Appendix 5 – Analysis Results

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1 Introduction

The 2023 IRP uses scenarios and sensitivities to analyze how the changing energy landscape may impact Manitoba Hydro's electricity generation, transmission, distribution, and natural gas systems used to serve customer energy needs. Four scenarios were developed to explore a range of potential energy futures. In addition, several sensitivities were undertaken to further explore the effects of changes to various inputs or constraints in order to isolate specific impacts to the modelling results. This appendix summarizes the results of the modelling and analysis of the four scenarios and various sensitivities including the type of new generating resources, the pace of change, greenhouse gas (GHG) emissions, and costs.

2 Scenario Analysis

2.1 Introduction

This section discusses the modelling and analysis results specific to the four scenarios as described in Appendix 3 – Scenario Specific Inputs. Manitoba Hydro used the four scenarios to explore a reasonable range of what the energy future might look like in Manitoba. The scenarios are based on different amounts of change of decarbonization and decentralization in Manitoba. See Appendix 3 for further details of the scenario specific assumptions.

2.2 Demand Projections

The evaluation of the different scenarios begins with the demand projection for each scenario as it defines the problem which the analysis and modelling process is attempting to solve. Together with the demand projections, the planning criteria plays an equally important role by ensuring that the electrical system is planned to ensure a sufficient supply of both winter firm capacity and dependable energy. See Appendix 3 for an explanation on the development of the different scenario demand projections and see Appendix 4 – Analysis Approach for an explanation of the planning criteria and evaluation process.

The 2022 demand for both energy and winter firm capacity are 23,000 GWh and 4,500 MW respectively. By 2042 the amount of energy is projected to grow by 21%, 42%, 55% and 100% for scenarios 1 through 4 respectively. By 2042 the amount of winter firm capacity is projected to grow by 13%, 27%, 42% and 151% for scenarios 1 through 4 respectively. Scenario 4 results in the most significant rate of growth with the projection of dependable energy being equivalent to 2.0 times the 2022 demand and the projection for winter firm capacity being equivalent to 2.5 times the 2022 demand.

In addition to electricity, consideration is given to how future natural gas needs will change. Natural gas consumed could change where there is a greater focus on decarbonization. Scenarios 1 and 2 result in neither a decrease nor increase in the amount of natural gas consumed. While scenarios 3 and 4 result in natural gas consumption declining by 22% and 45% by 2042 respectively. In scenario 4, natural gas in 2042 is used mainly by industrial applications, such as a process input or feedstock, with some natural gas still being used for space heating. See Appendix 3 for further detail on how the demand projections were created for each of the scenarios.

2.3 Electrical Resource Options Selection

As described in Appendix 4, the resource optimization model selects new resources while seeking a least-cost expansion plan of resources that meets both the firm winter capacity and dependable energy needs for each of the scenarios. The type, quantity and timing of resources added in each scenario are based on their cost and characteristics relative to the other available resources. Some resources only provide energy (solar); some provide energy with limited firm capacity (wind); some only provide capacity but consume energy (battery and hydrogen turbines), while some provide both energy and capacity (natural gas turbines, hydropower stations, small modular reactors, and biomass generation). Some resources like natural gas turbines and biomass generation have fuel costs to produce energy while other resources like wind, small modular reactors, and hydroelectric stations incur very little cost to produce energy. The selection of resources to add to the system as load grows is a complex process that the resource optimization model is used to solve.

A caution on modelling results is that the final portfolio of resources identified by the model may not be the absolute lowest-possible cost solution. The model searches for the lowest cost plan through an iterative process that stops when the model meets the optimization threshold and convergence is achieved, indicating that the identified expansion plan is a low-cost solution based on well estimated operating costs in addition to assumed investment costs. It is possible that if the model's iterative process continued, an even lower-cost solution may be identified. However, this can lead to unmanageable model run times or an inability for the model to successfully complete the optimization process and is ultimately not practicable. Given that a lower cost portfolio of resources may exist, it is important to interpret the IRP modelling results as a collective set of results and to balance individual scenario or sensitivity insights with robust findings that are demonstrated repeatedly across model results.

Figure A5.1a and b provide the average annual energy and the firm winter capacity supplied by each type of resource in 2022 and compares it to the resource optimization model results in 2042 for each scenario. Both energy and capacity are considered when planning the system and in the selection of the different potential resource options to meet those needs.

The first key point illustrated by the graphs is that energy and capacity needs in 2042 for each scenario shown are still predominantly provided through the existing hydropower system. The existing hydropower system will continue to play a key role in the future under a range of conditions. As energy need grows within Manitoba, more of the surplus energy from existing hydropower resulting from varying water conditions that has been typically exported as short-term opportunity sales will be used within the province.

The second key point illustrated by the graphs is that energy from the existing system would be supplemented with additional energy from energy efficiency programs, wind, and imports. The biggest difference between the scenarios is in the amount of each new energy resource being selected. Based upon the current assumptions, energy efficiency is being shown as a key component to meeting future energy needs. Similarly, wind generation appears in each of the different scenarios as a low-cost energy resource that is being selected first for energy needs. And finally, interactions over the existing transmission lines with external markets will continue to play a significant role in the operation of Manitoba Hydro's system, with imported energy becoming more prominent over time with increasing amounts of load growth.

The third key point illustrated by the graphs is that future capacity needs are most economically served by natural gas turbines (Appendix 2 – New Resource Options). Each scenario has natural gas turbines being selected as a result of being a low-cost capacity resource. The main difference between scenarios is the amount of natural gas turbines required to meet projected load growth.

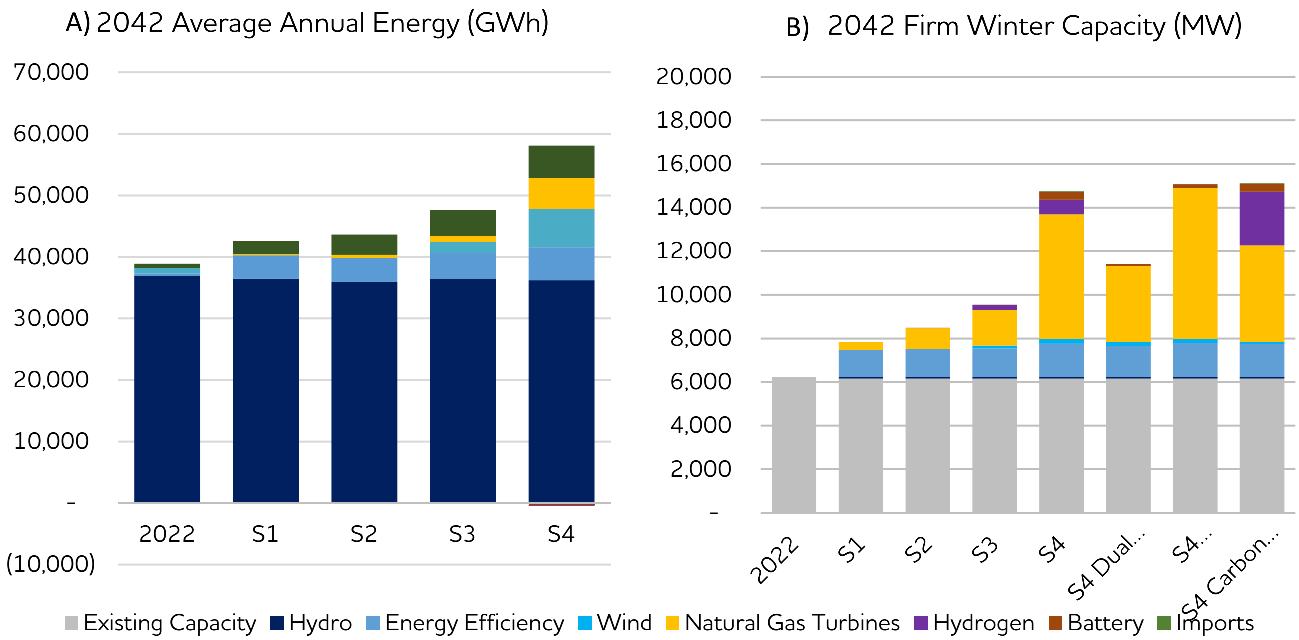


Figure A5.1a – 2042 Supply Mix Average Energy
Figure A5.1b – 2042 Firm Capacity for the four scenarios.

Of particular note is that scenario 4 has a significant step change in capacity compared to the other scenarios. The peak demand increase in winter is due to assumptions around the electrification of space heating and is driving the notable need for increased capacity resources by 2042. Within the supply mix for scenario 4, there is a significant amount of natural gas turbine generation to serve peak demand. The natural gas turbine portion represents approximately 60% of all nominal capacity resource additions by 2042. However, when the average energy production of the turbines is taken into consideration, they only contribute approximately 10% to the total energy used in 2042. This indicates that for most of the year, energy would be supplied through non-emitting electricity resources such as hydropower and wind. However, as wind resources cannot always be counted to serve load during peak demand periods, there is a need to pair variable renewable resources with a dispatchable resource. This is most economically served by natural gas turbines as they are a low-cost resource for providing capacity. While not specifically evaluated, the near-term model selection of natural gas turbines does not preclude potential future changes to the resource. With appropriate modifications, natural gas turbines can operate using a range of different fuels and can incorporate features such as carbon capture and storage.

An additional resource that is being selected within every scenario are upgrades to existing hydropower generating stations. While the amount of the upgrades is small in comparison to other resources, its selection appears in each of the scenario results, and is selected first before any other resource. This indicates that upgrades to existing hydropower is a cost-effective resource.

Of note in the analysis results are the resources that are not being selected within the optimization process for the different scenarios. In particular, new hydropower generation is not being selected for any of the scenarios. This is likely a result of new hydropower generation being much higher in cost than the projected cost of other competing resources such as wind and natural gas turbines. New hydropower generation also has high up-front capital costs and very long project lead times. See Appendix 2 for further detail on the characteristics of hydropower generation. Also of note is the absence of solar PV generation being selected within the optimization, either at the utility scale or distributed scale. This is likely due to its energy cost projections being higher than wind; solar PV does not provide any winter peak capacity to support system demand, and its energy production over the year is not a good complement to the existing hydropower dominated system. Small modular reactors and biomass are also not selected due to their higher cost. See Appendix 2 for further detail on the characteristics of different resource options.

2.4 Timing of New Resources and the Pace of Change

Each scenario represents different energy futures with different amounts of change. As a result, all scenarios experience electric load growth at different rates and the load projection for each scenario eventually exceeds the existing system's supply of dependable energy and firm winter capacity. Figure A5.2 illustrates the pace of change of growing electrical demand and the relationship with the capability of existing supply resources, including import/export agreements. The red lines indicate the existing system's capabilities with respect to dependable energy and firm winter capacity, while the shaded areas represent projected load growth of electricity adjusted for Efficiency Manitoba's projections for each scenario. The capacity provided by the existing system declines over time due to import/export agreements that expire. The need date for new resources occurs when persistent deficits start to appear, and these need dates are highlighted with yellow dots for each scenario.

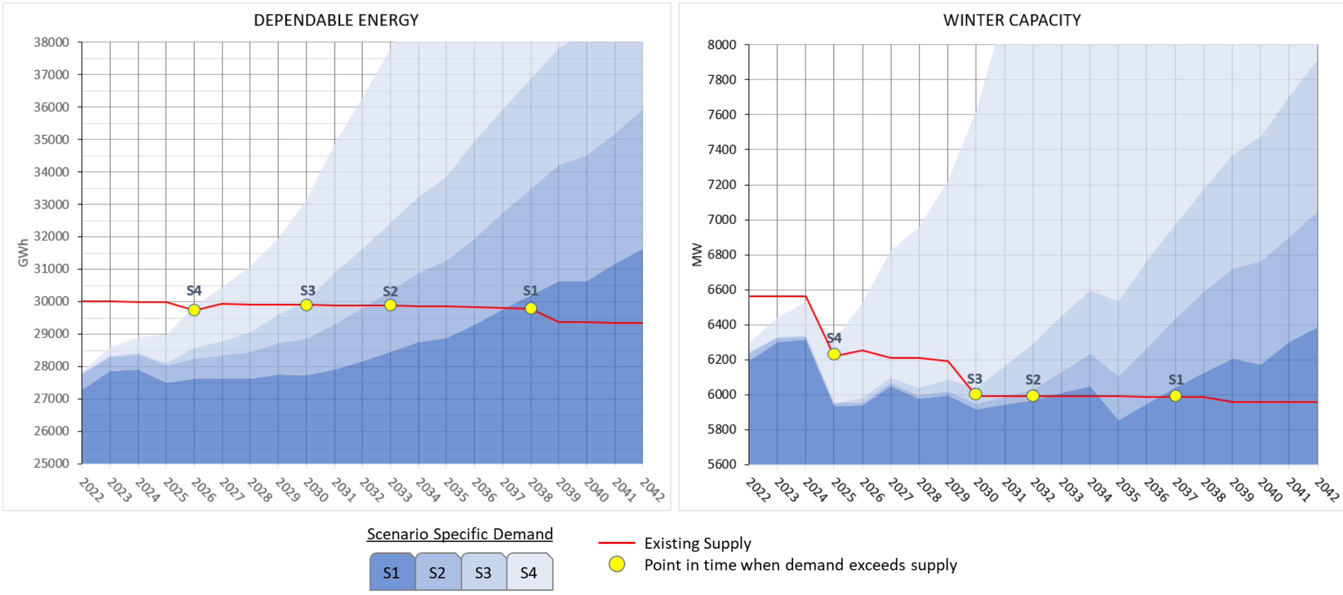


Figure A5.2 – Dates when Demand Exceeds Supply

Table A5.1 outlines the need dates for new resources for each scenario, for both dependable energy and winter peak capacity.

Table A5.1 – Need Dates for New Resources

IRP Scenario	Dependable Energy	Winter Peak Capacity
Scenario 1	2038	2037
Scenario 2	2033	2032
Scenario 3	2030	2030
Scenario 4	2026	2025

While in some scenarios, notably in scenario 1, new resources are not needed for many years, of particular note are the earlier need dates for scenario 4 of 2026 for dependable energy and 2025 for winter firm capacity. These early need dates for scenario 4 mean it would be challenging to plan, approve, and construct new resources to meet the demand projections in scenario 4. Furthermore, the growth of scenario 4's electrical demand is projected to continue at a rapid pace beyond the earliest need date, resulting in a continuous need to build new resources for nearly the entire 20-year study horizon. Such a rapid and continuous rate of growth would be challenging to supply from new resources.

Overall, the existing system continues to meet demand in the early years of scenario 1, 2, and 3. However, the amount of potential surplus winter capacity is limited during the first 10 years and can quickly be overtaken by demand depending on the pace of change. Beyond 10 years, all scenarios will need continued investment to meet demand, with a much greater requirement in scenario 4.

To further understand the pace of change of each scenario Figure A5.3 shows the resource supply mix at five-year intervals for each scenario. The pace of change for all scenarios is observed with the addition of new resources over time and the type of resources being selected. As indicated in the previous 'Electrical Resource Options Selection' section, the resources being selected are energy efficiency, wind, natural gas turbines, along with some battery storage and hydrogen turbines. The base Efficiency Manitoba plan covers the 20-year study horizon and is assumed under all scenarios with additional energy efficiency potentially selected in each scenario.

Scenario 1 has the slowest pace of change with much of its growth being met by energy efficiency with 1,300 MW being achieved over the 20-year study period mostly as a result of the base Efficiency Manitoba plan. In addition, a small amount of capacity is selected in the form of 370 MW of natural gas turbines in the 2038-42 period. Scenario 2 has a modestly faster pace with 1,400 MW of energy efficiency being added over the 20-year study period, and 500 MW and 440 MW of natural gas turbines capacity selected in the 2033-37 and 2038-2042 periods respectively for a total of 940 MW by 2042. Scenario 3 has a more accelerated pace of change with a similar amount of energy efficiency as scenario 2 but with 220 MW of natural gas turbine capacity being selected in the earlier 2028-32 period, then 770 MW and a further 650 MW of natural gas turbines in the next two periods for a total of 1,640 MW by 2042. In addition, scenario 3 has wind being selected for energy with 300 MW in the 2033-37 period and 340 MW in the 2038-42 period for a total of 640 MW by 2042.

As described previously, scenario 4 represents a step change in the magnitude and pace of change in comparison to the other scenarios. Energy efficiency continues to play a similar role with 1,600 MW over 20 years, however, the need date for both energy and capacity are advanced in time so much that approximately 500 MW of required capacity resources starts to appear in the near term 2022-27 period. This is important to highlight as this timeframe exceeds the lead time for planning, approving, and constructing new resources. These early new capacity additions are identified as an undefined placeholder resource, as it may not be possible to meet such an early and rapid growth in system needs. Once the later portion of the 2028-32 period occurs, there will be sufficient time to bring new resources online and placeholder resources required for the 2022-2032 period are replaced. In Figure A5.3, the 2022- 2027 and 2028-2032 time periods show the cumulative placeholder capacity additions required, whereas the 2033-2037 time period reflects the cumulative capacity additions with all previously built placeholder resources replaced by natural gas turbines. 1,500 MW of new natural gas turbines is required in the next two periods each for a total of 5,500 MW by 2042. By the latter part of the planning horizon modest amounts of hydrogen turbines and battery storage are also selected to help meet the large capacity need. In addition to capacity, 2,000 MW of wind is selected in the 2033-37 period to supply energy.

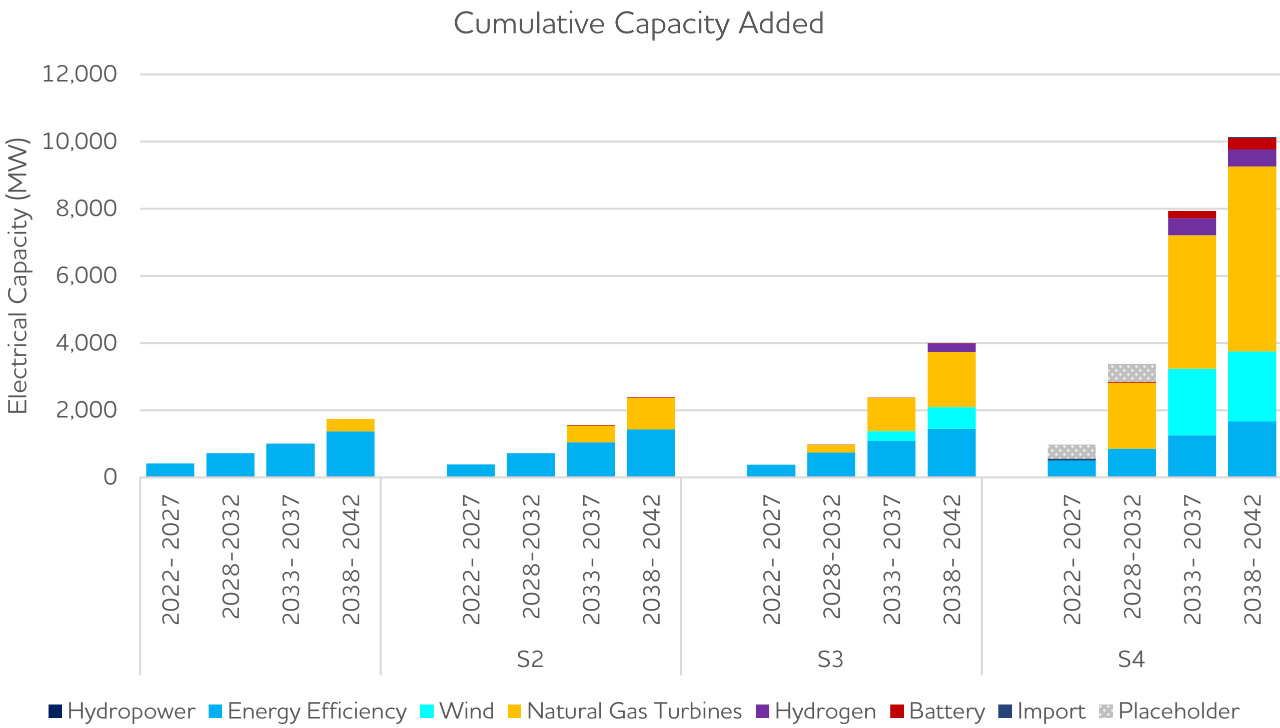


Figure A5.3 – Cumulative Capacity Added

2.5 System Operation Under Different Flow Conditions

Changes to the overall operation of the system under different flow conditions is also an important factor to consider for each of the scenarios. Figure A5.4 shows how the operation of the system changes in scenario 4 under dependable (drought) flow, average flow, and high flow (flood) conditions (refer to Appendix 1 – Existing System & Load for discussion on the hydraulic system including system inflow variability). Under dependable flow conditions in 2042 over 40% of the energy supplied is from existing hydropower assets and the amount of energy served from natural gas turbines increases to approximately 25% to compensate for the decrease in hydropower generation. Overall, even under dependable flow conditions, renewable energy from hydropower, wind, and energy efficiency account for 60-80% of the energy supplied. Under high flow conditions the reverse occurs with hydropower generation increasing and the amount of natural gas turbine generation decreasing. With the amount of energy imported and exported varying across a range of flow conditions, imported and exported energy will continue to be an important way for the electrical system to economically supply energy to customers.

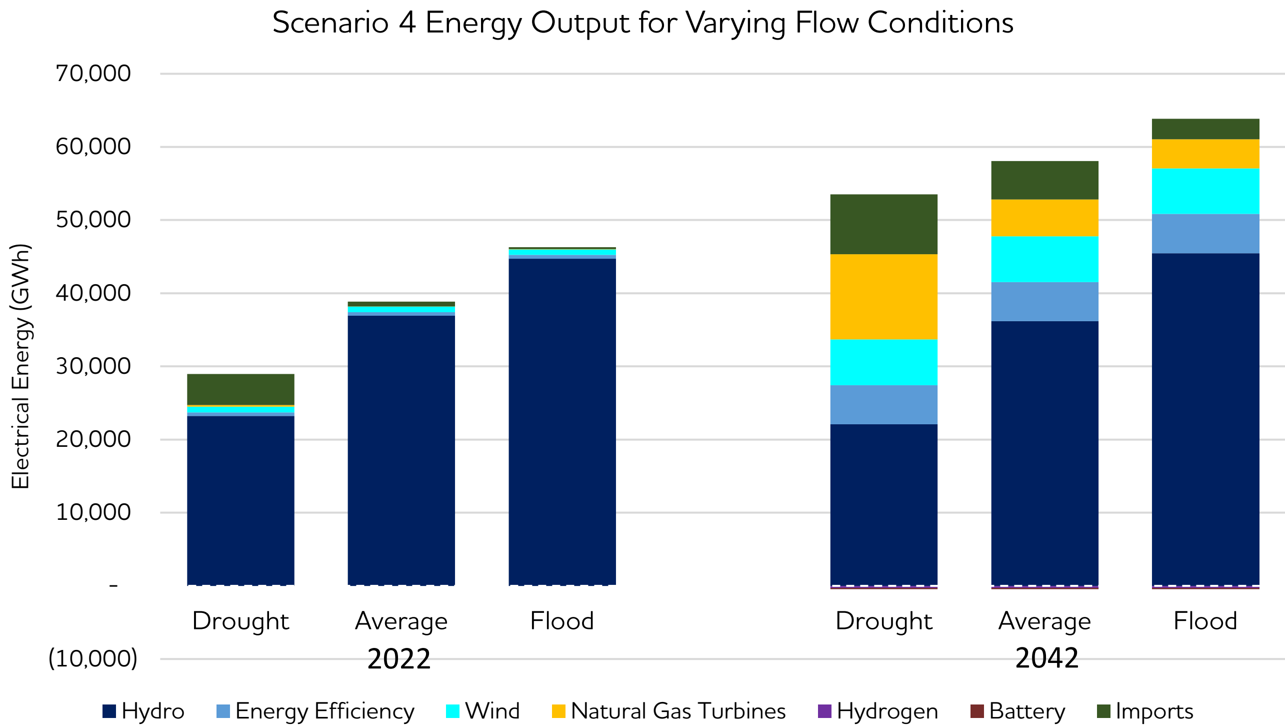


Figure A5.4 – Scenario 4 Energy Output for Varying Flow Conditions

2.6 Energy Efficiency

Each scenario includes an assumed level of energy efficiency savings (also referred to as Demand Side Management or DSM) that is achieved based on an extrapolation of Efficiency Manitoba's 2020-23 Efficiency Plan[1] that extends throughout the 20-year planning horizon (Efficiency Manitoba Plan). The modelling of scenarios assumes that the Efficiency Manitoba Plan energy savings are achieved so there are no optimizations of these energy savings. Appendix 2 described the additional energy savings market potential beyond the Efficiency Manitoba Plan energy savings that could be available to further reduce customer demand. This potential energy savings resource option is referred to as "Selectable Energy Efficiency" and is available to the resource optimization model to reduce customer demand instead of developing generation resource options. The following tables summarize the groupings of Selectable Energy Efficiency measures that were available for selection in the optimization to establish a least cost expansion plan. The selectable energy efficiency excludes the savings potential from heat pumps which are assessed in a sensitivity analysis.

[1] http://www.pubmanitoba.ca/v1/proceedings-decisions/appl-current/em-2020-23-plan.html

Table A5.2 – Energy Efficiency Savings Potential (GWh) In 2042

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Efficiency Manitoba Plan (extrapolated)	3,590	3,590	3,590	3,590
Selectable Energy Efficiency Measures[1]	201	512	630	1,772
Total Potential Demand Reduction	3,791	4,102	4,220	5,362

[1]Heat pump energy savings potential not included as a resource option for the scenarios.

The following chart compares the total modelled savings to the maximized market potential energy savings level by 2042. Potential energy savings from distributed solar PV is substantial so it is shown separately from all other energy efficiency measures. All four scenarios do not achieve the full market potential savings while scenario 4 develops the largest portion of market potential savings.

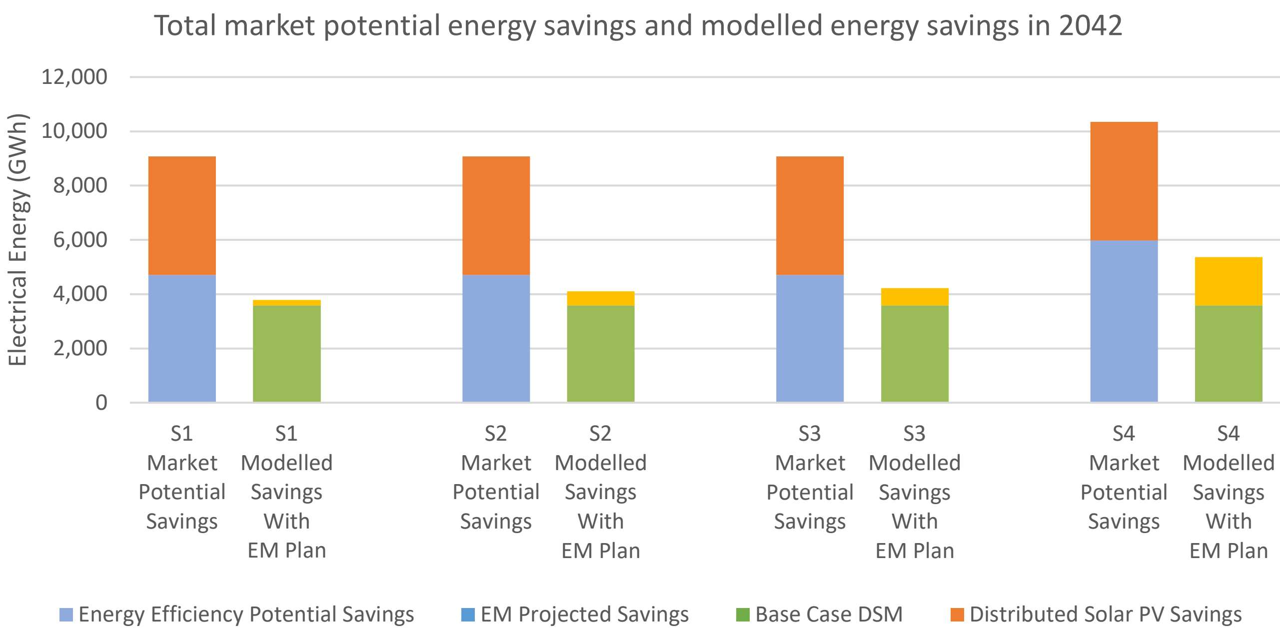


Figure A5.5 – Comparison of energy savings in 2042

The results in Table A5.2 and Figure A5.5 show that energy efficiency measures that are implemented over the 20-year period could avoid between 3,800 and 5,400 GWh hours of electricity use annually by 2042 depending on the scenario. Table A5.3 lists the Selectable Energy Efficiency savings in 2042 that is selected by the model for each scenario.

Table A5.3 – Selectable Energy Efficiency Savings (GWh) In 2042

	Grouping[1]	Scenario 1	Scenario 2	Scenario 3	Scenario 4
EE-M1	Commercial Lighting[2]	N/A	N/A	N/A	N/A
EE-M2	Commercial Uniform Load	29	292	377	281
EE-M3	Non-Residential Heating & Cooling	120	168	175	275
EE-M4	Industrial Custom	15	15	15	717
EE-M5	Non-Commercial Lighting[2]	N/A	N/A	N/A	N/A
EE-M6	Residential Heating and Cooling	1	1	27	163
EE-M7	Non-Commercial Uniform Load	36	36	36	337
EE-SPV1	Solar PV	0	0	0	0

[1] Heat pump energy savings potential not included as a resource option for the scenarios.

[2] No additional market potential available.

The lighting energy savings in the Efficiency Manitoba Plan exceed the market potential study's findings, so no extra savings are possible through selectable energy efficiency measures. Most of the additional energy efficiency savings that are selected are the Commercial Uniform Load groupings and the Non-Residential Heating and Cooling grouping. There is little adoption of the Industrial Customer, Residential Heating and Cooling and Non-Commercial Uniform Load groupings in scenarios 1, 2, and 3 but there is some notable adoption of these groupings in Scenario 4.

While distributed solar PV can provide energy savings, no distributed solar PV was selected for the portfolio of resources for each scenario above the savings already assumed in the demand projections. No additional distributed solar PV was selected because it does not provide any winter firm capacity and its cost of energy savings is higher than the cost of energy from other resource options. For further details on distributed solar PV see Appendix 2.

2.7 Greenhouse Gas Emissions

There are several sources of greenhouse gas (GHG) emissions in Manitoba. GHG emissions can be separated into four categories: stationary combustion (excluding electricity generation), transportation, electricity generation, and other sources. Only the first three of these GHG emission categories are energy dependent and are considered in this analysis. For further information on existing GHG emissions see Appendix 1, and for information on GHG emissions definitions and methodology see Appendix 4.

Each scenario explores a different future with respect to how, and how much energy is consumed. As a result, each scenario produces a range of different GHG emission profiles due to varying changes in the types of energy used. Moving from internal combustion engines to electric vehicles directly impacts electricity needs and future GHG emissions. Similarly, moving from natural gas heating to electrical heating impacts electricity needs and future GHG emissions. Finally, differences in electrical generation resources also impact future GHG emissions.

Figure A5.6 shows for each of the four scenarios how energy dependent GHG emissions change over time. This figure along with Table A5.4 also shows the relative changes of the different categories of GHG emissions between 2042 and current (2022) emissions. While modest provincial GHG emission reductions occur within scenario 1, substantial GHG emission reductions occur within scenarios 2, 3, and 4, with the most significant decline over time occurring in scenario 4. These reductions are mainly driven by the transportation sector. Despite the significant changes in energy usage and GHG emissions in scenario 4, the total GHG emissions reduction is equal to 5.9 Mt of CO_2e, which is a little higher than the overall reduction of scenario 3 at 5.2 Mt. The Natural Gas Turbine Sensitivities Section provides analysis of further GHG emissions reduction potential.

Table A5.4 – Change in Average Annual GHG Emissions (tCO_2e), 2042 versus 2022

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Stationary Combustion Emissions (Excluding Electricity Generation)	-80,000	-6,000	-1,100,000	-2,280,000
Transportation Emissions	-340,000	-3,050,000	-4,500,000	-5,840,000
Electricity Generation Emissions	90,000	290,000	400,000	2,180,000
All Energy Dependent Emissions	-320,000	-2,770,000	-5,200,000	-5,940,000

While all scenarios use additional natural gas turbine resources to generate electricity, overall provincial GHG emissions still decrease. This is due to GHG emissions being reduced in the transportation and stationary combustion categories of which a significant portion is space heating. While there may be more natural gas turbines, they are run infrequently in order to help meet peak electricity demands. Much of the time, when demand is low, the electrification of transportation and space heating is served through non-emitting renewable generation, such as hydropower and wind. Overall, a measured increase in GHG emissions in electricity generation, along with new renewable energy resources, can enable significant decreases in GHG emissions from other sources like transportation and space heating.

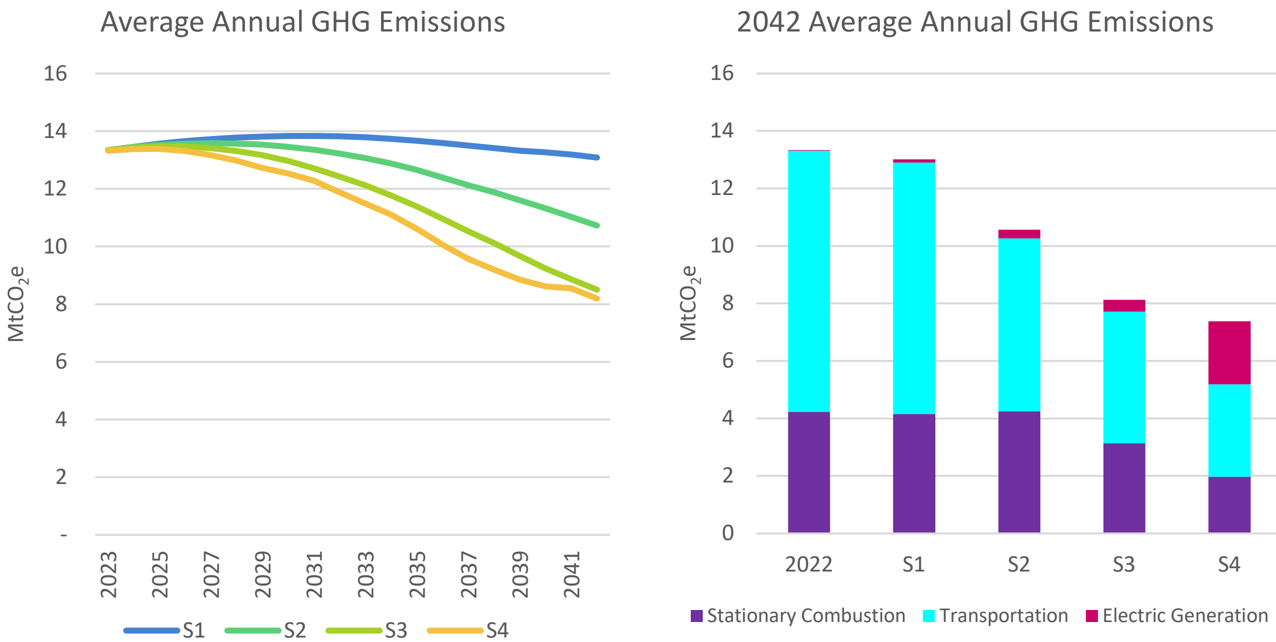


Figure A5.6 – Average Annual GHG Emissions[2]

2.8 Net System Costs

As described in Appendix 4, the evaluation process in the resource optimization model is based on a least net system cost optimization. Net system costs are comprised of both capital and operating costs, and include generation costs, transmission costs, distribution costs, generation fuel costs, import costs and export revenues, natural gas distribution costs, and customer natural gas costs. While the optimization process only considers new generation expansion and system operating costs of the electrical system, the existing system costs and customer natural gas costs are added following the modelling process to provide a total net system cost. This is calculated on an annual basis and on a cumulative present value basis over the entire 20-year evaluation horizon. All values are in real (or constant) 2021 Canadian dollars.

As seen in Figure A5.7 the cumulative present value of net system costs to 2042 for the combined electrical and natural gas systems are similar for scenarios 1, 2, and 3 at $43.6B, $45.7B, and $46.0B respectively. In contrast, the same value for scenario 4 is notably higher at $54.4B, which represents an $8.4B or 15% increase compared to scenario 3. When comparing the annual net system costs in 2042 there are more notable differences between the scenarios as seen in Figure A5.8. By 2042 scenario 1 has an annual net system cost of $2.9B, while for scenarios 2 and 3 the annual costs are $3.3B and $3.5B respectively. Scenario 4 remains much higher with an annual cost of $5.1B, which represents a 31% increase compared to scenario 3 and a 43% increase compared to scenario 1.

The reason for the relative differences between the scenarios from a cumulative present value basis versus the 2042 annual cost basis (most notably seen in the scenario 4 comparison to scenario 3) is the pace of

[2] Manitoba GHG emissions shown do not include non-energy dependent sources (i.e., “other sources:), like agricultural and waste emissions.

change in decarbonization, specifically the increased demand for electricity. Generally speaking, across all scenarios for the 20-year study horizon, limited near term costs are incurred beyond those to support the existing system for the first decade while more significant costs are incurred for the later decade. This is shown in Figure A5.3 where new resource additions are modest in the first decade and more substantial in the second decade. The cumulative present value of net system costs considers the costs over the entire planning horizon, while the 2042 annual cost provides an indication of where the costs are going by the end of the planning horizon. An additional observation from the analysis is that prior to taking into account costs for new investments to meet growing demand, there are notable costs to maintaining and operating the existing electrical and natural gas systems that are fixed and are not impacted by future resource choices. The relative magnitude of these costs is shown by the horizontal lines in Figure A5.7 and Figure A5.8 based on the 2022 existing system fixed costs.

Overall, financial investment is needed in all scenarios, different levels of increased electrical demand result in different net system costs, and as explained in previous sections the need for capacity resources is a major driver of costs.

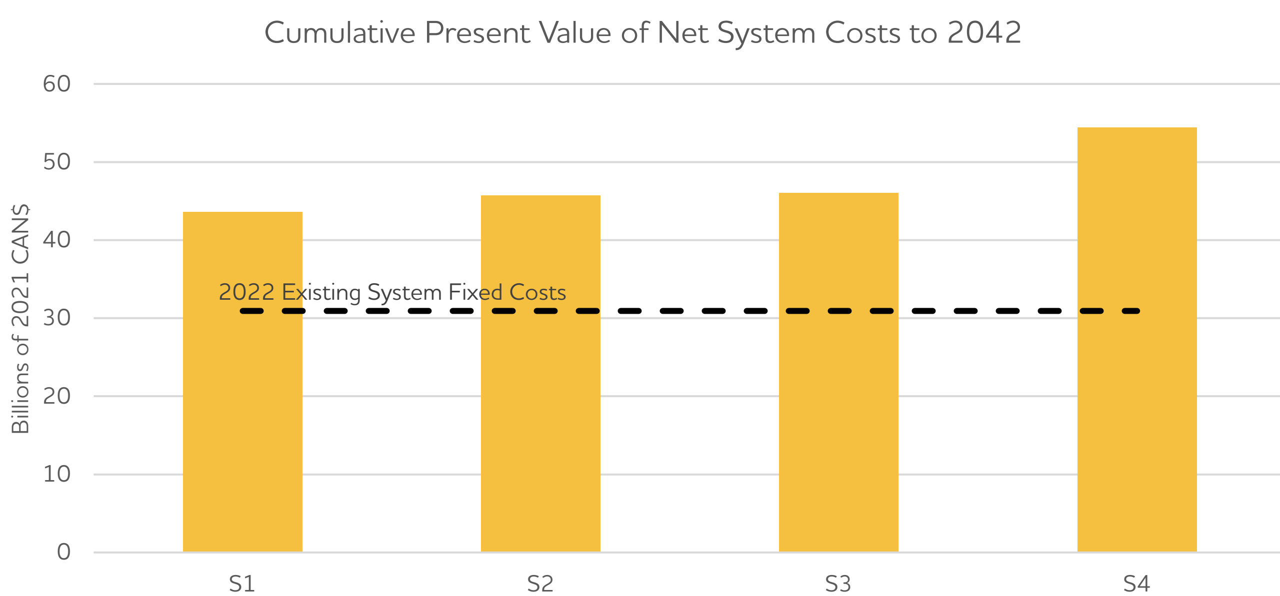


Figure A5.7 – Cumulative Present Value of Net System Costs to 2042

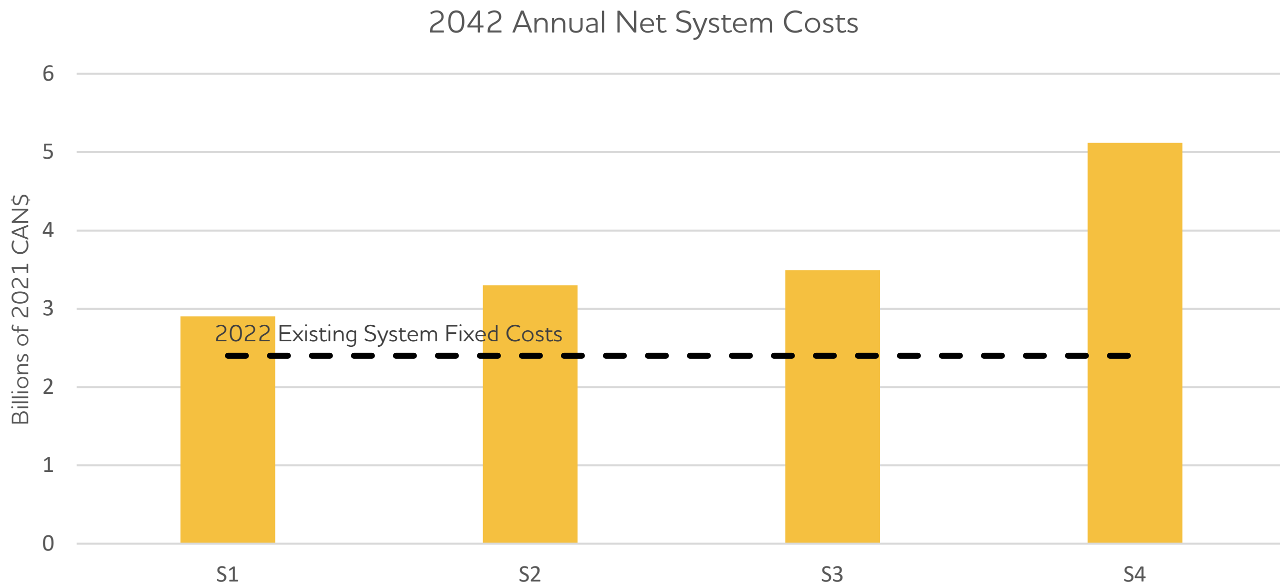


Figure A5.8 – Annual Net System Costs in 2042

2.9 Comparison of Relative Changes by Scenario

Understanding how different metrics change between scenarios helps to interpret the results of the evaluation. Figure A5.9 compares metrics for each scenario for firm capacity required (MW), annual net system costs ($B), combined energy supplied from electricity and natural gas (GJ), unit costs ($/GJ), and annual GHG emissions decrease (Mt). All values represent the percent change of 2042 values from 2022 values. Unlike on other figures, "energy" here is a combination of electrical energy and natural gas energy expressed in gigajoules (GJ). Additionally, all costs are in real (or constant) 2021 Canadian dollars and do not reflect the impact of inflation. Comparing 2042 annual values to 2022 annual values provides insight into what changes would result by the end of the study period under each scenario.

As previously seen, scenarios 1, 2, and 3 all result in somewhat similar results, with a step change for scenario 4. Figure A5.9 further reinforces that all scenarios will require some level of investment to meet future demand. Additionally, capacity needs and costs increase across the scenarios as decarbonization efforts increase, as loads increase, and as investments in new resources increase. The most substantial step change is from scenario 3 to scenario 4 which results in the firm capacity needs increasing from 54% to 137%, and annual net system costs increasing from 43% to 113% respectively.

The overall combined energy supplied by the electrical and natural gas systems increases across the scenarios with a range of 18% to 35%. Relative changes in the amount of GHG emissions is a slight reduction in scenario 1, 21% reduction in scenario 2, 39% reduction in scenario 3, and 45% reduction in scenario 4.

Figure A5.9 includes the unit cost of producing each GJ of energy based on dividing the annual net system cost by the energy supplied in 2042. The figure shows that the unit cost of energy supplied increases across each scenario with the unit cost of energy supplied in scenario 4 much higher than the other scenarios.

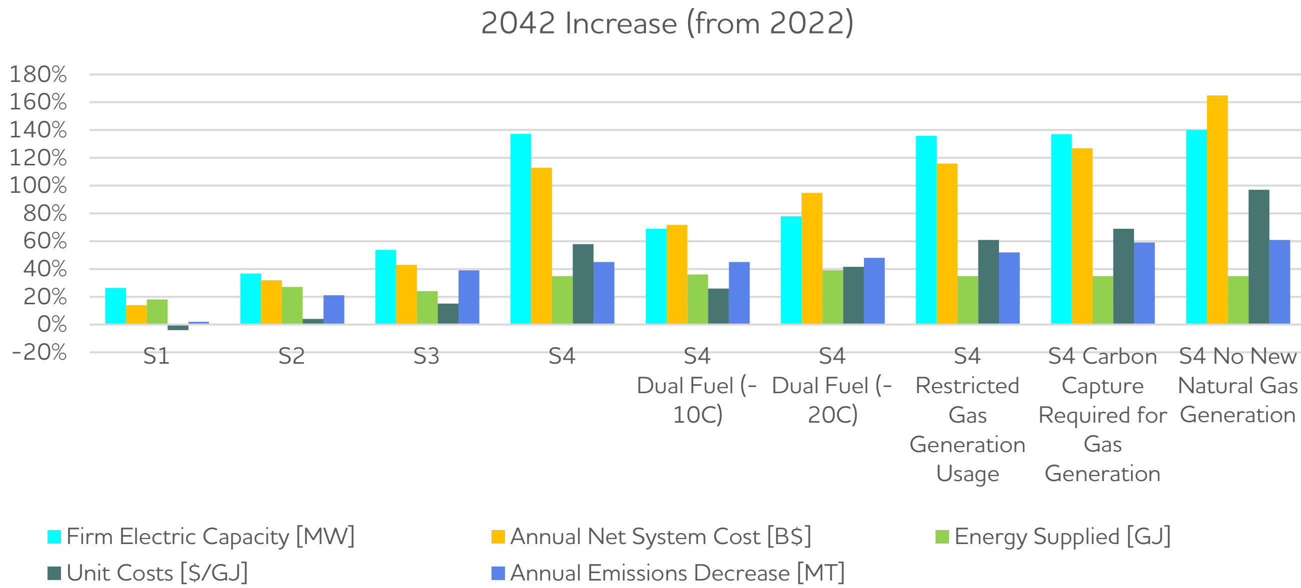


Figure A5.9 – Change in Capacity, Energy, Cost, and GHG Emissions[3]

~~2.10~~ Net System Costs vs. GHG Emissions

The results presented above illustrate the relationship between provincial GHG emission reductions and the net system costs for the combined electrical and natural gas distribution systems. While there is a steady decline in provincial GHG emissions over the four scenarios, there is also a steady increase in net system costs over the scenarios, with the largest change occurring between scenario 3 and scenario 4. Figure A5.10 combines the annual net system costs and Provincial GHG emissions for 2022 and 2042.

[3] GHG emission reduction percentages only consider energy-dependent sources; GHG emissions from non-energy dependent sources (i.e., "other sources:), like agricultural and waste emissions, were not included in the comparison.

In addition to the findings provided in the previous sections, the following are additional observations from Figure A5.10:

- Greater levels of decarbonization through increased electricity demand requires greater levels of investment.
- Manitoba Hydro can support the reduction of GHG emissions in the transportation sector at a relatively low cost. This is shown in Figure A5.10 by the relative differences between scenario 1 and 2 where the costs increase modestly while the GHG emissions from transportation decrease more substantially.
- Supporting the reduction of GHG emissions via electrification of stationary combustion is costly (per $tC0_2e$ reduced) and results in significant increases in costs and GHG emissions in the electrical system. This is shown in Figure A5.10 by the relative differences between scenario 3 and 4 where combined GHG emissions from stationary combustion and electrical generation increase modestly, while total costs increase substantially.
- Overall, limited use of natural gas in electrical generation can help support GHG emission reductions in other areas such as transportation.

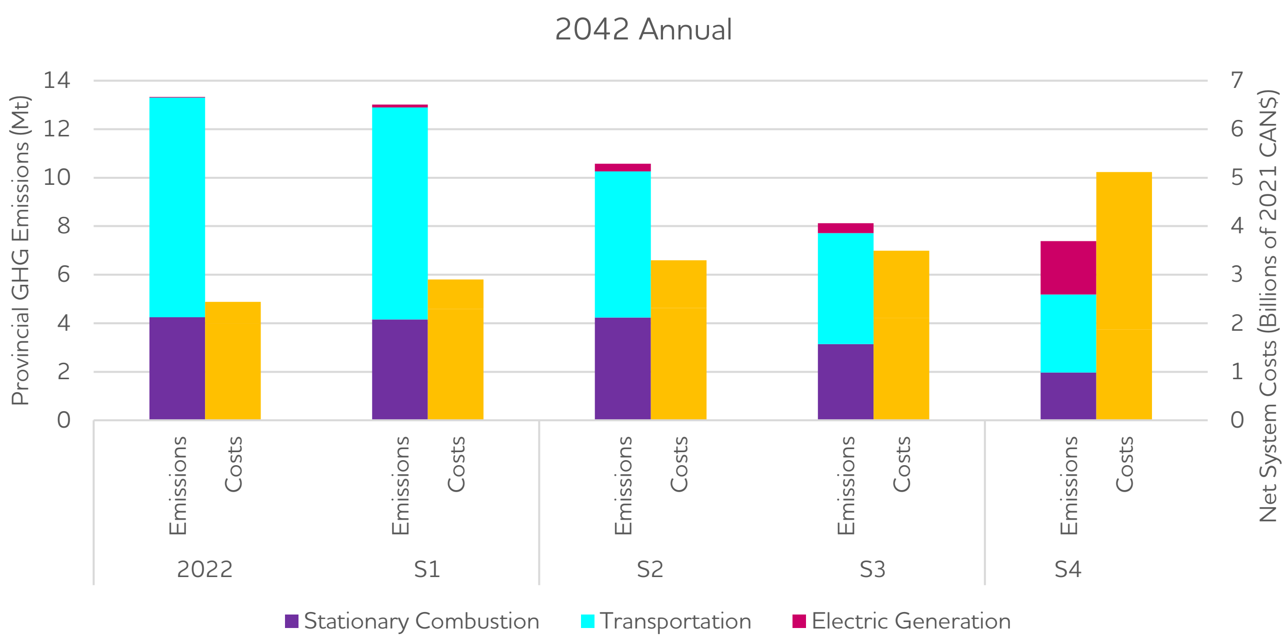


Figure A5.10 – Annual Emissions and Costs in 2042[4]

2.11 Transmission and Distribution Systems

Appendix 4 provides background on the incremental transmission and distribution infrastructure investments required to reliably serve the increasing peak demand projected to occur within each of the IRP scenarios. In addition, generator interconnection infrastructure includes the cost of new transmission

[4] Manitoba GHG emissions shown do not include non-energy dependent sources (i.e., "other sources:), like agricultural and waste emissions.

that is required to connect new generation resources to the electricity grid. Figure A5.11 illustrates the costs for the new transmission and distribution and new generator interconnection infrastructure for each of the IRP scenarios. These costs range from $0.6B for scenario 1 to $1.6B for scenario 3, with a step change for scenario 4 at $5.0B.

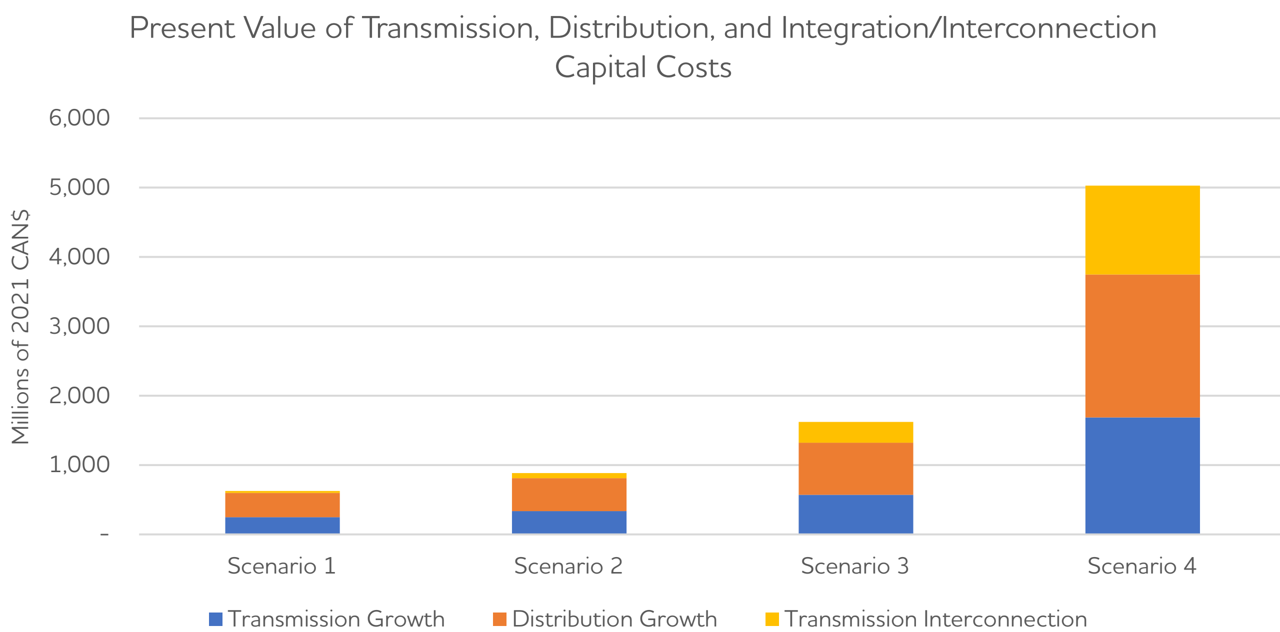


Figure A5.11 –Transmission, Distribution, and Interconnection Capital Costs

2.12 Natural Gas Distribution System

The 2023 IRP considers the natural gas distribution system in the electrical system planning process for the first time at Manitoba Hydro. This was undertaken to better represent and understand the various impacts and trade-offs between the two energy delivery systems. As this is the first time for such an evaluation, a simplified approach was utilized by incorporating the natural gas distribution system indirectly through changes to heating system preferences of customers and industrial electrification in the electrical and natural gas demand projections. Depending on the scenario, changes were made to the number of customers converting from natural gas heat to electric resistance heat or heat pump systems. The net result is a decrease in the volume of natural gas delivered by the natural gas system and a corresponding increase in the amount of electrical energy and firm winter capacity delivered by the electrical system.

These changes to the electrical demand projection were modelled within the resource optimization model to seek a least cost approach to serve the new demand. The changes to the natural gas demand projections are incorporated into the calculations which determine the total net system costs for the combined electrical and natural gas systems. The federal carbon price projection reaching \$170/tCO_2e is incorporated into the evaluation. The scenarios impacted the most by the decarbonization of space heating are scenario 3 where some customers incorporate air source heat pumps as part of a dual fuel system to reduce natural gas consumption while some switch to electric resistance heat, and scenario 4 in which many customers switch from natural gas heat to electric resistance and dual electric heating systems. The natural gas demand decreases in scenario 4 to about one half the current natural gas usage. Appendix 3 includes heating system assumptions for each scenario.

The method for including the natural gas distribution system in the resource optimization model is a simplified method that does not incorporate a number of natural gas system specific considerations. As a result, there are several areas requiring further investigation in the future including approaches to reducing the carbon intensity of the natural gas system. Approaches may include renewable natural gas blending, hydrogen blending, and more extensive use of dual fuel customer heating systems with air source heat pumps.

2.13 Summary

The four scenarios represent a wide range of potential futures, each representing different paces of change. The largest impact resulting from decarbonization efforts is that demand is anticipated to continue to grow in all scenarios based on the assumption customers will use more electricity as they adopt electric vehicles and use more electricity to heat their homes and businesses. Demand progressively increases for the first three scenarios but with a significant step change in scenario 4. This change is a result of scenario 4 assumptions related to accelerated decarbonization and a pathway towards net-zero. The impact of scenario 4 results in the need for 2.0 times the energy and 2.5 times the capacity of the current system. While a main driver for all scenarios is progressively increasing levels of electric vehicles, the most significant driver underlying the large and rapid growth in scenario 4 relative to the other scenarios is the assumptions that natural gas heating is converted to electric heating.

To meet the demand needs in each of the scenarios the resource optimization model selects new resources to seek a least-cost expansion plan that meets both the firm winter capacity and dependable energy needs. The selection of resources to add to the system as demand grows is a complex process that the resource optimization model is used to solve. Electrical energy and capacity needs in 2042 for each scenario continue to predominantly be provided through the existing hydropower system. Future energy needs are best served from energy efficiency, wind, and imports, while future capacity needs are best served by natural gas turbines. Each scenario has natural gas turbines selected as a low-cost capacity resource. An additional resource that is selected in every scenario are upgrades to existing hydropower generating stations as a low-cost resource. It is important to note that new hydropower and solar PV are resources that are not selected, indicating that they are not economically attractive compared to other potential resources.

Energy efficiency will continue to play a role in meeting Manitoba's future energy needs. This evaluation is the first time that Manitoba Hydro has included energy efficiency as a fully selectable resource to be evaluated on a level field with supply side resources. As a result, this is considered a first step with further investigations and evaluations required along with continued collaboration with Efficiency Manitoba.

With regards to GHG emissions, electricity generation currently represents only 0.1% of all provincial emissions. However, this percentage increases in all scenarios. In the future there may be more natural gas turbines being selected within each scenario, but they are run infrequently to help meet peak electricity demands, limiting the impact on emissions. Much of the time, the demand is served through emissions free renewable generation such as hydropower and wind. Of the four scenarios, scenario 4 reduces current GHG emissions the most, while the GHG emissions from its electricity generation contributes a larger portion of the provincial GHG emissions by 2042, increasing from 0.1% to 15% (on average).

To provide a more inclusive view of the total cost to meeting customer energy needs, costs were combined for both the electrical system and natural gas system over the 20-year planning horizon. The resulting cumulative net system costs for the first three scenarios are similar to each other, while scenario 4 is notably higher in cost due to larger assumptions of decarbonization and the resulting increases in electrical demand. Overall, financial investment is needed in all scenarios. Different levels of decarbonization through increased electricity demand result in different net system costs with the need for capacity resources being a major driver.

Overall, greater levels of decarbonization resulting in increased electricity demand will require greater levels of investment. Manitoba Hydro can support the reduction of GHG emissions in the transportation sector at a relatively low cost; however, supporting the reduction of GHG emissions by electrification of stationary combustion (building heat and industrial processes) is costly (per tC02e reduced).

The timing of new resources and the pace of change for scenarios 1 to 3 have need dates that are manageable to achieve as they start in 2030 and later. However, scenario 4 has a need date that is much earlier and could be challenging to plan, approve, and construct new resources in time to serve demand.

3 Sensitivity Analysis

3.1 Introduction

Sensitivities complement the scenario analysis in the previous section by exploring the impact of changes to various assumptions and inputs. A sensitivity starts with one of the scenarios and then changes a factor of interest to better understand its impact. A series of sensitivities were identified to help broaden the understanding of the modelling and analysis results. Many of the sensitivities focus on certain key assumptions that could influence results or strengthen understanding of the results. The list of sensitivity analyses performed is shown below. This section will discuss each one by presenting the objective, methodology, and results.

- Natural Gas Turbine Sensitivities:
    - Restricted use of natural gas turbines
    - Carbon capture and storage (CCS) required for all new natural gas turbines
    - No new natural gas turbines
    - GHG emissions budget
    - High GHG emissions cost
- Demand Side Sensitivities:
    - Demand response
    - Dual fuel for heating
    - Optimization of energy efficiency
    - Ground source and air source heat pumps
    - Lower customer incentive level for energy efficiency
    - Distributed solar PV
- Energy Price and Market Interactions Sensitivities:
    - Reduced imports
    - Increased import and export capability
    - Low export and import market price
- Other Sensitivities:
    - Climate change
    - Provincial fees
    - New hydropower
    - Wind
    - Solar PV - utility scale
    - Electric vehicles

Each sensitivity is based on an optimization that minimizes net system cost with all resources available for selection, except where stated otherwise. Sensitivities were run on select scenarios. Costs are all in 2021 Canadian dollars (CAN$) unless otherwise specified.

3.2 Natural Gas Turbine Sensitivities

Introduction

The modelling of the scenarios included no restrictions on natural gas turbines outside of technical and economic characteristics. The natural gas turbine sensitivities explored the impact on costs, resource selection, and GHG emissions with changing assumptions on the use of natural gas turbines. These sensitivities include:

- Restricted use of natural gas turbines;
- Carbon capture and storage (CCS) required for all new natural gas turbines;
- No new natural gas turbines;
- GHG emissions budget; and,
- High GHG emissions cost.

Scenario 4 represents the greatest degree of change and provides the greatest opportunity to explore changes in assumptions and inputs around the use of natural gas for electricity generation; therefore, it was the primary basis for the sensitivity analysis.

Restricted Use of Natural Gas Turbines

Objective

This sensitivity explored the impacts on the selection of resources, GHG emissions, and costs of assuming that natural gas turbines without CCS cannot be used to satisfy the dependable energy planning criterion; rather, these natural gas turbines could only be used to satisfy the capacity planning criterion. This means that sufficient resources would need to be in place to supply energy during the worst drought on record without accounting for energy from natural gas turbines without CCS. Natural gas turbines without CCS could still be relied on for capacity to meet peak demand.

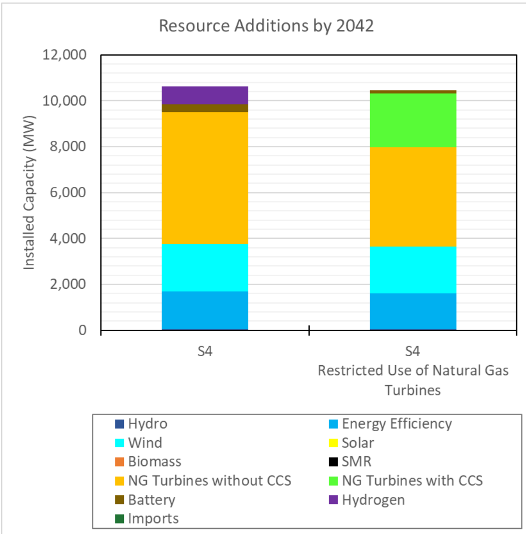
Methodology

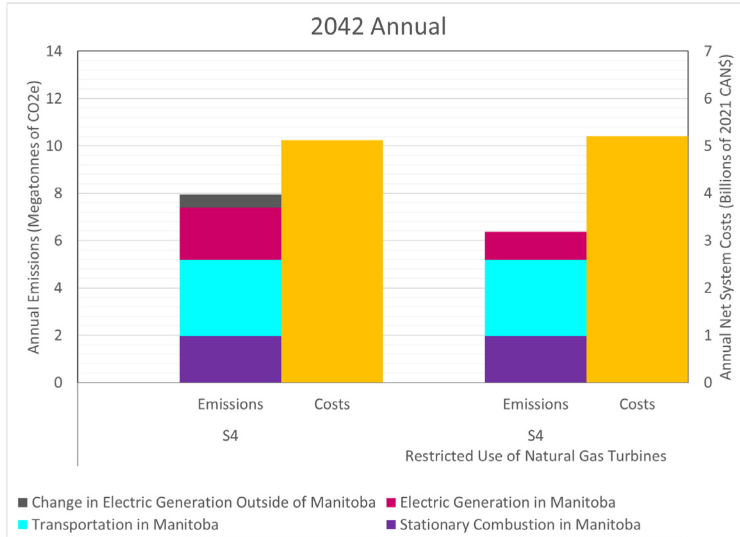
This sensitivity modifies scenario 4 so that there is no dependable energy attributed to new natural gas turbines without CCS. The dependable energy provided by existing natural gas turbines and for new natural gas turbines with CCS remained unchanged.

Results

Figure A5.12 illustrates a range of results of this sensitivity against the scenario 4 baseline. A total of 2,300 MW of natural gas turbines with CCS was added, satisfying the requirement for dependable energy and firm winter capacity. In addition, 1,400 MW of natural gas turbines without CCS along with 800 MW of hydrogen turbines was removed, with 4,300 MW of natural gas turbines without CCS remaining as capacity resources.

Manitoba electricity generation GHG emissions, regional electricity generation GHG emissions, and provincial GHG emissions in 2042 decreased, driven by the reduction of 53% (1.4 MT CO_2e) of Manitoba electricity generation GHG emissions. The annual net system cost in 2042 increased by 2% ($0.1B) and the cumulative present value of net system costs to 2042 increased by 2% ($0.9B) (Figure A5.18) driven by the higher capital cost of natural gas turbines with CCS.





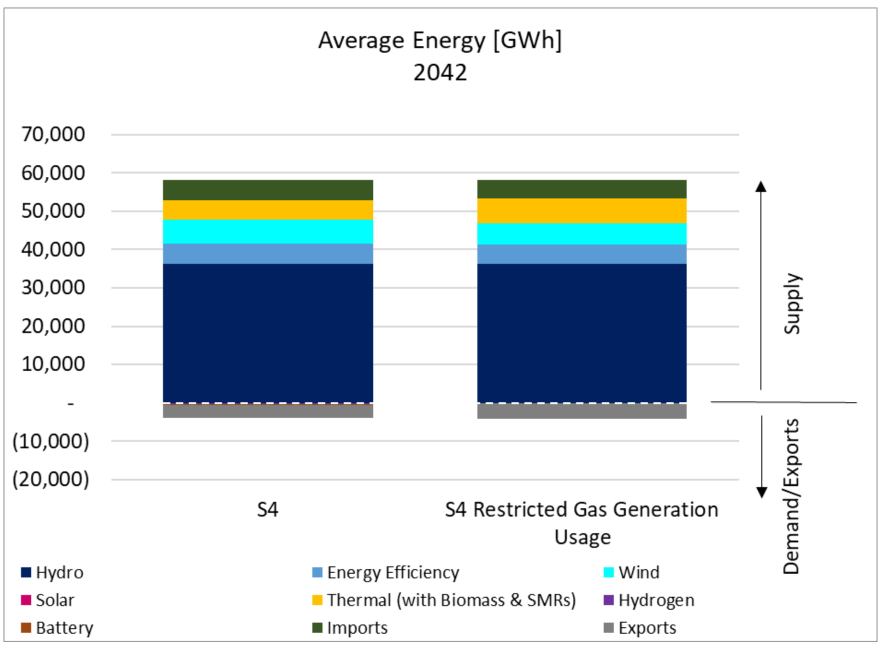


Figure A5.12a – Comparison of Resource Additions in 2042 for a Restricted Natural Gas Generation case
Figure A5.12b – Comparison of Manitoba Annual emissions in 2042 exclusive of non-energy dependent sources and of annual net system costs in 2042, for a Restricted Use of Natural Gas Generation Case[5]
Figure A5.12c – Comparison of 2042 Supply Mix Average Energy for a Restricted Use of Natural Gas Generation Case

[5] Manitoba GHG emissions shown do not include non-energy dependent sources (i.e., "other sources"), like agricultural and waste emissions.

Carbon Capture and Storage (CCS)

Objective

This sensitivity limits the selection of natural gas turbines to explore the impact of assuming all new natural gas turbines must use CCS. It explores the impact of this assumption on resource selection, GHG emissions, and cost.

Methodology

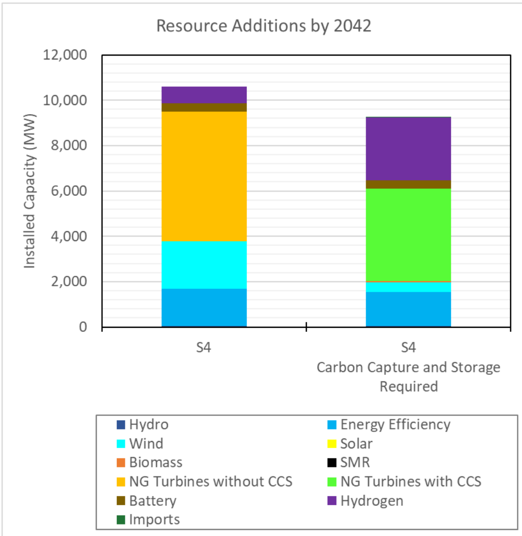
A sensitivity was created using scenario 4 by removing the option to select natural gas turbines without CCS from the model.

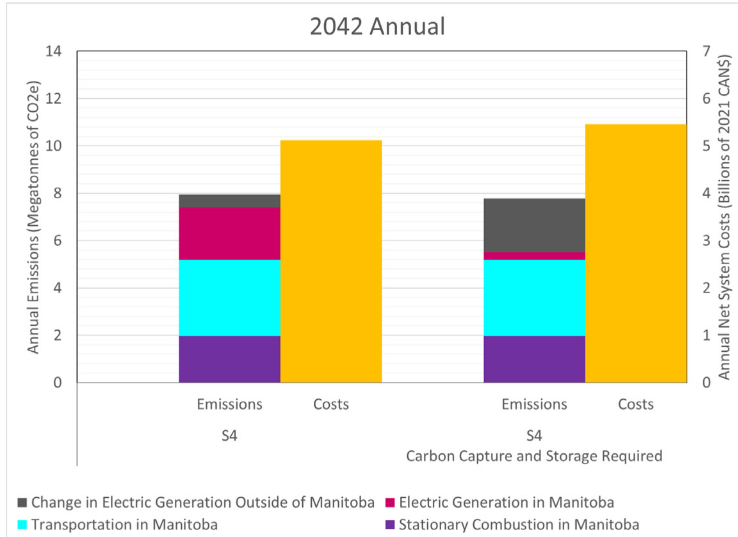
Results

When new natural gas turbines without CCS are not permitted and compared to scenario 4 a range of impacts result to the selection of resources. As shown in Figure A5.13a, there is 4,100 MW of natural gas turbines with CCS and an additional 2,000 MW of hydrogen turbines to replace 5,700 MW of natural gas turbines without CCS. The 4,100 MW of natural gas turbines with CCS produced 50% more energy in 2042 than the 5,700 MW of natural gas turbines without CCS. Natural gas turbines with CCS operated at a higher capacity factor than other thermal units due to reduced operating costs from reduced emission costs. There is 1,700 MW less wind, resulting in 80% less wind energy being produced. This is a result of the natural gas turbines with CCS having already been selected for capacity, being operating more often as an economical source of energy (Figure A5.13c).

Manitoba electricity generation GHG emissions, regional electricity generation GHG emissions, and provincial GHG emissions all decreased in 2042, driven by the 87% (2.2 Mt CO_2e) decrease in Manitoba electricity generation of GHG emissions shown in Figure A5.13b. However, electricity generation GHG emissions outside of Manitoba increased as Manitoba becomes a larger net importer of electricity, on average, under this sensitivity. Compared with the Restricted Use of Natural Gas Turbines sensitivity, regional electricity generation GHG emissions are higher throughout the study period. Therefore, the CCS sensitivity results in both higher regional electricity generation GHG emissions and higher costs than the Restricted Use of Natural Gas Turbines sensitivity.

The annual net system costs in 2042, shown in Figure A5.13b, increased by 7% ($0.3B) and the cumulative present value of net system costs to 2042 increased by 4% ($1.9B) (Figure A5.18). The higher net system cost occurs mainly because natural gas turbines with CCS and hydrogen turbines are more costly than natural gas turbines without CCS paired with wind generation.





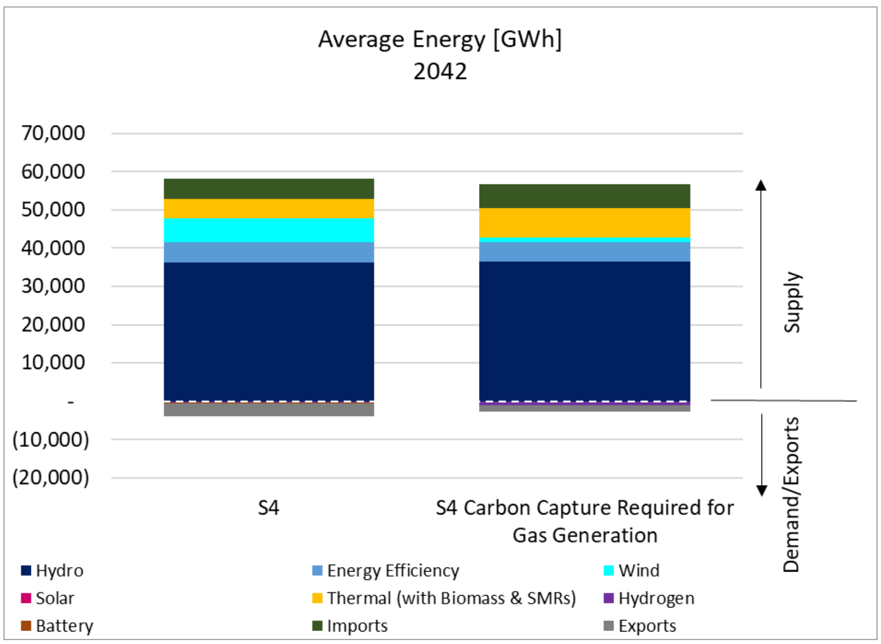


Figure A5.13a – Comparison of Resource Additions in 2042 for a CCS requirement for natural gas turbines
Figure A5.13b – Comparison of Manitoba Annual GHG emissions in 2042 and of annual net system costs in 2042, for a CCS requirement for natural gas turbines[6]
Figure A5.13c – Comparison of 2042 Supply Mix Average Energy for a CCS requirement for natural gas turbines.

[6] Manitoba GHG emissions shown do not include non-energy dependent sources (i.e., "other sources:), like agricultural and waste emissions.

No New Natural Gas Turbines

Objective

This sensitivity explores the impact on resource selection, GHG emissions, and costs of eliminating all new natural gas turbines from the resource options available for selection, with or without CCS.

Methodology

Sensitivities were created using scenarios 2, 3, and 4 by removing the option to select any form of new natural gas turbines. By removing all forms of natural gas turbines there are limited resource options remaining to provide firm winter capacity and as a result the model is highly constrained.

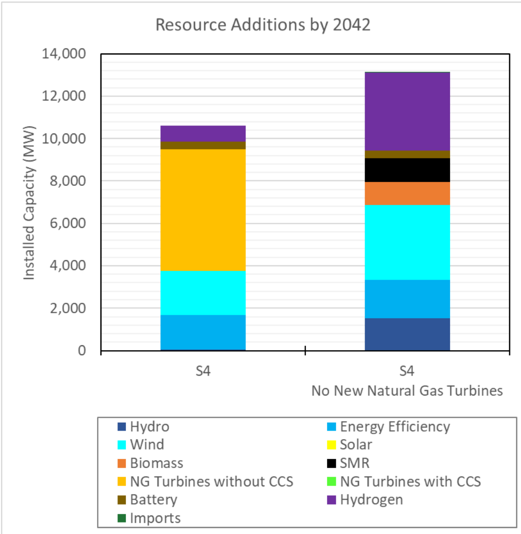
Results

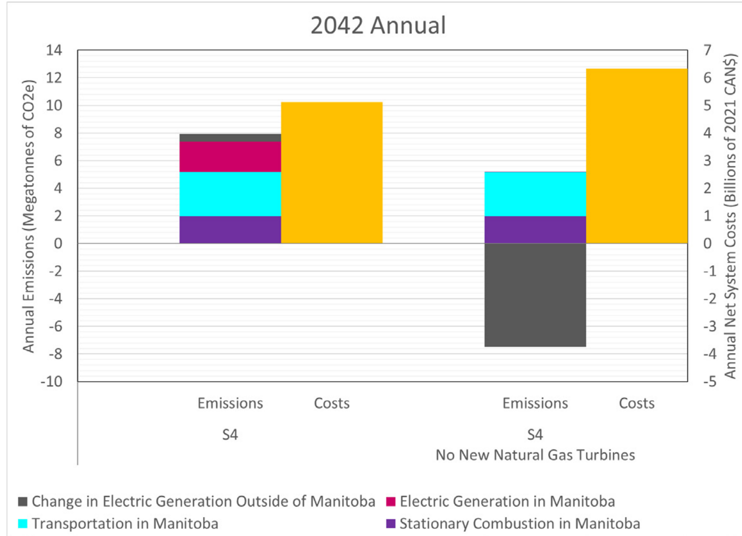
Removing all types of new natural gas turbines as resource options, results in a range of impacts that are common to scenarios 2, 3, and 4 (Figure A5.14). Natural gas turbines without CCS are replaced primarily by wind for energy and hydrogen turbines for capacity. Natural gas turbines without CCS are eliminated: 900 MW in scenario 2, 1,600 MW in scenario 3, and 5,700 MW in scenario 4. Wind increased by 2,000 MW in scenario 2, 2,500 MW in scenario 3, and 1,500 MW in scenario 4. Hydrogen turbines increased by 500 MW in scenario 2, 1,300 MW in scenario 3, and 2,900 MW in scenario 4.

In addition, the selection of battery storage and energy efficiency increased. With the addition of wind resources, exports increased by 80% in scenario 2, 120% in scenario 3, and 280% in scenario 4, however imports decreased by 50% in scenarios 2 and 3, and 80% in scenario 4 (Figure A5.14).

Removing new natural gas turbines as a resource option results in a range of impacts specific to scenario 4 that are shown in Figure A5.14. Scenario 4 with no new natural gas turbines was the only sensitivity where biomass (1,078 MW), SMRs (1,131 MW), and new hydropower (Conawapa 1,485 MW) were selected as resource options. Even with the strong demand for resources in scenario 4 the full potential of energy efficiency measures (Figure A5.5) was not selected. Utility scale solar PV continued to not be selected. Compared to scenario 4, there is a substantial increase in costs, a notable decrease in GHG emissions from electrical generation, and a reliance on technologies that are less mature.

In 2042, Manitoba electricity generation GHG emissions from new resources were eliminated and Manitoba and regional electricity generation GHG emissions decreased. The decrease in regional electricity generation emissions was due to increased exports, decreased imports (on average), and the reduction in Manitoba electricity generation emissions. The annual net system cost in 2042 (Figure A5.14) and the cumulative present value of net system costs to 2042 (Figure A5.18) increased less than 5% for scenarios 2 and 3, but increased 24% ($1.2B) and 8% ($4.5B) respectively for scenario 4.





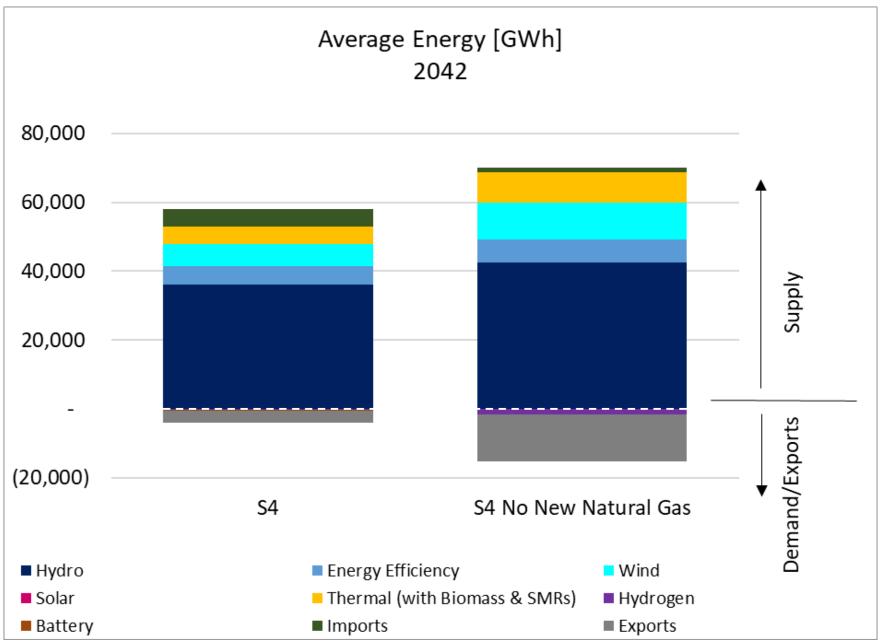


Figure A5.14a – Comparison of Resource Additions in 2042 for No New Natural Gas Turbines

Figure A5.14b – Comparison of Manitoba Annual GHG emissions in 2042 and of annual net system costs in 2042, for No New Natural Gas Turbines[7]

Figure A5.14c – Comparison of 2042 Supply Mix Average Energy for No New Natural Gas Turbines

[7] Manitoba GHG emissions shown do not include non-energy dependent sources (i.e., “other sources”), like agricultural and waste emissions.

GHG Emissions Budget

Objective

This sensitivity explores the impacts on resource selection, GHG emissions, and costs, of imposing an aggregated GHG emissions generation intensity limit (a “budget” or “cap”) on all provincial electricity generation.

Methodology

Sensitivities using an aggregated generation intensity constraint (in tCO_2e/GWh) were created by applying a GHG emissions budget (in tCO_2e) to scenarios 2, 3, and 4, equal to 25 tCO_2e/GWh multiplied by the scenario demand. Using emissions intensity, instead of a constant absolute emissions constraint across all scenarios, was chosen to both provide equity between scenarios due to the different demand assumptions and to match the approach of several federal regulatory efforts such as the Output-Based Pricing System and Clean Electricity Regulations (Appendix 6 – Policy Landscape). The 25 tCO_2e/GWh limit was selected using an iterative process, with the intent being to produce deeper GHG emission reductions than the Restricted Use of Natural Gas Turbines sensitivity while still providing some GHG emissions flexibility for the resource optimization model. The GHG emissions budget was applied by dividing the full study horizon into periods of time. In each period, the total GHG emissions budget was the sum of budgeted GHG emissions for each year in that period. The total provincial electricity generation GHG emissions volume in a period had to be less than that period’s budget amount, above which a prohibitive penalty cost was incurred. This approach allowed for modest control over the distribution of emissions over time, while still providing some flexibility for system expansion and operation optimization. The GHG emissions budget was applied to Manitoba’s electricity generation in all flow cases.

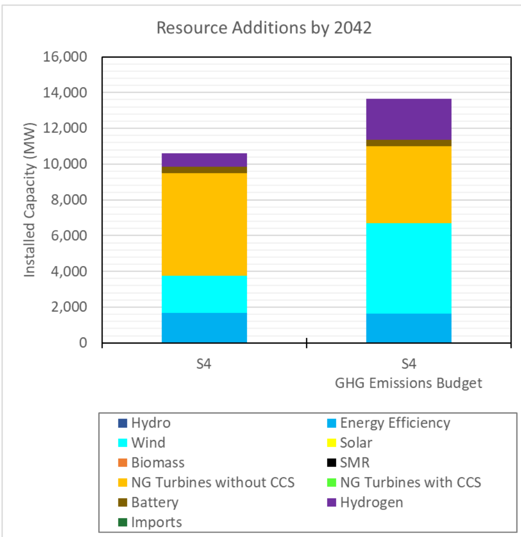
Results

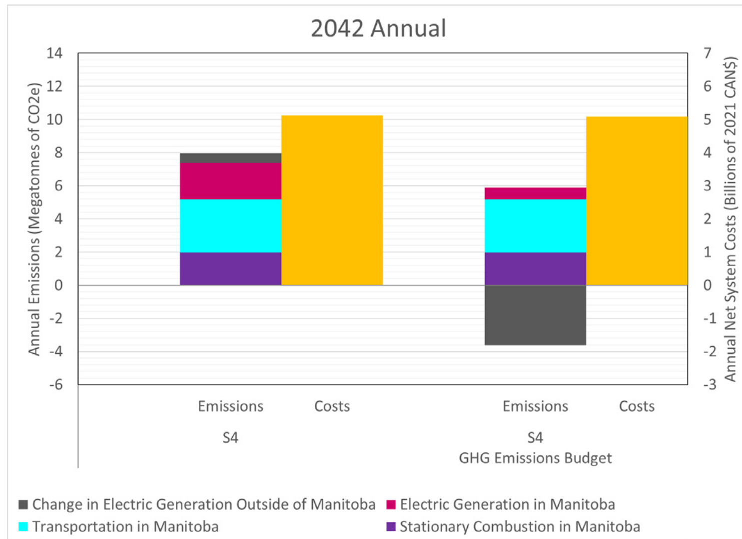
The GHG emissions budget constraint increased the amount of wind generation for scenarios 2, 3, and 4, resulting in increased exports and decreased imports in 2042 (see Figure A5.15c). In scenarios 2, 3, and 4 the energy generated from natural gas turbines without CCS decreased, even in scenario 3 where the installed capacity of natural gas turbines without CCS increased. The emissions budget allowed for flexibility in using natural gas turbines without CCS to provide firm capacity for winter peak demand.

Manitoba electricity generation GHG emissions, regional electricity generation GHG emissions, and provincial GHG emissions in 2042 decreased for scenario 4 because of the application of the emissions budget constraint. Manitoba electricity generation GHG emissions decreased by 70% (1.5 Mt of CO_2e) in scenario 4 reflecting the reduction in the operation of natural gas turbines without CCS. Scenario 2 and scenario 3 emissions already satisfied the GHG emissions budget constraint. However, Manitoba electricity generation GHG emissions decreased by 40% (0.1 Mt of CO_2e) in scenario 2 due to differences in the capacity expansion solution and remained unchanged in scenario 3. In scenarios 2 and 3 the regional electricity generation GHG emissions decreased due to the increase in net exports.

The assumed GHG emissions budget, which significantly reduced GHG emissions in scenario 4, had negligible impacts (between 0% and 1% increase) on the annual net system costs in 2042 and similarly on the cumulative present value of net system costs to 2042 for scenarios 2, 3, and 4. This demonstrates that a flexible GHG emissions budget can cost-effectively decrease substantial electrical generation emissions in high demand growth scenarios. Further analysis is required to determine whether more aggressive intensity constraints (e.g., 5 t/GWh or 15 t/GWh), which would result in even lower sectoral GHG emissions, would result in acceptable (i.e., cost-effective) increases in net system costs.

Results for scenario 4 have the most notable changes and are shown in Figure A5.15. As previous discussed, scenarios 2 and 3 already satisfied the emissions budget so the results are not show in the figure.





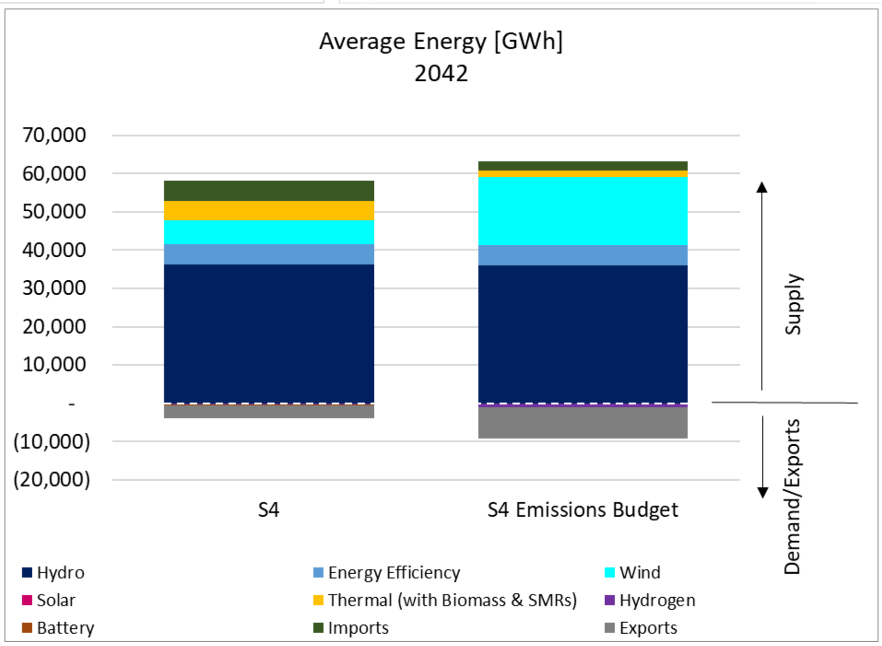


Figure A5.15a – Comparison of Resource Additions in 2042 for a GHG Emissions Budget
Figure A5.15b – Comparison of Manitoba Annual GHG emissions in 2042 and of annual net system costs in 2042, for a GHG Emissions Budget[8]
Figure A5.15c – Comparison of 2042 Supply Mix Average Energy for a GHG Emissions Budget.

[8] Manitoba GHG emissions shown do not include non-energy dependent sources (i.e., “other sources:), like agricultural and waste emissions.

High GHG Emissions Cost

Objective

This sensitivity explores the impact on selection of resources, GHG emissions, and costs of applying costs to electricity generation GHG emissions at a higher rate than was included in the scenario analysis.

Methodology

GHG emission costs in scenario 4 assumes that the carbon price on electricity generation GHG emissions reaches \$170/tCO_2e nominal by 2030 and then stays constant in real dollar terms thereafter. In the high GHG emissions cost sensitivity, the carbon price on electricity generation emissions reaches \$170/tCO_2e nominal by 2030 and then increases by \$5/tCO_2e real each year. In nominal dollars, the average annual increase from 2031 to 2042 was \$12/tCO_2e, comparable to the \$15/tCO_2e price increases projected for the pre-2031 period. This is shown in Figure A5.16.

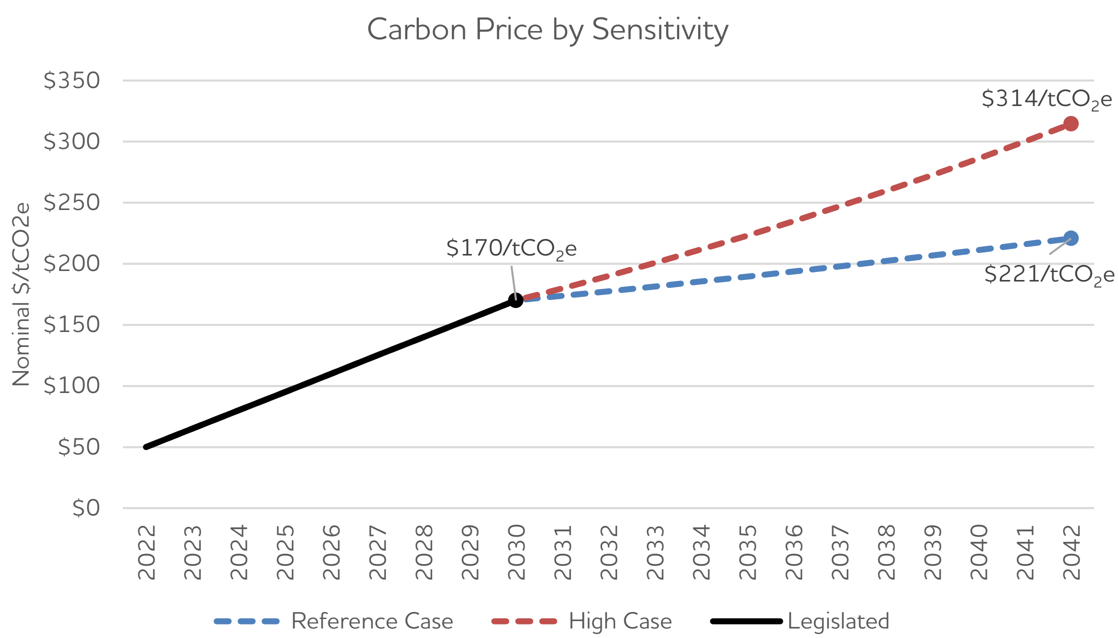


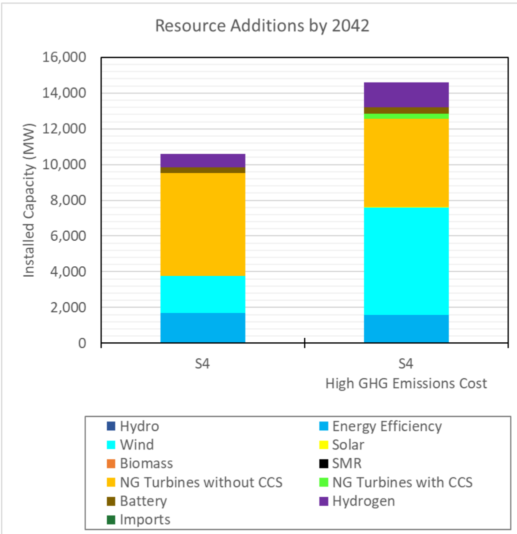
Figure A5.16 – Carbon Price by Sensitivity

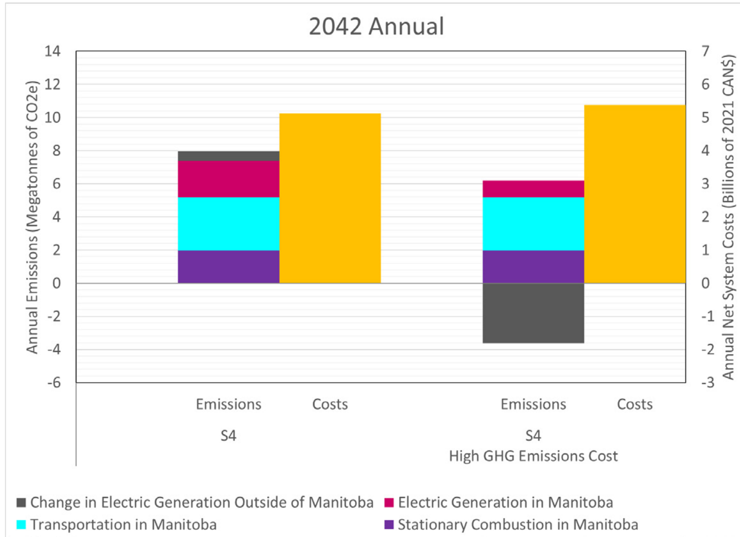
Results

The resource mix for this sensitivity was similar to scenario 4 up to 2030. After 2030, as the GHG emissions cost increased, the amount of wind, hydrogen fueled turbines, and natural gas turbines with CCS increased because these resources become more cost effective than building and operating natural gas turbines without CCS. By 2042, natural gas turbines without CCS decreased by 800 MW and natural gas turbines with CCS increased by 300 MW. Wind generation increased by 3,900 MW and hydrogen turbines increased by 600 MW, as shown in Figure A5.17a.

Manitoba electricity generation, regional electricity generation, and provincial GHG emissions in 2042 all decreased driven by increased exports, decreased imports, and a decrease of 54% (1.2 MT CO_2e) of Manitoba electricity generation emissions shown in Figure A5.17b. Because the GHG price increase is gradual (compared with the scenario case), on a cumulative basis, this sensitivity was less effective at reducing GHG emissions than other natural gas turbine sensitivities. The majority of emission reductions occur in the final years of the study period.

The annual net system costs in 2042 increased by 5% ($0.3B), as shown in Figure A5.17b, and the cumulative present value of net system costs to 2042 increased by 1% ($0.7B).





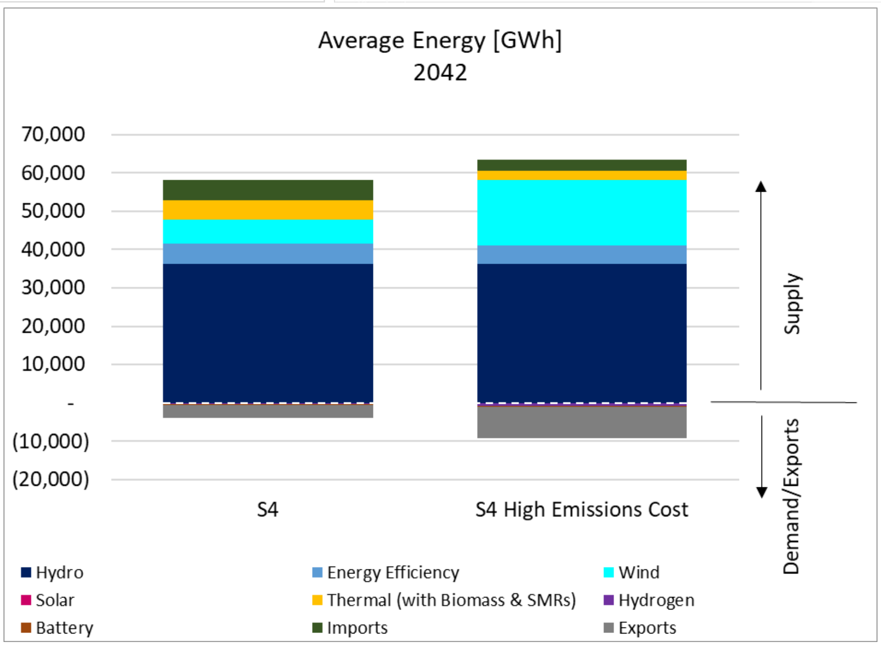


Figure A5.17a– Comparison of Resource Additions in 2042 for High GHG Emissions Cost
Figure A5.17b – Comparison of Manitoba Annual GHG emissions in 2042 and of annual net system costs in 2042, for High GHG Emissions Cost[9]
Figure A5.17c – Comparison of 2042 Supply Mix Average Energy for High GHG Emissions Cost

[9] Manitoba GHG emissions shown do not include non-energy dependent sources (i.e., "other sources:), like agricultural and waste emissions.

Summary From Natural Gas Turbine Sensitivities

Restricting the types and use of new natural gas turbines in the Manitoba Hydro system reduces GHG emissions but increases Manitoba Hydro's costs. The sensitivities show that Manitoba's electrical generation GHG emissions could be reduced through restricted use of natural gas turbines, the use of carbon capture and storage technology, or a prohibition on new natural gas turbines, but it would cost more to achieve these lower GHG emissions. A restriction that allows for some use of natural gas turbines without CCS (e.g., the GHG Emission Budget Sensitivity) is more cost effective at reducing emissions than prohibiting the use of natural gas turbines without CCS.

Figure A5.18 shows the cumulative present value of net system costs to 2042 for the scenarios and the natural gas turbine sensitivities. The incremental cumulative present value of net system costs to 2042 above the fixed system costs ranges from $12B for scenario 1 to $22B for scenario 4. The natural gas turbine sensitivities increase's this range to $27B, with the largest incremental costs associated with the No New Natural Gas Generation sensitivity.

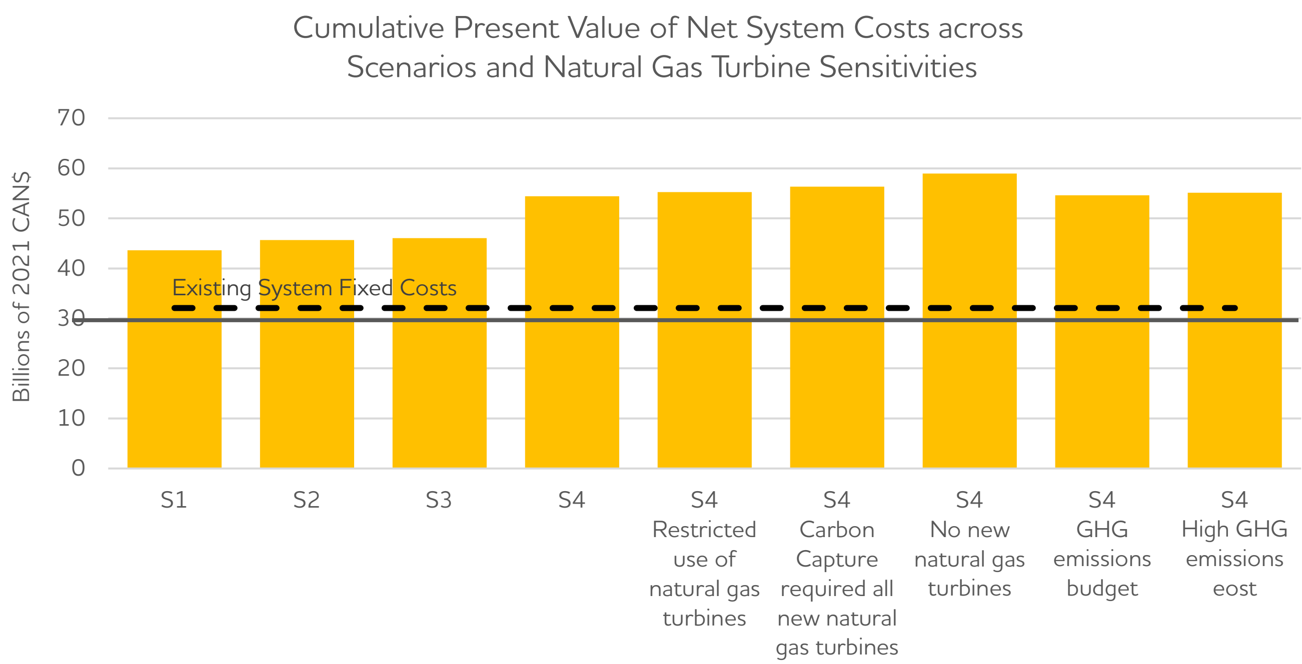


Figure A5.18 – Cumulative costs for scenarios and natural gas turbine sensitivities

Comparing the incremental cost per GHG emission reduction ($/t$CO_2$e reduced) cumulative metrics shown in Table A5.5 and Table A5.6 illustrates how less flexible (e.g., restrictions on the use of specific technologies such as natural gas turbines) and/or more stringent (i.e., deeper reductions in absolute GHG emissions) restrictions on electrical generation result in higher $/t$CO_2$e reduced in Manitoba's electrical generation sector. For example, the GHG Emissions Budget sensitivity results in a cost of avoided emissions of $80/t$CO_2$e relative to scenario 4, while the No New Natural Gas Turbines sensitivity results in a cost of avoided emissions of $688/t$CO_2$e relative to the Carbon Capture & Storage sensitivity. A flexible restriction on electrical generation emissions that allows for the use of natural gas turbines to meet peak demand would likely be a cost-effective way to reduce Manitoba's overall GHG emissions. A flexible regulation would also help avoid unwanted outcomes such as a relative increase in regional electrical generation GHG emissions resulting from employing a CCS strategy with less wind and less exports as seen in the CCS sensitivity.

Summary comparison charts of the different resources selected as well as the emissions and costs for the different Natural gas turbine sensitivities are shown in Figure A5.19 and Figure A5.20.

Table A5.5 – Natural Gas Turbine Sensitivities Compared to Scenario 4

Scenario 4 Natural Gas Turbine Sensitivities	Incremental MB Electricity Generation GHG Emissions Compared to Scenario 4	
	$/tCO_2e$ Reduced (2022-2042 Cumulative)	CO_2e Reduced (2022-2042 Cumulative)
GHG Emissions Budget	$80	7.7 Mt
Restricted Use of Gas Turbines	$162	9.8 Mt
Carbon Capture & Storage	$197	18.0 Mt
No New Natural Gas Turbines	$425	19.6 Mt

Table A5.6 – Natural Gas Turbine Sensitivities Compared to Restricted Use of Natural Gas Turbines

Scenario 4 Natural Gas Turbine Sensitivities	Incremental MB Electricity Generation GHG Emissions Compared to Restricted Use of Natural Gas Turbines	
	$/tCO_2e$ Reduced (2022-2042 Cumulative)	CO_2e Reduced (2022-2042 Cumulative)
Carbon Capture & Storage	$237	8.2 Mt
No New Natural Gas Turbines	$688	9.8 Mt

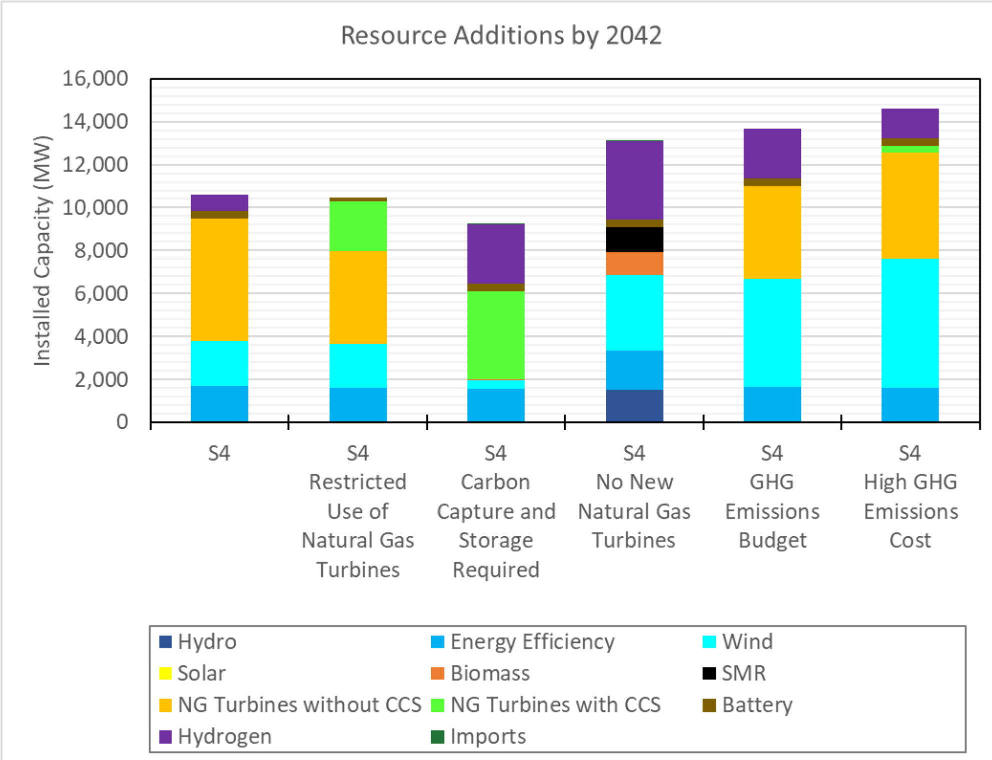


Figure A5.19 – Resource Additions by 2042 for Natural Gas Turbine Sensitivities

Figure A5.20 – Emissions[10] and Costs for Natural Gas Turbine Sensitivities

[10] Manitoba GHG emissions shown do not include non-energy dependent sources (i.e., “other sources:), like agricultural and waste emissions.

3.3 Demand Side Sensitivities

Introduction

Various sensitivity analyses were undertaken to explore the impact of different demand side measures. The areas of focus include:

- Demand Response
- Dual Fuel for Heating
- Optimization of Energy Efficiency
- Ground Source and Air Source Heat Pumps
- Lower Customer Incentive Level for Energy Efficiency
- Distributed Solar PV

Demand Response

Objective

This sensitivity explored the impacts of demand response programs that reduce winter peak demand to determine if there is economic potential to further explore developing DR programs in Manitoba.

Examples of demand response programs include:

- Residential Direct Load Control (e.g., EV Smart Charger Control, WiFi thermostat)
- Commercial/Industrial Interruptible Rates & Manual Curtailment
- Dynamic Rates

Methodology

In all four scenarios, electric load was modified to reflect demand response programs that reduce winter peak demand. Demand response programs reduced winter peak demand in the months of December, January, and February by flattening the demand profile. A simplifying assumption is that the total annual energy requirements would remain unchanged, recognizing that some larger, higher capacity factor loads would likely experience a reduction in energy consumed when the load is curtailed. Due to the relatively small scale of potential demand response programs identified and their interactive effects, load modification was selected over optimizing demand response as a selectable resource. This allowed the model to optimize around the assumed maximum potential peak demand reduction for demand response, providing visible results on the impact of demand response on Manitoba Hydro's system, future resource selection, and cost. Further, modelling individual demand response programs would obscure the evaluation of demand response as a resource option as each program is relatively small in comparison to the magnitude of the supply and demand optimization problem. Resource selection outcomes for such small options may not be meaningful at the model's resolution. Including individual programs would also fail to capture interactive effects between programs. Figure A5.21 shows an example of how the peak demand was flattened with demand response measures by moving the demand for energy from a high demand period to a low demand period.

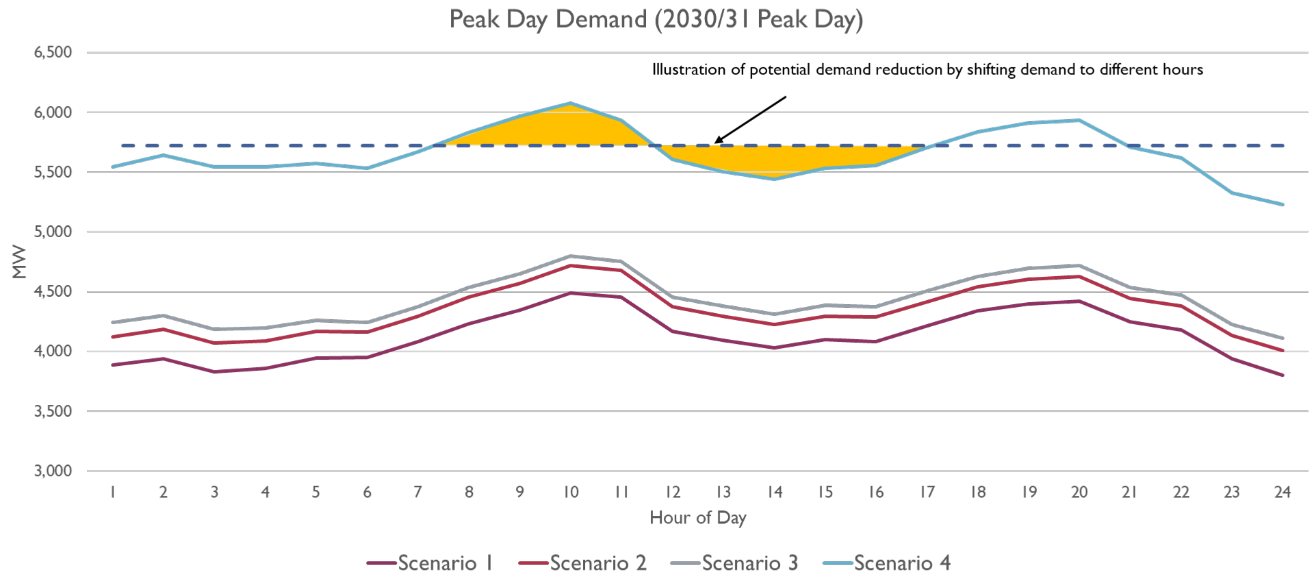


Figure A5.21 – Illustration of Demand Response Load Shifting

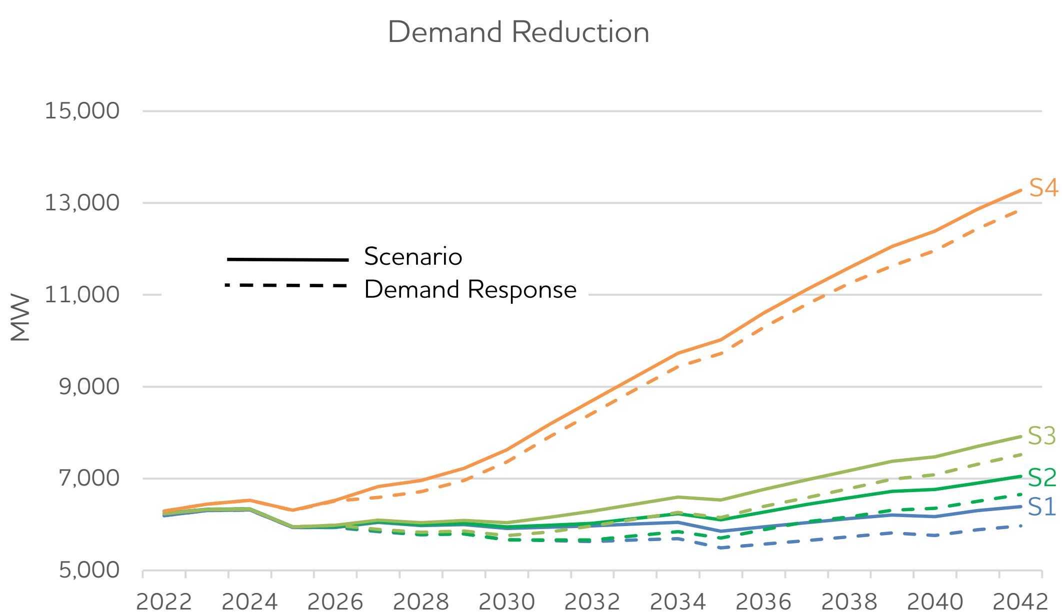


Figure A5.22 – Peak Day Demand Reduction

The analysis leveraged the results of a market potential study conducted by a consultant. For industrial demand response, the existing Curtailable Rate Program at 162 MW was extended throughout the study period to represent an enhanced and expanded program with more participants contributing to the overall demand reduction. Demand response for other customer load shapes were established and limitations on hourly reduction were identified based on the demand projections for each scenario. There were three DR load shapes studied and applied in the sensitivity analysis, which were 2023-2033, 2033-2036, and after 2036 as load shapes changed over these periods. To ensure demand response options were aligned with supply side decisions, the timing of demand response resources was aligned with the first need for new capacity resources in each scenario. The annual impact of the load modification to each of the scenarios is shown in Figure A5.22.

Results

The following general comments can be made when comparing each sensitivity back to its scenario case. Demand response was introduced as a load modification and is relatively small in comparison to the overall growth in most scenarios., The resulting detailed resource selection outcome is not as material as the impact to the timing of required investment in capacity resources and the overall reduction in need, which is summarized in the table below. Overall, demand response reduced the need for new capacity resources such as natural gas turbines, hydrogen turbines, and batteries.

Table A5.7 – Demand Response Impacts on Scenarios

Scenario	Scenario Winter Capacity Need Date	DR Sensitivity Winter Capacity Need Date	Change in MW need in 2042
Scenario 1	2037	2042	419
Scenario 2	2032	2037	394
Scenario 3	2030	2033	395
Scenario 4	2025	2025	425

The regional electricity generation GHG emissions impacts for each scenario are difficult to attribute completely to demand response, given the resolution of the model and the magnitude of demand response savings. In general, GHG emissions were reduced, but these reductions may be partly attributable to different model optimization pathways taken while attempting to solve for the lowest cost portfolio of resources, and not solely to demand response. The main modelling outcome is that if GHG emitting technology is selected in a base plan, demand response defers the need for these resources and the timing of their emissions. The resolution of the model in relation to the magnitude of demand response savings does not support meaningful conclusions about changes to the operation and emissions from those deferred resources. If comparison to a base plan with no new natural gas generation was explored, demand response would have no GHG emissions impact.

The analysis showed that demand response may be cost effective, and demand response programs have the most value in scenario 4 where demand is higher. For scenarios 1, 2 and 3 the change in cumulative present value of net system costs to 2042 is less than 0.5%. For scenario 4, the cumulative present value of net system costs to 2042 decreased by 1.3% ($0.7B). For scenario 4, the present value of the demand response program costs to 2042 was $0.3B, resulting in a net present value of the demand response program of $0.4B. Due to the potential that some of these benefits may be attributed to changes in the capacity expansion solution, and not attributable to demand response alone, additional study is required to isolate the benefit of demand response.

Dual Fuel for Heating

Objective

The scenario results have shown that electrification of space heating would have a substantial impact on peak demand during the winter heating season. Significant investment in new generation, transmission, and distribution infrastructure would be required to meet this large increase in peak demand. A dual fuel heating concept was explored as a potential means of reducing the winter peak demand to mitigate the financial impact of full electrification of space heating.

Dual fuel heating systems use electric air source heat pumps (ASHP) to heat and cool buildings when the outside air temperature is above the ASHP minimum operating temperature of the equipment. Typical ASHP equipment operate to a minimum temperature of -10°C while ASHPs designed for colder temperatures can operate to a minimum temperature of -20°C. This approach to heating buildings uses natural gas furnaces to heat when the outside air temperature is below the ASHP minimum operating temperature. On cold days the natural gas furnace is used for heating and the heat pump is turned off. This avoids electric resistance heating during peak demand on the coldest days which can reduce the need to construct new generation, transmission, and distribution assets to support winter peak demand.

Methodology

Scenario 4 assumes that most customers switch from natural gas furnaces to electric resistance heating. The sensitivity of scenario 4 with dual fuel assumes that most customers keep their natural gas furnaces and install ASHPs when their conventional air conditioners reach end of life and that new buildings with natural gas service install ASHP systems. The cost of the ASHPs is included in the calculation of the net system cost. Separate demand projections were created for conventional ASHPs operated down to an outside air temperature of -10°C and cold climate ASHPs operated down to -20°C. The required generation resources were then optimized around the new demand projections.

Figure A5.23 shows the resulting reduction in peak demand when a dual fuel system is implemented for scenario 4 for switchovers at two different temperatures. The peak demand with scenario 4 is high as customers replace their natural gas furnaces with electric resistance heating. If customers used a dual fuel system that uses electricity when the outside air temperature is above -20°C and natural gas heat below, then the peak electrical demand will drop as shown in Figure A5.23. If the switchover from electric to natural gas occurs at -10°C, there will be even fewer periods when a customer is using electric heat which results in a further drop in peak electric demand. The figure illustrates the impact to electricity consumption as a result of changing assumptions from all electric space heating in scenario 4, to the two dual fuel sensitivities.

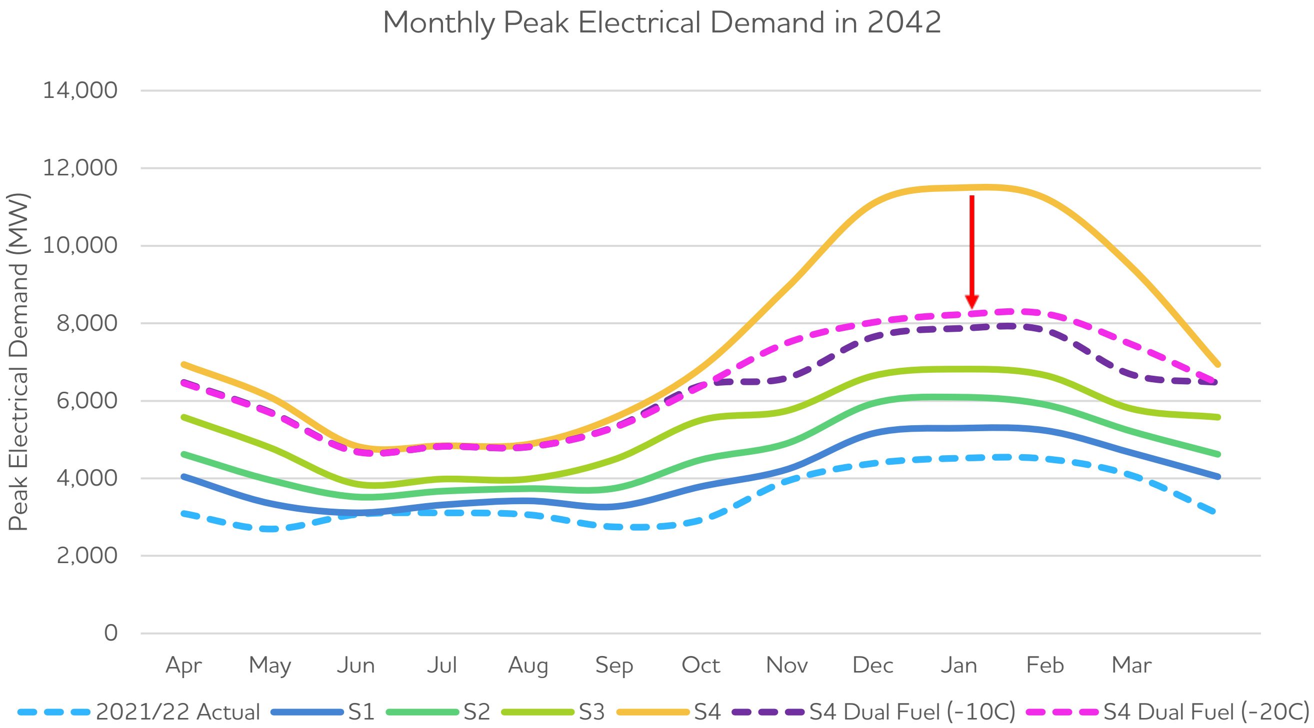


Figure A5.23 – Peak Monthly Electric Demand in 2042

Results

Dual Fuel sensitivities of scenario 4 show a range of impacts. Dual fuel heating in place of electric resistance heating reduces the need for new capacity resources by 45% (4,770 MW) in the case of the -10°C sensitivity and by 38% (3,980 MW) in the case of the -20°C sensitivity as shown in Figure A5.24.

The annual net system costs, including the incremental cost of the air source heat pumps, by 2042 for the combined electrical and natural gas systems are lower by 19% ($0.9B) in the case of the -10°C sensitivity and 7% ($0.3B) in the case of the -20°C sensitivity as shown in Figure A5.25. The cumulative present value of net system costs to 2042 are lower by 8% ($4.4B) in the case of the -10°C sensitivity and 1% ($0.8B) in the case of the -20°C sensitivity.

Dual-fuel heating would increase provincial stationary combustion (excluding electricity generation) GHG emissions relative to scenario 4 assumptions; however, these increases would be offset by decreases in provincial electrical generation emissions, resulting in comparable levels of provincial GHG emissions. This is shown is Figure A5.25 with the scenario and the two sensitivities resulting in similar levels of GHG emissions in the range of 7.4 Mt.

There are little financial and GHG emission reduction benefits using air source heat pumps that operate at a -20°C compared to systems that operate at -10°C, as shown in Figure A5.25. Dual-fuel heating delays the earliest need for new capacity resources in scenario 4 from 2025 to 2027 for both dual-fuel sensitivities.

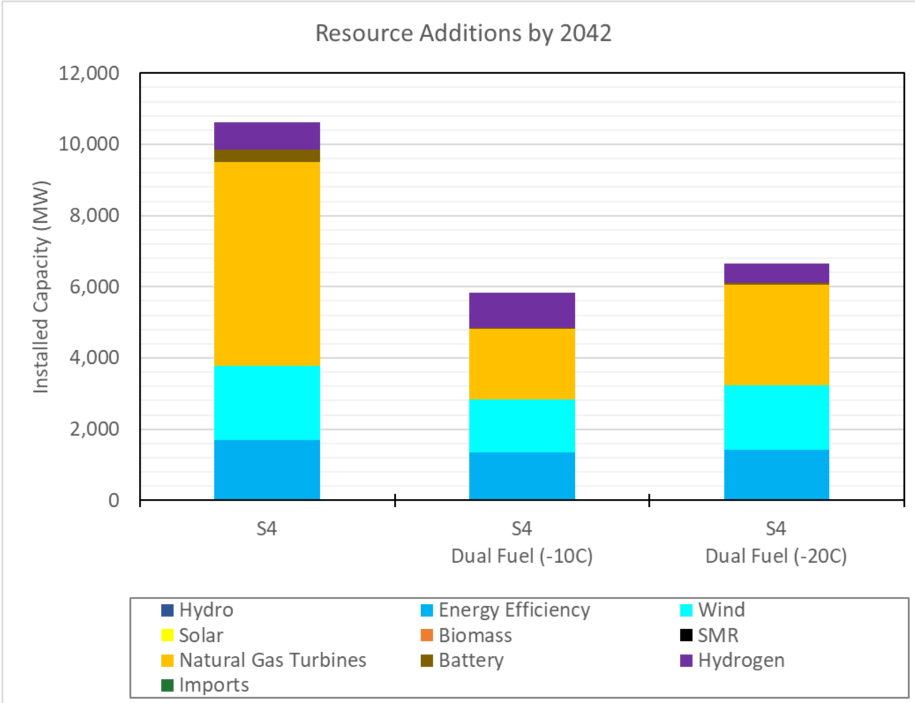


Figure A5.24 – Resource Additions by 2042 for Dual Fuel Sensitivities

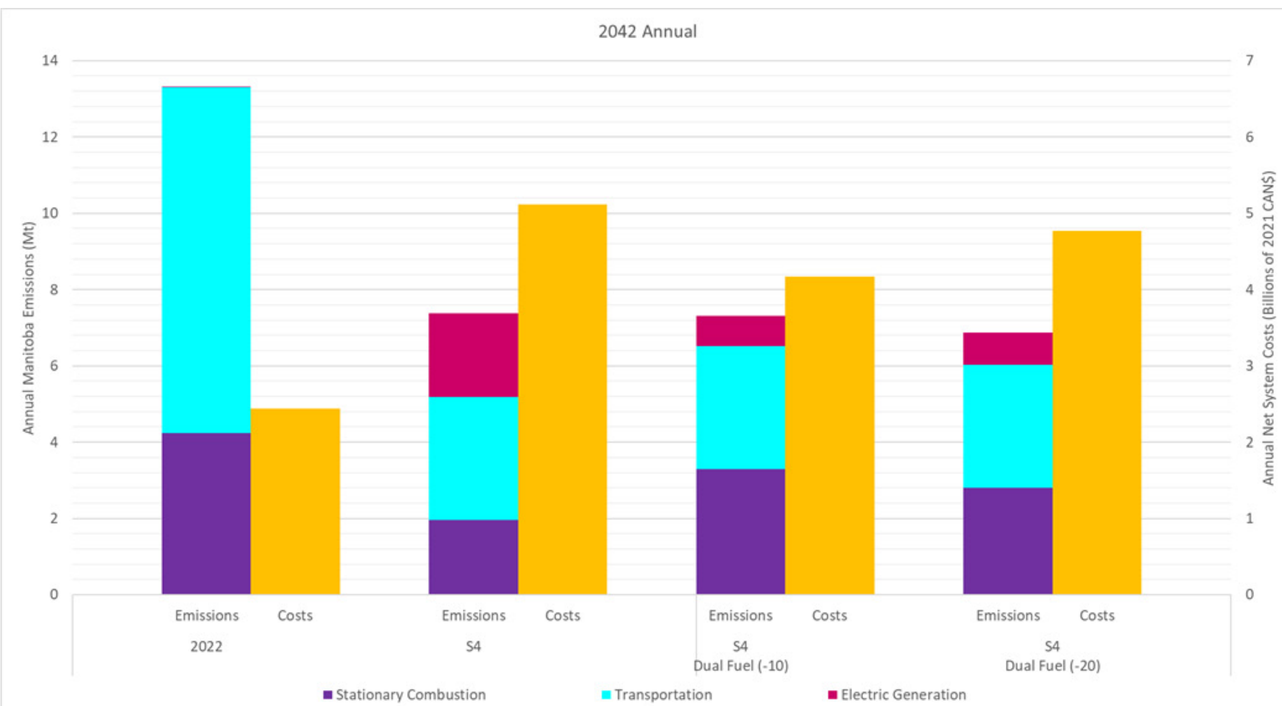


Figure A5.25 – Annual Emissions and Costs in 2042[11]

[11] Manitoba GHG emissions shown do not include non-energy dependent sources (i.e., "other sources:), like agricultural and waste emissions.

Optimization of Energy Efficiency

Objective

This sensitivity aims to explore changes to the generation supply resource mix for alternative approaches to energy efficiency modelling. These include Full Optimization of Energy Efficiency Potential and Full Development of Energy Efficiency Potential.

Methodology

The scenario analysis in the first section of this appendix assumes that energy and demand savings resulting from the Efficiency Manitoba Plan is achieved and that only the remaining energy savings potential is available to be selected for optimization relative to new generation options (see the energy efficiency section under Scenario Analysis). In this sensitivity analysis, the Efficiency Manitoba Plan savings are excluded as a resource option.

Full Optimization of Energy Efficiency was investigated by including the Maximized Level of energy efficiency savings potential as a selectable resource option using a similar approach to other supply options. Full Development of Energy Efficiency was investigated by assuming all Maximized Level of energy efficiency savings potential is achieved by including energy efficiency as a resource in the IRP scenarios. This sensitivity analysis assumes all energy efficiency is selectable and excludes the Efficiency Manitoba Plan energy savings.

The Maximized level of market potential energy and capacity savings for the energy efficiency groupings are presented in Table A5.8 and Table A5.9 respectively.

The modelling and analysis of the IRP scenarios assumed the cost and peak demand savings for the efficiency plan provided by Efficiency Manitoba extrapolated to 20 years. As the efficiency plan and the selectable energy efficiency groups included in the model are based on different assumptions it was necessary to adjust the cost and peak demand savings so that they are based on similar assumptions in order to compare the results of the scenarios to the sensitivities. Scenarios noted with an asterisk (*) in the figures include the adjustment.

Table A5.8 – Energy Efficiency Main Groupings – Maximized Level Market Potential Energy Savings (GWh) by 2042

Grouping		Scenario 1,2,3	Scenario 4
EE-M1	Commercial Lighting	342	362
EE-M2	Commercial Uniform Load	815	1,512
EE-M3	Non-Residential Heating & Cooling	289	395
EE-M4	Industrial Custom	1,363	1,363
EE-M5	Non-Commercial Lighting	147	201
EE-M6	Residential Heating and Cooling	186	246
EE-M7	Non-Commercial Uniform Load	1,563	1,894
	Total	**4,705**	**5,973**

Table A5.9 – Energy Efficiency Main Groupings – Maximized Level Market Potential Capacity Savings (MW) by 2042

Grouping		Scenario 1,2,3	Scenario 4
EE-M1	Commercial Lighting	58	48
EE-M2	Commercial Uniform Load	104	193
EE-M3	Non-Residential Heating & Cooling	116	163
EE-M4	Industrial Custom	174	174
EE-M5	Non-Commercial Lighting	25	27
EE-M6	Residential Heating and Cooling	75	102
EE-M7	Non-Commercial Uniform Load	200	242
	Total	**752**	**950**

Results

By 2042, the Fully Optimized energy efficiency sensitivity runs provide 430 MW, 508 MW and 571 MW of firm capacity which is 25%, 12% and 26% less than the energy efficiency firm capacity in scenarios 2, 3, 4 respectively as shown in Figure A5.26. For scenario 1 there is a 32% increase in firm capacity from energy efficiency because the resource mix for this sensitivity includes fewer natural gas turbines and more hydrogen turbines paired with energy resources consisting of wind generation and energy efficiency along with higher export prices relative to the other scenarios. The reduction in the energy efficiency drives the addition of other new energy resources and capacity resources in the supply mix. Scenarios 2, 3 and 4 include more capacity resources including natural gas turbines, battery, and hydrogen turbines with amounts varying for each scenario. In addition to capacity resources, more wind energy is selected for scenario 1 which is driven by higher export prices and lower load growth resulting in increased surplus energy and exports to neighbouring markets.

For the sensitivity analysis with the Fully Developed energy efficiency potential, there is a reduction of 496 MW or less natural gas turbine capacity included in the resource mix by 2042 relative to the scenarios. Similarly, up to 634 MW less natural gas turbine capacity is included in the resource mix by 2042 relative to the Fully Optimized resource mix.

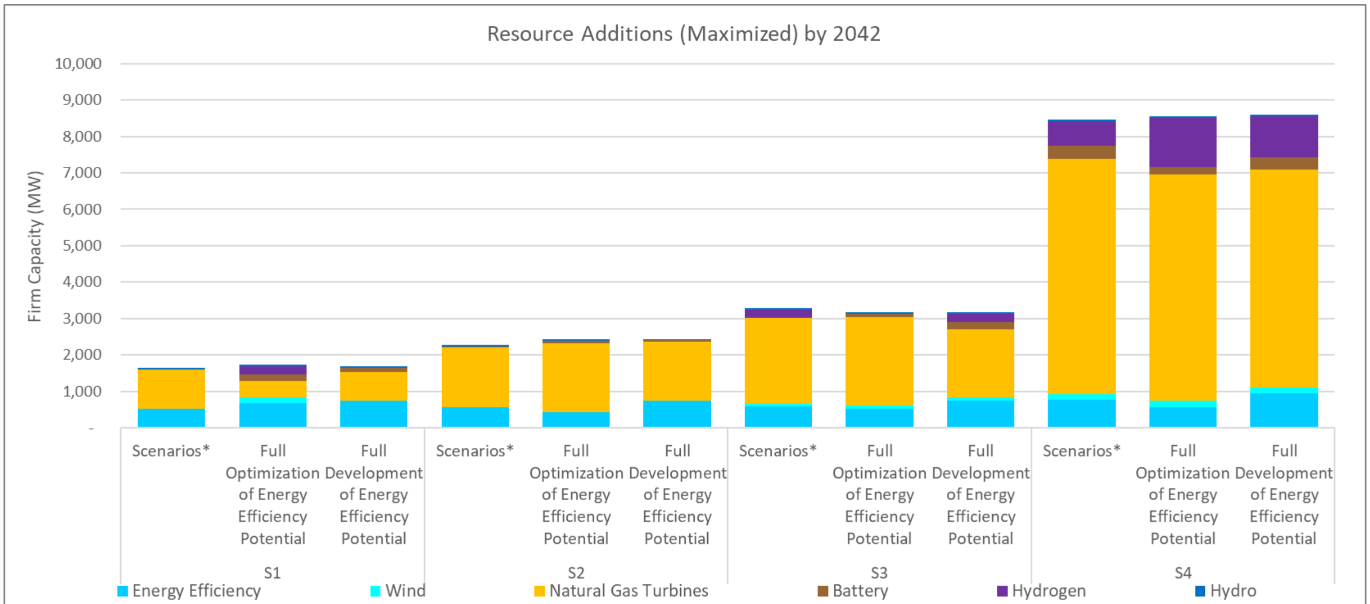


Figure A5.26 – Resource Additions - Full Optimization and Full Development of Energy Efficiency Measures

Figure A5.27 illustrates which of the energy efficiency savings potential for each of the main groupings are selected for the IRP scenarios and for the Fully Optimized sensitivity cases. The energy efficiency main groupings that are selected most include Residential and Non-Residential Heating and Cooling, Commercial Uniform Load, and Industrial Custom; suggesting they are more cost effective than the other main groupings. The energy efficiency main groups that are selected least are Non-Commercial Uniform Load, Commercial Lighting and Non-Commercial Lighting main groupings. The Lighting groupings are fully developed in the Efficiency Manitoba Plan while the Fully Optimized sensitivity cases developed approximately 50% to 75%. Table A5.10 provides example measures within each of these groupings.

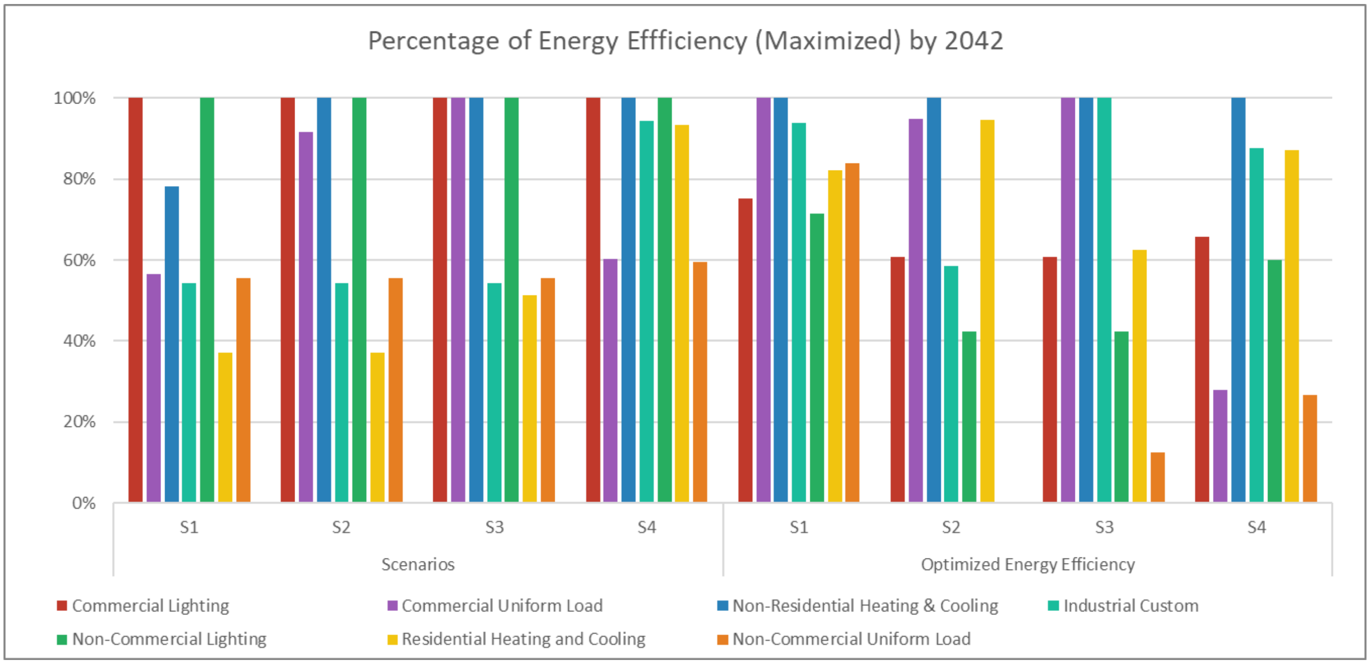


Figure A5.27 – Percentage of Energy Efficiency Savings Potential Selected (MW) - Comparing Scenarios and Full Optimization of Energy Efficiency

Table A5.10 – Example Energy Efficiency Measures

Groupings	Example Energy Efficiency Measures
Lighting	LED lighting, lighting controls
Heating and Cooling	Efficient windows, attic insulation, basement insulation, air sealing, building shell improvements, efficient windows
Industrial Custom	Reducing electricity used in industrial applications
Commercial Uniform Load	Custom compressed air, energy management systems, custom refrigeration
Non-Commercial Uniform Load	Advanced power strips, custom compressed air, energy management systems

As shown in Figure A5.28, the cumulative present value of total energy efficiency costs for the Fully Optimized energy efficiency sensitivities are 27% to 72% lower than the adjusted present value of costs of the total energy efficiency savings for the IRP scenarios (see Methodology section above for explanation of cost adjustment). The difference between the present value of costs of the energy efficiency savings in isolation between the Fully Developed energy efficiency sensitivity case and the scenarios is 14% or lower for all the scenarios.

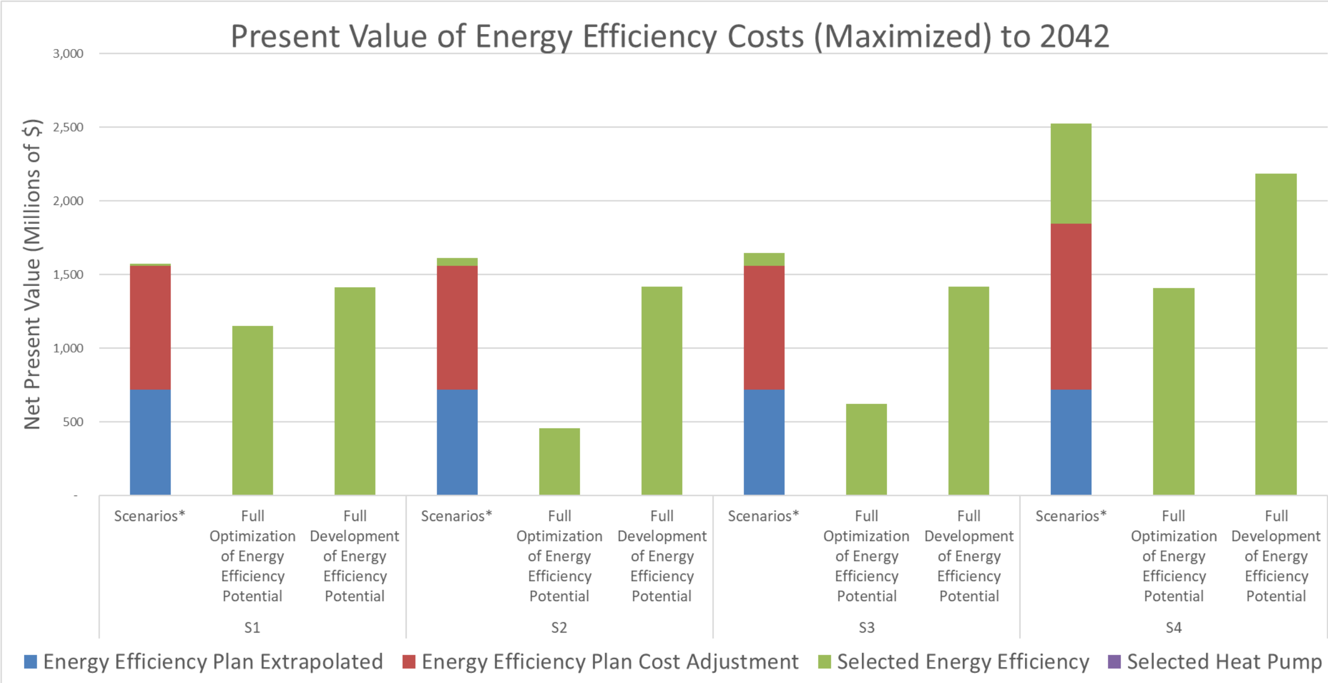


Figure A5.28 – Present Value of Energy Efficiency Costs to 2042

The cumulative present value of net system costs to 2042 are within 0.5% ($200M) when comparing the Fully Optimized and Fully Developed energy savings sensitivities to the scenario results (Figure A5.29) indicating there is relatively little economic difference when fully optimizing or fully developing the energy efficiency savings. Due to the potential that differences in the costs and benefits may be due to differences in the capacity expansion solution, and not attributable to the energy efficiency savings alone, additional study is required to isolate the cost and value impact of energy efficiency savings.

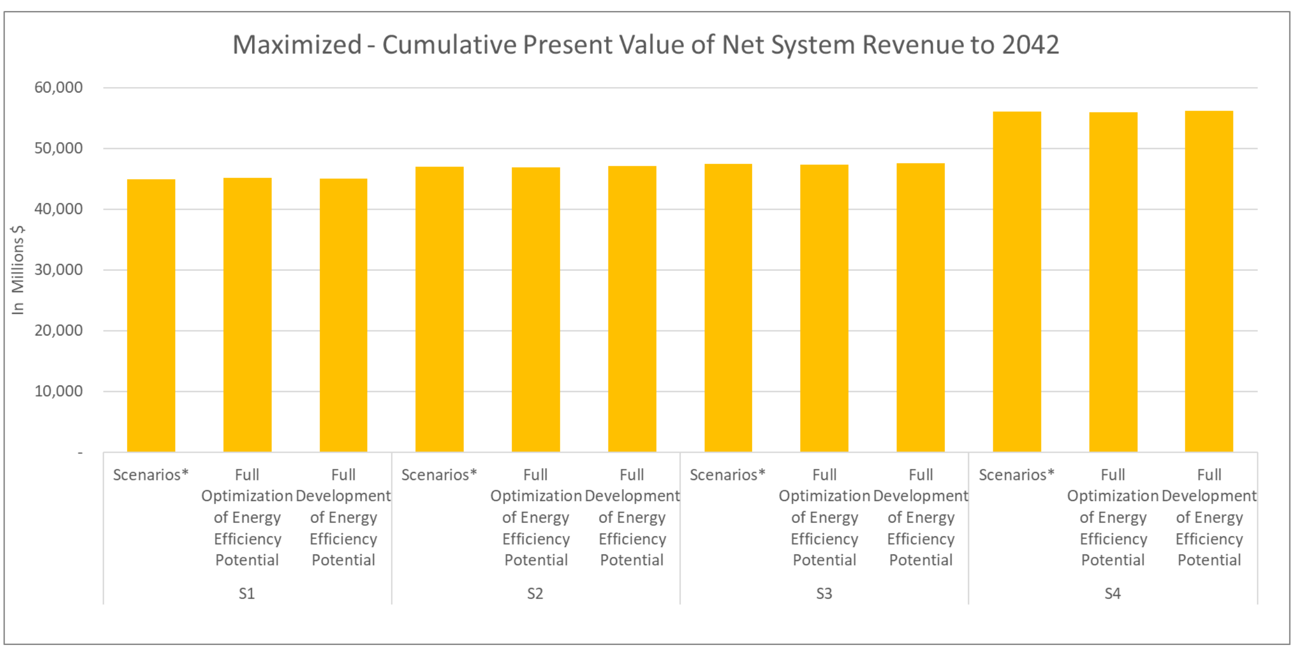


Figure A5.29 – Present Value of Cumulative Net Present Energy Efficiency Costs to 2042

Ground Source & Air Source Heat Pumps

Objective

Ground source heat pumps (GSHP) and air source heat pumps (ASHP) provide a means for reducing the demand for electricity compared to electric resistance heat. This sensitivity analysis was undertaken to explore the cost effectiveness and value of heat pumps for reducing electricity consumption in the IRP scenarios.

Methodology

This sensitivity analysis uses the same methodology outlined in the Optimization of Energy Efficiency sensitivity section with the addition of Heat Pumps as selectable resource options using a similar approach to other supply options energy savings groupings. The Maximized level of market potential energy and capacity savings for the heat pump groupings are presented in Table A5.11 and Table A5.12 respectively.

Table A5.11 – Heat Pump Groupings – Maximized Level Market Potential Energy Savings (GWh) by 2042

Grouping		Scenario 1, 2, 3	Scenario 4
EE-HP1	ASHP Agricultural Industrial	174	44
EE-HP2	ASHP Other	149	628
EE-HP3	ASHP Commercial	175	250
EE-HP4	ccASHP Agricultural Industrial Commercial	132	46
EE-HP5	ccASHP Other	186	447
EE-HP6	GSHP Agricultural Industrial	96	112
EE-HP7	GSHP Commercial	506	623
EE-HP8	GSHP Other	454	865
	Total	**1,872**	**3,015**

Table A5.12 – Heat Pump Groupings – Maximized Level Market Potential Capacity Savings (MW) by 2042

Grouping		Scenario 1, 2, 3	Scenario 4
EE-HP1	ASHP Agricultural Industrial	0	0
EE-HP2	ASHP Other	0	0
EE-HP3	ASHP Commercial	0	0
EE-HP4	ccASHP Agricultural Industrial Commercial	0	0
EE-HP5	ccASHP Other	0	0
EE-HP6	GSHP Agricultural Industrial	43	52
EE-HP7	GSHP Commercial	224	286
EE-HP8	GSHP Other	201	397
	Total	**468**	**735**

Results

Including air source and ground source heat pumps as selectable resources does not materially change the resource mix for the scenarios with the Efficiency Manitoba Plan and the fully optimized energy efficiency cases. No air source heat pumps are selected in any of the four scenarios. In scenario 4, the ground source heat pumps that are selected are installed prior to 2029, after which generation options are first available to be developed based on their lead time. The ground source heat pump potential that is selected in scenario 4 provides 107 MW of peak demand savings (Figure A5.30). Since there is no substantive adoption of ground source heat pumps, this suggests that heat pumps are not as cost effective as other types of energy efficiency measures or other generation resource options based on the cost and performance assumptions used for this analysis. The scenarios noted with an asterisk (*) in the figures include the firm capacity adjustment explained in the Methodology section of Optimization of Energy Efficiency.

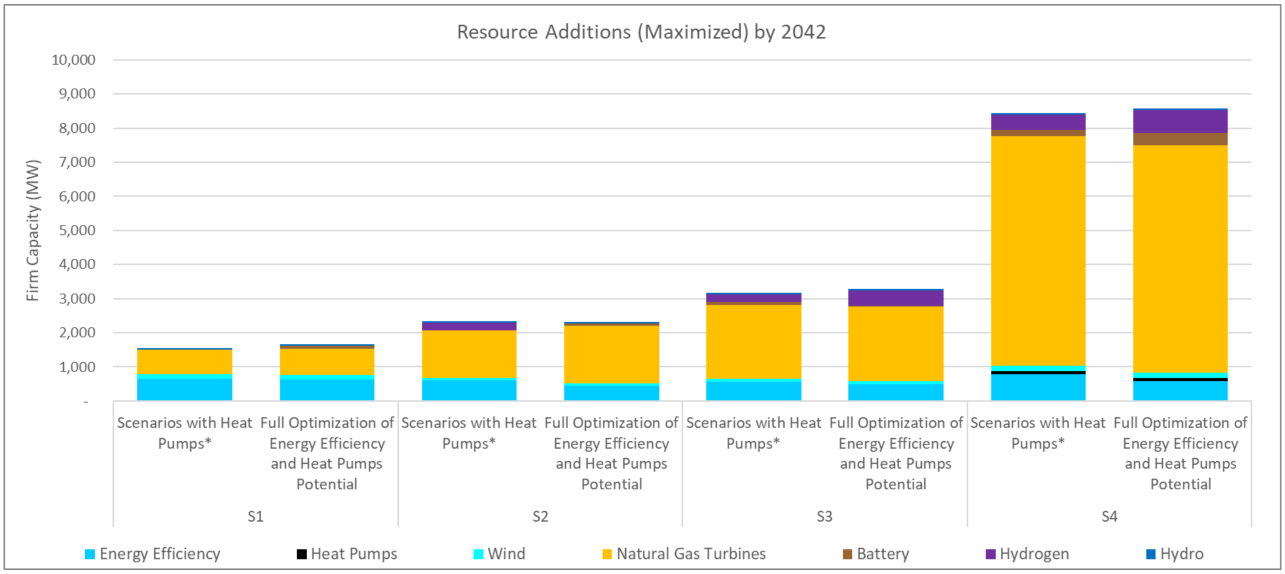


Figure A5.30 – Resource Additions When Including Heat Pumps

GSHPs are relatively expensive compared to other types of resource options in terms of both the cost of energy and capacity (Figure A5.35 and Figure A5.36). For this reason, GSHPs are generally not cost competitive relative to other resource options and are not included in the resource mix. The performance and cost of GSHPs can vary widely, and further study in the future is required to refine assumptions.

Lower Market Potential for Energy Efficiency Savings

Objective

This sensitivity aims to explore changes to the generation supply resource mix using a lower market potential for energy efficiency savings. A lower market potential excludes high-cost energy efficiency measures and reduces customer incentive levels.

Methodology

The scenario analysis assumes that energy and demand savings resulting from the Efficiency Manitoba Plan is achieved and that only the remaining energy savings potential is available to be selected for optimization relative to new resource options. Appendix 2 explains that there are three levels of market potential developed based on a study conducted by a consultant and that the scenarios assume the Maximized Market Potential Savings Level for the scenarios. Based on the same market potential study conducted for Efficiency Manitoba this sensitivity evaluates the impact of assuming the Enhanced Market Potential Savings Level, which reduces the total cost of the energy efficiency by an average of 14%. Each of these sensitivity cases include energy savings potential from air source and ground source heat pumps at the Maximized and Enhanced Market Potential level. Table A5.13 and Table A5.14 list the Enhanced Level Market Potential energy efficiency savings for the scenarios which are lower than the maximized market potential by about 30%. Table A5.15 and Table A5.16 list the Enhanced Level Heat Pump Market Potential for the scenarios which are lower than the Maximized Level market potential energy and capacity savings (Tables A5.11 and A5.12) by about 35% and 55% respectively.

Table A5.13 – Energy Efficiency Main Groupings - Enhanced Level Market Potential Energy Savings (GWh) by 2042

Grouping		Scenario 1, 2, 3	Scenario 4
EE-M1	Commercial Lighting	304	319
EE-M2	Commercial Uniform Load	433	816
EE-M3	Non-Residential Heating & Cooling	230	312
EE-M4	Industrial Custom	1,356	1,356
EE-M5	Non-Commercial Lighting	110	164
EE-M6	Residential Heating and Cooling	127	169
EE-M7	Non-Commercial Uniform Load	726	933
	Total	**3,285**	**4,068**

Table A5.14 – Energy Efficiency Main Groupings - Enhanced Level Market Potential Capacity Savings (MW) by 2042

Grouping		Scenario 1, 2, 3	Scenario 4
EE-M1	Commercial Lighting	52	42
EE-M2	Commercial Uniform Load	55	104
EE-M3	Non-Residential Heating & Cooling	92	129
EE-M4	Industrial Custom	173	173
EE-M5	Non-Commercial Lighting	19	22
EE-M6	Residential Heating and Cooling	51	70
EE-M7	Non-Commercial Uniform Load	93	119
	Total	**535**	**659**

Table A5.15 – Heat Pump Groupings - Enhanced Level Market Potential Energy Savings (GWh) by 2042

Grouping		Scenario 1, 2, 3	Scenario 4
EE-HP1	ASHP Agricultural Industrial	156	49
EE-HP2	ASHP Other	148	441
EE-HP3	ASHP Commercial	173	256
EE-HP4	ccASHP Agricultural Industrial Comm	122	43
EE-HP5	ccASHP Other	171	423
EE-HP6	GSHP Agricultural Industrial	26	32
EE-HP7	GSHP Commercial	237	288
EE-HP8	GSHP Other	234	347
	Total	**1,267**	**1,878**

Table A5.16 – Heat Pump Groupings - Enhanced Level Market Potential Capacity Efficiency Savings (MW) by 2042

Grouping		Scenario 1,2,3	Scenario 4
EE-HP1	ASHP Agricultural Industrial	0	0
EE-HP2	ASHP Other	0	0
EE-HP3	ASHP Commercial	0	0
EE-HP4	ccASHP Agricultural Industrial Comm	0	0
EE-HP5	ccASHP Other	0	0
EE-HP6	GSHP Agricultural Industrial	11	15
EE-HP7	GSHP Commercial	105	132
EE-HP8	GSHP Other	104	159
	Total	**220**	**306**

Results

Relative to the Maximized Market Potential Level the Enhanced Market Potential Savings Level generally results in less adoption of energy efficiency measures and heat pumps for the sensitivities that assume the Efficiency Manitoba Plan is achieved as well as for the Fully Optimized Energy Savings cases. Generally, there are small changes to the resource selection where there is more or less of each generation resource depending on the IRP scenario as shown in Figure A5.31.

Figure A5.32 and Figure A5.33 illustrate the reasons for less energy efficiency being selected for the Enhanced Market Potential Savings Level relative to the Maximized Level. Although some measures for the Enhanced Level are fully developed because they are cost effective, there is less total energy savings potential available relative to the Maximized Level. As shown in Figure A5.32 and Figure A5.33, some of the energy efficiency main groupings have less energy efficiency developed for the Fully Optimized cases because the Efficiency Manitoba Plan assumes there is more energy efficiency savings than there is market potential. The market potential energy savings are indicated by the dashed red lines.

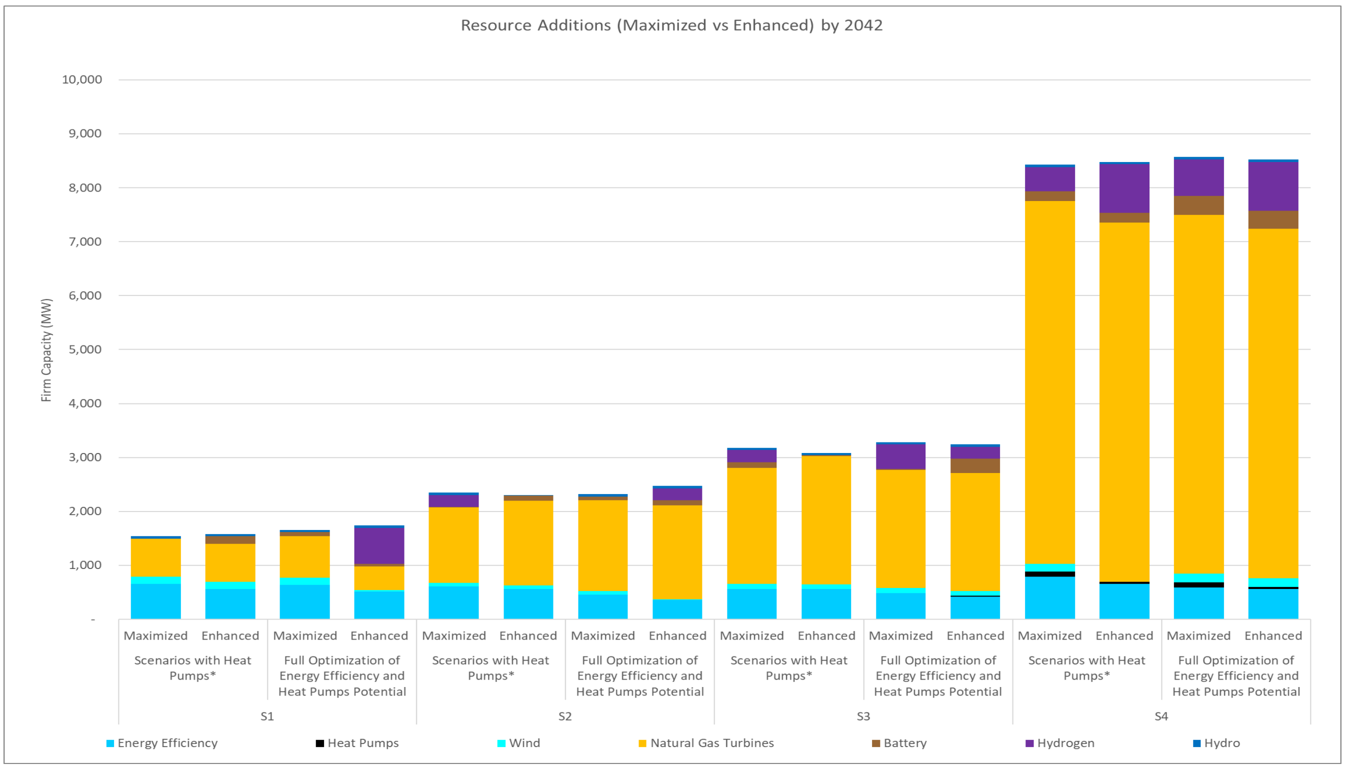


Figure A5.31 – Resource Additions Comparing Maximized and Enhance Market Potential Energy Efficiency Levels

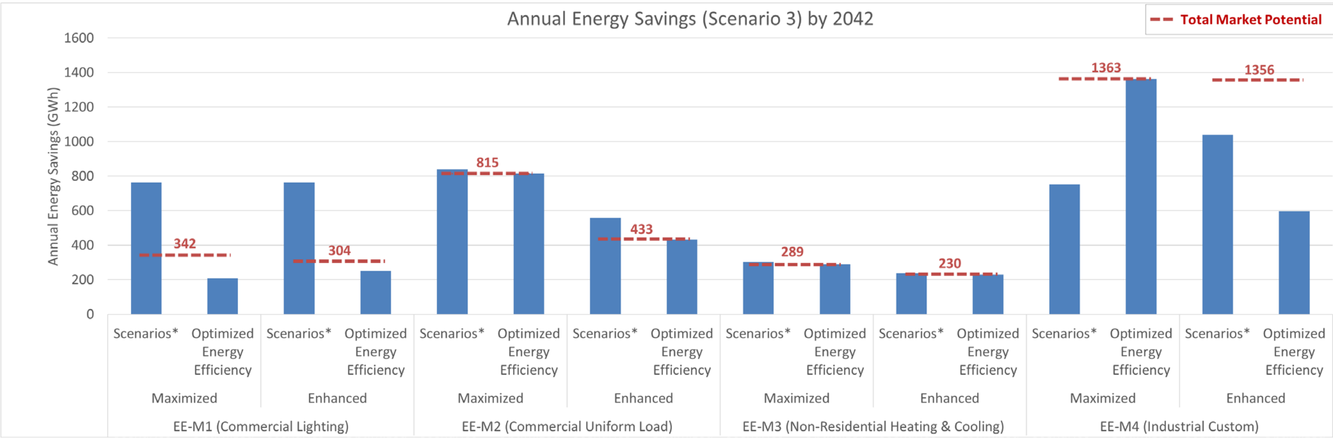


Figure A5.32 – Firm Energy Potential Selected (Scenario 3)

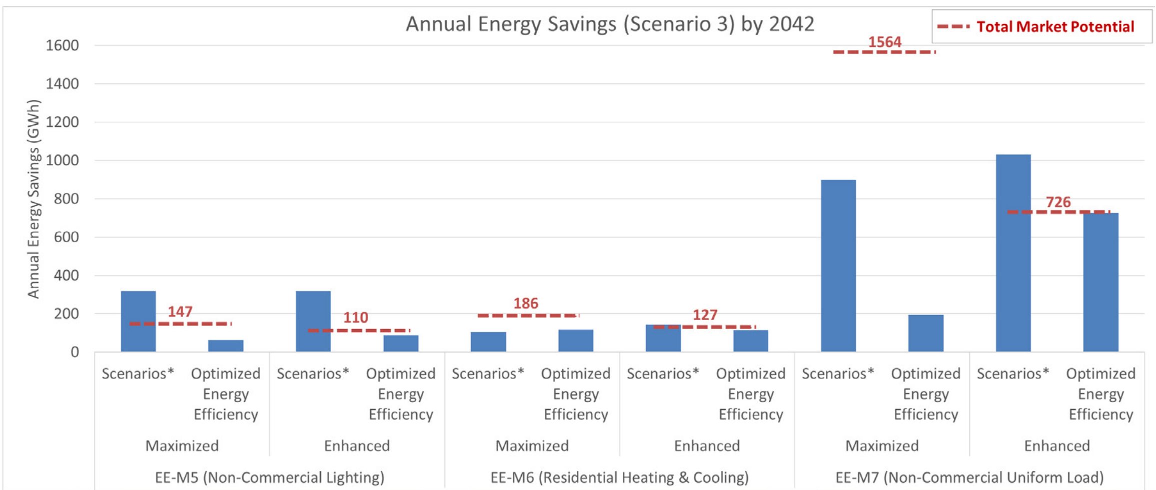


Figure A5.33 – Firm Energy Potential Selected (Scenario 3)

The cumulative present value of net system costs to 2042 are reduced by up to 1% ($530M) when assuming the Enhanced Market Potential assumptions when comparing to the Maximized Market Potential assumptions for the scenarios and the Fully Optimized cases. Due to the potential that differences in the costs and benefits may be due to differences in the capacity expansion solution, and not attributable to the energy efficiency savings alone, additional study is required to isolate the cost and value impact of energy efficiency savings.

Distributed Solar Photovoltaic (PV) Generation

Objective

While the scenario net demand projections assumed some distributed solar PV, the scenario modelling found that no additional distributed solar PV is cost effective. This sensitivity explores the impact of assuming more distributed solar PV in the scenario 3 net demand projection.

Methodology

The demand projection for scenario 3 was adjusted to include twice the amount of distributed solar PV that was assumed in the scenario. The scenario 3 demand projection incorporates 573 MW of installed distributed solar PV by 2042. For this sensitivity the amount is doubled to 1146 MW over the same timeframe. As indicated in Appendix 3, it is expected that 75% of the energy produced would be utilized by the customer and 25% would be sold back to the grid. As this portion of the distributed solar PV forms part of the overall demand projection and is not in the optimization process, no costs are attributed to the additional distributed solar PV within the resource optimization model. Additional distributed solar PV beyond the amount included in the scenario demand projection is available for selection within the optimization process.

Results

Doubling the distributed solar PV resulted in a range of impacts. Wind resource selections are increased but delayed by one to six years, hydrogen turbines are no longer being selected, there are minor reductions to energy efficiency, and there are minor increases to natural gas turbines. Figure A5.34 shows the resource selections for scenario 3 and the resulting sensitivity by resource type in 2042. As the doubling of scenario 3 assumed projected distributed solar PV was modelled as a planned addition to the existing system, the additional installed solar capacity does not appear in the figure.

In comparison to scenario 3, the delay in new wind additions to the system resulted in increased energy from natural gas turbines and imports and reduced exports until new wind is added. After the addition of new wind in 2040, energy from natural gas turbines and imports are reduced and exports increased. The net result is a negligible change to the generation emissions and a 0.8 Mt decrease in annual regional electricity generation emissions by 2042.

Doubling the distributed solar PV results in increases in the annual net system cost in 2042 of $0.04B (1%) and in the cumulative present value of net system costs to 2042 of $0.5B (1%). Overall, doubling the amount of distributed PV provided no measurable value even when considering the large investment necessary for the additional distributed solar PV, which is not included in the net system cost. This demonstrates that distributed solar PV reduces overall energy consumption but does not materially reduce the cost associated with supplying energy to customers when solar energy is not available.

Distributed solar PV has a higher total resource cost than utility scale solar PV, which was also not selected by the model.

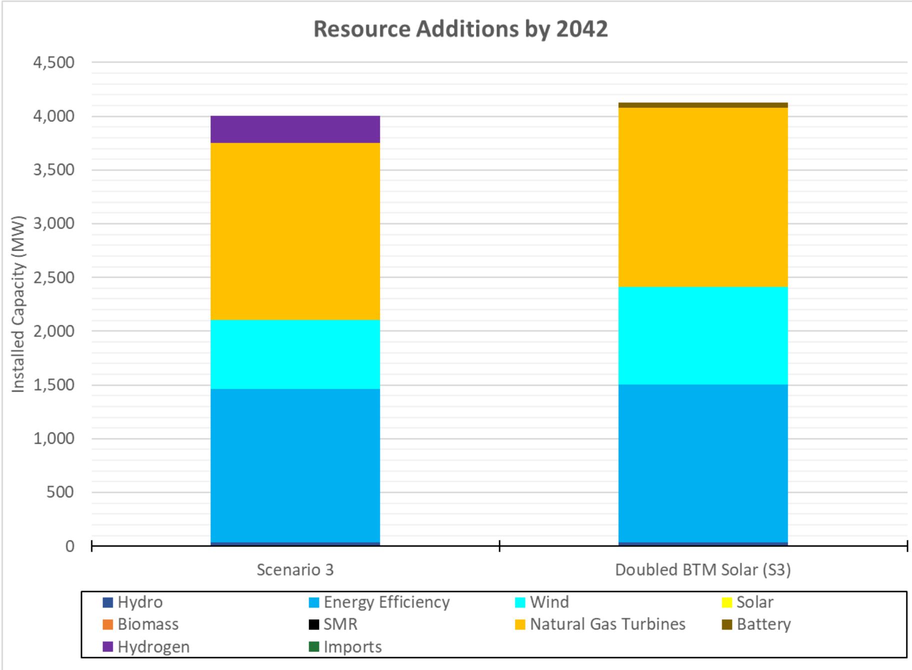


Figure A5.34 – Doubled Distributed Solar PV – Resource Additions by 2042

Summary Cost Comparison of Demand Side Sensitivities

The levelized cost of energy and capacity are shown in Figure A5.35 and Figure A5.36 respectively and illustrate the relative cost difference between resource options and how the cost differences impact which resources are being selected. The charts show a range of costs for each type of resource which reflect differences in costs over time, and in the case of energy efficiency, the range of costs for specific measures. The costs result from taking all resource costs and spreading them over all energy that is generated, or all capacity that is provided, over the lifespan of the resource. The two charts reflect two separate and independent cost metrics that allow for the comparison of costs on a unit basis, either $/MWh or $/kW-year. Appendix 2 – New Resource Options provides a comparison to additional resources.

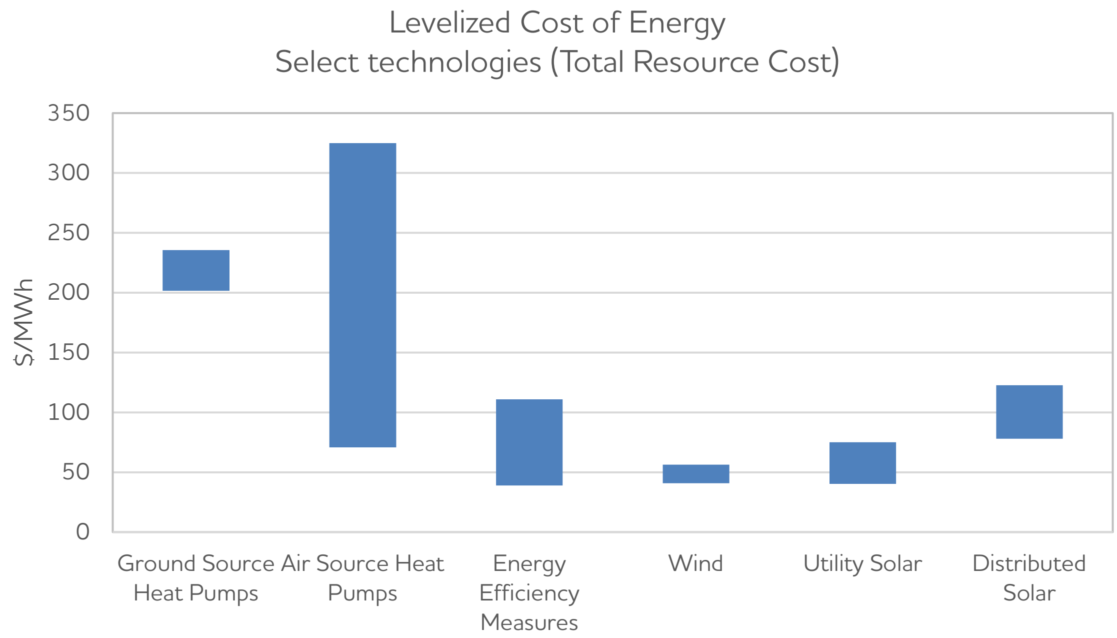


Figure A5.35 – Levelized Cost of Energy of Select Technologies[12]

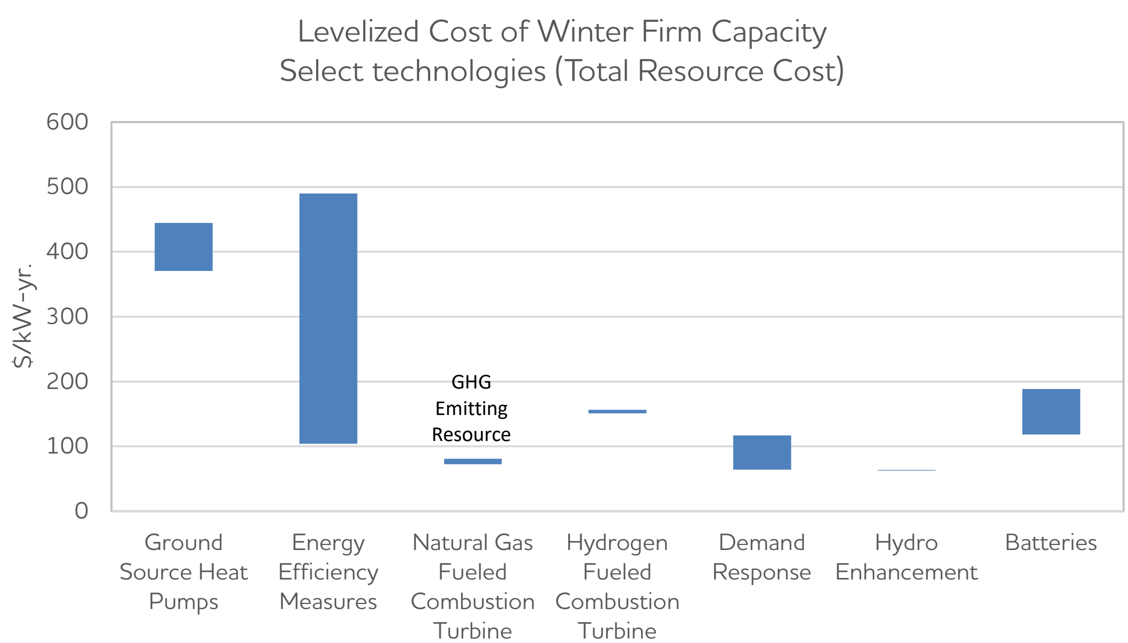


Figure A5.36 – Levelized Cost of Winter Firm Capacity of Select Technologies[12]

[12] Solar and air-source heat pumps are not included in the capacity chart because they do not provide winter firm capacity. Wind appears in the energy chart, but not in the capacity chart because as a capacity resource, its costs would be very high relative to the other resource options.

Figure A5.35 illustrates that wind and utility scale solar are low-cost energy resources that are comparable to low-cost energy efficiency measures. In the dual fuel sensitivity section, it was shown that dual fuel heating may provide value as a strategy to mitigate the costs associated with electrifying space heating while achieving some GHG emission reductions. Although air source heat pumps appear to be expensive to provide energy, they are a low-cost way to decarbonize space heating when paired with natural gas heating when compared to electric resistance heating.

Figure A5.36 illustrates that demand response, enhancements to existing hydropower generating facilities, and natural gas turbines are low-cost capacity resources. The figure also shows that the lower end of the energy efficiency measures have a cost of capacity that is only slightly more expensive.

The advantages of GHSPs include being more efficient than electric resistance heating, which reduces both energy and peak capacity needs, and having shorter implementation lead times than utility scale generation resources. However, these figures illustrate that GSHPs are relatively expensive capacity resources compared to other options.

Figure A5.36 does not include solar generation as it does not provide any winter capacity, which reduces its overall value as a generation resource option and is a contributing factor for not appearing in any of the resource mixes for any of the scenarios. The figures also do not indicate the total amount of each resource type that could be developed, for example only so much demand can be reduced or shifted through energy efficiency or demand response, so those resources have less potential than hydrogen turbines.

3.4 Energy Price and Market Interactions Sensitivities

Introduction

Manitoba Hydro's existing predominantly hydropower system benefits from access to neighbouring generation systems and associated markets for import and export of power. These interactions have significant economic and regional electricity generation GHG emissions implications that include:

a) improving reliability by enabling imports during drought conditions and under supply contingencies (e.g., temporary loss of supply due to equipment outages);
b) increasing revenues by enabling the export of surplus hydropower and import of market energy at costs lower than the cost of thermal resources available within Manitoba; and
c) ability to lower regional electrical generation GHG emissions by net exporting (renewable) electricity when surplus is available, reducing generation from fuel-based resources in non-Manitoba markets.

The following sensitivities explore the impacts of import and export prices and capability on the selection of new resources, emissions, and costs:

- Reduced Imports
- Low Export and Import Market Price

Reduced Imports

Objective

The potential availability of imports from the market in the future, or a decision to rely less on the market for dependable energy, can have an impact on future resource needs. This sensitivity explores the impacts of reducing imported energy on resource selection, GHG emissions, and costs.

Methodology

For this sensitivity, the scenario 3 import capacity from the Midcontinent Independent System Operator (MISO) market was reduced by 50% starting in 2030, at which time all allowances for using imports for dependable energy were eliminated. Export availability and prices remained unchanged.

Results

A 50% restriction on import capability and 100% restriction on imports for dependable energy results in physical imports being reduced by 65% by 2042 as seen in Figure A5.37. This energy is replaced by quadrupling the amount of wind added to the system by 2042 as seen in Figure A5.38. While this adds a significant amount of wind energy, new wind generation comes with a relatively small amount of firm capacity. In this case, the amount of firm capacity supplied by the new wind did not change the amount of new natural gas turbines and hydrogen turbines required to meet system firm capacity needs. However, energy provided by the additional wind resulted in more surplus energy and a doubling of opportunity exports in 2042. New resource additions for the reduced import sensitivity are shown in Figure A5.43.

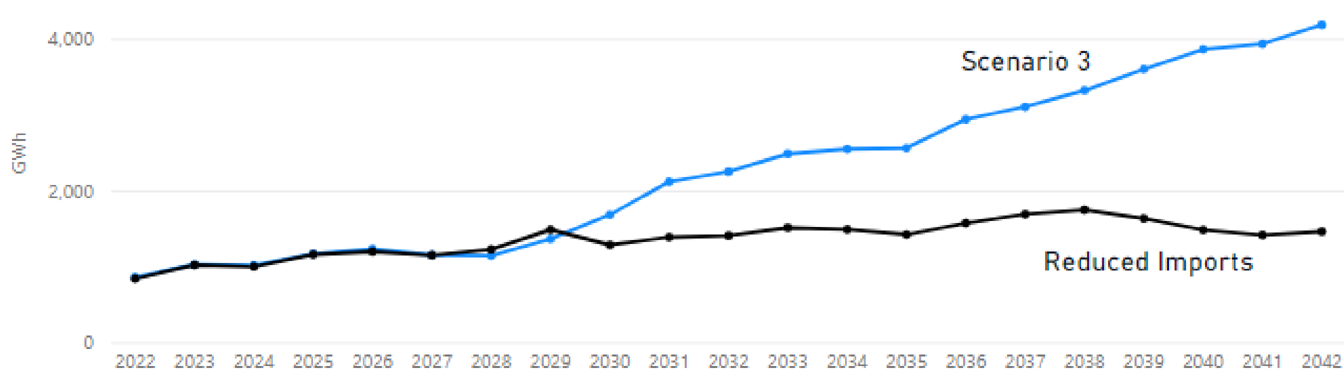


Figure A5.37 – Reduced Imports Sensitivity - Average Import Energy by Year

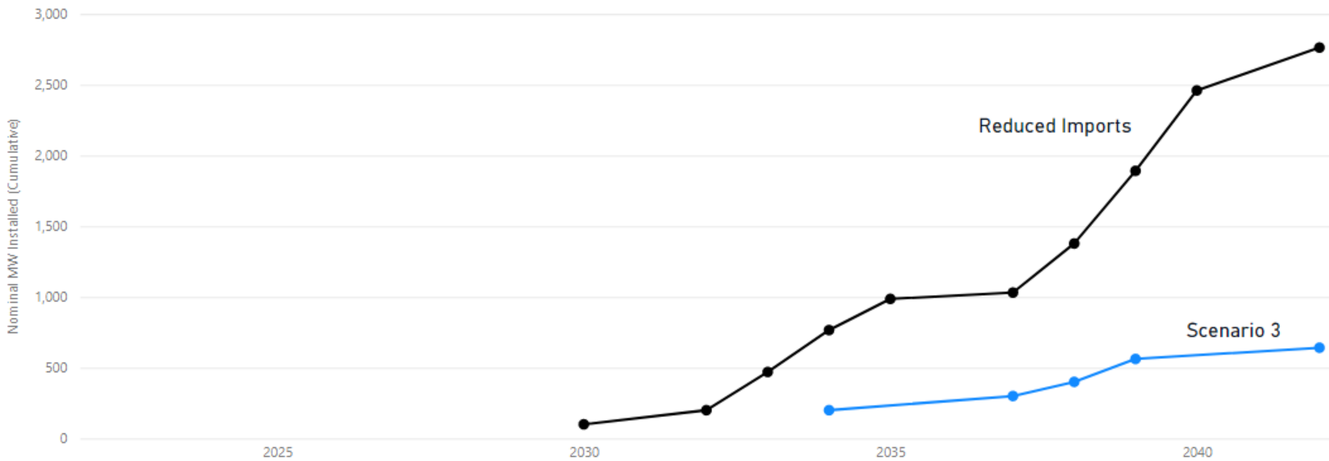


Figure A5.38 – Reduced Imports Sensitivity - Cumulative Nominal MW of Wind Installed by Year

The incremental cost of reducing Manitoba Hydro's import capability and eliminating any dependable energy from imports is $1.1B in cumulative present value of net system costs to 2042 (Figure A5.44). The direct impact of the additional wind is an increase to the cumulative present value cost by $1.3B with an offsetting increase in export revenue of $0.5B. With more wind added to the system and the accompanying changes to the resource selection, Manitoba Hydro's generation emissions reduce by 31% in 2042 as compared to scenario 3. The increased export and decreased import activity results in increased avoided GHG emissions in external markets.

Low Export and Import Market Price

Objective

The changing energy landscape results in some uncertainty in the long-range projection for the price of electricity in the MISO market. There is some risk that the market price for exported and imported energy could be less than is assumed in the scenarios. This sensitivity explores the impact of lower export and import market prices on the selection of new resources, emissions, and costs.

Methodology:

To determine the impact of lower export and import market prices, the annual average import and export price was reduced to $5/MWh which is above the cost of water rental fees for hydropower generation, but it is significantly below expected market prices. Market prices vary by year, month, and block as further described in Appendix 4. Applying the relationship between average annual prices and block prices can result in some instances of negative opportunity export prices at the block level, and in these cases both the export and import prices were set to $0/MWh. Setting the import prices to $0/MWh during these instances maintains a degree of consistency between export and import market prices.

Results

Less attractive export energy pricing changes the system's hydropower generation patterns, as market arbitrage (see Interconnections in Appendix 1) becomes less economic. This results in less overall hydropower energy production with a 10% decrease by 2042. This effect is enhanced by the availability of $0/MWh imports, which further dampens the economic signal to push the hydropower generation system to produce more energy. The change in hydropower generation is shown in Figure A5.39, the change in exports is shown in Figure A5.40, and the change in imports is shown in Figure A5.41.

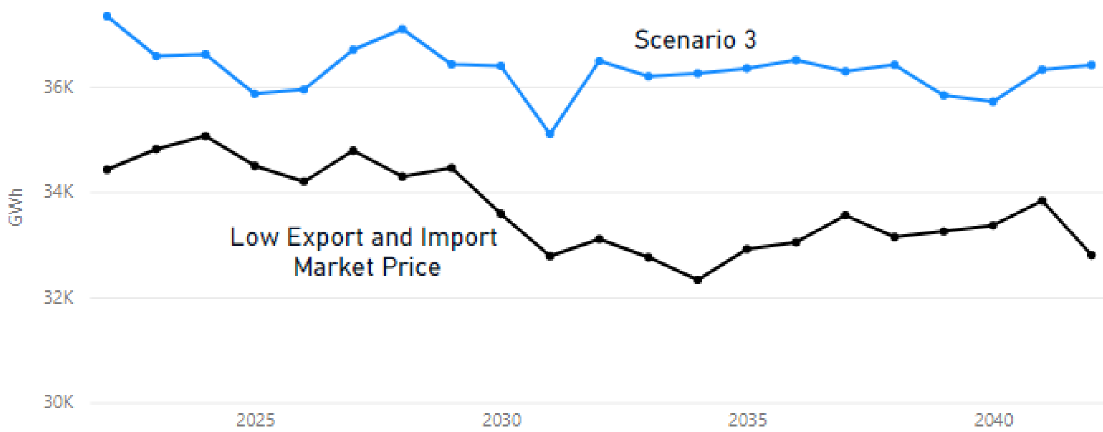


Figure A5.39 – Low Export and Import Market Prices – Average Annual Energy from Hydropower Generation

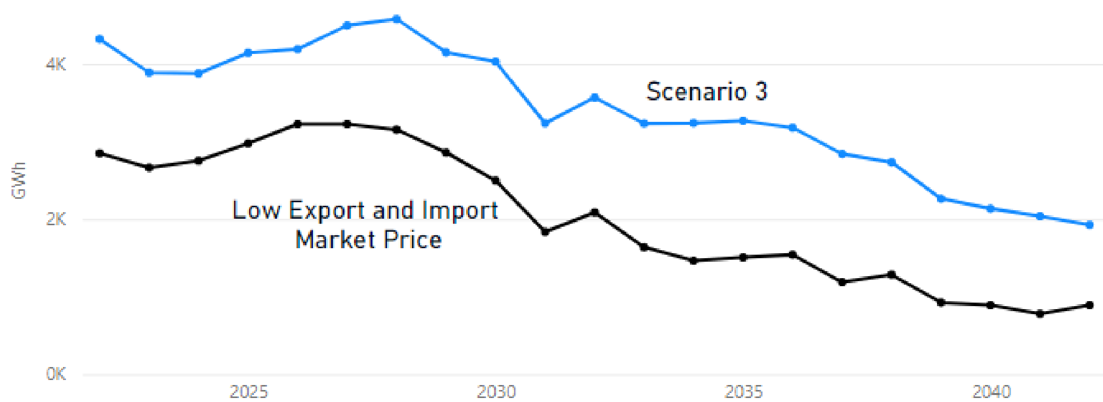


Figure A5.40 – Low Export and Import Market Prices – Average Annual Opportunity Exports

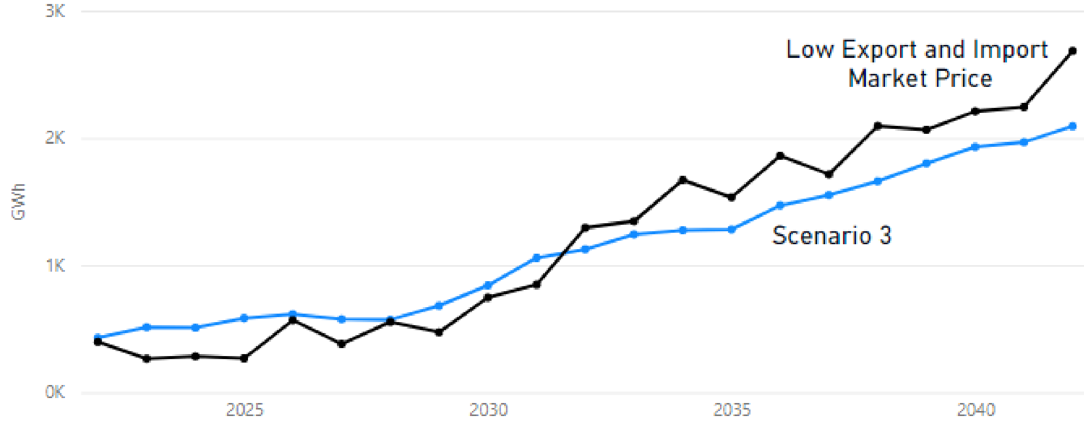


Figure A5.41 – Low Export and Import Market Prices – Average Annual Energy from Imports

Increased imported energy volumes and reduced exports also delays new wind resource additions. The first addition of new wind is delayed by four years and most new wind is introduced in the final year of the study. The total new wind in 2042 increases by 32%, but the cumulative amount of energy wind provided to the system throughout the study is reduced by 23% compared to Scenario 3. This is demonstrated in Figure A5.42.

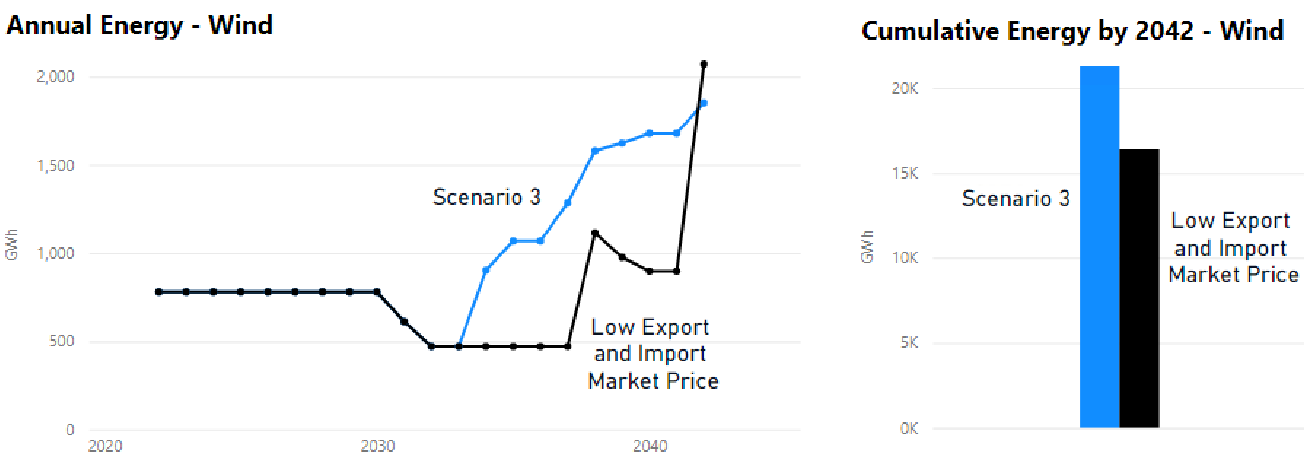


Figure A5.42 – Low Export and Import Market Price – Average Wind Energy (Annual and Cumulative to 2042

Low export prices and import prices increase electricity generation GHG emissions in Manitoba. With less hydropower generation, natural gas turbine dispatch increases throughout the study horizon, resulting in a 0.1 Mt increase in provincial electricity generation GHG emissions in 2042 (compared with scenario 3). With less exported energy and more imported energy, avoided regional GHG emissions from Manitoba Hydro's market activities also increase by 1.9 Mt.

With lower export prices, the volume of opportunity exports reduces by 54% at the end of the study period. Reduced exports volumes and value are the primary driver for the $2.0B (4%) increase to the cumulative present value of net system costs to 2042 for this sensitivity.

New resource additions by 2042 are summarized in Figure A5.43, while average annual GHG emissions in 2042 and average annual net system costs in 2042 are summarized in Figure A5.44 in the following Summary section.

Summary

Market interactions depend on Manitoba Hydro's access to external electricity energy markets and the price of energy in those markets. Both aspects were studied through different sensitivities.

Sensitivity results confirmed that external market access and market price projections impact the quantity, type, and timing of new generation resources, with substantial impacts on new wind generation. Collectively, the sensitivity results confirmed that the importance of interconnections to markets outside of Manitoba will continue, as imports serve as an important and economic energy resource for Manitoba Hydro. However, expansion plans with significant import or export energy volumes have increased risk exposure to market price and availability risks.

Figure A5.43 compares resource additions by 2042 based on installed capacity across all sensitivities. Figure A5.44 compares the annual emissions and costs in 2042.

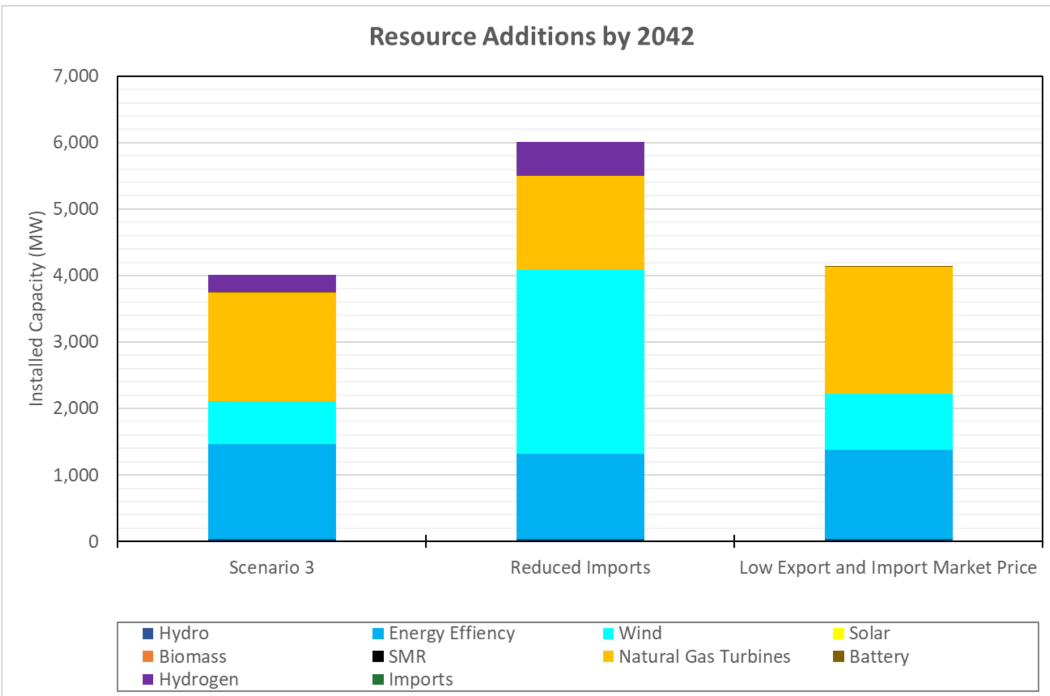


Figure A5.43 – Energy Price and Market Interactions – Resource Additions by 2042

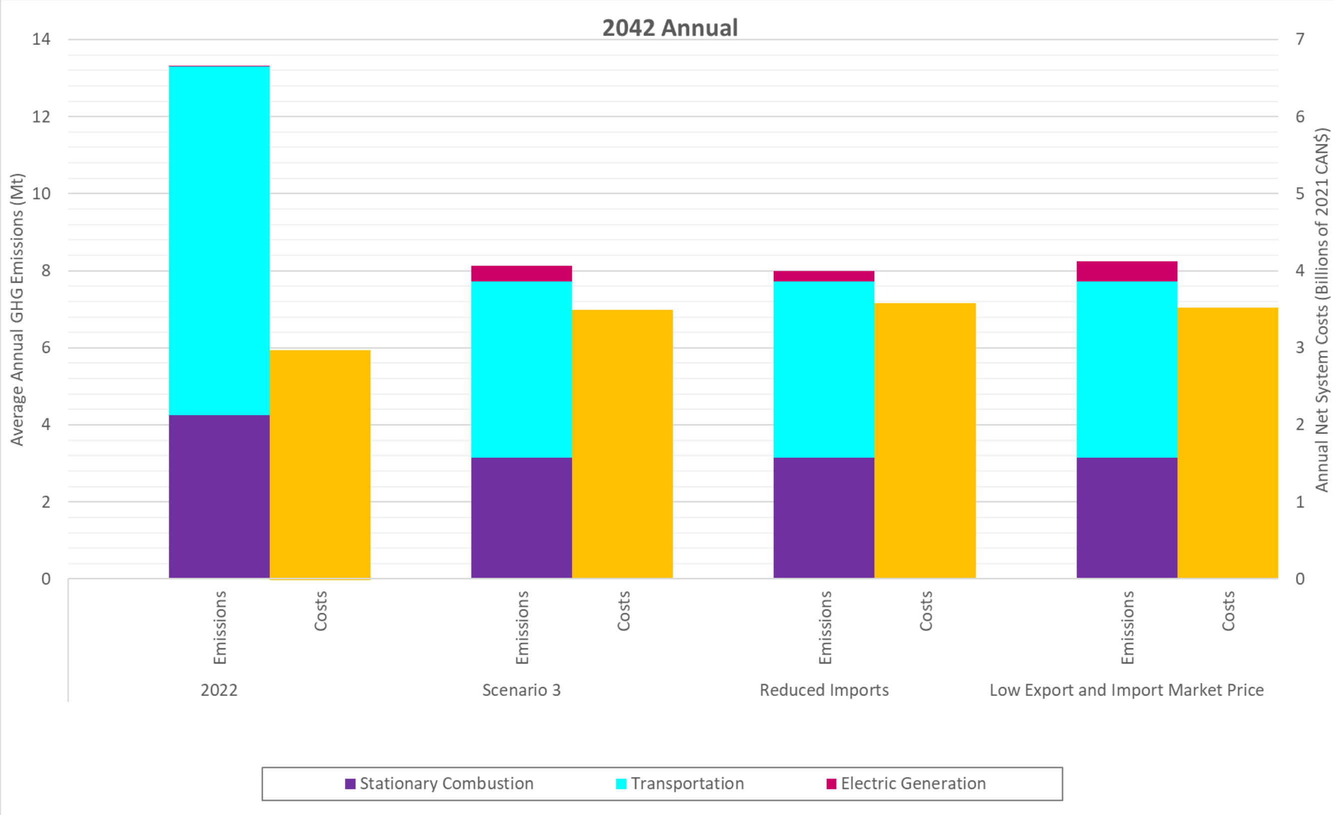


Figure A5.44 – Energy Price and Market Interaction – 2042 Annual Emissions and Costs

A summary of the findings from the reduced import sensitivity is provided in Table A5.17. Reducing import capability resulted in an increase in new wind added to the system, with wind acting as a means of replacing imported dependable energy. Increased wind generation also translated into increased opportunity exports, and reductions in Manitoba Hydro's generation and regional generation emissions. Both the 2042 annual net system costs and the cumulative present value of net system costs to 2042 increase, as increased net revenues from system operations are negated by the increased costs from building new wind.

Table A5.17 – Market Interactions Summary – Market Access

Description	Impact	Selected Wind (MW)	Annual Net System Costs in 2042 ($B)	Cumulative PV of Net System Costs ($B)
Reduced Imports	No dependable energy accredited to imports. Import of opportunity energy is reduced by 50%.	+2,100	+0.1	+1.1

Market price implications were explored by investigating a sensitivity with reduced export prices and import prices. Findings from the low export and import market price sensitivity are summarized in Table A5.18. In this sensitivity the following impacts were observed: wind is still selected but is added to the system later in the study horizon, a reduction in the use of hydropower generation resources for market arbitrage was observed, and lower cost imports out-compete wind energy until later in the study horizon. At times of $0/MWh imports, hydropower generation may be reduced, and spill may occur as at these times when it is cheaper to import energy rather than to generate hydropower and incur water rental costs. However, the net effect of low export and import costs was an increase in the cumulative present value of net system costs to 2042, as opportunity export revenues were significantly reduced. By 2042, there was no change in net annual system costs. Manitoba Hydro's emissions also increased in this sensitivity.

Table A5.18 – Market Interactions Summary – Market Prices

Description	Impact	Selected Wind (MW)	Annual Net System Costs in 2042 ($B)	Cumulative PV of Net System Costs ($B)
Low Export and Import Prices	Average annual export prices are reduced to $5/MWh, import prices approach $0/MWh with export prices but are otherwise unchanged.	+203	+0.0	+2.0

Export and import volumes are affected by many factors. In scenarios 1, 2, 3, and 4, as Manitoba's demand increases over time, new capacity resources are required and more surplus energy, which was previously exported, is consumed in Manitoba. However, the Reduced Imports and Low Export and Import Market Price sensitivities demonstrate that volumes of imports and exports are affected by other factors as well, including physical interconnection capability and market prices. The generation supply mix of a given resource selection is influenced by these factors, and the resulting system is operated such that market interactions provide the most economic benefit.

3.5 Other Sensitivities

Other sensitivities were undertaken to explore specific issues or resources:

- Climate Change
- Provincial Fees
- New Hydropower
- Wind
- Solar PV – Utility Scale
- Electric Vehicles

Climate Change

Objective

Climate change has the potential to impact Manitoba through its effect on the water supply used for generating hydropower and through its effect on demand for capacity and energy. The purpose of this sensitivity is to explore a range of potential impacts of climate change on the selection of resources, GHG emissions, and costs.

Methodology

The climate change sensitivities that were analyzed were selected to reflect a representative range of potential inflow and electrical energy demand changes. Climate change implications specific to Manitoba Hydro were determined through analysis and modelling that relied upon future projections of temperature and precipitation derived from Global Climate Models (GCMs) driven by various future GHG emission scenarios (known as Representative Concentration Pathways; RCPs).

Electrical demand changes were determined from an ensemble of 47 bias-adjusted GCM simulations with temperature data available at the daily resolution. Using methods consistent with the scenario 3 demand projection, daily temperatures were combined with weather effect coefficients to calculate the normal-weather effect on energy and peak demand based on moving 25-year windows. The incremental weather effect between the study period (e.g., 2018 to 2042 for study year 2042) and the baseline period (1996 to 2020) was applied to the scenario 3 demand projection and the resulting projected energy and peak demands were then reported at the monthly resolution. Aspects of this methodology are described in greater detail in Manitoba Hydro's 2015 "Projected Climate Change Impacts on Energy and Peak Demand in Manitoba" report.[13]

For peak demand assessments, a quantile-based approach is utilized to recognize that the peak demand may not always occur during the absolute maximum or minimum daily temperature.

Changes to future inflows are derived from a modelling chain that begins with temperature and precipitation data from 40 GCM Simulations. GCM-simulated changes in monthly temperature and precipitation are based on differences between a baseline period (1981 to 2010) and a future period (2040 to 2069). These changes are used to adjust a reference dataset of gridded temperature and precipitation, to create gridded future climate scenarios. These future climate scenarios are then used to drive calibrated and validated hydrological models to produce future inflow scenarios, which are then further processed to adjust Manitoba Hydro's reference flow dataset (known as Long Term Flow Data; LTFD). More information on the future climate scenarios, hydrological models, and LTFD adjustment process can be found in

13 https://www.researchgate.net/publication/372459779_PROJECTED_CLIMATE_CHANGE_IMPACTS_ON_ENERGY_AND_PEAK_DEMAND_IN_MANITOBA

Manitoba Hydro's 2020 Climate Change Report [14]and in Ouranos' 2020 A Guidebook to Integrate Climate Data in Energy Production for Value Modelling[15].

All climate-change affected inflows developed for this analysis are based on differences between the baseline period (1981 to 2010) and the future period (2040 to 2069) and these inflows are applied to every year in the study period; there is no transition from the unadjusted LTFD record (the standard inflows used for all other IRP scenarios and sensitivities) as the study progresses. This approach may over-estimate climate change impacts in the near-term but appropriately reflects system conditions and requirements towards the end of the study.

A cluster analysis was performed to identify five GCM simulations that sample a wide range of the uncertainty in mean annual energy production and mean winter energy demand resulting from the ensemble of GCM simulations. The five selected GCM simulations are listed in Table A5.19, along with their corresponding sensitivity name. CC 3 is the median projection identified during the cluster analysis. Note that climate change implications for wind and solar energy production were not considered in these sensitivities.

Table A5.19 – Global Climate Model Name and Emissions Scenarios

Sensitivity Name	Global Climate Model Simulation (Model Name and Emissions Scenario)	Inflows
CC 1	MRI-CGCM3 rcp85	Highest
CC 2	GFDL-ESM2G rcp85	↓
CC 3	CSIRO-Mk3.6.0 rcp85	
CC 4	MIROC-ESM rcp85	
CC 5	BNU-ESM rcp45	Lowest

The selected sensitivities (CC 1 through CC 5 in Figure A5.45) span both increasing and decreasing annual inflows, but consistently have reduced winter energy and peak capacity demands as higher temperatures in the winter reduce space heating requirements. In the summer, there are small overall reductions in energy demand seen but increasing summer temperatures result in larger peak capacity demands from larger air conditioner loads on hot days. Summer energy demand decreases with global warming because the analysis considers only two seasons: summer and winter. Summer months are from April to September. The reduced heating requirement in shoulder months (spring and fall) have higher impact on the energy demand than the increased use of air conditioning in peak demand months of July and August.

Figure A5.45 shows the range of impacts of the five climate change models on mean annual flow (water supply) and on peak demand and energy demand, compared to scenario 3. While varying levels of increase

[14] https://www.hydro.mb.ca/environment/pdf/climate_change_report_2020.pdf

[15] https://www.ouranos.ca/en/projets-publications/valeurs-actifs-hydro%C3%A9lectriques

and decrease in mean annual flows are captured by the climate change sensitivities, analysis of the 40 GCM simulations points towards a slightly wetter future on average. Climate change impacts on demand are expected to be modest.

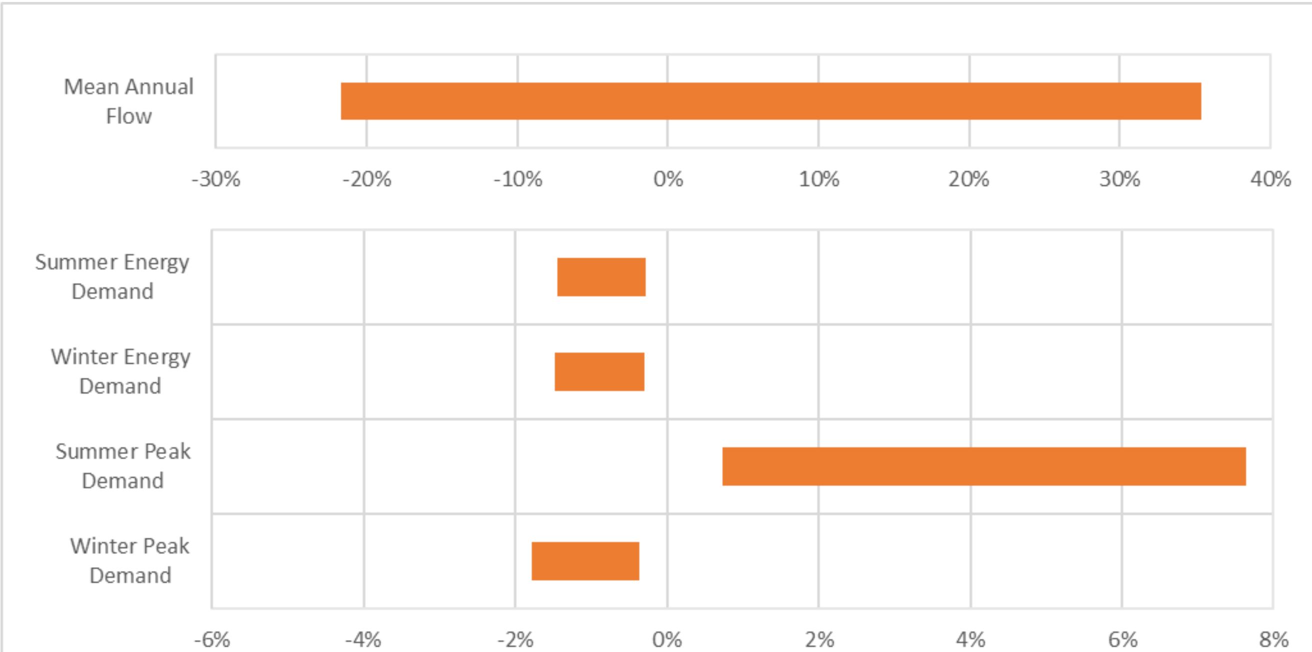


Figure A5.45 – Potential Impacts of Climate Change on Water Supply and Electric Demand

(Note: The winter energy demand period is from October through March, while the summer energy demand period is from April through September. The winter peak demand is defined as the highest monthly peak demand value from December, January, and February, while the summer peak demand is defined as the highest monthly peak demand value from June, July, and August.)

Results

The range of resources added across the sensitivities are shown in Figure A5.46. In comparison to scenario 3, a range of observations can be made. Some climate change sensitivities select a similar amount of wind, while others select no wind. Some climate change sensitivities select more energy efficiency; others select less, while others had little change; however the differences were not substantial. Some sensitivities select a similar amount of natural gas turbines, while others select notably more natural gas turbines. Some sensitivities barely select hydrogen turbines while others select substantial amounts.

The results from the five climate change scenarios indicate a wide range of impacts on the magnitude of resources being selected. Of note is that the type of resources being selected are not changing and that other resource options are not appearing.

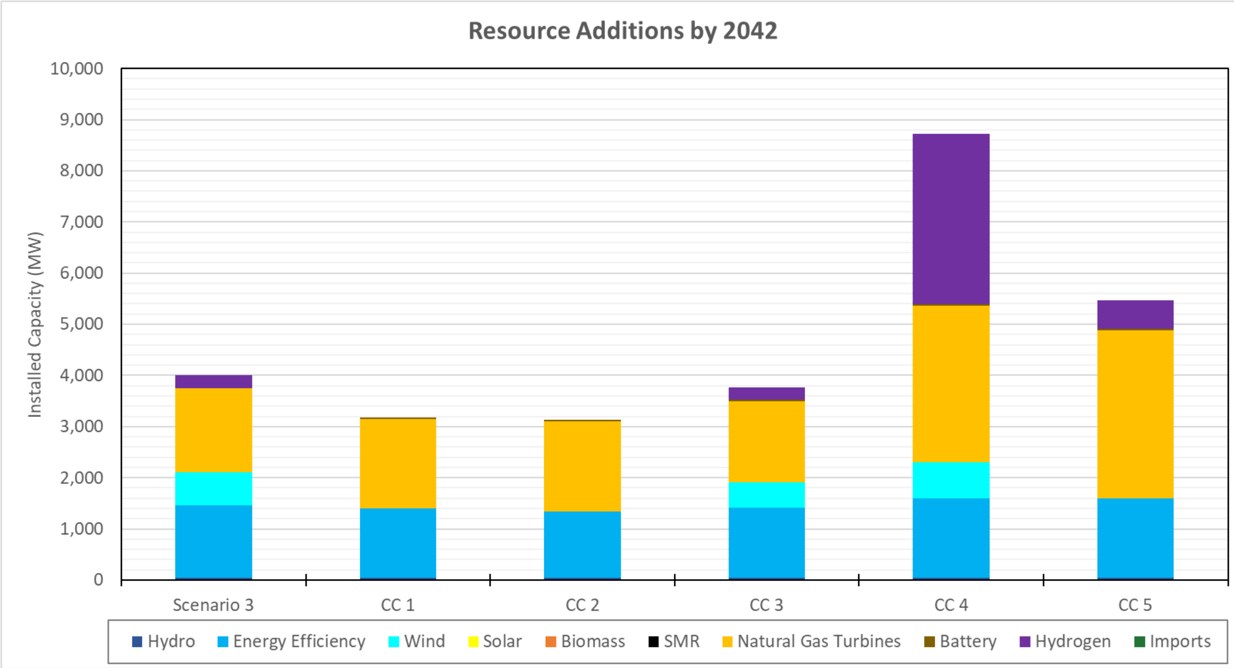


Figure A5.46 – Climate Change – Resource Additions by 2042

Figure A5.47 illustrates distinct relationships identified between the climate impacted inflows, energy generation, and market activity. As inflows decrease, hydropower generation and opportunity exports decrease, and imports increase. As shown by CC 3, CC 4, and CC 5, increases in natural gas turbine capacity additions and dispatch under lower inflow conditions were observed, along with varying levels of hydrogen turbine additions (shown in Figure A5.47 and Figure A5.48), where hydrogen turbines have net negative annual energy as seen in Figure A5.48. CC 4 has less system inflows than CC 3, resulting in natural gas turbines being installed and dispatched more frequently as hydropower generation becomes less abundant, and in hydrogen turbines being more valuable for their ability to shift energy from the summer to the winter. Sensitivity CC 5 has the lowest inflows, which triggers a change in reservoir operating trends. Different water management strategies are used in CC 5 to avoid energy deficits, resulting in corresponding changes to operating costs. This change in reservoir operations influences the resource additions for this sensitivity, notably the selection of hydrogen and wind.

The results for CC 4 and CC 5 have a lower level of confidence than those for CC 1, CC 2, and CC 3, and provide only high-level indications of what resource portfolios might look like under the modelled conditions. The lower inflows contained within CC 4 and CC 5 stress the production costing model's ability to find viable solutions that adhere to the models operating limits. This influences the final results and reduces the precision of the optimization. Further investigation into lower-inflow sensitivities is needed.

The impacts of higher flow conditions on natural gas turbines and wind are less clearly defined. The existing, hydropower dominated system can produce more energy on average and the resource selection optimization is less constrained by its ability to meet demand. Choices between natural gas turbines, hydrogen turbines, and wind resources are influenced by the economic trade-offs offered by these resources as they interact with the system. Average annual energy in 2042 by resource is presented in Figure A5.48.

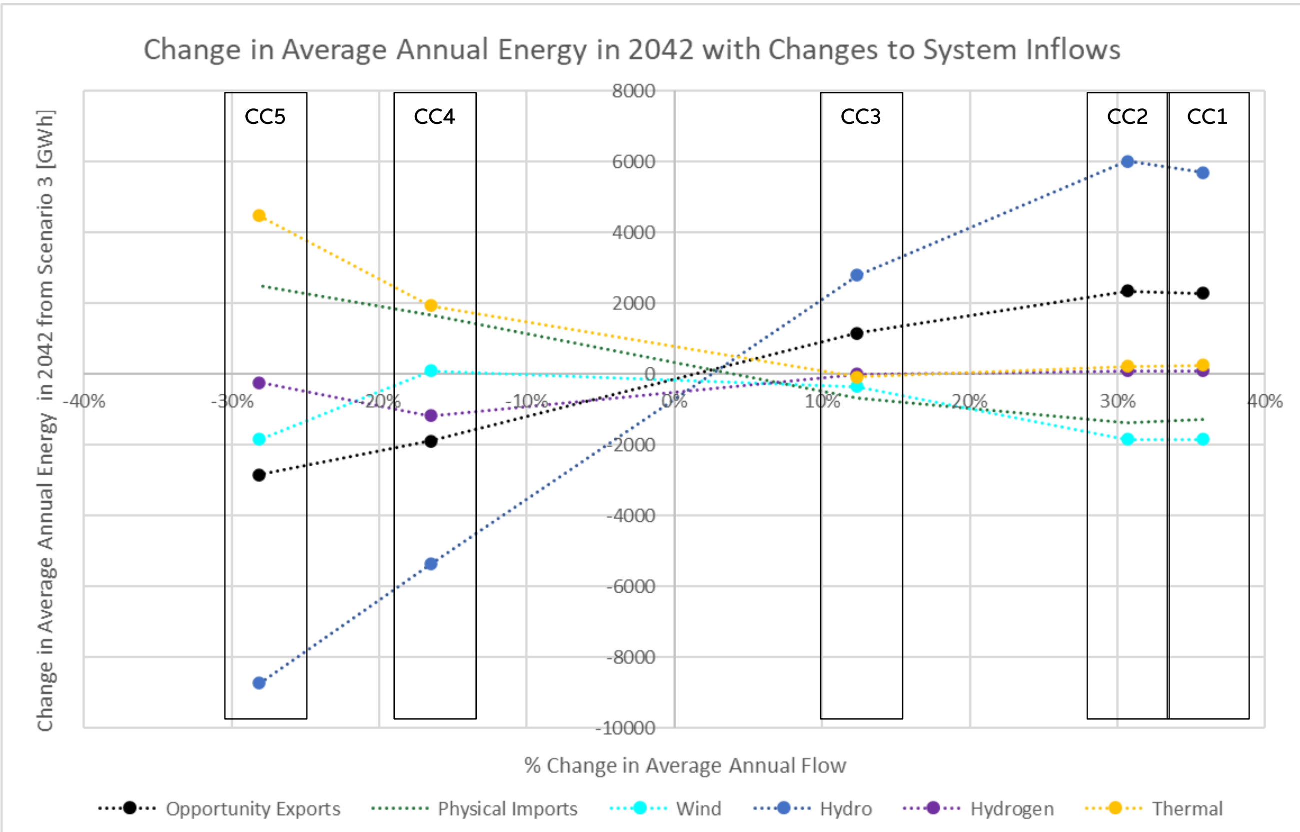


Figure A5.47 – Change in Average Annual Energy in 2042 with Change in Average Annual Flow

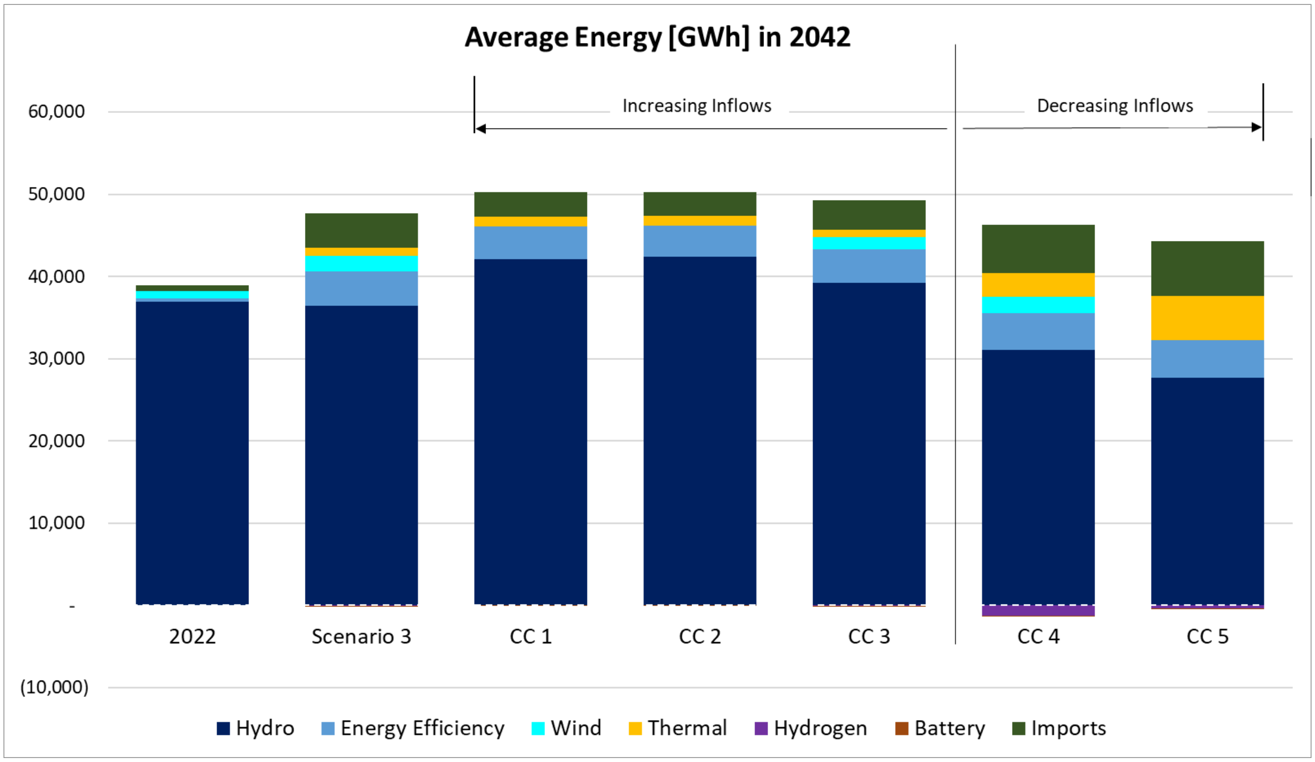


Figure A5.48 – Climate Change – Average Energy in 2042

(Note: Increasing and decreasing inflow labels are relative to average annual inflows assumed in scenario 3.)

With higher inflows, Manitoba Hydro's generation emissions increase by 0.0 to 0.4 Mt in 2042 as a result of changes to future resource selection and system operations, while regional GHG emissions are reduced by 1.1 to 2.2 Mt in 2042. With lower inflows, increased reliance on natural gas generation resulted in Manitoba Hydro's generation emissions increasing by 0.7 to 1.7 Mt in 2042, while regional emissions in 2042 increase by 2.1 to 3.1 Mt. Increases in regional emissions are driven by changes to Manitoba Hydro's market activity, with decreased export and increased import generally resulting in higher regional emissions.

Higher inflows resulted in annual net system costs in 2042 decreasing by $0.1B, and the cumulative present value of net system costs to 2042 decreasing by $0.7B to $1.9B. Lower inflows resulted in annual net system costs in 2042 increasing by $0.7B to $0.9B, and the cumulative present value of net system costs to 2042 increasing by $7.6B to $8.0B. These results demonstrate that under scenario 3 customer electric demand assumptions, Manitoba Hydro's possible economic disadvantages from reduced future inflows are greater than the possible advantages from increased inflows. Note that all climate change sensitivities are equally probable.

GHG emissions and annual net system costs in 2042 across the climate change sensitivities are summarized in Figure A5.49.

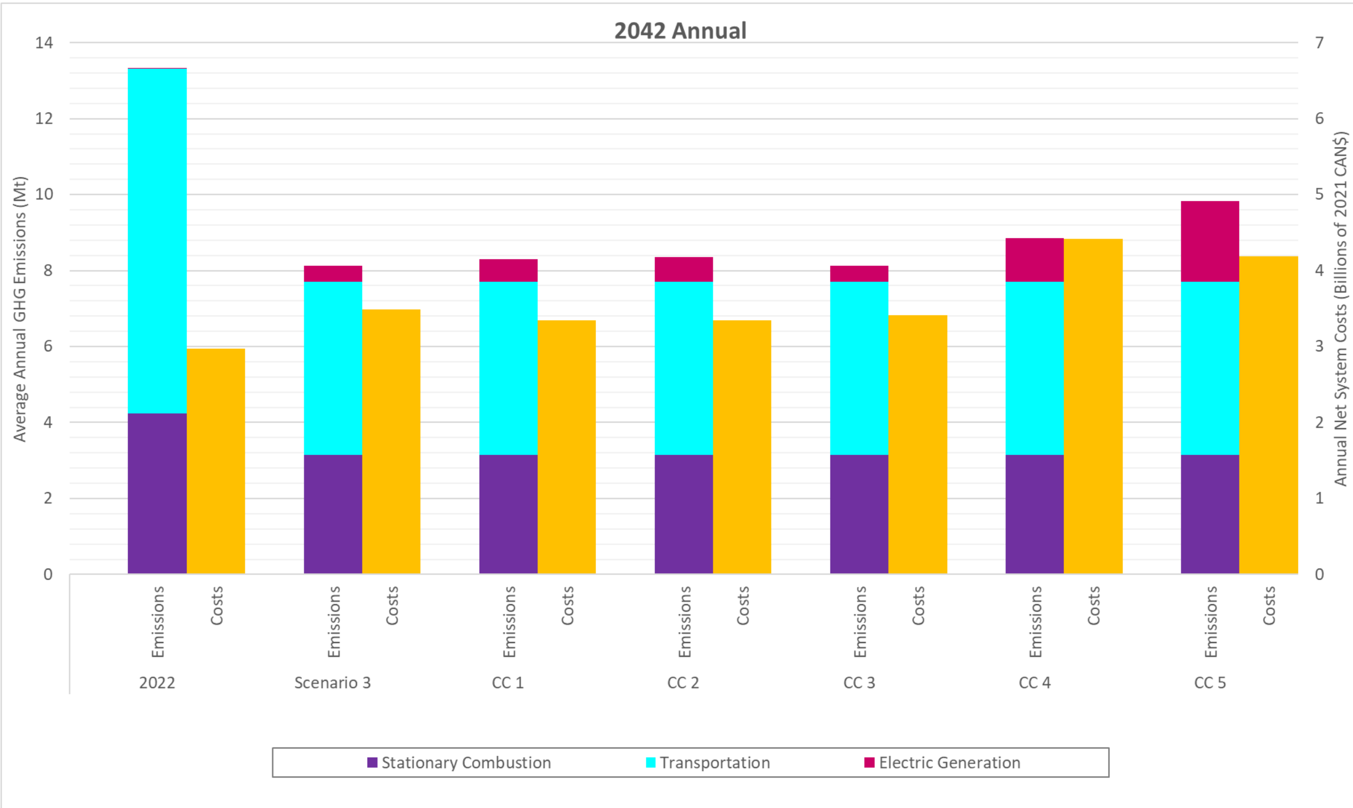


Figure A5.49 – Climate Change – 2042 Annual Emissions and Costs

Provincial Fees

Objective

Scenarios and sensitivities were substantially developed, modelled, and evaluated prior to November 2022 when the Government of Manitoba reduced the provincial guarantee fee and water rental fees by 50%. This sensitivity was undertaken to evaluate the impact of this change in cost.

The provincial guarantee fee is paid annually to the Minister of Finance on all outstanding short and long-term debt of Manitoba Hydro. The provincial guarantee fee is an annual fee payable to the Province of Manitoba in return for the guarantee of Manitoba Hydro's debt. It also includes provisions for additional service costs incurred by the Minister of Finance for acting as fiscal agent on behalf of Manitoba Hydro. This fee is included in the model and evaluations as part of the Real Weighted Average Cost of Capital (RWACC).

The water rental fee is a fee paid to the provincial government for water used to generate electricity. This fee is included in the model as an operating cost per MWh generated by hydropower stations in Manitoba.

Methodology

Sensitivities were set up to compare the results of scenario 3 and scenario 4 with the original provincial guarantee fee of 1.0% and water rental fee of $3.34/MWh with the new reduced fees of 0.5% and $1.67/MWh respectively.

Results

The reduced fees did not substantially change the type and timing of new resources in scenario 3 and scenario 4, as shown in Figure A5.50. Nor did the reduced fees substantially change the operation of the system, including natural gas generation dispatch and hydropower generation as shown in Figure A5.51. The differences in hydrogen turbines and natural gas turbines are not considered substantial as they are both peaking capacity resources. Reduced fees did not change the result that new hydropower was not selected, even in scenario 4.

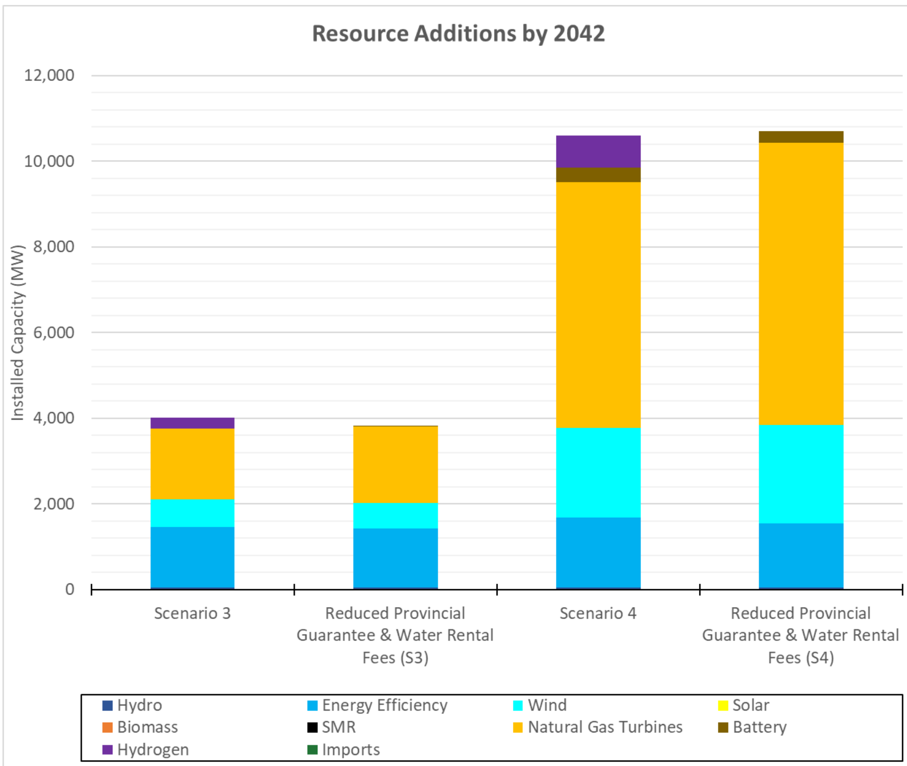


Figure A5.50 – Provincial Fees - Resource Additions by 2042

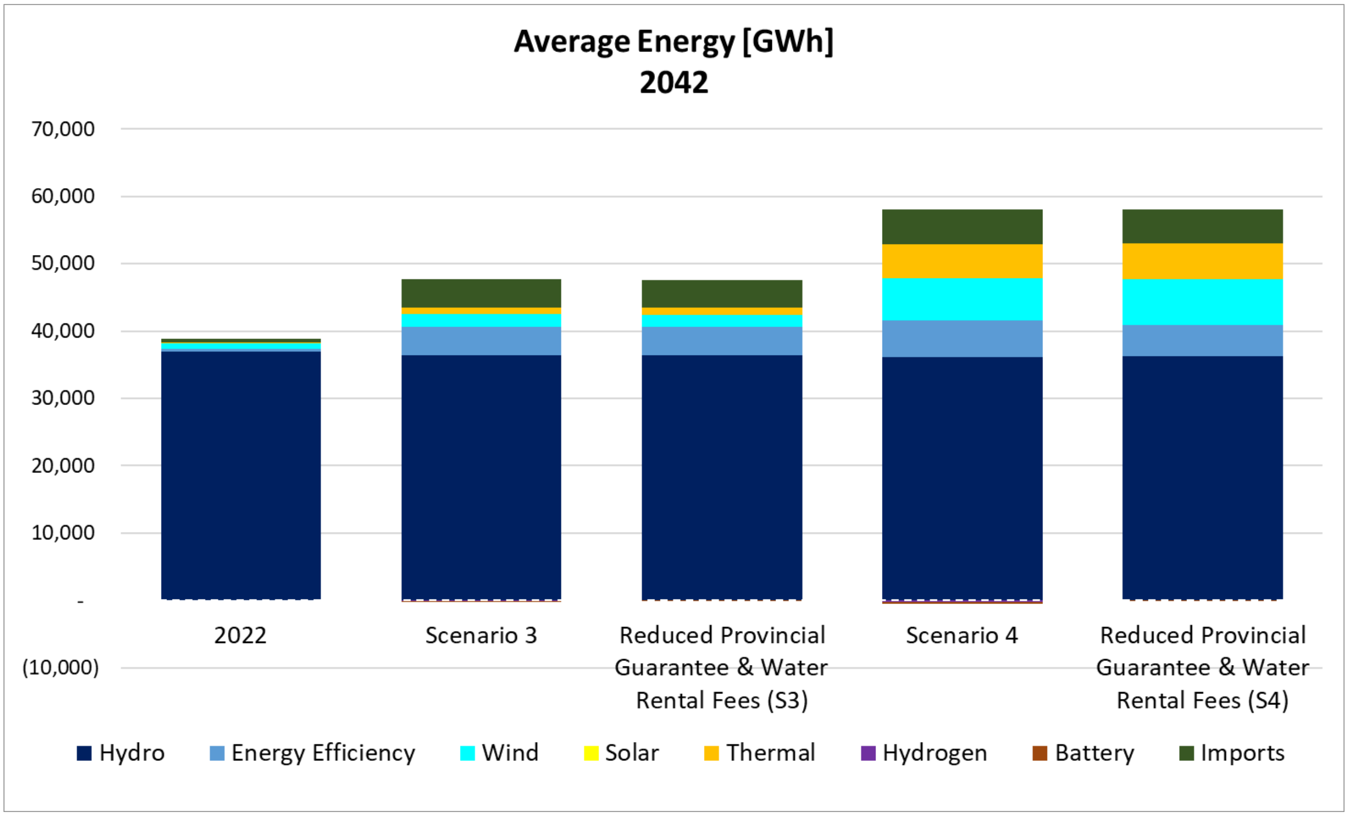


Figure A5.51 – Provincial Fees – Average Energy in 2042

Manitoba Hydro's electricity generation GHG emissions, regional electricity generation GHG emissions, and provincial GHG emissions in 2042 did not substantially change for the scenario 3 provincial fees sensitivity. In the scenario 4 sensitivity, Manitoba Hydro's regional electricity generation GHG emissions were reduced by 0.3 Mt, but all other emissions remained unchanged.

For the scenario 3 sensitivity, the annual net system costs in 2042 were reduced by $0.1B (2%) and the cumulative present value of net system costs to 2042 changed by $1.3B (3%). For the scenario 4 sensitivity, the annual net system costs in 2042 were reduced by $0.2B (4%), and the cumulative present value of net system costs to 2042 changed by $1.5B (3%). It should be noted that the change in the provincial guarantee fee was taken into consideration through the discount rate used in the analysis, as such the revised discount rate is applied to all cashflows such as capital, operating, and net market interactions. The changes noted here do not necessarily reflect the direct impact to the amount paid to the province as a result of securing Manitoba Hydro's debt.

Emission and cost results for the scenario 3 and 4 sensitivities are shown in Figure A5.52 below.

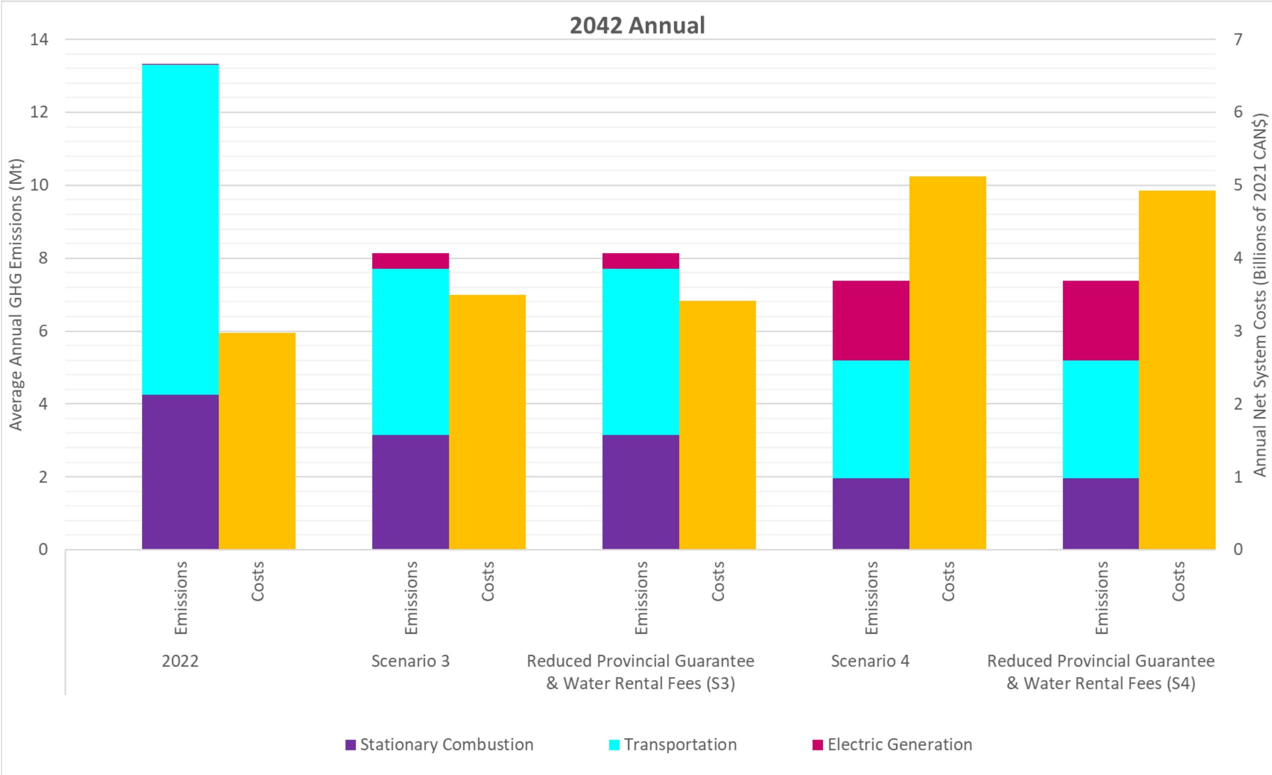


Figure A5.52 – Provincial Fees – 2042 Annual Emissions and Costs

New Hydropower

Objective

In all but one of the over 70 scenario and sensitivity cases, new hydropower was not found to be cost effective by the resource optimization model. The only case where new hydropower was found to be cost effective was in the sensitivity to scenario 4 reflecting no new natural gas turbines being permitted. This sensitivity aims to understand the value of new hydropower resources relative to other types of resources.

Methodology

This sensitivity assumes scenario 4 only permits new natural gas turbines with CCS as a selectable resource and includes the Conawapa hydropower station as a must select resource at the earliest year that it could be put into service, which is 2041. Conawapa was assumed because it has the lowest levelized cost of energy compared to other potential new hydropower resources in Manitoba. The value of Conawapa was calculated based upon the difference in the cumulative present value of net system costs to 2042 for the sensitivity case with and without Conawapa included. This incremental value was then compared to the cost of Conawapa, taking into account the length of time it was available within the window of the 20-year study period.

Results

Including Conawapa within the expansion plan results in a reduced need for both firm capacity and dependable energy. As a result, this impacts the quantity of other resources being selected, including wind and natural gas turbines with CCS.

The result is that for resource selections that include new hydropower to be as economic as a scenario that includes natural gas turbines with CCS, new hydropower would require at least 30% more revenue in order to offset the higher cost of new hydropower. Alternatively, the cost would need to reduce by at least 30% to be in alignment with the market value. This result is dependent on the cost and type of resource that it would compete against. If there are no restrictions on new natural gas turbines, then even more revenue would be required, or an even lower cost of new hydropower would be required. Further work is needed to provide additional understanding and insight into the overall competitiveness of new hydropower resources.

Wind

Objective

The cost of wind is assumed to reduce over time and is reflected in the scenario modelling. This sensitivity explores the impact on the resource mix if the cost of wind does not decline as fast as projected and results in higher costs over time.

Methodology

Scenarios 3 and 4 were adjusted to assume a projected capital cost curve for wind that declines at a slower rate than otherwise assumed in the scenarios. The projected rates of cost decline are based on projections developed by the National Renewable Energy Laboratory (NREL) for a range of technological developments and applied to Manitoba specific resource information. Figure A5.53 shows the reference levelized cost, assumed for the scenarios and high levelized cost of energy projections, assumed for the sensitivity analysis.

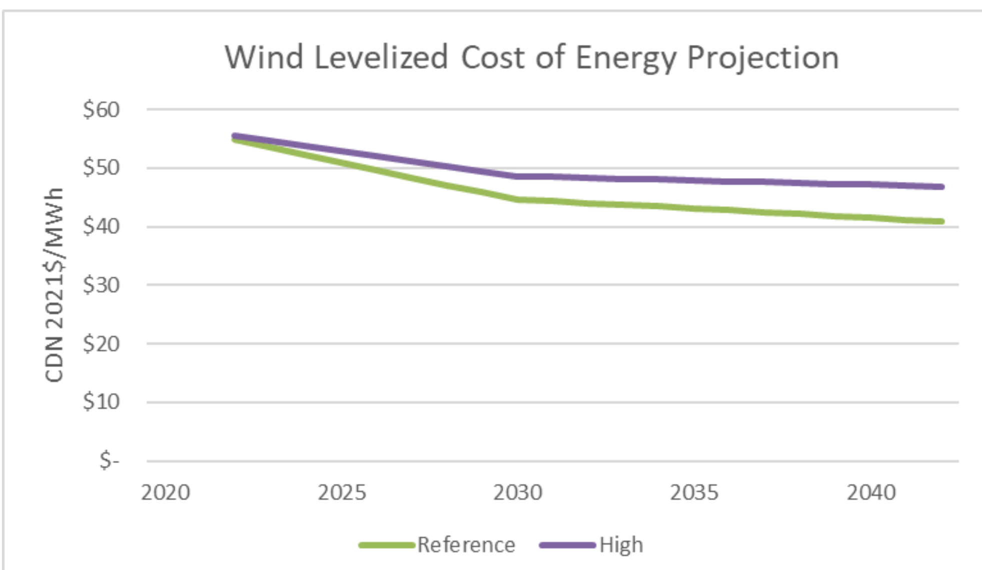


Figure A5.53 – Expected and Modified Levelized Cost of Wind Energy

Results

The assumed higher capital costs of wind did not strongly affect the expansion planning for the scenario 3 sensitivity but did result in notable changes in the scenario 4 sensitivity. Higher wind capital costs in the scenario 4 sensitivity resulted in approximately half as much wind being selected along with a delay in new wind additions as shown in Figure A5.54. In both the scenario 3 and scenario 4 sensitivities, wind remained an important part of the expansion plan despite the increased costs. Resource additions by 2042, broken down by resource type, are shown in Figure A5.55.

In both higher-cost wind sensitivities, the total amount of wind selected decreased. In the scenario 3 sensitivity, the reduction in new wind was relatively small at 8%, whereas the scenario 4 sensitivity saw a more significant decrease of 46%. This range in results is not unexpected as wind, even at a higher cost, is still a cost competitive energy resource. A likely driver for the difference in results is that the ratio of dependable energy need to firm capacity need for scenario 3 is higher than for scenario 4. As a result, there is more emphasis on seeking new energy resources in scenario 3, and more emphasis on seeking new capacity in scenario 4. Of importance is that with the exception of potential changes to the amount and timing of natural gas turbines and the elimination of hydrogen fueled turbines, no other energy resources such as solar PV or biomass were selected to replace wind.

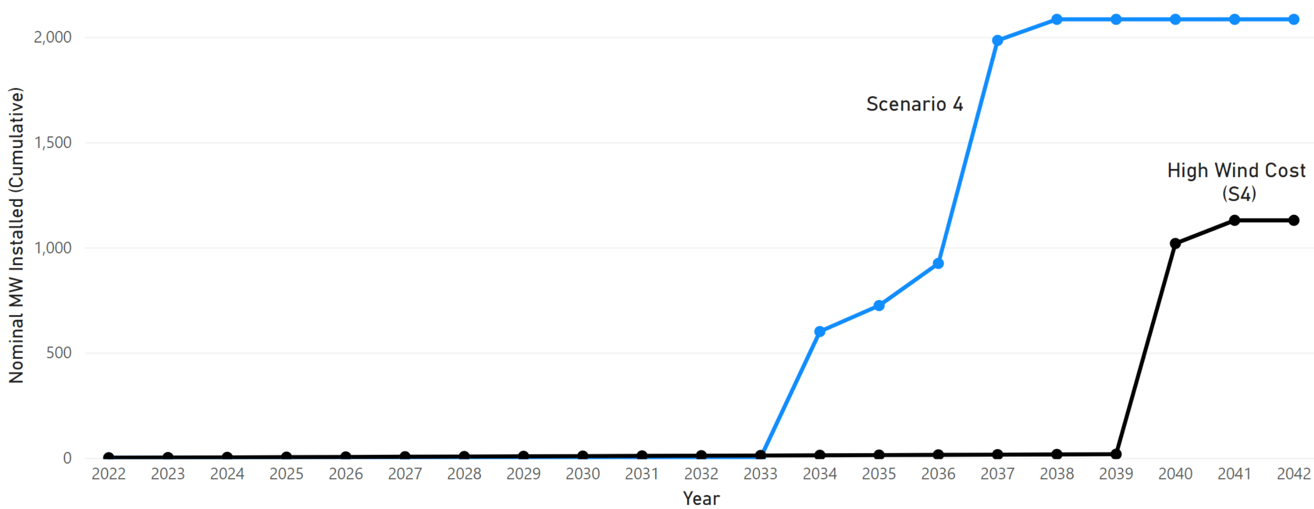


Figure A5.54 – Scenario 4 - Cumulative Nominal MW of Wind Added by Year

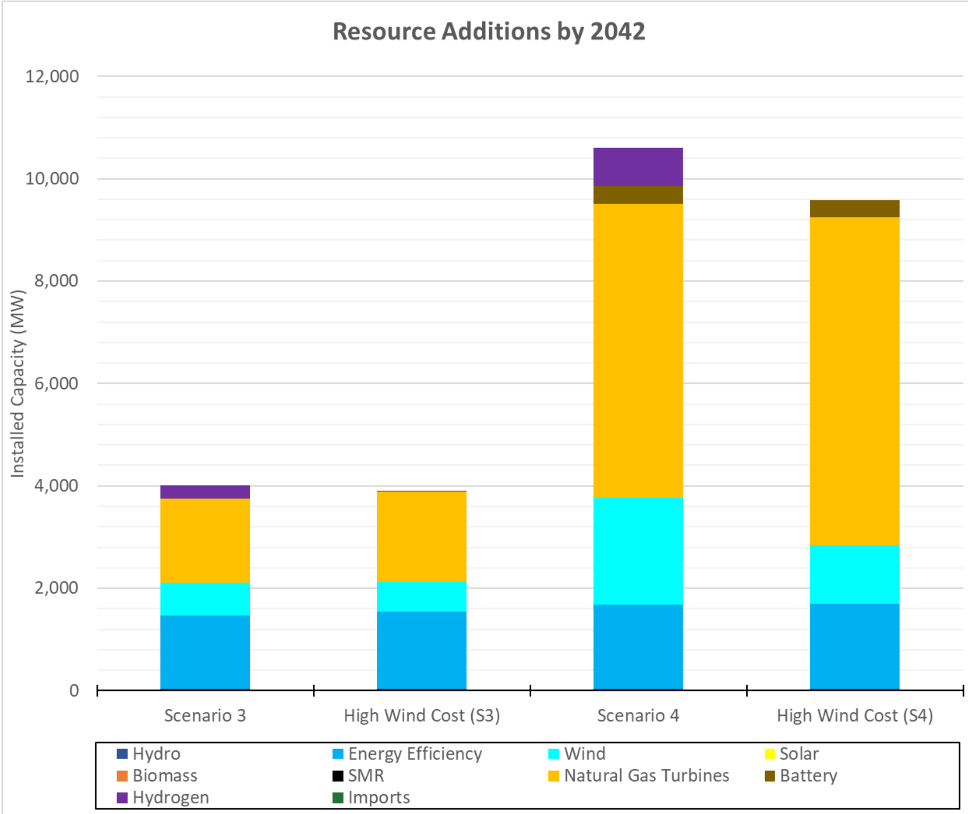


Figure A5.55 – High Wind Costs - Resource Additions by 2042

In the scenario 3 high-cost wind sensitivity, changes to the resource selection resulted in negligible changes in annual net system costs in 2042 and the cumulative present value of net system costs by 2042. Additionally, there were minimal changes in the amount of exports, imports, and thermal generation usage. Manitoba Hydro's resulting emissions from generation increased by 0.1 Mt by 2042. These impacts are illustrated in Figure A5.56.

In the scenario 4 high-cost wind sensitivity, changes in the resource selection resulted in reduced opportunity exports, increased imports, more natural gas turbine usage, and no hydrogen turbines. The higher cost wind results in an increased cost of surplus energy which reduces the cost effectiveness of hydrogen turbines resulting in no hydrogen turbines. Cumulatively, these changes had a relatively small impact on the annual net system costs in 2042 and the cumulative present value of net system costs by 2042, resulting in increases of 1% or less as shown on Figure A5.56. Annual generation emissions increased by 0.9 Mt in 2042, also shown on Figure A5.56, with the increased dispatch of natural gas turbines.

Overall, wind continued to be selected over a range of other resources and continued to play an important role within both scenarios, even at a higher cost. The exact amount and timing of wind may change, but wind is an economic energy resource under the range of potential future costs tested, with no other energy resources supplanting its selection.

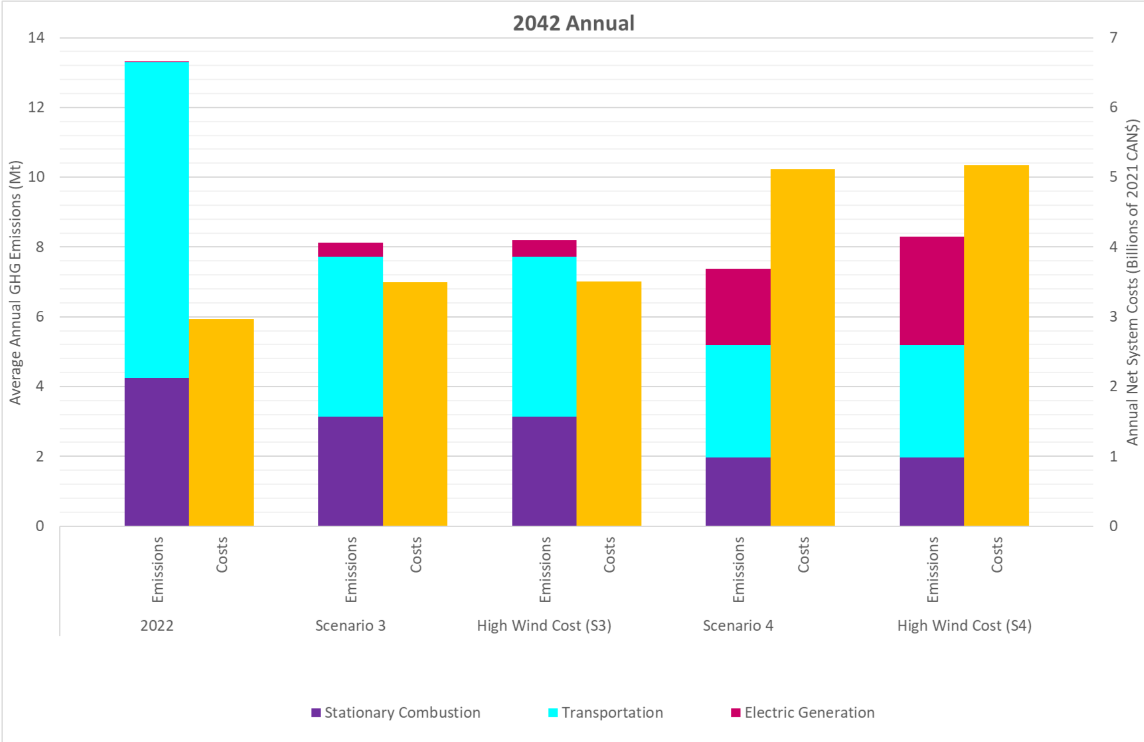


Figure A5.56 – High Wind Costs - Emissions and Costs

Solar PV – Utility Scale

Objective

This sensitivity explored how the price of solar PV generation impacts its economic competitiveness within the overall evaluation. In over 70 scenarios and sensitivities, utility scale solar generation was only selected once in the sensitivity with high GHG emissions costs. Solar generation provides electricity during some hours of the day but not when Manitoba demand peaks in the winter during non-daylight hours (Figure A5.57). Given that one of the main drivers for the need to build new resources is to provide for the growing winter capacity requirements, adding solar PV would not contribute towards Manitoba's increasing winter capacity needs.

This sensitivity explores if reduced investment costs for new utility-scale solar PV would make this type of generation economic for the Manitoba Hydro system, based on characteristics other than winter firm capacity. Solar PV can provide summer firm capacity, summer and winter dependable energy, and is assumed to have a 21% average production capacity factor. See Appendix 2 for further information on the resource characteristics of solar PV.

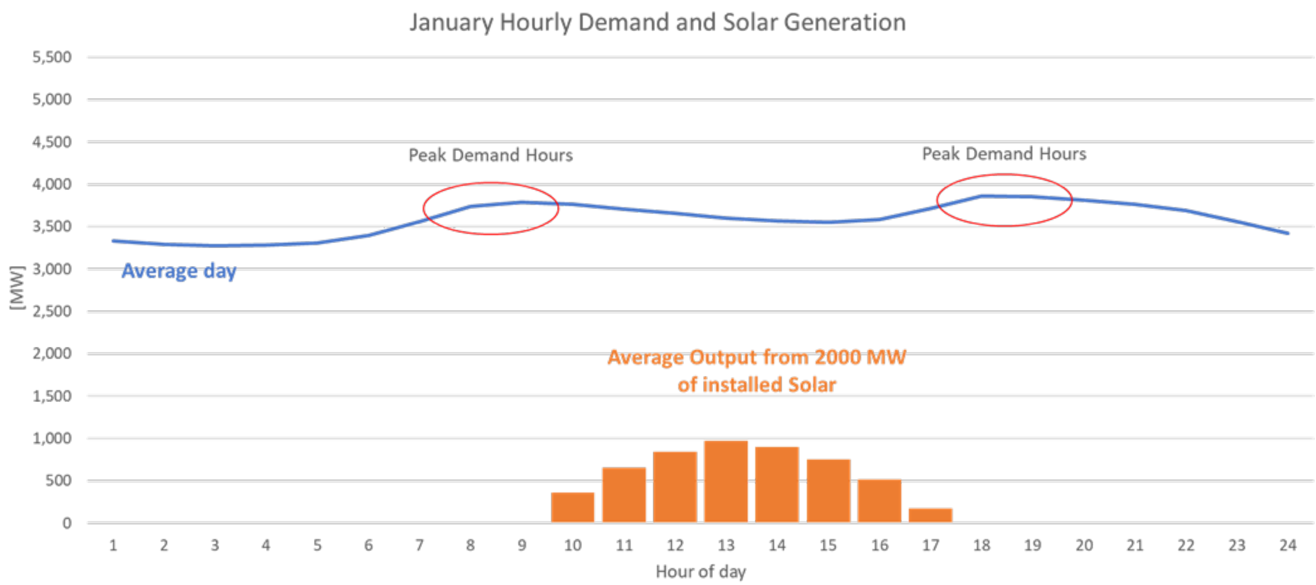


Figure A5.57 – January Hourly Demand and Solar Generation

Methodology

For scenario 4, the future capital cost projections for solar were reduced in two sensitivities. The first sensitivity reduced the costs of solar below the cost of wind. The second sensitivity reduced the costs further to just above the average annual import prices.

Results

Reducing the cost of solar PV to be less than the cost of wind did not improve the competitiveness of solar PV and it continued not to be selected in the resource optimization process. Reducing the cost of solar PV resources to just above the market import price resulted in 1,700 MW of solar being selected towards the end of the planning horizon in 2040. Of note is that the selection of solar PV only occurred in a single year and that year also included 1,800 MW of wind also being selected. The observation being that even under these favorable conditions solar has a challenging time competing against wind. Overall, utility-scale solar PV is not as cost-effective as other resources available in Manitoba, even when tested on the assumption that it is less expensive than new wind generation. Solar PV options were available for the model to select in all scenarios and sensitivities. However, solar PV was only selected in one sensitivity with high emissions costs. Generally, solar PV was not found to be as cost-effective compared to other resource options, including when reducing the cost of solar generation. Solar PV will continue to be studied for potential improvement in economics.

Electric Vehicles (EVs)

Objective

The scenarios evaluated contain a range of different electric vehicles (EV) adoption rates unique to each scenario. However, the impact of different EV adoption rates is difficult to interpret across the scenarios as the scenarios are a complex combination of a range of different input variables. The intent of this sensitivity is to explore the impact of the pace of EV adoption in isolation.

Methodology

To isolate the impact of the pace of EV adoption, scenario 2 was compared to sensitivities with the higher EV pace of adoption from scenarios 3 and 4.
The sensitivities of scenario 2 with higher EV load growth were:

- Scenario 2 with scenario 3 EV load.
- Scenario 2 with scenario 4 EV load.

Results

In both sensitivities, the increase in the pace of EV adoption resulted in the model selecting more natural gas turbine capacity to serve the firm demand.

Annual net system costs in 2042 were unchanged for the sensitivity with the EV adoption rate similar to scenario 3 and increased by 6% ($0.2B) for the sensitivity with the EV adoption rate similar to scenario 4. The cumulative present value of net system costs to 2042 increased by 1% ($0.3B) and 2% ($1.0B) for the two sensitivities respectively.

As shown in Figure A5.58, increasing the assumed uptake of EVs in scenario 2 led to reductions in transportation and overall provincial GHG emissions. However, Manitoba Hydro's own electricity generation emissions showed slight increases, as more natural gas turbines were required to address the increased firm capacity requirements associated with the larger EV load. The finding being that Manitoba Hydro can support higher EV adoption rates at a range of paces without incurring substantial increases in costs or GHG emissions.

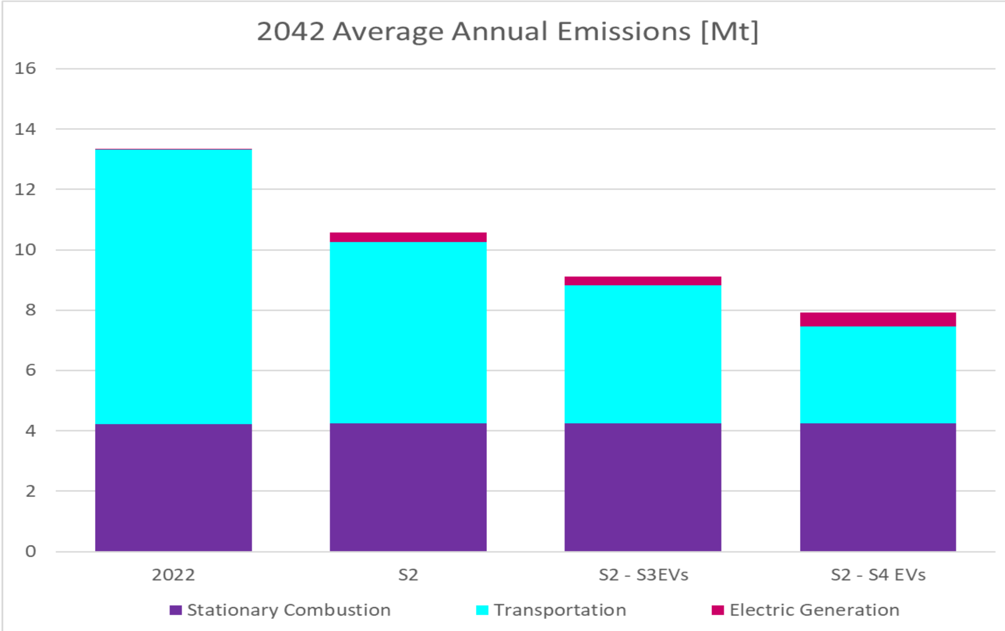


Figure A5.58 – 2042 Average Annual Emissions (Mt)

END OF APPENDIX