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A COMPREHENSIVE GUIDE TO ELECTRICITY GENERATION OPTIONS IN CANADA

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A COMPREHENSIVE GUIDE TO
ELECTRICITY GENERATION OPTIONS IN CANADA

A Comprehensive Guide to Electricity Generation Options in Canada

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Acronyms and Abbreviations

AB	Alberta
Adv.	Advanced
AESO	Alberta Electric System Operator
BC	British Columbia
BIMAT	Biomass Inventory Mapping and Analysis Tool
BWR	Boiling Water Reactor
CACO2	Cost of avoided CO_2 emissions
CAES	Compressed air energy storage
CANDU	Canadian Deuterium Uranium
CAPEX	Capital cost
CCS	Carbon capture and storage
CEI	Carbon emissions intensity
CEPA	Canadian Environmental Protection Act
CERI	Canadian Energy Research Institute
CF	Capacity factor
CHP	Combined heat and power
CO_2	Carbon dioxide
CO_2eq.	Carbon dioxide equivalent
CSP	Concentrating solar power
CT	Combustion turbine
CWEEDS	Canadian Weather Energy and Engineering Datasets
EGS	Enhanced Geothermal System
EOR	Enhanced oil recovery
FCR	Fixed charge rate
FOM	Fixed O&M cost
GHG	Greenhouse gas
GIS	Geographic information system
GW	Gigawatt
GWh	Gigawatt hour
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
kW	Kilowatt
kWh	Kilowatt hour
LCOE	Levelized cost of electricity
LR	Large reactor
MB	Manitoba
MMBtu	Million British thermal unit
MW	Megawatt

MWh	Megawatt hour
NB	New Brunswick
NEB	National Energy Board
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NGCHP	Natural gas combined heat and power mode of operations
NGSC	Natural gas simple cycle
NL	Newfoundland and Labrador
NREL	National Renewable Energy Laboratory
NS	Nova Scotia
O&M	Operating and maintenance
OCC	Overnight capital cost
ON	Ontario
PC	Pulverized coal
PE	Prince Edward Island
PV	Photovoltaic
PWR	Pressurized Water Reactor
QC	Quebec
ROR	Rate of return
SAM	System Advisor Model
SCPC	Supercritical pulverized coal
SK	Saskatchewan
SMR	Small modular reactor
TCR	Total capital requirement
USCPC	Ultra-supercritical pulverized coal
VOM	Variable O&M cost
WCSB	Western Canadian Sedimentary Basin

Executive Summary

The purpose of this research was to document the variation in electricity generation costs by province across Canada. Governments and stakeholders are in discussion regarding how to decarbonize our electricity system and use it for the substitution of some energy services from fossil fuels such as home heating and transportation.

The electricity grid across Canada is fragmented by province and as such each faces different costs. While there are other elements associated with the management of our electricity systems such as smart grids and demand-side management, generation is still the key part of the system to provide services we have come to depend on in modern society.

CERI has undertaken an extensive and comprehensive look at the options facing provincial governments. These generation options represent part of the solution to a complex challenge of just in time delivery of electricity to our businesses and homes. We have developed detailed datasets and analytical tools that not only compare and contrast the choices within a province, but also demonstrate that one size does not fit all.

Our assessment is based on the economic cost of adding new generation, either for the replacement of generators retiring or to help meet growing demand as more services move from other energy sources to electricity. The results are summarized in Table E.1. They show the lowest cost generation options by province for firm and intermittent power. Also, in comparison to a natural gas combined cycle plant (NGCC), the cost of reducing carbon emissions is negative in all cases.

Table E.1: Provincial Results

Province	Least Cost Intermittent Power (cents/kWh)	Least Cost Firm Power (cents/kWh)	Cost of Reduced CO_2 Emissions of the Firm Power Option ($/tonne)
NL	Wind – 6.1	Wind + Hydro – 7.6	N/A
PE	Wind – 6.3	Wind + NGCC – 7.2	-57
NS	Wind – 6.4	Wind + NGCC – 7.8	-110
NB	Wind – 6.8	Wind + NGCC – 7.4	-44
QC	Wind – 6.8	Biomass – 5.2	-88
ON	Wind – 6.6	Biomass – 5.1	-93
MB	Wind – 6.4	Biomass – 5.1	-17
SK	Wind – 5.6	Biomass – 5.0	-17
AB	Wind – 5.7	Biomass – 4.9	-20
BC	Wind – 7.5	Biomass – 4.3	-40

The provincial results indicate that wind, NGCC and biomass are options to consider across the country when evaluating the least cost options to add electricity generation to provincial grids. Costs range from a low of 4.3 cents/kWh in British Columbia (BC) for firm biomass generation to a high of 7.8 cents /kWh in Nova Scotia (NS) for a hybrid wind and NGCC option. In all cases, the selection of these options leads to a decrease in emissions at a lower cost than the base case option of NGCC. A caveat with respect to biomass is the amount of resource available. While it is the cheapest firm power option in several provinces, the amount of electricity that can be generated is limited, in comparison to other generation alternatives.

If we consider the more expensive options for electricity generation, they include small modular reactors, coal, solar and geothermal. These options may have other characteristics that would promote their use, for example, in off-grid locations. However, from a cost perspective in terms of both retail prices and reduction in carbon dioxide emissions they are more expensive.

We have put our best efforts to provide information that enables comparison of generation technologies on a common ground. For example, for intermittent generation sources, we estimate the cost of managing their variability in several different ways. These include the assessment of levelized cost of electricity (LCOE) and emissions of firming intermittent sources with natural gas-fired generation and compressed air energy storage systems.

CERI has not included elements such as smart grid investments, demand response or energy efficiency activities in this analysis. What our research does provide is an economic benchmark from which to judge the cost effectiveness of those programs. If the programs can reduce electricity consumption at a cost less than the generation option, then they would be considered economic. It should also be noted that the full cost of generation as an avoided cost benchmark can only be used if there is permanent avoidance of new generation. If these demand management programs only delay the generation investment, it is the time value of the delay which provides the economic benchmark. Generally speaking, demand management programs that are more expensive than the generation option may provide other benefits, but would not be justified on a simple cost/benefit basis.

Chapter 1: Introduction

Electricity supply in Canada is challenged by policies and programs aimed at decarbonizing the system. Canada and its provinces are working toward a transition away from carbon emissions to a lower environmental impact, and to further use of the system for non-traditional services such as transportation, and increased use in industry, commerce and for residential heating. This study considers all the electricity generation options old and new and provides information for decision makers on the economic and environmental impacts of these options. It will further show that these impacts vary by province based on each one's unique starting point of existing generation and transmission, as well as baseload and peak demand.

The electricity generation mix in the Canadian provinces consists of hydro, gas, oil, coal, nuclear, biomass, wind, solar and tidal sources. In 2015, renewables (mostly hydro) accounted for 66% of the electricity generation, with the majority of the hydro power production coming from Quebec, British Columbia, Ontario, Manitoba, and Newfoundland (NEB, 2017). The combination of hydro, nuclear, coal and gas constitute about 98% of Canada's generation mix (NEB, 2014). However, between provinces, the generation mix differs in accordance with the resource availability, technology cost variabilities and policy preferences. These differences also precipitate into various production efficiencies, environmental impacts and electricity supply costs.

According to the forecasts made by Canada's National Energy Board (NEB), over the period 2018-2040, electricity demand in Canada will grow at about 1% per year. However, this does not take into consideration the total new generation required as provinces pursue new demands on the system for services such as electric vehicles, and changes to the traditional grid associated with decentralized energy sources. While it may be difficult to accurately forecast the amount of new generation needed at any given time, this report should provide some evidence as to the price and emissions outcomes associated with different decisions.

Canada's provinces will experience different opportunities and challenges associated with expanding their electricity generation infrastructure. Some of these opportunities and challenges include impacts on electricity rates, energy resource availability, existing infrastructure, energy and environmental policies and regulations. Canada, along with the rest of the world, is amid a historic global transition to a low-carbon energy future. Energy policies and regulations that could be implemented by Canadian provinces to drive this transition would inevitably constrain generation unit additions. Canada is a signatory to the Paris agreement, with a federal-provincial target to reduce GHG emissions by 30% below 2005 levels by 2030, and a later goal to achieve up to 80% reduction below the same baseline by 2050 (CERI, 2017). Most provinces have set goals to transition their electricity generation infrastructure to meet these climate goals.

Proven and commercially-ready options to decarbonize the electricity system exist. These range from zero emitting technologies such as wind, geothermal, tidal, nuclear and solar. Some are debatable zero emissions options such as hydro and biomass, because of different interpretations regarding the emissions impacts of reservoirs or forestry or waste practices. And finally, some emitting technologies such as natural gas and coal for which carbon capture would be a requirement if they were to be used to help meet Canada's climate goals.

Most provinces already have adaptation and operating experience with some or all these technologies. For example, wind power accounts for approximately 9% of current electricity generation infrastructure in Alberta. In Ontario, which has the largest power generation fleet in Canada by installed capacity, nuclear power accounts for 35% of the installed capacity. Ontario also has the largest transmission system connected solar photovoltaic capacity of 380 MW. Saskatchewan has installed and operates the world's first commercial size coal-fired carbon capture and storage facility.

Whether conventional technologies with carbon capture or more modern technologies such as renewable energy sources, new infrastructure additions would inevitably affect the electric power generation cost in respective jurisdictions. Some technologies will also add complexities to electric power system operations. For example, integration of larger amounts of variable power generation sources such as wind power and solar power would require additional technical interventions to maintain desired levels of power system reliability.

This brings up another key aspect of this analysis – the total system impact of the different electricity generation options. Electricity produced by the different options is not the same. It comes with different properties of quality, availability, and reliability. The challenge is to integrate these properties to provide the specific transmission system outputs consumers have come to expect such as reliability, availability, baseload service, peaking service, ramping and black start. This means it is misleading to simply compare output of generation types. One must consider how the options affect the entire system. These different properties of electricity output impose additional challenges to the transmission grid. Some are resolved through innovative operating changes, others by adding additional technologies to match generation output to that expected by electricity grid customers.

For example, consider the challenge of operating electric power systems with large amounts of wind power. As a major electric power generation option, one issue with wind power is its variability in supply. A wind power plant would produce electricity only when the wind is blowing; typical wind power capacity factors in Canada are in the order of 30%. In ideal locations, such as those in southern Alberta, this can be as high as 40%. Since electricity supply and demand need to be instantaneously matched, the variability of wind power is a challenge for reliable operation of electric power systems. Several options are being proposed and utilized to mitigate the variability of wind power, including firming the wind power supply using flexible generating units such as hydropower, natural gas generating units, and electricity storage systems.

Such interventions increase the cost of power system operations, effectively increasing the electricity rates that the end users would have to pay. Furthermore, depending on the technical options to mitigate impact variability, there is uncertainty in net GHG emissions reductions achievable with variable renewable energy sources.

Objectives

The objective of this study is to provide an energy, economic and greenhouse gas emissions assessment of generation technologies available in Canada. The study will provide insights into the economics of different generation technologies by considering resource potential in different provinces, level of technical maturity of different options, and technical improvements in generation equipment. The analysis will consider the economic cost of providing baseload and peak electricity from non-renewable, renewable and nuclear generation.

For each of the technologies assessed, in each province, the study will address the following questions:

1. What is the annual electricity generation potential?
2. What is the cost of electricity generation (measured in cents/kwh):
    a. In stand-alone mode of operation?
    b. In baseload mode of operation?
    c. As a peak load asset?
3. What is the emissions abatement cost (measured in $/tCO2eq) by province?

Structure of the Report

Chapter 2 of this report describes the economic assessment methodology and metrics. It notes the unique comprehensiveness of the economic analysis from the perspective of the total cost impacting the electricity system of each option. Chapter 3 details the assumptions, resource potential and economic and environmental information associated with each generation option. In Chapter 4 we bring together the options and display them province by province to show the different results and how one size or one solution does not fit for the entire country. Chapter 5 summarizes the results, notes where additional work can aid decision makers, the challenges of additional data needs and finally how this analysis can assist provinces with their energy efficiency program discussions. The appendices provide additional analytical details to aid in the transparency of CERI's analysis.

The results in Chapter 4 provide a province by province estimate of the avoided economic and total costs (including costs associated with carbon emissions). This is important as it provides a baseline by which energy efficiency programs can be assessed. The concept is that energy efficiency options may be cheaper than new or replacement generation. The avoided cost is the cost of the next unit of generation needed to meet demand. If that unit can be avoided entirely, energy efficiency programs that can be delivered at a cheaper cost per kWh are economic. If the new generation unit can be delayed a few years, the cost savings of that delay becomes the economic benchmark, but not the entire cost of the new generation unit. Throughout this report, references will be provided to guide this understanding.

Chapter 2: The Challenge

In Canada, we face a challenge of information. Our electricity systems are very complex, yet we have a limited understanding of that complexity due to the lack of information. How will non-traditional technologies interact with the current system? How do we incorporate the use of distributed generation? How do we pay for common infrastructure with changes in business models? How do we accommodate concerns of affordability? How does a system behave with large percentages of intermittent generation options?

While this broad range of questions needs attention, this study focuses on only a portion of the analysis – the generation sub-sector and how that interacts with the transmission grid to provide the expected services to consumers. It does not identify which options should be used, how distributed generation can be incorporated or the amount of electricity that will be needed. It does provide the building blocks for decision makers such that neither they nor system customers are surprised by the economic or environmental performance of the provincial grids as electricity generation choices are implemented.

Generation Options

What the study will answer is how much a new or replacement unit of electricity generation will cost and by how much carbon emissions will be reduced. While numerous estimates exist from various sources, none take a comprehensive look at the province by province impacts. Stakeholders should be aware of the total cost and average emissions changes of their choices. To make such a comparison, CERI chose the following electricity generation technologies to assess in this study:

- Fossil fuel-fired generation
    - Coal with carbon capture and storage (CCS)
    - Natural gas simple cycle
    - Natural gas combined cycle (and with carbon capture and storage)
    - Natural gas combined heat and power
- Nuclear power
    - Large scale reactors
    - Small modular reactors
- Renewable electricity generation
    - Reservoir hydroelectric
    - Wind (onshore and offshore)
    - Grid scale solar photovoltaic
    - Biomass
    - Geothermal

This is not an exhaustive list. The study does not include generation at the distribution level of the electricity grid. This could include, for example, municipal combined heat and power, small scale photovoltaics, or municipal landfill gas generation. It also does not include tidal energy. Further work should be done to include these options in the analysis. However, these options do not have an impact on the size or configuration of the transmission grid, which was used as the basis to scope this study.

In addition, several constraints have been made to focus the analysis including:

- CCS and nuclear are assessed without province-specific factors
- No natural gas-fired generation is assessed in PE and NL as there is no natural gas infrastructure to support large scale natural gas-fired generation
- Biomass resource data is very limited in the Atlantic provinces. The datasets examined indicate zero biomass electricity potential in almost all of Atlantic Canada
- Geothermal resources are available only in BC, AB, and SK. While there are undoubtedly additional resources in other provinces, the data is lacking to provide an estimate of resource potential in other provinces
- No reservoir hydroelectric potential is considered for PE

As noted earlier, energy efficiency programs are also not expressly examined in this analysis. For the most part, the results of this analysis provide a baseline for the assessment of the economic potential of energy efficiency options.

The technologies are individually assessed by considering their potential in each Canadian province. We use different data sources to assess their potential, and always with a view to assessing the accuracy and objectivity of the datasets. These sources and assessment methodologies are described in the report.

Methodology

The levelized cost of electricity (LCOE) is a key metric for this analysis. The LCOE is presented in cents per kWh to provide an easy comparison to the retail commodity price charged across the country. This metric represents the cost of constructing and operating an electricity generation plant. It is a standard metric used for screening and comparing different power generating options. LCOE is calculated using the information available at the point of decision making, based on discounted project cash flow analysis.

The challenge with determining the LCOE is what costs to include. On a stand-alone basis, only the plant costs are considered. There is no recognition of the difference in quality, availability or reliability of the electricity produced. Yet that is not how customers consume electricity. It needs to be available on demand and with certain characteristics to provide the service we have come to expect.

As such, the LCOE presented here takes two forms. In addition to the stand-alone version, there is a cost estimate that converts the generation option into a baseload service with optional specific transmission costs resulting from siting limitations. It is the latter version that present an objective comparison of the cost impacts of the different generation options on our provincial electricity systems.

We calculate the stand-alone cost by considering the following factors:

- Project life
- Expected return on investment
- Construction period
- Financing structure (i.e., debt equity ratio)
- Provincial and federal tax rates
- Depreciation schedule
- Any applicable investment tax credits
- Fuel costs
- Capacity factor
- Operating and maintenance costs

Going beyond the stand-alone cost requires the assessment of additional costs:

- For fossil fuel plants, we include the costs of carbon capture and storage, as well as carbon pricing.
- For variable renewable options, there is the cost of energy storage or firming by other flexible sources to convert the produced electricity into the baseload or peak service requirement of the grid.
- For options which have siting constraints imposed by the specific location of the resource, additional transmission costs are considered.
- For nuclear, we include the cost of long term disposal of low, medium and high level radioactive waste.

Federal and provincial tax rates have impacts on LCOE estimates as depreciation of capital investments can be claimed as a tax-deductible business expenditure (CanmetENERGY, 2013). The net tax rates (federal and provincial combined) we assumed for different provinces are listed in Table 2.1.

Table 2.1: Net Tax Rates

Province	Net Tax Rate (%)
Alberta	27
British Columbia	26
Manitoba	27
New Brunswick	28.5
Newfoundland and Labrador	30
Nova Scotia	31
Ontario	26.5
Quebec	26.9
Saskatchewan	27%

There is significant debate regarding how broadly the cost analysis is spread. In this case, we have included our view of the significant costs. The reader will note that this analysis includes waste disposal costs, carbon management costs, energy storage costs and unique transmission-related costs.

Some would suggest that this casts the analysis too broadly. Why include energy storage costs or firming costs when there is some resilience in the system and geographic dispersion such that the intermittency has a minimal impact? Others might suggest that waste disposal costs are unfairly considered when there is only the responsibility of nuclear operators to expressly track and contain their waste. Yet others would note that there is a debate regarding the upstream methane emissions associated with natural gas that is not fully recognized in the electricity cost assessment. CERI's assessment is guided by the major cost drivers directly applicable to the technologies themselves and their integration with the transmission system. Adding or removing some of the cost elements may change the overall cost assessment, however, CERI's assessment indicates that these adjustments are not material.

In addition to the stand alone and total system cost, the analysis provides a comparison of carbon dioxide (CO_2) emissions abatement costs. In most provinces, the reference generation option is natural gas combined cycle. PE is connected to the NB grid, so NB's reference is also used for PE. In NL, the reference case is reservoir hydroelectricity which has zero carbon emissions.

We were unable to determine reliable resource data for biomass and geothermal energy in several provinces. As such, analysis of those technologies was excluded from those respective provinces. Hydroelectric potential in PE is estimated to be negligible. Therefore, hydropower was excluded from PE. Table 2.2 shows the technologies assessed in different provinces (a check mark (✓) indicates inclusion).

Table 2.2: Technology Assessments by Province

Province	Technology					
	Natural Gas	Hydroelectric	Wind	Solar	Biomass	Geothermal
NL	x	✓	✓	✓	x	x
NS	✓	✓	✓	✓	x	x
PE	x	x	✓	✓	x	x
NB	✓	✓	✓	✓	x	x
QC	✓	✓	✓	✓	✓	x
ON	✓	✓	✓	✓	✓	x
MB	✓	✓	✓	✓	✓	x
SK	✓	✓	✓	✓	✓	✓
AB	✓	✓	✓	✓	✓	✓
BC	✓	✓	✓	✓	✓	✓

Nuclear energy and carbon capture and storage technologies are assessed without association to specific provinces. This is mainly due to the complexities of the technologies, and lack of multiple project information to make robust economic assumptions. As such, these two sets of results should be treated as national level results.

For variable renewable generation technologies that are non-dispatchable, we first calculate the LCOE based on the resource availability (e.g., in the case of a wind plant, electricity is produced and delivered only if the wind is blowing). We then calculate the cost of firmed up generation (i.e., in baseload mode of operation). The economics of firming up of variable generation by different back up sources (e.g., gas powered units and/or storage technologies) is examined.

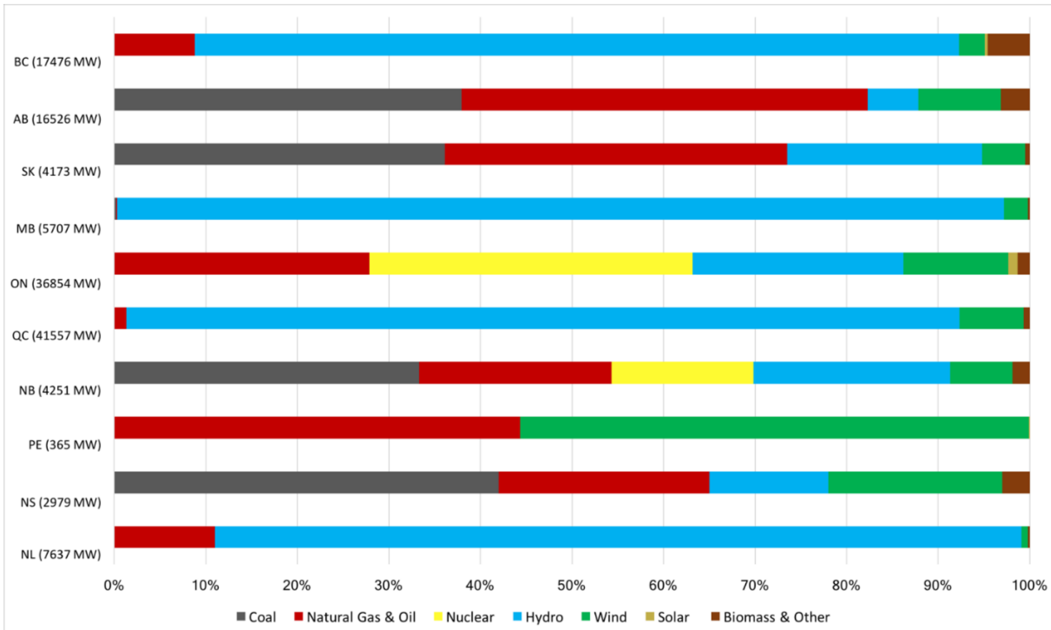
Calculation of LCOE and CO_2 costs requires an estimation of the amount of annual electricity production. For natural gas, biomass, geothermal and coal-based generation technologies, this is done by assuming typical capacity factors. For more resource flow constrained options such as hydro, wind and solar, this is done by estimating the resource availability in respective provinces.

Current State of Electricity Generation in Canada

The current state of the electricity grid in Canada differs by province. With different starting points comes different considerations of the cost of integrating new generation. In addition, the transmission infrastructure, resource siting and demand profiles mean that one size does not fit all in Canada. Interties also need to be considered. Those with other provinces and with nearby states can influence the decision making and the outcome of the cost and emissions impacts of different generation options.

Figure 2.1 depicts the installed power generation capacity in Canadian provinces by technology over the 2015-2016 period. The actual electricity generation in a given province in a given year does not usually follow the same proportions as installed capacity. This is due to many factors such as fuel costs, resource availability and system specific constraints. Figure 2.2 shows the actual electricity generation by technology in the same period.

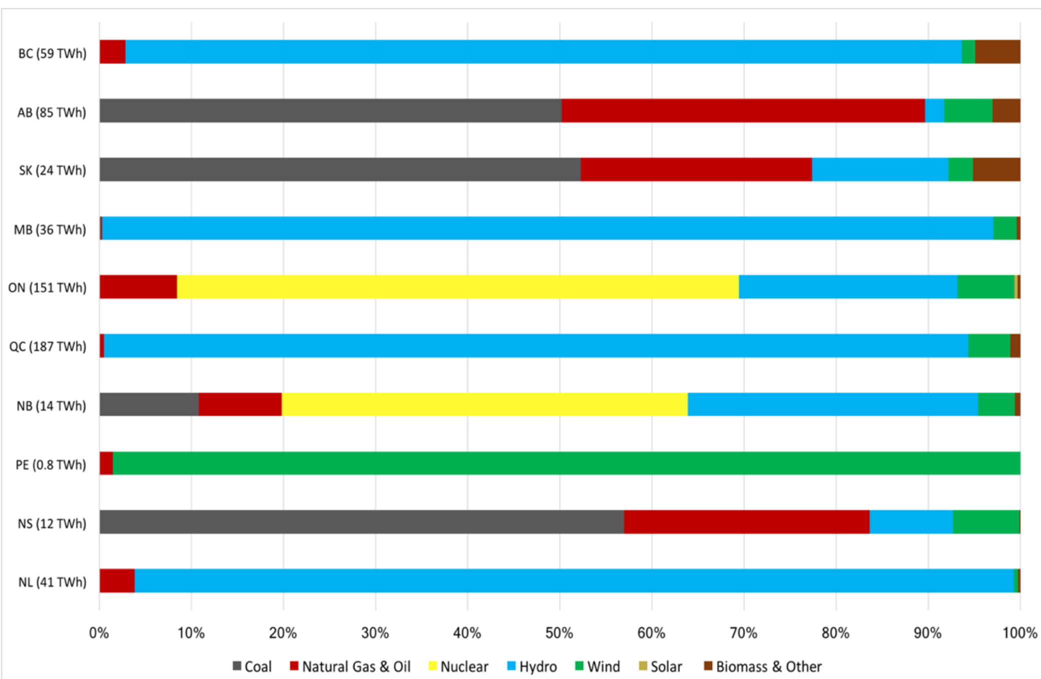
Figure 2.1: Installed Electricity Generation Capacity in Canadian Provinces, 2015



Data source: (NRCan, 2016). Figure by CERI

The number in parenthesis next to the province name indicates the total installed capacity at the end of 2015. Horizontal bars depict the relative contributions of each group of generation technology to the installed capacity.

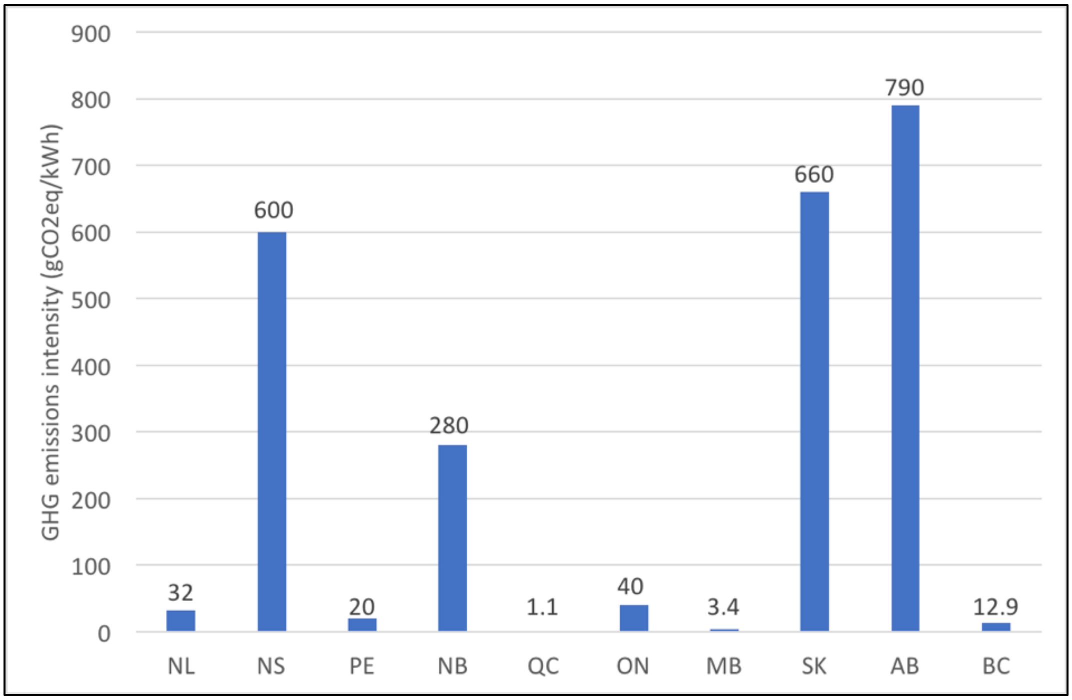
Figure 2.2: Electricity Generation by Technology in Canadian Provinces, 2015



Sources: (ECCC, 2017; NEB, 2017; NRCan, 2016). Figure by CERI

The number in parenthesis next to the province name indicates the total generation in 2015. Horizontal bars depict the relative contributions of each group of generation technology to electricity production

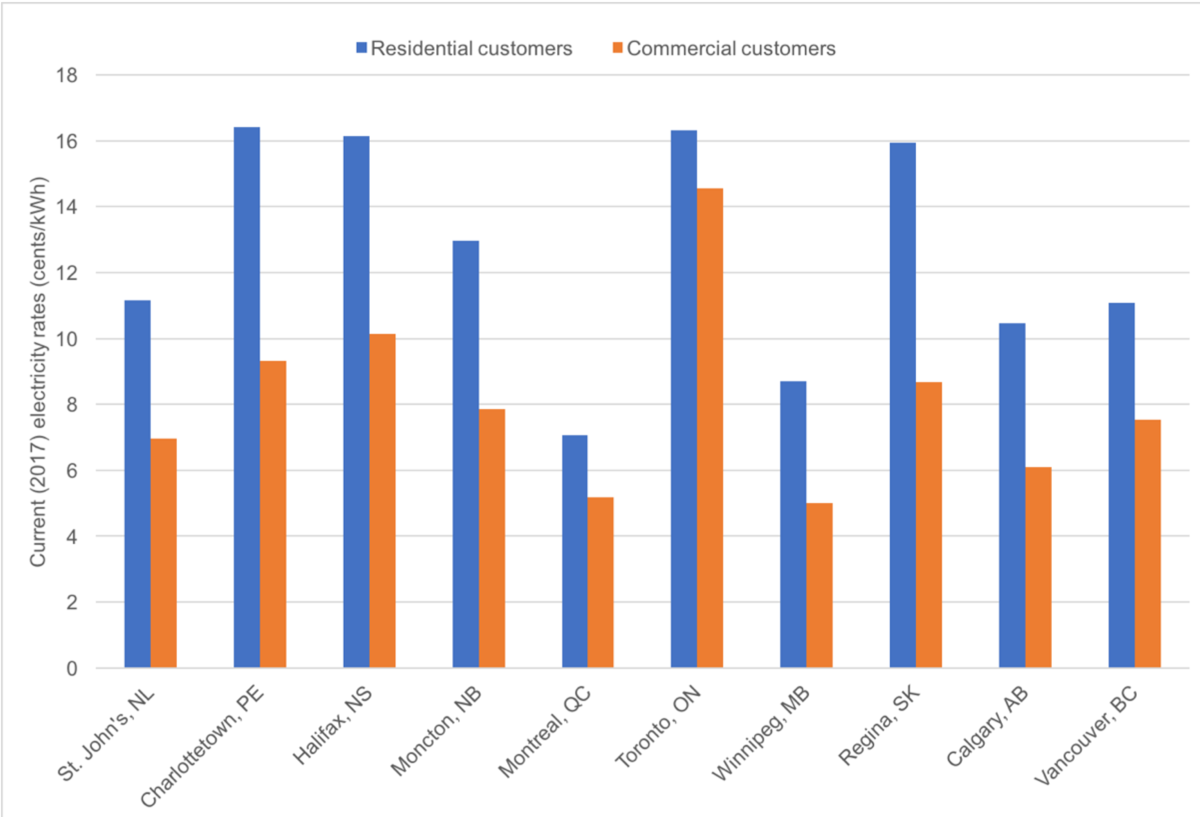
Figure 2.3: GHG Emissions Intensity of Electricity Generation in Canadian Provinces, 2015



Source: Data, (ECCC, 2017) Figure by CERI.

As can be seen from Figure 2.2, the generation mix varies greatly by province depending on the power generation fleet of respective provinces. This has led to higher diversity in GHG emissions intensity among provinces. As can be seen from Figure 2.3, current GHG emissions intensity of some provinces – ones that are hydropower dominated – have a lower GHG emissions intensity compared to that of fossil fuel dominated provinces.

Figure 2.4: Retail Electricity Prices, 1st Quarter 2017



Source: Data from Hydro Quebec annual electricity survey. Figure by CERI

Figure 2.4 shows the average electricity rates for residential and commercial customers in major Canadian cities, covering all provinces in Q12017. Relatively high rates are observed in the Atlantic provinces, Ontario and Saskatchewan. Hydropower rich provinces generally have lower electricity rates. Due to lower natural gas prices, Alberta currently has historically low electricity prices.

Another observation is that the actual generation mix of each province is not very diversified. In other words, almost all provinces have a dominant generation technology that produces more than 50% of electricity. Only New Brunswick appears to have a relatively diversified generation mix. Dominance of a certain fuel results from resource availability, investments on generation and fuel delivery infrastructure, and financial contracts. These path dependencies pose a challenge for any major transitions in power generation systems in Canadian provinces.

Chapter 3: Generation Options

Throughout this analysis, we have built datasets to document our estimates of the technical potential and economic costs of technologies assessed in all provinces.

Capital costs of different generation technologies were obtained from various Canadian and US sources. To calculate province-specific LCOE estimates, we develop and apply a set of provincial capital cost multipliers to capture the variations in capital costs in different provinces. Our approach accounts for the share of different capital cost components (i.e., equipment, material and labour) and their variations in different provinces. Material and labour costs are assumed to vary across the provinces.

The breakdown in costs include the share of the capital cost component for different technologies and the provincial multipliers for different technologies used. The breakdowns are listed in Tables 3.1 and 3.2.

Table 3.1: Share of Capital Cost Components

Technology	Labour	Materials	Equipment
Biogas	25%	15%	60%
Biomass	45%	15%	40%
CHP	20%	8%	73%
Coal-PC	33%	5%	63%
Coal-IGCC	28%	5%	68%
Gas CCGT	20%	8%	73%
Gas CT	50%	15%	35%
Geothermal	15%	35%	50%
Hydro-Pumped Storage	40%	30%	30%
Hydro large	40%	30%	30%
Hydro Small	50%	30%	20%
Nuclear	40%	40%	20%
Reciprocating Engines	50%	15%	35%
Solar PV	15%	15%	70%
Solar Thermal	20%	40%	40%
Wind	10%	20%	70%

Table 3.2: Provincial Capital Cost Multipliers

Technologies	Atlantic Region	Quebec	Ontario	Prairies	British Columbia
Biomass	0.99	1.01	1.05	1.07	1.00
CHP	0.99	1.01	1.03	1.04	1.01
Coal_PC	0.99	1.02	1.05	1.06	1.01
Coal_IGCC	0.99	1.01	1.04	1.05	1.01
Gas CCGT	0.99	1.01	1.03	1.04	1.01
Gas CT	0.99	1.01	1.06	1.08	1.00
Geothermal	0.99	1.01	1.03	1.04	1.00
Hydro large	0.99	1.01	1.05	1.07	1.00
Hydro small	0.98	1.01	1.06	1.09	1.00
Nuclear	0.99	1.01	1.06	1.08	1.00
Reciprocating engines	0.99	1.01	1.06	1.08	1.00
Solar PV	0.99	1.00	1.02	1.03	1.00
Wind	1.00	1.00	1.02	1.03	1.00

Further cost assumptions are used for each resource type. These are documented in the option-specific sections in this chapter. They include:

- Resource potential and commodity costs (where applicable)
- Economic, financial and environmental parameters
- Stand-alone levelized cost of electricity

Several economic parameters need to be made for calculation of LCOE. Selection of these parameters should consider technology-specific attributes (life time, associated risk, etc.), project ownership structure, cost of debt, etc. Throughout the analysis, we have taken best efforts to minimize the impacts of financing parameters on relative order of technologies with respect to LCOE by using the same set of financing parameters. However, in some cases, technology-specific assumptions must be made to provide sound analysis. Unless explicitly stated under the section pertaining to a certain technology, parameters listed in Table 3.3 are used for LCOE calculations.

Table 3.3: Common Assumptions Made for LCOE Calculations

Parameter	Value	Notes
Expected rate of return (nominal)*	10%	
Nominal debt interest rate	6.5%	Based on average of Canadian bond yields
Inflation rate	2%	
Net tax rate	Table 2.1	An average value of 27% is used for CCS and nuclear power analysis
Transmission losses	4%	
Project term debt (% of capital cost)	50% for investor owned utility cases (IOU) 60% for publicly owned utility cases (POU)	IOU is assumed for Alberta and Ontario where the electricity system is deregulated. POU is assumed for all other provinces

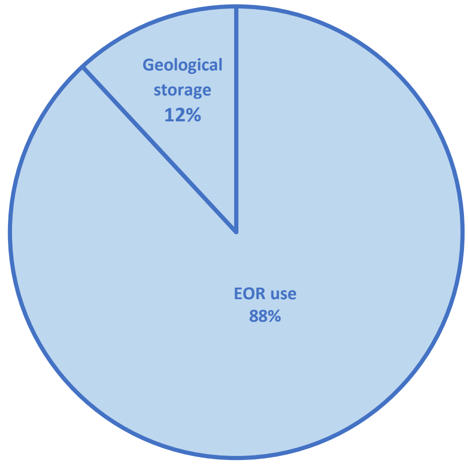
*With respect to expected rate of return, notable exceptions are hydropower and CCS technologies. Hydropower assets have very long operating period that can be several decades. A lower rate of return of 7%, that is consistent with projects with long lifetimes is used. Fossil fuels with CCS is an emerging technology with limited project development and operating experience. As such it has a higher associated risk. As such a higher rate of return of 12% is used for the analysis. Nominal debt interest rate too is higher at 8%, reflecting the lenders risk aversion. Use of higher rate of returns for high risk project, reflecting the developers risk aversion, is consistent with established cost assessment frameworks (NETL, 2011).

Coal with Carbon Capture and Storage

According to the International Energy Agency (IEA), carbon capture and storage (CCS) is the only technology capable of delivering significant emissions reductions from the use of fossil fuels in power generation and industrial applications. The technology is expected to contribute about one-eighth of total global emissions reduction in 2050 to limit average global temperature rise to 2^oC. In 20150, under the 2^oC scenario – which limits the average global warming increase to 2^oC – CCS is expected to capture and store 5.5 Gt/year, resulting in about 94 billion metric tonnes of (Gt) CO_2 being captured and stored between 2013 and 2050. This includes almost 14 GtCO_2 in “negative emissions” from bioenergy (biomass energy) combined with CCS. However, CCS performance during the two decades of deployment shows a rate of progress which falls below expectations of emissions capture playing a significant role in limiting global warming.

In 2017, there were fifteen large-scale CCS projects at an operating stage capturing about 31 Mt/year of CO_2. The number of CCS projects is expected to rise to thirty by 2019 with about 40 MtCO_2/year being used for both enhanced oil recovery (EOR) and dedicated geological storage. As shown in Figure 3.1, about 88% of the 31 MtCO_2/year captured is used for EOR while 3.7 MtCO_2/year is injected into geological reservoirs for dedicated storage (Global CCS Institute, 2017).

Figure 3.1: Projects at Operating Stage



Source: Global CCS Institute

Five projects, including two Canadian industrial separation projects (Alberta Carbon Trunk Line: Agrium CO_2 stream and the North West Sturgeon Refinery CO_2 stream) are expected to come online between 2017 and 2018. Carbon dioxide from the two Canadian plants which amounts to 1.5-2 $MtCO_2$/year will be used for EOR. In total, the projects in construction stage are expected to use 1.9-2.4 $MtCO_2$/year for EOR and 3.4-4 $MtCO_2$/year for dedicated geological storage. Thus, it is expected that a total of about 5.3-6.4 $MtCO_2$/year will be captured.

Regulations have changed the state of coal-fired generation in Canada making it impossible to build new coal-fired power plants without CCS. Under the Canadian Environmental Protection Act (CEPA), a performance standard that came into effect in 2015, a new rule applied to new coal-fired electricity generation units and the units that have reached the end of their useful life. The Federal regulation "Reduction of carbon emissions from coal-fired generation of electricity (SOR/2012-167)" sets an emissions intensity limit equivalent to that of the natural gas combined cycle with an emissions intensity of 420 $kgCO_2$/MWh (Governmnet of Canada, 2015). As such, under current regulations, the only plausible path for coal-fired electricity generation is with CCS.

Canada is already a global leader in CCS developments. The boundary dam CCS project in Saskatchewan is the first commercial plant that captured CO_2 from a coal power plant. In 2014, this project was commissioned to integrate CCS in its operations. The expectation is that the experiences learned from this plant will help make future projects economical in Canada and internationally.

In this analysis, we assess the levelized cost and CO_2 costs of coal with CCS. Economic and technical assumptions made for the CCS assessment are presented in Tables 3.4 to 3.6.

Table 3.4: Coal Power Plant Technologies and Properties

Technology	Conditions		Net Plant Efficiency	Net Plant Heat Rate
	Pressure (psi)	Temperature (ºF)	(%)	HHV (Btu/kWh)
Pulverized Coal (PC) – Subcritical	2400	1050/1050	35	9751
Supercritical (SC)	>3600	1050/1075	38-45	8981
Ultra-supercritical (USC)	>3600	1050/1150 and above	47	8126

Source: EPRI; Tan, 2012; Finkenrath et al., 2012

Table 3.4 shows different coal power generation technologies and steam properties. Subcritical and supercritical power plants have boilers that operate at subcritical and supercritical steam conditions, respectively. At supercritical conditions of steam (217.8 atmospheres), there appears to be no difference in state properties between liquid and gaseous phases.

Table 3.5: Total Capital Requirement (TCR) for New Pulverized Coal Power Plants (2016 $ values)

Source	Technology	CAPEX ($CA/kW)
EIA (2016)	USCPC	4906
Rubin (2015)	SCPC	3602
E3 (2014)	SCPC	4826
EIA (2013)	Adv. PC	4506
Worley Persons (2011)	USCPC	2716
Worley Persons(2011)	SCPC	2592
Worley Persons (2011)	SCPC	2590
Black & Veatch (2011)	SCPC	3900
IEA (2010)	SCPC	2878
IEA (2010)	SCPC	3052
NETL (2010)	SCPC	3098
Average/median	USCPC, Adv. PC & SCPC	3532/3239
Average/median	USCPC & Adv. PC	4043/4506
Average/median	SCPC	3341/3168

USCPC - Ultra supercritical PC; SCPC - supercritical PC; Adv. PC – Advanced PC which is like USCPC because it has all advanced pollution control technologies.

From the reports and papers reviewed, the total capital requirement (TCR) of all new coal power plants (USCPC, Adv. PC & SCPC) averages about $3,532/kW[1] with a minimum and maximum TCR of $2,590 and $4,906 per kW installed capacity, respectively. The maximum value comes from the EIA (2016) and is for USCPC power plants. This value and that reported by EEE (2014) skew the average value upwards; therefore, it is instructive to evaluate SCPC and USCPC plants separately.

Table 3.6: Operation and Maintenance Expenses for New Pulverized Coal Power Plants (2016 $ values)

Source	Fixed O&M (CA$/kW-yr)	Variable O&M (CA$/MWh)
EIA (2016)	56.8	6.2
EIA (2013)	52.5	6.2
E3 (2014)	45.6	NA
USCPC	56.8	6.2
SCPC	47.4	5.6

The annual capacity factor for coal power plants, which is the percentage of installed capacity used to serve a system load, is reported by the Alberta Electric System Operator (AESO) to vary between 68% and 77% from 2012 to 2016. In 2016, the capacity factor of coal reached 69% – on average (AESO, 2017a). Here, a 70% capacity factor is assumed.

[1] Unless otherwise stated, all prices in Canadian dollars.

Table 3.7: Coal-fired Power Plant Assumptions

Abbreviation	Parameters	SCPC	SCPC w/CCS	USPC	USPC w/CCS
MW	Net capacity (MW)	650	650	650	650
HR	Heat rate (MMBtu/MWhe)	8.5	11.35	8.5	11.35
CF	Capacity factor	70%	70%	70%	70%
η	Thermal to electricity efficiency	40%	30%	40%	30%
CEI	Carbon emissions intensity (kgCO_2/MWh)	788	105	788	105
TCR	Total capital requirement for ($/kW)	3168	4881	4506	6689
FOM	Fixed O&M cost ($/kW-year)	47	92	57	95
CO_2TAX	Carbon tax or price (CA$/ton CO_2)	20	20	20	20
CO_2COST	Costs associated with CO_2 price or tax (CA$/MWh)	16.6	16.6	16.6	16.6
T	Assumed plant life (years)	30	30	30	30
	Project term debt (% of capital cost)	50%	50%	50%	50%
	Nominal debt interest rate	8%	8%	8%	8%
	Effective tax rate (Federal 15% and Provincial 12%)	27%	27%	27%	27%
	Transmission losses	4%	4%	4%	4%
	Construction period (years)	4	4	4	4
	Nominal construction interest rate	8%	8%	8%	8%
ROR	Expected rate of return (nominal)	12%	12%	12%	12%
FCR	Fixed charge rate (per year)	0.091	0.091	0.091	0.091

Note: Fossil fuels with CCS is an emerging technology with limited project development and operating experience. As such, it has a higher associated risk. There is also a higher risk of coal without CCS due to the exposure to carbon management policies. As such, a higher rate of return of 12% is used for the analysis. Nominal debt interest rate is also higher at 8%, reflecting the lenders risk aversion. Use of higher rates of return for high risk projects, reflecting the developers risk aversion, is consistent with established cost assessment frameworks. Sensitivity analyses were conducted to gain insights into parameter variations. If an expected rate of return of 10% is used, LCOE will reduce by 7-8% compared to LCOE under the above assumptions.

For calculating the levelized cost of an SCPC plant, the median CAPEX value (shown in Table 3.5) for SCPC plants is used. AESO estimates system average losses, presented here as transmissions losses, in Alberta for 2016 at 3.8% and this value is used for our calculations. Construction time for new coal power plants is estimated to be around four years.

Advanced PC and the USCPC have similar configurations. These plants have advanced pollution control technologies; therefore, they are evaluated together. The average TCR for advanced PC and USCPC plants is $4043/kW as compared to an average capital requirement value of $3341/kW for only SCPC plants.

Table 3.8: Heat Rate, Net CO_2 Emissions, LCOE and CO_2 Cost of Coal (ultra-supercritical pulverized coal, USCPC)

	Without CCS	With CCS
Coal-fired generation (USCPC)		
Heat rate (GJ/MWh)	8.9	12.0
Net CO_2 emissions ($kgCO_2$/MWh)	788	105
LCOE of USCPC (cents/kWh)	9.8	14.7
CO_2 costs (\$/$tCO_2$2): USCPC w/o CCS as the reference case		71

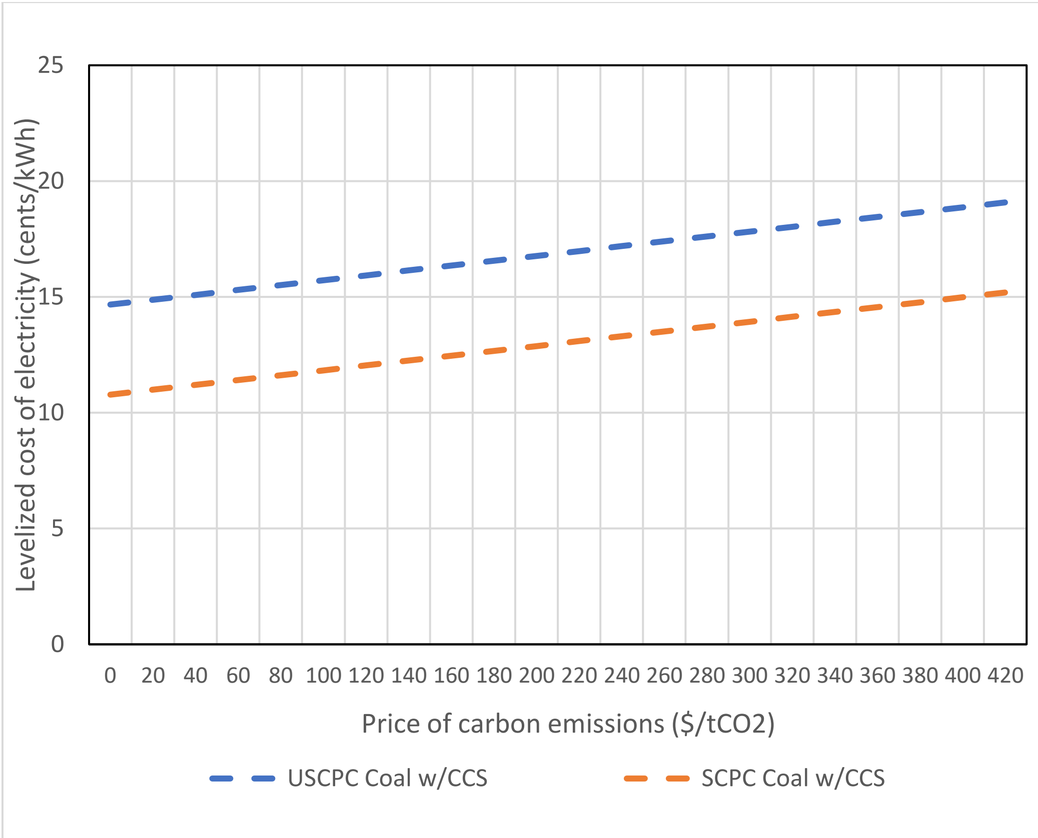
Table 3.8 presents the main results of CCS cost and performance assessment. The addition of CCS increases the LCOE of coal-fired electricity generation with USCPC by 34%. Two factors primarily contribute to the increased cost. First is the higher capital cost incurred due to the CCS equipment. Second, the addition of CCS increases the heat rate, increasing the fuel cost. The heat rate is increased by 34% (this is referred to as the heat rate penalty) for USCPC. The addition of CCS reduces the net CO_2 emissions by 88-90%.

The reason for the interest in CCS is to deploy this technology for fossil fuel-based electric power generation to reduce CO_2 emissions. As such, the cost of avoided CO_2 emissions is an important metric to measure the economic effectiveness of CCS compared to other low carbon power generation options. As discussed in Chapter 2, the calculation of CO_2 cost is done against a reference case. The reference case represents the most likely technical option to produce electricity. In this case, the reference is coal without CCS. Further on in the report, we show a different reference case – natural gas combined cycle.

Under current Canadian regulations, coal-fired power plants cannot be built without CO_2 emissions intensity of 420 kg/MWh or lower. That makes it prohibitive to build a coal-fired power plant without CCS. One exception to this is a situation where a coal-fired power plant already exists without CCS. In that case, it would be a CCS retrofit situation and the LCOE estimates would be different than the ones in Table 3.8.

The CO_2 cost of USCPC with CCS is $71/tCO2 under the reference option. A further comparison to NGCC and NGCC with CCS is discussed later.

Figure 3.2: Impact of Carbon Pricing on the LCOE of Coal Plants



Carbon pricing also impacts the economic effectiveness of CCS as an option to produce electricity from coal (see Figure 3.2). Under currently developed CO_2 capture technologies, roughly 90% of the CO_2 produced is captured. While higher capture is technically possible, it would significantly increase the heat rate penalty of capture. As such, CO_2 emissions from coal-based electricity generation with CCS is non-zero and carbon pricing would increase the LCOE. At a carbon price of $50/tCO2, the levelized cost for USCPC and SCPC with CCS is 15.2 cents/kWh and 11.3 cents/kWh, respectively.

The captured CO_2 must be safely transported, disposed of, utilized or stored. Thus, there are economic and environmental implications of CO_2 capture and compression, pipeline transportation, and geological storage in suitable aquifers. Utilization for EOR have been used in part to secure project financing in the early stages of CCS technology development.

According to Lakeman et al. (2005), Canada has one of the world's best regions for geological storage in the depleted or underutilized pore space of the Western Canadian Sedimentary Basin (WCSB). The WCSB covers northeastern BC, Alberta, southern and central Saskatchewan and southwestern Manitoba. A huge knowledge base of the storage potential of reservoirs in the WCSB has been built over many years. A recent study (Consoli and Wildgust, 2017) estimates Canada's total resource potential for CO_2 sequestration to be 198-671 Gt-CO_2. This has increased from 120 Gt-CO_2 estimated by Lakeman et al. (2005). To put the Canadian CO_2 storage capacity in perspective, assuming a capacity utilization factor of 70% and national emissions level of 722 Mt-CO_2eq. (in 2015), it will take between 192 and 650 years to exhaust the 198-671 Gt-CO_2 storage potential.

CO_2 storage faces challenges related to storage suitability, safety and regulatory compliance. For storage to be suitable it should have preferred geologies of a tectonically stable region with large oil and gas reservoirs and deep saline aquifers that are confined by thick, regional-scale shaly aquitards (Bachu, 2006). The suitability of the reservoirs is an important requirement that the storage sites must meet to reduce the possibility of CO_2 leakage back to the surface. There are safety concerns during the different stages of CO_2 capture, pipeline transport, injection and storage. These concerns relate to corrosion and CO_2 leakage. Even more important in the CO_2 storage discussion is the long-term fate of the stored CO_2, which seems to be uncertain. Furthermore, regulatory issues of reservoir ownership require clarity.

Natural Gas

We examined three natural gas electricity generation technologies:

- Combined cycle generators (NGCC)
- Simple cycle generators (NGC)
- Natural gas combined heat and power mode of operations (NGCHP)

Natural gas combined cycle (NGCC) generation is one of the most widely installed baseload electricity generation technologies in North America. The popularity of NGCC has been driven by relatively low capital cost requirements, higher efficiency, lower natural gas prices, and lower environmental pollutant emissions. Natural gas simple cycle generation is mainly used as peaking units and ancillary service providers. In natural gas combined heat and power (NGCHP) operations, both electricity and thermal energy are produced. Production of two energy outputs effectively increases the net fuel consumption efficiency.

It is estimated that Canada has more than 1,100 Tcf of remaining marketable natural gas resources, with 79% of it in the WCSB, 11% in northern Canada, 8% on the east coast, and the remaining 2% on the west coast, Ontario and Quebec.[2]

Canadian production activity mirrors the concentration of the available resources. The WCSB saw the majority of production. Northern Canada has seen small but declining production due to maintenance issues, production costs and a lack of transportation infrastructure, while Eastern Canada has seen declining production due to high supply costs and low levels of investment.

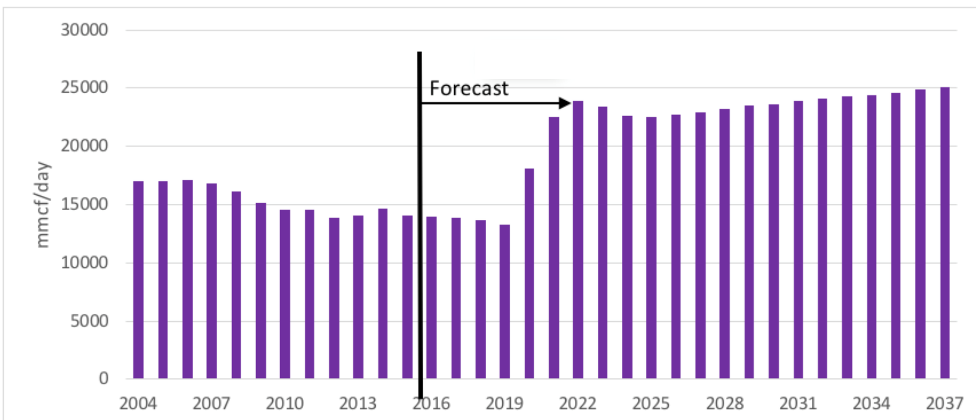
Over the next 20 years, the WCSB is expected to represent almost 99.99% of Canadian production as production declines are seen in every other Canadian producing jurisdiction. Total Canadian natural gas production is expected to increase over the next 20 years, attributable to a predicted

[2] National Energy Board, Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040, January 2016, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html, pp. 61

rebound in the price of natural gas, and a demand for LNG. Expected production through 2037 is shown in Figure 3.3. Production is forecasted to decline in the near term until 2019, after which point it will climb to above 25 Bcfd by the end of the forecast period. The forecast includes potential supply to service LNG plants (and was made prior to recent LNG project cancellation announcements).

Electricity generation from natural gas will not be constrained by a lack of the resource in any province except PE and NL where natural gas transportation and distribution infrastructure do not exist.

Figure 3.3: Canadian Natural Gas Production Forecast



Source: CERI, PSAC, CAPP, NEB, EIA

Table 3.9 presents the main economic and technical assumptions we make for economic assessment of natural gas-fired electricity generation technologies. Estimated stand-alone LCOE values are presented in Table 3.10.

Table 3.9: Economic and Technical Assumptions for Natural Gas Generation Technologies

Parameters	NGCC	NGSC	CHP
Net capacity (MW)	400	120	120
Heat rate (GJ/MWhe)	Z7	10.29	6.3-12.3
Capacity factor	70%	20%	86%
Thermal to electricity efficiency	51%	35%	51% - 69%
Carbon emissions intensity (kgCO_2/MWh)	353	514	290 - 370
Total capital requirement ($/kW)	1433	1039	2452 - 5647
Assumed plant life (years)	20	20	20
Project term debt (% of capital cost)	50%	50%	50%
Nominal debt interest rate	6.5%	6.5%	6.5%
Transmission losses	4%	4%	4%
Construction period (years)	3	3	3
Nominal construction interest rate	8%	8%	8%
Expected rate of return	10%	10%	10%

Table 3.10: Levelized Cost of Electricity from Natural Gas Generation Technologies by Province (cents/kWh)

		LCOE under Different Prices on Carbon Emissions			
Province	**Technology**	**$0/tCO$_2$**	**$20/tCO$_2$**	**$30/tCO$_2$**	**$50/tCO$_2$**
AB	NGCC	5.4	6.2	6.5	7.3
BC	NGCC	5.5	6.2	6.6	7.3
MB	NGCC	5.5	6.2	6.6	7.4
NB	NGCC	7.8	8.6	8.9	9.7
NS	NGCC	8.6	9.3	9.7	10.5
ON	NGCC	8.2	8.9	9.3	10.1
PE	NGCC	7.8	8.6	8.9	9.7
QC	NGCC	8.1	8.9	9.3	10.0
SK	NGCC	5.4	6.1	6.5	7.3
AB	NGSC	11.8	12.9	13.4	14.5
BC	NGSC	11.8	12.9	13.4	14.5
MB	NGSC	11.9	13.0	13.6	14.6
NB	NGSC	15.1	16.2	16.8	17.8
NS	NGSC	16.3	17.3	17.9	19.0
ON	NGSC	15.7	16.8	17.3	18.4
PE	NGSC	15.1	16.2	16.7	17.8
QC	NGSC	15.6	16.7	17.2	18.3
SK	NGSC	11.8	12.9	13.4	14.5
AB	CHP (<5WM)	10.3	11.3	11.7	12.7
BC	CHP (<5WM)	10.3	11.3	11.8	12.7
MB	CHP (<5WM)	10.4	11.4	11.9	12.8
NB	CHP (<5WM)	13.3	14.3	14.8	15.7
NS	CHP (<5WM)	14.3	15.3	15.8	16.7
ON	CHP (<5WM)	13.8	14.8	15.2	16.2
PE	CHP (<5WM)	13.3	14.3	14.7	15.7
QC	CHP (<5WM)	13.7	14.7	15.2	16.1
SK	CHP (<5WM)	10.3	11.2	11.7	12.7
AB	CHP (>5WM)	6.0	6.9	7.3	8.2
BC	CHP (>5WM)	6.0	6.9	7.4	8.3
MB	CHP (>5WM)	6.1	7.0	7.4	8.3
NB	CHP (>5WM)	8.8	9.7	10.2	11.1
NS	CHP (>5WM)	9.8	10.7	11.1	12.0
ON	CHP (>5WM)	9.3	10.2	10.6	11.5
PE	CHP (>5WM)	8.8	9.7	10.2	11.1
QC	CHP (>5WM)	9.2	10.1	10.6	11.5
SK	CHP (>5WM)	5.9	6.8	7.3	8.2

The LCOE of natural gas generation is influenced by natural gas prices. However, where lower gas prices are observed (mainly in Western Canada) capital cost and capacity factor have the highest influence. CO^2 costs were assumed to vary from \$0 to \$50/ton. The natural gas prices used in this analysis are shown below in Table 3.11.

Table 3.11: Natural Gas Prices

Province	CAN (2016) \$/GJ
Canada (average)	3.71
Nova Scotia	7.39
New Brunswick	6.21
Quebec	6.73
Ontario	6.77
Manitoba	2.73
Saskatchewan	2.55
Alberta	2.60
British Columbia	2.69

Note: Prices have been estimated using historic information obtained from Statistics Canada (CANSIM Table 129-0003 Sales of natural gas, annual)

NGCC emits significantly lower GHGs compared to coal-fired electricity generation (353 $kgCO_2$/MWh compared to 1077 $kgCO_2$/MWh of pulverized coal power generation). Carbon pricing contributes on average 9% of LCOE of natural gas technologies depending on the province. However, under tighter carbon emissions constraints, emissions from NGCC power plants can also be a significant source of GHG emissions from electricity power generation. Therefore, integrating CCS into NGCC is currently being explored as a carbon emissions reductions measure in the electric power sector. Cost impacts are shown in Table 3.12.

Table 3.12: Heat Rate, LCOE, Net CO_2 Emissions and Cost of CO_2 Avoided for NGCC Power Plants with or without Capture

	NGCC without CCS	NGCC with CCS
Heat rate (MMBtu/MWh)*	6.65	7.98
Levelized Cost of Electricity (cents/kWh)*	5.5	10.9
Net CO_2 emissions ($kgCO_2$/MWh)**	353	42
Cost of CO_2 avoided (\$/ton CO_2)		173.6

*average values calculated from values reported for NGCC plants in Akbilgic et al. (2015) are used.

**Using the heat rates and a CO_2 intensity of 50.3 $kgCO_2$/GJ natural gas

Figure 3.4: Natural Gas Combined Cycle LCOE with CCS

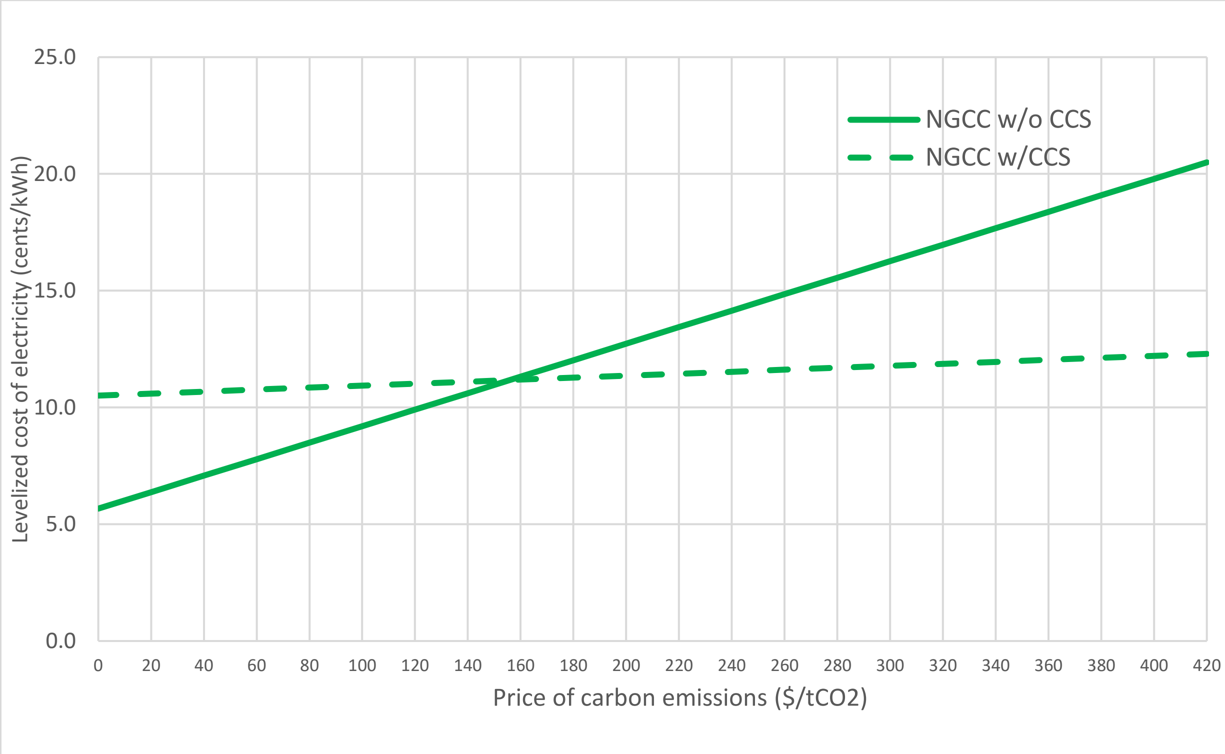


Figure 3.4 details the change in LCOE for NGCC with CCS at different prices for carbon emissions. We note that emissions are reduced from 353 Kg of CO_2/MWh to 42. The breakeven carbon price for the addition of CCS is approximately \$160 t/CO_2. The analysis in Figure 3.4 is based on natural gas costs for BC.

Nuclear

Electricity from nuclear power is clean and reliable. For this reason, nuclear power plants are usually operated as baseload plants. About 15% of Canada's electricity supply comes from nuclear energy, which accounted for approximately 60% of Ontario's baseload in 2015. New Brunswick is the other Canadian province having nuclear energy in the electricity supply mix. These existing nuclear power plants are of the Canadian Deuterium Uranium (CANDU) type design. However, the desire to overcome current challenges to new nuclear power development both locally and internationally is driving innovations in nuclear reactor designs and delivery.

The emerging reactors (advanced reactors) are expected to have better safety features, higher efficiencies, longer life spans, dispatchability, shorter build times, and improved economics. These attributes are anticipated to enhance the potential for advancement of the Canadian nuclear power sector. Canadian opportunity for advanced reactors include applications in remote residential and industrial areas, where they can serve both electricity and heating requirements.

Interest in new nuclear power plant development has been expressed in Alberta and Saskatchewan, with possibilities of new additional capacities in Ontario and New Brunswick. The technologies being considered vary from the improved CANDU designs to the advanced Pressurized Water Reactor (PWR) type designs and high temperature reactors. Several small and medium reactor designs are also being proposed for remote residential and mining locations in Ontario, Saskatchewan, Alberta and other areas. The odds of emerging nuclear technologies gaining significant entry in the future energy mix is also augmented by progress in design of more passive safety systems and expedited construction enabled by simplification and modularization. These factors are considered crucial for social acceptability and a cost-effective delivery of the emerging nuclear reactor technologies.

In this analysis, we develop a nuclear supply cost model to capture the economics of both large reactors (LRs) and small modular reactors (SMRs). Tables 3.14 and 3.15 present the economic assumptions we make for LRs and SMRs in the supply cost model. The ability to scale and modularize is an advantage of SMRs compared to LRs. Since modularity would require transportation of the design components from factory to site, it is implementable at lower capacities. Nevertheless, while small modular reactors offer economies of series production, large reactors can offer economies of scale if project contingencies are adequately contained.

LRs came with (or promised) economies of scale and SMRs are expected to offer economies of series production. The benefits of series production, replication, modularity, and design and technological learning make the specific capital cost (i.e., cost per unit of capacity) of SMRs very competitive relative to large reactors.

Standardization and modularized fabrication of SMRs is expected to shorten build times (to between 3 to 4 years) and lower siting costs. Major technology options being adopted in SMR designs are: light water reactors, fast neutron reactors, graphite-moderated high temperature reactors and molten salt reactors (Boldon & Sabharwall, 2014; WNA, 2017a). The designs could also be categorized based on the type of coolant. The Ontario Ministry of Energy is considering various designs of SMRs (<25 MWe) for off-grid remote locations for mining and residential communities. The designs include: PWR, Gas Cooled Reactor (GCR), Lead-cooled Fast Reactor (LFR), Sodium Fast Reactor (SFR), and Molten Salt Reactor (MSR) (HATCH, 2016).

SMR designs considered to be commercially-ready include: advanced PWR, advanced Boiling Water Reactor (BWR), advanced heavy water reactor, high-temperature gas-cooled reactor, and liquid metal-cooled fast reactor (Boldon & Sabharwall, 2014). Existing high-temperature gas-cooled reactors are experimental reactors which already fall within the SMR capacity range, these include: the high temperature engineering test reactor (HTTR) in Japan and the high temperature reactor (HTR-10) in China. These reactors operate at elevated temperatures, around 800-900˚C which make them suitable for cogeneration applications. Liquid-cooled fast reactors are expected to be factory built and assembled onsite, with fuel cycles of between 7 to 20 years and lifetime capacity factor of about 95%. They have been deployed for electricity generation, breeding, cogeneration, and desalination (Boldon & Sabharwall, 2014). Table 3.13 shows the schedule of SMR designs that are close to deployment in various countries.

Table 3.13: SMR Designs at Various Stages of Implementation

Name	Country	No. of Units	Unit Capacity	Fuel Options	Expected Date	Comments
CAREM-25	Argentina	1	25 MWe		2017/2018	Can serve a population of about 100,000
KLT-40S	Russia	2	35 MWe		2017	Floating NPP installed on existing Russian icebreakers
RITM-200	Russia	2	50 MWe		2018	To be installed on new icebreakers
HTR-PM (or HTR-200)	China	2	210 MWe	Moderate-enriched Uranium (8.9%)	2017	Design is based on the experimental HTR-10

Source: (Boldon & Sabharwall, 2014; Campbell, 2016)

Most of the remaining SMR designs are either at the conceptual design stage or at the basic design stage. Some of these include: Nuclear Institute of China's ACP100 (100 MWe), Korea's Atomic Energy Research Institute's SMART-100 (100MWe), Russia's OKBM VBER-300 (300 MWe), Babcock & Wilcox's mPower (American, 180 MWe), NuScale Power's NuScale (American, 50 MWe), and Westinghouse's SMR (225 MWe) (Campbell, 2016).

Based on the opinions of industry experts, the factors supporting further development and deployment of nuclear power can be summarized as follows:

- Higher performance of existing plants through learning-by-doing, resulting in higher capacity factors over the last two decades
- Longer lifespan of new and refurbished plants (up to 60 years)
- The potential to extend operating licenses
- The ability to certify new designs to take advantage of modularization and standardization
- The possibility of applying for combined construction and operating licenses
- Improved economic potentials of the new designs when delivered in a timely manner
- No GHG emissions
- Ability of new designs to support growth of renewable energy systems
- Stakeholders who are pro-nuclear energy development
- Cheap and relatively stable fuel prices

Relative to coal and gas, fueling nuclear plants is cheaper but the capital cost is higher. The economics of new nuclear plants depend largely on the capital cost and is responsible for not less than 60% of the plant's levelized cost of electricity. In places where there is no direct access to low-cost fossil fuels, nuclear power is known to be cost-competitive with other sources of electricity generation. The cost of nuclear power can be broken down into these components (WNA, 2017b):

- Capital costs – for site preparation, construction, procurement, commissioning, and financing.
- Operating costs – includes fuel, operation and maintenance costs, in addition to provisions for decommissioning and end-of-life management of equipment and wastes. O&M costs can be divided into FOM and VOM. FOM are incurred whether a plant is running or not. VOM depends on output level.
- External costs – considered to be zero for nuclear power except when the cost of a serious accident, which is not insurable, is considered. Nuclear power is found to have a better economic performance when externalities (social, health and environmental costs) are captured in the costing of power plants.

We calculate the LCOE of a hypothetical advanced nuclear reactor which is scalable from 100 MWe to 1000 MWe. We compare the LCOE impact of building such a reactor using the conventional development approach with the effect of build modularization. Tables 3.14 and 3.15 detail the design characteristics and economic parameters of conventional and modular reactors.

Table 3.14: LR Nuclear Power Plant Design Characteristics and Economic Parameters

Abbreviation	Parameters	Value
OCC	Overnight capital cost ($/kW)	6276
DDE	Detailed design and engineering cost ($M)	500
CC	Contingency cost	20%
O&M	Operation and maintenance costs ($/MWh)	21.3
FC	Fuel costs ($/MWh)	13.2
MW	Net Capacity (MW)	1000
CF	Capacity factor	90%
	CO_2 emissions ($kgCO_2$/MWh)	~0
FCR	Fixed charge rate	0.049
CRF	Capital recovery factor	0.063
T	Assumed plant life (years)	30
	Inflation rate	2%
ROR	Expected rate of return	10%
	Project term debt (% of capital cost)	60%
	Nominal debt interest rate	6.5%
	Effective tax rate	27%
	Construction period (years)	6
	Nominal construction interest rate	8%

Table 3.15: SMR Nuclear Power Plant Design Characteristics and Economic Parameters

Abbreviation	Parameters	Value
OCC	Overnight capital cost ($/kW)	17688
DDE	Detailed design and engineering cost ($M)	500
CC	Contingency cost	20%
O&M	Operation and maintenance costs ($/MWh)	21.3
FC	Fuel costs ($/MWh)	13.2
MW	Net Capacity (MW)	100
CF	Capacity factor	90%
	CO_2 emissions ($kgCO_2$/MWh)	~0
LCOE	Levelized cost of electricity ($/MWh)	214
FCR	Fixed charge rate	0.051
CRF	Capital recovery factor	0.066
T	Assumed plant life (years)	30
	Inflation rate	2%
R	Expected rate of return	10%
	Project term debt (% of capital cost)	50%
	Nominal debt interest rate	6.5%
	Effective tax rate	27%
	Construction period (years)	3
	Nominal construction interest rate	8%

As mentioned, the construction period for modular reactors is assumed to be 3 years, half that of the large conventional reactors. In addition, the plant life is longer than the typical natural gas generation option. Both these changes to time periods improves the economics of the SMR option.

Table 3.16: Cost of Long Term Storage

Source	O&M (cents/kWh)	Fuel (cents/kWh)	Decommissioning (cents/kWh)	Waste Management (cents/kWh)
WNA (2017)	2.13	0.99	0.13-0.26	0.13
HATCH (2016)	-	-	6.78	0.11

Table 3.16 shows the unique costs for long term storage of radioactive waste. A cost for this parameter is included in the LCOE shown in Table 3.17

Table 3.17: LCOE of Non-Modular and Modular Nuclear Reactors

Capacity (MWe)	LCOE Non-Modular (cents/kWh)	LCOE Modular (cents/kWh)
100	21	16
200	16	12
300	14	10
400	13	12
500	12	12
600	11	11
700	10	10
800	10	10
900	10	10
1000	9	9

For all nuclear power reactors, co-siting of multiple units of the same design bring appreciable unit cost reduction. Further improvements on the economics are achieved through reactor and construction standardization, design simplification – including the addition of inherent safety features, technology learning through continuous development, and a streamlined licensing and regulatory process.

Although both small and large reactor technologies may incorporate advanced capabilities, large scale reactors require a larger amount of upfront financial investment in order to commence construction. In addition, project management challenges are not uncommon at such scales of high-technology development. Consequently, small modular reactors are considered the alternative to be developed at a scale not more than 300 MWe. Along with their advanced operational attributes, they can be factory-fabricated and assembled on site with a more manageable schedule than large reactors.

Hydroelectricity

Hydropower is a major source of electricity generation in Canada. In addition to providing a clean and reliable supply of electricity, the hydropower industry is a significant contributor to the Canadian economy. Most provinces have the potential to develop new hydropower plants as they deliver a reliable supply of low carbon electricity (Figures 3.5 and 3.6). Development of these new hydropower plants could potentially be complicated by new transmission line requirements, undesired land use impacts, as well as environmental and social impacts.

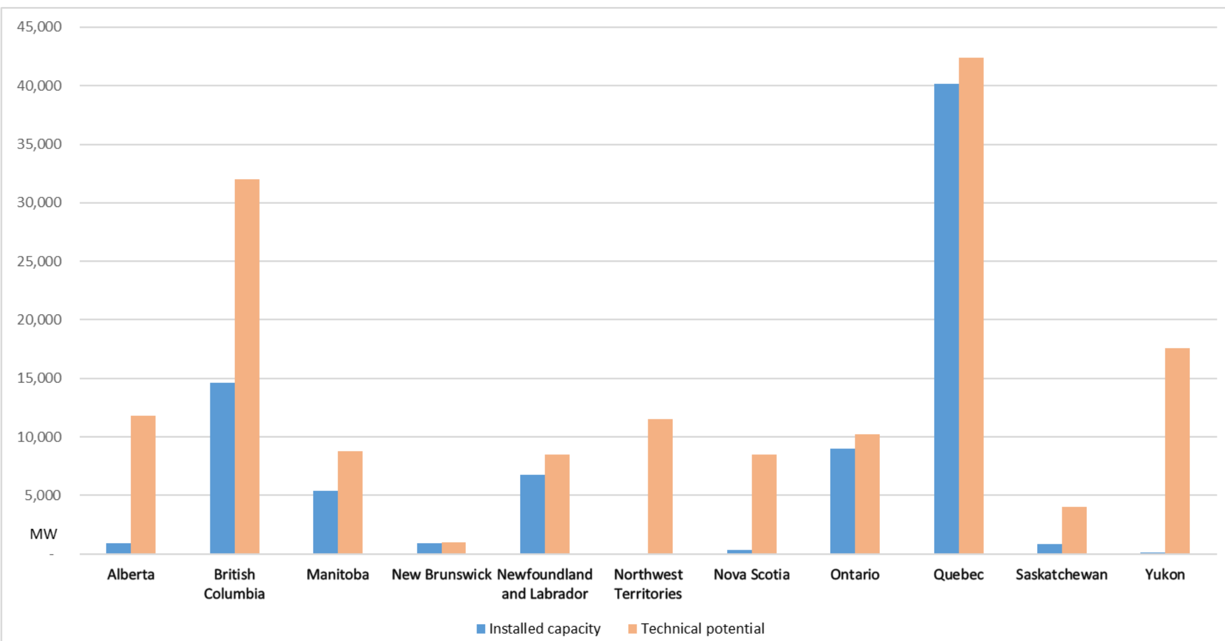
A study conducted by HEC Montreal in 2011 (Desrochers et al., 2011) analyzed hydro potential in Canada by building three different scenarios: "Business as Usual" (projects that have already been approved), "Mid" (projects that have more than 50% likelihood of proceeding within a 20-year period) and "Optimistic" (projects that have less than 50% chance of being built). The scenarios were aggregated into three regions: Western region (Yukon, British Columbia and Alberta), Central region (Northern Territories, Nunavut, Saskatchewan and Manitoba), and

Eastern region (Ontario, Quebec and Atlantic Canada). This study collected project information directly from Canadian hydropower generators.

The analysis identified 158 hydropower projects over 20 years (non-small hydro projects only) within the three regions. The data indicates that the projects are split almost equally between the Western and Eastern regions of Canada. About a third of the projects are upgrades or restorations mainly located in eastern Canada. More than 80% of new constructions are run-of-rivers (mostly concentrated in the Western region) while most storage hydro projects are situated in the Eastern region. In the most optimistic case, Canada could foresee the installation of 29,060 MW of capacity. Canadian hydropower output could increase by 137 TWh over the next 20 years in the "Optimistic" scenario. Figure 3.5 shows the mean annual hydroelectric output by region, which represents the amount of energy that can be produced annually.

In this analysis, we provide a cost analysis of the hydropower potential sites in the provinces and territories of Canada. Using technical and economic hydropower information, we estimate future hydroelectric potential.

Figure 3.5: Canadian Hydro Capacity and Potential (MW)



Source: CERI, Canadian Hydro Association; Statistics Canada

Data for the analysis was compiled from publicly available reports of various utilities, corporations, governments, news agencies, and non-governmental organizations.

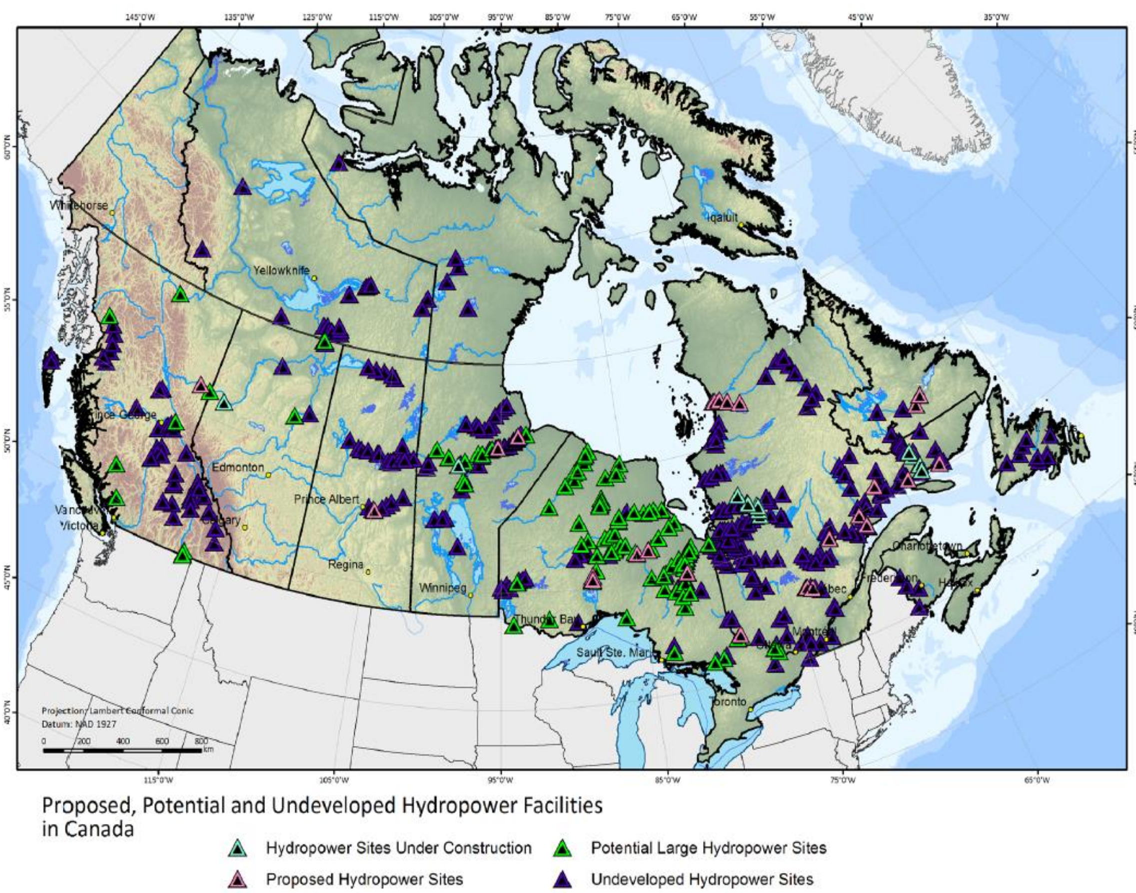
To narrow down the sites analyzed in this study, the following factors are considered.

- A requirement for large quantities of electricity that is reliably supplied with minimal variation to meet baseload power supply in each of the provinces. The potential hydroelectric sites need to have both higher production capabilities (large hydro and run-of-river) and high capacity factors. This study considered only sites with higher than 100 MW of technical potential that can be operated at an average capacity factor of around 50% or more.

- This study examines only hydropower potential available in nine provinces: Alberta, British Columbia, Manitoba, Ontario, Quebec, New Brunswick, Saskatchewan, Nova Scotia, and Newfoundland and Labrador.
- Developing several geographically dispersed hydropower plants with relatively smaller capacities was not considered as an option because that would lead to higher transmission costs and cumulative environmental impacts.

Generation from intermittent resources, such as run-of-river hydro is determined by environmental conditions such as river flows. As a result, intermittent resources cannot be dispatched to run in response to changes in customer demand or market prices, and therefore have low dependable capacity. In contrast, non-intermittent resources such as large hydroelectric and pumped storage are highly dispatchable. The ability to store water and release it during times of system need makes pumped storage a potentially useful capacity resource. These units can respond quickly to variations in system demand and can provide ancillary services such as voltage regulation.

Figure 3.6: Potential Sites to Develop Hydropower Generation in Canada



Potential hydropower site costs in the different provinces were calculated using the System Advisor Model (SAM) (NREL, 2017). Table 3.18 shows the main assumptions made for estimation of LCOE of each project.

Table 3.18: Financial Assumptions Made in Calculating Levelized Cost of Electricity

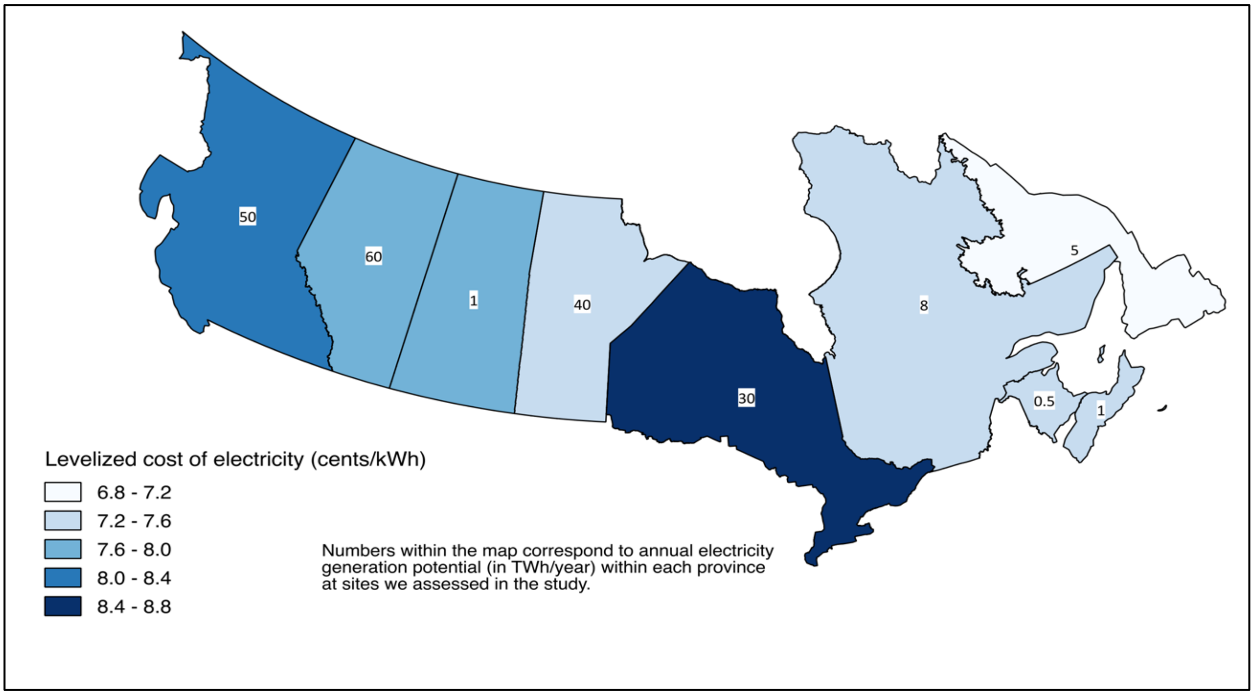
Abbreviation	Parameters	Value/Range
TCR	Total capital requirement ($/kW)	5422
FOM	Fixed operation and maintenance costs (CA$/kW-yr)	57.84
VOM	Variable *O&M* costs (CA$/MWh)	6.2
MW	Net Capacity (MW)	>100
CF	Capacity factor	50-80%
LCOE	Levelized cost of electricity ($/kWh)	6-9 cents
FCR	Fixed charge rate	0.054-0.058
CRF	Capital recovery factor	0.043-0.049
T	Assumed plant life (years)	50
	Inflation rate	2%
ROR	Rate of return	7%
	Project term debt (% of capital cost)	60%(POU); 50% (IPP)
	Nominal debt interest rate	6.5%
	Transmission connection costs ($/kW)	282
	Construction period (years)	8 years (Capital spending schedule: 20,15,15,10,10,10,10, 10% of TCR)
	Tax rates	Table 2.1
	Nominal construction interest rate	8%

Note: Hydroelectricity projects have long life spans covering several decades. Taking this into account, we use a project life of 50 years for LCOE estimates for hydroelectric projects. As such a lower rate of return of 7% and nominal debt interest rate of 6.5% are used for the analysis. These values are representative for protects with long life spans.

A larger fraction of the capital cost of a hydroelectric power plant is spent on items that are disproportionate to the nameplate capacity of the plant; for example, on planning, feasibility studies, permitting, environmental impact assessments and access roads. Furthermore, the magnitude of some environmental and social impacts such as impacts on natural ecosystems, fishery, and involuntary relocation of people tend to be disproportionate to the capacity of the plant. Therefore, developing the full capacity of a given site leads to more favorable economics than partial development.

Figure 3.7 depicts the estimated LCOE values of potential hydroelectric power generation projects in different provinces. Hydroelectric power generation is constrained by water resource availability. For all sites, we estimate the annual power generation potential. Combined hydroelectric power generation potential in the sites we assessed in different provinces are indicated in Figure 3.7.

Figure 3.7: LCOE Distribution and Annual Hydroelectric Power Generation Potential in Different Provinces



Sites with suitable hydroelectric potential tend to be in remote areas away from major demand centers, requiring new transmission lines to connect them. Transmission development is also capital-intensive but the costs shown in Figure 3.7 do not include transmission costs. These transmission costs are included in Table 3.19.

Therefore, it is important that high capacity factors be maintained to keep transmission costs low. Furthermore, due to the amount of transmission requirements, if sufficient demand is available, developing larger sites with high capacity factors leads to lower overall costs than developing several smaller sites. Cost of transmission to connect hydropower to the bulk transmissions system or demand centres varies greatly by site-specific conditions.

For example, the Keeyask hydropower project that is currently under construction on the Nelson River in northern Manitoba is 695 MW. The hydropower plant is expected to operate at an average capacity factor of 80% (Manitoba Hydro, 2013). To connect this site to the existing bulk transmission system requires construction of three 138 kV transmission lines on an approximately 38 km long right of way (between the Keeyask site and Radisson substation). We estimate the cost of these lines and required substation upgrades to be $252 million. At the rated power and the capacity factor that the unit is expected to operate, the average transmission cost of moving power to the generating station will be 0.36 cents/kWh.

In CERI Study 155, we estimated the transmission requirements to connect an 1100 MW hydropower project on the Slave River in northern Alberta (CERI, 2016). To connect this site to Fort McMurray (the closest major demand centre) would require construction of an approximately 400 km long new transmission system that can move 1100 MW of electricity. CERI estimated the transmission cost to be 3 cents/kWh (with HVDC) to 5.1 cents/kWh (with HVAC).

As mentioned above, a large fraction of total capital required to develop hydropower is spent on site-specific factors such as planning, feasibility studies, permitting, environmental impact assessments, and access roads. Therefore, it is difficult to provide generalized estimates of LCOE of hydropower without making detailed site-specific cost estimates. Making such site-specific estimates is beyond the scope of this study. Estimates provided generally cover all equipment and engineering costs. As such the estimates may be interpreted as minimum average costs.

Canadian provinces have a long and, in some cases, contentious history with developing and operating hydropower (Froschauer, 2000). Several factors lead to challenges that are unique to hydropower. A prominent one, particularly in the case of large hydro, is land use impacts that have significant social and ecological implications. Such factors have led to project delays and possible cancellations even after the construction has commenced. A prominent example is the Site C hydroelectric project in BC, where construction started in 2015 but was only recently approved for completion.

Development of the hydropower plants and transmission systems require massive amounts of irreversible capital investments. Therefore, the viability of implementation of any of the hydropower options assessed in this study depends on providing project developers the certainty of capital cost. Moreover, development of these hydropower plants would lead to environmental and socioeconomic impacts that extend beyond the jurisdictions where they would be sited. Therefore, inter-jurisdiction coordination and stakeholder consultation is vital for the successful implementation of any hydroelectric project.

LCOE of hydroelectric power in the sites assessed are listed in Table 3.19.

Table 3.19: LCOE of Hydroelectric Power in Different Provinces (sites with capacity potential greater than 100 MW[3])

Province	LCOE (cents/kWh)	LCOE with Transmission Cost (cents/kWh)
AB	7.7	9.7
BC	8.0	10.0
MB	7.3	9.3
NB	7.6	9.6
NL	6.8	9.8
NS	7.5	9.5
ON	8.8	10.8
QC	7.6	9.6
SK	7.8	9.8

Note: Average transmission costs of connection vary significantly; in the range of as high as 0.3-5 cents/kWh. For Newfoundland and Labrador, transmission cost is based on the Labrador Island Link transmission line of the Muskrat Falls project. For other provinces, transmission cost is assumed to be 2 cents/kWh.

The levelized cost of electricity from hydro is higher than NGCC but lower than NGCC with CCS. The major differences between the use of hydroelectricity and natural gas is the longer lead times for hydroelectricity projects and site limitations. Natural gas plants can be sited almost anywhere, however, even with CCS, there will still be some carbon emissions associated with natural gas use as compared to hydroelectricity.

Wind Energy

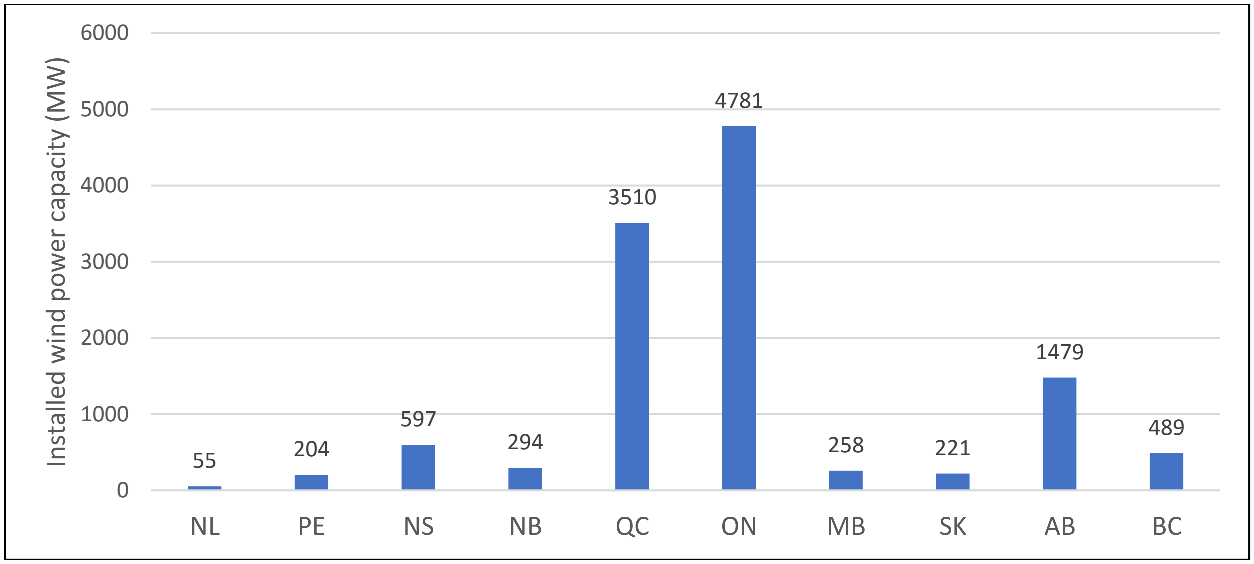
Wind power is one of the rapidly growing electric power generation technologies in the world. From 53 GW in 2005 to 433 GW in 2015, global installed wind capacity has grown by 65% (REN, 2016). Canada is among the top 10 countries in terms of installed wind capacity. As of December 2016, total installed wind capacity was 12 GW. Currently, approximately 6% of Canada's electricity demand is satisfied by wind power.[4] All provinces have wind power installed with the largest capacity installed in Ontario, Quebec, and Alberta (Figure 3.8). Prince Edward Island has the highest penetration at 61% of the installed generation capacity. Wind power satisfies about one third of the province's electricity demand.

In most provinces, wind power is receiving increased attention as a proven technology to produce electricity without GHG emissions. As such, the Canadian wind industry continues to have stable growth that has been observed over the past several years.

[3] In Prince Edward Island, we did not find information about any sites that meet out selection criteria (i.e., 100MW or more of potential capacity)

[4] Powering Canada's Future, December 2016, Canadian Wind Energy Association. http://canwea.ca/wp-content/uploads/2017/03/Canada-Current-Installed-Capacity_e.pdf

Figure 3.8: Installed Wind Power Capacity by Province



Source: CanWEA

To assess wind power generation potential in Canada, we used a high-resolution wind energy dataset developed for the Pan-Canadian Wind Integration Study (PCWIS) published by the Canadian Wind Energy Association. The dataset was developed by GE Energy Consulting/Vaisala by utilizing mesoscale modeling of a wind speed time series (GE Energy Consulting & GE Energy Consulting, 2016).

The full dataset includes 4,984 potential wind sites of which 346 were selected to perform the modeling in the four PCWIS scenarios. Site locations are indicated in Figure 3.9. The number of sites considered in the PCWIS vary by province. Annual energy generation potential of all sites in a given province is sufficient to satisfy 35% of the forecasted energy demand of the province (GE Energy Consulting & GE Energy Consulting, 2016).

For this analysis, we use the same 346 sites used for the PCWIS. The time series dataset provides the hourly electricity output (in MW) of a wind power generation system installed at each site. We use these hourly outputs to estimate total energy generation, LCOE, LCOE of baseload mode operation, and capacity value calculations. Table 3.20 details the technical and financial assumptions used in the LCOE calculations.

Province-specific capital cost estimates are obtained from a survey of Canadian renewable energy project costs published by Clean Energy Canada (Moorhouse & Killan, 2015).

Table 3.20: Technical and Financial Parameters used for LCOE Estimates

Abbreviation	Parameters	Value
Plant Performance Data		
MW	Net Capacity (MW)	Varies by site
CF	Capacity factor	Calculated by the resource model
CEI	Carbon emissions intensity (kgCO_2/MWh)	0
Plant's Costs and Economic Assumptions		
TCR for Onshore	Total capital requirement – Onshore wind ($/kW)	2000-2600
TCR for Offshore	Total capital requirement – Offshore wind ($/kW)	3500
FOM for Onshore	Fixed O&M cost for onshore ($/kW/year)	23
FOM for Offshore	Fixed O&M cost for offshore ($/kW/year)	35
T	Assumed plant life (years)	20
	Project term debt (% of capital cost)	50%
	Nominal debt interest rate	6.5%
	Effective tax rate	Table 2.1
	Transmission losses	4%
	Construction period (years) – equal share of capital spending during construction period	2
	Nominal construction interest rate	8%
ROR	Expected rate of return	10%

As wind power is non-emitting, there will be no impact on wind generated electricity resulting from carbon pricing. A key consideration is the capacity factor that can be applied to wind without a firming source such as compressed air or a natural gas back-up generator. This challenge captures the difficulty in assessing intermittent power generation with firm power generation, which is a key expectation of grid connected customers.

Table 3.21: Wind Power LCOE Assessment Results

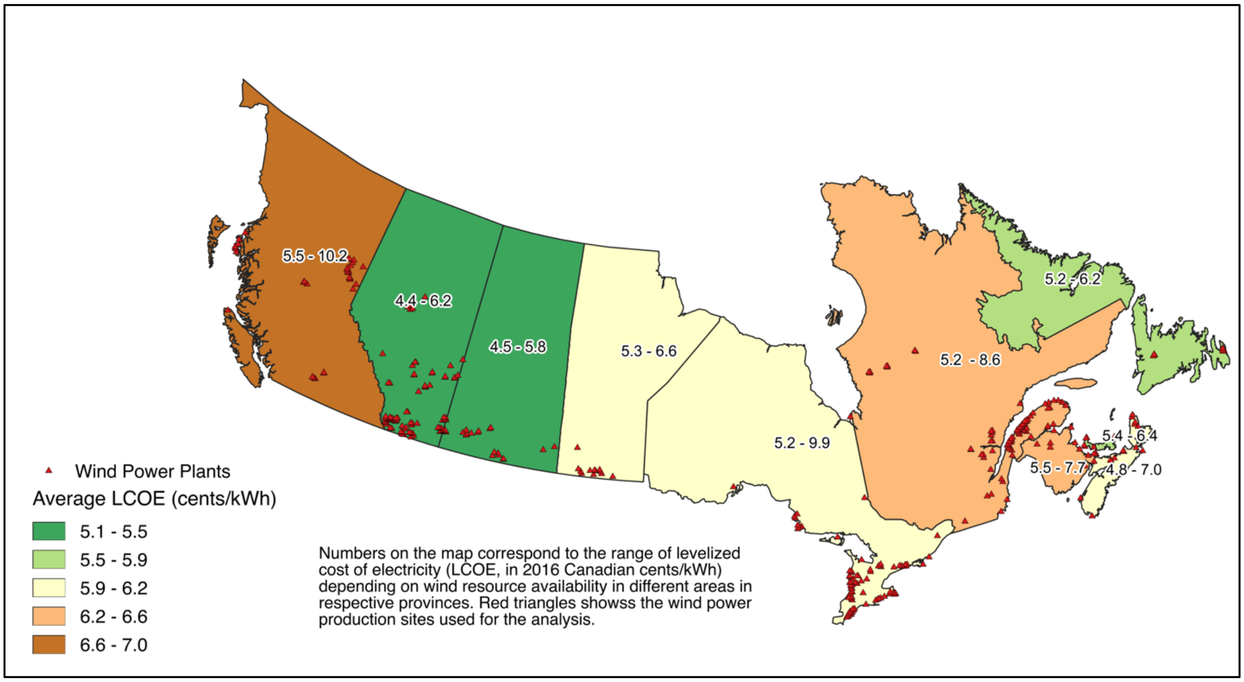
Province	Number of Sites	Levelized Cost of Electricity (cents/kWh) Average	Minimum	Maximum
Onshore Wind				
AB	75	5.2	4.4	6.2
BC	35	7.0	5.5	10.2
MB	12	5.9	5.3	6.6
NB	11	6.3	5.5	7.7
NL	8	5.6	5.2	6.2
NS	13	5.9	4.8	7.0
ON	83	6.1	5.2	9.9
PE	6	5.8	5.4	6.4
QC	81	6.3	5.2	8.6
SK	20	5.1	4.5	5.8
Offshore Wind				
NB	1	8.3	7.7	8.9
NS	2	8.9	8.3	9.5

The levelized cost shown in Table 3.21 is without a back-up system to firm the load. This might lead readers to assume the cost of wind power is equal to or lower than natural gas generated electricity. Again, the challenge is to equate the electricity in terms of the same properties. Table 3.21 details the intermittent wind power costs. Additional capital cost is needed to firm this power and equate it to the power provided by NGCC.

Figure 3.9 illustrates the national distribution of wind power costs. The LCOE of wind power is dominated by the capital cost. The next most influential factor is resource availability at different sites. The best wind resources are available in Alberta and Saskatchewan, leading to lower LCOE compared to other provinces. The two provinces also have the lowest reported capital cost (Moorhouse & Killan, 2015). In all provinces, potential wind power production sites are available that can produce electricity with LCOE less than 10 cents/kWh.

Offshore wind, although with higher energy potential, has comparatively higher LCOE due to high capital cost. Furthermore, there is still lower project experience. As such there is lower amount of data available to make robust cost estimates.

Figure 3.9: LCOE Distributions of Potential Wind Sites in Canadian Provinces



In contrast, THE onshore wind industry is matured and well established in Canada as well as in the rest of the world. Onshore wind project construction can typically be completed within 2 years (Black & Veatch, 2012). Electricity system operators ALSO have experience with operating power systems with large amounts of wind power (cite AESO, IESO, PE). State-of-the-art techniques are available to forecast wind power production with reasonable accuracy to assist system operators in planning operations and control.

Variability of wind power generation remains a challenge for wind power integration. Examination of hourly production outputs of the sites we assessed in this study reveals that more wind power is available during the night, where demand is lower. More production potential is available in winter than summer.

Capacity Value of Wind Power

Capacity value of a power generating asset refers to its ability to satisfy the load when demanded by the power system. A power system is strained for supply during peak demand periods. Therefore, in practice the capacity value is associated with a unit's ability to satisfy the load during peak demand periods. The capacity value of dispatchable generators (i.e., fossil fuel-fired generation units, nuclear and dispatchable renewables such as hydro, biomass and geothermal) is limited by their forced outage rates. For fossil fuel-fired electric power plants, the forced outage rate is less than 5% of the time. Other technology-specific factors may also influence the capacity value (e.g., ramp rates, minimum down times, hydro water management constraints, etc.). Wind power, as well as variable renewable generating sources such as solar PV, are unable to provide power on demand. They follow the resource availability patterns, not the system demand. Therefore, the capacity value of those units should be assessed by taking their observed availability into account.

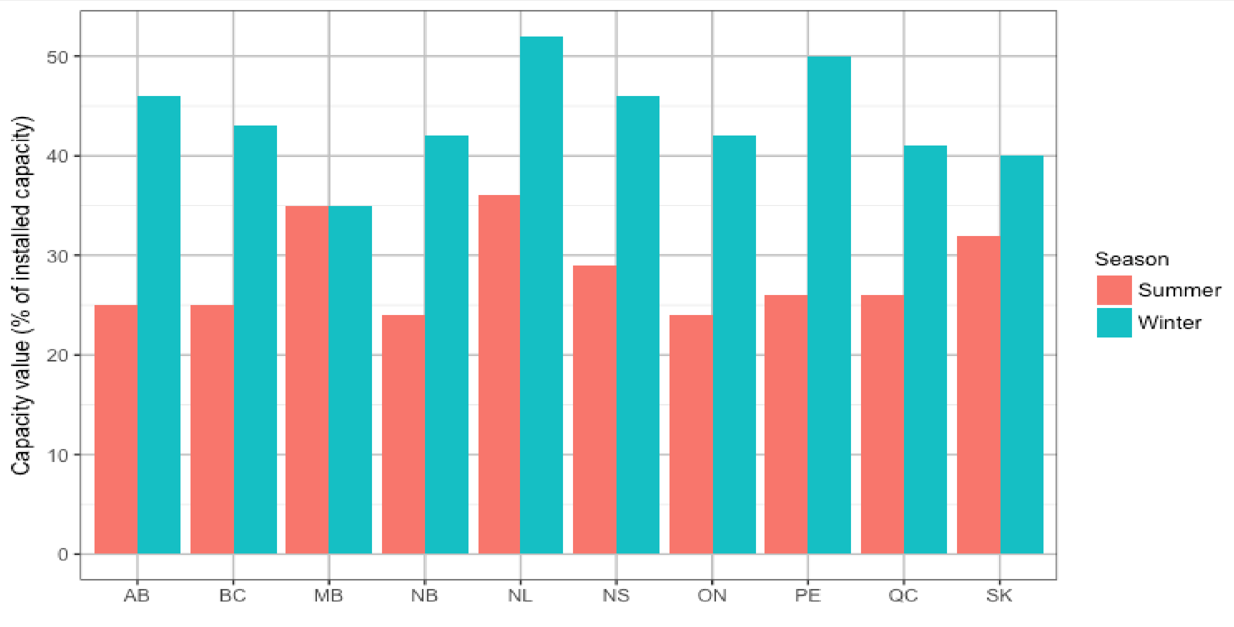
There are various ways to estimate the capacity value of variable generators. These include: expected unserved energy (EUE), loss of load hour (LOLH), loss of load expectation (LOLE), effective load carrying capacity (ELCC), etc. (D'Annunzio & Santoso, 2008; Keane et al., 2011; Lannoye et al., 2010; Oree et al., 2017). Estimation of these metrics require power system level simulations and reliability assessments that require power system specific information. Such analysis is beyond the scope of this study.

In this study, we use an alternative method to estimate the average capacity values of wind power generation systems. To do so we estimate their average availability during periods where the electric power systems experience winter peak demand and summer peak demand. Similar statistical methods are being employed in larger power systems such as PJM[5] interconnection and the power system of the state of New York (NYISO). In Alberta, the AESO is proposing to use the average availability as one metric to determine the capacity value of variable generation (AESO, 2017b).

In Canadian power systems, winter peaking conditions occur in January, February, November, and December during the hours of 4:00 pm through 11:00 pm. Summer peaking conditions are experienced in July and August during the hours of 12:00 pm through 6:00 pm. We use the hourly production outputs of wind power generation units for this analysis to estimate the average hourly production value during the two peaking periods (i.e., winter and summer) in all Canadian provinces. The capacity value is estimated as a percentage of installed capacity of respective wind power generation units. Figure 3.10 shows the average capacity values of wind power generation units in different provinces.

[5] PJM Interconnection is a regional transmission organization in the United States. It is part of the Eastern Interconnection grid operating an electric transmission system serving all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

Figure 3.10: Average Capacity Value of Stand-alone Wind Power Generation Units



As shown in Figure 3.10, a higher winter capacity value is observed in all provinces with one exception – Manitoba – where the winter and summer capacity values are the same. Wind power has a relatively higher winter capacity value of 35-52% of the installed capacity. Summer capacity values are in the order of 25-35% of the installed capacity.

The cost of firming wind power is discussed later in this chapter.

Solar Energy

Globally, over the past decade, solar energy-based electricity generation has grown exponentially. The most dominant form is photovoltaic (PV) conversions that grew from 6 GW in 2006 to 303 GW by the end of 2016, at both the utility scale and distributed generation scale. Concentrating solar power (CSP) has also grown significantly from 0.4 GW 2006 to 4.8 GW in 2016. The cost of the technology dropped significantly making it an economically viable generation option to produce electricity. Solar energy has a high potential to produce electricity with negligible greenhouse gas emissions. In terms of deployment scale, solar electricity generation has high flexibility where a given installation can range from residential rooftop scale to transmission connected utility scale. Although solar remains relatively small in terms of market penetration, it is seeing a sustained growth in Canada. The period 2008-2014 is marked by the significant growth of installed capacity for solar PV in Canada, which in 2014, reached 1,843 megawatts of installed capacity.[6] A clear majority of this capacity is in Ontario. Currently,

[6] About Renewable Energy, Natural Resources Canada. http://www.nrcan.gc.ca/energy/renewable-electricity/7295#solar ; http://www.iea-pvps.org/index.php?id=93&eID=dam_frontend_push&docID=4061

transmission connected solar PV capacity in Ontario is 380 MW. Over the same period, the capital cost of solar PV has reduced significantly. Table 3.22 shows the reported capital cost of solar PV.

Table 3.22: Capital Cost Trends of Solar PV Systems in Canada, 2009-2016

Installation Type ($CAD/W)	2009	2010	2011	2012	2013	2014	2015	2016
Residential systems (< 10kW)	8.5	6.5-8.0	6.79	3.0-5.0	3.44	3.0-4.0	2.8-6.0	3.0-3.5
Commercial and industrial systems	6.0-8.0	6.0	5.27	4.0	3.27	2.2-2.9	2.2-2.9	2.0-3.0
Utility scale ground mounted systems	-	4.0	3.5	2.8	2.88	2.0-2.6	2.0-2.6	< 2.0

Source: (CanmetENERGY, 2017)

In this analysis, we provide a detailed spatially explicit assessment of solar energy potential and economics in Canada. The focus of this analysis is the economics of solar energy as a utility scale electricity generation source. More specifically, we focus on utility scale solar photovoltaic electricity generation.

Solar energy potential across Canada is assessed by using the Canadian Weather Energy and Engineering Datasets (CWEEDS) published by Environment and Climate Change Canada (ECCC).[7] The CWEEDS files are computer datasets of hourly weather conditions such as solar radiation, temperature, wind speed, etc. These datasets start as early as 1953 and provide all data required to estimate the output of a solar energy conversion system installed at the location corresponding to the dataset.

We used the most recent CWEEDS data published in July 2017 that includes 492 Canadian locations with at least 10 years of data for the period 1998-2014. Of the 492 sites, 472 are in the provinces (the rest are in the three territories). Use of this data enabled resource assessments at very high spatial resolution and longer time series data for all provinces improving the robustness of the analysis.

To estimate the output of a PV system installed in each of the 474 locations in the 10 provinces, we use the System Advisor Model (SAM) developed by the US National Renewable Energy Laboratory (NREL, 2017). Using the physical characteristics of commonly used solar energy conversion technologies, SAM can simulate the output of a solar energy conversion system at designated locations. Table 3.23 provides cost of performance parameters used in determining output.

[7] Engineering Climate Datasets. http://climate.weather.gc.ca/prods_servs/engineering_e.html

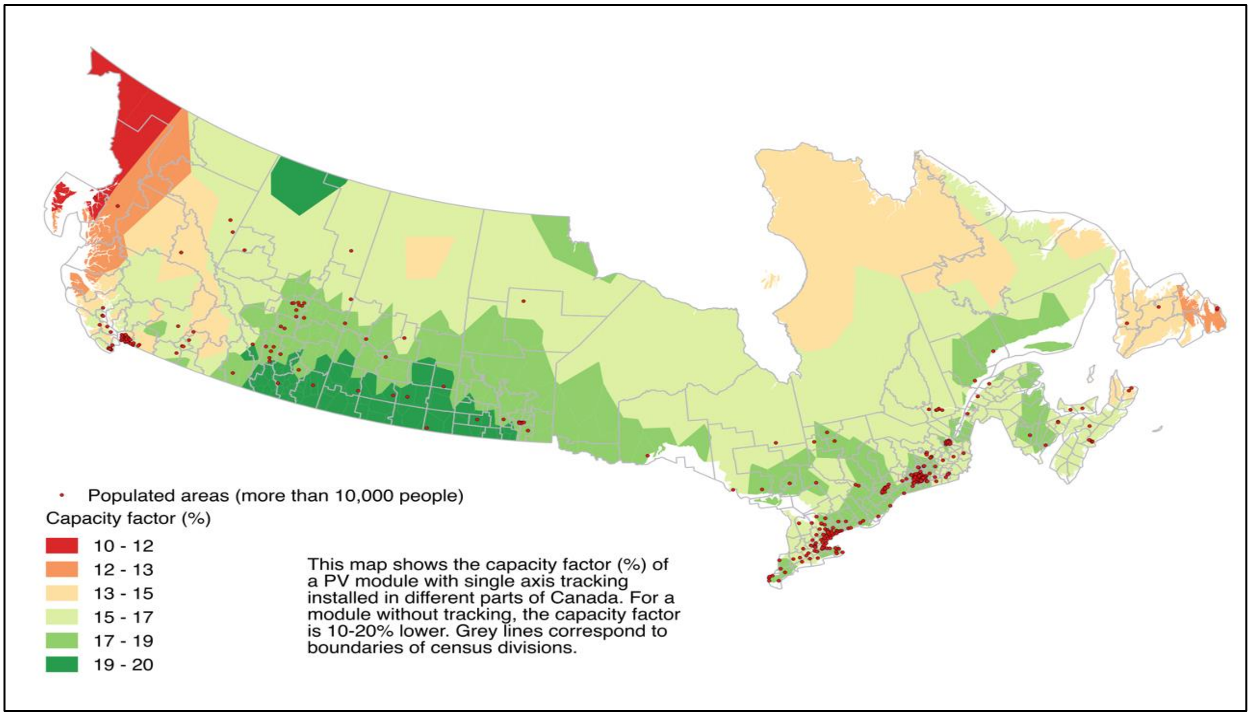
Table 3.23: Cost and Performance Parameters Used for Solar PV Analysis

Abbreviation	Parameters	Value
Plant Performance Data		
MW	Base capacity for analysis (MW)	1
CF	Capacity factor	Calculated by the resource model
CEI	Carbon emissions intensity (kgCO_2/MWh)	0
Plant's Costs and Economic Assumptions		
TCR for fixed mount	Total capital requirement for *fixed mount* ($/kW)	2000
TCR for tracking mount	Total capital requirement *for 1 axis tracking* ($/kW)	2140
FOM for fixed mount	Fixed O&M cost for fixed mount ($/kW/year)	24
FOM for tracking	Fixed O&M cost for tracking mount ($/kW/year)	26
T	Assumed plant life (years)	20
	Project term debt (% of capital cost)	50%
	Nominal debt interest rate	6.5%
	Effective tax rate	Table 2.1
	Transmission losses	4%
	Construction period (years) – equal share of capital spending during construction period	2
	Nominal construction interest rate	8%
ROR	Expected return on investment	10%

Source of Capital Cost: NRCan, CANSIA, US NREL; Variable O&M cost was assumed to be negligible. Solar PV energy estimates are made for a 1 MW reference plant. Output of higher capacities is obtained by linear scaling.

Using the SAM model along with the CWEEDS dataset, we estimate the hourly output of a 1 MW PV system installed in all 474 locations. We model both fixed mount PV systems and single axis tracking PV systems. A PV system with sun tracking system maximizes the output by automatically orienting PV panels and avoiding losses due to shading by adjacent sub arrays. We then aggregate hourly outputs to estimate monthly and annual outputs. Figure 3.11 shows capacity factors across the country.

Figure 3.11: Capacity Factors for PV in Canada



Compared to single axis tracking, fixed mounted PV systems have a lower capacity factor by 10-20% depending on the province. Recent estimates of utility scale PV systems indicate that the additional capital cost requirement of single axis tracking systems is 7% higher than that of fixed mount array systems. Despite the higher capital cost, the increase in production due to single axis tracking can result in a 10-14% lower LCOE.

Hourly output values are used to estimate the capacity value and variability assessment. Annual outputs are used for the economic assessment to calculate LCOE. Hourly data is used to estimate results around baseload mode of operation, capacity value estimations, and estimation of ramping reserve requirements. LCOE is calculated for all years that data is available. LCOE estimates of solar PV in different provinces are detailed in Table 3.24.

Table 3.24: Summary of Solar PV Potential and LCOE Estimates

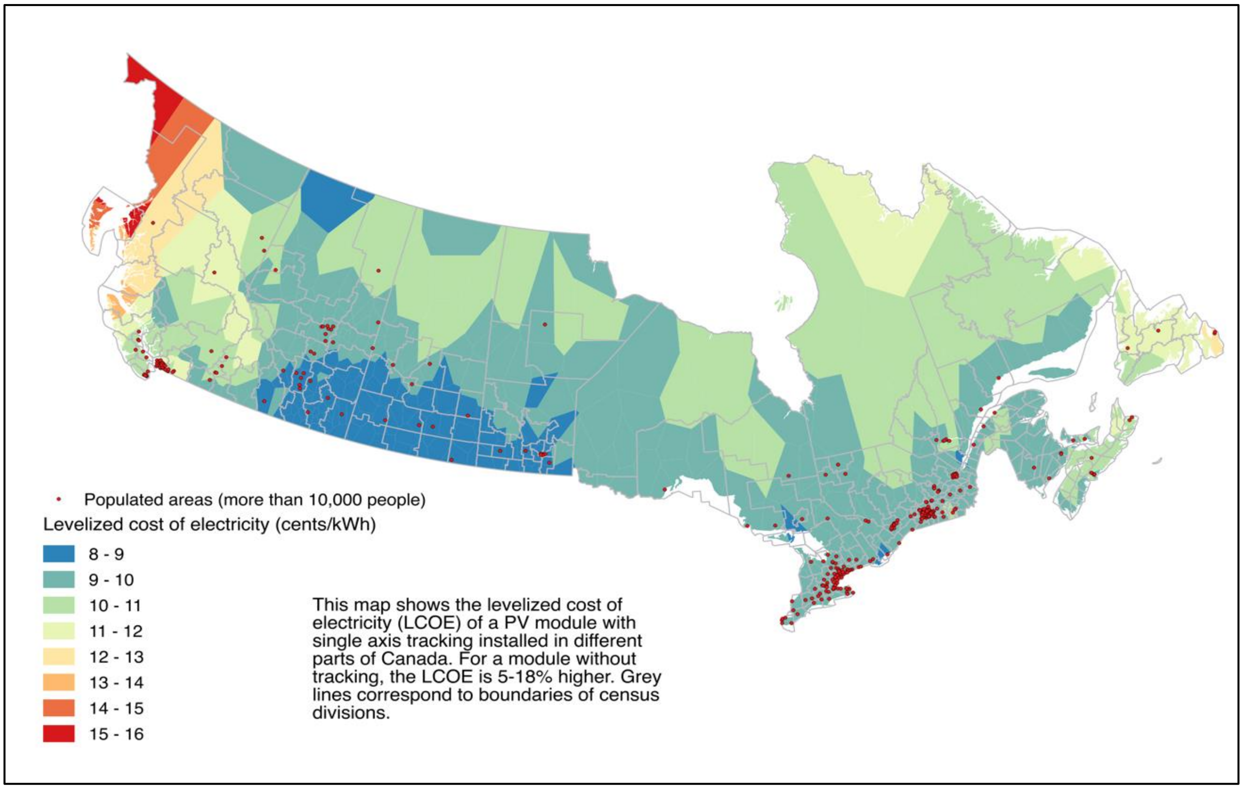
Prov.	No. of Weather Data Locations	Average Capacity Factor (%) – Fixed	Average LCOE (cents/kWh) - Fixed	Average Capacity Factor (%) - Tracking	Average LCOE (cents/kWh) - Tracking
AB	99	15	10	18	9
BC	77	13	12	15	11
MB	38	15	10	18	9
NB	13	14	11	17	10
NL	28	13	12	15	11
NS	29	14	12	16	10
ON	61	15	11	17	9
PE	7	14	11	17	10
QC	80	14	11	17	10
SK	42	15	10	19	9

Figure 3.12 provides a visual representation of LCOE for a single axis tracking solar PV system installed in different parts of the country. As can be seen from Figures 3.11 and 3.12, coastal provinces have lower solar PV capacity factors and consequently, higher LCOE. In central provinces, the variation of solar PV potential within a province is relatively lower. Higher solar PV potential is available in most cities and populated places.

LCOE of PV systems are dominated by the system capital cost and resource availability. We estimated the resource data using one of the most detailed publicly accessible solar insolation datasets. Capital costs are obtained from a status of the photovoltaic systems market in Canada published by Natural Resources Canada.[8] The only incentive assumed is the accelerated capital investment depreciation that would lower the net tax. The estimated levelized costs vary from 9-17 cents/kWh for fixed mount systems and 8-16 cents/kWh for single tracking systems. For comparison, the LCOE of natural gas combined cycle generation is in the range of 5-12 cents/kWh.

[8] Photovoltaic Technology Status and Prospects: Canadian Annual Report 2015, http://www.nrcan.gc.ca/energy/renewables/solar-photovoltaic/publications/18449

Figure 3.12: LCOE for Single Tracking Solar PV in Canada



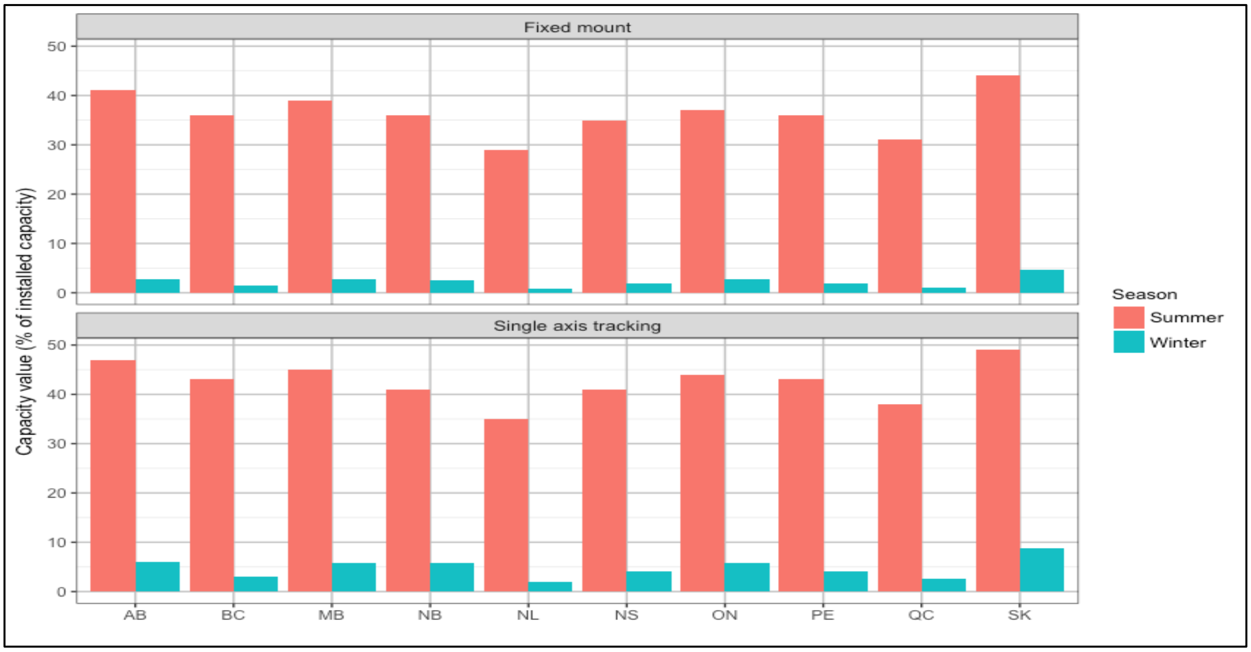
Capital cost is the dominant contributor of LCOE of solar PV. Throughout this analysis, we took the base price of utility scale solar PV to be $2,000/kW for fixed mount PV and $2,140/kW for single axis tracking PV. We use the same prices for all provinces due to the still limited project experience. Since the operating costs are negligible, any increase (or decrease) in capital cost would proportionally increase (or decrease) the LCOE.

In this analysis, we did not assess solar PV installed at residential or distributed commercial scale. LCOE in such applications would be higher due to higher installation costs, although capital costs of such systems are also on a downward trend.

Capacity Value of Solar PV Systems

Using an identical method as the capacity value estimation method used for wind power, we estimate the capacity value of solar PV systems installed in Canadian provinces. Figure 3.13 depicts the estimated winter and summer capacity values for solar PV. As shown in the figure, summer capacity value of solar PV systems can be as high as 40-50% of installed capacity. Higher capacity values are observed in Alberta and Saskatchewan. Furthermore, single axis tracking improves both summer and winter capacity values. Since winter peak hours are in the evening, winter capacity value of fixed mount solar PV is negligible. With tracking, the capacity value can rise to 5-8% of installed capacity.

Figure 3.13: Seasonal Capacity Values for Solar PV



Incremental Transmission and Baseload Costs for Wind and Solar

One challenge for wind and solar power to be integrated into existing power systems as utility scale generation is the spatial dispersion of sites with good resources. Sites with good resources tend to be away from demand centers. As such, new transmission lines are required to be developed to connect the power generating units to the grid. In this section, we estimate the cost of new transmission requirements to connect wind and solar power generating sites assessed in this study.

It is not always possible to site generation close to demand centers. As such, the electricity grid must be extended to collect power from production locations and deliver to final consumers. In some cases, generators can be sited with relatively lower site specific constraints, lowering grid extension requirements (Andrade & Baldick, 2017). Often for renewable resources, additional amounts of transmission extensions are required to connect new generating units. What follows is the incremental transmission cost of site limited generation. All new generation will require some form of new transmission, these are assumed to be not material in the overall assessment of the economics of different generation options. Here we are only adding incremental costs beyond what would typically be needed.

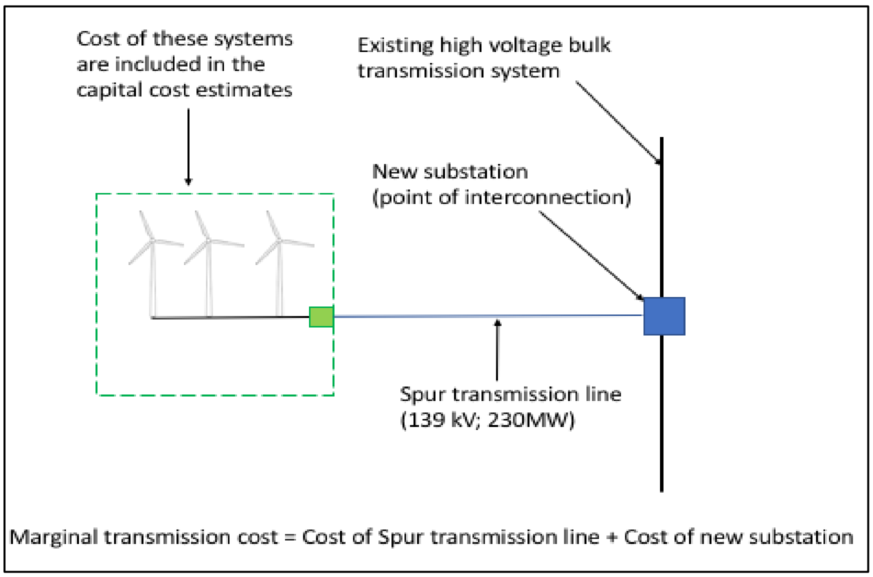
New transmission requirements to connect a new generating project consists of three systems (Andrade & Baldick, 2017):

1. Spur transmission line
2. Point of interconnection
3. Bulk transmission system (common to all generation options)

A bulk transmission system is the shared infrastructure that allows the flow of electricity from multiple generating units to multiple demand centers. In some cases, new generators put operating constraints on bulk transmission systems in the form of overloading of the existing system, requiring reinforcements. We assume the same bulk system impacts for all generation options.

Spur transmission is a relatively short transmission line connecting a generator to the bulk transmission system (Figure 3.14). The point of interconnection is a facility with a set of transmission system components that allows the connection of spur transmission to bulk transmission systems.

Figure 3.14: Transmission Cost Calculation Framework



In this analysis, we assume the new transmission requirements to connect a new generating unit to be a combination of a new spur transmission line and a new substation (see Figure 3.14). The type of new spur transmission lines needed depends on the capacity of the generator, distance, and transmission codes. For this analysis, we consider a single circuit high voltage AC (HVAC) 138 kV (kilo-volt) new spur transmission line is developed to connect a generator to the existing bulk power system through a new 138 kV/240 kV substation (i.e., at the substation, transmission voltage is stepped up to 240 kV from 138 kV).

A single circuit 138 kV HVAC line has a typical capacity of 230 MW. We assume that the new plant that is connected has the same generation capacity. This can be achieved by combining sites in the same area to make a single system with an aggregated capacity of 230 MW. We calculate the transmission cost (henceforth referred to as marginal transmission cost) for three lengths (10km, 25km, and 50km). More than 92% of the wind power sites we used for this analysis fall within these distances.

For variable generation, annual net generation is determined by the annual average capacity factor. We consider several capacity factors, taking into account typical capacity factors of wind and solar PV energy. We also estimate the marginal transmission cost for a generation system with a capacity factor of 90% for comparison purposes. This also pertains to a renewable power generation system that is in baseload mode of operation (described below).

The estimates of transmission cost at different distances and capacity factors are listed in Table 3.25. Results presented in the table pertain to both wind and solar PV. Wind power has a capacity factor of 30-40% depending on local resource conditions. Solar PV has capacity factors in the order of 15% to 20%.

The capacity factor of the generation system has the highest influence on transmission cost. This demonstrates one of the main challenges associated with the integration of variable renewable energy into existing electricity systems: lower utilization increases transmission cost. However, the cost can be reduced by sharing a spur transmission line with several renewable generation systems. For example, resource data estimates made in this analysis shows that solar PV is available during the day and more steady wind resources are available at night. By optimally selecting renewable generation sources and siting them accordingly, the transmission cost can be reduced. This requires further analysis that will be included in upcoming CERI studies.

Table 3.25: Transmission Cost by Distance and Capacity Factor

Spur Transmission Line Length	Capital Cost ($/km)*	Transmission Cost at Different Capacity Factors (cents/kWh)				
		15%	20%	30%	40%	90%
10km	11,587	0.61	0.46	0.31	0.23	0.10
25km	6,822	0.91	0.68	0.45	0.34	0.15
50km	5,233	1.40	1.05	0.70	0.52	0.23

*Includes the cost of a new 138 kV transmission line and a new 138/240kV substation (i.e., unit transmission cost = (capital cost of transmission line + capital cost of substation)/transmission distance). Annual operating and maintenance cost is assumed to be 1% of capital cost. Average transmission costs are calculated by considering an expected rate of return of 10% and a project life of 30 years. Different capacity factors represent typical capacity factors of new generating units as follows: Solar PV (fixed mount) = 15%; Solar PV (Tracking mount) = 20%; Wind (average sites) = 30%; Wind (good sites) = 40%; Conventional thermal generation / wind and solar PV in baseload mode of operation = 90%.

Firm Power for Wind with NGCC

A second challenge for wind and solar power to be integrated as a utility scale generating option is its variability in supply. Since power systems do not have large scale energy storage capability, electricity supply and demand must be matched instantaneously by controlling supply. However, with variable resources such as wind and solar PV, production is controlled by resource flow conditions (i.e., blowing wind and the level of solar radiation striking a PV panel).

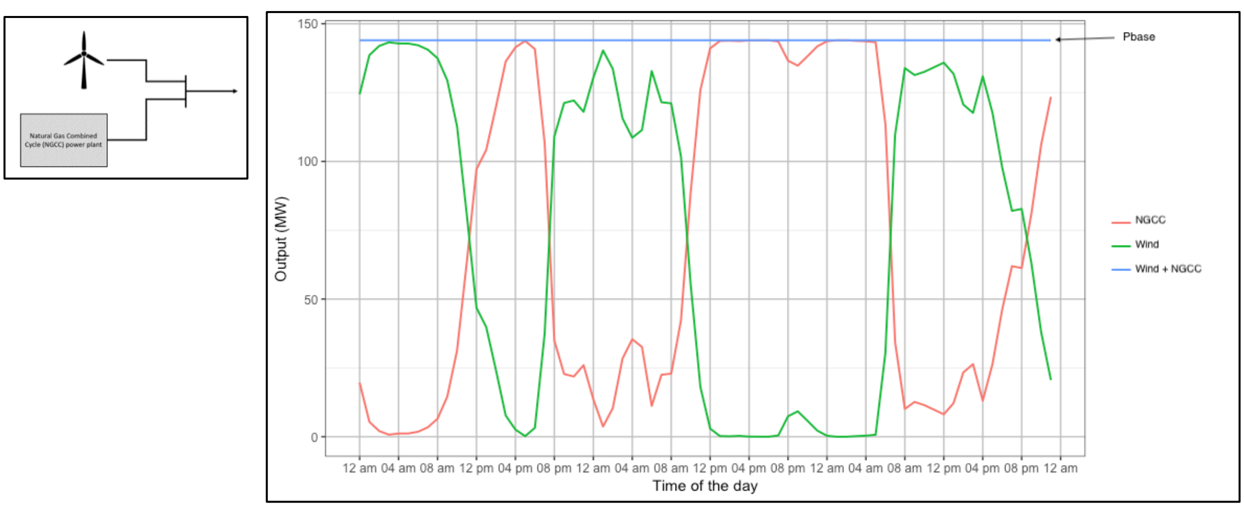
For example, a wind power plant would produce electricity only when the wind is blowing; typical wind power capacity factors in Canada are in the order of 30%. In suitable sites, such as the ones in southern Alberta, this can be as high as 40%. Electricity demand is variable and systems operators carry sufficient variable resources to maintain power system reliability by matching supply and demand. The addition of variable generating resources will exacerbate the net variability seen by electric power systems, requiring additional resources to ensure supply and demand are matched. Several options are being proposed and utilized to mitigate this variability including firming using flexible generating units such as hydropower, natural gas-fired generating units, and electricity storage systems.

In this section, we assess the average baseload cost of electricity supplied by a wind power plant that operates as a dispatchable source of electricity through coordinated operation with a natural gas combined cycle (NGCC) unit.

The coordinated operation of generators essentially mimics the behavior of typical power system operations where generators are dispatched up or down to satisfy time varying demand. The system is managed such that the generating fleet would follow the load and generators are dispatched minimizing the operating cost. However, in the case of baseload mode operating of variable generators, the dispatchable generator would back up the output of the variable source to provide a constant electricity output (as in the case of typical baseload generating unit).

The system we are assessing consists of a wind farm and a NGCC unit connected to a single transmission system node (point of interconnection). Both units have identical installed capacity of Pbase (i.e, installed capacity of wind = installed capacity of NGCC = Pbase). At every hour, output of the wind power plant is set to be the amount determined by available wind resources. Output of the combined system is kept constant at Pbase by dispatching the NGCC unit up or down as depicted in Figure 3.15 where the hourly operation of the combined system over a period of three days is shown.

Figure 3.15: Operation of Wind + NGCC Coordinated System



The LCOE of the combined system is calculated by dividing the total annualized cost of the combined system (consists of annualized capital cost, annual operating and maintenance cost, any non-fuel variable cost and fuel cost of the NGCC unit) by the annual output of the wind + NGCC system.

We simulate the operation of a wind + NGCC plant installed at all sites we considered for this analysis. Several other factors need to be taken into account:

- NGCC units have minimum stable operating points in the range of 30% of the rated capacity of the unit. Therefore, if the required firming power level is less than the minimum stable level of the unit, the NGCC output was set to be zero. As such, the net capacity factor of the combined system is in the order of 98% in all provinces.
- In contrast to regular baseload operation when a NGCC unit is operating in cyclical mode, as in the case of operating as a firming unit of a wind power plant, several factors lead to higher costs. The efficiency of the NGCC unit would be lower due to part-load operations, ramping, and higher number of start-ups and shutdowns (Kumar et al., 2012). In this analysis, by following NREL's Western Wind and Solar Integration Study, we assume the combined efficiency penalty to be 10% of the rated efficiency of the NGCC unit (NREL, 2013).

We calculate the LCOE of the wind + NGCC coordinated systems installed in all sites assessed in this study. For comparison, we also calculate the LCOE of a stand-alone NGCC plant operating at the same capacity factor as the wind power generating system that is in baseload mode of operation. The cost of avoided CO_2 emissions (CO_2 COSTS) is calculated by taking the stand-alone NGCC plant as the baseline. The average LCOE and abatement cost in each province are calculated by averaging over the sites. Average LCOE, carbon intensity, and CO_2 costs (against a NGCC baseline) for wind + NGCC system are listed in Table 3.26.

Table 3.26: LCOE and CO_2 of Wind + NGCC Coordinated System

Prov.	LCOE (cents/kWh)			Carbon Intensity (gCO_2/kWh)			CO_2 Costs (\$/tCO2)		
	Avg.	Min.	Max.	Avg.	Min.	Max.	Avg.	Min.	Max.
AB	5.3	5.2	5.4	233	224	253	100	85	130
BC	5.9	5.8	6.1	253	232	284	180	140	290
MB	5.8	5.7	5.9	239	228	247	140	120	160
NB	7.3	6.9	7.7	238	203	261	61	20	120
NS	7.6	7.1	8.0	262	186	242	22	-18	54
ON	7.7	7.5	8.4	250	228	292	68	40	230
PE	7.1	7.0	7.2	231	232	228	41	33	48
QC	7.6	7.3	8.0	248	246	262	57	28	110
SK	5.3	5.2	5.4	244	229	253	110	89	130

The carbon emissions in this configuration are approximately 200-260 gCO_2/kWh. Operations of a NGCC plant in wind firming mode increases its emissions and cost due to reduced efficiency. This also contributes to the higher CO_2 abatement costs. Use of other firming power options such as coordinating with hydro power or storage will result in lower overall emissions. However, this may lead to higher costs. In provinces with higher natural gas prices (e.g., eastern and Atlantic Canada), the LCOE of the combined system is lower than that of a stand-alone NGCC. The LCOE of the combined system falls in between LCOE of wind and NGCC in stand-alone operating mode.

Firm Power for Wind with a Compressed Air Energy Storage System (CAES)

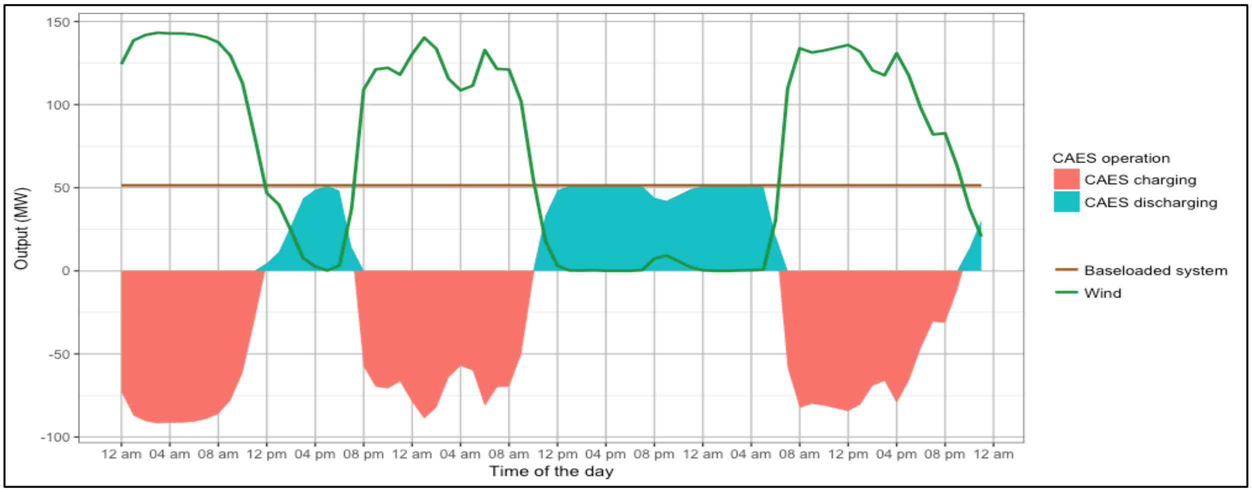
Another technical option to mitigate variability of wind and solar PV is to integrate with electricity energy storage (EES) systems. In this analysis, we estimate LCOE and CO_2 costs of a wind generating unit that coordinates with a compressed air energy storage (CAES) system to operate as a dispatchable power plant.

CAES has widespread suitability in most of North America. CAES is essentially a gas turbine where air compression and expansion through the turbine are time shifted. When storing energy, CAES systems use electricity to compress air and store it in a reservoir, either an underground cavern (salt domes, porous rocks caped by an impermeable cap, depleted oil and gas reservoirs, etc.) or aboveground pipes or vessels. When electricity is needed, the compressed air is heated, expanded, and directed through an expander or conventional turbine generator to produce electricity (Akhil et al., 2015).

As air is already compressed, natural gas required to run the turbine generator is approximately 50-60% lower than a typical open cycle combustion turbine (3.9-5 GJ/MWh). Two CAES plants are currently in commercial operation, one in Germany and another in Alabama. Underground CAES storage systems are most cost-effective with storage capacities up to 400 MW. Siting such plants involves finding and verifying the air storage integrity of a geologic formation appropriate for CAES in a given utility's service territory (Akhil et al., 2015).

A CAES system is sized to provide a baseload output equivalent to the installed capacity of the wind power plant adjusted for its average capacity factor. As the rated output of the combined plant is equal to the annual average output of the stand-alone wind power plant, it is possible to provide power throughout the year without depending on other generating plants. Figure 3.16 shows the operational schedule of the CAES to allow for firm electricity output.

Figure 3.16: Hourly Operation of a Wind Power Plant in Coordination with a CAES System Over a Period of Three Days



The significant cost and performance parameters of CAES assumed for the analysis are listed in Table 3.27.

Table 3.27: Cost and Performance Parameters of a CAES

Parameter	Value
Capital cost – Capacity ($/kW)	1437
Capital cost – Storage ($/kWh)	13
Fixed OM cost ($/kW-year)	34
Non-fuel variable OM cost (cents/kWh)	0.4
Heat rate (MJ/kWh)	4.5
Round trip efficiency	75%
Natural gas price ($/GJ) (varies by province)	2.6-7.3

Main data source of CAES costs and performance parameters: Akhil et al., 2015

In each province, a single wind power site is used for this analysis. Table 3.28 lists the CAES size, LCOE, and CO_2 costs of wind + CAES systems that we assessed for each province. LCOE of the wind + CAES coordinated system is 50-60% higher than that of a stand-alone wind power generating plant installed at the same location.

Table 3.28: Wind + CAES Coordinated System Costs

Prov.	Stand-alone Wind Capacity (MW)	Stand-alone Wind Capacity Factor (%)	Baseload Capacity (MW)	CAES Storage System Size (MWh)	Baseload Capacity Factor (%)	Carbon Intensity (gCO_2/kWh)	Wind + CAES (baseload) LCOE (cents/kWh)	CO_2 COSTS (\$/tCO_2)
AB	144	36	50	18,883	96	89	9.2	175
BC	192	33	60	38,539	95	91	11.0	261
MB	160	39	40	52,324	96	94	9.4	188
NB	256	37	90	969	99	80	10.0	118
NL	160	40	60	571	95	84	9.6	99
NS	336	45	200	1,112	99	66	8.3	20
ON	160	36	60	27,017	97	85	11.0	133
PE	256	40	100	22,022	96	80	9.6	96
QC	288	38	100	1,072	99	82	9.9	100
SK	336	36	100	90,845	95	92	9.3	183

Carbon intensity of the wind + CAES system is significantly lower than that of the wind + NGCC system and stand-alone NGCC system. The costs of CO_2 abatement vary significantly by province. Provinces with higher natural gas prices have lower CO_2 costs. The size of the CAES system required will vary by province and size of the system.

Firm Power for Solar PV with NGCC or CAES

As in the case of wind power, solar PV is also a variable source of electricity and unable to provide electricity on demand. Using an identical method to baseload wind energy analysis, we estimated the LCOE and CO_2 costs of a solar PV system that is in coordinated operation with NGCC or a CAES system. The results of those analyses are presented in Tables 3.29 (solar PV + NGCC) and 3.30 (solar PV + CAES). In the case of the solar PV + CAES combined system, only the single axis tracking PV is considered.

Table 3.29: Costs of a Solar PV + NGCC Coordinated System

	LCOE (cents/kWh)			Carbon Intensity (gCO_2/kWh)			CO_2 COSTS ($/$tCO_2$)		
	Avg.	Min.	Max.	Avg.	Min.	Max.	Avg.	Min.	Max.
Fixed Mount PV									
AB	5.6	5.6	5.7	330	234	336	640	470	920
BC	5.7	5.7	5.8	342	258	351	1500	600	8000
MB	5.7	5.7	5.8	329	245	334	630	530	850
NB	8.0	8.0	8.0	331	215	334	650	580	720
NS	8.8	8.8	8.9	335	216	338	780	640	1000
ON	8.4	8.3	8.4	330	193	336	620	520	830
PE	8.0	8.0	8.1	334	230	335	730	650	850
QC	8.3	8.3	8.5	334	196	339	670	530	1100
SK	5.6	5.6	5.7	329	243	337	630	510	1000
Single Axis Tracking PV									
AB	5.6	5.6	5.7	317	172	326	420	310	590
BC	5.8	5.7	5.9	332	214	347	800	410	3000
MB	5.7	5.7	5.8	316	195	323	410	360	540
NB	7.9	7.9	8.0	321	134	322	400	360	450
NS	8.8	8.7	8.8	323	130	330	470	390	620
ON	8.3	8.2	8.4	319	97	326	380	320	510
PE	8.0	7.9	8.0	323	156	327	460	400	530
QC	8.3	8.2	8.4	321	97	331	410	320	650
SK	5.6	5.6	5.7	316	183	328	410	330	640

Table 3.30: Costs of a Solar PV (tracking) + CAES Coordinated System

Prov.	Stand-alone PV Capacity (MW)	Stand-alone PV Capacity Factor (%)	Baseload Capacity (MW)	CAES Storage System Size (MWh)	Baseload Capacity Factor (%)	Carbon Intensity (gCO_2/kWh)	PV+CAES (baseload) LCOE (cents/kWh)	CO_2 COSTS (\$/tCO_2)
AB	247	20	50	47,300	91	154	16.6	610
BC	279	18	50	54,800	90	157	18.9	741
MB	263	19	50	51,000	91	156	17.7	670
NB	286	17	50	36,800	90	161	20.5	714
NL	315	16	50	47,600	90	158	22.5	808
NS	300	17	50	59,900	90	161	21.9	744
ON	281	18	50	52,800	92	154	20.0	647
PE	298	17	50	38,600	90	162	21.4	765
QC	278	18	50	52,100	90	156	20.1	658
SK	254	20	50	61,100	90	158	17.2	657

Stand-alone solar PV capacity factors are in the order of 12-20%; for solar PV + NGCC coordinated systems, most of the electricity is supplied by the NGCC plant. This brings the LCOE of the combined system closer to the stand-alone NGCC plant. Furthermore, the emissions intensity is also close to the NGCC making the CO_2 cost abatement high.

Due to lower capacity factors and complete unavailability of solar resources at night, there is significant demand for the CAES storage system requirements. This makes the LCOE of the combined system almost 100% higher than that of the stand-alone solar PV system.

Biomass Energy

Substitution of carbon neutral fuels for fossil fuels is one of the main ways to mitigate the impact of fossil fuel GHGs. In addition to its large fossil fuel resources, Canada has large biomass resources that makes it a unique location to explore biomass electricity generation. Biomass power options with manure and municipal solid waste (MSW) have the lowest net offsets (low emissions associated with its production) relative to other renewable power generation (Samson et al., 2008). Emissions from wood-based biomass generation contain 75% less nitrogen oxide than coal emissions and virtually no sulphur dioxide. Wood-based biomass generation produces 80% less greenhouse gas emissions than combined cycle natural gas (OPG, 2015).

This study considers three biomass fuels in Canada:

- agricultural biomass (including both seeds and straw of barley, wheat, flaxseed, oats, corn, canola, and soybeans),
- forest biomass (including roadside harvest residue and mill residue), and
- urban wood waste.

The amount of each of these resources is calculated for each census division using the Biomass Inventory Mapping and Analysis Tool (BIMAT) provided by Agriculture and Agri-Food Canada (Agriculture and Agri-food Canada, 2017). BIMAT provides information on type of biomass available in different parts of Canada, their properties and transportation cost within a user defined area. In BIMAT, we select a point within a census division and set a transportation distance to cover the full division.

Biomass transportation distance varied by the census division in different provinces and is in the range of 30-200 km. To estimate annual energy generation potential, we considered the type of resources available, their heating value, moisture content, biomass transportation distance, and costs. The economy of scale of generating units is also taken into account (Kumar et al., 2003). Energy estimates and cost calculations are made using the biomass module of the NREL's System Advisor Model (SAM) (NREL, 2017).

A summary of information used for energy and cost estimates is presented in Table 3.31. We estimate the biomass electricity generation potential at each census division and the associated cost. This information is used to develop biomass-fired electricity supply curves for each Canadian province.

Table 3.31: Summary of Information used for Biomass Energy and Cost Estimates

Technology	Source	Cost (base year)	Currency	Nominal Capacity (MW)	Overnight Capital Cost ($/kW)	Var. O&M, $/MWh	Fixed Cost ($/kW-year)	Heat Rate (Btu/kWh)
CC – Combined Cycle	(EIA, 2013)	2012	USD	20	8,180 [9]	$17.49	$356.07	12,350
BFB – Bubbling Fluidized Bed	(EIA, 2013)	2012	USD	50	4,114 [10]	$5.26	$105.63	13,500
Biomass Stand-alone (standard Rankine cycle)	(Black & Veatch, 2012)	2015	USD	50	3,830	15	95	14,200
Biomass Co-firing	(Black & Veatch, 2012)	2015	USD		990	0	20	10,000
Woody Biomass	(Avista, 2011)	2011	USD	25	4,170	4.16	207	13,500
Manure Digester	(Avista, 2011)	2011	USD	0.85	4,862	27.01	51.8	10,250
Biomass Direct Combustion	(Lazard, 2011)		USD	35	3000-4000	15	95-100.5	14500
Biomass Direct Combustion	(Black & Veatch, 2010)	2010	USD	>15	4000-5000			14000-16000
Combined heat and power (CHP)	(PacifiCorp, 2011)	2010	USD	50	3,509	0.96	38.8	10,979
Woody residue – Greenfield, no CHP	(NWPCC, 2010)	2006	USD	25	3000	0.73	194	15500
Conventional steam electric plant	(E3, 2014)		USD		4,250		155	14,800
Biomass Direct Combustion in steam turbines	(BC Hydro, 2013)	2013	USD	35	4740	21		
Biomass Direct Combustion	Kumar et.al (2003)	2000	CAD	450	1242			

Financial parameter assumptions:

Capacity factor = 70%; Expected rate of return = 10%; Plant life = 30 years; Project term debt = 50-60% depending on ownership; Nominal debt interest rate = 8%; construction interest rate = 8%.

Biomass-fired electricity supply curves for different provinces are shown in Figure 3.17. Saskatchewan shows the largest potential at upwards of 25,000 GWh at a cost of around 5 cents/kWh. British Columbia shows the smallest potential at approximately 1,000 GWh that reaches about 7 cents/kWh.

[9] VOM expenses include major maintenance
[10] VOM expenses include major maintenance

Figure 3.17: Biomass Energy Supply Curves for Canadian Provinces

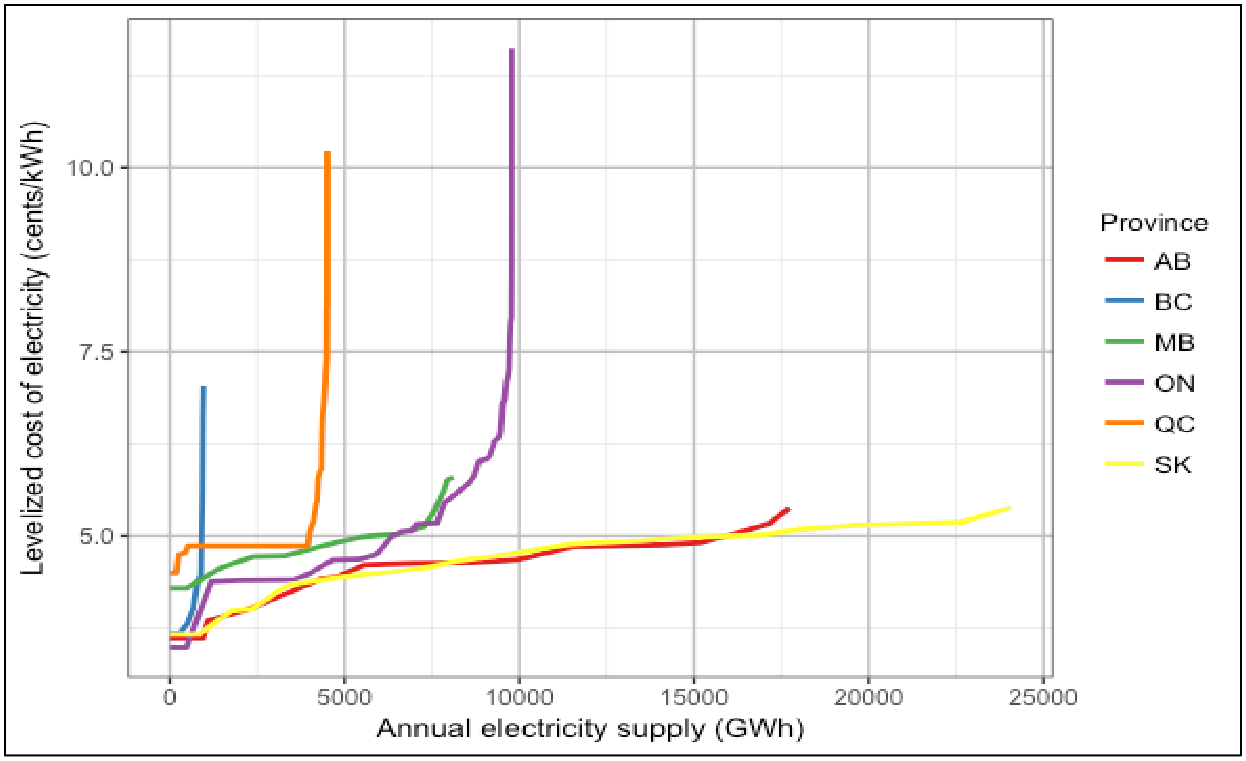


Table 3.32 provides a summary of the biomass energy potential and LCOE for select provinces. The LCOE of biomass is relatively low in all provinces. Biomass energy can provide electricity on demand. Therefore, it has the same operational flexibility as a fossil fuel-fired generating unit. Technologies that can be used to produce electricity from biomass are well established and mature. In most situations, biomass is a freely available resource where it needs to be disposed of from the production sites (e.g., forestry residues, agricultural residues).

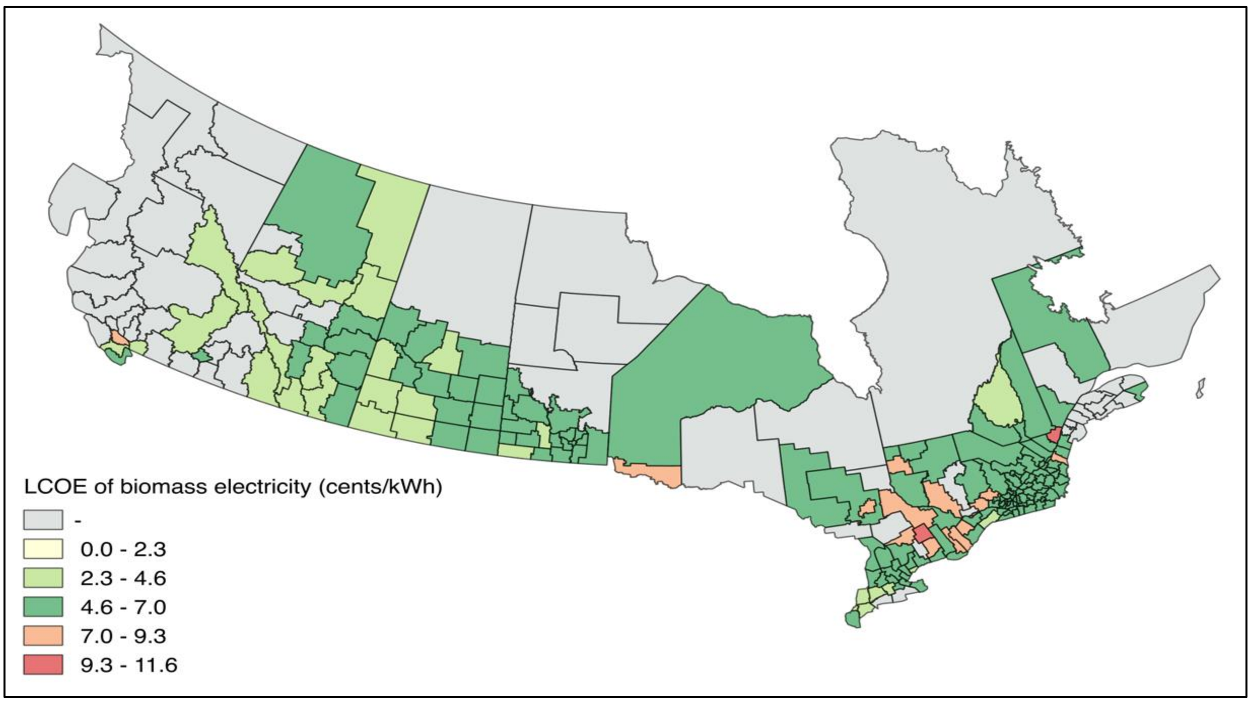
The cost of CO_2 emissions avoided (CO_2 COSTS) for biomass as compared to our NGCC reference case is also indicated in Table 3.32. The energy weighted average LCOE is used for the CO_2 COSTS calculations. Since the average LCOE is less than the NGCC LCOE in all provinces, the CO_2 COSTS is negative in all cases.

Table 3.32: Annual Energy Potential and LCOE of Biomass by Region

Province	Annual Energy Potential (GWh/year)	LCOE (cents/kWh)			
		Energy Weighted Average	Minimum	Maximum	CO_2 COSTS ($/t$CO_2$)
AB	17,724	4.7	3.6	5.4	-20
BC	950	4.1	3.7	7.0	-40
MB	8,123	4.9	4.3	5.8	-17
ON	9,776	4.9	3.5	11.6	-93
QC	4,500	5.0	4.5	10.2	-88
SK	24,061	4.8	3.7	5.4	-17

Figure 3.18 shows the geographic distribution of the cost of biomass-based electricity across the country. The highest costs are in south central Ontario.

Figure 3.18: Distribution of LCOE of Biomass Energy in Canadian Provinces by Census Division



Several challenges, however, exist for biomass. The efficiency of converting biomass to electricity is impacted by the quality (in terms of type and moisture content) of biomass used. Therefore, additional fuel preparation systems are required. Fuel quality and efficiency of preparation systems are also impacted by weather conditions. Biomass is a dispersed fuel source and it must be collected and transported to the generation plant. The cost of transportation is a main contributor to the variable cost of generation. In our analysis, the transportation cost is included. Transportation distances considered are in the order of 50-200 km. As the distance increases, the

LCOE rises proportionally. In Figure 3.18 the areas with lower LCOE correspond to solid biomass availability at less than 100 km.

Without dedicated biomass supply sources (e.g., biomass plantations maintained to supply biomass for electricity generation), the amount of energy that can be produced is limited by the operations of other industrial systems that produce biomass residue (e.g., lumber industry, paper and pulp industry). Therefore, biomass is a resource with energy limited annual potential. Maintaining a dedicated biomass source is necessary to maintain this option as a feasible option for the reliable supply of electricity.

Further analysis (not included here) could consider solid biomass being co-fired with coal in boilers of existing coal-fired electricity generating units. Similarly, biogas (e.g., landfill gas) can be co-fired with natural gas in gas turbines (CGA, 2014). In addition, biomass-fired electricity generation with carbon capture and storage can produce electricity with net negative CO_2 emissions (IEA, 2016). Negative emissions options are an important aspect of the Paris Accord on Climate, and need further study.

Geothermal Energy

Geothermal energy is derived from heat produced in the subsurface of the earth by the natural decay of radiogenic elements in the upper crust, and the primordial energy from the formation of the planet. This energy flow is all around the world but specific geologic conditions may make it economically viable for human use. The heat from the ground can be used for electricity generation purposes (hydrothermal resources and Enhanced Geothermal System (EGS) and for space heating (low temperature).

EGS is available in geologic formations where hot rock exists without water (Hot Dry Rock or HDR) or any fluid to carry the heat to the surface thereby requiring that an engineered system be built to inject hot water into the rock and pump it back to the surface. Due to the lack of permeability (i.e., the interconnectedness of pore spaces in the rock), the hot dry rock is hydraulically fractured to create fractures and enhance permeability in existing natural fractures to facilitate fluid circulation.

EGS technology has the potential to unlock the earth’s energy reserve. Meanwhile, hydrothermal options are geologic systems in which the reservoir contains both heat and the fluid (water); the temperature of the fluid ranges widely from hot water to dry steam, the share of each component (water and steam) varies by site. The water-dominated systems can also be divided into hot water and wet steam.

Geothermal has an inherent advantage over other renewable and fossil power generation. Its advantage over other renewables is it can serve as a baseload, reliable up to 95%. Over fossil generation, it has a small environmental footprint: 1-8 acres per MW versus 5-10 acres per MW for nuclear and 19 acres per MW for coal and zero carbon emissions.

Canada has significant geothermal resources. However, the extraction of this energy source is limited by geological, technical, and regulatory challenges. The 2012 Geological Survey Canada' Geothermal Energy Resource Potential Inventory shows a broad distribution of geothermal resources across Canada. These resources range from a volcanic belt in the Cordillera, to a sedimentary basin with porous rock, and the Canadian shield with a moderate or low temperature due to the decay of radiogenic heat sources.

Currently, there are no commercial-scale geothermal power plants in Canada. The company Deep Earth Energy Corp. is developing a 10 MW nameplate project in Saskatchewan's Williston sedimentary basin near Estevan. The project is run by a partnership with Natural Resources Canada and SaskPower.

Resource estimation of geothermal resources is challenging and full of uncertainties. To normalized practices, the industry had developed a code for public reporting. The code recognizes three levels of geothermal resources: Inferred, Indicated and Measured based on increasing levels of geological confidence and knowledge.

Producing electricity from geothermal is a capital-intensive process depending on location, geology, reservoir size, temperature and plant type. The breakdown of the costing shows three categories according to development phase: exploration and drilling wells, construction and discounted future drilling and well stimulation.

- The first component is exploration and drilling (exploration, confirmation, and development) representing 20% to 60% of the overall cost depending on the resource type. Drilling cost and depth are statistically linked through an exponential function. Three datasets have been considered in the analysis to capture the variability of the drilling cost-depth relationship: PSAC's 2016 Well Cost Study, Majorowicz. J et al. (2010) and Geophires V1.0 Beckers KF. The minimal cost from those three datasets has been considered for each depth category in the analysis.
- The second is plant construction. Costs here depend on the technology (flash systems, binary), capacity, and the remoteness of the site (required road access or not). According to Tester et al. 2006 the power plant cost is correlated with the resource temperature and the capacity scale.
- Considering resource depletion over the lifespan of the geothermal plant, new wells need to be drilled or new fracking for EGS is needed to reopen and widen fractures in the rock. This represents the third cost component. These later costs must be considered in any economic assessment of geothermal resource development.

Together these three cost components combine for the total cost shown in Table 3.33. The table lists the minimal depth needed to reach 150^{o}C for Enhanced Geothermal Systems (EGS).

Table 3.33: Capital Cost of Geothermal at Different Depths

Depth (km)	3.5	4.3	5.1	5.9	6.7	7.5
Capital Cost ($/kW)	7,677	8,890	9,801	11,001	12,283	13,842

Table 3.34: Economic and Technical Parameters Assumed for Enhanced Geothermal (EGS) Assessment

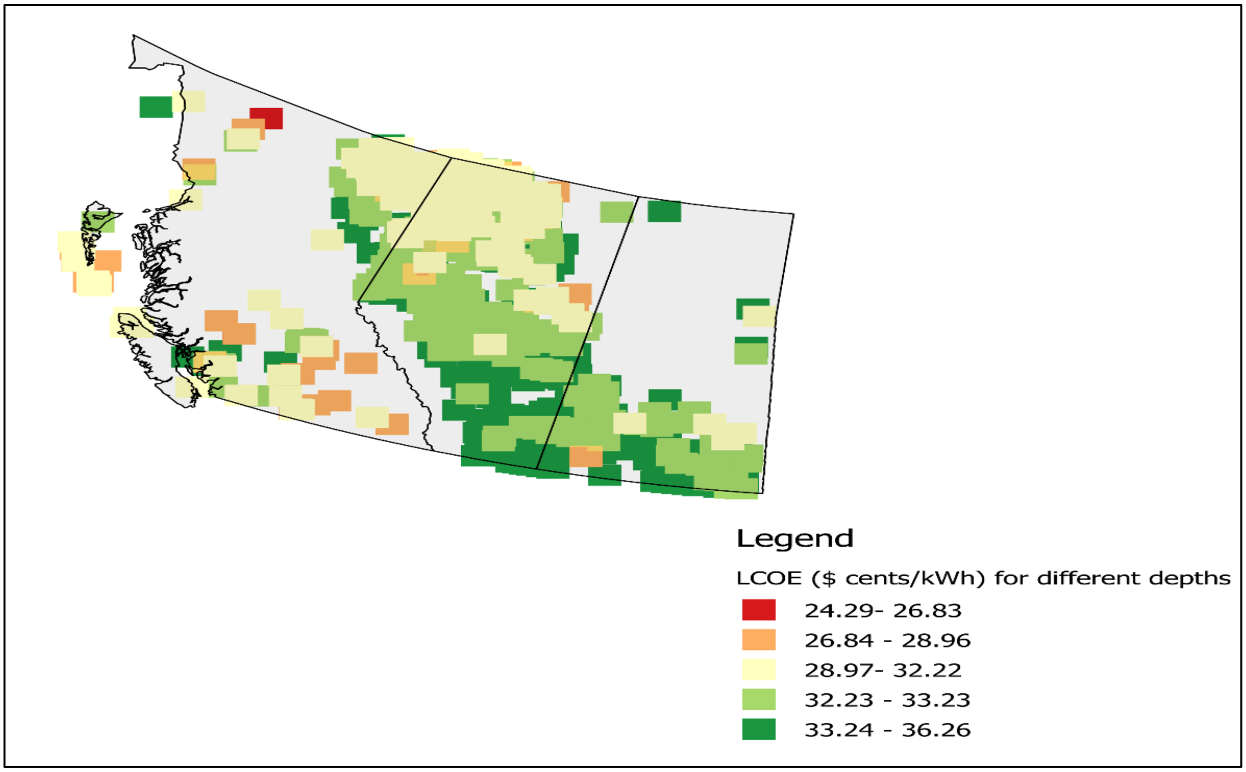
Abbreviation	Parameters	Value
TCR	Total capital requirement ($/kW)	Table 3.27
FOM	Fixed operation and maintenance (O&M) costs (CA$/kW-yr)	70
VOM	Variable O&M costs (CA$/MWh)	3
MW	Capacity (MW)	10
	Thermal to electricity efficiency	95%
CF	Capacity factor	91%
	CO_2 emissions (gCO_2/kWh)	0-9
T	Assumed plant life (years)	20
	Inflation rate	2%
ROR	Expected rate of return (nominal)	10%
	Project term debt (% of capital cost)	40%
	Nominal debt interest rate	6.5%
	Effective tax rate	Table 2.1
	Transmission losses	4%
	Construction period (years)	3
	Nominal construction interest rate	8%

Hydrothermal resources also hold potential considering sites with high temperature and significant size (CAN 11.4 cents/kWh for the Meager Creek site), however for small capacity and/or medium temperatures (less than 150ºC) the cost is higher than the actual average PPA agreement in place (CAN 10.5 cents/kWh) in most jurisdictions. Overall, hydrothermal resources are more cost competitive than EGS systems, but analysis should be performed project by project.

The LCOE of EGS is approximately CAN 24.3 cents/kWh for shallower depths at 3500 m in some geographic locations (best resources). In areas of lower geothermal potential, the costs range from CAN 29.0-32.3 cents/kWh or depths ranging from 5100 m to 5900 m. For places where depths range from 6000 m to 7500 m, the cost of energy increases to CAN 36.3 cents/kWh at the high end, and are well above the cost of most other electricity generation options. One important caveat. If suitable geothermal resources are available in pre-existing wells, the overall LCOE for geothermal will be 20-50% lower than the afore-mentioned values.

Medium quality geothermal potential is well distributed among British Columbia, Alberta and Saskatchewan. These provinces are also where more data regarding underground conditions exist because of their oil and gas exploitation history. Figure 3.19 maps the distribution of the resource in those provinces.

Figure 3.19: Geothermal Potential and LCOE Distribution



The estimated data collected are inferred from oil and gas exploration and exploitation. The levelized cost of geothermal is sensitive to temperature, depth and many other geophysical parameters. For instance, a 10°C reduction in temperature in the well can cause the most significant cost increase (10 cents/kWh) over all other parameters. However, a similar temperature upsurge amounts only to a 2.7 cents/kWh cost reduction impact. The divergence can be explained by the role of the target temperature for EGS situated at 150ºC, any drop from that level will have an asymmetrical negative impact on project economics.

Despite the potential for EGS, hydrothermal resources are mostly envisioned for electricity generation because it manifests on the surface as thermal springs and geysers. Some jurisdictions are assessing their provincial potential in order to include them in their resource planning. BC Hydro has shortlisted geothermal sites suitable for electricity generation in its report, "An Assessment of the Economic Viability of selected Geothermal Resources in British Columbia". Western Canadian provinces have been considering hydrothermal resources as part of their electricity generation mix.

A review of the planned projects (Table 3.35) shows a wide variation depending on the resources considered. The analysis highlights two projects proposed in British Columbia (Sloquet Hot Springs and Meager Creek) and the DEEP Energy projects near Estevan in Saskatchewan.

Table 3.35: Review of Planned Hydro-Geothermal Projects in Western Canada

Parameters	Sloquet Hot Springs	Meager Creek-Pebble Creek	DEEP Project
Reservoir Area (sq. km)	2	6	
Reservoir Thickness (m)	1100	2500	100-150
Rock Porosity	0.05	0.05	
Reservoir Temperature (°C)	175	230	120
Rock Volumetric Heat Capacity (kJ/m^3 °C)	2613	2613	
Rejection Temperature	15	15	65
Utilization Factor	0.45	0.45	
Plant Capacity Factor	0.90	0.90	
Power Plant Life	20	20	40
Gross Power plant estimated (MW)	10	100 for each	10
Transmission Line Costs (Million)	2.1	13.2	
Depth (m)	1250	2500	3200
Total Cost per Gross kW installed (CAD$ 2015)	8200	5700/5600	8000
LCOE ($Cents/kWh)	21.1	11.4	41.5

Hydrothermal resources have potential at sites with high temperature and significant size (100 MW) at 11.4 cents/kWh, such as the Meager Creek site. However, for small capacity (10 MW) and/or medium temperature (less than 150ºC), the cost is higher than the actual average PPA agreement in place (10.5 cents/kWh) in most of the jurisdictions. Overall, hydrothermal resources are more cost competitive than EGS systems, but analysis should be performed project by project.

The potential for EGS exists throughout Canada, but the cost of drilling and, by extension, the LCOE (24.3 cents/kWh) is prohibitive. This makes geothermal options economically challenging as a generation option for grid-based electricity supply. These challenges could be overcome to some degree through technology innovation or pre-existing well infrastructure.

Chapter 4: Generation Options for the Provinces

All Canadian provinces are forecasted to have typical electricity demand growth rates (between 0.5-2% per year) over the next two decades (NEB, 2017). This however, could increase with the implementation of large scale electrification of end-use energy services.

In this section, we summarize generation options by province. Two main datasets are provided for each province: 1) Figures 4.1-4.10 that depict the estimated LCOE and CO_2 emissions intensity of each generation option; and 2) Tables 4.1-4.10 that summarize the different metrics of each generation option. In the summary tables, three LCOE values are provided:

1. Stand-alone LCOE (in cents/kWh): LCOE measured at the facility
2. Stand-alone LCOE with transmission cost: LCOE measured at the facility and cost of any new transmission lines required to connect the facility to existing bulk power systems (see Figure 3.14 and Table 3.19 for transmission cost calculations)
3. Firm power LCOE with transmission cost: This is the LCOE (including transmission cost) of firm power options available for the respective provinces. This result provides the most complete comparison of generating options as all options have the same level of reliability, and ability to supply power on demand. Cost is calculated at the point of interconnection with the bulk electricity transmission system

For each generating option, CO_2 emission intensity and CO_2 COSTS are provided. CO_2 COSTS is calculated against a province-specific reference case (indicated as *reference case* in the summary tables). The tables are sorted by *Firm power LCOE with transmission cost* metric to indicate the least cost generation option. This metric is not calculated for variable sources such as wind and solar PV that are not dispatchable.

Firm power LCOE of the least cost option can be viewed from different perspectives. If demand-side interventions (e.g., demand-side management and energy efficiency improvements) can be used to avoid the need to build generation, firm power LCOE of the least cost option represents the avoided new generation cost (in cents/kWh of avoided generation). Since economic and population growth will inevitably lead to demand growth, it is possible that demand-side interventions cannot completely avoid new generation, but only delay (say, 5 years for example). In that case, the avoided cost is the difference between firm power LCOE of the least cost option and the same value discounted for the delayed period. Taking this into account, we calculate the avoided cost of delaying generation by 5 years.[1] Both metrics can be used to screen and benchmark demand-side intervention measures.

[1] Avoided cost by delaying new generation = Firm power LCOE with transmission cost x $(1-(1+WACC)^{-d})$, where, WACC = weighted average cost of capital. d = number of year new generation was avoided by. For the presented results, d = 5.

Newfoundland and Labrador

Currently, electricity generation capacity in Newfoundland and Labrador is dominated by hydropower, where it contributes to almost 95% of electricity generation. Total electricity generation capacity is nearly 7650 MW. Electricity demand in Newfoundland and Labrador is forecasted to see a modest growth over the next two decades (1% or lower). The average age of generating assets is approximately 40 years with much of the transmission system built before 1980. Reinforcement of the aging power system infrastructure is a challenge and is expected to be a main factor for future electricity rate increments (Power Advisory LLC, 2015).

The province is currently developing a major hydroelectric generation facility – the Muskrat Falls project – on the lower Churchill River. Phase one of the project includes an 824 MW hydropower generation facility and over 1600 km of transmission lines. Combined power generation capacity of the Muskrat Falls project is approximately 3000 MW. When completed, the Muskrat Falls project, along with existing generation infrastructure, will be sufficient to satisfy future electricity demand of the province. Excess power produced by the project will be exported to neighboring provinces – mainly to Nova Scotia through the 500 MW HVDC Maritime Link that is under construction – as well as to the United States, bringing export revenues to the province.

Due to hydropower dominance, GHG emissions intensity of the electricity sector is very low at 33 gCO2eq/kWh (ECCC, 2017). Since future generations in the province will also be hydropower, GHG emissions management in the province's power system is likely not be a concern.

Figure 4.1: LCOE and Carbon Emissions Intensity of Electricity Generation Options for Newfoundland and Labrador

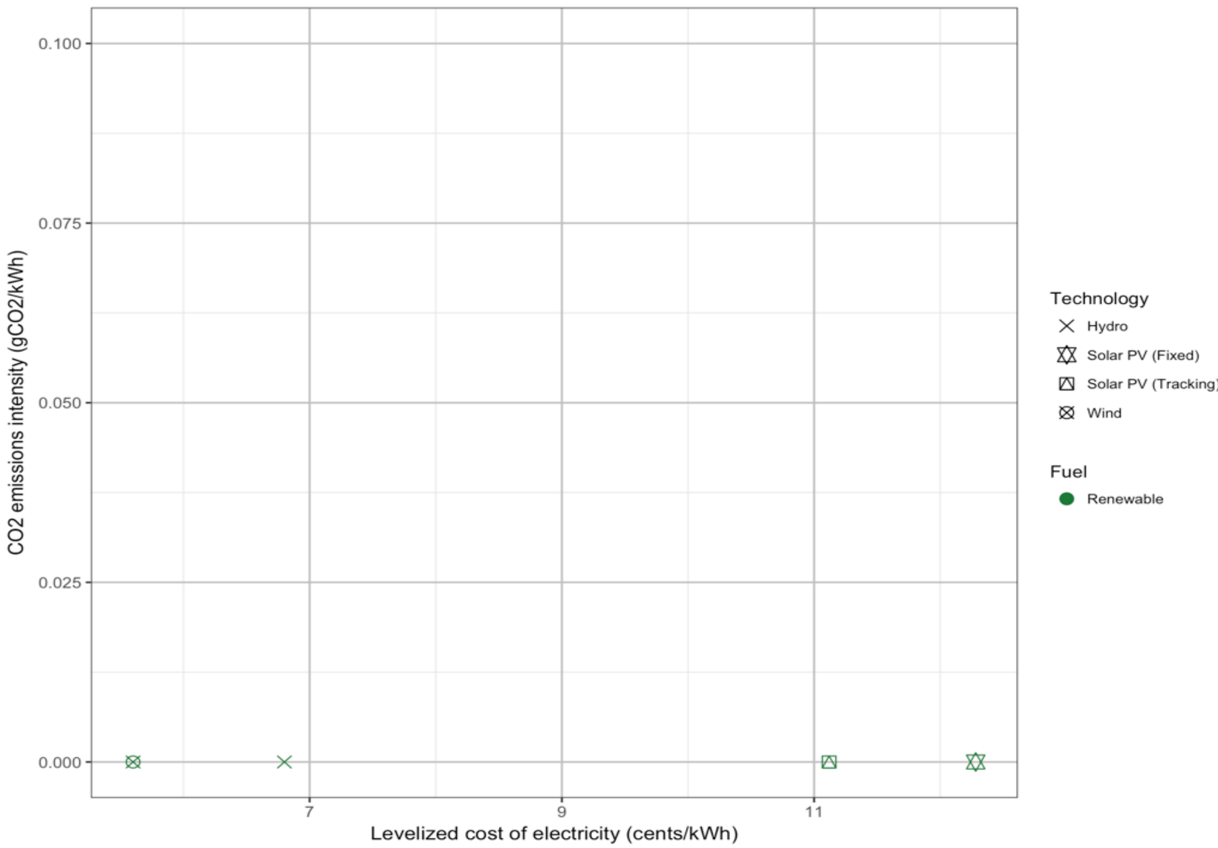


Table 4.1: Electricity Generation Options for Newfoundland and Labrador

Technology	Stand-alone LCOE	Stand-alone LCOE with Transmission Cost	Firm Power LCOE with Transmission Cost	Carbon Intensity (gCO_2/kWh)	CO_2 COSTS (\$/tCO_2)
Wind + Hydro	5.6	7.6	7.6	0	NA
Solar PV (Fixed) + Hydro	6.8	8.8	8.8	0	NA
Solar PV (Tracking) + Hydro	6.8	8.8	8.8	0	NA
Hydro	6.8	9.8	9.8	0	NA
Solar PV (tracking) + CAES	23	23	23	0	NA
Wind	5.6	6.1	Not firm	0	NA
Solar PV (Tracking)	11	12	Not firm	0	NA
Solar PV (Fixed)	12	13	Not firm	0	NA

All LCOE values are in cents/kWh

The results of generation technologies assessed for the province are presented in Figure 4.1 and Table 4.1. Since large-scale natural gas-fired generation is not feasible in the province, we assess the LCOE of firming variable generation (i.e., wind and solar PV) by hydropower.

Onshore wind power firmed by hydropower is the least cost generation option for the province (7.6 cents/kWh). As such the avoided cost of delaying the marginal new generation unit by 5 years is 2.5 cents/kWh.

The province has low solar resources, leading to higher LCOE for solar PV technologies. Currently, the province does not have sufficient natural gas infrastructure to support natural gas-fired generation. Due to the relatively lower electricity demand in the province, investment in natural gas infrastructure for electricity generation is reported to be uneconomic (Ziff Energy Group, 2012). Since the reference power generation option for NL is emissions free hydropower, the calculation of CO_2 costs is not meaningful.

Prince Edward Island

Prince Edward Island has the lowest electricity demand. Nevertheless, the province is forecasted to have a steady electricity demand growth of nearly 1.1% per year leading to an approximate 16% increase in demand by 2030 compared to present levels (NEB, 2017). Currently, only about one third of demand is satisfied by electricity produced in the province. The rest is imported mainly form New Brunswick. Two new (180 MW each) underwater transmission lines are currently being developed to increase the import capability (Ross, 2017). Present electricity interconnections with New Brunswick consists of two cables with a total capacity of 200 MW. These lines are over 40 years old. Infrastructure additions will inevitably increase future electricity prices.

Figure 4.2: LCOE and Carbon Emissions Intensity of Electricity Generation Options for Prince Edward Island

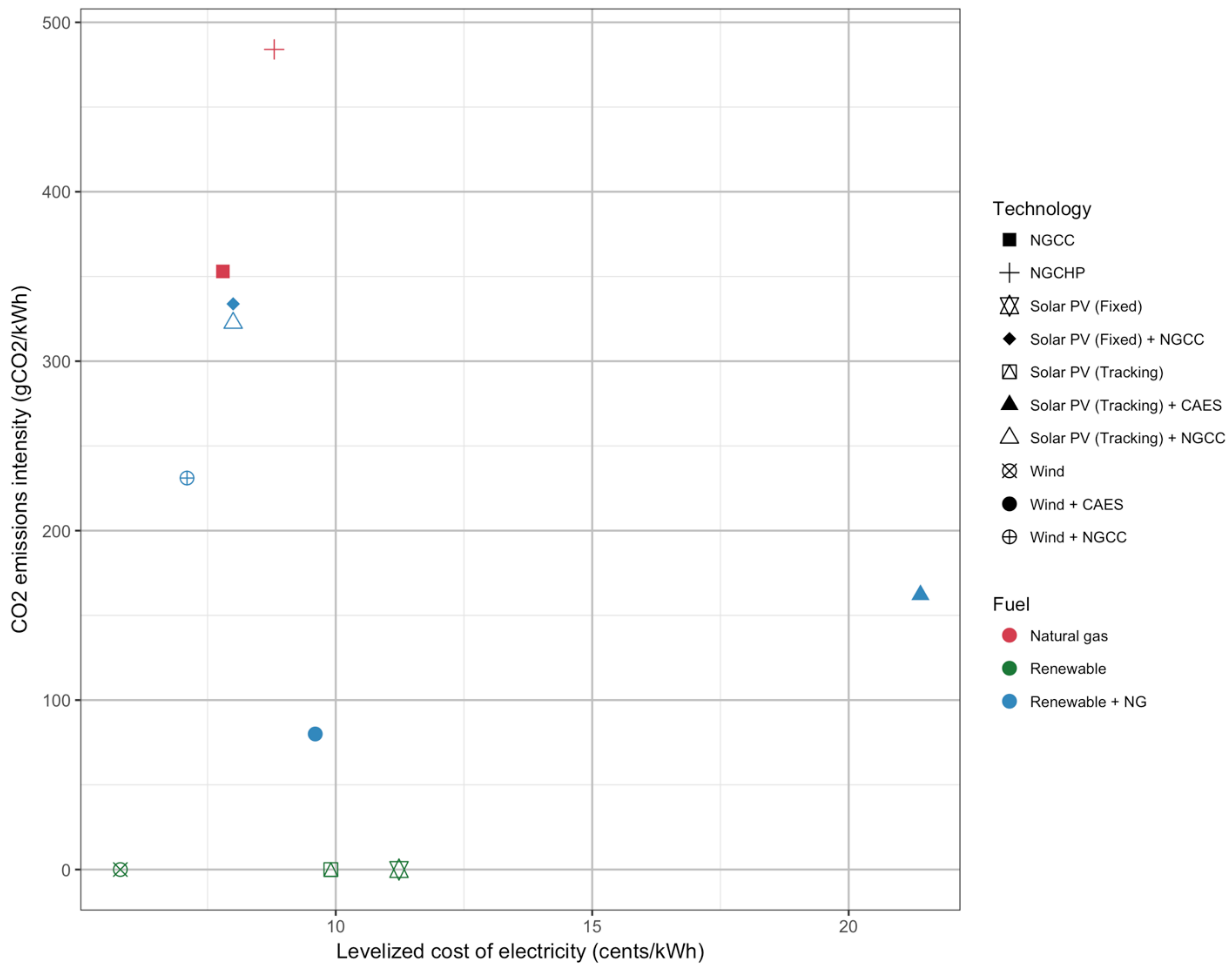


Table 4.2: Electricity Generation Options for Prince Edward Island

Technology	Stand-alone LCOE	Stand-alone LCOE with Transmission Cost	Firm Power LCOE with Transmission Cost	Carbon Intensity (gCO_2/kWh)	CO_2 COSTS (\$/tCO_2)
Wind + NGCC	7.1	7.2	7.2	231	-57.4
NGCC	7.8	7.9	7.9	353	Reference case
Solar PV (Fixed) + NGCC	8	8.2	8.2	334	104.3
Solar PV (Tracking) + NGCC	8	8.2	8.2	323	65.71
NGCHP	8.8	8.9	8.9	484	Higher LCOE and CO_2 intensity
Wind + CAES	9.6	9.8	9.8	80	65.93
Solar PV (Tracking) + CAES	21	22	22	162	712.5
Wind	5.8	6.3	Not firm	0	-56.66
Solar PV (Tracking)	9.9	10	Not firm	0	59.62
Solar PV (Fixed)	11	12	Not firm	0	97.25

All LCOE values are in cents/kWh

More than 99% of the province's own generation is wind power where the installed capacity is currently 202 MW. Several other wind power projects are planned to come online over the period 2019-2025.[2] Our generation assessments for the province are summarized in Figure 4.2 and Table 4.2. The wind + NGCC option has the lowest firm power LCOE (7.2 cents/kWh). The avoided cost of delaying the marginal new generation unit by 5 years is 2.4 cents/kWh.

The province does not currently have natural gas delivery infrastructure to support gas-fired generation. However, since most of the energy is imported from New Brunswick where NGCC is taken to be the reference case, the CO_2 costs of different generation technologies for PE is calculated by taking the same reference case. Due to higher natural gas prices in the Atlantic Canada region, the NGCC LCOE is higher than that of wind power options. This result in negative CO_2 costs for those two options.

Approximately 1% of the province's electricity generation comes from diesel-fired units that provide peaking power. In 2015, the combined GHG intensity of electricity generation in Prince Edward Island was 20 gCO_2/kWh. Due to their higher dependency on electricity imports, carbon management policies in New Brunswick may potentially increase future electricity prices (Campbell, 2017).

[2] PEI Energy Corporation http://www.peiec.ca/2019-wind-farm.html

Nova Scotia

Nova Scotia's current generation capacity is nearly 3000 MW. Annual generation in 2015 was 11,129 GWh (NRCan, 2016). Both installed capacity and power generation is dominated by coal-fired electricity. As such, the GHG emissions intensity of power generation in 2015 was 600 gCO_2/kWh (ECCC, 2017). The electricity demand growth rate is less than 1% and by 2030 the demand is expected to increase by approximately 10%. Under federal GHG emissions management regulations, the coal-fired electricity generation fleet in Nova Scotia would have had to retire by 2030 (Governmnet of Canada, 2015). However, the province has reached an agreement with the federal government to operate the coal units beyond 2030 but achieve deeper emission reductions to meet the equivalent of closing all the plants by 2030.

Figure 4.3: LCOE and Carbon Emissions Intensity of Electricity Generation Options for Nova Scotia

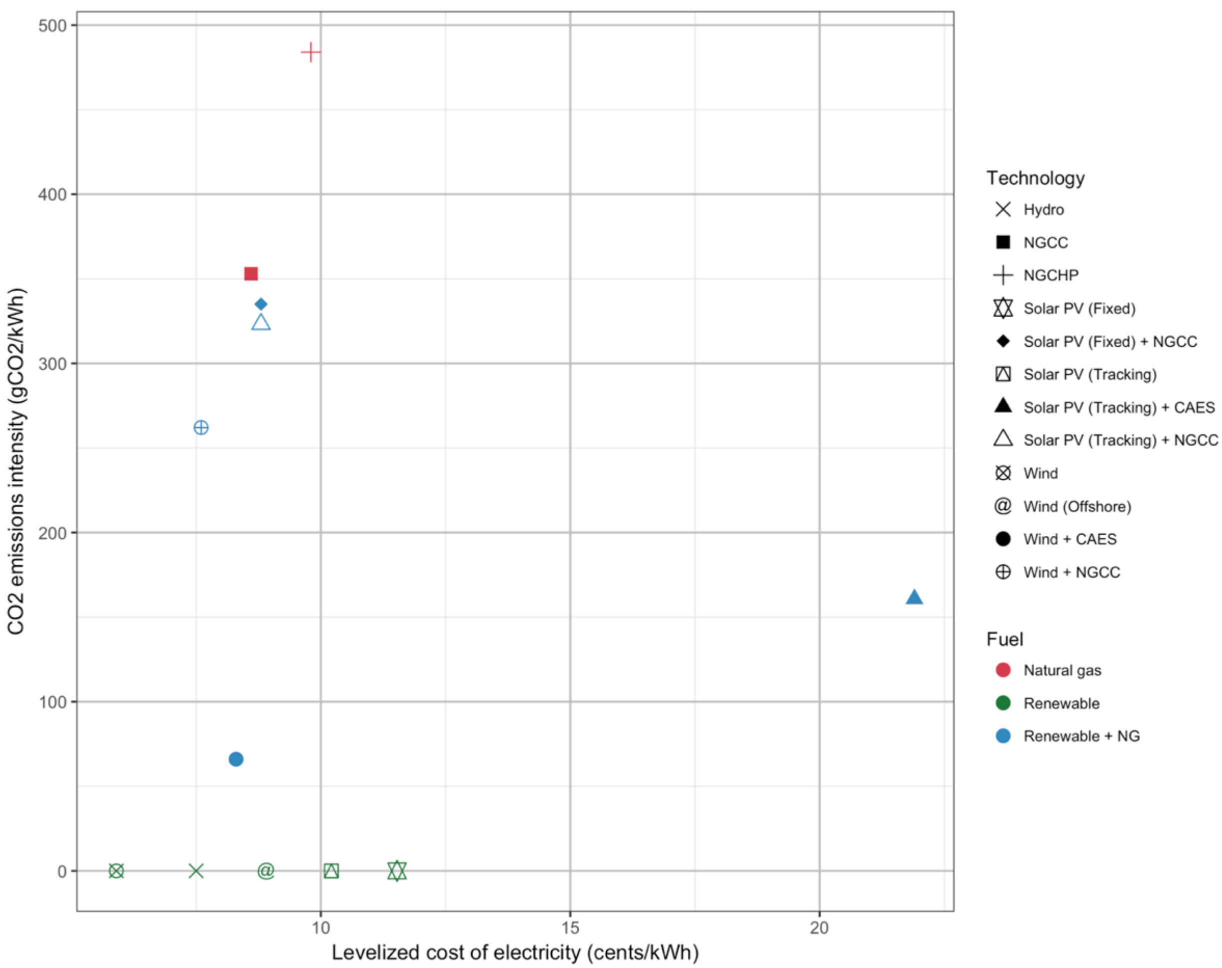


Table 4.3: Electricity Generation Options for Nova Scotia

Technology	Stand-alone LCOE	Stand-alone LCOE with Transmission Cost	Firm Power LCOE with Transmission Cost	Carbon Intensity (gCO_2/kWh)	CO_2 COSTS (\$/tCO_2)
Wind + NGCC	7.6	7.8	7.8	262	-110
Wind + CAES	8.3	8.5	8.5	66	-10.45
NGCC	8.6	8.7	8.7	353	Reference case
Solar PV (Fixed) + NGCC	8.8	9	9	335	111.4
Solar PV (Tracking) + NGCC	8.8	9	9	323	67.14
Hydro	7.5	9.5	9.5	0	-31.16
NGCHP	9.8	9.9	9.9	484	Higher LCOE and CO_2intensity
Offshore Wind	8.9	9.9	9.9	0	8.499
Solar PV (Tracking) + CAES	22	22	22	161	691.9
Wind	5.9	6.4	Not firm	0	-76.49
Solar PV (Tracking)	10	11	Not firm	0	45.61
Solar PV (Fixed)	12	12	Not firm	0	82.92

Results of the generation options assessed for Nova Scotia are summarized in Figure 4.3 and Table 4.3. The least cost options for firm electricity generation in Nova Scotia is the wind + NGCC option (7.8 cents/kWh). This option has a CO_2 emissions intensity (262 gCO_2/kWh) 70% lower than the 2005 grid average CO_2 emissions intensity. The avoided cost of delaying the marginal new generation unit by 5 years is 2.6 cents/kWh.

The province has sufficient natural gas delivery infrastructure to support gas-fired generation and NGCC can potentially be developed as a baseload generation option to replace current coal-fired generating units. However, higher natural gas prices lead to higher LCOE for NGCC. As such, all onshore wind options – including the wind + CAES option – and hydropower have lower LCOE values than NGCC, making their CO_2 COSTS negative.

Nova Scotia is planning to reduce the GHG intensity of its electricity system by importing hydroelectric power from the Muskrat Falls project in Newfoundland and Labrador. Nova Scotia is financing the Maritime Link, a 170-km subsea HVDC transmission line between Newfoundland and Nova Scotia to allow electricity transfer between the two provinces.

New Brunswick

New Brunswick has a relatively diversified electricity generation system that currently has an installed capacity of 4251 MW. Approximately 55% of the installed capacity consists of fossil fuel-fired generation (coal, fuel oil, diesel, and natural gas). New Brunswick is one of the two Canadian provinces that has nuclear power generation (the other being Ontario). The 660 MW Point Lepreau Nuclear Generating Station produces 31% of electricity generation in New Brunswick. Approximately 36% of the electricity generation is from fossil fuel-fired generation making the GHG intensity of generation in 2015 280 gCO_2eq/kWh. The province has a total of 15 electricity interconnections with Quebec, Nova Scotia, Prince Edward Island, and Maine.

Figure 4.4: LCOE and Carbon Emissions Intensity of Electricity Generation Options for New Brunswick

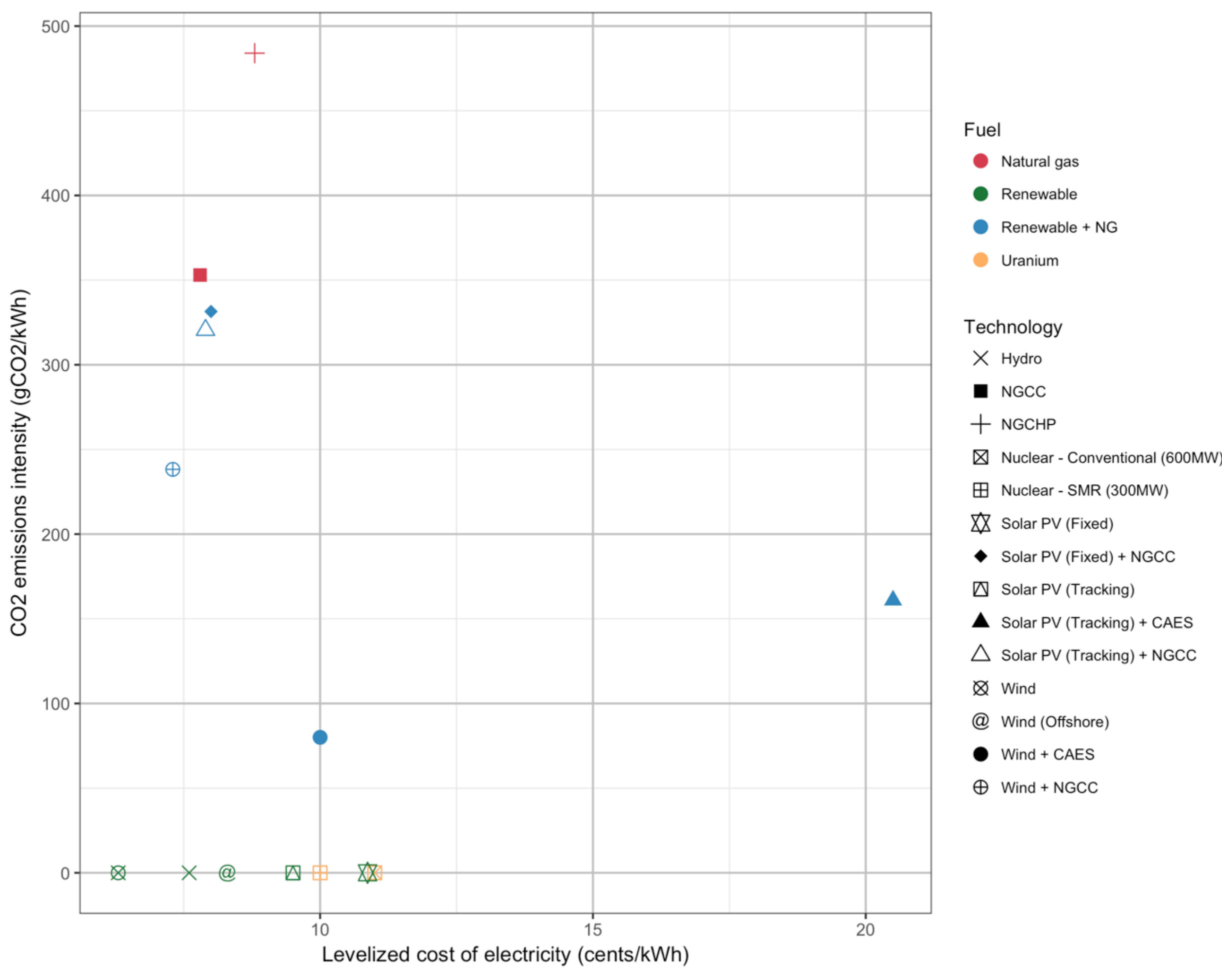


Table 4.4: Electricity Generation Options for New Brunswick

Technology	Stand-alone LCOE	Stand-alone LCOE with Transmission Cost	Firm Power LCOE with Transmission Cost	Carbon Intensity (gCO_2/kWh)	CO_2 COSTS ($\$/tCO_2$)
Wind + NGCC	7.3	7.4	7.4	238	-43.57
NGCC	7.8	7.9	7.9	353	Reference case
Solar PV (Tracking) + NGCC	7.9	8	8	320	30.77
Solar PV (Fixed) + NGCC	8	8.2	8.2	331	92.86
NGCHP	8.8	8.9	8.9	484	Higher LCOE and CO_2 intensity
Offshore Wind	8.3	9.3	9.3	0	14.16
Hydro	7.6	9.6	9.6	0	-5.666
Nuclear - SMR (300MW)	10	10	10	0	62.32
Wind + CAES	10	10	10	80	80.59
Nuclear - Conventional (600MW)	11	11	11	0	90.65
Solar PV (Tracking) + CAES	21	21	21	161	661.3
Wind	6.3	6.8	Not firm	0	-42.49
Solar PV (Tracking)	9.5	10	Not firm	0	48.24
Solar PV (Fixed)	11	11	Not firm	0	86.94

Figure 4.3 and Table 4.3 summarize the results of the generation options assessment for New Brunswick. The least cost options for firm electricity generation in New Brunswick is the wind + NGCC option (7.4 cents/kWh). The least cost option has a CO_2 emissions intensity (238 gCO_2/kWh) 39% lower than 2005 grid average CO_2 emissions intensity. The avoided cost of delaying the marginal new generation unit by 5 years is 2.5 cents/kWh.

Several of these options have lower (or zero) GHG emissions intensity than current average intensity of 280 gCO_2eq/kWh. Six options have a CO_2 COSTS value less than $\$50/tCO_2$.

Quebec

At 41,556 MW, Quebec's power system has the largest installed generation capacity in Canada. More than 91% of the installed generation capacity is hydroelectric generation. Hydroelectricity accounts for approximately 95% of the electricity produced in Quebec. Of over 200 TWh of annual electricity generation in Quebec, 11% is exported to neighboring provinces and to the United States through interconnections with Ontario, New Brunswick, Newfoundland and Labrador, New England, and New York. Quebec's power system serves approximately 4.2 million customers. The industrial sector (including agricultural) consumes 47% of the electricity followed by the residential sector at 39% and the commercial sector at 14% (NRCan, 2017). Electricity demand in the province is expected to grow at a rate of nearly 1.5% per year, increasing the demand by 35 TWh by 2030 (NEB, 2017).

Figure 4.5: LCOE and Carbon Emissions Intensity of Electricity Generation Options for Quebec

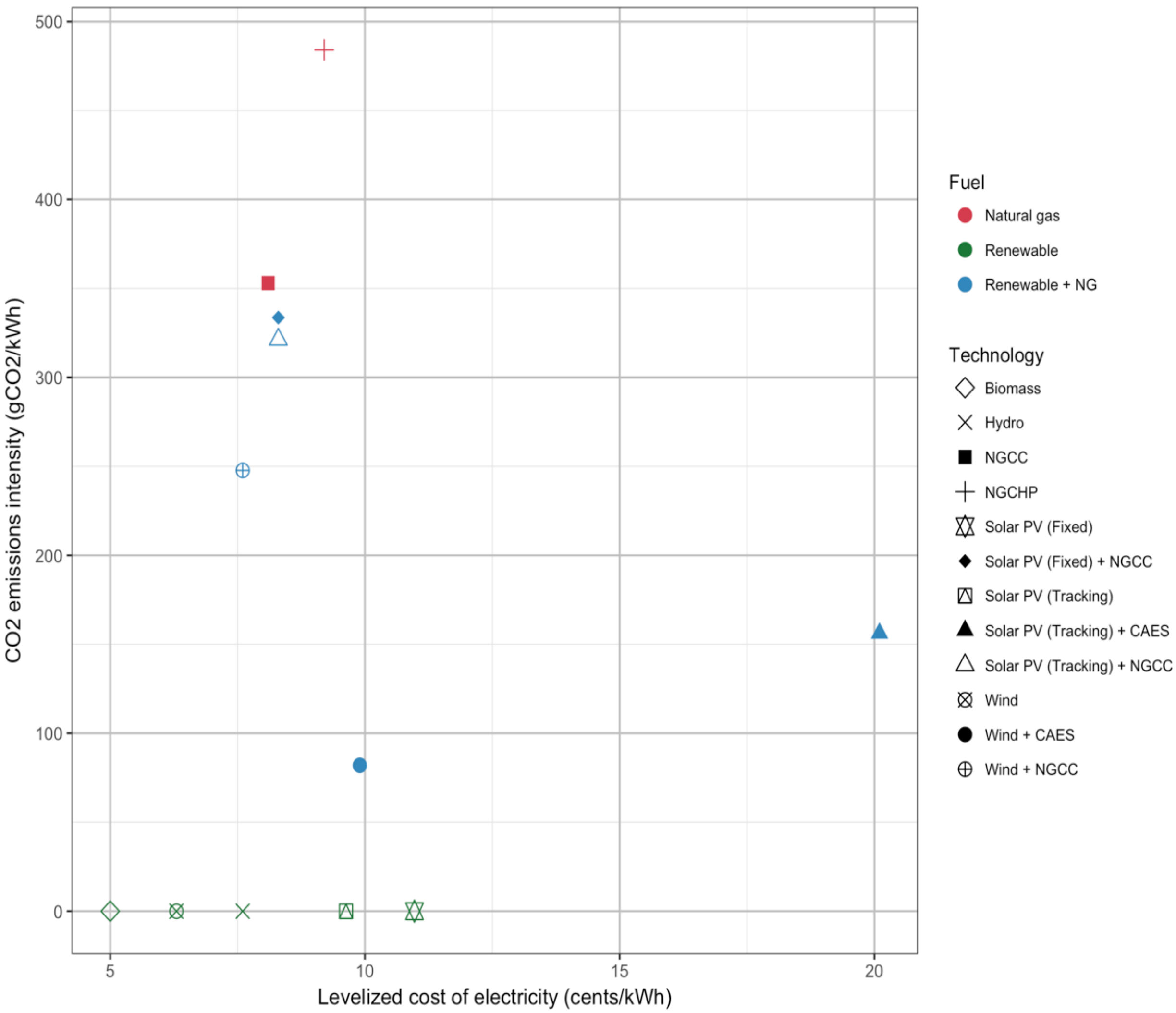


Table 4.5: Electricity Generation Options for Quebec

Technology	Stand-alone LCOE	Stand-alone LCOE with Transmission Cost	Firm Power LCOE with Transmission Cost	Carbon Intensity (gCO_2/kWh)	CO_2 COSTS (\$/tCO_2)
Biomass	5	5.2	5.2	0	-87.82
Wind + NGCC	7.6	7.8	7.8	248	-47.5
NGCC	8.1	8.2	8.2	353	Reference case
Solar PV (Fixed) + NGCC	8.3	8.5	8.5	334	103.1
Solar PV (Tracking) + NGCC	8.3	8.5	8.5	321	63.08
NGCHP	9.2	9.3	9.3	484	Higher LCOE and CO_2 intensity
Hydro	7.6	9.6	9.6	0	-14.16
Wind + CAES	9.9	10	10	82	66.42
Solar PV (Tracking) + CAES	20	20	20	156	609.9
Wind	6.3	6.8	Not firm	0	-50.99
Solar PV (Tracking)	9.6	10	Not firm	0	43.32
Solar PV (Fixed)	11	12	Not firm	0	81.38

The province has sufficient generation capacity to satisfy the growing electricity demand. Several other hydroelectricity projects are currently under construction – including the 1550 MW Romaine project – to satisfy future electricity demand. Due to hydropower dominance, current GHG emissions intensity of power generation in Quebec is a mere 1.1 gCO_2/kWh (ECCC, 2017).

The least cost options for firm electricity generation in Quebec is biomass-fired generation (5.2 cents/kWh). Biomass is resource limited and our estimates show that at that cost, about 3750 GWh of electricity can be produced in Quebec. The avoided cost of delaying the marginal new generation unit by 5 years is 1.7 cents/kWh.

Our assessment shows that in addition to hydropower, the province has resources to produce emissions-free electricity from biomass, wind and solar PV at a cost of 10 cents/kWh or lower (see Figure 4.5 and Table 4.5). The existence of a larger fleet of hydropower generation provides sufficient flexible resources to integrate larger amounts of variable renewable energy sources in Quebec.

Ontario

Installed generation capacity in Ontario is currently at 36,853 MW. The generation fleet is dominated by nuclear power (35%) followed by gas and oil powered generation (28%). More than 60% of power production comes from the nuclear generation fleet, resulting in low GHG emissions intensity at 40 gCO_2eq/kWh. Ontario currently has the largest fleet of wind (4213 MW) and solar PV (380MW) generation found anywhere in Canada. The Ontario power system serves approximately 5 million customers. Power demand is dominated by the industrial sector at 40%. Demand growth is estimated to be less than 1% per year.

Ontario's electricity system faces several challenges in satisfying the demand of Canada's largest customer base for electricity while ensuring affordability and system reliability. Factors such as reinforcements that are required for the aging infrastructure, refurbishment of the nuclear energy fleet that produces the majority of electricity in the province, integration of large amounts of renewable energy, and capacity contracts to ensure dependable capacity have contributed to the rising cost of electricity in Ontario. Retirement of the remaining units of the Pickering nuclear power complex may exacerbate the situation by potential capacity shortages (CNA, 2016). With phased retirements of the emissions free nuclear fleet, maintaining lower GHG emissions intensities as required by Ontario's climate change mitigation plans will be challenging.

Figure 4.6: LCOE and Carbon Emissions Intensity of Electricity Generation Options for Ontario

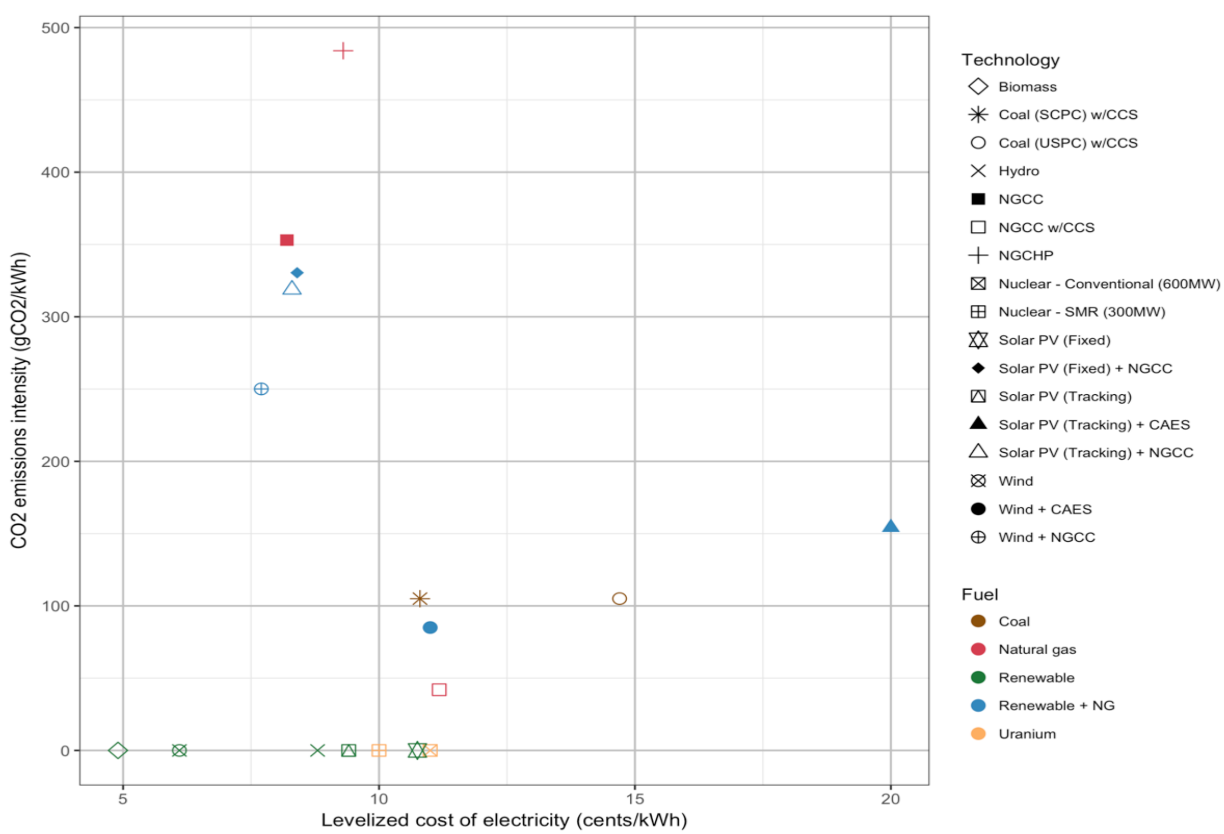


Table 4.6: Electricity Generation Options for Ontario

Technology	Stand-alone LCOE	Stand-alone LCOE with Transmission Cost	Firm Power LCOE with Transmission Cost	Carbon Intensity (gCO2/kWh)	CO2 COSTS ($/tCO2)
Biomass	4.9	5.1	5.1	0	-93.48
Wind + NGCC	7.7	7.8	7.8	250	-48.57
NGCC	8.2	8.3	8.3	353	Reference case
Solar PV (Tracking) + NGCC	8.3	8.5	8.5	319	29.23
Solar PV (Fixed) + NGCC	8.4	8.6	8.6	330	88.57
NGCHP	9.3	9.4	9.4	484	Higher LCOE and CO_2 intensity
Nuclear - SMR (300MW)	10	10	10	0	50.99
Hydro	8.8	11	11	0	17
NGCC w/CCS	11	11	11	42	95.67
Nuclear - Conventional (600MW)	11	11	11	0	79.32
Coal (SCPC) w/CCS	11	11	11	105	104.8
Wind + CAES	11	11	11	85	104.5
Coal (USPC) w/CCS	15	15	15	105	262.1
Solar PV (Tracking) + CAES	20	20	20	154	593.6
Wind	6.1	6.6	Not firm	0	-59.49
Solar PV (Tracking)	9.4	9.9	Not firm	0	34.21
Solar PV (Fixed)	11	11	Not firm	0	72.23

The results of the generation options assessment for Ontario are presented in Figure 4.6 and Table 4.6. The least cost options for firm electricity generation in Ontario is biomass-fired generation (5.1 cents/kWh). At that cost, about 6200 GWh of electricity can be produced by biomass in Ontario. Current electricity generation in Ontario is 151,000 GWh per year. The avoided cost of delaying the marginal new generation unit by 5 years is 1.6 cents/kWh.

Biomass and hydropower can potentially provide zero GHG emissions electricity at a relatively lower generation cost. However, both have limited annual energy capacities. Other low cost and zero emission technologies such as onshore wind and solar PV are variable supply sources. Firming those sources with natural gas-fired generating sources will increase net GHG emissions leading to uncertainties in maintaining lower GHG intensities for power generation. As Ontario already has experience with nuclear power, that can be a potential future generation option. Ontario is currently assessing the feasibility of several SMR nuclear technologies for remote power applications (HATCH, 2016). NGCC with CCS can potentially be another option to produce power at lower GHG intensity, but this technology is yet to be commercially demonstrated. Coal CCS, although there is Canadian experience, may not be a feasible option; at 105 gCO_2/kWh, it still has higher GHG intensity than Ontario's current fleet average intensity.

An optimal mix of generation technologies and electricity import arrangements with neighboring provinces may lead to low cost and low emissive future electricity generation in Ontario. Designing such mix is beyond the scope of this study. Nevertheless, this study provides data and information necessary to provide insights into the optimal generation mix for Ontario.

Manitoba

Manitoba is another hydropower-rich province, where hydropower accounts for 97% of the current installed capacity of 5700 MW. Manitoba's electricity demand is dominated by the residential sector (41%). The province exports approximately 28% of the electricity produced, mainly to the United States. Demand growth is forecasted to be 0.8-1% per year.

Figure 4.7: LCOE and Carbon Emissions Intensity of Electricity Generation Options for Manitoba

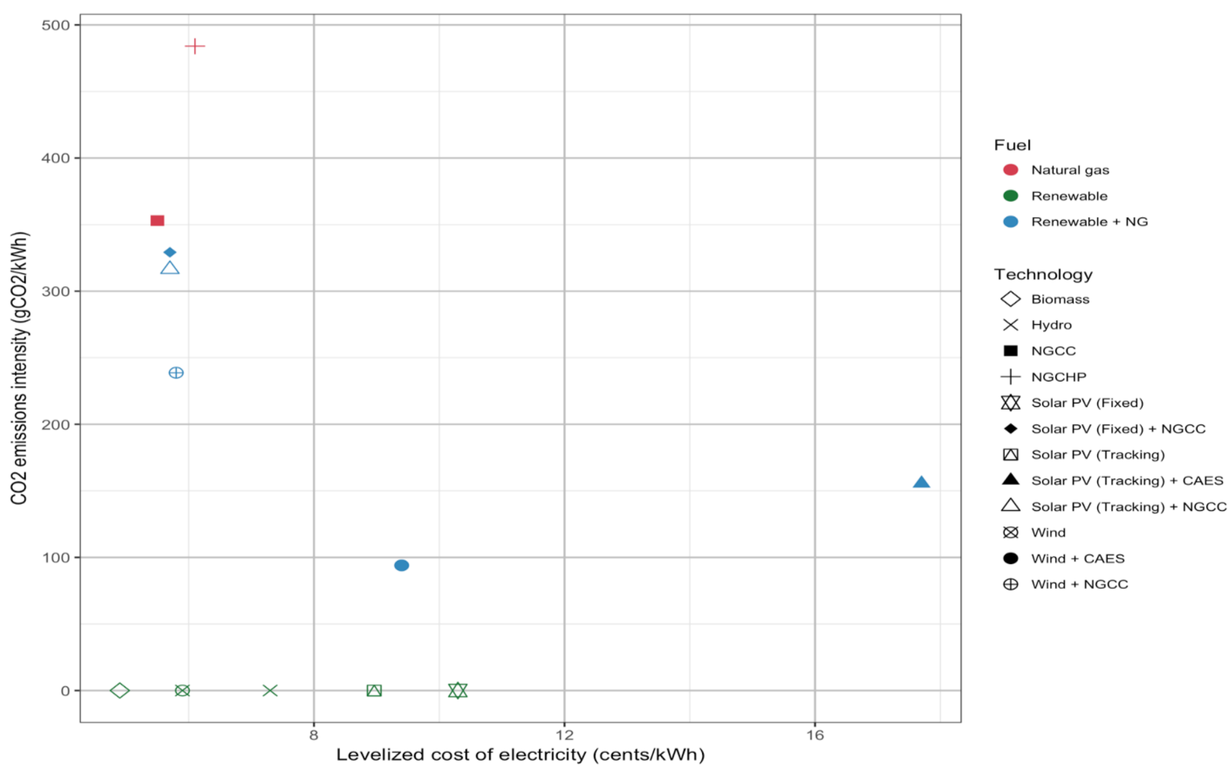


Table 4.7: Electricity Generation Options for Manitoba

Technology	Stand-alone LCOE	Stand-alone LCOE with Transmission Cost	Firm Power LCOE with Transmission Cost	Carbon Intensity (gCO2/kWh)	CO2 COSTS ($/tCO2)
Biomass	4.9	5.1	5.1	0	-17
NGCC	5.5	5.6	5.6	353	Reference case
Solar PV (Fixed) + NGCC	5.7	5.9	5.9	329	84
Solar PV (Tracking) + NGCC	5.7	5.9	5.9	316	54.67
Wind + NGCC	5.8	6	6	239	26.25
NGCHP	6.1	6.2	6.2	484	Higher LCOE and CO_2intensity
Hydro	7.3	9.3	9.3	0	50.99
Wind + CAES	9.4	9.6	9.6	94	150.6
Solar PV (Tracking) + CAES	18	18	18	156	617.7
Wind	5.9	6.4	NA	0	11.33
Solar PV (Tracking)	9	9.5	NA	0	98.06
Solar PV (Fixed)	10	11	NA	0	135.9

Figure 4.7 and Table 4.7 summarize the results of our generation options assessment for Manitoba. The least cost options for firm electricity generation in Manitoba are biomass (5.1 cents/kWh), closely followed by NGCC (5.8 cents/kWh). The avoided cost of delaying the marginal new generation unit by 5 years is 1.5 cents/kWh.

From the results, in addition to further potential to develop hydropower generation, the province has sufficient wind and solar PV resources to develop zero emissions generation. Hydropower units can be coordinated with variable resources to provide large volumes of net zero GHG emissions. NGCC in Manitoba has relatively lower LCOE of 5.8 cents/kWh and it is one of the least cost generation options available for the province. However, carbon pricing will impact the economics of NGCC.

Saskatchewan

Saskatchewan's current generation capacity is nearly 4200 MW. Both installed capacity as well as power generation is dominated by coal-fired electricity. Coal-fired generation accounts for 52% of the power generation followed by natural gas-fired generation (25%). The fossil fuel dominance of power generation has led to a high GHG emissions intensity of 660 gCO_2/kWh in 2015 (ECCC, 2017). As a GHG emissions reduction option, Saskatchewan has developed the world's first commercial scale coal-fired power generation plant with CCS.

Figure 4.8: LCOE and Carbon Emissions Intensity of Electricity Generation Options for Saskatchewan

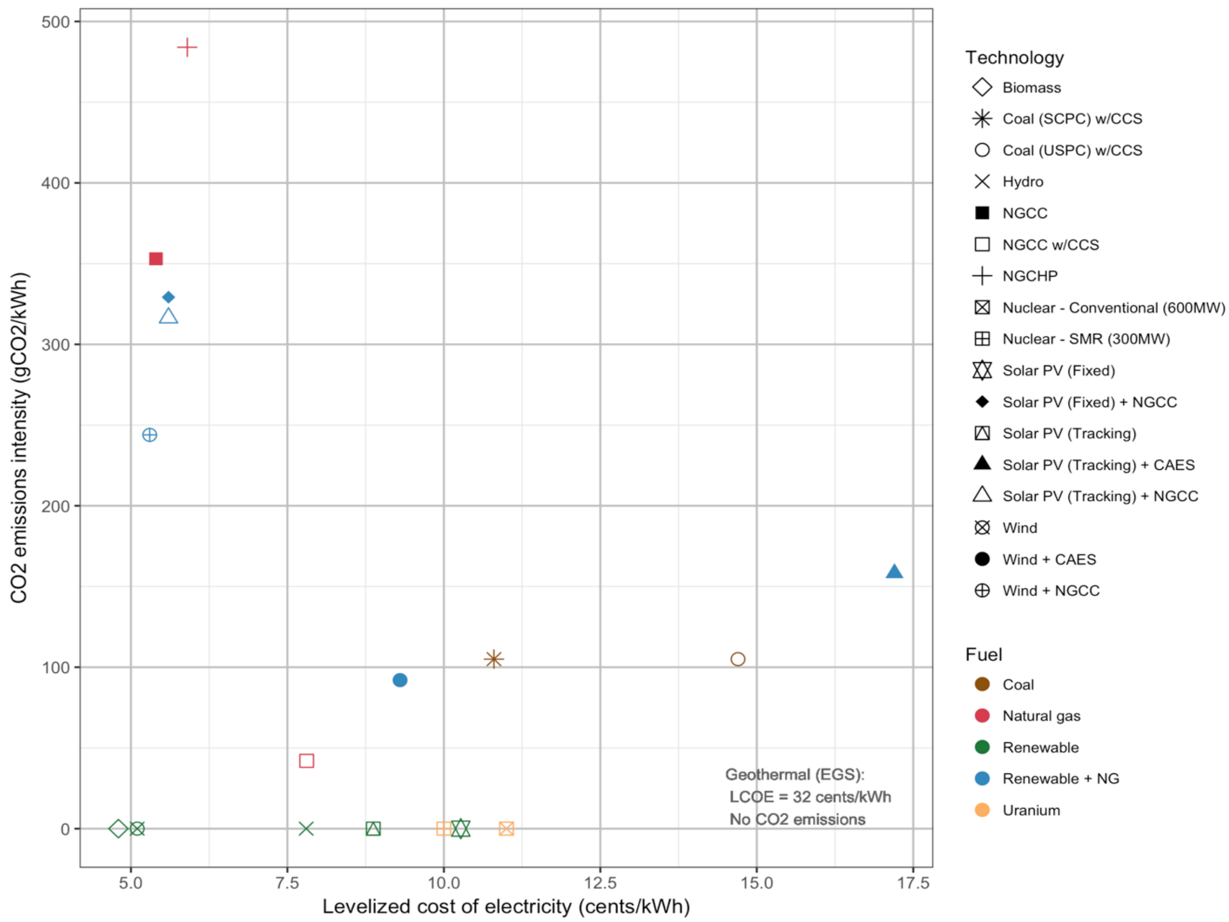


Table 4.8: Electricity Generation Options for Saskatchewan

Technology	Stand-alone LCOE	Stand-alone LCOE with Transmission Cost	Firm Power LCOE with Transmission Cost	Carbon Intensity (gCO2/kWh)	CO2 COSTS ($/tCO2)
Biomass	4.8	5	5	0	-17
Wind + NGCC	5.3	5.4	5.4	244	-9.167
NGCC	5.4	5.5	5.5	353	Reference case
Solar PV (Fixed) + NGCC	5.6	5.8	5.8	329	84
Solar PV (Tracking) + NGCC	5.6	5.8	5.8	316	54.67
NGCHP	5.9	6	6	484	Higher LCOE and CO_2 intensity
NGCC w/CCS	7.8	7.9	7.9	42	77.42
Wind + CAES	9.3	9.5	9.5	92	149.4
Hydro	7.8	9.8	9.8	0	67.99
Nuclear - SMR (300MW)	10	10	10	0	130.3
Nuclear - Conventional (600MW)	11	11	11	0	158.6
Coal (SCPC) w/CCS	11	11	11	105	217.7
Coal (USPC) w/CCS	15	15	15	105	375
Solar PV (Tracking) + CAES	17	17	17	158	605.9
Geothermal (EGS)	32	32	32	0	753.5
Geothermal (Hydro-geothermal)	41	41	41	0	1008
Wind	5.1	5.6	NA	0	-8.499
Solar PV (Tracking)	8.9	9.4	NA	0	98.36
Solar PV (Fixed)	10	11	NA	0	138

Saskatchewan is forecasted to have a relatively high electricity demand growth of 1.7-2%. More than 52% of the electricity is consumed by the industrial sector. To avoid early retirement of its coal-fired generation fleet, Saskatchewan has also come to an agreement with the federal government to run one or more coal-fired power plants beyond 2030. In return, the province will have to achieve higher GHG reductions elsewhere in its electricity sector (McCarthy, 2017). To do so, the province is planning to increase its renewable generation capacity to 50% of installed capacity by 2030. It is also assessing the retrofit potential of its coal units with CCS (Harper et al., 2016).

The results of generation technologies assessed for the provinces are presented in Figure 4.8 and Table 4.8. The least cost options for firm electricity generation in Saskatchewan are biomass (5 cents/kWh), closely followed by wind + NGCC (5.4 cents/kWh). Compared to the 2005 grid average CO_2 emissions intensity, the two least cost options have CO_2 emissions intensities 100%

and 69% lower, respectively. The avoided cost of delaying the marginal new generation unit by 5 years is 1.5 cents/kWh.

These results show that Saskatchewan has several cost competitive renewable generation options – both variable and firm – that can be developed to meet its 50% by 2030 target. The province has both excellent wind and solar PV resources. The best resource sites are closer to major demand centers, potentially minimizing transmission cost.

Alberta

Current installed generation capacity in Alberta is 16,526 MW with coal-fired generation and natural gas-fired generation contributing 38% and 44%, respectively. Historically, power production in Alberta is dominated by coal. In 2015, coal-fired units produced 67% of electricity in Alberta. Due to coal dominance, GHG intensity of power generation in Alberta is the highest among Canadian provinces. In 2015, the intensity was 790 gCO_2/kWh. Alberta has relatively limited electricity interconnections. Current connections are with British Columbia, Saskatchewan and Montana.

The industrial sector consumes more than 55% of the electricity used in Alberta. The average forecasted growth rate for the period 2016-2030 is 0.8% per year. Under Alberta's Climate Leadership Plan, all coal units are expected to retire in, or before, 2030. The same plan requires 30% or more electricity generation in Alberta to be produced by renewable generation technologies. Alberta has had a price on carbon emissions since 2007, making it one of the first North American jurisdictions to enact carbon pricing (Harper et al., 2016). Carbon pricing is expected to be gradually increased, although how it applies to power generation is still being finalized (Government of Alberta, 2017).

Figure 4.9: LCOE and Carbon Emissions Intensity of Electricity Generation Options for Alberta

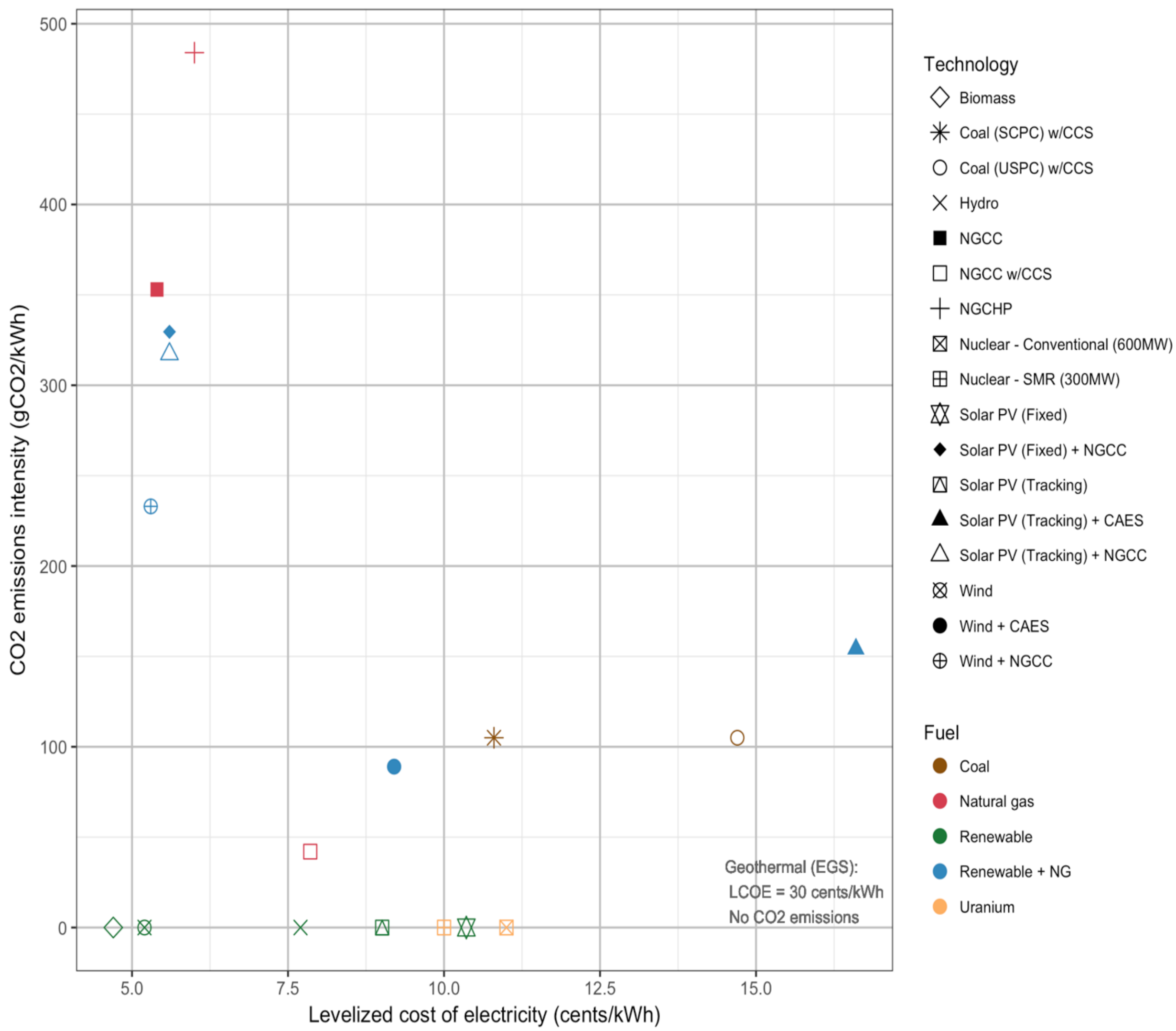


Table 4.9: Electricity Generation Options for Alberta

Technology	Stand-alone LCOE	Stand-alone LCOE with Transmission Cost	Firm Power LCOE with Transmission Cost	Carbon Intensity (gCO2/kWh)	CO2 COSTS ($/tCO2)
Biomass	4.7	4.9	4.9	0	-19.83
Wind + NGCC	5.3	5.4	5.4	233	-8.333
NGCC	5.4	5.5	5.5	353	Reference case
Solar PV (Fixed) + NGCC	5.6	5.8	5.8	330	85.33
Solar PV (Tracking) + NGCC	5.6	5.8	5.8	317	56
NGCHP	6	6.1	6.1	484	Higher LCOE and CO_2 intensity
NGCC w/CCS	7.9	8	8	42	78.96
Wind + CAES	9.2	9.4	9.4	89	143.9
Hydro	7.7	9.7	9.7	0	65.16
Nuclear - SMR (300MW)	10	10	10	0	130.3
Nuclear - Conventional (600MW)	11	11	11	0	158.6
Coal (SCPC) w/CCS	11	11	11	105	217.7
Coal (USPC) w/CCS	15	15	15	105	375
Solar PV (Tracking) + CAES	17	17	17	154	563.3
Geothermal (EGS)	30	30	30	0	696.9
Wind	5.2	5.7	NA	0	-5.666
Solar PV (Tracking)	9	9.5	NA	0	102.2
Solar PV (Fixed)	10	11	NA	0	140.4

A main challenge for Alberta's electricity sector is ensuring sufficient reliable capacity is available to satisfy the electricity demand upon retirement of coal-fired generating units by 2030. As aforementioned, coal units currently produce more than 60% of the provinces electricity.

The results of the generation options assessment for Alberta are presented in Figure 4.9 and Table 4.9. The least cost options for firm electricity generation in Alberta are biomass (4.9 cents/kWh and Wind + NGCC (5.4 cents/kWh). CO_2 emissions intensity of these two options are respectively, 100% to 75% lower than grid average CO_2 emissions intensity in 2005. The avoided cost of delaying the marginal new generation unit by 5 years is 1.6 cents/kWh.

The province has limited hydropower resources. However, a 340 MW run-of-river hydropower project is currently in the regulatory hearing stage. There is potential to develop up to 1500 MW of hydropower capacity in the northeast corner of the province. This option would require a minimum of 300 km of new transmission line development, at a minimum average transmission cost of 3 cents/kWh.

Wind, solar PV and natural gas resources are plentiful in the province. Sites with higher wind and solar PV resources are concentrated in the southern part of the province. Coordinated development of these sites can potentially reduce the transmission cost.

Being the province with the highest CO_2 emissions from electricity generation in Canada, Alberta is actively pursuing options to reduce carbon emissions from the electricity sector. All generation options available for Alberta significantly lower CO_2 emissions intensities compared to 2005 grid average levels (900 gCO_2/kWh). The province has a reliable supply of relatively low cost natural gas. A combination of natural gas-fired generation and renewable resources can potentially supply lower GHG emissive electricity at a competitive cost.

British Columbia

In British Columbia, more than 90% of the electricity is produced by hydroelectricity. The province exports approximately 15% of its power generation. However, BC has recently become a net importing province (NRCan, 2016). As the majority of electricity is produced by hydropower, the current GHG intensity of generation is in the order of 12 gCO_2eq/kWh. Demand growth in BC is forecasted to be 0.7% per year in the period 2016-2030.

Figure 4.10: LCOE and Carbon Emissions Intensity of Electricity Generation Options for British Columbia

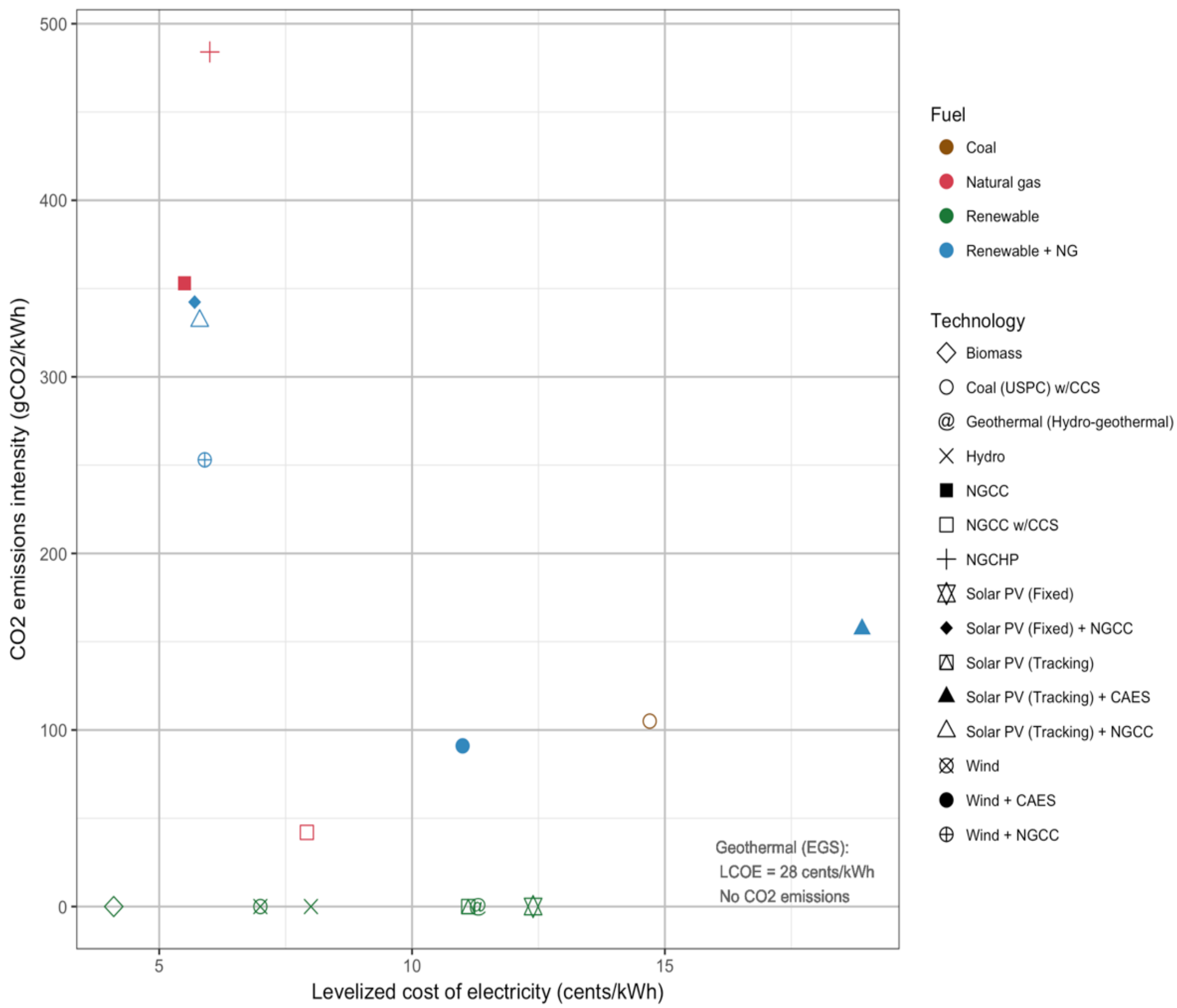


Table 4.10: Electricity Generation Options for British Columbia

Technology	Stand-alone LCOE	Stand-alone LCOE with Transmission Cost	Firm Power LCOE with Transmission Cost	Carbon Intensity (gCO2/kWh)	CO2 COSTS ($/tCO2)
Biomass	4.1	4.3	4.3	0	-39.66
NGCC	5.5	5.6	5.6	353	Reference case
Solar PV (Fixed) + NGCC	5.7	5.9	5.9	342	187.5
Solar PV (Tracking) + NGCC	5.8	6	6	332	141.2
NGCHP	6	6.1	6.1	484	Higher LCOE and CO_2 intensity
Wind + NGCC	5.9	6.1	6.1	253	40
NGCC w/CCS	7.9	8	8	42	77.8
Hydro	8	10	10	0	70.82
Wind + CAES	11	11	11	91	209.9
Geothermal (Hydro-geothermal)	11	11	11	0	164.3
Solar PV (Tracking) + CAES	19	19	19	157	684.3
Geothermal (EGS)	27	27	27	0	609.1
Wind	7	7.5	NA	0	42.49
Solar PV (Tracking)	11	12	NA	0	158.9
Solar PV (Fixed)	12	13	NA	0	195.3

Figure 4.10 and Table 4.10 summarize the results of the generation options assessment for BC. Least cost options for firm electricity generation in British Columbia is biomass-fired generation (4.3 cents/kWh). Our biomass energy assessment for British Columbia is less robust compared to other options. The next least cost option is NGCC (5.6 cents/kWh). However, NGCC emissions intensity is 15 times the grid average CO_2 emissions intensity in British Columbia in 2005. The avoided cost of delaying the marginal new generation unit by 5 years is 1.5 cents/kWh.

The province is currently developing an 1100 MW new hydropower generation facility – the Site C Project – on the Peace River. Small scale hydropower resources are available in most parts of the province. However, most have higher average costs of generation due to high capital cost.

According to the analysis, the least cost options are biomass-fired generation and NGCC. Biomass, however, is a limited energy resource. The province generally has lower wind and solar PV resources, leading to higher LCOE.

Of the sites assessed, BC has the best geothermal resources, particularly hydro-geothermal resources. The LCOE is still over 11 cents/kWh and the resource is spatially dispersed. These factors leave NGCC to be the least cost generation option for BC. However, carbon pricing, which BC has already enacted, will influence the economics of NGCC.

Chapter 5: Conclusion

Electric power systems in all Canadian provinces are currently at a juncture where the power generation infrastructure needs to be expanded, reinforced, or transformed. In some cases, the need is to satisfy growing demand for electricity. In other cases, transformations are required to meet climate change mitigation targets.

In periods of transformational change for critical infrastructure such as the electric power system, it is prudent that public policy makers and utility decision makers have access to high quality, up to date information on electricity generation technologies to make informed decisions.

This report provides an objective review of generation technologies, their potential in different provinces, and their economic costs. To CERI's knowledge, this is the most in-depth publicly available review of generation technologies available for Canadian provinces available to date.

The main economic metric used to screen generation technologies is the levelized cost of electricity (LCOE). LCOE, measured in cents/kWh, is a metric that represents the cost of constructing and operating an electric power generation plant. It is a standard metric used for screening and comparing different power generating options. Use of LCOE as a screening metric has received some criticism as it does not consider variations in operation attributes of different technologies. Lower availability of variable resources, however, is factored into the LCOE calculation as lower utilization leads to higher LCOE.

It should be noted that while this research focuses on the economic assessment of the options, social and cultural values can also play a role. Depending on the jurisdiction, the value of the social and cultural impacts can result in projects that are not the least cost being selected. This research does not presume to quantify those values which are best left to a consultation process and trade off discussion amongst stakeholders.

The estimation of the full system integration cost of generation technologies required power system level simulation studies. Providing such analysis is beyond the scope of this study. However, to provide a comprehensive assessment, we also provide estimates of capacity values of variable generation technologies. As such, decision makers can use LCOE along with capacity values to make informed comparisons of different technologies.

The cost of avoided CO_2 emissions is calculated for technologies that are assessed to provide decision makers with information about competitiveness of different technologies to meet GHG emissions management targets. CO_2 costs are calculated against a province-specific reference case.

The analysis included 11 power generation technologies. Six of them are assessed with province-specific cost and energy resource assessments. Three carbon capture and storage technologies and two nuclear power technologies are assessed at national level. In cases where province-specific cost estimates are not available, they are inferred by applying a CERI in-house power generation capital cost index.

The results are examined first by technology and then by exploring how different generation options are stacked up in individual provinces. The latter screening, presented in Chapter 4, provides important datasets that enable comparison of generation technologies in different provinces in an unbiased and objective manner. It also provides an economic benchmark for generation and incremental transmission against which energy efficiency programs can be measured. Below the benchmark, energy efficiency programs would be cost effective. Above that benchmark, adding new generation is cheaper.

Table 5.1: Provincial Results

Province	Least Cost Intermittent Power (cents/kWh)	Least Cost Firm Power (cents/kWh)	Cost of Reduced CO_2 Emissions of the Firm Power Option ($/tonne)
NL	Wind – 6.1	Wind + Hydro – 7.6	N/A
PE	Wind – 6.3	Wind + NGCC – 7.2	-57
NS	Wind – 6.4	Wind + NGCC – 7.8	-110
NB	Wind – 6.8	Wind + NGCC – 7.4	-44
QC	Wind – 6.8	Biomass – 5.2	-88
ON	Wind – 6.6	Biomass – 5.1	-93
MB	Wind – 6.4	Biomass – 5.1	-17
SK	Wind – 5.6	Biomass – 5.0	-17
AB	Wind – 5.7	Biomass – 4.9	-20
BC	Wind – 7.5	Biomass – 4.3	-40

The provincial results indicate that wind, NGCC and biomass are options to consider across the country when evaluating the least cost options to add electricity generation to provincial grids. Costs range from a low of 4.3 cents/kWh in BC for firm biomass generation to a high of 7.8 cents/kWh in NS for a hybrid wind and NGCC option. In all cases, the selection of these options leads to a decrease in emissions at a lower cost than the base case option of NGCC.

As NGCC is used as the reference case in most provinces to calculate the cost of reduced CO_2 emissions, it will be influenced by changes in natural gas prices. Province-specific natural gas prices we assumed for this analysis are listed in Table 3.11. A 1% increase in natural gas prices would increase the LCOE of NGCC by 0.3-0.6%. Also note that changes in natural gas price would change the LCOE of wind and solar PV coordinated with NGCC. A 1% increase in natural gas prices would lower the CO_2 emissions reduction cost of the least cost generation options listed in Table 5.1 by 1-3%.

Due to a lack of province-specific natural gas price forecasts for electric power generation, we used the most recent observed industrial natural gas prices (obtained from CANSIM Table 129-0003 Sales of natural gas, annual). While several organizations provide natural gas price forecasts, we were unable to find a source that provided provincial natural gas prices as applicable to electric power generation. While the NEB's Canada's Energy Future report provides forecasts of natural gas prices by end use sector (i.e., residential, commercial, and industrial), the most recent report provided only forecasts at the national level. Development of a natural gas price forecast is beyond the scope of this study and as such we used the annual average industrial natural gas prices observed in 2016 for this analysis.

CERI has developed its analytical framework to enable the comparison of generation technologies. For example, for intermittent generation sources, we estimate the cost of establishing baseload operations in different ways. These include the assessment of LCOE and emissions of firming intermittent sources with natural gas-fired generation and compressed air energy storage systems.

CERI has not included elements such as smart grid investments, demand response or energy efficiency activities in this analysis. What this research does provide is an economic benchmark from which to judge the cost effectiveness of these programs. If the programs can reduce electricity consumption at a cost less than the generation option, then they would be considered economic. Programs that are more expensive than the generation option may provide other benefits, but would not be justified on a simple cost/benefit basis.

Reviewers have noted that we have not addressed tidal options in our analysis. The technologies are not as mature as the ones assessed in this study. In addition, tidal resources are geographically limited and would not be a reasonable option to assess for most provinces. Further work is needed to assess the likelihood of this option in the future.

Distribution level generation options can also be an important consideration. However, CERI has attempted to address this point by indicating the additional cost to connect generation to a transmission grid. It is assumed if distributed resources are being considered, the economic cost would preclude the need for additional generation.

While the study is based on providing base and peak load services, the need for flexibility during the operating day is becoming increasingly important. In such a situation, unique resources might be needed to meet these intra-day electricity demands. However, the need for base and peak requirements is still paramount as these traditional service demands remain. Intra-day flexibility provides an added demand and therefore an added value that can be considered as part of the evaluation of different generation options.

One area that was quite challenging to provide reliable cost estimates was transmission interconnection costs. To provide the full transmission cost, the entire electric system level assessment is required. Such analysis is beyond the scope of this study. Even estimating the cost of incremental transmission links required to connect a new generator is challenging as it requires spatial information about existing bulk power transmission systems and exact siting location of the generator. In this study, we did not focus on optimal sizing of electricity generation units. However, we provide best transmission cost estimates by estimating the transmission cost for a few representative cases.

Data limitations was a major challenge for this study. More specifically, resource data on hydropower and biomass was quite limited. Similar issues were encountered with cost data. Due to the limited project experience in the provinces, Canadian sources are lacking for important cost data such as capital costs. In some cases, we inferred the costs using data from the United States. Putting this information in one publicly accessible document is a major contribution of this work.

For the analysis, we developed several new resource datasets that are spatially and temporally explicit. For example, the solar PV dataset is at one-hour temporal resolution and its spatial resolution is Canadian census divisions. By integrating resource data with population data, we can gain insights into questions such as the distributed generation potential and optimal placement of generation units considering the demand centers and transmission needs. The latter question is not within the scope of this project; however, it may be analyzed in a future CERI study.

Fossil Fuel-Fired Generation

With federal regulations prohibiting coal-fired electricity, natural gas-fired generation remains as the only feasible option for large scale fossil fuel-fired generation. Due to lower natural gas prices, natural gas combined cycle power generation (NGCC) offers a low cost, dependable option for electricity generation in western Canada. In eastern and Atlantic Canada, relatively higher natural gas prices and supply constraints lead to higher LCOE for NGCC.

Coal-fired generation with CCS is a commercially-ready technology that has already been demonstrated in Saskatchewan. However, higher capital costs and higher heat rates (i.e., efficiency penalty) have led to higher LCOE for coal with CCS. Carbon pricing also impacts the economic effectiveness of CCS. Under currently developed CO_2 capture technologies, only up to 90% of the CO_2 produced is captured. While higher capture is technically possible, it would significantly increase the heat rate penalty of capture. As such, CO_2 emissions from CCS is non-zero and carbon pricing would increase the LCOE.

Nuclear Power

A nuclear power renaissance is plausible in Canada under restrictions on carbon emissions. However, traditional large reactors may be uneconomic due to the high capital cost and operational limitations. Small modular reactors on the other hand can provide scalable electricity generation options in Canada. Currently, nuclear power options are more expensive than natural gas, hydro, wind, and biomass.

Renewable Energy Options

All provinces are endowed with various renewable energy resources that can be developed for electricity generation with low or zero GHG emissions. Not all renewable energy sources are readily available in all provinces. Hydro and biomass resources – that can provide dispatchable electricity – have limited availability. Relatively low-cost hydro resources have already been developed in Canada. The remaining sites are characterized by high capital investment requirements and long-distance transmission. Refurbishment of existing hydropower units with more efficient new turbines can make marginal increases to the generation infrastructure.

The dataset we used for wind power assessment shows that potential sites with sufficient wind resources are available in all Canadian provinces. Sites we used for the analysis can potentially satisfy 30% of electricity demand in respective provinces. Our analysis shows that transmission developments to connect these wind power generation sites will not increase the average cost significantly. In many provinces, wind power was found to be the least cost generation option.

Solar PV costs have steadily declined in recent years. As such. solar PV can also produce electricity in many Canadian provinces at a LCOE less than 10 cents/kWh. It was shown in the analysis that single axis tracking solar, although requiring slightly higher capital investments, reduces LCOE of solar PV by up to 12% from increased energy output.

Intermittency is a major challenge for wind power and solar PV. In the analysis, we find that wind firmed up by coordinating with NGCC leads to lower LCOE and CO_2 costs in several provinces. This fact leads to another important conclusion.

Electric power systems are complex systems that require different generation units that operate in coordination to provide affordable electricity while ensuring the integrity of the system. Coordinated operation of wind power and NGCC, for example, essentially mimics the behavior of typical power system operations where generators are dispatched up or down to satisfy time varying demand. The system is managed such that the generating fleet would follow the load and generators are dispatched minimizing the operating cost.

Transforming the electricity generation system is not merely picking one technology option and using it to displace all other generating systems. An optimal mix of generation technologies can provide affordable electricity while complying with environmental regulations such as GHG emissions reductions. This study provides an up-to-date set of information for policy makers to find an optimal generation technology mix.

The review is conducted by utilizing predominantly publicly available information. Using this information, this study provides a dataset that can form the foundation for future in-depth analyses such as identification of optimal generation mixes (e.g., integrated resource plans), trade off analyses (e.g., cost-benefit analysis of policy decisions) and benchmarking of emerging technology assessments.

The datasets developed include economic assessments, reviews of recent cost estimates, spatially and temporally explicit resource datasets, graphical summaries of technology attributes, and resource maps. We invite the reader to access the data portals that will be published soon on CERI's website to review these datasets.

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