Appendix 2 – New Resource Options

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1 Introduction

Manitoba Hydro monitors and maintains an inventory of electricity generation resource options that have potential to meet Manitoba's future electricity needs. This inventory consists of different technologies including utility scale generation, enhancements to existing generating stations, distributed generation, and energy efficiency (demand side management) measures. Each of these resource options is considered and evaluated in the planning process based on their technical and economic characteristics. Descriptions for each of these resource options are provided in this appendix, including an overview of how they function, advantages and challenges associated with each resource, and a summary of key characteristics used within resource evaluations. The resource inventory reflects a diversity of fuel types, dispatchability, technological maturity, costs, and greenhouse gas (GHG) emissions. Descriptions of the resource characteristics are provided in the final section of this appendix for reference.

A key component of the resource planning process for supplying energy and capacity is the overall economic competitiveness of different options. Summary graphs of the levelized cost of energy and levelized cost of capacity are provided for comparison purposes. Within modelling evaluations, the relative cost of energy and capacity contributed to the existing electricity system and the existing resource mix determines the economic competitiveness of resource options.

2 Resource Options

In total there are 15 different resource options with some having more than one variation available. The following is a list of the resource options within the inventory:

- Variable Renewable Resources
  - Wind Generation
  - Solar Photovoltaic Generation
- Dispatchable Resources
  - Hydropower Generation
  - Natural Gas Simple Cycle Gas Turbine
  - Natural Gas Combined Cycle Gas Turbine
  - Market Capacity Imports
  - Biomass Generation
- Emerging Technology Resources
  - Hydrogen Simple Cycle Gas Turbine
  - Hydrogen Combined Cycle Gas Turbine
  - Natural Gas Combined Cycle Gas Turbine with Carbon Capture & Storage
  - Small Modular Reactor
  - Battery Storage
- Energy Efficiency
  - Main Grouping
  - Heat Pump Grouping
  - Distributed Solar Photovoltaic

Variable renewable resources, or intermittent resources, produce energy when the right conditions exist, such as when the sun is shining. As a result, they are good for energy needs but cannot always be counted on for capacity as they cannot be reliably operated to meet peak demands. Dispatchable resources are those that can be turned on and off as needed, and as a result are good capacity resources.

2.1 Wind Generation

Wind generation produces electricity using the force of wind to rotate blades of a turbine that are connected to a generator. A typical wind turbine assembly includes a generator, gearbox, and controls, which are housed in a compartment (a nacelle) located at the top of a turbine tower. The amount of wind energy transferred to a turbine is proportional to the sweeping area of the blades and the wind speed. Typical utility-scale wind farms consist of multiple three-bladed wind turbines (2.7 MW to 3.5 MW) spaced throughout a large footprint. Wind farms are scalable and can be built to any size. Operation of wind farms produce negligible GHG emissions.

Manitoba has the potential to develop at least several thousand megawatts of wind generation. There are currently areas within the province with suitable wind quality to achieve average capacity factors greater than 40%. Figure A2.1 provides the average capacity factor and average energy from a wind resource. If tower heights continue to rise and turbine efficiencies continue to improve the achievable capacity factor is also expected to improve.

Wind generation is a variable, or intermittent, resource with both seasonal and daily variability, typically producing slightly more energy during nighttime. Wind generation has limited firm capacity. The ability of wind to provide firm capacity during the winter coincident peak load in Manitoba is currently about 20% of the installed capacity. As the total amount of wind generation increases on the system, there is a decrease in the incremental amount of firm winter capacity provided by the additional wind generation. As a result of the limited firm capacity provided by wind generation, other types of generation are required to provide firm capacity and dispatchability to ensure that sufficient electricity is generated during peak demand hours.

There is a cost associated with integrating non-dispatchable resources such as wind into the existing electrical system. This includes the cost associated with the sub-optimal operation of the existing electrical system to incorporate the variability of wind production. The cost of transmission for delivering power to the grid can have a notable impact on overall cost. As increasing amounts of wind capacity are added, more extensive transmission upgrades are required.

Sub-zero weather presents operating challenges and requires upgrades to allow turbines to safely operate to -30C. Beyond this temperature operations may be restricted to prevent long term damage.

The levelized cost of wind has decreased over the years and is now one of the lowest cost electrical energy resources available, including in Manitoba. Continued technological development of wind turbines are forecast to result in further decreases in its levelized cost of energy out to 2030.

Table A2.1 – Advantages and Challenges of Wind Resource Options

Resource	Advantages	Challenges
Wind	• Negligible operating GHG emissions • Low-cost electrical energy resource • No fuel costs • Relatively short construction time • Scalable resource • Levelized energy costs expected to decline	• Variable resource • Most of the capacity is non-firm • Incremental winter firm capacity decreases with total wind generation • Increasing transmission costs with larger amounts of wind generation • Cold weather operation

Wind Characteristics

Represented as eight distinct blocks with increasing levels of transmission costs and decreasing levels of accredited winter capacity starting at 20% and reducing to 1% as more wind is added. Technical information provided for a standard 100 MW resource assuming the reference project lead time for an in-service date. Further explanation of the levels of firm capacity is provided in Appendix 4 – Analysis Approach.

Capacity	
Nominal Capacity	100 MW
Winter Firm Capacity	20 MW
Summer Firm Capacity	20 MW

Energy	
Dependable Energy	356 GWh/yr
Average Energy	381 GWh/yr

General Parameters	
Average Capacity Factor	44%
Heat Rate	N/A
Asset Life	25 years
Operating GHG Emission Intensity	0 kg CO_2e/MWh
Project Lead Time	Short: 5, Reference: 7, Long: 9 years
Reference In-Service Date	2030

Average Lifetime Operating & Maintenance Costs	
Fixed O&M Costs	$42/kW-yr
Variable Non-Fuel O&M Costs	$0.00/MWh
System Integration Costs	$3.91/MWh

Cost (2021 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$220 M	$2,196/kW	$53/MWh	$940/kW-yr
Without Transmission	$165 M	$1,649/kW	$44/MWh	$763/kW-yr

Figure A2.1 – Wind Characteristics and Costs

2.2 Solar Photovoltaic Generation

Solar photovoltaic (PV) generation is a solid-state semiconductor device that transforms light energy from the sun into electricity. Unlike most other generation options, solar PV produces direct current (DC) electricity. Electricity created can be used directly, converted into alternating current (AC), or stored in a battery for future use. Individual solar cells are relatively small and connected to form modules that make up larger panels, which are placed in arrays. Solar PV stations typically consist of many solar PV arrays connected in a solar "farm". To optimize energy production, arrays can be oriented towards the sun or use mechanical tracking systems to follow the sun's daily path across the sky. Solar farms are scalable and can be built to any size required.

During operation, no combustion or other chemical reactions are involved, resulting in a GHG emission free electrical energy resource. Solar resources are variable, or intermittent, so generation potential varies based on season, time of day, angle of the sun relative to the panels, geographical location, and cloud cover. On average, Southern Manitoba has a good quality solar resource. The solar resource in Manitoba is much stronger in the summer, with potential solar generation in June, July and August approximately double that for December, January, and February. The low power-to-size ratio of the arrays leads to significant spatial requirements for large-scale operations and can require large areas of land.

Generally, solar generation potential is opposite to Manitoba's energy needs. In summer, solar generation produces most electricity (more daylight hours and greater solar intensity) when electricity needs are the lowest. In winter, solar generation produces limited electricity (less daylight hours and lower solar intensity) when electricity needs are greatest. Furthermore, the ability of solar generation to provide firm capacity during Manitoba's winter peak coincident load is zero. As much of the system's winter peak load occurs during the non-daylight hours, solar provides little to no energy when it is needed most.

The levelized cost of solar PV electrical energy has reduced substantially over the past decade and has resulted in it becoming a competitive form of electricity in many jurisdictions. Despite these dramatic cost reductions, the cost of solar PV produced in Manitoba continues to be greater than wind, a competing low-cost, GHG emissions free resource. Continued technological development and economies of scale of solar are forecasted to continue to result in energy costs decreasing out to 2030.

Table A2.2 – Advantages and Challenges of Solar PV Resource Options

Resource	Advantages	Challenges
Solar Photovoltaics	• Negligible operating GHG emissions • Costs projected to decline • Low maintenance • Scalable resource • No fuel costs • Generation can be located near transmission or load	• Currently higher energy cost than wind • Highly variable • No firm capacity in winter • Energy production profile does not pair well with Manitoba Hydro's system needs • Low solar conversion efficiencies • Low power to size ratio

Solar Photovoltaic Characteristics

Represented as utility scale solar PV with single axis tracking. Evaluated in two blocks of increasing transmission costs that are scalable to any size. Technical information provided for a standard 100 MW resource assuming the reference project lead time for an in-service date.

Capacity	
Nominal Capacity	100 MW
Winter Firm Capacity	0 MW
Summer Firm Capacity	35 MW

Energy	
Dependable Energy	144 GWh/yr
Average Energy	188 GWh/yr

General Parameters	
Average Capacity Factor	21%
Heat Rate	N/A
Asset Life	30 years
Operating GHG Emission Intensity	0 kg CO_2e/MWh
Project Lead Time	Short: 6, Reference: 9, Long: 12 years
Reference In-Service Date	2032

Average Lifetime Operating & Maintenance Costs	
Fixed O&M Costs	$22/kW-yr
Variable Non-Fuel O&M Costs	$0.00/MWh
System Integration Costs	$3.22/MWh

Cost (2021 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$156 M	$1,557/kW	$68/MWh	N/A
Without Transmission	$148 M	$1,478/kW	$66/MWh	N/A

Figure A2.2 – Solar PV Characteristics and Costs

2.3 Hydropower Generation

Hydropower generates electricity by using the conversion of potential energy to kinetic energy from water that flows down an elevation. A typical generating station consists of a dam across a river, a powerhouse with generators, and a spillway. Water behind the dam is channeled into the powerhouse through a draft tube and onto a turbine. As the water is pushed down through the draft tube it passes through the turbine, causing it to rotate. The rotating turbine is connected to a generator which rotates to produce electricity.

To operate a dam safely, spillways are used to allow water to bypass around the generating station during times of high river flows, when there is too much water for the generating station to use. Additionally, some hydropower stations have reservoirs to help moderate the seasonal effects of natural water flows. Run-of-river hydropower stations have no reservoirs and are subject to natural water flow variations. Most of Manitoba Hydro stations have limited storage capabilities within the immediate forebay but have storage located further upstream.

Manitoba's peak load is during the winter heating season; however, river flows are highest during the spring when electricity demand is generally at or near its lowest. The availability of storage reservoirs within the hydraulic system allows fuel, in the form of water, to be stored during low demand seasons and used later during higher demand seasons.

Hydropower generating stations have very high upfront capital costs, along with very long planning and construction timelines. Additionally, hydropower stations typically have a very high capacity factor and very low operating and maintenance costs. In Manitoba, water rentals are paid to the provincial government on an annual basis based on the quantity of electricity generated from each plant.

The potential environmental impacts of large hydropower facilities, due to flooding, changes to water regime and habitat, require environmental assessments that can result in long regulatory review and approval processes.

Hydropower stations have very long useful service lives. Some of Manitoba Hydro's generating stations have been in service for over 100 years. For economic analysis purposes, the life of a new hydropower generating station is assumed to be 72 years, which reflects a combination of the different service lives of the mechanical and electrical equipment, and the service lives of the concrete and earthen structures.

Table A2.3 – Advantages and Challenges of Hydropower Resource Options

Resource	Advantages	Challenges
Hydropower	• Source of firm capacity • Reliable • Long life (over 70 years) • Negligible operating GHG emissions • Reservoirs provide energy storage	• High up front capital costs • Long lead times to implement • Sites typically not located near load centers • Seasonal water variations • Generation impacted by drought • Environmental impacts and long regulatory approval process

New Hydropower Resource Options

Manitoba Hydro's current inventory of potential hydropower stations includes 12 sites with total winter firm capacity of 3,500 MW. These 12 potential sites encompass a wide range of locations, electrical capacity, electrical energy, costs, and economics. Nine of the sites are included within the evaluation and are listed here:

Table A2.4 – Potential Hydropower Stations

Name	Nominal Capacity	Winter Firm Capacity	Dependable Energy
Bladder Rapids Generating Station	510 MW	-	3,100 MWh
Conawapa Generating Station	1,485 MW	1,265 MW	7,000 MWh
Early Morning Generating Station	80 MW	60 MW	500 MWh
First Rapids Generating Station	210 MW	195 MW	1,300 MWh
Gillam Island Generating Station	1,080 MW	850 MW	4,900 MWh
Kepuche Generating Station	210 MW	190 MW	1,100 MWh
Manasan Generating Station (High Head)	270 MW	250 MW	1,600 MWh
Manasan Generating Station (Low Head)	70 MW	60 MW	500 MWh
Notigi Generating Station	120 MW	100 MW	830 MWh

Detailed characteristics are provided for two of the hydropower sites with the most economic potential; Conawapa and Notigi.

Conawapa Characteristics

A ten unit generating station located on the Nelson River in Northern Manitoba. It is located downstream of the Limestone Generating Station and would operate as a run-of-river plant.

Capacity	
Nominal Capacity	1,485 MW
Winter Firm Capacity	1,265 MW
Summer Firm Capacity	1,360 MW

Energy	
Dependable Energy	4,930 GWh/yr
Average Energy	7,000 GWh/yr

General Parameters	
Average Capacity Factor	57%
Heat Rate	N/A
Asset Life	72 years
Operating GHG Emission Intensity	0 kg CO_2e/MWh
Project Lead Time	Reference: 18 years
Reference In-Service Date	2041

Average Lifetime Operating & Maintenance Costs	
Fixed O&M Costs	$13/kW-yr
Variable Non-Fuel O&M Costs	$3.34/MWh
System Integration Costs	$0.00/MWh

Cost (2021 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$9,902 M	$6,668/kW	$77/MWh	$401/kW-yr
Without Transmission	$9,332 M	$6,284/kW	$73/MWh	$378/kW-yr

Figure A2.3 – Conawapa Characteristics and Costs

Notigi Characteristics

A two unit generating station located on the Burntwood River in northern Manitoba. A powerhouse would be added to the existing Notigi site to take advantage of the current control infrastructure.

Capacity	
Nominal Capacity	120 MW
Winter Firm Capacity	100 MW
Summer Firm Capacity	100 MW

Energy	
Dependable Energy	750 GWh/yr
Average Energy	830 GWh/yr

General Parameters	
Average Capacity Factor	85%
Heat Rate	N/A
Asset Life	72 years
Operating GHG Emission Intensity	0 kg CO_2e/MWh
Project Lead Time	Reference: 10 years
Reference In-Service Date	2033

Average Lifetime Operating & Maintenance Costs	
Fixed O&M Costs	$46/kW-yr
Variable Non-Fuel O&M Costs	$3.34/MWh
System Integration Costs	$0.00/MWh

Cost (2021 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$1,259 M	$10,492/kW	$84/MWh	$657/kW-yr
Without Transmission	$1,002 M	$8,348/kW	$68/MWh	$525/kW-yr

Figure A2.4 – Notigi Characteristics and Costs

Enhancements to Existing Hydropower Stations

Enhancements to existing generating stations represents a potential source of additional electrical energy and capacity resources. There are potential improvements at existing hydropower stations that could be implemented to increase their electrical energy and/or capacity. One potential enhancement is to replace a turbine runner and other components at the Long Spruce Generating Station to increase the discharge through a unit resulting in more generating capacity. The project would result in additional electrical capacity at the station but would not result in any additional electrical energy. The potential enhancement to Long Spruce Generating Station is the only such project that has been incorporated into the analysis at this time however there is additional potential to enhance more units at Long Spruce and units at other generating stations.

Long Spruce Supply Side Enhancement Characteristics

A supply side enhancement (SSE) opportunity at the Long Spruce Generating Station to rerunner one of the existing units during a planned maintenance overhaul. The enhancement provides additional capacity but no energy. Assuming reference project lead time for an in-service date.

Capacity	
Nominal Capacity	38 MW
Winter Firm Capacity	38 MW
Summer Firm Capacity	38 MW

Energy	
Dependable Energy	0 GWh/yr
Average Energy	0 GWh/yr

General Parameters	
Average Capacity Factor	0%
Heat Rate	N/A
Asset Life	50 years
Operating GHG Emission Intensity	0 kg CO_2e/MWh
Project Lead Time	Reference: 4 years
Reference In-Service Date	2027

Average Lifetime Operating & Maintenance Costs	
Fixed O&M Costs	$0/kW-yr
Variable Non-Fuel O&M Costs	N/A
System Integration Costs	N/A

Cost (2021 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$47 M	$1,243/kW	N/A	$63/kW-yr
Without Transmission	$42 M	$1,111/kW	N/A	$56/kW-yr

Figure A2.5 – Long Spruce SSE Characteristics and Costs

2.4 Natural Gas Simple Cycle Gas Turbine

A simple cycle gas turbine (SCGT) is a type of internal combustion engine with an upstream rotating compressor, a combustion chamber, and a downstream turbine. Fuel is mixed with air and ignited in the combustion chamber, with the greatly expanded products of combustion forced into the turbine section. The products of combustion are directed through nozzles onto the turbine's blades causing the turbine to spin. The spinning turbine is then connected to a generator to produce electricity.

A SCGT is typically fueled by natural gas, however other fuels are also possible. Often dual-fuel capability with oil as a backup can be used to increase the availability of the generation when natural gas supplies are curtailed, though use of fuel oil as a backup fuel is infrequent and has become less common in recent years. For example, the SCGT units in Brandon have backup fuel however during their 20 years of operation the backup fuel has never been used.

SCGTs are a supply option that includes scalability, low capital costs, and high operational flexibility. SCGTs are available in a variety of sizes ranging from sub-megawatt to over 500 MW in size. SCGT power plants can consist of one or several turbine generator units. This allows a plant's capacity to better match system requirements, avoiding capital investment in excess of system needs.

SCGTs can be designed with quick-start capability, making them capable of ramping quickly to full load. This makes them suitable as emergency backup and can also provide regulation or shaping services for varying loads from variable resources such as wind. SCGTs are extensively used for meeting short-term peak load demands and providing grid support functions. However, this resource option is rarely used purely for electrical energy production due to its low efficiency relative to a combined cycle gas turbine (CCGT).

Environmentally, natural gas SCGT's water requirements are minimal and nitrogen oxide (NOx) air emissions can be controlled to low levels. GHGs are emitted at a rate of 532 kg CO_2e/MWh under normal plant operations. As a generating resource that produces GHG emissions, there are future risks regarding potential emission regulations that may increase the cost and/or restrict the use of this type of resource. See Appendix 6 for further detail on the changing policy landscape.

The natural gas SCGT resource option is a mature and reliable technology with further increases in gas turbine performance anticipated in the coming decades. These improvements are anticipated to result in subtle cost improvements over time.

Table A2.5 – Advantages and Challenges of Natural Gas SCGT Resource Options

Resource	Advantages	Challenges
Natural Gas Simple Cycle Gas Turbine (SCGT)	• Proven and reliable technology • Dispatchable resource • Low-cost capacity • Ideal for peaking and quick start operations • Reliable source of electrical energy during drought	• High variable operating cost • Fuel price risk and volatility • Less efficient than CCGT • Fossil fuel-based resource producing GHG emissions • Future GHG policy risk

Natural Gas SCGT Characteristics

Represented as a General Electric (GE) 7FA simple cycle gas turbine.

Capacity	
Nominal Capacity	210 MW
Winter Firm Capacity	223 MW
Summer Firm Capacity	196 MW

Energy	
Dependable Energy	1,603 GWh/yr
Average Energy	91-366 GWh/yr

General Parameters	
Average Capacity Factor	5-20%
Heat Rate	9,938 BTU/kWh
Asset Life	30 years
Operating GHG Emission Intensity	532 kg CO_2e/MWh
Project Lead Time	Reference: 6 years
Reference In-Service Date	2029

Average Lifetime Operating & Maintenance Costs	
Fixed O&M Costs	$18/kW-yr
Variable Non-Fuel O&M Costs	$5.99/MWh
System Integration Costs	$0.00/MWh

Cost (2021 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$223 M	$1,060/kW	$177-321/MWh	$79/kW-yr
Without Transmission	$210 M	$1,002/kW	$175-313/MWh	$76/kW-yr

Figure A2.6 – Natural Gas SCGT Characteristics and Costs

2.5 Natural Gas Combined Cycle Gas Turbine

A combined cycle gas turbine (CCGT) employs a SCGT along with a heat recovery steam generator using the Rankine cycle. A SCGT ignites a gas-air fuel mixture that expands and is forced through a turbine to rotate an electric generator. In addition, a second system is combined with the SCGT to capture the waste exhaust heat from the process and uses it in a Rankine cycle generator to convert high pressure water into steam. The expanding steam causes a second turbine that is connected to a generator to rotate and produce additional electricity. Use of the otherwise wasted heat of the turbine exhaust gas yields higher thermal efficiencies compared to SCGTs.

Typical CCGT units operate with natural gas as the working fuel. Often dual-fuel capability with oil as a backup can be used to increase the availability of the generation when natural gas supplies are curtailed, though use of fuel oil as a backup fuel is infrequent and has become less common in recent years. A CCGT is capable of providing base and intermediate load service with capacity factors commonly seen in industry ranging from 35% to 70%.

A natural gas CCGT is a supply option that includes attributes of high thermal efficiency, low to moderate capital cost, high reliability, lower air emissions, short lead times, and excellent operational flexibility. A CCGT is available in a variety of configurations ranging from less than 10 MW to over 1,000 MW in size.

With the use of a CCGT there are nitrogen oxide (NOx) and carbon dioxide (CO_2) emissions. Nitrogen oxide emissions can be controlled to low levels with the use of existing technology. GHGs are emitted at a rate of 358 kg CO_2e/MWh under normal plant operations. As a generating resource that produces GHG emissions, there are future risks regarding potential emission regulations that may increase the cost and/or restrict the use of this type of resource. See Appendix 6 for further detail on the changing policy landscape.

Water consumption for power plant condenser cooling appears to be an issue of increasing importance in North America. Water consumption can be reduced by use of dry (closed cycle) cooling, though at added cost and reduced efficiency. In the future, it is likely that an increasing number of new projects will use dry cooling.

Table A2.6 – Advantages and Challenges of Natural Gas CCGT Resource Options

Resource	Advantages	Challenges
Natural Gas Combined Cycle Gas Turbines (CCGT)	• Intermediate or baseload service • Dispatchable resource • Proven and reliable technology • More efficient than SCGT • Reliable source of electrical energy during drought	• Fuel price risk and volatility • Fossil fuel-based resource producing GHG emissions • Future GHG policy risk

Natural Gas CCGT Characteristics

Represented as a GE 7FA combined cycle gas turbine.

Capacity	
Nominal Capacity	308 MW
Winter Firm Capacity	325 MW
Summer Firm Capacity	291 MW

Energy	
Dependable Energy	2,339 GWh/yr
Average Energy	926-1,852 GWh/yr

General Parameters	
Average Capacity Factor	35-70%
Heat Rate	6,680 BTU/kWh
Asset Life	30 years
Operating GHG Emission Intensity	358 kg CO_2e/MWh
Project Lead Time	Reference: 6 years
Reference In-Service Date	2029

Average Lifetime Operating & Maintenance Costs	
Fixed O&M Costs	$24/kW-yr
Variable Non-Fuel O&M Costs	$3.18/MWh
System Integration Costs	$0.00/MWh

Cost (2021 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$392 M	$1,272/kW	$107-124/MWh	$100/kW-yr
Without Transmission	$374 M	$1,214/kW	$106-123/MWh	$97/kW-yr

Figure A2.7 – Natural Gas CCGT Characteristics and Costs

2.6 Market Capacity Imports

Imports from other jurisdictions over existing transmission lines are a potential resource option available to meet capacity requirements. Manitoba Hydro currently has a strong connection to the Midcontinent Independent System Operator (MISO) market in the United States (U.S.) providing energy and capacity. Depending on evolving market conditions, Manitoba Hydro could import electricity to meet short-term capacity needs in the future. Capacity imports are considered as a potential resource option with the associated energy imports taken into account through the modelling process within the limits of the generation planning criteria.

Manitoba Hydro's current long-term firm capacity import limit on existing transmission lines from the U.S. is 1,400 MW and this import capability can be fully used for energy import purchases during the equivalent of the off-peak period, as may be required by water conditions. Capacity purchases are intended as a short-term bridging resource until other forms of capacity are brought online. As a result, capacity purchases are limited to durations of five years or less, and a maximum of 50 MW. Larger capacity imports would most likely require capacity resources to be built in the U.S. specifically to serve Manitoba needs. Currently, the MISO market is evolving to be winter peaking and has little or no surplus capacity to meet Manitoba needs.

Generation from the MISO market is aggregated across all generation types to determine the associated GHG emission intensity profile as well as other hazardous air emissions. The average GHG emission intensity of generation in MISO-North was 448 kg CO_2e/MWh in 2020, down from 701 kg CO_2e/MWh in 2010, and is expected to continue dropping in the future. A GHG emission intensity of 448 kg CO_2e/MWh is slightly less than a natural gas SCGT but higher than a natural gas CCGT. Overall, the generation energy mix in 2022 in MISO was 31% non-emitting, with the bulk of the energy coming from wind and nuclear.

Table A2.7 – Advantages and Challenges of Import Resource Options

Resource	Advantages	Challenges
Market Capacity Imports	• Can be a flexible short lead time resource • Short duration purchases	• Prices subject to prevailing market conditions • MISO is currently short of capacity • MISO's generation mix and market are evolving resulting in uncertainty

Market Capacity Imports Characteristics

Capacity purchases of five years or less, up to a maximum of 50 MW at any given time.

Capacity	
Nominal Capacity	50 MW
Winter Firm Capacity	50 MW
Summer Firm Capacity	50 MW

Energy	
Dependable Energy	0 GWh/yr
Average Energy	0 GWh/yr

General Parameters	
Average Capacity Factor	N/A
Heat Rate	N/A
Asset Life	Contracts up to 5 years
Operating GHG Emission Intensity	448 kg CO_2e/MWh
Project Lead Time	Reference: 1 year
Reference In-Service Date	2024

Average Lifetime Operating & Maintenance Costs	
Fixed O&M Costs	$0/kW-yr
Variable Non-Fuel O&M Costs	$0.00/MWh
System Integration Costs	$0.00/MWh

Cost (2021 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	N/A	N/A	N/A	Market Based
Without Transmission	N/A	N/A	N/A	Market Based

Figure A2.8 – Market Capacity Imports Characteristics and Costs

2.7 Biomass Generation

Biomass materials such as waste wood, agricultural waste, crop residues or dedicated crops can be converted into heat, electricity, or both. Conventional steam-electric plants with or without cogeneration will likely be the chief technology for future electricity generation using crop or wood residues. Solid-fuel biomass fired power plants can use processes such as direct combustion or gasification. Direct combustion of biomass uses mature steam turbine plant technology involving a traditional four component process including a stoker-fired boiler, a turbogenerator, a condenser, and a boiler feed pump. A stoker-fired boiler has the flexibility to combust variably sized biomass having variable moisture content. This plant configuration can also be easily adapted to allow co-firing with other fuels such as natural gas.

Biomass is often shredded into small pieces to allow the fuel to be dried uniformly, which increases the combustion efficiency. Fuel handling can be more challenging versus traditional fuels – some biomass materials can plug fuel handling systems or boilers. The optimal size for a biomass fired electrical generating station is most likely in the 15 to 30 MW range due to a balance between the economies-of-scale and the cost of collecting, storing, and transporting fuel to site. Currently the cost of energy produced from this form of technology is high and is strongly dependent upon the cost to transport fuels.

This form of energy production can be considered carbon neutral since it replaces the natural release of CO_2 from biological decay by utilizing the material for energy production and releasing CO_2 during combustion. However, there is still an environmental impact as this resource produces CO_2 comparable to that of coal-fired generation.

The principal barriers to development of solid-fuel biomass plants are capital costs, the availability of cogeneration load for other commercial uses providing waste heat, and ensuring an adequate, stable, and economic supply of fuel.

The potential generation of all major biomass resources in Manitoba is estimated to be 4,000 to 5,000 GWh equivalent of energy. Since biomass resources are broadly geographically distributed, up to 40% of the levelized cost of energy is based on collection and transportation costs. With the development of various bioenergy industries, there is the potential for increased competition and prices for the same biomass feedstocks.

Table A2.8 – Advantages and Challenges of Biomass Resource Options

Resource	Advantages	Challenges
Biomass	• Dispatchable • Mature technologies	• High-cost energy & capacity source • Energy cost highly dependent on transportation fuel costs • Hazardous air emissions comparable to coal • Limited resource in Manitoba

Biomass Characteristics

Represented as a wood waste biomass plant.

Capacity	
Nominal Capacity	30 MW
Winter Firm Capacity	32 MW
Summer Firm Capacity	28 MW

Energy	
Dependable Energy	95 GWh/yr
Average Energy	5-218 GWh/yr

General Parameters	
Average Capacity Factor	2-83%
Heat Rate	13,500 BTU/kWh
Asset Life	40 years
Operating GHG Emission Intensity	0/1,620 (wo/w fuel) kg CO_2e/MWh
Project Lead Time	Reference: 8 years
Reference In-Service Date	2031

Average Lifetime Operating & Maintenance Costs	
Fixed O&M Costs	$97-296/kW-yr
Variable Non-Fuel O&M Costs	$6.19/MWh
System Integration Costs	$0.00/MWh

Cost (2021 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$176 M	$5,865/kW	$138-2,417/MWh	$397-596/kW-yr
Without Transmission	$162 M	$5,410/kW	$135-2,283/MWh	$375-574/kW-yr

Figure A2.9 – Biomass Characteristics and Costs

2.8 Hydrogen SCGTs and CCGTs

Hydrogen fueled turbines use the same technology as SCGTs and CCGTs but are designed to operate using hydrogen fuel. They produce power in the same way as SCGTs and CCGTs and have similar characteristics (See sections 2.4 and 2.5). One of the primary differences is that hydrogen turbines (SCGTs and CCGTs) produce no GHG emissions while operating. The other difference is the limited supply of hydrogen fuel, which is more restrictive than natural gas, resulting in restricted operating run time for hydrogen fueled units.

As utility scale hydrogen turbines are still in the development stage and are not expected to be commercially available until 2030, a high-level concept and cost estimate for hydrogen turbines was developed. This provided a wider range of non-emitting capacity resource options in the resource evaluation process. The hydrogen turbine concept is comprised of the following components: 100% hydrogen fueled combustion turbines (SCGT & CCGT); electrolyzer hydrogen production facilities with an associated electrical load on the Manitoba Hydro grid; hydrogen transportation; and hydrogen storage facilities. Due to the high cost and limited availability of fuel supply, it is used as a winter peaking resource exclusively.

A range of operating times and storage volumes were used to represent the needs of a capacity resource during peak winter cold periods. The resulting capacity factors used were 2%, 4%, 8%, 12%, 15%, and 19%. Due to the large volume of storage required, geological salt dome storage is assumed. The concept includes a small electrolyzer that refills the storage facility slowly over a 6 month timeframe during the summer, outside of the winter peak demand period. Generally, as capacity factors increase, CCGT's become more competitive than SCGT's because of better unit efficiencies overcoming higher capital costs.

Costs include the turbines, electrolyzers, transportation, salt dome storage, and operating & maintenance (O&M) costs. The cost and amount of electricity to produce the hydrogen is determined by the model. The resulting cost of the hydrogen capacity with a 2% capacity factor is approximately double the cost of natural gas fueled SCGTs, and four times with a 4% capacity factor.

Overall, hydrogen can be used to provide long duration energy storage. Converting electricity into hydrogen is in the range of 70-80% efficient plus any system process losses, compression losses, and storage losses. Converting hydrogen back into electricity using combustion turbines is typically 35-60% efficient depending upon the turbines used. The process of converting electricity back and forth from hydrogen results in an overall efficiency in the range of 25-50%, depending upon the specific technologies for electrolyzers, turbines, and other losses.

Table A2.9 – Advantages and Challenges of Hydrogen Turbine Resource Options

Resource	Advantages	Challenges
Hydrogen Turbine (SCGT & CCGT)	• Dispatchable peaking resource • Non GHG-emitting resource • Some technology components are proven	• Operating time limited by available fuel • Very high fuel costs • Double the cost of NG turbine capacity • Still in development stage • Large scale geological storage

Hydrogen SCGT Characteristics

Represented as a GE 7FA simple cycle with a hydrogen fuel supply that is restricted to 2% to 19% capacity factors. The unit is coupled with an electrical load to represent the electrolyzer and to account for the energy consumed.

Capacity	
Nominal Capacity	210 MW
Winter Firm Capacity	223 MW
Summer Firm Capacity	0 MW

Energy	
Dependable Energy	Summer: -119 to -1,193 GWh/yr Winter: +35 to +353 GWh/yr
Average Energy	Summer: -119 to -1,193 GWh/yr Winter: +35 to +353 GWh/yr

General Parameters	
Average Capacity Factor	2-19%
Heat Rate	9,938 BTU/kWh
Asset Life	30 years
Operating GHG Emission Intensity	0 kg CO_2e/MWh
Project Lead Time	Reference: 8 years
Reference In-Service Date	2031

Average Lifetime Operating & Maintenance Costs	
Fixed O&M Costs	$24-290/kW-yr
Variable Non-Fuel O&M Costs	$15.25/MWh
System Integration Costs	$0.00/MWh

Cost (2021 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$451-2,196 M	$2,146-10,455/kW	$617-1,117/MWh	$155-764/kW-yr
Without Transmission	$438-2,183 M	$2,088-10,397/kW	$615-1,098/MWh	$152-761/kW-yr

Figure A2.10 – Hydrogen SCGT Characteristics and Costs

Hydrogen CCGT Characteristics

Represented as a GE 7FA combined cycle with a hydrogen fuel supply that is restricted to 2% to 19% capacity factors. The unit is coupled with an electrical load to represent the electrolyzer and to account for the energy consumed.

Capacity	
Nominal Capacity	308 MW
Winter Firm Capacity	325 MW
Summer Firm Capacity	0 MW

Energy	
Dependable Energy	Summer: -122 to -1,222 GWh/yr Winter: +52 to +517 GWh/yr
Average Energy	Summer: -122 to -1,222 GWh/yr Winter: +52 to +517 GWh/yr

General Parameters	
Average Capacity Factor	2-19%
Heat Rate	6,680 BTU/kWh
Asset Life	30 years
Operating GHG Emission Intensity	0 kg CO_2e/MWh
Project Lead Time	Reference: 8 years
Reference In-Service Date	2031

Average Lifetime Operating & Maintenance Costs	
Fixed O&M Costs	$27-71/kW-yr
Variable Non-Fuel O&M Costs	$9.64/MWh
System Integration Costs	$0.00/MWh

Cost (2021 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$641-2,428 M	$2,080-7,882/kW	$460-1,075/MWh	$156-584/kW-yr
Without Transmission	$623-2,410 M	$2,023-7,825/kW	$458-1,056/MWh	$153-581/kW-yr

Figure A2.11 – Hydrogen CCGT Characteristics and Costs

2.9 Natural Gas CCGT with Carbon Capture and Storage

A combined cycle gas turbine with carbon capture and storage (CCGT+CCS) employs a standard CCGT along with equipment capable of capturing CO_2 emissions from the generator exhaust and storing the emissions. CCGT+CCS units have similar characteristics to CCGT units with the primary difference being lower net GHG emissions.

The aim of CCS is to permanently store CO_2 emissions in underground geological formations. CCS is a technology that is still in the demonstration stage of its technological development, with only a few dozen operating examples worldwide. The ability to capture 100% of all CO_2 emissions is challenging and not yet practical. A 90% capture threshold has become a typical target based on technological achievability and economics. Higher CO_2 capture rates may eventually be possible. There are substantial costs to adding CCS to a generating unit. This cost adds approximately 150% per MW of capacity for a CCGT unit, although this is highly variable based upon individual project parameters.

CCS equipment requires a significant amount of power to separate out CO_2, as well as for its compression, transportation, and storage in geological formations. As a result, the net capacity from a generating unit is derated by 10% and the unit efficiency by 11% to account for this consumption of power.

The prairie region, including southwestern Manitoba, possesses the appropriate geological formations to potentially store CO_2. Geological storage of CO_2 may exist in sedimentary basins, depleted oil and gas fields, saline formations, and shale formations. Currently, new legislation in Manitoba is required before captured CO_2 can be stored in geological formations.

Table A2.10 – Advantages and Challenges of Natural Gas CCGT+CCS Resource Options

Resource	Advantages	Challenges
Natural Gas CCGT with Carbon Capture & Storage (CCGT+CCS)	• Intermediate or baseload service • Dispatchable resource • Reliable source of electrical energy and capacity during drought • Manitoba has the appropriate geology for potential storage • Low net life cycle GHG emissions • Future GHG policy opportunity	• Fuel price risk and volatility • High cost for CCS • Notable power consumption for CCS impacting net generation • Does not capture 100% of GHG emissions • Future GHG policy risk • Demonstration stage of technological development

Natural Gas CCGT+CCS Characteristics

Represented as a GE 7FA combined cycle with 90% carbon capture and storage.

Capacity	
Nominal Capacity	308 MW
Winter Firm Capacity	293 MW
Summer Firm Capacity	262 MW

Energy	
Dependable Energy	2,111 GWh/yr
Average Energy	850-1,700 GWh/yr

General Parameters	
Average Capacity Factor	35-70%
Heat Rate	7,506 BTU/kWh
Asset Life	30 years
Operating GHG Emission Intensity	40.2 kg CO_2e/MWh
Project Lead Time	Reference: 8 years
Reference In-Service Date	2031

Average Lifetime Operating & Maintenance Costs	
Fixed O&M Costs	$43/kW-yr
Variable Non-Fuel O&M Costs	$8.25/MWh
System Integration Costs	$0.00/MWh

Cost (2021 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$960 M	$3,117/kW	$162-204/MWh	$247/kW-yr
Without Transmission	$942 M	$3,059/kW	$161-203/MWh	$243/kW-yr

Figure A2.12 – Natural Gas CCGS+CCS Characteristics and Costs

2.10 Small Modular Reactor

Nuclear power plants use the fission of radioactive material such as uranium, thorium, or plutonium as a fuel to generate electricity. The difference between a nuclear power plant and a conventional steam turbine plant is the way in which steam is created. In a conventional steam turbine plant, steam is created via combustion in a boiler. In a nuclear power plant, steam is created via the heat released by a controlled nuclear reaction. The reaction creates tremendous amounts of thermal energy, which is then captured by tubes containing pressurized water. The thermal energy from the reaction then converts the pressurized water into steam, which is used to rotate a turbine and a generator. Other than the method by which heat is created, the remaining components of a nuclear plant are the same as those of the heat recovery steam generator within a CCGT plant. Nuclear provides steady baseload power output but is generally not effective at changing its output to follow changes in load demand.

Small modular reactors (SMRs) are nuclear fission reactors that are smaller than conventional 1,000 MW scale nuclear reactors, typically less than 300 MW in size. They are being designed to be manufactured in portable modules at a plant and transported to site for installation. The intent is for modular reactors to reduce on-site construction, increase containment efficiency, and enhance safety. Enhanced safety would come from the greater use of passive safety features that operate without human intervention. SMRs also have the potential to reduce staffing levels versus conventional large scale nuclear reactors.

SMR designs range from scaled down versions of conventional nuclear designs to next generation designs. Expert opinions are highly varied regarding SMR costs, with some suggesting that recent fundamental design changes will result in significant cost reductions, while others suggest that they will likely be just as expensive on a per MW basis as full scale nuclear reactors. There are currently 150 individual SMR design concepts at various stages of design and development throughout the world. As of early 2023, there are two SMRs in operation in the world, one in China and one in Russia. This is an emerging technology with a high level of uncertainty on cost, performance, and attainment of commercial success.

For evaluation purposes two different SMR sizes have been considered at this time. They are based on the two most advanced designs currently at the regulatory approval and final design stages in North America. The two sizes are 77 MW based on the NuScale SMR and 300 MW based on the GE BWRX-300 SMR in the advanced stages of development by Ontario Power Generation.

Nuclear waste disposal continues to be an issue facing the industry, as there is currently no operational long-term storage facility in North America. Additionally, Manitoba's High-Level Radioactive Waste Act R10 currently prohibits the long-term storage of high-level radioactive waste in Manitoba.

Table A2.11 – Advantages and Challenges of SMR Resource Options

Resource	Advantages	Challenges
Small Modular Reactor	• No operating GHG emissions • Reliable baseload power	• Technology still in demonstration stage • High level of cost uncertainty • Societal concerns about safety and security • Long term radioactive waste disposal

Small Modular Reactor Characteristics

Represented as a 77 MW NuScale unit and a 300 MW GE BWRX-300 unit.

Capacity	
Nominal Capacity	77/300 MW
Winter Firm Capacity	77/300 MW
Summer Firm Capacity	77/300 MW

Energy	
Dependable Energy	607/2,367 GWh/yr
Average Energy	607/2,367 GWh/yr

General Parameters	
Average Capacity Factor	90%
Heat Rate	10,000 equ. BTU/kWh
Asset Life	40 years
Operating GHG Emission Intensity	0 kg CO_2e/MWh
Project Lead Time	Reference: 8 years or more
Reference In-Service Date	2031+

Average Lifetime Operating & Maintenance Costs	
Fixed O&M Costs	$134/kW-yr
Variable Non-Fuel O&M Costs	$4.25/MWh
System Integration Costs	$0.00/MWh

Cost (2021 CAN$)	Base Estimate (77MW/300MW)	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$682/2,750 M	$8,863/kW	$83/MWh	$659/kW-yr
Without Transmission	$675/2,628 M	$8,761/kW	$83/MWh	$653/kW-yr

Figure A2.13 – Small Modular Reactor Characteristics and Costs

2.11 Battery Storage

There are many different types of electrochemical storage technologies available: liquid metal, lithium-ion, sodium-ion, sodium sulfur, solid state, and vanadium redox flow. Of these, lithium-ion battery storage is one of the most mature battery technologies that currently dominates the electrical energy storage market and is expected to remain so for the next five to ten years. Lithium-ion batteries provide flexible configurations, high power and energy density, high round trip efficiency, and a low self-discharge rate. Some of the challenges faced by lithium-ion batteries are the potential for fire and/or explosion due to uncontrolled overheating, sensitivity to overcharging and temperature, and some raw material cost and availability.

Battery storage can respond to system demands in seconds and have typical storage capacities of four to six hours. They require a small physical footprint and can be sited almost anywhere. It is assumed batteries would be located at existing transmission sub-stations and as a result would incur limited transmission upgrade costs. For evaluation purposes, the size of a battery is assumed to have a duration of five hours. In some instances, battery storage may be paired with variable renewable resources, such as wind and solar, in order to assist in integrating the resources into the electrical system.

As battery storage is typically used in a daily cycle and as Manitoba is a winter peaking system, the maximum amount of battery storage that the system can utilize is based on the difference between the winter daytime peak demand and the winter nighttime low demand. This enables charging during the nighttime and discharging during the daytime to serve peak demand. Based on the current Manitoba winter demand profile the difference between the daytime highs and nighttime lows is approximately 700 MW. The resulting maximum battery storage limit is half of this amount at 350 MW, with half being served by discharging the battery and the other half being used for charging. For evaluation purposes this is assumed to remain the same over the study period and for all scenarios.

Battery storage is a net consumer of electrical energy due to the overall efficiency losses in the charge/discharge cycles, with a total efficiency of 90%. In comparison to other resource options, batteries have relatively short asset lives of approximately 15 years, which contrasts with 25, 40, and 72 years for other resources.

Additional indirect benefits include transmission/distribution asset deferral, congestion relief, time shifting of energy, energy arbitrage, ancillary services (frequency regulation, frequency response, black start support, voltage control), and customer services (power reliability, time of use or demand charge reductions). However, many of these benefits can be difficult to quantify or evaluate and are not represented at this time.

Table A2.12 – Advantages and Challenges of Battery Storage Resource Option

Resource	Advantages	Challenges
Battery Storage	• Highly flexible • Modular sizing • Low to no transmission costs • Can assist in integrating renewables	• High cost • Short asset life • Small storage volumes • Evolving technology

Battery Storage Characteristics

Represented as a lithium-ion battery with five hours of storage capability. Selectable as a resource in evaluations for any size needed up to a cumulative total of 350 MW. Technical information provided for a standard 100 MW resource assuming the reference project lead time for an in-service date.

Capacity	
Nominal Capacity	100 MW
Winter Firm Capacity	100 MW
Summer Firm Capacity	100 MW

Energy	
Dependable Energy	-109 GWh/yr
Average Energy	-109 GWh/yr

General Parameters	
Average Capacity Factor	17%
Round Trip Efficiency	90%
Asset Life	15 years
Operating GHG Emission Intensity	0 kg CO_2e/MWh
Project Lead Time	Early: 3, Reference: 6, Late: 8 years
Reference In-Service Date	2029

Average Lifetime Operating & Maintenance Costs	
Fixed O&M Costs	$37/kW-yr
Variable Non-Fuel O&M Costs	$0.00/MWh
System Integration Costs	$0.00/MWh

Cost (2021 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$162 M	$1,624/kW	N/A	$188/kW-yr
Without Transmission	$156 M	$1,563/kW	N/A	$183/kW-yr

Figure A2.14 – Battery Storage Characteristics and Costs

2.12 Energy Efficiency

Energy efficiency, also referred to as demand side management (DSM), refers to using less energy to delay or defer new resources. While there are many ways to reduce energy consumption in various sectors, the energy efficiency measures for this IRP focus on reducing the amount of electricity or natural gas used and its resulting impact on peak winter demand. Energy efficiency measures can reduce the use of existing electrical generating infrastructure, serve more customers with existing resources, or defer the need for new generation resources and transmission and distribution infrastructure.

Energy efficiency programs are implemented in Manitoba through Efficiency Manitoba. Efficiency Manitoba's legislated mandate is to "develop and support energy efficiency initiatives that reduce provincial consumption of electricity by 1.5% and natural gas by 0.75% annually".[1] Energy efficiency measures are packaged together and offered to residential, income-based, Indigenous, commercial, agricultural, and industrial customer segments through over 40 programs. Energy efficiency can also be achieved through changes to codes and standards.

One of the main considerations with energy efficiency measures as a resource option is that even with regulation and legislation, achieving energy reductions is dependent upon customers' actions. The energy savings potential used by Manitoba Hydro is estimated by Efficiency Manitoba and is based on a variety of assumptions including technological development, anticipated customer energy usage/savings, and market cost projections. As a result of these factors, uncertainty surrounding expected savings from energy efficiency measures is fundamentally different from the uncertainty and risk associated with traditional forms of resource supply options. Energy efficiency savings do not have the same level of certainty of supply achievement in the future as other generation or energy storage resource options if strictly pursued through voluntary market directed programs, where only a portion of a targeted amount may be achieved.

Manitoba Hydro has sought to consider energy efficiency measures in a similar way to other supply options like traditional generation resources. To do this, the full incremental cost of energy efficiency measures is used, which are costs above the price of standard products. This total resource cost of an energy efficiency measure includes Efficiency Manitoba's administration costs, the incremental product costs (to purchase energy efficient products instead of standard products, including incentives), and other avoided costs. The incremental product costs include customer incentives that cover a portion or all the incremental product cost. Energy efficiency measures are evaluated using technology specific asset lives unique to each program, measure, or grouping. Once an asset has come to the end of its useful life, it is assumed to be replaced at additional cost to continue with the energy and capacity savings benefits.

An additional benefit of energy efficiency measures is that by reducing demand for electricity there is the potential to reduce the need to enhance and/or expand the existing transmission and distribution systems. This avoided cost is calculated on a cost per kW of capacity savings that occur during Manitoba's winter peak demand. Manitoba Hydro determined how much each energy efficiency measure contributes to reducing the winter peak electricity demand, which may only be a portion of the maximum hourly energy

[1] https://efficiencymb.ca/about/

savings that can be provided by the energy efficiency measure. This avoided cost to the transmission and distribution systems is included within the total resource cost calculation to account for this benefit.

Energy efficiency measures were analyzed in two ways. First, Efficiency Manitoba's 2020-23 Efficiency Plan (Efficiency Manitoba Plan) was extrapolated through the 20-year planning horizon. Figure A2.15 shows the energy efficiency savings at common bus. As described in Appendix A3, these electricity savings were assumed to be achieved and therefore were subtracted from the electrical load projections for each of the IRP scenarios. This results in less electrical load than otherwise would need to be met for each scenario.

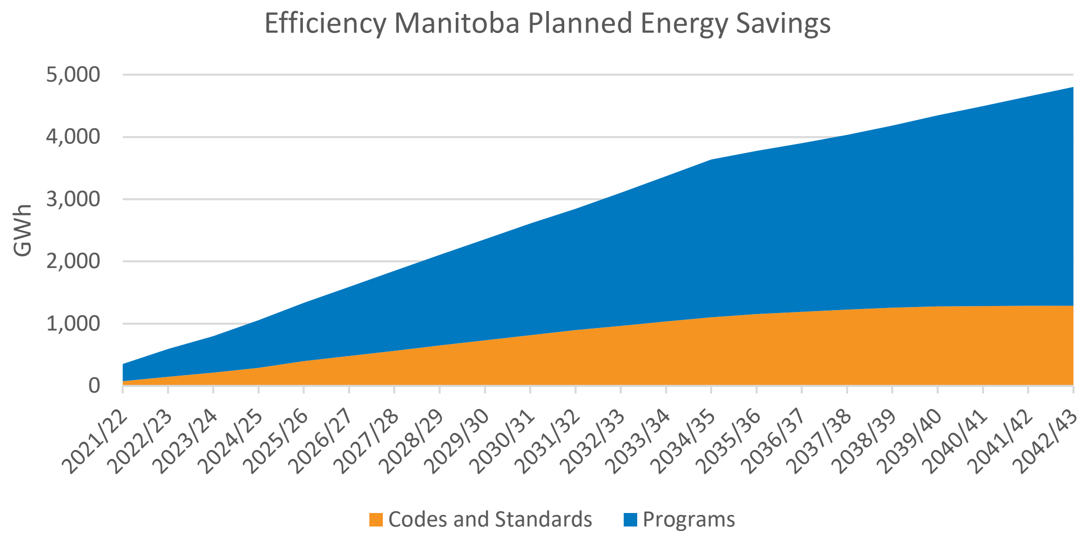

Figure A2.15 – Efficiency Manitoba Planned Savings Applied to Electrical Load[2]

Second, a market potential study conducted for Efficiency Manitoba determined that more energy savings could be achieved through additional potential energy efficiency measures. The market potential study included three levels of energy savings potential reflecting different incentive levels. These include a reference level, enhanced level, and maximized level. The energy efficiency potential for the maximized level is used in the evaluation and is included in the model where it competes on a level playing field with other supply options. A sensitivity analysis was undertaken to explore the impact of assuming the enhanced level which reduces the product incentive cost of energy efficiency measures and market potential. (see Appendix 5 – Analysis Results). The model can select extra energy efficiency measures as an option to meet future energy needs. This is above and beyond what is already assumed in the Efficiency Manitoba Plan extrapolated to 20 years. Manitoba Hydro used the results of this market potential study and worked with Efficiency Manitoba to group similar types of energy efficiency measures based on their energy savings profile so that they could be included as a selectable and scalable resource option in the model.

[2] 2022 savings shown are cumulative planned savings of the 2020-23 Efficiency Plan up to 2022

A projection of some anticipated codes and standards changes were incorporated into the load projections used for each scenario. However, additional codes and standards changes were not represented in the selectable energy efficiency resources incorporated into the modelling portion of the evaluation.

Table A2.13 – Advantages and Challenges of Energy Efficiency Resource Options

Resource	Advantages	Challenges
Energy Efficiency	• Can be a low-cost resource • Modular packages • Postpones the need for new resources • Short implementation time	• Limited market potential • Capacity savings are measure specific • Program participation is dependent upon customer behavior and market conditions • Wide range of costs between measures

Selectable Energy Efficiency

The market potential study conducted for Efficiency Manitoba includes over 100 individual energy efficiency measures spread over commercial, industrial, residential, agricultural, income-based, and Indigenous customer sectors. To represent these energy efficiency measures within the model, measures with similar savings profiles and costs were grouped together to establish weighted average parameters. Each of these groupings has its own market potential, energy benefits, summer and winter firm capacity contributions, asset life, and costs. This range includes two main categories of energy efficiency groupings: main groupings and heat pump groupings. In total, seven main groupings and eight heat pump groupings are included in the model as shown in Table A2.14 and Table A2.15 respectively.

Manitoba Hydro developed energy savings profiles for each of the groupings. Manitoba Hydro determined the firm capacity contribution of the energy savings groupings based on the grouping's energy savings that are coincident with summer and winter peak demand for each of the scenarios. The contribution of air source heat pumps to winter capacity savings is zero as they are assumed to only operate down to -10°C and -20°C (for cold climate heat pumps), requiring supplemental heating from another system when temperatures are colder (e.g., electric resistance or natural gas heating). The performance and cost of GSHPs can vary widely, with further study in the future required to refine assumptions.

Capital costs may vary over time depending upon market penetration levels or technological development. Transmission and distribution avoidance benefits are a function of the energy efficiency groupings contribution to the coincident winter firm load and is included as an avoided cost benefit.

The following tables provide energy efficiency groupings established for each of the IRP scenarios. Refer to Appendix 5 for the energy and peak demand savings potential for each energy efficiency grouping.

Table A2.14 – Energy Efficiency – Main Groupings

Grouping	Scenario 1, 2, 3, 4
EE-M1	Commercial Lighting
EE-M2	Commercial Uniform Load
EE-M3	Non-Residential Heating & Cooling
EE-M4	Industrial Custom
EE-M5	Non-Commercial Lighting
EE-M6	Residential Heating and Cooling
EE-M7	Non-Commercial Uniform Load

Table A2.15 – Energy Efficiency – Heat Pump Groupings

Grouping	Scenario 1, 2, 3	Scenario 4
EE-HP1	Residential Air Source Heat Pumps	Agricultural & Industrial Air Source Heat Pumps
EE-HP2	Other Air Source Heat Pumps	
EE-HP3	Other Cold Climate Air Source Heat Pumps	Commercial Cold Climate Air Source Heat Pumps
EE-HP4	Residential Cold Climate Air Source Heat Pumps	Agricultural & Industrial Commercial Cold Climate Air Source Heat Pumps
EE-HP5	Income Based Indigenous Cold Climate Air Source Heat Pumps	Cold Climate Air Source Heat Pump
EE-HP6	Agricultural & Industrial Ground Source Heat Pumps	
EE-HP7	Commercial Ground Source Heat Pumps	
EE-HP8	Other Ground Source Heat Pumps	

The avoided cost of transmission and distribution resulting from peak demand savings is provided in Table A2.16. More information about transmission and distribution cost assumptions are provided in Appendix 4.

Table A2.16 – Energy Efficiency – Transmission & Distribution Benefits

Load Growth	<=4,000 MW	>4,000 MW
Transmission	$28/kW-yr	$43/kW-yr
Distribution	$46/kW-yr	$46/kW-yr
Total	$74/kW-yr	$89/kW-yr

Distributed Solar PV

Distributed solar offsets customers' electricity consumption when installed behind the meter, with surplus solar generation going into the Manitoba Hydro grid. Solar generation profiles were used to establish a summer coincident peak savings based on annual energy savings from Efficiency Manitoba's market potential study. Distributed solar provides no winter coincident peak savings resulting in no winter firm capacity savings. The asset life of distributed solar PV is 30 years.

Distributed solar PV generation was modeled as a selectable and a scalable resource option, with the amount achievable based upon Efficiency Manitoba's market potential study maximized level.

Table A2.17 – Energy Efficiency – Solar PV Grouping

Grouping	Scenario 1, 2, 3, 4	Scenario 4
EE-SPV1	Solar PV	

Energy Efficiency – Main Groupings Characteristics

Represented as seven energy efficiency groupings with the parameters representing cumulative values from 2022 to 2042 based on the maximized level. The nominal capacity is the maximum savings achieved, while the winter/summer values are the coincident contribution to peak load.

Capacity	Scenario 1, 2, 3	Scenario 4
Nominal Capacity	361 MW	568 MW
Winter Firm Capacity	345 MW	548 MW
Summer Firm Capacity	239 MW	370 MW

Energy	Scenario 1, 2, 3	Scenario 4
Dependable Energy	2,053 GWh/yr	3,247 GWh/yr
Average Energy	2,053 GWh/yr	3,247 GWh/yr

General Parameters	Scenario 1, 2, 3	Scenario 4
Average Capacity Factor*	28-100%	28-100%
Heat Rate	N/A	N/A
Asset Life**	10-18 years	10-18 years
Operating GHG Emission Intensity	0 kg CO_2e/MWh	0 kg CO_2e/MWh
Project Lead Time	Minimum of 1 year	Minimum of 1 year
Reference In-Service Date	2024	2024

Average Lifetime O&M Costs	Scenario 1, 2, 3	Scenario 4
Fixed O&M Costs	$0/kW-yr	$0/kW-yr
Variable Non-Fuel O&M Costs	$0.00/MWh	$0.00/MWh
System Integration Costs	$0.00/MWh	$0.00/MWh

Cost (2021 CAN$)	Base Estimate (Initial Invest.)	Overnight Cost (Non Coinc. Peak)	Levelized Cost of Energy	Levelized Cost of Winter Capacity
Scenario 1, 2, 3				
With Avoided T&D Cost	$1,630 M	$1,535-4,197/kW	$45-108/MWh	$94-385/kW-yr
Without Avoided T&D Cost	N/A	N/A	N/A	$168-459/kW-yr
Scenario 4				
With Avoided T&D Cost	$3,164 M	$1,678-5,037/kW	$57-111/MWh	$106-499/kW-yr
Without Avoided T&D Cost	N/A	N/A	N/A	$186-579/kW-yr

Figure A2.16 – Energy Efficiency Main Groupings Characteristics and Costs

Energy Efficiency - Air Source Heat Pump Grouping Characteristics

Represented as five air source heat pump groupings for each of the scenarios for 2022 to 2042 based on the maximized level identified in Efficiency Manitoba's market potential study.

Capacity	Scenario 1, 2, 3	Scenario 4
Nominal Capacity	539 MW	895 MW
Winter Firm Capacity	0 MW	0 MW
Summer Firm Capacity	0 MW	0 MW

Energy	Scenario 1, 2, 3	Scenario 4
Dependable Energy	817 GWh/yr	1,415 GWh/yr
Average Energy	817 GWh/yr	1,415 GWh/yr

General Parameters	Scenario 1, 2, 3	Scenario 4
Average Capacity Factor*	18-22%	18-22%
SCOP	1.5	1.5
Asset Life	18 years	18 years
Operating GHG Emission Intensity	0 kg CO_2e/MWh	0 kg CO_2e/MWh
Project Lead Time	Short: 1, Long: 3 years	Short: 1, Long: 3 years
Reference In-Service Date	2024	2024

Average Lifetime O&M Costs	Scenario 1,2,3	Scenario 4
Fixed O&M Costs	$0/kW-yr	$0/kW-yr
Variable Non-Fuel O&M Costs	$0.00/MWh	$0.00/MWh
System Integration Costs	$0.00/MWh	$0.00/MWh

Cost (2021 CAN$)	Base Estimate (Initial Invest.)	Overnight Cost (Non Coinc. Peak)	Levelized Cost of Energy	Levelized Cost of Winter Capacity
Scenario 1,2,3				
With Avoided T&D Cost	$2,244 M	$1,284-5,721/kW	$71-374/MWh	N/A
Without Avoided T&D Cost	N/A	N/A	N/A	N/A
Scenario 4				
With Avoided T&D Cost	$2,773 M	$1,284-4,967/kW	$71-325/MWh	N/A
Without Avoided T&D Cost	N/A	N/A	N/A	N/A

Figure A2.17 – Energy Efficiency ASHP Grouping Characteristics and Costs

Energy Efficiency - Ground Source Heat Pump Grouping Characteristics

Represented as three ground source heat pump groupings for each of the scenarios for 2022 to 2042 based on the maximized level identified in Efficiency Manitoba's market potential study.

Capacity	Scenario 1,2,3	Scenario 4
Nominal Capacity	557 MW	844 MW
Winter Firm Capacity	468 MW	735 MW
Summer Firm Capacity	0 MW	27 MW

Energy	Scenario 1,2,3	Scenario 4
Dependable Energy	1,056 GWh/yr	1,600 GWh/yr
Average Energy	1,056 GWh/yr	1,600 GWh/yr

General Parameters	Scenario 1,2,3	Scenario 4
Average Capacity Factor*	24%	24%
SCOP	2.5	2.5
Asset Life	25 years	25 years
Operating GHG Emission Intensity	0 kg CO_2e/MWh	0 kg CO_2e/MWh
Project Lead Time	Short: 1, Long: 3 years	Short: 1, Long: 3 years
Reference In-Service Date	2024	2024

Average Lifetime O&M Costs	Scenario 1,2,3	Scenario 4
Fixed O&M Costs	$0/kW-yr	$0/kW-yr
Variable Non-Fuel O&M Costs	$0.00/MWh	$0.00/MWh
System Integration Costs	$0.00/MWh	$0.00/MWh

Cost (2021 CAN$)	Base Estimate (Initial Invest.)	Overnight Cost (Non Coinc. Peak)	Levelized Cost of Energy	Levelized Cost of Winter Capacity
Scenario 1,2,3				
With Avoided T&D Cost	$5,587 M	$3,532-6,132/kW	$185-242/MWh	$345-485/kW-yr
Without Avoided T&D Cost	N/A	N/A	N/A	$417-548/kW-yr
Scenario 4				
With Avoided T&D Cost	$5,584 M	$5,114-5,971/kW	$202-325/MWh	$370-444/kW-yr
Without Avoided T&D Cost	N/A	N/A	N/A	$440-513/kW-yr

Figure A2.18 – Energy Efficiency GSHP Grouping Characteristics and Costs

Energy Efficiency – Distributed Solar PV Characteristics

Selectable distributed solar PV available in scenarios 1, 2, 3, and 4 for 2022 to 2042 based on the maximized level identified in Efficiency Manitoba's market potential study.

Capacity	
Nominal Capacity	2,650 MW
Winter Firm Capacity	0 MW
Summer Firm Capacity	981 MW

Energy	
Dependable Energy	4,364 GWh/yr
Average Energy	4,364 GWh/yr

General Parameters	
Average Capacity Factor	21%
Heat Rate	N/A
Asset Life	30 years
Operating GHG Emission Intensity	0 kg CO_2e/MWh
Project Lead Time	Short: 1, Long: 2 years
Reference In-Service Date	2024

Average Lifetime Operating & Maintenance Costs	
Fixed O&M Costs	$0/kW-yr
Variable Non-Fuel O&M Costs	$0.00/MWh
System Integration Costs	$0.00/MWh

Cost (2021 CAN$)	Base Estimate (Initial Invest.)	Overnight Cost (Non Coinc. Peak)	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Avoided T&D Cost	$8,544 M	$2,064/kW	$103/MWh	N/A
Without Avoided T&D Cost	$8,544 M	$2,064/kW	$103/MWh	N/A

Figure A2.19 – Energy Efficiency Distributed Solar PV Characteristics and Costs

* Capacity factor determined using the maximum and averaged energy savings that would be achieved. The range reflects the different energy efficiency groupings.

** Asset life represents the weighted average life of all measures included in each of the energy efficiency groupings.

3 Resource Options Comparison

A simplified method of viewing the relative competitiveness of the various resource options is the comparison of the levelized costs of energy (LCOE) and levelized cost of capacity (LCOC). They represent the average cost per MWh and per kW-yr of building and operating a generating resource over the life of an asset. Key components include capital costs, fuel costs, fixed and variable maintenance costs, discount rate, energy production, firm winter capacity, and asset life. Some resources primarily produce electrical energy, some primarily produce electrical capacity, and some provide a combination of both. Resources that are primarily a source of electrical energy are shown in Figure A2.20. Resources that are primarily a source of electrical capacity are shown in Figure A2.22. Resources that provide a combination of both energy and capacity are shown on both charts. Due to the number of competing resources, a second set of zoomed in versions are provided in Figure A2.21 and Figure A2.23. See the glossary for further details on LCOE and LCOC calculations.

Levelized costs are an indication of the overall average cost of producing electrical energy and capacity, and do not provide an indication of the value of production. Determining the value and relative economics of individual resources is complex and involves modelling the interactions between new resources and the existing electrical system. For the purposes of making investment decisions, other factors are also considered, like technical issues including system characteristics, system needs, and planning criteria, along with environmental and social impacts.

In addition, levelized costs allocate appropriate costs to electrical energy and capacity production in isolation. The metric does not provide for a blended allocation of electrical energy and capacity together. As a result, energy and capacity can only be viewed in isolation. As with any projections, there are uncertainties with all factors and their values can vary regionally and across time as technologies evolve and forecasts change.

The graphs represent the projected levelized cost of energy and capacity over the 20-year study period. The dashed line represents the portion of the study period in which a resource is assumed to be unavailable for selection in the modeling process as a result of project lead times required to plan, approve, and construct the resources. In contrast, the solid line represents the portion of the study period in which a resource is assumed to be available in the model for selection as there is sufficient lead time to plan, approve, and construct projects.

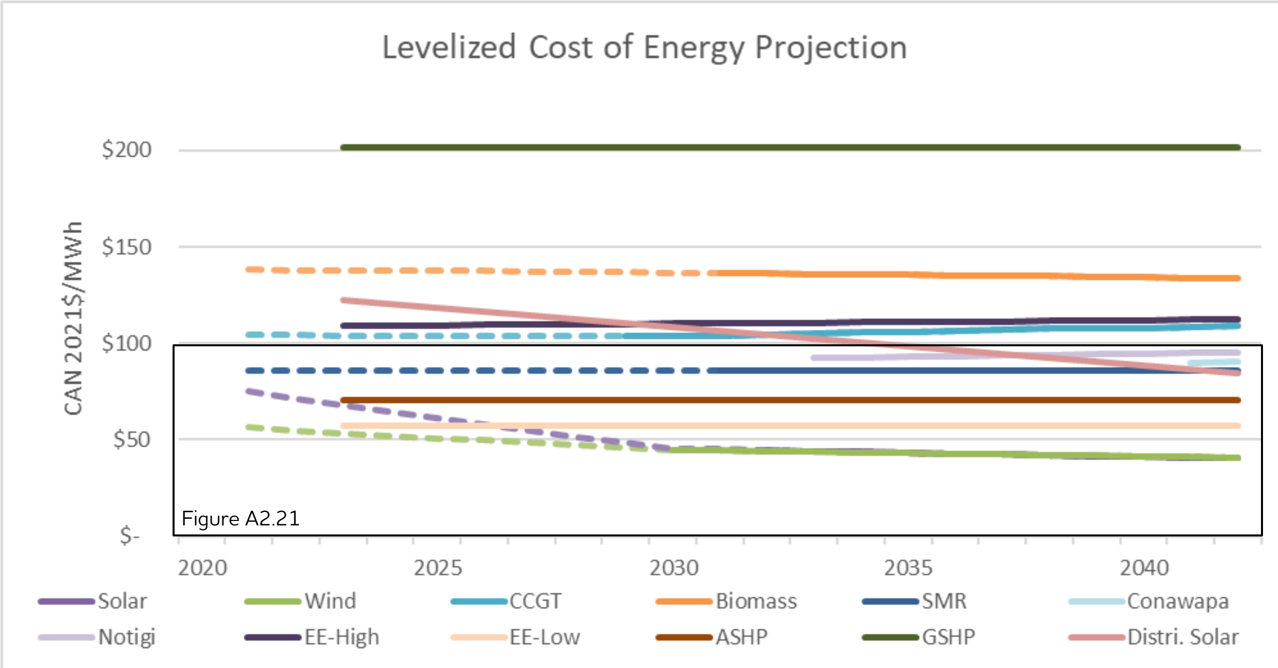

Figure A2.20 – Levelized Cost of Energy Projection

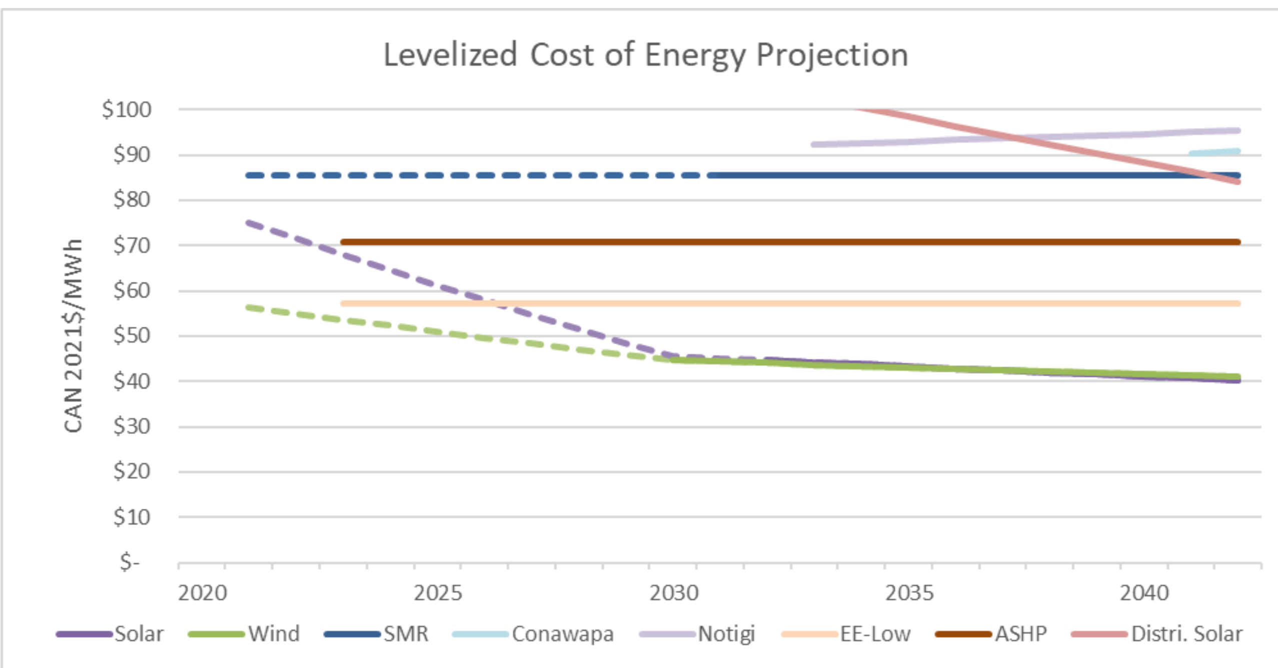

Figure A2.21 – Levelized Cost of Energy Projection - Detailed

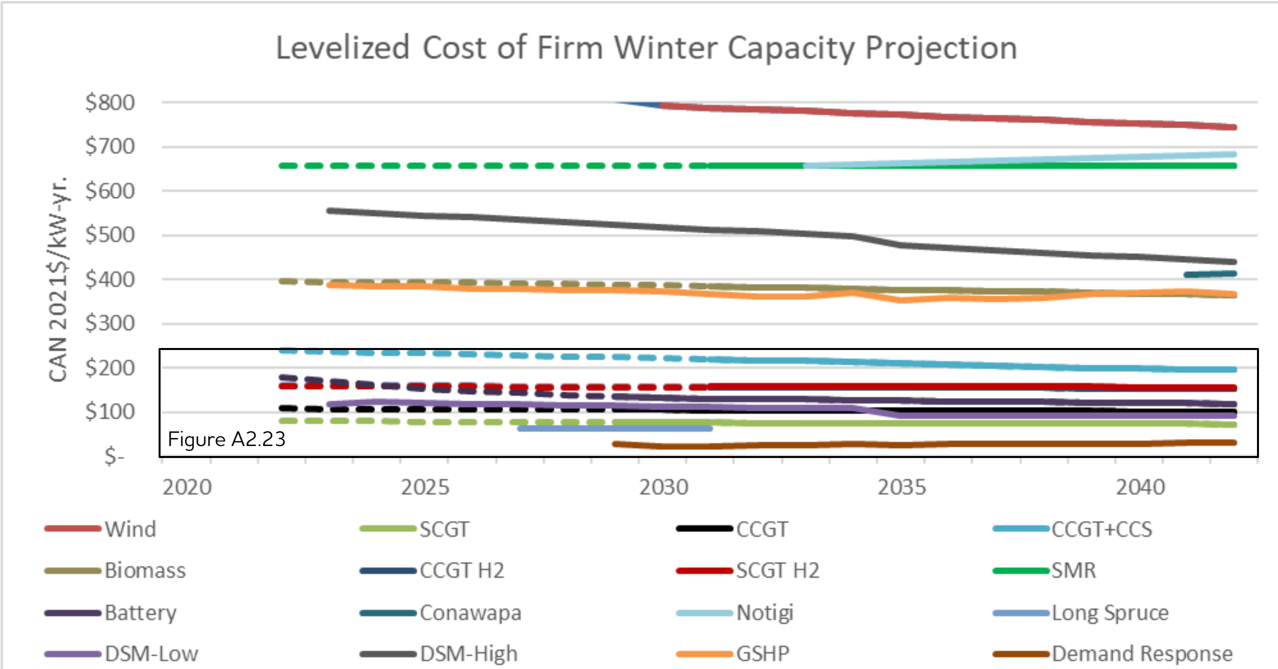

Figure A2.22 – Levelized Cost of Firm Winter Capacity Projection

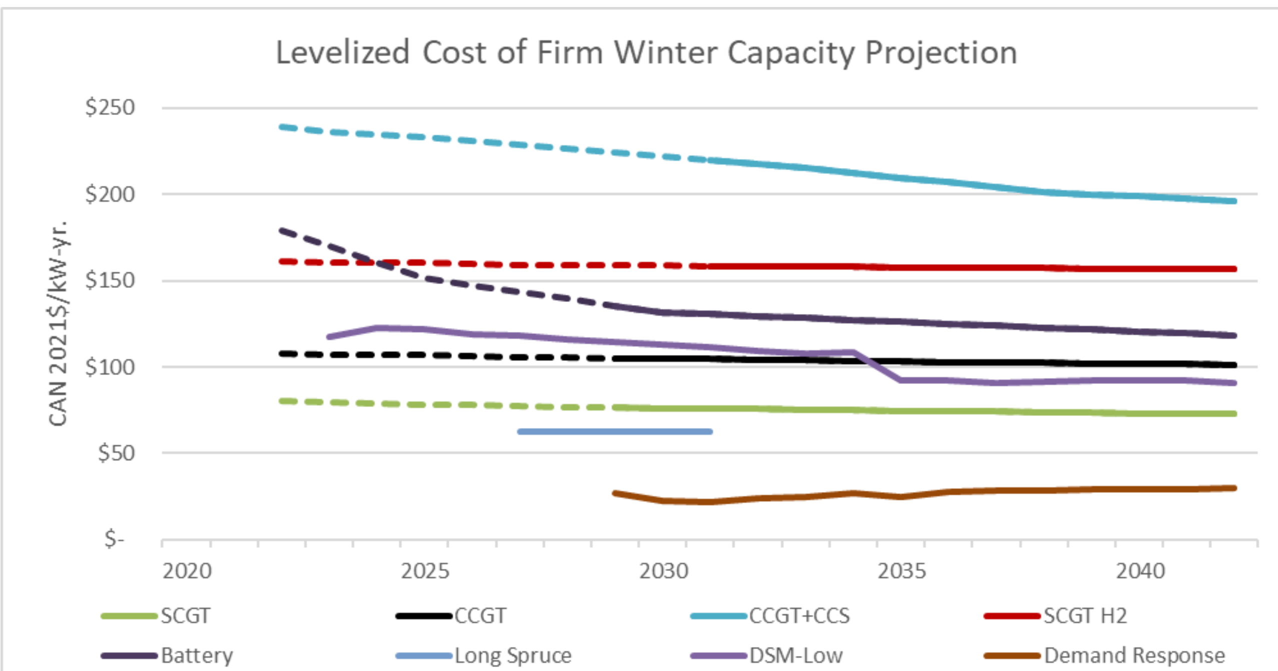

Figure A2.23 – Levelized Cost of Firm Winter Capacity Projection – Detailed

4 Resource Characteristic Descriptions

Capacity

Nominal Capacity (MW)

The approximate capacity rating of a plant based on normal operating conditions. For thermal options, it is equal to the annual average output under onsite atmospheric pressure (elevation) and temperature conditions. For hydropower options, it assumes a rounding of the installed capacity to the nearest 10 MW. For solar or wind, it represents the maximum output of the resource.

Summer Firm Capacity (MW)

The power generated or avoided (in the case of demand side measures) by a resource during Manitoba's peak demand hours through the summer months. For thermal options, a decrease in nominal capacity may occur due to higher ambient temperatures resulting in degraded performance. For hydropower resources, capacity losses at other hydropower stations incurred as a result of a new hydropower resource are netted out against the new resource's capacity. Variable resources such as wind and solar are not considered dispatchable or firm and therefore receive partial credit for their capacity.

Winter Firm Capacity (MW)

The power generated or avoided (in the case of demand side measures) by a resource during Manitoba's peak demand hours through the winter months. For thermal options, an increase in nominal capacity occurs due to lower ambient temperatures resulting in improved performance. For hydropower resources, downstream tailwater icing conditions can cause a plant's peak capacity to decrease. In addition, capacity losses at other hydropower stations incurred as a result of a new hydropower resource are netted out against the new resource's capacity. Variable resources such as wind and solar are not considered dispatchable or firm; there is partial capacity credit for wind and no credit for solar.

Energy

Average Energy (GWh/year)

The amount of electrical energy that a resource can produce under the average of a range of flow conditions. For hydropower options, it is the average amount of energy produced based on 110 years of flow history. For non-hydropower options, it represents the energy that would be expected under the same average of all flow conditions. For thermal resources, it is determined as part of the modelling process and varies depending on a range of factors. For informational purposes a range is provided based upon typical operating ranges seen in industry. For variable resources it is equal to their average energy production.

Dependable Energy (GWh/year)

The amount of electrical energy that a resource can produce during an extended drought where water flow conditions are equivalent to the lowest on record for the entire Manitoba hydropower system. For non-hydropower options, it represents the amount of energy that can reliably be produced under these same conditions. Thermal resources are assumed to operate to their full potential, net of forced outages and maintenance for dependable energy requirements.

Asset Life (years)

Represents the weighted average composite life of the various components of a resource. It does not necessarily indicate the maximum life of a project, as a resource may last longer with additional major capital investment in component refurbishment or replacement. For energy efficiency measures it represents the weighted average life of individual measures included in each of the energy efficiency groupings. Some measures will have a life that is shorter or longer than the weighted average.

Average Capacity Factor (%)

The ratio of average energy produced by a resource option on an annual basis to the maximum theoretical energy produced during continuous operation based on nominal capacity. For thermal resources, it is presented as a typical operating range, with the actual amount determined within the model.

Average Lifetime Operations and Maintenance Costs

Fixed Operating & Maintenance Costs (2021 CAN$/kW)

The fixed cost of operating and maintaining a resource that do not vary significantly with electrical generation levels such as general and administration expenses, staffing expenditures, plant support equipment, and routine maintenance. Values are reported as an annual average cost over the lifetime of the resource. Costs for hydropower resources were developed internally within Manitoba Hydro. Costs for SMRs were obtained from a publicly available source from Sargent and Lundy. Costs for all other resources are based on an average of publicly available sources that include the US Energy Information Agency, National Renewable Energy Laboratory, Lazard, and Lawrence Berkeley.

Variable Non-fuel Operating & Maintenance Costs (2021 CAN$/MWh)

The variable cost of operating and maintaining a resource that includes costs that noticeably vary with electrical generation levels such as water treatment, disposal of waste, chemicals, catalysts, lubricants, and other consumables. This does not include operating fuel costs. Costs for hydropower resources were developed internally within Manitoba Hydro. Costs for SMRs were obtained from a publicly available source from Sargent and Lundy. Costs for all other resources are based on an average of publicly available sources that include the US Energy Information Agency, National Renewable Energy Laboratory, Lazard, and Lawrence Berkeley.

Integration Costs (2021 CAN$/MWh)

The cost of integrating non-dispatchable variable resources such as wind and solar into the province's existing electrical system. This amount includes the cost associated with the sub-optimal operation of the existing electrical system. Currently costs associated with potential increased maintenance, potential impacts to Transmission Reliability Margin (TRM) and Automatic Generation Control (AGC), as well as seasonal energy variations are not included.

Base Estimate (2021 CAN$ millions)

The projected overnight capital cost of a resource with no interest or escalation and is presented in 2021 dollars. Costs for hydropower resources were developed internally within Manitoba Hydro. Costs for SMRs came from a publicly available report from Sargent and Lundy. Costs for all other resources are based on an average of publicly available sources that include the US Energy Information Agency, National Renewable Energy Laboratory, Lazard, and Lawrence Berkeley. In addition to the current cost of resources, future cost curves were used based upon projections from the National Renewable Energy Laboratory.

Heat Rate (BTU/kWh)

The amount of energy in BTUs required to generate one kWh of electrical energy. It is a measurement of a generating unit's thermal efficiency. It is applicable to thermal resource options only.

Levelized Cost of Capacity (2021 CAN$/kW-yr)

A standard simplified cost metric for comparing a resource based on the cost of producing a unit of capacity (CAN$/kW-yr). It is determined by the present value of a resource's capital cost, fixed operating costs, and taxes, divided by the present value of the firm winter capacity provided over the life of a resource. Values are expressed with and without transmission costs included. Values are calculated utilizing Manitoba specific inputs and values where appropriate. This simplified metric does not allocate costs for energy produced and should only be used when comparing the cost of capacity between resources.

Levelized Cost of Energy (2021 CAN$/MWh)

A standard simplified cost metric for comparing resources based on the cost of producing a unit of energy (CAN$/MWh). It is determined by the present value of a resource's capital cost, fixed and variable operating costs, fuel costs, and taxes, divided by the present value of the average expected energy produced over the life of a resource. Values are expressed with and without transmission costs included. Where applicable, values have been adjusted for line losses for transmitting energy from northern stations to southern load. Values are calculated utilizing Manitoba specific inputs and values where appropriate. This simplified metric does not allocate costs for capacity and should only be used when comparing the cost of energy between resources.

Operating GHG Emission Intensity (kg CO_2e/MWh)

The intensity of greenhouse gas emissions produced per MWh generated during the operating phase of a resource. Emission intensity can vary with loading but is presented at full operating load within this appendix.

Overnight Cost (2021 CAN$/kW)

The projected base estimate expressed per unit of capacity and excludes interest and escalation. In industry this is often referred to as the overnight cost.

Project Lead Time (years)

The lead time necessary to plan, license, and construct a resource, including any new transmission needed to connect the resource to the grid. Planning and licensing includes site investigations, preliminary design, environmental assessments, and regulatory approvals to develop a resource. Construction includes the final design, procurement, and construction of a resource. A project lead time's main impact is on the date a resource could potentially be put into service within an evaluation. The uncertainty with project lead time is represented by an expected short, reference, and long-range estimate.

Reference In-Service Date (date)

The earliest a resource could be in-service based on the reference project lead time.

Transmission Cost (2021 CAN$)

The cost of associated transmission required to interconnect a new resource to the existing electrical system. It is in addition to a resource's generating station cost, typically provided within industry references. It is presented with, and without, values for the Base Estimate, Overnight Cost, Levelized Cost of Energy, and Levelized Cost of Capacity. Transmission concepts and cost estimates were developed for each resource option based upon an assumed location and size. If necessary, the concepts included a staged level of transmission development based upon increasing amounts of capacity added for each resource (i.e. wind).