Appendix 6

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 have different technical and economic characteristics included in the model for resource evaluations. Further evaluation is done outside of the model, including through evaluation metrics. 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 electrical 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 21 different resource options with some having more than one variation available. The following is a list of the resource options within the inventory:

- Variable Resources
  - Wind Generation
  - Solar Photovoltaic Generation
- Dispatchable Resources
  - Hydropower Generation
  - Enhancements to Existing Hydropower
  - Natural Gas Combustion Turbine
  - Aeroderivative Combustion Turbine
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  - Biomass with Carbon Capture & Sequestration
  - Small Modular Reactor
  - Battery Storage
- Selectable Energy Efficiency
  - Residential Home Insulation
  - Air Source Heat Pumps
  - Ground Source Heat Pumps
  - Electric Thermal Storage Systems
  - Custom Energy Solutions

Most fuel-based resource options (e.g., natural gas combustion turbines, biomass generation, biodiesel combustion turbines) use, or can potentially use, biofuels (e.g., biodiesel, biomass, biomethane) instead of fossil fuels, which can mitigate the GHG emissions impacts of electricity generation (More details are provided in Appendix 5 - Load Projections.

Variable 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.

Emerging technology is a term generally used to describe a new technology, but it may also refer to the continuing development of an existing technology. Emerging Technology Resources are options currently in the demonstration and early commercial development phase and are potentially available within the next decade.

Energy efficiency, also referred to as demand side management (DSM), refers to customers reducing their consumption of energy and/or peak demand. Each load projection includes a base level of energy efficiency (More details are provided in Appendix 5 – Load Projections). Efficiency Manitoba, in collaboration with Manitoba Hydro, established this base level in 2024 by preparing a longer-term extrapolation of future energy efficiency savings adhering to the mandated minimum average annual targets as outlined in the Efficiency Manitoba Act (More details are provided in Appendix 4 - Policy Landscape). Selectable energy efficiency represents potential energy efficiency programming above and beyond the base level of energy efficiency included in each load projection and consists of 11 energy efficiency groups.

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 spaced throughout a large footprint. Wind farms are scalable and can be built to a range of sizes. Operation of wind farms produce negligible GHG emissions.

Manitoba has the potential to develop several thousand megawatts of wind generation. There are currently areas within the province with suitable wind quality to achieve average utilization factors greater than 40%. Figure A2.1 provides the average utilization factor and average energy from a wind resource. If tower heights continue to rise and turbine efficiencies continue to improve the achievable utilization 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 and the winter months. 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 the total cost of wind. 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 30oC. 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 A6.1 - 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 costs expected to decline	• Variable resource • Most of the capacity is non-firm • Incremental winter firm capacity decreases with total wind install • 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. Further explanation of firm capacity is provided in Appendix 7.1 – Modelling & Analysis Approach.

Capacity	
Nominal Capacity	100 MW
Winter Firm Capacity	20 MW
Summer Firm Capacity	16 MW

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

General Parameters	
Average Utilization factor	44%
Heat Rate	N/A
Asset Life	25-30 years
Operating GHG Emission Intensity	≈0 kg CO_2e/MWh
Project Lead Time [1]	Short: 5, Reference: 7, Long: 9 years
Reference In-Service Date	2032

Average lifetime operating & Maintenance costs	
Fixed O&M Costs	$50/kW-yr
Variable Non-Fuel O&M Costs	$0.00/MWh
System Integration Costs	$4.59/MWh

Cost (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$214 M	$2,138/kW	$56/MWh	$1,070/kW-yr
Without Transmission	$180 M	$1,796/kW	$50/MWh	$946/kW-yr

Figure A6.1 - ZEV Sales Targets

[1] Modelled in-service dates for wind generation is discussed in Appendix 7.1 – Modelling and Analysis Approach

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 a range of sizes.

Operation of solar farms produce negligible GHG emissions. 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 generation produced in Manitoba continues to be greater than wind, a competing low-cost, low GHG emissions resource. Continued technological development and economies of scale of solar are forecasted to continue to result in energy costs decreasing out to 2030.

Table A6.2 - 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 a range of sizes. Technical information provided for a standarvd 100 MW resource assuming the reference project lead time for the in-service date.

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

Energy	
Dependable Energy	150 GWh/yr
Average Energy	188 GWh/yr

General Parameters	
Average Utilization 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	2034

Average lifetime operating & Maintenance costs	
Fixed O&M Costs	$24/kW-yr
Variable Non-Fuel O&M Costs	$0.00/MWh
System Integration Costs	$3.78/MWh

Cost (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$177 M	$1,769/kW	$88/MWh	N/A
Without Transmission	$168 M	$1,680/kW	$84/MWh	N/A

Figure A6.2 - 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 flows down through the draft tube it passes through the turbine, pushing the turbine blades 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 variations in water flow. Most Manitoba Hydro stations have limited storage capabilities within the immediate forebay; however, there is normally water storage located further upstream.

Manitoba's peak load is during the winter heating season; however, natural river flows are often high 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 high upfront capital costs, along with very long planning and construction timelines. Additionally, hydropower stations typically have a very high utilization factor and low operating and maintenance costs compared to other resources. 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 lengthy regulatory review and approval processes. Hydroelectric development can alter natural carbon cycles, primarily through the flooding of organic matter and its resulting decomposition over time. Manitoba Hydro has directly studied reservoir GHG emissions and have estimated the impact of recent hydroelectric projects.[2] Hydroelectric reservoir GHG emissions are considered in the lifecycle GHG assessment of hydropower generation (more details are provided in Appendix 7.2 - Modelling & Analysis Results).

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.

[2] https://keeyask.com/wp-content/uploads/2012/07/Climate.pdf

Table A6.3 - 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 • 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 a 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 A6.4 - Potential Hydropower Stations

Name	Nominal Capacity	Winter Firm Capacity	Average Energy
Bladder Rapids Generating Station	510 MW	-	3,100 GWh
Conawapa Generating Station	1,485 MW	1,043 MW	7,000 GWh
Early Morning Generating Station	80 MW	50 MW	500 GWh
First Rapids Generating Station	210 MW	164 MW	1,300 GWh
Gillam Island Generating Station	1,080 MW	765 MW	4,900 GWh
Kepuche Generating Station	210 MW	190 MW	1,100 GWh
Manasan Gererating Station (High Head)	280 MW	176 MW	1,600 GWh
Manasan Generating Station (Low Head)	90 MW	80 MW	500 GWh
Notigi Generating Station	120 MW	84 MW	830 GWh

Detailed characteristics are provided for two of the hydropower sites with the most economic potential; Conawapa and Notigi. However, most sites are included within the model evaluation.

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	1,043 MW
Summer Firm Capacity	1,121 MW

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

General Parameters	
Average Utilization 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	2043

Average lifetime operating & Maintenance costs	
Fixed O&M Costs	$19/kW-yr
Variable Non-Fuel O&M Costs	$1.67/MWh
System Integration Costs	$0.00/MWh

Cost (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$12,512 M	$8,425/kW	$106/MWh	$641/kW-yr
Without Transmission	$11,304 M	$7,612/kW	$97/MWh	$583/kW-yr

Figure A6.3 - Conawapa Characteristics and Costs

Notigi Characteristics

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

Capacity	
Nominal Capacity	120 MW
Winter Firm Capacity	84MW
Summer Firm Capacity	84MW

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

General Parameters	
Average Utilization 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	2035

Average lifetime operating & Maintenance costs	
Fixed O&M Costs	$64/kW-yr
Variable Non-Fuel O&M Costs	$1.67/MWh
System Integration Costs	$0.00/MWh

Cost (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$1,369 M	$11,408/kW	$101/MWh	$872/kW-yr
Without Transmission	$1,077 M	$8,972/kW	$81/MWh	$694/kW-yr

Figure A6.4 - Notigi Characteristics and Costs

Enhancements to Existing Hydropower Stations

Enhancements to existing hydropower generating stations represents a potential source of additional electrical energy and capacity. There are potential improvements at existing hydropower stations that could be implemented to increase their electrical energy and/or capacity. Potential enhancements that have been identified include the replacement of outdated generating units at Pointe du Bois Generating Station and the uprating of existing generating units along the lower Nelson River. The uprates would entail replacement of turbine runner, generator, and other components at the Long Spruce and Kettle Generating Stations to increase the discharge through the units, resulting in more generating capacity.

The additional four units at Point du Bois Generating Station would result in additional capacity and energy. These additional four units are expected to have the same unit characteristics as the units currently being installed as part of the Point du Bois Energy Renewal Project (PREP). This project would benefit from potentially being completed prior to winter 2030 when new capacity is required. The implementation of this project would require limited engineering scope as the unit design is already complete and no additional powerhouse or transmission upgrades are anticipated.

Planned maintenance outages scheduled at Kettle and Long Spruce Generating Stations provide an opportunity to upgrade these units. By extending the planned outage, instead of overhauling a single component of the existing asset, a larger unit would be installed within the existing powerhouse footprint. The unit replacement would result in additional accredited capacity at the stations but would not result in any additional energy. These units are assumed to be in service starting in 2032. Three different cases were evaluated as shown in the table below. Each case results in incrementally more capacity ranging from 25 MW up to 179 MW (winter firm capacity):

Cost (2024 CAN$)	Kettle GS Replaced Units	Long Spruce GS Replaced Units	Total Number	Levelized Cost of Winter Capacity
Case 1	0	1	1	25
Case 2	1	2	3	77
Case 3	3	4	7	179

Figure A6.5 - Replacement Units by Case

Lower Nelson Supply Side Enhancement Characteristics – Case 1

A supply side enhancement (SSE) opportunity at the Long Spruce Generating Station exists to rerunner an existing unit during a planned maintenance overhaul. Transmission upgrades would not be required to support the incremental capacity. The enhancement provides additional capacity but no additional energy. Assuming reference project lead time for an in-service date in 2032.

Capacity	
Nominal Capacity	27 MW
Winter Firm Capacity	25 MW
Summer Firm Capacity	26 MW

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

General Parameters	
Average Utilization factor	1 - 3%
Heat Rate	N/A
Asset Life	50 years
Operating GHG Emission Intensity	≈0 kg CO_2e/MWh
Project Lead Time	Reference: 7 years
Reference In-Service Date	2032

Average lifetime operating & Maintenance costs	
Fixed O&M Costs	N/A
Variable Non-Fuel O&M Costs	N/A
System Integration Costs	N/A

Cost (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	N/A	N/A	N/A	N/A
Without Transmission	$78 M	$2,882/kW	N/A	$159/kW-yr

Figure A6.6 - Long Spruce SSE 1 Characteristics and Costs

Lower Nelson Supply Side Enhancement Characteristics – Case 2

A supply side enhancement (SSE) opportunity at the Long Spruce Generating Station and Kettle Generating Station exists to rerunner a total of three existing units during a planned maintenance overhaul. One unit would be replaced at Kettle GS and two units at Long Spruce GS. Transmission upgrades would not be required. The enhancements provide additional capacity but no additional energy. Assuming reference project lead time for an in-service date in 2032.

Capacity	
Nominal Capacity	85 MW
Winter Firm Capacity	77 MW
Summer Firm Capacity	80 MW

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

General Parameters	
Average Utilization factor	1 - 3%
Heat Rate	N/A
Asset Life	50 years
Operating GHG Emission Intensity	≈0 kg CO_2e/MWh
Project Lead Time	Reference: 9 years
Reference In-Service Date	2032-2033

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 (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	N/A	N/A	N/A	N/A
Without Transmission	$220 M	$2,588/kW	N/A	$150/kW-yr

Figure A6.7 - Long Spruce SSE 2 Characteristics and Costs

Lower Nelson Supply Side Enhancement Characteristics – Case 3

A supply side enhancement (SSE) opportunity exists at the Long Spruce and Kettle Generating Stations to rerunner a total of seven existing units during a planned maintenance overhaul. Three units would be replaced at Kettle GS and four units at Long Spruce GS. Transmission upgrades would be required to support the incremental capacity. The enhancement provides additional capacity but no energy. Assuming reference project lead time for an in-service date in 2032.

Capacity	
Nominal Capacity	201 MW
Winter Firm Capacity	179 MW
Summer Firm Capacity	188MW

Energy	
Dependable Energy	0 GWh/yr
Average Energy	≈250 GWh/yr

General Parameters	
Average Utilization factor	1 - 3%
Heat Rate	N/A
Asset Life	50 years
Operating GHG Emission Intensity	≈0 kg CO_2e/MWh
Project Lead Time	Reference: 9 years
Reference In-Service Date	2032-2036

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 (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$590 M	$2,934/kW	N/A	$188/kW-yr
Without Transmission	$473 M	$2,352/kW	N/A	$148/kW-yr

Figure A6.8 - Long Spruce SSE 3 Characteristics and Costs

Pointe du Bois Additional Units Supply Side Enhancement Characteristics

PREP Phase 1 is in execution to replace eight of the 16 units by 2027. A potential opportunity exists to replace an additional four units at Pointe du Bois GS. These additional four units would provide an additional 26 MW of firm capacity and 110 GWh/yr of average energy. The scope of the project is significantly reduced compared to Phase 1 as most of the required powerhouse and transmission components would already be in place. It is assumed that the ISD would be 2029.

Capacity	
Nominal Capacity	26 MW
Winter Firm Capacity	26 MW
Summer Firm Capacity	26 MW

Energy	
Dependable Energy	0 GWh/yr
Average Energy	250 GWh/yr

General Parameters	
Average Utilization 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	2029-2030

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 (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	N/A	N/A	N/A	N/A
Without Transmission	$142 M	$5,447/kW	$74/MWh	$340/kW-yr

Figure A6.9 - Pointe du Bois – Additional Units Characteristics and Costs

2.4. Natural Gas Combustion Turbine

A combustion turbine (CT), also referred to as 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 onto the turbine's blades causing the turbine to rotate. The rotating turbine is then connected to a generator to produce electricity.

A CT is typically fueled by natural gas, however other fuels (e.g., biodiesel, biomethane, hydrogen) are also possible. Often dual-fuel capability with diesel as a backup can be used to increase the availability of the generation when natural gas supplies are limited. Use of diesel as a backup fuel is infrequent and has become less common. For example, the CT units in Brandon have backup diesel fuel; however, during their 20 years of operation the backup fuel has never been used (outside of testing).

CTs are a supply option that are scalable, have low capital costs, and have high operational flexibility. CTs are available in a range of sizes from 50 MW to 500 MW. CT 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.

CTs 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. CTs are extensively used for meeting short term peak load demands and providing grid support functions. However, this resource option is rarely used purely for base load electricity generation due to its low efficiency relative to a combined cycle combustion turbine (CCCT).

At a typical heat rate, 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 air emission regulations that may increase the cost and/or restrict the use of this type of resource. More details are provided in Appendix 4 – Policy Landscape for details on the changing policy landscape. The operation of CTs on alternative fuels, such as biomethane (likely using a credit system, Appendix 7.1 – Modelling and Analysis Approach) or hydrogen blending, could reduce GHG emissions (more details are provided in Appendix 5 – Load Projections).

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

Table A6.5 - Advantages and Challenges of Natural Gas CT Resource Options

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

Natural Gas CT Characteristics

Represented as a General Electric (GE) 7FA combustion turbine.

Capacity	
Nominal Capacity	233 MW
Winter Firm Capacity	248 MW
Summer Firm Capacity	218 MW

Energy	
Dependable Energy	1,789 GWh/yr
Average Energy	20-102 GWh/yr

General Parameters	
Average Utilization factor	1-5%
Heat Rate	9,847 BTU/kWh
Asset Life	30 years
Operating GHG Emission Intensity	532 kg CO_2e/MWh
Project Lead Time	Reference: 5 years
Reference In-Service Date	2030

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 (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$378 M	$1,622/kW	$391-1,663/MWh	$124/kW-yr
Without Transmission	$363 M	$1,486/kW	$382-1,618/MWh	$121/kW-yr

Figure A6.10 - Natural Gas CT Characteristics and Costs

Aeroderivative CT Characteristics

Represented as a General Electric (GE) LM6000 aeroderivative combustion turbine. An aeroderivative CT is a small unit that is approximately 1/5 the size and nearly double the cost per MW of the Natural Gas CT. Aeroderivatives are typically used in specific applications such as load following, grid support as a sync, and small capacity additions when load growth is low.

Capacity	
Nominal Capacity	45 MW
Winter Firm Capacity	48 MW
Summer Firm Capacity	40 MW

Energy	
Dependable Energy	346 GWh/yr
Average Energy	4-20 GWh/yr

General Parameters	
Average Utilization factor	1-5%
Heat Rate	9,483 BTU/kWh
Asset Life	30 years
Operating GHG Emission Intensity	505 kg CO_2e/MWh
Project Lead Time	Reference: 5 years
Reference In-Service Date	2030

Average lifetime operating & Maintenance costs	
Fixed O&M Costs	$31/kW-yr
Variable Non-Fuel O&M Costs	$8.52/MWh
System Integration Costs	$0.00/MWh

Cost (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	NA	NA	NA	NA
Without Transmission	$121 M	$2,708/kW	$571-2,570/MWh	$197/kW-yr

Figure A6.11 - Aeroderivative CT Characteristics and Costs

2.5. Natural Gas Combined Cycle Combustion Turbine

A combined cycle combustion turbine (CCCT) employs a CT along with a heat recovery steam generator using the Rankine cycle. A CT 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 CT 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 CTs.

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

A natural gas CCCT is a supply option that includes attributes of high thermal efficiency, low to moderate capital cost, high reliability, lower air emission intensities than standard CTs, short lead times, and excellent operational flexibility. A CCCT is available in a variety of configurations up to 1,000 MW in size, but are generally on the large side.

Assuming a typical heat rate, 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 air emission regulations that may increase the cost and/or restrict the use of this type of resource. See Appendix 4 – Policy Landscape for further detail on the changing policy landscape. The operation of CCCTs on alternative fuels, such as biomethane (likely using a credit system, Appendix 7.1 – Modelling and Analysis Approach) or hydrogen blending, could reduce GHG emissions (see Appendix 5 – Load Projections).

Operational use of a CCCT results in nitrogen oxide (NOx) that can be controlled to low levels with the use of existing technology. Water consumption for power plant condenser cooling appears to be an issue of increasing importance. Water consumption can be reduced by use of dry (closed cycle) cooling, though at added cost and reduced efficiency.

Table A6.6 - Advantages and Challenges of Natural Gas CCCT Resource Options

Resource	Advantages	Challenges
Natural Gas Combined Cycle Combustion Turbines (CCCT)	• Intermediate or baseload service • Dispatchable resource • Proven and reliable technology • More efficient than CT • 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 CCCT Characteristics

Represented as a GE 7FA combined cycle combustion turbine.

Capacity	
Nominal Capacity	362 MW
Winter Firm Capacity	382 MW
Summer Firm Capacity	342 MW

Energy	
Dependable Energy	2,756 GWh/yr
Average Energy	159-793 GWh/yr

General Parameters	
Average Utilization factor	5-25%
Heat Rate	6,290 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	2031

Average lifetime operating & Maintenance costs	
Fixed O&M Costs	$32/kW-yr
Variable Non-Fuel O&M Costs	$4.59/MWh
System Integration Costs	$0.00/MWh

Cost (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$644 M	$1,779/kW	$135-491/MWh	$147/kW-yr
Without Transmission	$620 M	$1,714/kW	$134-482/MWh	$143/kW-yr

Figure A6.12 - Natural Gas CCCT Characteristics and Costs

2.6. 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.

As the fuel is assumed to be net-zero (More details are provided in Appendix 5 – Load Projections, operation of biomass generators do not directly produce net human-caused (anthropogenic) GHG emissions; however, there is still an environmental impact as this resource can produce other air contaminant emissions (e.g., NOx) 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 quantity of biomass generation that could be deployed in Manitoba would be limited, based on solid biomass fuel availability (More details are provided in Appendix 5 – Load Projections and the BECCS section below) assumed for this generation resource. Since biomass resources are broadly geographically distributed, up to 40% of the levelized cost of energy is based on collection and transportation costs. As various bioenergy industries develop, competition for the same biomass feedstock may result in corresponding increased prices.

Table A6.7 - Advantages and Challenges of Biomass Generation Resource Options

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

Biomass Generation Characteristics

Represented as a solid fuel biomass plant with no cogeneration.

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

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

General Parameters	
Average Utilization factor	2-83%
Heat Rate	13,500 BTU/kWh
Asset Life	40 years
Operating GHG Emission Intensity	≈0 kg CO_2e/MWh
Project Lead Time	Reference: 8 years
Reference In-Service Date	2033

Average lifetime operating & Maintenance costs	
Fixed O&M Costs	$97-211/kW-yr
Variable Non-Fuel O&M Costs	$8.47/MWh
System Integration Costs	$0.00/MWh

Cost (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$244 M	$8,119/kW	$167-3,205/MWh	$519-633/kW-yr
Without Transmission	$228 M	$7,601/kW	$154-3,042/MWh	$494-607/kW-yr

Figure A6.13 - Biomass Characteristics and Costs

2.7. 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 separately.

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 accredited energy import purchases up to 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 and provide accredited energy only for the 7x4 on-peak period. As a result, capacity purchases in the model are limited to durations of five years or less, and a maximum of 50 MW. Currently, the MISO market is evolving toward peak demand during both summer and winter and has little or no winter surplus capacity to meet Manitoba needs.

A non-baseload or "marginal" factor of aggregated generation in the MISO market is used to determine the associated GHG emission intensity profile of market capacity imports (as well as avoided GHG emissions related to electricity exports). The marginal GHG emission intensity of generation in MISO-North was 820 kg CO_2e/MWh in 2022,[3] down from 938 kg CO_2e/MWh in 2010, and is expected to continue dropping in the future. A GHG emission intensity of 820 kg CO_2e/MWh is higher than a natural gas combustion turbine – this is consistent with both coal and natural gas generation typically being "on the margin" in MISO, which means that these generation facilities are the first to shut off when demand is reduced.

Table A6.8 - 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 on capacity • MISO's generation mix and market are evolving resulting in uncertainty • Includes fossil fuel-based resources producing GHG emissions

[3] https://portfoliomanager.energystar.gov/pdf/reference/Emissions.pdf?_gl=1*zrriaj*_ga*MTA1Mzg5OTA4OS4xNzUzOTg1NzY4*_ga_S0KJTVVLQ6*czE3NTM5ODU3NjgkbzEkZzEkdDE3NTM5ODU3NzQkajU0JGwwJGgw

Market Capacity Imports Characteristicvs

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	73 GWh/yr
Average Energy	0 GWh/yr

General Parameters	
Average Utilization factor	N/A
Heat Rate	N/A
Asset Life	Contracts up to 5 years
Operating GHG Emission Intensity	See Appendix 7.1
Project Lead Time	Reference: 3 years
Reference In-Service Date	2028

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 (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	N/A	N/A	N/A	NA
Without Transmission	N/A	N/A	N/A	NA

Figure A6.14 - Market Capacity Imports Characteristics and Costs

2.8. Biodiesel Combustion Turbine

A biodiesel combustion turbine is a variant of the natural gas combustion turbine. They produce power in the same way as CTs and have similar characteristics (See section on Natural Gas Combustion Turbines) along with a dual-fuel capability. Biodiesel CTs use a liquid fuel known as hydrogen derived biodiesel or more simply biodiesel for the combustion process. Biodiesel has an identical chemical composition as fuel oil and petroleum diesel. Biodiesel is tested to the same specification as petroleum diesel, ASTM D975 in North America.

One of the primary differences of a biodiesel CT is that it's considered a net-zero GHG resource as the fuel can be produced with a variety of biological feedstocks (animal fats, seed oils, vegetable oils, and waste cooking oils). Another difference is the limited supply of fuel, which is more restrictive than natural gas, resulting in restricted operating run time for biodiesel fueled units. There is currently limited supply of biodiesel in the market where it is assumed that supply will develop in the future as demand for this fuel increases.

A benefit for biodiesel CTs is that there are few changes required to the station to operate using biodiesel as it is considered a drop-in replacement to the existing No.2 fuel oil/diesel used in typical dual-fuel facilities. The only change required could potentially be a need for larger on-site fuel storage tanks to allow for more frequent operation using biodiesel as the primary fuel, as opposed to using No.2 fuel oil as back-up fuel.

The units would be suitable for meeting infrequent peak load events and to provide emergency backup. This resource option cannot be used exclusively for energy production due to its limited supply of fuel on site. Alternatively, the units can be permitted to operate on biomethane under significant drought conditions to complement its biodiesel peaking operations.

Environmentally, nitrogen oxide (NOx) emissions are higher with biodiesel than with natural gas and typically requires more extensive control measures. As the fuel is assumed to be net-zero, operation of biodiesel CTs produce negligible GHG emissions.

Table A6.9 - Advantages and Challenges of Biodiesel CT Resource Options

Resource	Advantages	Challenges
Biodiesel Combustion Turbine (CT)	• Proven and reliable CT technology • Dispatchable resource to a limited amount • Low-cost capacity • Ideal for peaking and quick start operations • Non-fossil fuel	• High variable operating cost • Fuel price risk and volatility • Limited fuel supply on site • Limited market to supply fuel

Biodiesel CT Characteristics

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

Capacity	
Nominal Capacity	233 MW
Winter Firm Capacity	248 MW
Summer Firm Capacity	218 MW

Energy	
Dependable Energy	20/1789 GWh/yr
Average Energy	20 GWh/yr

General Parameters	
Average Utilization factor	1 %
Heat Rate	9,403 BTU/kWh
Asset Life	30 years
Operating GHG Emission Intensity	≈0 kg CO_2e/MWh
Project Lead Time	Reference: 5 years
Reference In-Service Date	2030

Average lifetime operating & Maintenance costs	
Fixed O&M Costs	$21/kW-yr
Variable Non-Fuel O&M Costs	$ 7.37/MWh
System Integration Costs	$0.00/MWh

Cost (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$415 M	$1,780/kW	$1,919/MWh	$127/kW-yr
Without Transmission	$400 M	$1,637/kW	$1,868/MWh	$123/kW-yr

Figure A6.15 - Biodiesel CT Characteristics and Costs

2.9. Hydrogen CTs and CCCTs

Hydrogen fueled turbines use the same technology as CTs and CCCTs but are designed to operate using hydrogen fuel. They produce power in the same way as CTs and CCCTs and have similar characteristics (See sections 2.4 and 2.5). One of the primary differences is that the operation of hydrogen turbines produces negligible GHG emissions (more details are provided in Appendix 7.1 – Modelling and Analysis Approach). 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.

Today, turbine and generator manufacturers offer units capable of up to 30% hydrogen blended with natural gas. Utility scale hydrogen turbines fueled with 100% hydrogen are still in the development stage. To provide a wider range of non-fossil fuel capacity resource options in the resource evaluation process, a high-level concept for hydrogen turbines was developed. The hydrogen turbine concept comprises the following components: 100% hydrogen fueled combustion turbines (CT & CCCT); electrolyzer hydrogen production facilities with an associated electric load on the grid; hydrogen transportation; and hydrogen storage facilities. This is a theoretical concept – the studies required to prove technical viability have not been undertaken. 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 periods. The resulting utilization factors used were 2%, 4%, and 8% for a combustion turbine and 12%, 15%, and 19% for a CCCT. 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 utilization factors increase, CCCT's become more competitive than CTs 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% utilization factor is approximately double the cost of natural gas fueled CTs, and four times with a 4% utilization factor.

Overall, hydrogen is a form of 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 A6.10 - Advantages and Challenges of Hydrogen Turbine Resource Options

Resource	Advantages	Challenges
Hydrogen Turbine (CT & CCCT)	• Dispatchable peaking resource • Negligible operating GHG emissions • Some technology components are proven	• Operating time limited by fuel • Very high fuel costs • Double the cost of natural gas CT capacity • Still in development stage • Large scale geological storage

Hydrogen CT Characteristics

Represented as a GE 7FA simple cycle with a hydrogen fuel supply that is restricted to 2% to 8% utilization factors. The unit is coupled with an electric load to represent the electrolyzer and to account for the energy consumed.

Capacity	
Nominal Capacity	233 MW
Winter Firm Capacity	248 MW
Summer Firm Capacity	-37 to -148 MW

Energy	
Dependable Energy	Summer: -142 to -566 GWh/yr Winter: +39 to +157 GWh/yr
Average Energy	Summer: -142 to -566 GWh/yr Winter: +35 to +157 GWh/yr

General Parameters	
Average Utilization factor	2-8%
Heat Rate	9,847 BTU/kWh
Asset Life	30 years
Operating GHG Emission Intensity	≈0 kg CO_2e/MWh
Project Lead Time	Reference: 10 years
Reference In-Service Date	2035

Average lifetime operating & Maintenance costs	
Fixed O&M Costs	$21/kW-yr
Variable Non-Fuel O&M Costs	$63.93/MWh
System Integration Costs	$0.00/MWh

Cost (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$902-2,287 M	$3,873-9,817/kW	$1,225-1,866/MWh	$272-682/kW-yr
Without Transmission	$887-2,272 M	$3,808-9,752/kW	$1,220-1,842/MWh	$268-679/kW-yr

Figure A6.16 - Hydrogen CT Characteristics and Costs

Hydrogen CCCT Characteristics

Represented as a GE 7FA combined cycle with a hydrogen fuel supply that is restricted to 12% to 19% utilization factors. The unit is coupled with an electric load to represent the electrolyzer and to account for the energy consumed.

Capacity	
Nominal Capacity	362 MW
Winter Firm Capacity	382 MW
Summer Firm Capacity	-220 to -367 MW

Energy	
Dependable Energy	Summer: -843 to -1,405 GWh/yr Winter: +365 to +608 GWh/yr
Average Energy	Summer: -843 to -1,405 GWh/yr Winter: +365 to +608 GWh/yr

General Parameters	
Average Utilization factor	12-19%
Heat Rate	6,290 BTU/kWh
Asset Life	30 years
Operating GHG Emission Intensity	≈0 kg CO_2e/MWh
Project Lead Time	Reference: 10 years
Reference In-Service Date	2035

Average lifetime operating & Maintenance costs	
Fixed O&M Costs	$32/kW-yr
Variable Non-Fuel O&M Costs	$36.35/MWh
System Integration Costs	$0.00/MWh

Cost (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$3,482-5,314 M	$9,618-14,681/kW	$746-812/MWh	$687-1,040/kW-yr
Without Transmission	$3,458-5,291 M	$9,552-14,615/kW	$743-808/MWh	$683-1,036/kW-yr

Figure A6.17 - Hydrogen CCCT Characteristics and Costs

2.10. Natural Gas CCCT with Carbon Capture and Sequestration

A combined cycle combustion turbine with carbon capture and sequestration (CCCT+CCS) employs a standard CCCT along with carbon capture and sequestration (CCS) equipment. CCS (also known as Carbon Capture & Storage; Carbon Capture Utilization & Storage; CCUS) is a process by which carbon dioxide (CO_2) from industrial activities is separated out before it is released into the atmosphere. The CO_2 is then transported to a long-term sequestration location or product.

There are a variety of existing and proposed technologies to separate CO_2 with various energy efficiencies. Operationally, CCS processes only function properly under continuous steady loading, and do not function properly with frequent starts and stops. As a result, CCS is typically only used on CCCT units with high-utilization factors (or large baseload industrial consumers, more details are found in Appendix 5 – Load Projections) and is not used on combustion turbines with low-utilization factor peaking operations.

CCS is an emerging technology but has been proven at scale with around 45 commercial capture facilities in operation globally.[4] Existing CCS facilities are designed to capture around 90% of the CO_2.[5] CCS equipment requires a significant amount of power to separate out CO_2, as well as for its compression, transportation, and sequestration. Depending on technology this energy requirement ranges from 1 to 5 GJ per tonne of CO_2 captured and stored.[6,7] Manitoba Hydro assumes the net capacity from a generating unit is derated by 10% and the unit efficiency by 11% to account for CCS's consumption of power. (More details are provided in Appendix 5 – Load Projections)

There are substantial costs to adding CCS to a generating unit. These costs add approximately 120% per MW to the cost of a CCCT unit, although this is highly variable based upon individual projects. Levelized costs for the GHG reductions achieved in CCCT-CCS are estimated to be between $220 to $1,500 per tonne CO_2 stored (2024$). Costs per tonne CO_2 stored decrease with a higher utilization factor as more CO_2 is stored, but the capital and fixed costs stay the same.[8]

[4] https://www.iea.org/energy-system/carbon-capture-utilisation-and-storage

[5] https://www.sciencedirect.com/science/article/abs/pii/S036054421630216X

[6] 2024 EIA Cost and Performance (https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf) (one source used to develop generation resource modelling parameters)

[7] For this estimation Manitoba Hydro considered both lifecycle costs and operational costs. Similar cost ranges can be expected in other types of commercial capture facilities, with baseload facilities being on the lower end.

[8] https://ghgprotocol.org/sites/default/files/standards/ghg_project_accounting.pdf

To effectively contribute to net-zero goals, the CO_2 stored from CCS must be stored for very long timescales. Typically, this is assumed to occur in geological formations deep underground such as sedimentary basins, depleted oil and gas fields, saline formations, and shale formations. Long-term sequestration in products may also adequately meet additionality requirements.[9]

Manitoba Hydro has not done any studies related to the geological storage of CO_2 in Manitoba. However, potential large-scale geological sites are known to exist in southwest Manitoba with up to 13,500 million tonnes of prospective storage from the Deep Cambrian Sands.[10] As an additional indicator of technical potential, the private sector has started to express interest in starting to capture and store CO_2 in southwest Manitoba.

Table A6.11 - Advantages and Challenges of Natural Gas CCCT+CCS Resource Options

Resource	Advantages	Challenges
Natural Gas CCCT with Carbon Capture & Sequestration (CCCT+CCS)	• Intermediate or baseload service • Dispatchable resource • Reliable source of electrical energy and capacity during drought • Manitoba has the appropriate geology for potential sequestration of CO_2 • Low net life cycle GHG emissions • Low operating GHG emissions	• Fuel price risk and volatility • High cost for CCS • Notable power consumption for CCS impacting net generation • Does not capture 100% of GHG emissions • Demonstration stage of technological development

Natural Gas CCCT+CCS Characteristics

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

[9] https://cleanprosperity.ca/wp-content/uploads/2024/04/Evaluation_of_carbon_capture_and_storage_potential_in_Canada.pdf

[10] https://natural-resources.canada.ca/funding-partnerships/minnedosa-ethanol-plant-CO_2-sequestration

Capacity	
Nominal Capacity	362 MW
Winter Firm Capacity	344 MW
Summer Firm Capacity	308 MW

Energy	
Dependable Energy	2,480 GWh/yr
Average Energy	143-714 GWh/yr

General Parameters	
Average Utilization factor	5-25%
Heat Rate	6,982 BTU/kWh
Asset Life	30 years
Operating GHG Emission Intensity	40 kg CO_2e/MWh
Project Lead Time	Reference: 10 years
Reference In-Service Date	2035

Average lifetime operating & Maintenance costs	
Fixed O&M Costs	$78/kW-yr
Variable Non-Fuel O&M Costs	$8.62/MWh
System Integration Costs	$0.00/MWh

Cost (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$1,419 M	$3,920/kW	$244-910/MWh	$346/kW-yr
Without Transmission	$1,395 M	$3,855/kW	$242-900/MWh	$342/kW-yr

Figure A6.18 - Natural Gas CCCT+CCS Characteristics and Costs

2.11. Biomass with Carbon Capture and Sequestration

A biomass unit with carbon capture and sequestration (BECCS) employs a standard biomass steam turbine along with CCS (refer to the previous section for a description of CCS). This carbon dioxide removal (CDR) technology is an emerging technology in its demonstration phrase, with only about two million tonnes of biogenic CO_2 currently being captured annually.[11] However, both biomass generating stations and CCS are more established independently.

In alignment with the International Panel on climate Change,[12] and because biomass combustion is assumed to be net-zero (more details are provided in Appendix 5 – Load Projections), Manitoba Hydro assumes BECCS is a net-negative GHG emission (i.e., GHG removal) technology.

Adding CCS to biomass generation approximately doubles the cost per MW of capacity, although this is highly variable based upon individual project parameters. While BECCS is a high cost energy and capacity source, as a negative GHG emissions technology BECCS has the potential to be cost competitive (more details are provided in Appendix 7.2 – Modelling and Analysis Results) under either a net-zero grid constraint or within a net-zero economy.

The quantity of BECCS that could be deployed in Manitoba would be limited, based on solid biomass fuel availability assumed for this generation resource (more details are provided in Appendix 5 – Load Projections): "…deploying BECCS at large scale would require a large amount of land to cultivate the biomass required for bioenergy. This could have consequences for sustainable development if the use of land competes with producing food to support a growing population, biodiversity conservation or land rights."[13]

[11] https://www.iea.org/energy-system/carbon-capture-utilisation-and-storage/bioenergy-with-carbon-capture-and-storage

[12] https://www.ipcc.ch/sr15/faq/faq-chapter-4/

[13] https://www.ipcc.ch/sr15/faq/faq-chapter-4/

Table A6.12 - Advantages and Challenges of BECCS Resource Options

Resource	Advantages	Challenges
Biomass with Carbon Capture & Sequestration	• Dispatchable resource • Biomass is a mature technology • Manitoba has the appropriate geology for potential sequestration of CO_2 • Facilitates the achievement of a net-zero grid • Low relative cost for negative GHG emissions.	• High-cost energy & capacity source • Energy cost highly dependent on transportation fuel costs • Air contaminant emissions (e.g., NOx) comparable to coal • Limited biomass resource in Manitoba • High cost for CCS • Notable power consumption for CCS impacting net generation • Demonstration stage of technological development

BECCS Characteristics

Represented as a wood waste biomass plant with 95% carbon capture and sequestration rate.

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

Energy	
Dependable Energy	207 GWh/yr
Average Energy	Up to 207 GWh/yr

General Parameters	
Average Utilization factor	Up to 83%
Heat Rate	19,965 BTU/kWh
Asset Life	40 years
Operating GHG Emission Intensity	-966 CO_2e/MWh
Project Lead Time	Reference: 10 years
Reference In-Service Date	2035

Average lifetime operating & Maintenance costs	
Fixed O&M Costs	$160-347/kW-yr
Variable Non-Fuel O&M Costs	$13.55/MWh
System Integration Costs	$0.00/MWh

Cost (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$592 M	$19,738/kW	$324-7,262/MWh	$1,183-1,370/kW-yr
Without Transmission	$577 M	$19,220/kW	$293-7,081/MWh	$1,158-1,345/kW-yr

Figure A6.19 - Biomass + CCS Characteristics and Costs

2.12. Nuclear 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 CCCT 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 in comparison to traditional large scale nuclear reactors. Enhanced safety would come from the greater use of passive safety features that operate without human intervention.

Nuclear SMR designs range from scaled down versions of conventional nuclear designs to next generation designs. Expert opinions are highly varied regarding nuclear 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 nuclear SMR design concepts at various stages of design and development throughout the world. As of early 2023, there were two nuclear 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.

Two different nuclear SMR sizes have been considered based on the most advanced designs in North America. The sizes are 77 MW based on the NuScale design, and 300 MW based on the GE BWRX-300 design which is in the advanced stages of development by Ontario Power Generation, and Tennessee Valley Authority.

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

Table A6.13 - Advantages and Challenges of SMR Resource Options

Resource	Advantages	Challenges
Nuclear Small Modular Reactor	• Negligible 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

Nuclear 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 Utilization 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: 10 years or more
Reference In-Service Date	2035+

Average lifetime operating & Maintenance costs	
Fixed O&M Costs	$163/kW-yr
Variable Non-Fuel O&M Costs	$6.71/MWh
System Integration Costs	$0.00/MWh

Cost (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$818/3,291 M	$10,969/kW	$121/MWh	$778/kW-yr
Without Transmission	$809/3,152 M	$10,507/kW	$112/MWh	$753/kW-yr

Figure A6.20 - Small Modular Reactor Characteristics and Costs

2.13. 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 or so 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. It is assumed batteries would be located near existing transmission sub-stations and as a result would incur limited transmission upgrade costs. For evaluation purposes, a five-hour battery size is assumed. In some instances, battery storage may be paired with variable 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 2025 IRP scenarios.

Battery storage is a net consumer of electrical energy due to the overall efficiency losses in the charge/discharge cycles, with a round-trip efficiency of 90%. In comparison to other resource options, batteries have relatively short asset lives of approximately 15 years, which contrasts with 25-72 years for other resources. They are often oversized to allow for degradation over time.

Additional indirect benefits include transmission/distribution asset deferral, transmission 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 A6.14 - 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 variable resources • Negligible operating GHG emissions	• 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	-35 GWh/yr
Average Energy	-109 GWh/yr

General Parameters	
Average Utilization factor	17%
Heat Rate	90%
Asset Life	15 years
Operating GHG Emission Intensity	≈0 kg CO_2e/MWh
Project Lead Time	Early: 3, Reference: 5, Late: 8 years
Reference In-Service Date	2030

Average lifetime operating & Maintenance costs	
Fixed O&M Costs	$77/kW-yr
Variable Non-Fuel O&M Costs	$0.00/MWh
System Integration Costs	$0.00/MWh

Cost (2024 CAN$)	Base Estimate	Overnight Cost	Levelized Cost of Energy	Levelized Cost of Winter Capacity
With Transmission	$303 M	$3,028/kW	N/A	$362/kW-yr
Without Transmission	$297 M	$2,972/kW	N/A	$356/kW-yr

Figure A6.21 - Battery Storage Characteristics and Costs

2.14. Additional Energy Efficiency

Energy efficiency, also referred to as demand side management (DSM), refers to customers reducing their consumption of energy and/or peak demand. This is often achieved through adoption of improved design standards or equipment, but it can also be achieved through behavioural changes. This resource can reduce the use of existing generating infrastructure, serve more customers with existing resources, or defer the need for new generation, transmission, and distribution infrastructure.

Manitoba Hydro collaborated with Efficiency Manitoba to include customer sited resources in the 2025 IRP analysis in three ways: Efficiency Plan Projection (more details are provided in Appendix 5 – Load Projections), load projection planning assumptions (more details are provided in Appendix 5 – Load Projections), and Additional Energy Efficiency. Efficiency Manitoba provided parameters for most of the additional energy efficiency groups to Manitoba Hydro which was based on a 2022 market potential study conducted by Dunsky Energy + Climate for Efficiency Manitoba.[14] In addition to the efficiency measures included in the market potential study, Manitoba Hydro conducted its own investigations and developed parameters for two groups that include electric thermal storage (ETS).

The quantity of Additional Energy Efficiency is determined by subtracting measure savings included in the Efficiency Plan Projection and/or load projections from the maximized market potential in the study. The estimate of market potential saving is based on a variety of assumptions including technological development, anticipated customer energy usage/savings, and market cost projections. Advantages and challenges of the selectable resource options are provided below:

Table A6.15 - Advantages and Challenges of Additional Energy Efficiency Resource Options

Resource	Advantages	Challenges
Additional Energy Efficiency	• Can be a low-cost resource • Modular packages • Can have shorter implementation time than other resources	• Energy and capacity savings are program specific • Program participation is voluntary • Finite market potential • Launching a new program takes time to ramp up • Wide range of costs between programs

[14] https://efficiencymb.ca/wp-content/uploads/Efficiency-Manitoba-15-year-Market-Potential-Study.pdf

Manitoba Hydro has sought to consider and evaluate energy efficiency measures in a similar way to other supply options like traditional generation resources. 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 Plan Projection.

Additional Energy Efficiency consists of 11 energy efficiency groups as shown in the table below. Each group has its own unique estimate of the market potential, energy benefits, summer and winter firm capacity contributions, asset life, and costs.

Table A6.16 - Additional Energy Efficiency

No	Category	Groups
1	EEH	Residential - Home Insulation
2	ASHP	Residential - Energy Efficiency Assistance Program Cold Climate Air Source Heat Pump
3	ASHP	Residential - Community Heat Pump Cold Climate Air Source Heat Pump
4	ASHP	Residential - Air Source Heat Pumps
5	GSHP	Residential - Energy Efficiency Assistance Program - Ground Source Heat Pumps
6	GSHP	Residential - Community Heat Pump - Ground Source Heat Pumps
7	GSHP	Residential - Ground Source Heat Pumps
8	ETS	Residential - Electric Furnace with Electric Thermal Storage
9	ETS with ASHP	Residential - Electric Furnace with Electric Thermal Storage & Cold Climate Air Source Heat Pump
10	GSHP	Commercial - Ground Source Heat Pumps
11	EEI	Industrial - Custom Energy Solutions

Manitoba Hydro developed energy savings profiles for each of the additional energy efficiency groups. The firm capacity contributions were determined based on the group's energy savings that are coincident with the summer and winter peak demand for each of the load projections.

The cost of Additional Energy Efficiency includes program delivery costs (staff salaries, advertising, administrative costs, etc.) and incentive costs. The incremental product cost for Selectable Energy Efficiency represents the additional cost to a customer to purchase or implement an energy efficient product or measure instead of a standard product or measure (e.g., standard refrigerator vs. a high efficiency refrigerator). Incentives provided by Efficiency Manitoba can lower the incremental product cost for customers, making energy efficiency measures more economically attractive. In the 2025 IRP, for all additional energy efficiency groups, it is assumed that incentives cover all of the incremental product costs for customers.

Manitoba Hydro reimburses Efficiency Manitoba for all program delivery and incentive costs, less any funds available from other sources. Additional Energy Efficiency is evaluated using technology specific asset lives unique to each group. Once an asset reaches the end of its useful life, it is assumed to be replaced at additional incremental product cost to base line technology to continue with the energy and capacity savings benefits.

An additional benefit of Additional Energy Efficiency 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 peak demand and is provided in Table A6.17.

Table A6.17 - Energy Efficiency – Transmission & Distribution Benefits

Load Growth	<=4,000 MW	>4,000 MW
Transmission	$35.20/kW-yr	$50.40/kW-yr
Distribution	$49.81/kW-yr	$49.81/kW-yr
Total	$85.01/kW-yr	$100.21/kW-yr

Home Insulation (1)

The home insulation group refers to the savings achieved by installing additional insulation to residential homes. The cost and parameters were provided by Efficiency Manitoba.

Air Source Heat Pumps (2,3,4)

Air source heat pumps represent the space conditioning savings in residential homes. In the heating mode, an air source heat pump makes a home warmer by moving heat from the outdoor air into the home. In the cooling mode, it works in reverse by moving heat from inside a home to the outside air. The contribution of air source heat pumps to winter capacity savings is zero as they are assumed to only operate down to -10oC (for standard heat pumps) and -20oC (for cold climate heat pumps), requiring supplemental heating from another system when temperatures are colder (e.g., electric resistance or natural gas heating). The cost and parameters were provided by Efficiency Manitoba.

Ground Source Heat Pumps (5,6,7,10)

A ground source heat pump represents a system of underground pipes with circulating fluid in a closed or open loop system by transferring heat to or from the ground. In the heating cycle, the fluid absorbs the heat from the ground. The process is reversed in the cooling cycle such that the heat from the home is redistributed into the ground. Local climate, underground soil type, land availability, accessibility to groundwater or surface water bodies, local design and installation workforce are some of the site-specific conditions that will dictate design of vertical or horizonal GSHP system. It is assumed that the GSHP system are designed to meet entire space conditioning load of the customer. If the GSHP system is coupled with an electric auxiliary heating source such that auxiliary heating source is meeting most of the winter peak load, then there will be little capacity savings.

The ground source heat pump groups represent the savings in residential and commercial categories for individual systems. Due to their site-specific nature and various configurations, the performance and cost of GSHPs can vary widely. The parameters of the ground source heat pumps for additional energy efficiency are provided by Efficiency Manitoba which assumes that GSHP systems are more efficient than GSHP systems assumed by Manitoba Hydro in the load forecast (more details are provided in Appendix 5 – Load Projections for more details). The performance of GSHP system can affect the economics of GSHP system for the customer.

Electric Thermal Storage (8,9)

An electric thermal storage (ETS) system is an electric home heating device that contains ceramic bricks to store heat in an insulated box. Typically, the bricks are heated by electric elements when electricity demand on the grid is low, and releases heat when electricity demand on the grid is high, resulting in a reduction in peak demand. These units can be coupled with cold climate air source heat pumps to reduce electricity consumption and provide energy bill savings to the customer. ETS systems are common in Nova Scotia, Quebec, other parts of Canada, and parts of the United States and Europe with colder climates. Currently, there are no known ETS installations in Manitoba and Efficiency Manitoba does not have any programs associated with this demand response technology. Manitoba Hydro investigated this technology and established the load profiles, cost and parameters.

Industrial Custom (11)

This group represents a collection of customized energy efficiency solutions in an industrial setting (e.g., compressed air systems, large industrial retrofit). The cost and parameters of this group were provided by Efficiency Manitoba.

Additional GSHP Analysis (External to 2025 IRP)

For an independent view of the relative potential of GSHP systems as a resource, Manitoba Hydro requested a consultant compare a GSHP system to replace electric resistance heating in a single family dwelling if the alternative capacity resource were a natural gas fired turbine and the alternative energy prices were MISO market pricing using a Total Resource Cost (TRC) test with costs including all incremental costs whether paid by the participant (the customer installing the GSHP), by Efficiency Manitoba, by Manitoba Hydro or by Manitoba taxpayers and the benefits being savings in the costs to supply energy and capacity (but not including avoided T&D costs). Further analysis considered the alternative resource not being a natural gas fired turbine but new hydrogeneration or a SMR.

Independent GSHP Economic Analysis by Consultant	TRC Test with a CT being the Alternative Resource - COST	TRC Test with a CT being the Alternative Resource - BENEFITS
Electric Bill Savings		
Incremental Appliance Cost	$2.92B	
Avoided Electric Supply Cost		$1.36B
Benefit/Cost (BC) Ratio	46.6%	

Figure A6.24 - GSHP Independent GSHP Economic Analysis by Consultant

Key Takeaways:

1) The total cost of the Manitoba energy system (TRC) increases [when GSHPs replace electric resistance heating] because the cost of GSHPs exceeds the avoided energy supply costs.

2) From an energy supply perspective, GSHP are two times more expensive than a new gas CT.

3) From an energy supply perspective (TRC test), GSHPs are about the same price as new hydropower or SMRs.

This independent analysis used data and analysis methods developed by or selected by the consultant and while the consultant could not model the interaction of new GSHPs with Manitoba Hydro's other resources to the extent that Manitoba Hydro's IRP model does, this analysis is considered to be "robust" and its "results should be interpreted as directional".

It is noteworthy that the independent analysis was based on assumptions of GSHP performance (e.g. GSHP Avg Winter COP = 3.14 and GSHP Peak Load COP=3.28) which were more generous than those Manitoba Hydro has observed in GSHP monitoring and in customer energy consumption records.

A similar analysis conducted for a networked GSHP system which did not include substantial diversity in space heating and cooling diversity concluded that economies of scale were not apparent. Furthermore, the economic performance of the networked GSHP system modelled was inferior to that of GSHPs to replace electric resistance heating in a single-family dwelling. For example, while GSHPs to replace electric resistance heating in a single-family dwelling were evaluated to be about the same price as new hydropower or SMRs from an energy supply perspective, a networked GSHP system was evaluated as being substantially more expensive than new hydropower or SMR resources.

In summary, independent analysis indicates that while GSHPs to replace electric resistance heating in single family dwellings do not appear to be economic in the near-term, such systems are expected to be economic choices when more expensive resources such as new hydropower and SMRs are being considered. However, networked GSHP systems that do not include substantial diversity in space heating and cooling may not become economically competitive even when more expensive resources such as new hydropower and SMRs are being considered.

Further work is required to better understand the drivers of when GSHPs will be cost effective, including:

- Increased performance in cold climate (COP)
- Impact to peak demand, including impact of any auxiliary equipment used in the operations of the GSHP
- Cost of the GSHP
- Incentive levels of the GHSP system

These reviews by a third party of the economic potential GSHPs were based on the judgement of an independent consultant whose assumptions about GSHP performance and energy prices did not necessarily align with Manitoba Hydro's assumptions. For example, the consultant modelled higher SCOP values than Manitoba Hydro (noted above) and used its proprietary MISO market energy price forecast. The results of these reviews did not inform Manitoba Hydro's modelling assumptions but were interpreted as an indication that Manitoba Hydro's modelling assumptions were directionally compatible with the consultant's evaluation of the relative economic potential of GSHPs and selected other future resource options.

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

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

Additional Energy Efficiency - Residential Home Insulation

The parameters represent cumulative values from 2025/26 to 2035/36 (2035) and 2025/26 to 2049/50 (2050) based on the maximized level. The nominal capacity is the maximum savings potential, while the winter/summer values are the coincident contribution to peak load.

Capacity	2035	2050
Nominal Capacity	29MW	63 MW
Winter Firm Capacity	26MW	57 MW
Summer Firm Capacity	3MW	4 MW

Energy	2035	2050
Dependable Energy	NA	NA
Average Energy	63 GWh/yr	139 GWh/yr

General Parameters	2035	2050
Average Utilization factor*	25%	25%
Heat Rate	N/A	N/A
Asset Life**	20 years	20 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	2025	2025

Average lifetime o&m Costs	2035	2050
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 (2024 CAN$)	Base Estimate (Initial invest.)	Overnight Cost (Non Coinc. Peak)	Levelized Cost of Energy	Levelized Cost of Winter Capacity
2035: With Avoided T&D Cost	$67 M	$1,681/kW	$73/MWh	$93-101/kW-yr
2050: With Avoided T&D Cost	$147 M	$1,681/kW	$73/MWh	$79-108/kW-yr

Figure A6.22 - Energy Efficiency Residential Home Insulation Characteristics and Costs

Additional Energy Efficiency - Air Source Heat Pump Group Characteristics

The parameters represent cumulative values from 2025/26 to 2035/36 and 2025/26 to 49/50 based on the maximized level identified in the Efficiency Manitoba' s market potential study for three air source heat pump groups. A numerical range in a parameter value represents the variation across The Load Projections, 1 2, and 3. ASHP coupled with ETS is provided in a separate table.

CAPACITY	2035	2050
Nominal Capacity	26 - 71 MW	114 - 216 MW
Winter Firm Capacity	0 MW	0 MW
Summer Firm Capacity	1 MW	9 - 11 MW

Energy	2035	2050
Dependable Energy	N/A	N/A
Average Energy	64 - 175 GWh/yr	250 – 522 GWh/yr

General Parameters	2035	2050
Average Utilization factor*	N/A	N/A
SCOP	ASHP = 2.67; ccASHP = 3.10	ASHP = 2.67; ccASHP = 3.10
Asset Life	20 years	20 years
Operating GHG Emission Intensity	0 kg CO_2e/MWh	0 kg CO_2e/MWh
Project Lead Time	Min: 1, Long: 3 years	Minimum of 1 year
Reference In-Service Date	2025	2025

Average lifetime o&m Costs	2035	2050
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 (2024 CAN$)	Base Estimate (Initial invest.)	Overnight Cost (Non Coinc. Peak)	Levelized Cost of Energy	Levelized Cost of Winter Capacity
2035: With Avoided T&D Cost	$291 M	$1,578-3,622/kW	$52-175 / MWh	N/A
2049/50: With Avoided T&D Cost	$1,042 M	$1,421 - 1,554-/ kW	$51-199/MWh	N/A

Figure A6.23 - Energy Efficiency ASHP Grouping Characteristics and Costs

Additional Energy Efficiency – Ground Source Heat Pump Group Characteristics

The parameters represent cumulative values from 2025/26 to 2035/36 and 2025/26 to 2049/50 based on the maximized level identified in Efficiency Manitoba's market potential study.

CAPACITY	2035	2050
Nominal Capacity	130 - 153 MW	481 - 590 MW
Winter Firm Capacity	121 - 140 MW	448 - 537 MW
Summer Firm Capacity	2 MW	12 - 18 MW

Energy	2035	2050
Dependable Energy	N/A	N/A
Average Energy	289 - 341 GWh/yr	1,072 - 1,315 GWh/yr

General Parameters	2035	2050
Average Utilization factor*	25%	25%
SCOP	3.30	3.30
Asset Life	25 years	25 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	2025	2025

Average lifetime o&m Costs	2035	2050
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 (2024 CAN$)	Base Estimate (Initial invest.)	Overnight Cost (Non Coinc. Peak)	Levelized Cost of Energy	Levelized Cost of Winter Capacity
2035				
2035: With Avoided T&D Cost	$480 M	$1,616–2,571/ kW	$60-95/ MWh	$63-151/kW-yr
2050: With Avoided T&D Cost	$1,850 M	$1,613–2,689/ kW	$67-100/ MWh	$11-167/kW-yr

Figure A6.24 - Energy Efficiency GSHP Group Characteristics and Costs

Additional Energy Efficiency – Electric Thermal Storage System

The parameters represent cumulative values from 2025/26 to 2035/36 and 2025/26 to 2049/50 based on the maximized level for two electric thermal storage systems groups, one with electric resistance heat and one with a cold climate air source heat pump

CAPACITY	2035	2050
Nominal Capacity	38 - 79MW	130 - 283MW
Winter Firm Capacity	38 - 79MW	130 - 283 MW
Summer Firm Capacity	0 MW	0 MW

Energy	2035	2050
Dependable Energy	N/A	N/A
Average Energy	38 - 79 GWh/yr	130 - 283 GWh/yr

General Parameters	2035	2050
Average Utilization factor*	5%	5%
SCOP	2.5	2.5
Asset Life	20 years	20 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	2027	2027

Average lifetime o&m Costs	2035	2050
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 (2024 CAN$)	Base Estimate (Initial invest.)	Overnight Cost (Non Coinc. Peak)	Levelized Cost of Energy	Levelized Cost of Winter Capacity
2035: With Avoided T&D Cost	$114 M	$1,765-2,575/ kW	$501/MWh	$82-161/kW-yr
2050: With Avoided T&D Cost	$385 M	$1,756-2,575/ kW	$501/MWh	$30-161/kW-yr

Figure A6.25 - Additional Energy Efficiency – Custom Energy Solutions

Additional Energy Efficiency – Custom Energy Solutions

The parameters represent cumulative values from 2025/26 to 2035/36 and 2025/26 to 2049/50 based on the maximized level for industrial custom energy solutions based on the maximized level identified in Efficiency Manitoba's market potential study.

CAPACITY	2035	2050
Nominal Capacity	152 MW	331 MW
Winter Firm Capacity	126 MW	261 MW
Summer Firm Capacity	115 MW	230 MW

Energy	2035	2050
Dependable Energy	N/A	N/A
Average Energy	881 GWh/yr	1,916 GWh/yr

General Parameters	2035	2050
Average Utilization factor*	71%	75%
SCOP	N/A	N/a
Asset Life	15 years	15years
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	2025	2025

Average lifetime o&m Costs	2035	2050
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 (2024 CAN$)	Base Estimate (Initial invest.)	Overnight Cost (Non Coinc. Peak)	Levelized Cost of Energy	Levelized Cost of Winter Capacity
2035: With Avoided T&D Cost	$910 M	$4,407/kW	$89/MWh	$559-673/kW-yr
2050: With Avoided T&D Cost	$1,982 M	$4,379/kW	$88/MWh	$574-654/kW-yr

Figure A6.26 - Energy Efficiency Custom Energy Solutions Characteristics and Costs

3 | Emerging Technology

Emerging technology represents a range of potential new resource technologies that are at a different stage of development compared to mature resources that are commercially available. Emerging technology resources are still in the early research and development stage and are not yet commercially available or may be a less practical resource to develop in Manitoba when compared to other jurisdictions. Development of new technologies typically follow a standard technological development pathway. One method developed to determine the overall maturity of a technology along this pathway is the Technology Readiness Level (TRL) created by NASA in the 1970s. This methodology provides a standardized approach for determining the progress of individual technologies from scientific principle to commercial product. The technological maturity levels include: 1. Basic principles observed & reported, 2. Formulation of application, 3. Proof of concept, 4. Component validation in lab, 5. Component validation in environment, 6. Process development unit, 7. Pilot plant, 8. Commercial pilot plant, and 9. Commercial service (i.e., commercially available). See table below for descriptions of each of the different levels. While this methodology doesn't fully address a technologies commercial viability or large-scale adoption, or a technologies progress through its phases of maturity, it is useful in providing an overall structure for an otherwise complex topic.

TRL		Description
1	Basic Principles Observed and Reported	Observation of material properties or other physical/chemical phenomena that can then be translated into applied research and development (R&D).
2	Formulation of the Application	Practical applications of basic physical principles are identified, and generalizations assumed for physical/chemical data not readily available.
3	Proof of Concept	Initiation of active R&D for the specific application and detailed analytical studies to design the application and predict its performance. Lab studies to physically verify engineering/scientific assumptions of analytical studies.
4	Component Validation in Laboratory Environment	Component-level test assemblies are created from available "pieces" as a functional unit in a laboratory setting and be generally consistent with the eventual system.
5	Component Validation in Relevant Environment	Component-level assemblies are designed and function independently as a unit. Relevant environment is likely to be a lab or a small process development unit that simulates the operational environment.
6	Process Development Unit (Prototype Components in a Relevant Environment)	Prototype components are those whose design and function are essentially the same as expected for full-scale deployment. Full system integration is not required at this stage and the relevant environments may include field power plant settings or smaller pilot/test plant installations.
7	Pilot Plant (Integrated, Fully Functional Prototype Incorporating Features of Anticipated Full-Scale Deployment in an Operational Environment)	Includes all components or unit processes expected at full scale and may be deployed as an adjunct to an operating power plant. May be deployed as an adjunct to an existing power plant. Deployed with an operations/control system of a scope comparable to full-scale implementation of the technology.
8	Commercial Pilot Plant (Deployment of Technology in Final Form Under Expected Conditions)	Performance guarantees supportable by TRL 7 experience including capacity, material use/production, and energy use/production. TRL 8 may be bypassed if achieving TRL 7 provides sufficient confidence to technology developers and customers for commercial service requirements of TRL 9.
9	Normal Commercial Service	Full-scale implementation with enforceable performance guarantees including capacity, material use/production, and energy use/production. Standard industry warrantees.

Figure A6.27 - Technology Readiness Levels [Source: EPRI, Technology Deployment Timelines Report, December 2023, Table 1]

Each of the different resource options within this inventory are somewhere along this technological maturity pathway. Many generation resources are at TRL 9, which are commercially available for development, such as hydropower, combustion turbines, and wind. Other technologies that are in an advanced level of development but not yet commercially widespread, that are included within the main resource options inventory include nuclear small modular reactors (TRL 6), carbon capture and sequestration (TRL 6-9), hydrogen fueled turbines (TRL 6), and alternative fuels: biomethane and biodiesel (TRL 6). These technologies are included within the inventory of resource options for evaluation to provide insight into their potential future use within the Manitoba Hydro system, even if they are not yet commercially available.

Beyond these, there are a range of other resource technologies that are at a medium or lower maturity level. Resources at these levels are not included with the main inventory or evaluations due to a lack of technical information on the resources, a lack of commercially available products, the technologies have not yet been proven to be technically viable, or high costs. Examples of emerging technology that are in the medium to lower levels of development that are not included within the main inventory include:

- **Long Duration Energy Storage (TRL 3-6+):** storing large amounts of energy, typically in the range of 100 hours, in chemical, mechanical, or thermal mediums. Examples include a range of different battery chemistries (chemical), compressed air energy storage (mechanical), and molten salt (thermal).
- **Hydrokinetic (TRL 5):** capturing energy from the speed of flowing rivers without the use of a dam, powerhouse, or spillway.
- **Solar Thermal (TRL 6+):** capturing energy from the sun by concentrating solar rays with reflectors/mirrors or lenses to produce heat. The heat can be used directly, stored, or used within a generator to produce electricity.
- **Enhanced Geothermal (TRL 6):** capturing energy from the earth's heat with the use of deep geological drilling in the range of 5-10 km. The heat can be used within a generator to produce electricity.

To assist in staying abreast of industry developments and emerging technologies, Manitoba Hydro is a member of industry associations such as the Electric Power Research Institute (EPRI) and the Center for Energy Advancement through Technological innovation (CEATI). These memberships provide the opportunity to collaborate on the assessment and evaluation of different emerging energy technologies along with monitoring industry trends.

4 | 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 A6.27. Resources that are primarily a source of electrical capacity are shown in Figure A6.28. Resources that provide a combination of both energy and capacity are shown on both charts. See the glossary for further details on LCOE and LCOC calculations. See Appendix 7.1 – Modelling and Analysis Approach for detail on how the model itself evaluates the different resources.

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, including technical considerations such as 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, the cost of energy and capacity can only be viewed in independently. 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.

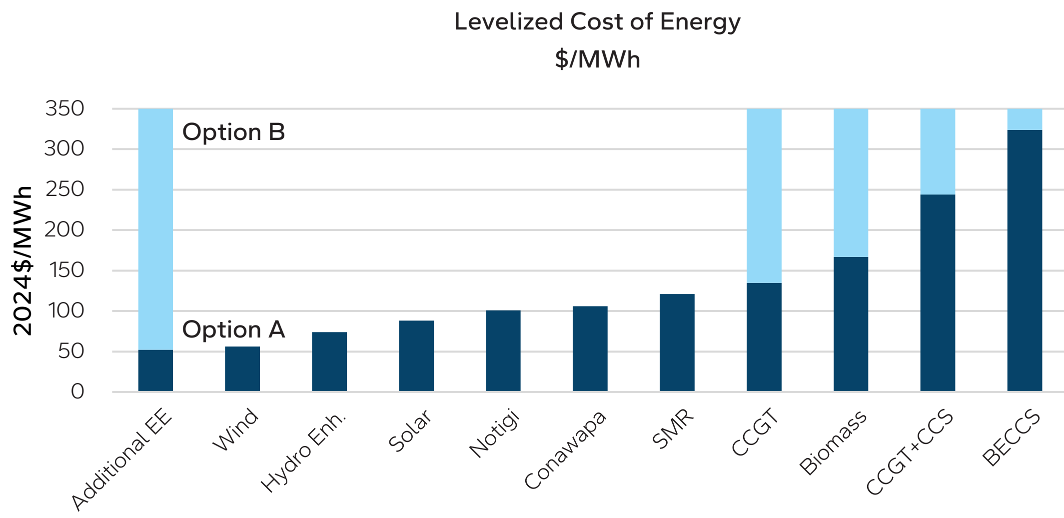

Figure A6.28 - Levelized Cost of Energy (2024$)

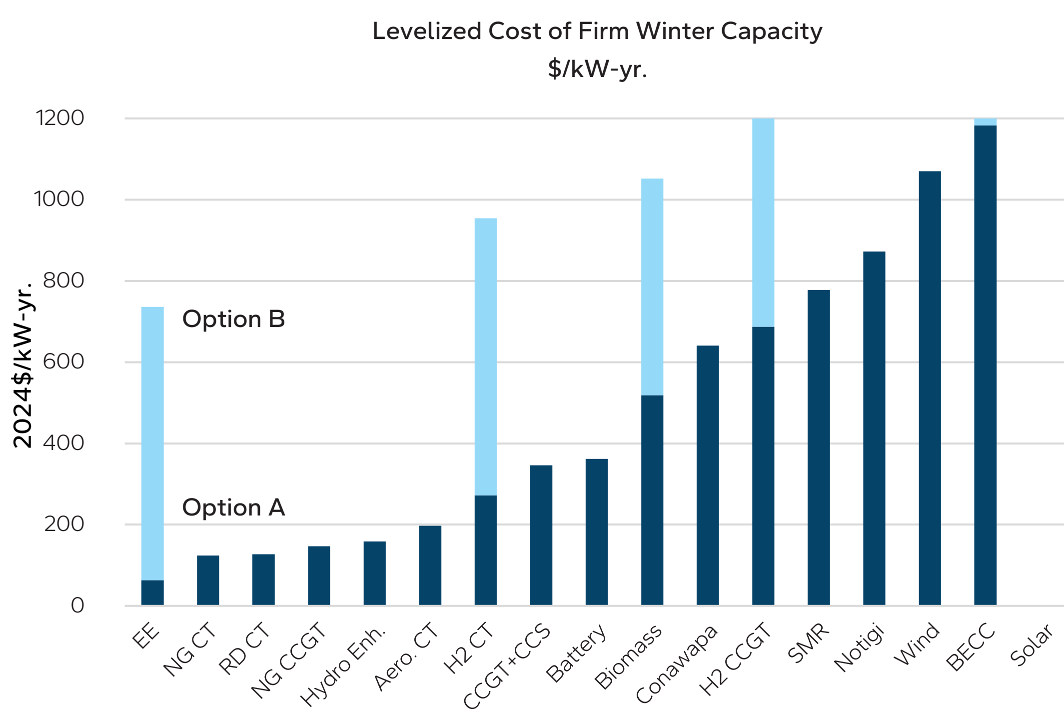

Figure A6.29 - Levelized Cost of Firm Winter Capacity (2024$)

5 | Resource Characteristic Descriptions

Capacity

Nominal Capacity (MW)

The approximate capacity rating of a generating station based on normal operating conditions. For fuel-based 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 fuel-based 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 112 years of flow history. For non-hydropower options including customer side solutions, average energy is based on each resource's specific characteristics and is independent of flow conditions. For fuel-based 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 including customer side solutions, dependable energy is based on each resource's specific characteristics and is independent of drought conditions. Fuel-based resources are assumed to be available 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 have a longer operating lifespan 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 groups. Some measures will have a life that is shorter or longer than the weighted average.

Average Utilization 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 fuel-based 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 (2024 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 (2024 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 (2024 CAN$/MWh)

The cost of integrating non-dispatchable variable resources such as wind and solar into the province's existing electrical system. This is an estimate of the cost associated with the sub-optimal operation of the existing electrical system resulting from incorporating the variable power output from wind and solar resources. 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 (2024 CAN$ millions)

The projected overnight capital cost of a resource with no interest or escalation and is presented in 2024 CAN$. 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 fuel-based resource options only.

Round Trip Efficiency (%)

The percentage of electrical energy that is returned from a battery after a charging and discharging cycle in comparison to the total energy used. The higher the value to more efficient the process is.

Levelized Cost of Capacity (2024 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 (2024 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 GHG emissions produced per MWh generated during the operating phase of a resource. GHG emission intensity can vary with loading but is presented at full operating load within this appendix.

Overnight Cost (2024 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 duration range estimate.

Reference In-Service Date (date)

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

Transmission Cost (2024 CAN$)

The cost of associated transmission required to interconnect a new resource to the existing electrical system, also referred to the generator interconnection cost. 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).