflected in an expected value of $821 million which falls between that of the Preferred Development Plan at $1,085 million and Plan 15 at $760 million.

Figure 10.17 displays the five plans in the "750 MW interconnection" category. Two of the plans with a 750 MW interconnection reflect the proposed 300 MW sale to WPS, while the other three plans reflect the sale of all surplus capacity and energy at forecasted long-term electricity export prices. When all five plans are considered together, there is a noticeable distinction in the upside potential (beyond the 70th percentile) for the plans with the Conawapa G.S. There is a smaller range across the five plans below the 40th percentile, with the plans with natural gas generation lying to the right of the other three plans, indicating less downside risk.

Plan 12 (K19/C31/750MW) and the Preferred Development Plan are higher in expected value when compared to the other plans. On the basis of both the expected value and upside potential, the Preferred Development Plan is the most attractive plan with a "750 MW interconnection" plan. Plan 12 is a reasonably close second choice.

Figure 10.17 Probabilistic Analysis: S-Curves
Plans With 750 MW Interconnection



Development Plan	6	15	12	5	14
	K19/Gas31 /750MW	K19/C25 /750MW	K19/C31 /750MW	K19/Gas25 /750MW WPS Sale & Inv	K19/C25 /750MW WPS Sale & Inv
Millions of 2014 NPV dollars					
Ref-Ref-Ref NPV	1091	1427	1360	1097	1696
P10 - "Risk"	-1181	-2186	-1594	-828	-1429
P90 - "Reward"	2215	3360	3220	2256	3377
Expected Value	706	760	821	772	1085

Comparison of Development Plans Across Categories

Comparisons were made across categories to demonstrate the differences between development plans. Figures 10.18 to 10.21 compare a number of the major elements of the development plans, including:

- plans with a 250 MW interconnection or a 750 MW interconnection
  - o a 250 MW interconnection compared to no interconnection (Figure 10.18)

- a 250 MW interconnection compared to a 750 MW interconnection with natural gas-fired generation (Figure 10.19)
- a 250 MW interconnection compared to a 750 MW interconnection with Conawapa G.S. (Figure 10.20)
- a 250 MW interconnection with natural gas-fired generation compared to a 750 MW interconnection with Conawapa G.S. (Figure 10.21)

- plans with and without the proposed 300 MW WPS sale and related investment in the750 MW interconnection (Figure 10.20 and Figure 10.21)
- plans with and without Conawapa G.S.
  - Plans *without* Conawapa G.S. (Figure 10.18 and Figure 10.19)
  - Plans *with* Conawapa G.S. (Figure 10.20 and Figure 10.21).

As shown in Figure 10.18, when compared to the K22/Gas development plan, Plan 4 (K19/Gas24/250MW) is dominant and has an expected value that is higher by over $400 million. This means that it is more beneficial to advance the Keeyask G.S. and invest in a small interconnection than to consider any of the development plans without a new U.S. interconnection.

Figure 10.18 Probabilistic Analysis: S-Curves K22/Gas and K19/Gas24/250MW Plans

Development Plan	2	4
	K22/Gas	K19/Gas24 /250MW
Millions of 2014 NPV dollars		
Ref-Ref-Ref NPV	887	1346
P10 - "Risk"	-1249	-898
P90 - "Reward"	2007	2479
Expected Value	564	971

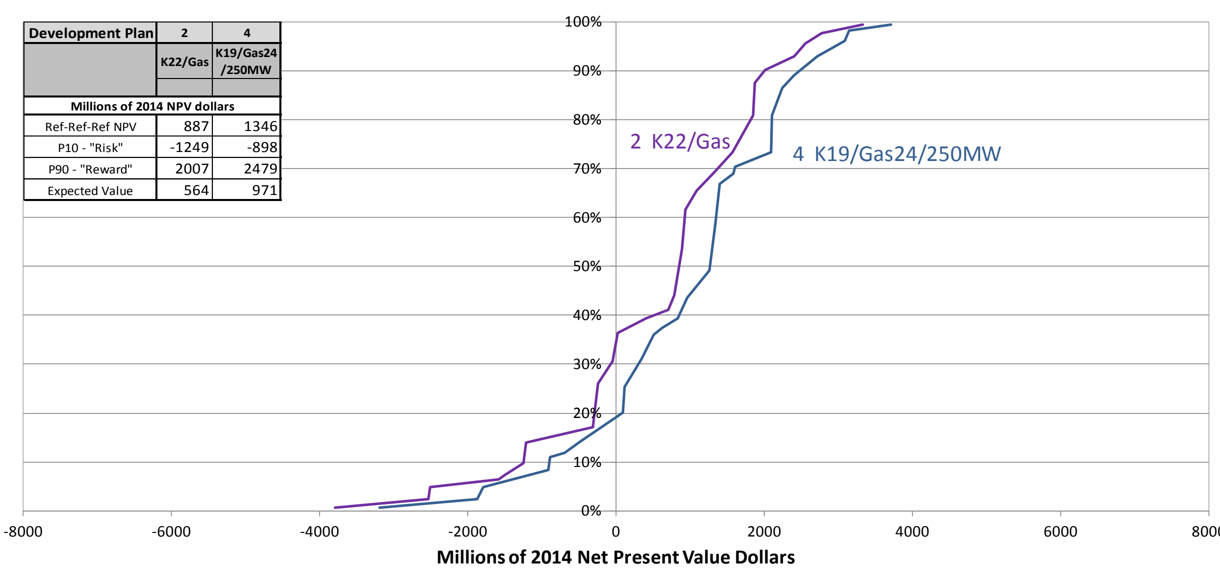
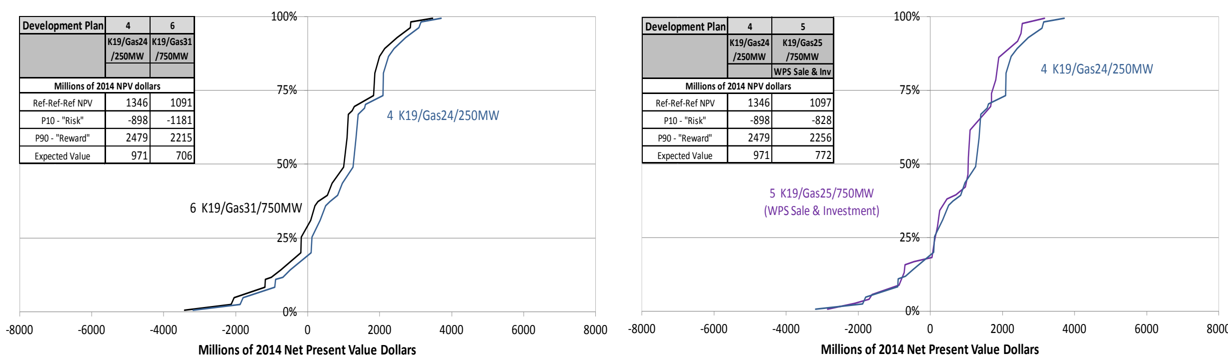


Figure 10.19 compares Plan 4 (K19/Gas24/250MW) to the 750 MW interconnection plans with natural gas-fired generation: Plan 5 (K19/Gas25/750MW) and Plan 6 (K19/Gas31/750MW). The chart on the left shows that Plan 4 dominates Plan 6.

The chart on the right shows that below the 40th percentile, risk profiles for Plan 4 and Plan 5 are similar because the additional value associated with the import capability of the large interconnection offsets the higher capital cost of the large interconnection. Above the 70th percentile, Plan 5 (with the 750 MW interconnection) has lower incremental NPVs as there is limited surplus energy to export on the large line to compensate for its higher capital cost. This illustrates that it is more beneficial to invest in a small interconnection when the Keeyask G.S. is followed by natural gas-fired generation.

Figure 10.19 Probabilistic Analysis: S-Curves
250 MW to 750 MW Interconnections
Development Plans with Natural Gas Generation



Development Plan	4	6
	K19/Gas24 /250MW	K19/Gas31 /750MW
Millions of 2014 NPV dollars		
Ref-Ref-Ref NPV	1346	1091
P10 - "Risk"	-898	-1181
P90 - "Reward"	2479	2215
Expected Value	971	706

Development Plan	4	5
	K19/Gas24 /250MW	K19/Gas25 /750MW
		WPS Sale & Inv
Millions of 2014 NPV dollars		
Ref-Ref-Ref NPV	1346	1097
P10 - "Risk"	-898	-828
P90 - "Reward"	2479	2256
Expected Value	971	772

Figure 10.20 shows various comparisons of plans with Conawapa G.S. and either a 250 MW or a 750 MW interconnection.

Figure 10.20 Probabilistic Analysis: S-Curves
250 MW to 750 MW Interconnections
Development Plans with Conawapa G.S.

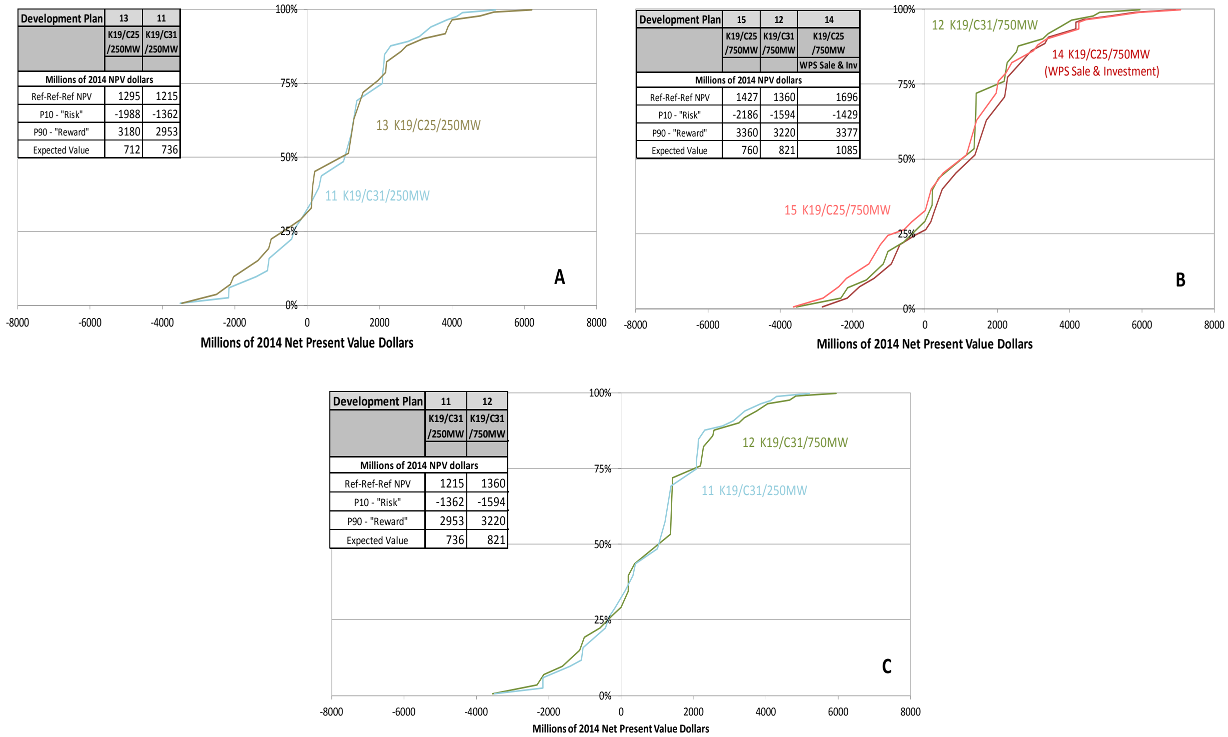


Chart A, on the left side of Figure 10.20, compares Plan 13 (K19/C25/250MW) to Plan 11 (K19/C31/250MW). From an expected value perspective, each plan yields similar values of $712 million and $736 million, respectively, and the NPV at Ref-Ref-Ref scenario for Plan 11 is only $80 million higher. In both plans surplus power from Conawapa G.S. is priced at forecasted long-term electricity export prices. With Plan 13 (Conawapa G.S. in 2025/26), the early years of Conawapa G.S. will have a greater surplus as Manitoba load is lower than it would be in 2031/32. This surplus is likely to exceed available export transmission capability more frequently with only a 250 MW interconnection. The incremental revenue from Plan 13 is unlikely to provide sufficient revenue to offset the additional capital cost of advancing it from 2031/32 to 2025/26 without a larger interconnection. The economic analysis slightly favours the development plan with Conawapa G.S. in 2031/32.

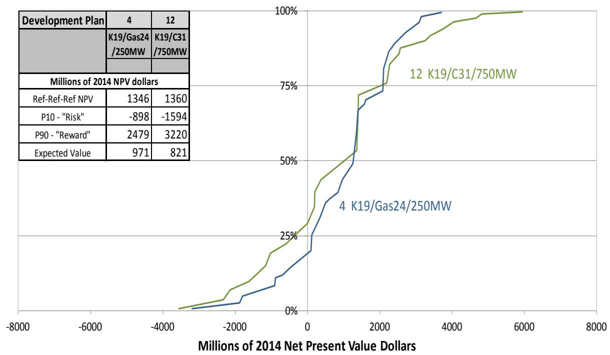
Chart B, on the right side of Figure 10.20, compares Plan 15 (K19/C25/750MW), Plan 12 (K19/C31/750MW) and the Preferred Development Plan (K19/C25/750MW (WPS Sale & Inv)). As explained in the comparison of "Development Plans with a 750 MW U.S. Interconnection - Five Plans", when the Preferred Development Plan is compared to Plan 15, the Preferred Development Plan (with the WPS Sale & Inv) has an expected value that is higher by over $300 million. Plan 15 has slightly more upside potential above the 90th percentile than the Preferred Development Plan, while Plan 12 (Conawapa 2031) benefits from the deferral of Conawapa G.S. This is reflected in an expected value of $821 million which falls between that of the Preferred Development Plan at $1,085 million and Plan 15 (Conawapa 2025) at $760 million. Chart B shows the Preferred Development Plan has the highest expected value and shows that a deferral of Conawapa to 2031 (Plan 12) yields similar results to Plan 15 (Conawapa 2025).

Chart C of Figure 10.20 compares Plan 11 (K19/C31/250MW) and Plan 12 (K19/C31/750MW) to illustrate the effect of developing a 750 MW interconnection as compared to a 250 MW interconnection. When comparing these two plans on an expected value basis, Plan 12 (with a 750 MW interconnection) exceeds Plan 11 by only $85 million while under the reference scenario Plan 12 exceeds the incremental NPV of Plan 11 by $145 million. The risk profiles are similar between the two plans with slightly more upside potential for Plan 12 above the 75th percentile where there is more opportunity to derive benefit from a larger interconnection. The two plans have very similar downside risk with slightly less risk for Plan 11 below the 25th percentile. From an expected value perspective, the analysis yields similar results and slightly favours Plan 12 (750 MW interconnection). Further analysis of other perspectives (financial, multiple accounts and optionality), which are provided in following chapters, will be important when considering whether to pursue a 250 MW or 750 MW interconnection.

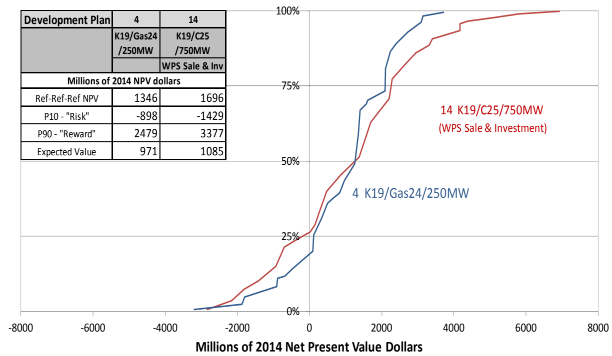
Figure 10.21 provides additional comparisons that demonstrate the difference between pursuing a 250 MW interconnection compared to a 750 MW interconnection. Plan 4

(K19/Gas24/250MW) is compared to Plan 12 (K19/C31/750MW) and to the Preferred Development Plan.

Figure 10.21 Probabilistic Analysis: S-Curves
250 MW to 750 MW Interconnections
Selected Development Plans with Conawapa G.S. or Gas



Development Plan	4	12
	K19/Gas24 /250MW	K19/C31 /750MW
Millions of 2014 NPV dollars		
Ref-Ref-Ref NPV	1346	1360
P10 - "Risk"	-898	-1594
P90 - "Reward"	2479	3220
Expected Value	971	821



Development Plan	4	14
	K19/Gas24 /250MW	K19/C25 /750MW
		WPS Sale & Inv
Millions of 2014 NPV dollars		
Ref-Ref-Ref NPV	1346	1696
P10 - "Risk"	-898	-1429
P90 - "Reward"	2479	3377
Expected Value	971	1085

In order to reflect the uncertainty in the outcome of the ongoing negotiations with WPS, Plan 12 is compared to Plan 4 as shown in the chart on the left side of Figure 10.21. These plans have different risk profiles, with Plan 4 being less sensitive to low energy prices and high discount rates. Plan 12 has greater upside potential when energy prices are high (regardless of whether capital cost or discount rate factors are at low, reference or high values) because in this plan there is surplus power from the Conawapa G.S. to take advantage of the higher energy prices. As Plan 12 (K19/C31/750MW) requires a higher capital investment in generation and in the U.S. interconnection when compared to Plan 4 (K19/Gas24/250MW), there is more exposure to higher discount rates. Plan 12 (without the WPS sale) has a higher volume of surplus energy priced at forecasted long-term electricity export prices rather than at fixed prices and is more exposed to lower energy prices than is Plan 4. While Plan 4 has an expected value of $150 million higher than Plan 12, careful consideration must be given to the trade-offs between the plans given the difference in their characteristics and in their risk profiles.

The chart on the right side of Figure 10.21 compares the Preferred Development Plan to Plan 4. When comparing these two plans on an expected value basis, the Preferred Development Plan exceeds Plan 4 by only $114 million, while under the reference scenario the Preferred Development Plan exceeds the incremental NPV of Plan 4 by $350 million. The Preferred

Development Plan has the highest incremental NPV of all of the development plans for the Ref-Ref-Ref scenario as shown in ***Chapter 9 – Economic Evaluations – Reference Scenario***.

The Preferred Development Plan has higher upside potential while Plan 4 (K19/Gas24/250MW) has less downside risk. Under scenarios where energy prices are low, the Preferred Development Plan as compared to Plan 4 yields lower incremental NPVs, with the exception of those scenarios where both energy prices and discount rates are low. At low energy prices, the surplus energy from the Preferred Development Plan does not result in sufficient revenues—when compared to Plan 4—to offset the higher capital cost of the Conawapa G.S. and a larger interconnection. The revenues are insufficient when energy prices are low primarily due to the assumption that surplus capacity and energy (beyond that which is under proposed or existing long-term contracts) are not at fixed prices but are exposed to a range of energy prices.

Generally, at reference or high energy prices, the Preferred Development Plan has greater incremental NPVs because there is surplus power from the Conawapa G.S. and a large interconnection to move the energy to the export market. Under the reference scenario, the Preferred Development Plan exceeds the incremental NPV of Plan 4 by $350 million while the difference in the expected value between the two plans is just over $100 million. Plans with the Conawapa G.S. protect the potential benefits associated with the development of a large interconnection. Given the different characteristics of these plans (Conawapa G.S. versus Gas, and 750 MW interconnection versus 250 MW interconnection), careful consideration must be given to the trade-offs between the plans. Further analysis of other perspectives (financial, multiple accounts and optionality), which are provided in following chapters, are important to the overall conclusions provided in ***Chapter 14 - Conclusions***.

10.1.5 Probabilistic Analysis Conclusions

In section 10.1, probabilistic analysis was used to compare 12 plans within and across three categories:

- development plans with no new U.S. interconnection designed to serve only Manitoba load and existing export commitments
- development plans with a 250 MW U.S. interconnection
- development plans with a 750 MW U.S. interconnection.

Table 10.7 Probabilistic Analysis – Expected Values and Reference NPV Incremental Economics – All Scenarios

Development Plan	1	3	7	2	4	13	11	6	15	12	5	14
	All Gas	Wind/Gas	SCGT/C26	K22/Gas	K19/Gas24 /250Mw	K19/C25 /250MW	K19/C31 /250MW	K19/Gas31 /750MW	K19/C25 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
											WPS Sale & Investment	
	Millions of 2014 NPV dollars											
Expected Value	-70	-1084	455	564	971	712	736	706	760	821	772	1085
Ref-Ref-Ref NPV	0	-775	738	887	1346	1295	1215	1091	1427	1360	1097	1696

The following conclusions are provided for the probabilistic analysis of development plans.

Conclusion from the evaluation of the four plans in the “Manitoba load” category (All Gas, Wind/Gas, K22/Gas and SCGT/C26):

- Based on the expected values, reference scenario NPVs and on risk profiles, the All Gas and Wind/Gas plans are effectively dominated, making both inferior to K22/Gas and SCGT/C26. The K22/Gas plan is preferable to the SCGT/C26 plan with the SCGT/C26 plan being a reasonable second choice. (Figures 10.11 and 10.12)

Conclusions from the evaluation of the three plans with a 250 MW interconnection (Plan 4 (K19/Gas24/250MW), Plan 11 (K19/C31/250MW) and Plan 13 (K19/C25/250MW)):

- It is more beneficial to advance Keeyask G.S. and invest in a small interconnection than it is to pursue development plans designed to serve only Manitoba load and existing export commitments. (Figure 10.18)
- Of the plans that contemplate a 250 MW interconnection, Plan 4 (K19/Gas24/250MW) is the most economic plan; however, careful consideration must be given to the trade-offs between the plans as there are notable differences in their risk profiles. (Figure 10.13)

Conclusion from the evaluation of the five development plans with a 750 MW interconnection (Preferred Development Plan (K19/C25/750MW (WPS Sale & Inv)), Plan 5 (K19/Gas25/750MW (WPS Sale & Inv)), Plan 12 (K19/C31/750MW), Plan 6 (K19/Gas31/750MW) and Plan 15 (K19/C25/750MW)):

- There is a noticeable distinction in the upside potential for the plans with the Conawapa G.S. As well, the Preferred Development Plan has a higher expected value than the other plans. On the basis of expected value, reference scenario NPV and upside potential, the Preferred Development Plan is the most attractive “750 MW interconnection” plan. Plan 12 is a reasonably close second choice. (Figures 10.14, 10.15, 10.16 and 10.17)

Comparisons were made across categories to demonstrate the differences between development plans. Figures 10.18 to 10.21 compare a number of the major elements of the development plans, including:

- plans with a 250 MW interconnection or a 750 MW interconnection
- plans with and without the proposed 300 MW WPS sale and related investment in the 750 MW interconnection (Figure 10.20 and Figure 10.21)
- plans with and without Conawapa G.S.
    - plans *without* Conawapa G.S. (Figure 10.18 and Figure 10.19)
    - plans *with* Conawapa G.S. (Figure 10.20 and Figure 10.21)

Conclusions from comparisons made across categories:

- Energy prices have the most significant impact on development plans with both Keeyask G.S. and Conawapa G.S. (including the Preferred Development Plan) and a 750 MW interconnection while discount rate has the most significant impact on plans with higher levels of natural gas-fired generation.
- The comparison of Plan 4 (K19/Gas24/250MW) to Plan 5 (K19/Gas25/750MW) shows it is more beneficial to invest in a small interconnection when the Keeyask G.S. is followed by natural gas-fired generation.

- While Plan 4 (K19/Gas24/250MW) has an expected value of $150 million higher than Plan 12 (K19/C31/750MW), careful consideration must be given to the differences in their characteristics and their risk profiles.
- While the Preferred Development Plan has a significantly higher incremental NPV under the reference scenario than that of Plan 4 (K19/Gas24/250MW) (over $350 million), the difference in their expected values is only $114 million. As a result, careful consideration must be given to the trade-offs between the plans given the different characteristics of these plans (Conawapa G.S. versus Gas and 750 MW interconnection versus 250 MW interconnection). Further analysis of other perspectives (financial, multiple accounts and optionality), which are provided in the following chapters, are important to the overall conclusions provided in **Chapter 14 - Conclusions**.

10.2 Sensitivity Analysis

Sensitivity analysis focuses on a single variable that tests the impact of that variable on selected development plans. This section will provide sensitivity analyses on drought, climate change, Manitoba load, and in-service delay.

10.2.1 Drought

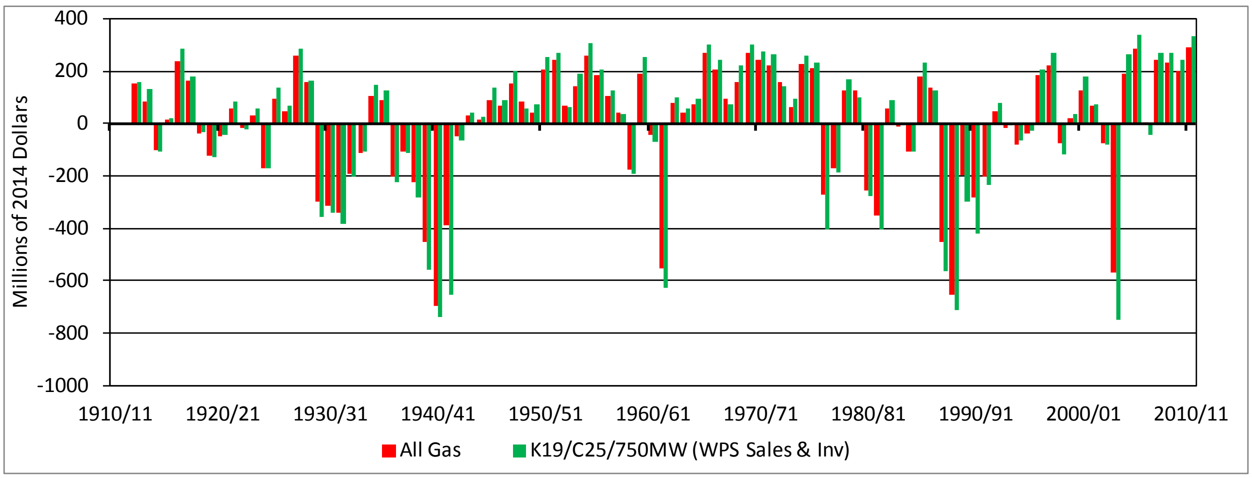
This section provides a comparison of the impact of a prolonged period of below-average streamflows (5-year drought) on incremental net revenues for the All Gas plan, K22/Gas plan, K19/Gas24/250MW plan and the Preferred Development Plan (K19/C25/750MW (WPS Sale & Inv). To assess the impact of energy prices and the timing of drought on the present value of revenues, analysis is provided for low, reference and high energy price scenarios for a 5-year drought starting in four future fiscal years as follows:

- 2014/15 — during construction of Keeyask
- 2021/22 — affecting early revenues from Keeyask and during construction of Conawapa
- 2027/28 — affecting early revenues from Conawapa

- 2032/33 — beyond early revenues from Conawapa.

The impact of specific annual flow cases on flow-related revenues will differ between development plans. Figure 10.22 shows the variation of flow-related revenues from average for the All Gas plan and the Preferred Development Plan for the 2032/33 fiscal year under each of the historic flow years from 1912-2010.

Figure 10.22 Sensitivity Analysis
Comparison of Flow Related Revenue Variability from Average
All Gas Plan and Preferred Development Plan (Reference Scenario)



Generally, Figure 10.22 shows that development plans with new hydro resources will yield incrementally higher revenues under higher flow periods and incrementally lower revenues under lower flow periods. There are several occurrences of severe drought in the historical record of flows as reflected in the years that have significantly lower than average revenue[2]. Of particular note, in the historic record, are the 5-year-periods centered on 1940 and 1990, both of which have a significant impact on flow-related revenues and provide a basis to compare this impact across development plans. While the 5-year period that spans fiscal years 1937/38 to 1941/42 has been shown to have a modestly greater financial impact, the analysis in this section is based on the 5-year period that spans fiscal year 1987/88 to fiscal year 1991/92 since

[2] A qualitative discussion on drought risk sensitivity related to a drought worse than the drought of record is presented in Chapter 10 Section 3.

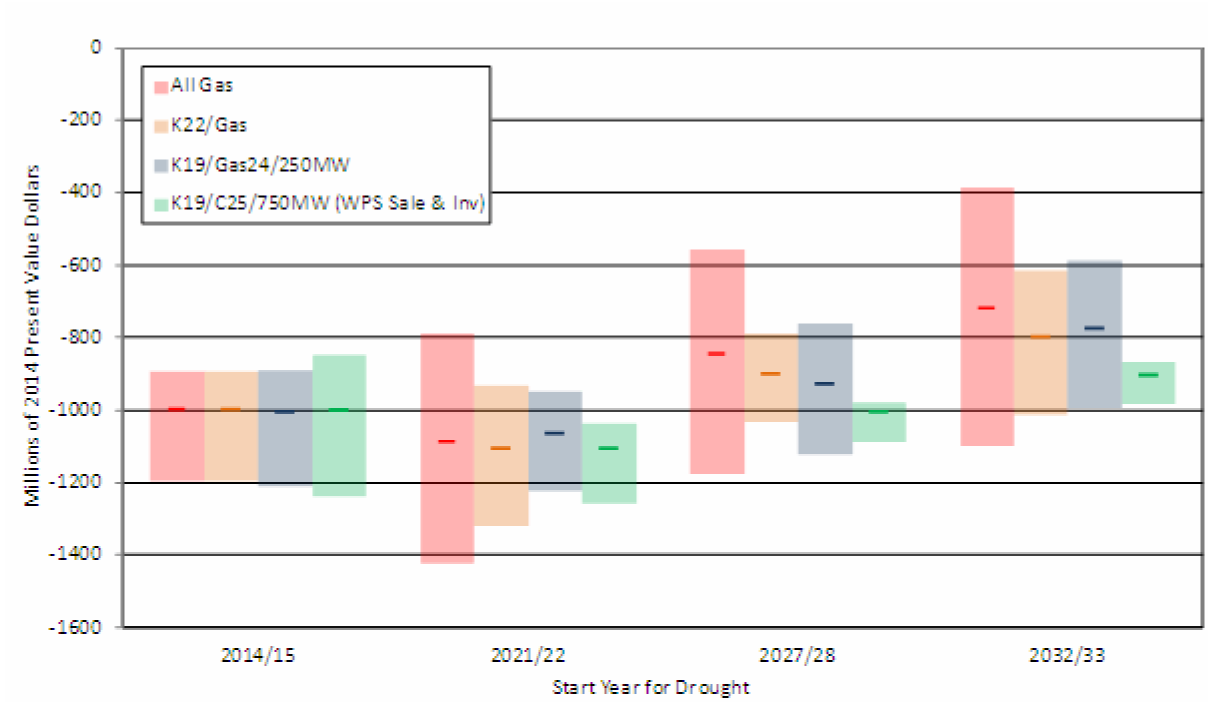
there is more confidence in the flow record and this period better reflects the current regulation patterns and water use practices in watersheds upstream of Manitoba.

Table 10.8 shows the incremental change in NPV to the reference scenario for four of the development plans presented in ***Chapter 9 – Economic Evaluations – Reference Scenario***, at low, reference and high energy prices for a 5-year drought starting in 2014/15, 2021/22, 2027/28 and 2032/33. This information is also displayed in Figure 10.23.

Table 10.8 Sensitivity Analysis – 5-year Drought Impact on Reference Scenario NPV Low, Reference and High Energy Prices

		Impact on Reference Scenario NPV Millions of 2014$ @ 5.05 discount rate			
Start year	Prices	All Gas	K22/Gas	K19/Gas24/250MW	K19/C25/750MW (WPS Sale & Inv)
2014/15	Low	-893	-892	-891	-849
	Ref	-997	-997	-1003	-999
	High	-1194	-1196	-1209	-1239
2021/22	Low	-789	-932	-949	-1035
	Ref	-1086	-1104	-1063	-1105
	High	-1422	-1320	-1223	-1257
2027/28	Low	-558	-787	-762	-1089
	Ref	-844	-898	-926	-1004
	High	-1174	-1034	-1123	-979
2032/33	Low	-386	-613	-589	-866
	Ref	-718	-798	-774	-902
	High	-1100	-1013	-996	-981

Figure 10.23 Sensitivity Analysis – 5-year Drought
Incremental Impact on Reference Scenario NPV
Low, Reference and High Energy Prices



For each of the four 5-year drought year periods identified in Figure 10.23, there is a coloured bar for the All Gas, K22/Gas, K19/Gas24/250MW, and K19/C25/750MW (WPS Sale & Inv) development plans. The horizontal dash in each bar is the change in NPV at reference energy prices and indicates the relative sensitivity to drought. Comparing the change in NPV at reference energy prices across the development plans, and into the future, shows that the incremental negative impact of drought is greater for plans with increasing amounts of new hydro-electric generation and a larger interconnection. This is due to a proportionally greater loss in flow-related export revenue in these plans during droughts.

The lower and upper ends of the bars represent the change in NPV due to energy prices, with the size range indicating the overall sensitivity to energy prices coincident with a drought. Overall, the All Gas plan has the greatest relative sensitivity to changes in energy prices over the course of a 5-year drought as shown in Figure 10.23. This is due to the ability of the plans with more new hydro and larger interconnection capability to generate revenue in those years in the

5-year drought that are above the critical low-flow year—such revenue offsets the additional cost of thermal generation and/or imports in the critical low-flow years. In plans with proportionally more natural gas-fired generation there is less ability to generate export revenues and, consequently, changes in energy prices translate directly into changes in the cost of generation and increasing sensitivity to energy prices into the future.

This section presented the impact of a 5-year drought on the incremental NPVs across development plans. ***Chapter 11 - Financial Evaluation of Development Plans*** includes an evaluation of drought on financial indicators, such as retained earnings, debt levels and consumer rates. In general, plans with more hydro-electric generation result in higher retained earnings which place Manitoba Hydro in a better financial position to withstand a drought.

10.2.2 Climate Change

As discussed in ***Appendix K - Manitoba Hydro Climate Change Report Fiscal Year 2012-2013***, Manitoba Hydro has long been investigating the potential impact of climate change on the operation and long-term planning of the generation system. These studies apply the results of global climate models (GCM) which simulate the changes to the global climate based on projected future emission scenarios focused on watersheds that contribute to the Manitoba Hydro system. A goal of these studies is to understand potential changes in temperature and precipitation as well as their impact on runoff and resulting streamflow. The results from GCM were used to establish a range of projected changes to average temperature, precipitation and runoff for different future time frames[3].

[3] Manitoba Hydro climate change studies to date have focused on potential changes in averages due to the strength of GCMs in being able to simulate change in climatic normals. While there is general scientific consensus that climate change may result in increased volatility of weather events, GCMs have a weaker signal of climate impacts to variability and to extreme events due to the coarseness of model resolution. Manitoba Hydro is working with Ouranos, several universities, and other utilities to investigate downscaling and post-treatment methods to quantify local impacts to extreme events and climatic variability. These studies are currently ongoing.

Changes to temperature and precipitation can have an overall effect on the planning and operation of Manitoba Hydro's system. More specifically, temperature and precipitation changes can have a direct impact on load and supply of hydro-electricity, respectively. While the effect of climate change on temperature and forecasted load has not been studied in detail, a general discussion on climate change effects related to a rise in temperature on forecasted load is provided in ***Appendix C – 2012 Electric Load Forecast***. Appendix C indicates that a uniform one degree Celsius of warming in Winnipeg throughout the year would result in a reduction in winter peak but an overall increase in energy demand as reduced winter heating requirements are more than offset by increased summer cooling requirements.

This section presents an analysis of the potential impact of climate-changed streamflow on projections of average revenue under the All Gas development plan, the K22/Gas development plan and the Preferred Development Plan (K19/C25/750MW (WPS Sale & Inv)). Comparison of these plans demonstrates the incremental effects of climate change on plans with no new hydro resources, one new hydro resource and two new hydro resources, respectively.

Runoff projections from an ensemble of GCM were used to adjust Manitoba Hydro's existing 99 year record of long-term streamflows to reflect potential changes in average runoff. The modified streamflow records were then used in Manitoba Hydro's Simulation Program for Long-term Analysis of System Hydraulics (SPLASH) model to provide average annual revenues. The main assumptions for this analysis were:

- Climate projections were based on the 2050 time frame as the 2050 projections are readily available among global climate model outputs and this time frame corresponds to the end of the 35-year planning horizon.
- A set of 109 global climate model outputs was sorted and ranked based on projected changes to average annual Manitoba Hydro system inflow. For the purpose of this evaluation, projected changes to runoff were chosen corresponding to the 5th, 25th, 50th, 75th, and 95th percentiles.

- The general results from the GCM reflect changes in overall averages and do not reflect changes to specific flows, in particular, extreme low flows. The long-term streamflows were adjusted based on the projected changes to runoff, while maintaining the historic drought levels for critical low flow years. Maintaining the historic droughts in the streamflow records preserves in-service dates for development plans and enables a direct comparison of revenue changes. A qualitative discussion on risk sensitivity related to a drought worse than the drought of record is presented in Section 10.3.
- There is general scientific consensus that the effects of climate change occur over the long-term.
- To model the long-term effects of climate change, calculations were done to derive incremental average revenues for each year from 2012-2047 using the 2050s climate adjustment for flows. This results in applying the full 2050 climate change impact in every year from 2012/13 to 2047/48. To introduce incremental change in climate to the average annual revenues from 2012-2047, the revenues were proportionally adjusted, starting with no adjustment to 2012/13 average annual revenues and 100% in 2050/51.

Table 10.9 provides a summary of the change in net revenue across the various climate change projections incremental to a base, which is the unadjusted flow case for each development plan for reference scenario assumptions as provided in ***Chapter 9 – Economic Evaluations – Reference Scenario***. In general, the results indicate that approximately 70% of the GCM projections show an increase in total runoff, which results in a related increase in revenue above that of the reference scenario. Conversely 30% of the projections show a decrease in average annual revenues below that of the reference scenario. As shown in Table 10.9, for all three development plans, revenues increase or decrease with corresponding increases and decreases in streamflows.

Table 10.9 Sensitivity Analysis - Climate Change
Incremental Impact on Reference Scenario NPV

Incremental Impact on reference scenario NPVs millions of 2014$ @ 5.05% discount rate					
Development Plan	Flow Ranked Percentiles from GCMs				
	5th	25th	50th	75th	95th
All Gas	(1,431)	(240)	560	922	1,697
K22/Gas	(1,519)	(244)	602	993	1,806
Preferred Plan	(1,847)	(276)	714	1,186	2,145

Table 10.9 shows that the All Gas plan has the least amount of variability, followed by the K22/Gas plan when compared to the Preferred Development Plan. This is shown by the difference in incremental NPV impacts between the 5th and 95th percentile flows which are $3,128 million ($1,697 million minus $-1,431 million), $3,325 million and $3,992 million for the All Gas plan, the K22/Gas plan and Preferred Development Plan, respectively.

Table 10.9 also shows that plans with more new hydro-electric generation have greater upside potential (higher incremental average revenues) and greater downside risk (lower incremental average revenues) as a result of changing streamflows. For a 95th percentile runoff change, the incremental NPV relative to the All Gas plan is increased by $109 million ($1,806 million minus $1,697 million) for the K22/Gas plan and by $498 million ($2,145 million minus $1,697 million) for the Preferred Development Plan. For a 5th percentile change in runoff, the incremental NPV relative to the All Gas plan is reduced by $88 million ($-1,519 minus $-1,431 million) for the K22/Gas plan and by $416 million ($-1,847 million minus -$1,431 million) for the Preferred Development Plan. The incremental NPV changes for the K22/Gas plan are less than those for the Preferred Development Plan but exhibit similar characteristics in that there is comparatively higher upside and greater downside effects on revenues relative to the All Gas plan.

Table 10.10 combines the results of the climate change analysis on the three selected development plans with the reference scenario economics presented in ***Chapter 9 – Economic Evaluations – Reference Scenario***. In Table 10.10 the incremental NPVs resulting from the climate changed stream flow analysis are added to the incremental NPVs from the reference scenario economics from ***Chapter 9 – Economic Evaluations – Reference Scenario*** with the All Gas reference scenario as the basis for comparison. As shown in Table 10.10 both the K22/Gas plan and the Preferred Development Plan have higher net benefits than the All Gas plan across the full range of climate change results and the Preferred Development Plan has the greatest net benefits of all three plans. Development plans with new hydro have a larger base of revenue than the All Gas and therefore can withstand the downside variability in streamflows and benefit more from the upside variability in streamflows.

Table 10.10 Sensitivity Analysis- Climate Change Incremental Impact on NPV Relative to All Gas Reference Scenario

	Incremental NPV benefit, millions of 2014$ @ 5.05% discount rate			
Development Plan	Reference Scenario	Reference Scenario at 5th percentile streamflow	Reference Scenario at 50th percentile streamflow	Reference Scenario 95th percentile streamflow
All Gas	0	($1431)	$560	$1,697
K22/Gas	$887	($632)	$1,489	$2,693
Preferred Plan	$1696	($151)	$2,410	$3,841

As the Manitoba Hydro system currently consists of predominantly hydro-based generation, all plans will be affected by changes in streamflow driven by climate change. In general, the projections from GCM indicate that it is more likely that there will be an increase in average annual streamflow as approximately 70% of projections show an increase in runoff. As a result it is more likely that there will be an increase in average revenues than there will be a decrease. This analysis shows that the All Gas plan has the least amount of variability when compared to the K22/Gas plan and the Preferred Development Plan. Plans with more new hydro-electric generation have greater upside potential (higher average revenues) and greater downside risk (lower average revenues) as a result of changing streamflows. Even when the 5^{th} percentile annual average system inflow is assumed, plans with new hydro generation have higher incremental NPVs when compared to the All Gas plan (K22/Gas plan: $799 million ($-632 million minus $-1,431 million) and Preferred Development Plan: $1,280 million ($-151 million minus $-1,431 million)).

10.2.3 Manitoba Load

This section presents an analysis of the potential impact of changes in Manitoba load to the incremental NPVs of three development plans: the All Gas development plan, the K22/Gas development plan and the Preferred Development Plan (K19/C25/750 MW (WPS Sale & Inv)). Comparison of these plans demonstrates the incremental effects of changes in load on plans with no new hydro resources, one new hydro resource and two new hydro resources, respectively.

This sensitivity analysis is based on the low and high load forecast described in ***Appendix C – 2012 Electric Load Forecast***. Figure 10.24 and Figure 10.25 show the 90th percentile and 10th percentile probability bands for the energy and peak capacity Manitoba load forecasts, respectively. This means that there is an 80% chance that Manitoba load will fall between the high and low bands for a given forecast year. The energy forecast bands correspond to an annual growth rate of 1.2% for the low band and 2.0% for the high band, compared to 1.6% per year for the base energy forecast. The capacity forecast bands correspond to an annual growth rate of 1.1% for the low band and 2.1% for the high band, compared to 1.6% per year for the base peak capacity forecast.

Figure 10.24 Sensitivity Analysis – Manitoba Load Forecast Energy Forecast Probability Bands

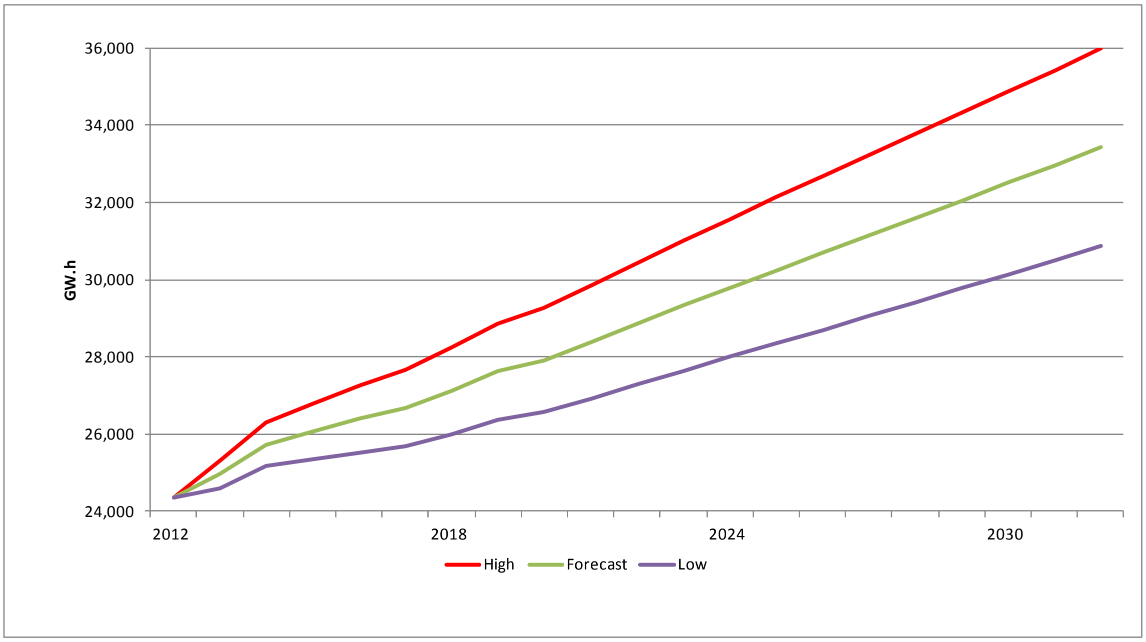
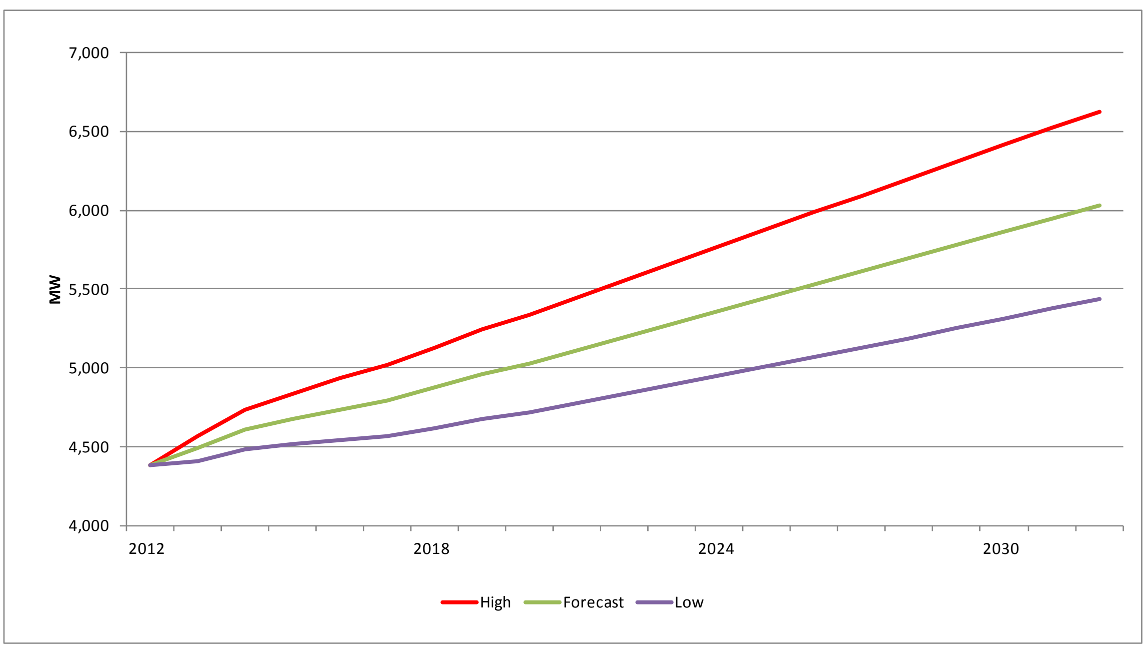


Figure 10.25 Sensitivity Analysis – Manitoba Load Forecast Peak Capacity Forecast Probability Bands



In order to evaluate the development plans, the in-service dates for new resources were adjusted in the All Gas plan, K22/Gas plan and the Preferred Plan, as required, to accommodate the change in the load forecast (consistent with the methodology described in ***Chapter 8 – Determination and Description of Development Plans***. For the Preferred Development Plan, the in-service dates for Keeyask G.S., Conawapa G.S. and the new U.S. interconnection were held constant and the effect of changes in Manitoba load are mainly reflected in increased or decreased surplus hydro-electric energy. As shown in Table 10.11[4], under the low load forecast, new resources are required for dependable energy in 2028/29 and persistent winter peak capacity deficits start in 2029/30. Assuming the high load forecast, new resources are required for dependable energy in 2020/21 and persistent winter peak capacity deficits start in 2021/22.

Table 10.11 Sensitivity Analysis – Manitoba Load
Supply-Demand Balances for High, Base and Low Load Forecast
Dependable Energy (GWh) and Winter Peak Capacity (MW)

No New Resources											
Fiscal Year	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**
90%th Percentile (2012 Load Forecast)											
System Surplus (Deficit) Dependable GW.h	251	(894)	(1,423)	(1,961)	(2,497)	(3,054)	(2,694)	(3,321)	(3,892)	(4,472)	(5,047)
System Surplus (Deficit) Winter Peak MW	112	-	(109)	(218)	(335)	(452)	(815)	(928)	(1,047)	(1,169)	(1,291)
2012 Load Forecast											
System Surplus (Deficit) Dependable GW.h	1,607	574	152	(279)	(713)	(1,168)	(733)	(1,262)	(1,712)	(2,197)	(2,678)
System Surplus (Deficit) Winter Peak MW	458	376	296	214	126	35	(301)	(388)	(481)	(577)	(674)
10%th Percentile (2012 Load Forecast)											
System Surplus (Deficit) Dependable GW.h	2,964	2,042	1,728	1,402	1,072	718	1,053	613	272	(79)	(428)
System Surplus (Deficit) Winter Peak MW	805	753	701	646	586	522	212	152	85	14	(58)

The description of the development plans under base, low and high load forecasts is provided in Table 10.12. The All Gas, K22/Gas and Preferred Development Plan described as "Base Load" in Table 10.12, are the same as those described in ***Chapter 8 – Determination and Description of Development Plans***. Under low and high load forecasts the resources are adjusted, as applicable, to accommodate the change in the load forecast.

[4] Based on Appendix 4.2 Manitoba Hydro Supply and Demand Tables, Section 3 NFAT 2012 Reference and Section 4 NFAT 2012 Sensitivities

Table 10.12 Sensitivity Analysis - Manitoba Load
Description of Development Plans

Order of Reference Scenario Capital Investment	Development Plan	Description of Development Plan
	All Gas Low Load	Natural Gas-Fired Generation starting in 2028/29
1	All Gas Base Load	Natural Gas-Fired Generation starting in 2022/23
	All Gas High Load	Natural Gas-Fired Generation starting in 2020/21
	K28/Gas Low Load	Keeyask 2028/29, Natural Gas-Fired Generation starting in 2037/38
2	K22/Gas Base Load	Keeyask 2022/23, Natural Gas-Fired Generation starting in 2029/30
	K19/Gas High Load	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2024/25
	K19/C25/750MW Preferred Development Plan Low Load	Keeyask 2019/20, Conawapa 2025/26, 750 MW Import/Export Interconnection 2020/21
14	K19/C25/750MW (WPS Sale & Inv) Preferred Development Plan Base Load	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export Interconnection 2020/21
	K19/C25/750MW Preferred Development Plan High Load	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2023/24, Conawapa 2025/26, 750 MW Import/Export Interconnection 2020/21

Table 10.13 presents the incremental NPVs for the low load and high load sensitivities for each development plan studied as compared to each respective base load development plan under the reference scenario. The table demonstrates that load changes have a larger impact on the All Gas development plan. Low load growth increases the NPV and high load growth decreases the NPV of the All Gas plan and the change is greater for this plan than for either the K22/Gas plan or the Preferred Development Plan. The variability in the impact on NPV decreases with the addition of new hydro resources and a new interconnection.

Table 10.13 Sensitivity Analysis- Changes in Manitoba Load
Incremental Impact on NPV Relative to Reference Scenario

	Incremental NPV benefit, millions of 2014$ @ 5.05% discount rate		
Development Plan	**Reference Scenario**	**10th percentile Manitoba Load (Low Load)**	**90th percentile Manitoba Load (High Load)**
All Gas	-	$3,470	($3,605)
K22/Gas	-	$3,319	($3,538)
K19/C25/750MW (WPS Sale & Inv) Preferred Plan	-	$3,164	($3,442)

Table 10.14 presents the incremental NPVs for the low load and high load sensitivities for each development plan studied as compared to the All Gas development plan. The reference scenario is also provided for comparison purposes.

Table 10.14 Sensitivity Analysis - Changes in Manitoba Load
Incremental Impact on NPV Relative to All Gas

	Incremental NPV benefit, millions of 2014$ @ 5.05% discount rate		
Development Plan	**Reference Scenario**	**10th percentile Manitoba Load (Low Load)**	**90th percentile Manitoba Load (High Load)**
All Gas	-	-	-
K22/Gas	$887	$736	$954
K19/C25/750MW (WPS Sale & Inv) Preferred Plan	$1,696	$1,390	$1,858

Table 10.14 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. Conversely under the high load sensitivity the incremental NPV for development plans with new hydro resources and a new interconnection increases relative to the All Gas development plan, but to a lesser degree than under the low load sensitivity.

Table 10.14 also shows that under the low and high load sensitivities the economic ranking of the development plans studied does not change. The 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.

10.2.4 In-service Date Delay

In order to demonstrate the sensitivity of the Preferred Development Plan to delays in the in-service date of Keeyask G.S. and Conawapa G.S., a development plan was studied in which the in-service date of both generating stations is delayed by one-year. Delaying the in-service dates of both plants decreases the NPV of the Preferred Development Plan by $97 million (2014$ @ 5.05% discount rate). A deferral in in-service dates will result in less surplus energy available for export thereby reducing export revenues. These lower revenues will be partially offset by the capital cost savings from the deferral. The decrease in NPV is attributable to lower export revenues being more than offset by the savings of delaying the capital expenditures by one year.

10.3 Other Factors which Contribute to Uncertainty

There are several other factors, in addition to those discussed in the probabilistic and sensitivity analyses, which may contribute to uncertainty in the economic analysis. The purpose of this section is to identify these other uncertainty factors, and to explain how they were considered in the NFAT submission analysis.

10.3.1 Export Market Uncertainty

As a predominantly hydro-electric system, Manitoba Hydro typically has surplus energy available to sell into the export market. It is the revenue from the sale of power surplus to the needs of Manitobans that contributes to the economic and financial benefits of all development plans, especially those with Keeyask and Conawapa G.S.

The uncertainty and risk related to the export market in terms of market access and export contract portfolio are discussed in the following sections.

10.3.1.1 Market Access

Market access risk is the potential for legal or regulatory restrictions which would limit Manitoba Hydro's surplus power from reaching the competitive marketplace free from unreasonable legal, regulatory, structural or tariff barriers.

Manitoba Hydro currently has excellent market access and sees no impending market access barriers on the horizon. Future development plans that include additional hydro development will result in increasing volumes of export energy, but a significant portion of the export energy is dependable energy which provides the basis for long-term relationships with major export customers. Such long-term relationships with major export customers reduce market access risk both as a result of the stability that long-term sales bring and as a result of stronger relationships between the major export customers, the regional power market and Manitoba Hydro.

Manitoba Hydro considers a complete loss of export markets to be a highly unlikely event, as Manitoba Hydro's products are competitively priced, energy is a significant expense for business and consumers, and there is significant political pressure in the U.S. to keep energy prices down. The North American Free Trade Agreement contains provisions designed to prevent restrictions on trade in energy. Although a U.S. policy objective is energy independence, this policy is in the context of North America and not just the continental U.S. proper[5]. There are however, a number of technical, legal and regulatory issues that need to be monitored on an ongoing basis to minimize the potential for a negative impact on export power sales.

Due to the subjective nature of market access risk, and its low probability, quantitative sensitivity analysis was not undertaken. However, the magnitude of the impact on Manitoba Hydro were restrictions to occur is judged to be similar to that encountered in the low export price cases, which were studied as part of the probabilistic analysis. Manitoba Hydro engages in a comprehensive set of activities to monitor and address market access issues, as detailed in ***Chapter 15 – Implementation and Risk Management Plan for Preferred Development Plan***, which include maintaining industry awareness, monitoring and assessing industry developments and maintaining positive relationships with key groups in the industry.

10.3.1.2 Export Contract Portfolio

Manitoba Hydro currently has a portfolio of export customers and a number of existing long-term power sales as indicated in ***Appendix 9.3 - Economic Evaluation Documentation***. Existing export contracts will expire over time and Manitoba Hydro expects, subject to resource availability, to negotiate replacement contracts with updated commercial terms and conditions. There is uncertainty as to how these negotiations will progress, and in turn how the export contract portfolio will evolve. To assist in managing the uncertainty associated with renewing or extending contracts, Manitoba Hydro contracts have a range of expiry dates. Manitoba Hydro works to maintain positive relationships with its portfolio of export customers to understand their needs, and to help ensure Manitoba Hydro's continued presence as an attractive supply option. Uncertainty with respect to price on future contracts has been addressed in the full

[5] See "*Obama says Canada a partner in US plans to make itself less dependent on oil,* The Globe and Mail, March 30, 2011."

range of energy prices used in the probabilistic analysis discussed in Section 10.1 of this chapter.

As of August 2013, negotiations have not been finalized for the proposed contract with WPS for up to 300 MW of long-term power. Discussions with WPS for varying amounts of capacity and energy have been ongoing since a term sheet was first signed with WPS in March 2008. These discussions continue and, in the event that no agreement with WPS is reached, Manitoba Hydro will consider alternative arrangements.

Manitoba Hydro has addressed the uncertainty of the potential 300 MW WPS sale by considering a range of development plans, including plans without a sale to WPS. For example, Plan 15 (K19/C25/750MW) uses the same resources as the Preferred Development Plan but does not include the potential 300 MW WPS sale. Of the 15 development plans listed in ***Chapter 9 – Economic Evaluations – Reference Scenario*** Table 9.3, only two include the potential sale to WPS for up to 300 MW.

10.3.2 New U.S. Transmission Interconnection

In order to maximize the potential benefits of Keeyask or Conawapa, a new U.S. transmission interconnection is desirable: the Preferred Development Plan includes a new interconnection with 750 MW import and export capability. As of August 2013, Manitoba Hydro and Minnesota Power are proceeding with planning and development activities for a new interconnection as outlined in ***Chapter 6 – The Window of Opportunity***, Section 6.5.3. However there are a number of business, technical and regulatory issues that need to be resolved before a commitment to the transmission project can be made. These include the capacity of the interconnection, project financing, business model and cost allocation.

Manitoba Hydro has addressed the uncertainty associated with the new interconnection by considering a range of possibilities, including development plans that do not include an interconnection. Of the 15 development plans considered in ***Chapter 9 – Economic Evaluations – Reference Scenario*** Table 9.3, five of the plans include a 750 MW import and export interconnection, three of the plans include a 250 MW export and 50 MW import interconnection, and seven of the plans include no new interconnection.

10.3.3 Drought Worse than the Drought of Record

As detailed in ***Appendix 4.1 - Manitoba Hydro Generation Planning Criteria***, Manitoba Hydro plans its system to ensure sufficient dependable energy is available to meet projected demand in the event of a repeat of the worst drought on the hydraulic record of approximately 100 years. There is the possibility that a drought worse than the one experienced in the last 100 years will occur.

All of the development plans Manitoba Hydro has considered satisfy the Generation Planning Criteria. However, development plans with more resources within Manitoba, and development plans with a larger interconnection, such as the Preferred Development Plan, give Manitoba access to a larger portfolio of supply resources. Should a system emergency occur as a result of a drought worse than the drought of record, Manitoba Hydro would be able to access greater amounts of emergency energy with the additional 750 MW of import capability provided by the Preferred Development Plan or any other development plans that include a new 750 MW interconnection.

10.3.4 Species at Risk Act

In November 2006, as part of the *Species At Risk Act* (SARA) process, the scientific Committee on the Status of Endangered Wildlife in Canada (COSEWIC) assessed Lake Sturgeon as “endangered” in most rivers in Manitoba, triggering a Fisheries and Oceans Canada (DFO) review process to consider Lake Sturgeon for listing under the SARA. In 2010 DFO conducted more thorough assessments of population status and trends, gathering the most up-to-date information from regional fisheries managers, Aboriginal traditional knowledge, academic researchers, and consultants. These assessments indicated that more recent population trends were notably different from those in the COSEWIC assessment and, importantly, point to initial signs of population recovery. DFO is now developing a recommendation package on whether or not to list Lake Sturgeon as endangered based on current scientific data, along with the results of consultations, socio-economic assessment, and a regulatory impact analysis statement. The DFO recommendation package is to be provided to the Governor in Council, which will have up to nine months to review to accept or reject the recommendation or to send it back to COSEWIC for review and/or updating. Based on recent experience, the internal DFO review could take more than a year before it is sent to the Minister. If the Governor in Council were to return the recommendation to the COSEWIC, it is estimated that this would add at least two more years before a listing decision would be made.

Manitoba Hydro has judged the likelihood of Lake Sturgeon being listed under SARA to be low. If it were to occur, the consequence would be the delay and if permits cannot be secured under the SARA, possible cancellation of the Keeyask and Conawapa projects.

Manitoba Hydro has dealt with the risk associated with the SARA process by evaluating the impacts of the timing of the decision as well as analyzing development plans that do not include hydro-electric development. The potential timing of a SARA listing decision has been evaluated against the terms of the export power contracts, both confirmed and under negotiation. Manitoba Hydro has also evaluated development plans that do not include new hydro-electric generation should the species be listed, and permits to construct and operate new generating stations cannot be secured. As well, Manitoba Hydro is proactively continuing and expanding its commitment to Lake Sturgeon stewardship on waterways affected by hydro-electric development to demonstrate that the species does not need to be listed as endangered under the SARA for it to be protected and for populations to recover. Further information on Manitoba Hydro's Lake Sturgeon stewardship can be found in ***Appendix 2.1 - Lake Sturgeon - Mitigation and Enhancement.***

10.3.5 Aboriginal and Community Relationships

Manitoba Hydro has benefit-sharing and adverse effects agreements with the local Cree Nations for the Keeyask Project and is committed to similar agreements for the Conawapa Project, although the exact nature of the agreements will vary. There are uncertainties associated with each project. For example, in the case of the Keeyask Project, actual financial results could be inconsistent with the projections when the Keeyask Joint Development Agreement was being negotiated. With the Conawapa Project, agreements may not be achieved between the negotiating parties.

The economic circumstances of Manitoba Hydro's major projects have changed during the past several years, due in part to lower energy prices. Manitoba Hydro and Nisichawayasihk Cree Nation, its partner in Wuskwatim G.S., are currently negotiating amendments to the Wuskwatim Development Agreement to deal with this issue. Manitoba Hydro made adjustments to the Keeyask Project development approach post-Wuskwatim. The Keeyask Cree Nations (KCNs) were always aware the Keeyask financial results modeled during negotiations were done so using the forecasting information available at that time. The availability of two investment options, common and preferred, provides the KCNs with an investment choice depending upon their risk tolerance.

Manitoba Hydro is obligated to have adverse effects arrangements in place with Tataskweyak Cree Nation (TCN), York Factory First Nation (YFFN) and Fox Lake Cree Nation (FLCN) (but not including War Lake First Nation (WLFN) and Shamattawa First Nation), under the terms of existing agreements that resolved Northern Flood Agreement (NFA) implementation and the adverse effects of the Churchill River Diversion and Lake Winnipeg Regulation projects and then existing works and power developments on the Nelson and Churchill Rivers. If negotiations are not successful, then the arrangements can be arbitrated.

There is no similar legal requirement to achieve benefit sharing agreements. Rather, benefit sharing is a corporate policy decision. Manitoba Hydro was at the forefront of such agreements in Canada when it began negotiations for the Wuskwatim and Keeyask Projects, and it views benefit-sharing as a foundational element to the successful development of its potential next major hydro-electric generation project on the Nelson River, i.e. Conawapa. Manitoba Hydro is following existing Conawapa protocols and process agreements to discuss benefit agreements with the local Cree Nations.

If negotiations on adverse effects agreements were unsuccessful, the process could be sent to arbitration in the case of TCN, YFFN and FLCN. If negotiations on benefit sharing were unsuccessful, Manitoba Hydro would have to evaluate its best course of action at that time, however it would not be subject to arbitration. In the absence of successful negotiations, there could be challenges to achieving the required licenses and approvals for Conawapa in a timely manner.

Further discussion on business risks related to the Aboriginal participation is contained in ***Chapter 15 - Implementation and Risk Management Plan for Preferred Development Plan.***

10.4 Uncertainty Analysis Summary

A summary of the drivers of uncertainty, the input affected, and how Manitoba Hydro assessed the uncertainty is provided in Table 10.15. For a summary of risk mitigation actions in support of the Preferred Development Plan, please see ***Chapter 15 – Implementation and Risk Management Plan for Preferred Development Plan,*** Section 15.7, Table 15.9.

Table 10.15 Economic Evaluation - Uncertainty Matrix

Economic Evaluation - Uncertainty Matrix

Source of Uncertainty	Description	Variable Affected	Method of Assessment
Key Risk Factor - Energy Prices			
Electricity Prices	Future market price of electricity (capacity and energy)	• Electricity export price forecast • Natural gas price forecast • Manitoba thermal fuel burn cost including transportation costs • Import costs	Manitoba Hydro utilizes a consensus based forecast of independent consultants that produce high, reference and low cases. Independent price forecast consultants consider a wide number of pricing factors, including natural gas prices; carbon policy, U.S. environmental policy, new resource capital costs, and MISO load growth. The full range of energy prices from low to high is considered in the probabilistic analysis of various development sequences. Also see Section 4 of Appendix 9.3 for the Electricity Export Price, Natural Gas Price and Carbon Price Forecasting Methodology. Manitoba Hydro engages in a comprehensive set of activities to address environmental policies including monitoring policy development and working with regulators, legislators, customers and the electric industry as a whole to help maintain a presence and help maintain positive relationships with key groups.
Natural Gas Prices	Future market price of natural gas		
MISO Load	MISO market region load growth		
Carbon Policy	Uncertainty towards implementation, timing and level of carbon pricing		
Other U.S. Environmental Policies	Uncertainty towards implementing a series of proposed U.S. environmental policies, their stringency and overall impact. (MATS, ash lagoon, CO_2 for new coal, CASPR, US RPS)		
Key Risk Factor - Capital Cost			
Keeyask & Conawapa Generating Stations	Labour escalation, low productivity rates and associated indirect costs.	• Capital cost of generation	Capital cost estimating contingency derived using integrated probabilistic risk model. Management reserve provides budget provisions for labour and escalation risks. A full range of capital costs is considered in the probabilistic analysis in Section 10.1. Also see Appendix 2.4 for information on developing capital cost estimates.
	Equipment and material costs (direct costs)	• Capital cost of generation	Contingency derived using integrated probabilistic risk model with support from independent consultant. A full range of capital costs is considered in the probabilistic analysis in Section 10.1. Also see Appendix 2.4.
Thermal Generation	Commodity escalation, schedule overruns and environmental legislation.	• Capital cost of generation	In capital cost estimating process engaged independent consultants to identify appropriate manufacturer/turbine models, develop cost estimates and assess systemic risks. A full range of capital costs is considered in the probabilistic analysis in Section 10.1. Also see Appendix 9.3 Section 1.1.2 Thermal G.S. - Natural Gas Fired Generation. Manitoba Hydro engages in a comprehensive set of activities to address environmental policies including monitoring policy development and working with regulators, legislators, customers and the electric industry as a whole to help maintain a presence and help maintain positive relationships with key groups.
Wind Generation	Technology advancements, commodity escalation, and policy.	• Capital cost of generation	Capital estimate developed using industry benchmarking, with independent consultant to assess systemic risks. A full range of capital costs is considered in the probabilistic analysis in Section 10.1. Also see Appendix 9.3 Section 1.1.3. Manitoba Hydro engages in a comprehensive set of activities including monitoring policy and technical development related to wind generation.
Transmission in Manitoba	Final routing, commodity escalation, schedule overruns and environmental legislation.	• Capital cost of transmission	Detailed estimates produced by Manitoba Hydro or generic per unit estimates used stage of development. A full range of capital costs is considered in the probabilistic analysis in Section 10.1. Also see Appendix 9.3 Section 1.1.4 Transmission. Manitoba Hydro engages in a comprehensive set of activities including monitoring transmission policy development, environmental policy, and working with regulators, legislators, customers and the electric industry as a whole to help maintain a presence and help maintain positive relationships with key groups.
Key Risk Factor- Economic Indicators			
Exchange Rate (CAD/USD)	Future exchange rates	• Electricity export revenues	Utilize a consensus based forecast of major banks and independent consultants for a forecast of future rates. As part of Manitoba Hydro's foreign currency exchange risk on U.S. dollar export revenues, Manitoba Hydro maintains a natural hedge with U.S. dollar cash flows, including outflows from U.S. denominated debt. A range of domestic inflation rates is incorporated into the real discount rate. A range of discount rates from low to high is considered in the probabilistic analysis in Section 10.1. The rate for the Provincial Guarantee Fee is set by the Government of Manitoba who will balance overall social interests.
Inflation Rates (U.S. & Cdn)	Future inflation rates	• Electricity export revenues	
Long-term Canadian Interest Rate	Future interest rates	• Real discount rate	
Provincial Debt Guarantee Fee	Future provincial debt guarantee fee	• Real discount rate	
Specific Risk Factor- Drought			
Multi year drought	Extended periods of low flows in the hydraulic system	• Export volumes • Export revenues • Import costs • Adequate dependable supply of energy	Economic impact of drought is considered through use of 99 year flow record. Specific impact of a five year drought is considered in the sensitivity analysis in Section 10.2.1. Financial impact of drought considered in Chapter 11. Generation Planning Criteria provide direction in ensuring an adequate dependable supply of energy.
Specific Risk Factor- Climate Change			
Long-Term Climate Change	Impact on precipitation and temperature	• Water inflow impact on energy production • Load forecast	Sensitivity analysis of revenue impact from lower or higher flow scenarios resulting from climate change is considered in Section 10.2.2. Electric load forecast includes change to temperature as a result of climate change as a possible event.
Specific Risk Factor- Manitoba Load/ DSM			
Manitoba Load Growth	Potential for higher/lower than expected load forecast. Also potential for large load addition or subtraction	• Amount of surplus energy and capacity in the system • Need for new resources	Sensitivities to 10% and 90% Manitoba load forecast and impact on the need for new resources is considered in Section 10.2.3.
Manitoba DSM	Future Power Smart programs and customer response	• Amount of surplus energy and capacity in the system	Sensitivities to 1.5 times and 4 times 2013 PowerSmart Plan DSM levels considered in Section 10.2.3. Engaged EnerNOC to work with Manitoba Hydro to assess the 20-year potentials of energy efficiency for electricity (See Appendix 4.3)

Source of Uncertainty	Description	Variable Affected	Method of Assessment
Specific Risk Factor- In-Service Date Delays			
Delay of Plant ISDs	Delay of Plant ISDs	• Export revenues • Capital cost of generation	Sensitivity Analysis to In-service delay considered in Section 10.2.4.
Other Risk Factors			
Export Contract Portfolio	Uncertainty in the renewal of export contracts which will be the subject of future negotiations, final terms of WPS contract not determined	• Export contract prices and volumes • Export revenues	Diversity of export customers and contract terms is maintained as are positive customer relationships. A full range of energy prices is considered in the probabilistic analysis in Section 10.1. Development plans without the WPS Sale are considered.
New US Transmission Interconnection Capacity & Ownership	Final design and capital allocation among proponents	• Capital costs • Export volumes	Studies include development plans with no new interconnection, 250 MW interconnection, and 750 MW interconnection with alternative ownership models.
Drought worse than drought on record	A drought worse than the drought of record used for system energy planning occurs	• Ability to serve Manitoba load • Export revenues	Development plans with a new 750 MW interconnection can provide additional amounts of dependable energy through curtailment of exports under certain circumstances and through energy imports which together approximate 5,000 to 6,000 GWhs per year when compared to other plans. See Appendix 9.3.
Market Access	Potential for legal or regulatory restrictions which would prevent Manitoba Hydro's surplus power from reaching the competitive marketplace free from unreasonable legal, regulatory, structural or tariff barriers	• Export revenues	Impact is similar to low export prices, which are considered in the probabilistic analysis. See Chapter 10 Section 10.3.4. Additional surplus energy from development plans with hydro options can be used for long-term sales, which reduces market access concerns.
Species at Risk Act	Potential for the listing of Lake Sturgeon under the Species at Risk Act	• Delay or cancelation of Keeyask or Conawapa	The economic evaluations include consideration of development plans that are not contingent on Keeyask or Conawapa. See Chapter 10 Section 10.3.5.
Aboriginal and Community Relationships/Agreements	Uncertainty of the final form of agreements with Aboriginal communities and the ongoing relationships as impacted by the agreements	• Long-term relationships and future development potential	Benefit sharing and adverse effects agreements completed for Keeyask and in progress for Conawapa. Without such agreements, there could be barriers to Conawapa licensing and approvals. See Chapter 10 Section 10.3.6. Continued regulatory and negotiation progress will assist with Aboriginal and community support.
System reliability	Risk of loss of system capability to deliver power from the bulk power system to the load.	• System load carrying capability and cost of expected unserved load	All development plans meet reliability requirement. Plans with a new interconnection increase system reliability. See Chapter 13 Section 13.3.2 Manitoba Hydro Customer Account - Reliability.

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