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Canada's Electricity Infrastructure
Building a Case for Investment

ENERGY, ENVIRONMENT AND TRANSPORTATION POLICY

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Insights You Can Count On

Canada's Electricity Infrastructure: Building a Case for Investment
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Preface

Canada's electric power industry has been one of the mainstays of Canada's economy, providing low-cost power to residences and businesses. With half of the generation assets built before 1980, the industry faces a pressing need to accelerate investment in infrastructure at all levels. This comes at a time when the industry must reduce greenhouse gas emissions, particularly from coal-fired generation, and when small-scale renewable energy and distributed generation are expected to play a greater role. This report examines the investments that might be made between 2010 and 2030 in Canada's electricity generation, transmission, and distribution industries.

CONTENTS

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EXECUTIVE SUMMARY

Canada's Electricity Infrastructure
Building a Case for Investment

At a Glance

- The Canadian electricity sector contributed $24.6 billion to Canada's economy in 2010 and employed 116,000 workers.
- The electricity sector is expected to invest $293.8 billion from 2010 to 2030 to maintain existing assets and meet market growth. Expected investments are $195.7 billion in generation, $35.8 billion in transmission, and $62.3 billion in distribution.
- The average annual investment of $15 billion is higher than in any previous decade. Investment must accelerate to accommodate a changing generation mix and changing market requirements, and to replace or update aging assets. Half of Canada's generation stations were built prior to 1980.

This report analyzes the current state of Canadian electricity infrastructure and determines the level of future investment required to meet electricity needs through 2030. It looks at the provincial investment plans in electricity generation, transmission, and distribution and compares them with future electricity demands and export plans.

Electricity is an important part of the Canadian economy. Existing trade with the United States market provides many economic benefits and continues to provide reliable energy to both countries. Canadians enjoy some of the lowest energy prices among Organisation for Economic Co-operation and Development (OECD) countries[1] and rely mostly on renewable or low-emission energy sources. Currently, the electricity sector faces major investments in new infrastructure, as many facilities are about to be retired or refurbished. In addition, the recent focus on green energy has also influenced investment actions. The majority of investments in the sector will be in electricity generation; however, transmission and distribution will also see significant investments in infrastructure.

Going forward, there are investment requirements of $293.8 billion in electricity infrastructure in Canada between 2010 and 2030. A large amount of spending is estimated to be on generation facilities that will replace old stations and add to renewable energy capacity.

The historic investment in the electricity sector has varied over the years, with periods of high investment in the 1970s and 1980s. Recently, the sector has once again seen growth in the investment levels. The Canadian electricity sector contributed $24.6 billion to the Canadian

1 Organisation for Economic Co-operation and Development, "OECD Economic Survey."

economy in 2010 (2 per cent of total GDP) and employed 116,000 workers. It is a net exporter of electricity, with exports totalling $2.3 billion in 2010. Although the sector has recently seen a significant increase in investment levels, it has not resulted in as large an increase in the productive capacity of the sector. This is due to a declining average life expectancy of capital, an increasing investment share in short-lifespan information technology, and a push toward renewable technology. Overall, the investment opportunities are currently at a high level, but the focus of investment areas has shifted.

To determine the generation investments between 2010 and 2030, a thorough web search was first performed to identify publicly owned and private generation facilities. The list was then verified using a literature review and key contacts. Next, the retirement and refurbishment dates were identified to indicate the future investment paths of the facility. After identifying all units that are operational, under construction, planned, or proposed, the estimated capacity was compared with the future market requirements. Market requirements were identified using the National Energy Board long-term outlook and the net trade capacity calculated for each province. Once the timing of the proposed projects was adjusted and future capacity requirements were determined, capital costs were applied to all generation projects and the total generation investment requirements were calculated. Transmission investment plans were calculated based on company long-term plans, system operator long-term plans, and regulatory filings. Distribution investment requirements were calculated for sustaining and growth requirements of the companies that own delivery infrastructure. The calculations were based on regulatory filings, regulatory summaries, company annual reports, and company capital plans.

Generating capacity under construction or in advanced stages of planning was found to be 17,427 megawatts. Quebec had the largest capacity at 5,238 megawatts (MW); Ontario, the second largest at 3,839 MW; and Alberta, the third at 2,636 MW. For the proposed generating capacity, Ontario was found to have the greatest number of proposed projects at 11,572 MW, Alberta was second at 7,543 MW, and British Columbia was third at 4,258 MW of proposed projects. The majority of the proposed projects in Canada are accounted for by renewable low-emission sources. Finally, the generation investments that Canada is facing total $195.7 billion (2010 dollars), with almost 60 per cent of that going toward new construction. Ontario faces the largest requirement of almost $60 billion; Alberta, the second largest at $44 billion; and Quebec, the third largest at $29 billion. These investments reflect refurbishment/retirement costs and the renewable energy Feed-in Tariff (FIT) program in Ontario; oil sands expansion and coal retirement in Alberta; and new hydro, new wind projects, and hydro refurbishment for Quebec.

The transmission investments identified in this report are likely to be underestimated, as few public documents identify the transmission investment plans, and some transmission requirements associated with new generation projects have not been identified. Overall, Canada faces $36 billion (2010 dollars) in transmission investments, with Alberta having the highest investments of almost $17 billion; Ontario, the second highest at $5 billion; and British Columbia, the third highest at $4 billion. In general, Canada has a north–south transmission network that connects with the United States. These interconnections play an important role in the electricity trade between the two countries and, currently, there are three major interconnections under development.

Canada faces $62 billion (2010 dollars) of distribution investments over the next 20 years. This includes sustaining and growth investments. Quebec has the highest requirement at $22 billion, Ontario faces $21 billion, and Alberta is third at $11 billion. Increasing levels of distributed generation use, smart grid developments, and changing electricity requirements will all affect future distribution investments.

The investment requirements of $293.8 billion averages just under $15 billion per year, which is significantly higher than the levels of investment in previous decades. The investments outlined in this report are driven largely by the replacement and refurbishment of aging infrastructure and implementation of renewable generation. Environmental regulations also play a significant role in the investment structure. Federal and provincial assessments protect environmental resources and determine the projects' future developments.

CHAPTER 1

Introduction

> **Chapter Summary**
>
> - This report considers the electricity infrastructure investment that will be required to maintain or enhance service quality while expanding to meet the needs of a growing market.
> - The electricity sector faces an infrastructure deficit, as do other essential services in Canada.
> - In addition to replacing aging assets, investment will be required to accommodate a changing generation mix and changing market requirements.

OVERVIEW

The main focus of this report is to study the current state of Canadian electricity infrastructure and analyze future investments that will be required to meet the electricity needs of Canadians through 2030. This is a particularly interesting period of time, as there are a range of important challenges facing the electricity sector in Canada. Electricity has long been a reliable source of energy for our businesses and homes. Now it needs important attention to renew infrastructure that was largely built to respond to post-war growth. Some hydro facilities were even built in the early 1900s. There are also aspirations to increase power exports to the U.S. and neighbouring provincial markets, which require additions to generation and transmission infrastructure. And finally, building all of this infrastructure is taking place alongside the need to minimize the environmental impacts of the economic activity.

The main focus of his report is to study the current state of Canadian electricity infrastructure and analyze future investments that will be required to meet the electricity needs of Canadians through 2030.

This report looks at the provincial investment plans in electricity generation, transmission, and distribution and compares them with future energy demands, export ambitions, and environmental regulations. We have looked at the investments from the perspective of those required to sustain and renew the existing infrastructure and those required to accommodate anticipated growth in provincial energy demand plus exports. Most provinces also have plans to add generation capacity from renewable sources such as wind or solar energy. Those provinces that use coal face pending federal regulations that will further impact the generation mix. Several provinces also see value in managing demand growth through demand-side management programs, and are studying the potential for smart grid investments to support the behavioural shifts in energy use requirements. Some have taken steps in that direction by installing smart meters.

Chapter 2 provides the summary of the methodology employed. Chapter 3 discusses the historical context for electricity investment in Canada. Chapters 4, 5, and 6 present the investment requirements for generation, transmission, and distribution, (respectively) together with some discussion of the key results and sensitivities. Chapter 7 presents some conclusions.

Since the 1980s, infrastructure underinvestment has put a strain on existing facilities and their deteriorating state has prevented innovation development and growth.

BACKGROUND

Infrastructure in Canada is currently under pressure, as many facilities are old and need to be retired or refurbished. This is true of the infrastructure that delivers a broad range of services to the public—transportation, water, electricity, and other forms of energy. A 2003 Statistics Canada study found that many components of government-owned infrastructure have passed their service life: wastewater treatment facilities have 63 per cent of their service life behind them, roads and highways 59 per cent, sewer systems 52 per cent, and bridges 52 per cent.[1] Many analysts have pointed to a growing infrastructure investment deficit resulting from historical investments that have not kept pace with the level required to keep infrastructure in peak condition. Because of this investment deficit, refurbishment and maintenance costs are escalating for many forms of infrastructure.[2]

Beginning in the 1980s,[3] underinvestment in infrastructure has put a strain on existing facilities and their deteriorating state has prevented innovation development and growth.[4] As infrastructure comes to the end of its operational life, there is a strong need to rebuild and invest in new facilities as refurbishment costs grow.

The electricity sector is no different. The North American power system is experiencing failures due to old and unreliable equipment. The northeast blackout of 2003 demonstrated the fragility of the power system and the need for system upgrades and better standards of operation. The Canadian electricity sector faces the need for upgrades and new facilities as power demand increases across the country.

The infrastructure deficit has been linked to low prices. Clearly there is a trade-off between prices that support industry growth and keep essential services affordably priced, and prices that permit timely renewal and expansion investments. Canadian electricity prices are among the lowest in the Organisation for Economic Co-operation and Development (OECD). This is attributed to our reliance on hydro-electric power, the lower cost of capital that is faced by government-owned firms, and regulated tariffs.[5] In addition, provinces have been restructuring in order to create lower electricity costs, be more responsive to changing market needs, and meet open-access regulatory requirements and maintain access to U.S. transmission facilities to facilitate trade.[6] As a result, electricity users benefit from low prices. The provinces that have hydro-generating facilities, namely British Columbia, Manitoba, and Quebec, enjoy the lowest prices for electricity.[7] And while generation costs are among the biggest factors affecting electricity prices, customer services costs, transmission costs, and distribution costs also play a role in the price of electricity. These factors are affected by population density and geography.

Moreover, thanks to trade with the U.S., the Canadian electricity industry has a great opportunity to be a strong and competitive industry. The sector benefits from existing transmission lines running across the border. Overall, Canada exports between 7 and 9 per cent of its power generation and is a net electricity exporter.[8]

1 Gaudreault and Lemire, "The Age."

2 Canadian Council for Public-Private Partnerships, "Infrastructure Investment."

3 Félio, "Managing."

4 Ontario Ministry of Finance, *Ontario's Long-Term Report*.

5 Organisation for Economic Co-operation and Development, "OECD Economic Survey."

6 Government of Canada, *Economic Scan*.

7 Ibid.

8 Ibid.

To maintain its competitive status, the Canadian electricity sector must ensure its reliability as " . . . in most areas of Canada, the expansion and strengthening of the transmission system continues to lag behind the growth in electricity demand and the expansion of generation capacity."[9] To stay competitive, the industry needs to follow the U.S. lead; invest in infrastructure; generate favourable rates of return; and make use of effective policies, regulatory efficiency, and customer education[10] to create a reliable market.

New government policies aim to promote new energy sources and greener technologies. These policies ensure a favourable environment for investment in new, renewable energy sources, thereby promoting new infrastructure. For example, Canada's Economic Action Plan includes the Clean Energy Fund, a five-year, $795 million program to support clean energy technology research.[11] Similarly, Ontario has introduced its Feed-in Tariff (FIT) program to encourage investment in renewable generation based on wind, solar, hydro, and biomass energy sources.

> The programme has prices that are intended to cover total project costs and provide a reasonable rate of return over a 20-year contract (40 years for waterpower), provides a straightforward way to obtain a contract for renewable electricity generation, and is open to various renewable energy technologies: biogas, biomass, landfill gas, solar photovoltaic (PV), wind and waterpower. The scheme has different prices for different technologies and different project sizes and includes domestic content requirements. The programme provides specific incentives for Aboriginal projects as well as for community-based projects.[12]

9 Government of Canada, *Economic Scan*, 87.

10 "Electricity and the Energy Challenge."

11 Natural Resources Canada, "Clean Energy."

12 International Energy Agency, "Ontario Feed-in Tariff."

Other provinces have implemented policies and programs to encourage growth in renewable energy. Many of these programs are linked to their climate action plans and are intended to reduce greenhouse gas emissions. Most of these renewable energy sources are intermittent in nature. Wind and solar, for example, generate electricity based on the forces of nature. The power is generated upon the availability of sun or wind, rather than when the market requires the energy. This means that investments must be made to integrate the power into the grid and to provide storage, backup, and power quality support.

New government policies ensure a favourable environment for investment in new, renewable energy sources.

The current focus on developing and implementing a "smart grid" is another factor that influences the level of investment in electricity infrastructure. Ontario has recently required that all residential and small commercial customers, regardless of location or size, have smart meters installed. These meters allow the end customer greater access to information that can be used to optimize energy consumption based on real-time pricing (although time-of-use pricing is currently limited to only four time periods with three rate levels). Smart meters can also accommodate two-way metering for those customers that own generation capability (most often roof-top solar panels). This level of load management and distributed generation places additional responsibilities on the other market participants, including distribution companies, transmission companies, and the grid operator.

This report considers the investments that are pending in each of Canada's provinces and territories to ensure that electricity infrastructure continues to operate in a safe, reliable, and cost-effective manner while responding to changes in market structure, changes in generation options, and growth in electricity requirements for domestic and export markets.

CHAPTER 2

Methodology

Chapter Summary

- Generation assets were categorized as operating, under construction, at an advanced planning stage, or proposed. Information was gathered for identified projects.
- Generation projects were compared with anticipated market demand as a means of determining how much new capacity would be built. Unit retirements or repowering were also considered, based on the age of the asset.
- Transmission investments are based on published long-term plans.
- Distribution investments are based on the requirements to sustain existing assets, as well as those to serve anticipated market growth.

PURPOSE

The main focus of this report is to study the current state of Canadian electricity infrastructure and analyze future investment plans and their ability to meet the electricity needs of Canadians through 2030. The report looks at the provincial investment plans in electricity generation, transmission, and distribution and compares them with future energy demands. For generation, the analysis also draws on publicly available data on announced capacity additions, using corporate plans, system operators' reliability reports, and government reports.

To assist in the evaluation of the projects for investment purposes, the projects were categorized as "Under Construction," "Under Development" (have regulatory approvals and are at advanced stages of planning), and "Proposed" (where little more than a public announcement may be all that has been done). Corporate websites of the proponents and independent system operators were relied on heavily to assist in assigning the projects to the categories.

Distribution investments include those needed to maintain and replace assets and accommodate growth.

For transmission investments, the announced plans are often based on a shorter planning horizon. The methodology must consider the time frame and level of investment identified. Transmission investments are also dependent on which generation projects actually proceed, as well as where they are located. Finally, transmission investments depend on the pace and location of load growth.

Distribution investments include those required to maintain and replace assets, as well as those to accommodate growth. The large number of distribution companies and lack of consistent planning horizon make this component of electricity infrastructure more difficult to examine at a project level. Distribution system investments are estimated based on factors such as historical replacement of depreciating assets and projected load growth within each province.

EVALUATION DOMAINS

In order to assess the state of electricity infrastructure in Canada, this report looks at three main components of the sector: electricity generation, electricity transmission, and electricity distribution. All three components make up the electricity sector in Canada.

The analysis is done on a provincial basis, due to differences in organizational structure and ownership between provinces. However, Canada's provinces and territories regulate distribution rates through public utility boards that oversee distribution companies that have a monopoly within a geographic franchise. In most cases today, the franchise relates to the assets required to deliver power to the consumer, while the source of electricity is a matter of choice. Electricity generation and transmission can be provided through a large public entity or be produced by a more competitive, bid-based system as is found in Alberta and Ontario.[1]

The generation facilities across Canada include various generation sources such as hydro, conventional steam, nuclear, internal combustion, combustion turbine, wind, and tidal, with hydro being the largest.[2] The transmission network has a north–south direction and runs south to the United States.[3] The transmission lines are essential for electricity delivery, especially to the U.S. market. They also play a key role in interprovincial trade and ensure overall system reliability.

EVALUATION APPROACH

GENERATION

To assess the state of generation infrastructure in Canada, a list of current generation projects in each province and territory was compiled. This was done through an exhaustive web-based search producing an extensive listing of all generation assets across Canada and a database of future projects. Publicly owned and independent producers were both included in the search. To the extent possible, large on-site interconnected generation was also tracked in the database; however, the list of generating facilities at industrial sites across Canada can by no means be seen as exhaustive.

The following information was gathered for each generating facility: project name, owner organization, total facility nameplate capacity (MW), initial year of operations, primary energy source, project cost, and retirement year (if applicable and/or available). This information gave us a starting point to determine existing generation assets across Canada.

The generation facilities across Canada include various generation sources such as hydro, conventional steam, nuclear, internal combustion, combustion turbine, wind, and tidal, with hydro being the largest.

The next step was a similar search, but for projects that are either proposed, under development, or under construction. The list was verified using a second round of literature review and information gathering from key contacts at power companies. In a few instances, a province's major projects inventory list was used to identify electricity generation projects currently under way. Once again, the following information was collected on publicly owned and independent power producers: project name, owner organization, total nameplate capacity (MW), initial year of operations, primary energy source, and project cost. For the new projects, a literature review was used to identify the likelihood of a project going forward.

Although the average age of generation facilities varies among provinces, and units are constantly being updated, half of Canada's operating stations came into service before 1980.[4] Given the age of the generating fleet in Canada, an important consideration was evaluating the potential retirement of generating facilities. Retirement announcements are rather sparse, and so an assessment

1 Government of Canada, *Economic Scan.*

2 Canadian Electricity Association, "Electricity Generation."

3 International Energy Agency, "Ontario Feed-in Tariff."

4 Based on the information gathered for this report. Additional detail is presented in Chapter 3.

methodology was employed using an estimate of the useful economic lives, presented in Table 1. To obtain a forecast of the retirement or refurbishment date, the useful life was added to the commissioning date, or date of last substantial refurbishment.

Table 1
Assumptions Used for Generation Retirement or Repowering

Energy source	**Estimates of useful economic lives** (years)
Coal	40
Natural gas/biomass	25
Hydro	50
Wind	20
Solar	20
Nuclear	25

Source: The Conference Board of Canada.

At the retirement date, an assessment was made as to whether the plant would be retired or refurbished. Unless a retirement was announced, it was assumed that—for natural gas, hydro, wind, solar, and nuclear—facilities would be refurbished. Natural gas systems are modular and easily replaced, taking advantage of the existing substations, transmission, pipelines, and building. With wind, there is little experience with refurbishments in Canada, but industry sources suggest it should only require expanding the bases and replacing the old turbines with new ones, and the existing electric delivery can be assumed to be utilized. Solar systems primarily retire outside of the time period of this report, but these too are relatively modular.

Whether nuclear and coal facilities were retired or refurbished depended on provincial policies and the business analyses of the proponents. Wherever available, government policy and proponent announcements on the retirement or refurbishment plans were relied on. When no announcements were available, we assumed that refurbishments were undertaken.

For the costs of the refurbishments or repowering, we assumed for natural gas, wind, and solar that the costs were 90 per cent of the new-build costs, because the existing building structures, fuel supply, and electrical distribution and transmission systems are used.[5] For nuclear, the costs published by the facility owners were used.

For coal, there were a few options: convert to biomass or natural gas, continue to use coal, continue to use coal with carbon capture and storage process applied to it, or retire. The costs of carbon capture and storage depend on the age of the facility, but it was estimated that applying such a process to the new coal-fired plant would increase the generated electricity costs by between 37 and 91 per cent.[6] The conversion costs of biomass and natural gas are not well-documented, but it is clear that the costs of conversion are vitally dependent on the accessibility of biomass and natural gas. From the few publicly available costs provided, it appears that the difference in costs is about 90 per cent of a new build.

Not all generation projects proceed to construction, as competition or regulatory processes reduce the list.

BALANCING SUPPLY AGAINST DEMAND

The total generation capacity from existing units, units under construction, planned units, and proposed units far exceeds the future market requirement for most provinces. This is not to suggest that generation is being over-built. It is simply that, in any market, as a need for new generation is identified, numerous projects are proposed. Not all of these projects proceed to construction, as competition or regulatory processes reduce the list. As a result, quantifying future investment in generation capacity requires a cross-check against forecasted demand, as well as some judgment regarding which generation technologies will be adopted. For example, provinces like Alberta, Saskatchewan, and Ontario, which have primarily thermal baseload generation systems, face limits with respect to additional wind or solar capacity that can be integrated.

5 This is based on a small sample of recent repowering projects. Given the changes that have occurred in generation technologies, repowering is able to take advantage of an existing site, but must replace virtually all of the facilities on the site.

6 Beauregard-Tellier, "The Economics."

The first step in the methodology was to generate a complete list of all existing and planned generating capacity. This list was adjusted to account for capacity retirements as indicated above. Once the total capacity for each technology in each province was determined, the energy output was calculated to give an estimate of the total energy that would be produced if all projects were implemented.

Transmission investments estimates are based primarily on data from company long-term capital plans, system operator long-term expansion plans, and regulatory filings.

The next step was to determine the total energy that will be required in each province. The starting point for electricity demand was the current reference case long-term outlook produced by the National Energy Board. That outlook ends in 2020, so the 2010–20 growth rate was applied to estimate energy demands for the subsequent decade. Statistics Canada's annual data series on total interprovincial receipts on electricity, total imports of electricity from the United States, total interprovincial deliveries of electricity, and total exports of electricity to the United States were used to determine net electricity trade for each province. The current level of trade (2009) was held constant through the future—except where there have been expansion policies to support expanding trade flows.

Comparing the energy that might be generated, based on the list of projects, with the energy required (including net trade) provided an estimate of the surplus or deficit of electric energy in each province in each year. This energy surplus was converted to a reserve margin using the weighted average capacity factor.

The final step in estimating generation capacity requirements was to adjust the timing of proposed projects (the category with the least certainty that projects will proceed). These adjustments were made based on the market requirements, provincial policies regarding renewable generation, the ability of the grid to integrate additional intermittent power sources, etc. The adjustments were made to maintain a reserve margin that is adequate to accommodate future growth, including potential increases in exports for provinces targeting export markets.

Once the level of future capacity was determined, capital costs were applied to all generation projects whether existing or proposed. In some instances, the costs were publicly available and were thus used for the projects that had them. For the majority of cases, however, the costs were not published. In those cases, generic costs were applied for each technology. In addition, the costs of refurbishment or repowering at the end of the useful life of each station, and the cost of retirement for stations that will be taken out of service, were applied. These costs were based on estimates gathered from recent projects and are applied at the end of life, as shown above. The sum of refurbishment/repowering, retirement, and new-build costs was then calculated as the investment in generation facilities that will be required.

TRANSMISSION

Transmission investments are estimated based on data from three primary sources: company long-term capital plans, system operator long-term expansion plans, and regulatory filings. This approach is somewhat problematic in that the plans have different time horizons and may not align perfectly with the generation options identified. However, a more detailed review is beyond the scope of this report. Simple extrapolation beyond the end of published plans is not useful, given that transmission investments are very project specific.

The first step in the methodology was to generate a complete list of all existing and planned generating capacity.

For most provinces, the transmission companies publish long-term capital plans that cover a period of between 5 and 20 years forward. In Alberta, the Alberta Electric System Operator (AESO) publishes a long-term system plan. In Ontario, the government recently published *Ontario's Long-Term Energy Plan: Building Our Clean Energy Future*, which identifies the total transmission investment required. The Ontario Power Authority (OPA) is in the process of preparing an updated long-term plan, so their transmission investment expectations are not yet public. The recently issued long-term energy plan includes $9 billion of transmission investments. The preceding Integrated Power System Plan (IPSP) provides some additional detail about future investment projects and requirements for the projects that had been announced up to 2007. In Alberta, there are also a number of regulatory filings for near-term projects. The transmission estimates in this report represent a compilation of investment plans and understate the future investments that are likely to take place, because they do not all cover the entire period through 2030.

Electricity distribution investments can be segmented between those that are required to sustain delivery capacity and those required to accommodate growth.

DISTRIBUTION

The electricity distribution sector refers to those companies or organizations that own and operate facilities to transmit electricity from transmission companies to retail consumers. It therefore excludes service providers that provide energy but do not own delivery infrastructure. Some companies involved in rural distribution or providing services in smaller communities also have transmission assets. The division between transmission and distribution activities is somewhat arbitrary—we have accepted the division as represented in annual reports and regulatory filings.

The methodology used to measure distribution investments is based on information from regulatory filings, regulatory summaries, company annual reports, and company capital plans. Ontario publishes an aggregated report of key electricity distribution statistics. Alberta requires distribution companies to file financial and operating data annually in a pre-determined format. For other provinces, annual reports and company capital plans provide an incomplete picture.

Electricity distribution investments can be segmented between those that are required to sustain delivery capacity and those required to accommodate growth. For sustaining investments, the starting point is an estimate of historical investments and annual depreciation expenses. Given that this is a regulatory matter for most companies, the depreciation rate is reasonably certain and reasonably consistent across distributors. The level of gross or net plant in service per gigawatt hour (GWh) of energy delivered is also fairly consistent within each province. Real investment in sustaining capacity can therefore be estimated based on a cumulative calculation of assets in service and depreciation. Investment in growth capacity can be calculated based on growth in internal demand for each province, plus an assumption regarding assets in service per GWh of energy delivered.

CHAPTER 3

Capital Stock, Investment, and Production

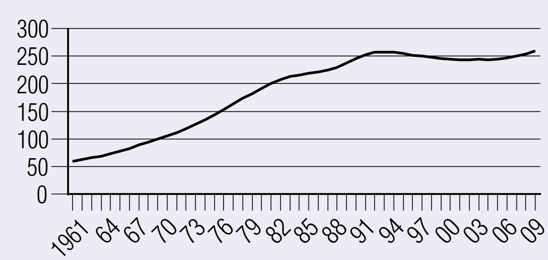
Chapter Summary

- Canada's electric power generation capacity grew at a phenomenal pace over the 1960s and 70s, averaging 6 per cent per year—but the pace of expansion slowed to 2.9 per cent annually over the 1980s and has averaged a lowly 0.5 per cent per year over the 1990s and 2000s.
- The contribution of electric power to our overall energy use increased sharply until the mid-1980s, but has remained relatively constant thereafter—accounting for a steady share of about 25 per cent of our domestic energy use.
- A growing share of investment, up two-thirds in recent years, has been required to replace and repair aging infrastructure.

CAPITAL STOCK GROWTH SLOWS

Data compiled by Statistics Canada suggest that growth in the productive capacity of Canada's electric power industry has slowed markedly in recent years. Chart 1 displays the inflation-adjusted levels of capital stock in the electric power industry—estimated at about $60 billion (in 2002 dollars) in 1961 and reaching just over $260 billion in 2010. Growth in the productive capacity of electric power generation was phenomenal over the 1960s and 70s, averaging 6 per cent per year; but the pace of expansion slowed to 2.9 per cent annually over the 1980s and has averaged a lowly 0.5 per cent per year over the 1990s and 2000s (even posting declines over the 1995–2005 period). Part of the reason for the slowdown can be attributed to the reduction in energy intensity that our economy has undergone in recent decades. Estimates of total energy used in Canada suggest that the amount of energy per unit of GDP has been declining sharply, from about 10.6 megajoules per unit of real GDP in 1978 to 6.4 in 2009. This decline in energy intensity suggests that even as real GDP has continued to expand, growth in demand for energy has been much weaker, averaging just 0.8 per cent per year over

Chart 1
Productive Capital Stock: Electric Power Industry
(2002 $ billions, hyperbolic end-year net stock)



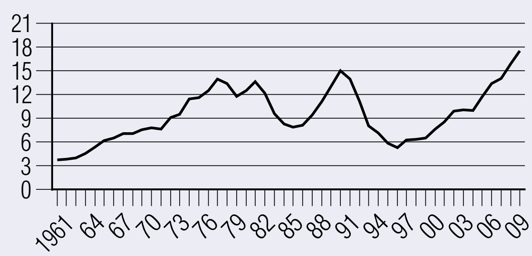
Note: Various depreciation methods are available from Statistics Canada to estimate the value of capital stock by industry sector. In this report we rely on hyperbolic depreciation because we feel that this measure best captures the productive capacity of the assets.
Source: Statistics Canada, Table 031-0002.

the 1978 to 2009 period.[1] And, while the contribution of electric power to our overall energy use increased sharply until the mid-1980s, it has remained relatively constant thereafter, accounting for a steady share of about 25 per cent of our domestic energy use.

In the 1960s, the average life expectancy of new capital surpassed 55 years; but life expectancy has steadily eroded over the past half century to less than 25 years—a sharp cut compared with other industry sectors.

The soft growth in electric power infrastructure that has occurred since the 1990s is due, of course, to weaker levels of private and public capital investment. The lower level of investment through the decade was partly a result of over-built generation capacity from the previous decades. In real terms, annual capital investment peaked in 1991 at over $15 billion, but then fell rapidly to just $5.3 billion in 1997. (See Chart 2.) Over the last five years, capital investment in the sector has been reinvigorated, rising steadily to reach and surpass the $15 billion mark in 2009 and 2010. However, while investment levels have been elevated in recent years, they no longer contribute as significantly to boosting productive capacity. This is because the average life expectancy of capital in the electric power generation sector is being steadily eroded. Information technology and other machinery comprise a growing share of total capital investment.

Chart 2
Investment: Electric Power Industry
(2002 $ billions)



Source: Statistics Canada, Table 031-0002.

1 Comparable data are available only over these years.

Because these assets have a shorter lifespan, they need to be replaced more quickly. This, together with a push toward renewable technology—which is more costly to build and maintain—is dampening the growth in total productive capacity despite the loftier investment levels.

Another way to think about this is to look at the service life and depreciation rates of investment in the industry. In the 1960s, the average life expectancy of new capital surpassed 55 years; but life expectancy has steadily eroded over the past half century to less than 25 years—a sharp cut even in comparison with other industry sectors. (See Table 2). The shorter life span of capital implies higher depreciation. For example, of the $17.5 billion in capital investment generated by the industry in 2010, roughly two-thirds was required to repair or replace retired capital, such that the net addition to productive capital was only $5.5 billion in that year.

The average life expectancy of capital in the electric power generation sector is being steadily eroded.

Corroborating these estimates is the rapid rise in capital investment that is going toward repairing existing and aging infrastructure. Annual spending on repairs by the electric power generation industry has shot up in recent

Table 2
Service Lives of New Capital
(number of years)

	1962	1985	2010
Electric power industry	55.6	43.0	21.3
Manufacturing	18.5	13.6	8.1
Mining, excluding oil and gas	18.4	13.8	11.9
Oil and gas extraction	29.9	17.3	14.2
Natural gas distribution	45.4	32.2	19.2
Transportation	26.2	21.9	12.9
All industries	25.3	19.7	11.5

Sources: Statistics Canada; The Conference Board of Canada.

years to average nearly $3 billion in 2007 and 2008 (in real 2002 dollars)—nearly double the levels averaged over the decade spanning 1994 to 2003.[2]

While the lion's share of production is intended for domestic use, Canada is a net exporter of electric power.

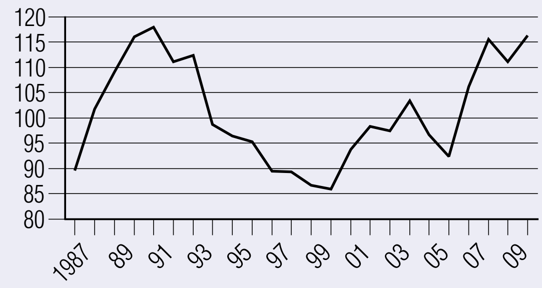
ELECTRIC POWER INDUSTRY CONTRIBUTION TO CANADA'S ECONOMY AND EMPLOYMENT

Electric power is mostly thought of as an input to industrial, commercial, and household use. Still, the industry creates its own value-added, mostly through wages and profits. Aligning with the growth in capital stock, output of electric power has stabilized in recent years, with Canadian production averaging roughly 444.4 million MWh in recent years.[3] In inflation-adjusted terms, the industry directly contributed about $24.6 billion to the Canadian economy in 2010 (2 per cent of total GDP) and employed 116,000 workers. (See Chart 3.) The total employment trend shown in Chart 3 follows a similar trend to capital investment, with a peak in the late 1980s, a decline through the late 1990s, and a subsequent increase. In addition, while the lion's share of production is intended for domestic use, Canada is a net exporter of electric power. In 2010, real net exports of electric power were worth $2.3 billion. Over the past decade, net exports have varied from just under $1 billion to almost $3.5 billion as economic and market conditions have changed. The average since 2000 has been $1.8 billion per year.

2 Data based on Statistics Canada's Private and Public Investment Intentions survey. These data were available only for the 1994 to 2008 period and were converted to real 2002 dollars using the national non-residential construction deflator.

3 Over the 2005 to 2009 period, production averaged 454.4 million MWh, but had peaked at 468.3 million MWh in 2008. Source is Statistics Canada tables 128-0002 and 128-0009.

Chart 3
Employment: Electric Power Industry
(000s)



Source: Statistics Canada Labour Force Survey.

The Electricity Sector Council has published detailed analyses of the historical and future employment requirements of the industry.[4] Their work points to several challenges that are not evident in the high-level data:

- meeting the challenge of recruiting workers with skills that are in short supply;
- transferring knowledge from an older, experienced workforce prior to its retirement;
- engaging youth as they begin their college or technical training; and
- retaining the existing skilled workforce.[5]

Average weekly earnings in the electricity sector have been significantly above average since 1990, making it attractive to potential employees.[6] Sector employees are generally well-educated, and employed in occupations that are directly related to that education. Employment is projected to increase by between 500 and 1,000 persons per year.[7]

4 See www.brightfutures.ca.

5 Electricity Sector Council. *Labour Market Demand.*

6 Ibid., 14.

7 Ibid., 31.

CHAPTER 4

Generation Investments

Chapter Summary

- With regard to generating capacity under construction or in advanced stages of planning, Quebec has the largest capacity at 5,238 MW; Ontario, the second largest at 3,839 MW; and Alberta, the third at 2,636 MW.
- Regarding the proposed generating capacity, Ontario has the largest number of proposed projects at 11,572 MW; Alberta, the second largest at 7,543 MW; and British Columbia, the third largest at 4,258 MW. The majority of the proposed projects in Canada are renewable or low-emission sources.
- The generation investments that Canada is facing total $195.7 billion (2010 dollars). Ontario faces the largest requirement of almost 60 billion, while Alberta has the second-largest requirement of 44 billion, and Quebec has the third largest at $29 billion.

CANADIAN OVERVIEW

This chapter reviews Canada's electricity generation capacity and the investments that will be required between 2010 and 2030 to maintain the current high level of service to end customers while accommodating growth in the domestic and export markets.

Canada has always had a strong reliance on renewable and low-emitting sources of electricity. As Table 3 shows, 67.9 per cent of currently operating capacity is either renewable energy or low emission, with 57 per cent of operating capacity accounted for by renewable energy. The energy mix varies substantially, with British Columbia, Manitoba, Quebec, and Newfoundland and Labrador's energy generated predominantly by hydroelectric systems. Alberta, Saskatchewan, Nova Scotia, and New Brunswick depend heavily on fossil fuels. Wind accounts for only 3.3 per cent of total installed capacity, and an even smaller share of energy generated, but has shown impressive growth in the past decade.

This chapter reviews Canada's electricity generation capacity and the investments required between 2010 and 2030 to maintain the current high level of service to end customers while accommodating market growth.

Table 4 summarizes generating capacity that is under construction or at advanced stages of planning as represented by project developers. Projects at the advanced planning stage typically have all of the necessary approvals—most with power purchase agreements—and have established a construction timeline. Advanced projects represent projects with the highest expectation that they will proceed to construction, although possibly at different timelines once construction begins.

Table 3
Existing Generation Capacity, by Province
(MW)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	N.S.	N.B.	N.L.	P.E.I.	Y.T.	N.W.T.	Nun.	Canada
Coal	0	6,232	1,682	339	4,227	0	1,232	516	0	0	0	0	0	14,228
Nuclear	0	0	0	0	11,356	675	0	635	0	0	0	0	0	12,666
Large hydro	13,626	1,040	840	5,043	8,078	25,208	342	932	6,630	0	70	0	0	61,809
Natural gas	1,377	5,308	1,523	129	9,219	1,402	415	348	81	0	0	0	0	19,802
Biomass	305	266	0	0	126	52	27	45	15	0	0	8	0	842
Landfill or biogas	1	0	0	0	0	0	0	0	0	0	0	0	0	1
Diesel	46	0	0	10	0	66	0	527	56	67	0	0	54	825
Fuel oil	46	0	0	0	0	66	222	1,387	500	112	0	65	0	2,398
Off-grid hydro	2	0	0	0	0	0	0	0	0	0	0	0	0	2
Small hydro	161	10	13	0	271	21	56	18	95	0	6	0	0	651
Waste heat	12	0	0	0	0	660	50	0	54	0	0	55	0	831
Wind	104	780	172	104	1,363	681	284	195	54	167	1	0	0	3,905
Wind, offshore	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	113	0	0	0	0	0	0	0	0	113
Other/unknown fuel	0	0	0	0	7	0	20	0	0	0	0	0	0	27
Subtotal	**15,679**	**13,636**	**4,230**	**5,625**	**34,760**	**28,830**	**2,648**	**4,602**	**7,485**	**346**	**77**	**128**	**54**	**118,100**

Source: The Conference Board of Canada.

Most of these projects are expected to come into service by 2015, and all of those that proceed will be operating by 2020. The nuclear capacity shown is for refurbishment rather than new build. Hydropower represents 44.7 per cent of the capacity shown in the table, suggesting that Canada's overall reliance on hydro capacity will decline. Wind power is expected to double its installed capacity. Natural gas represents the third-largest contributor to this category. The values shown in Table 4 are based on information extracted from project databases, corporate websites, and government sources. Individual projects have been verified to ensure the most current available information has been used, although errors or omissions are possible due to the large number of projects and the limited availability of information for some projects.

Table 5 presents an aggregation of generating capacity by province for potential additions from projects that have been planned or proposed. Some of these projects have timelines associated with them, but many do not. Much of this capacity is unlikely to proceed through the remaining planning stages, into construction, and eventually to operations. The level of proposed wind capacity, in particular, exceeds the level that the market will require in both Alberta and Ontario. In the case of Alberta, the operating capacity plus projects under construction or at advanced planning stages totals 1,389 MW. The proposed capacity is an additional 5,190 MW. However, the system operator has identified 850 MW as the level of wind capacity that can currently be integrated into the system without causing operating problems. The primary issue

Table 4
Generation Capacity Under Construction or at Advanced Planning Stage
(MW)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	N.S.	N.B.	N.L.	P.E.I.	Y.T.	N.W.T.	Nun.	Canada
Coal	0	46	0	0	0	0	0	0	0	0	0	0	0	46
Nuclear	0	0	0	0	1,500	0	0	40	0	0	0	0	0	1,540
Large hydro	1,700	100	0	2,380	862	2,643	0	0	0	0	10	10	0	7,705
Natural gas	72	1,699	346	0	1,293	0	0	0	0	0	0	0	0	3,410
Biomass	138	82	0	0	42	0	60	0	0	0	0	0	0	322
Landfill or biogas	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Off-grid hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small hydro	51	0	0	0	0	29	0	0	0	0	0	0	0	80
Waste heat	0	100	0	0	0	0	0	45	0	0	0	0	0	145
Wind	545	609	25	138	78	2,566	100	54	0	0	0	0	0	4,115
Wind, offshore	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	64	0	0	0	0	0	0	0	0	64
Other/unknown fuel	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	**2,506**	**2,636**	**371**	**2,518**	**3,839**	**5,238**	**160**	**139**	**0**	**0**	**10**	**10**	**0**	**17,427**

Source: The Conference Board of Canada.

is that wind power ramps up or down very rapidly as the wind strengthens or dies down.[1] As a result, operating conditions suggest that much of the proposed capacity will not be installed, or will not be installed until operating issues can be overcome. It is also important to note that the transmission capacity required to integrate additional wind power and the necessary investment is not fully captured in this report. In Alberta's case, the transmission system reinforcements are at least partly quantified in the transmission system plan.

Similarly, in the Ontario market, the subtotal of installed wind capacity plus projects under construction or at advanced planning stages totals 1,441 MW. An additional 1,529 MW of wind capacity was offered FIT contracts in April 2010. A further 5,683 MW of wind capacity was placed in a queue to await decisions on enabler transmission lines. On February 24, 2011, OPA announced that FIT contracts had been offered to additional projects, of which four are large wind projects totalling 615 MW of capacity. The challenge for Ontario will be to find a level of wind capacity which, together with baseload generation, does not exceed market demand in low-demand hours. In Ontario's case, the transmission investments needed to integrate additional wind farms are included for projects under construction, but not for wind projects in the FIT program that were recently awarded contracts or that are still awaiting an Economic Connection Test.

The clear message is that with 84.4 per cent of proposed generation accounted for by renewable and low-emission sources of energy, Canada will continue to rely primarily on clean energy generation sources in the long-term future.

1 The ramp rate refers to the rate at which energy generated from a wind farm increases or decreases with changes in wind velocity. Offsetting changes in generation from other sources are often required to balance supply against demand with very short notice. In a primarily thermal system such as Alberta's, this can be a challenge.

Table 5
Generation Capacity Proposed
(MW)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	N.S.	N.B.	N.L.	P.E.I.	Y.T.	N.W.T.	Nun.	Canada
Coal	0	1,186	0	0	0	0	0	0	0	0	0	0	0	1,186
Nuclear	0	0	0	0	0	0	0	1,085	0	0	0	0	0	1,085
Large hydro	1,283	0	250	0	52	2,967	0	0	3,153	0	0	18	0	7,723
Natural gas	0	613	0	0	1,550	0	0	10	50	0	0	0	0	2,223
Biomass	0	0	182	0	77	0	60	5	0	0	0	0	0	324
Landfill or biogas	0	0	0	0	56	0	0	0	0	0	0	0	0	56
Diesel	0	0	0	0	0	0	0	0	0	0	0	0	5	5
Fuel oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Off-grid hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small hydro	0	0	0	0	293	0	0	4	0	0	0	5	5	307
Waste heat	0	0	0	0	0	0	0	0	125	0	0	0	0	125
Wind	2,875	5,190	275	495	8,143	145	520	437	0	350	0	0	0	18,430
Wind, offshore	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	100	0	0	0	0	0	0	0	0	0	0	0	0	100
Solar	0	0	0	0	1,401	0	0	0	0	0	0	0	0	1,401
Other/unknown fuel	0	554	0	0	0	0	0	0	268	0	0	0	0	822
Subtotal	**4,258**	**7,543**	**707**	**495**	**11,572**	**3,112**	**580**	**1,541**	**3,596**	**350**	**0**	**23**	**10**	**33,786**

Source: The Conference Board of Canada.

GENERATION INVESTMENTS

Several steps are necessary to estimate the level of investments that is likely to be required over the coming 20 years. Given the likelihood that proposed capacity additions exceed the capacity that might be required, one of the most important steps is to compare available capacity with projected demand. This requires several intermediate steps.

For each province, the existing generating capacity by fuel/technology is known, as is the electric energy generated. The capacity factor for each technology can be estimated using these data.[2] Adding the capacity from generating stations that are operating, under construction, or planned, gives an estimate of the total available capacity. Applying the capacity factors for each technology gives an estimate of the total energy that can be generated. This energy can be compared with market demand (adjusted for both interprovincial and international estimated net trade) to determine the reserve margin that results. The planned capacity that is included or excluded from analysis can then be adjusted to maintain a constant reserve margin through time. This yields a level of capacity additions for which investment requirements can be determined.

Before calculating the net capacity additions, it is important to account for facilities that will be retired or repowered at the end of their useful life. This is particularly important for coal-fired units, given that pending federal emissions regulations are expected to impose stringent limits on all new coal stations as well as all stations that reach the end of their useful life after 2015. The assumption used for this report is that coal stations that reach the end

2 The capacity factor is simply the energy generated by a facility as a share of the energy that could be generated if it operated at full capacity every hour of the year.

of their useful life will be repowered with clean coal or carbon capture and storage (CCS) technology to meet the federal emissions standard.[3] The exceptions are units that the owner has already announced will be retired. An alternative assumption might have been that the units are all retired and replaced with some other technology (with natural gas being a prime candidate).

Table 6 shows the generating capacity additions that have been examined for investment requirements based on the methodology described above. Table 6 can be compared with Table 3 to determine the impacts that capacity additions are projected to have on each provincial generation mix. The largest capacity additions are in Ontario, Alberta, and Quebec. Ontario faces a growing market as well as the need to replace coal units that the Ontario government declares will be retired by 2014. Alberta reflects growth in demand for oil sands projects, general market growth, and retirement of several coal units. While we generally expect that coal in the early years will be retired, we viewed that it is possible that, for the later part, coal will be refurbished: we expect the sizable coal reserves will change the dynamics between coal and natural gas prices and, along with advances in clean coal technologies, will tip the scale back toward coal. The additions in Quebec reflect the province's Northern Plan, which will likely include a mix of hydro and wind, as well as large-scale hydro capacity to meet

Table 6
Generation Capacity Included in Investments
(MW)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	N.S.	N.B.	N.L.	P.E.I.	Y.T.	N.W.T.	Nun.	Canada
Coal	0	1,376	0	0	0	0	0	0	0	0	0	0	0	1,376
Nuclear	0	0	0	0	3,500	0	0	40	0	0	0	0	0	3,540
Large hydro	3,223	147	250	2,380	862	3,350	0	0	3,153	0	10	10	0	13,385
Natural gas	72	4,163	346	0	4,243	0	0	0	50	0	0	0	0	8,874
Biomass	138	0	182	0	77	0	180	0	0	0	0	0	0	577
Landfill or biogas	0	0	0	0	15	0	0	0	0	0	0	0	0	15
Diesel	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Off-grid hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small hydro	51	0	0	0	306	29	100	0	0	0	0	0	0	486
Waste heat	0	100	0	0	0	0	0	45	125	0	0	0	0	270
Wind	1,595	1,159	242	138	2,178	2,666	970	454	0	130	0	0	0	9,532
Wind, offshore	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	100	0	0	0	0	0	0	0	0	0	0	0	0	100
Solar	0	0	0	0	964	0	0	0	0	0	0	0	0	964
Other/unknown fuel	0	0	0	0	0	0	0	0	268	0	0	0	0	268
Subtotal	**5,179**	**6,945**	**1,020**	**2,518**	**12,145**	**6,045**	**1,250**	**539**	**3,596**	**130**	**10**	**10**	**0**	**39,386**

Source: The Conference Board of Canada.

3 This represents a significant uncertainty in our analysis. The cost assumptions for clean coal are based on a very limited number of published estimates. The costs for CCS are largely unknown at this stage, as the technology has not been applied to a generating station in North America. We have used a conservative capital cost assumption to avoid overstating the required future investment in generation.

ambitions to grow export sales. Most of the addition in Newfoundland and Labrador is accounted for by the Lower Churchill project. If the project does not proceed as planned, the growth in capacity will likely be much smaller.

The final step in determining the investment that might be required for generation assets over the coming 20 years is to apply costs for refurbishment/repowering, retirement, and new capacity, to the appropriate categories. The resulting investments are summarized in Table 7.

The investment profile for Ontario also reflects a tighter reserve margin than for the other provinces.

Ontario faces the largest investment requirements at just under $60 billion. This represents 30 per cent of the total investment for Canada and matches almost exactly Ontario's share of current generating capacity. Ontario faces the short-term costs of retiring the remaining coal units, as well as the investments in renewable capacity under the FIT program. Nuclear refurbishments will add to near-term costs, as will new-build nuclear—assuming that the additional Darlington units are eventually built. If no additional nuclear capacity is constructed, other technologies will need to be expanded to meet future market demand. In the longer term, Ontario will face refurbishment costs for aging natural gas units and wind farms. The investment profile for Ontario also reflects a tighter reserve margin than for other provinces. However, Ontario has significant access to neighbouring provinces and the U.S. for meeting demand, so it could make up its deficit through trade. Barring expanding trade though, the investment requirements could be understated.

Alberta accounts for the next-largest investment requirement at $44 billion. Oil sands expansion continues, with associated electricity requirements and project-related generation capacity. Alberta must also replace several coal units that will be retired—most likely with natural gas as well as some biomass. For this report, Sundance units 1 and 2 (576 MW) are assumed to be retired in 2011 as announced, Sturgeon and Rainbow in 2014 (152 MW combined), and Battle River in 2105 (106 MW). In the longer term, repowering the remaining coal units as they reach the end of life or end of Power Purchase Arrangement (PPA) and must meet new emissions standards will impose significant costs.

Generation investments in Quebec are projected to be just under $29 billion. The larger share of this investment will be in new hydro projects to meet growing market demands and new wind farms to add supply diversity. Significant refurbishment expenses for aging hydropower assets are also anticipated. This report assumes that the Gentilly nuclear station is refurbished, although decommissioning may also be a possibility.

Table 7
Investments in Generation Capacity
(2010 $ millions)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	N.S.	N.B.	N.L.	P.E.I.	Y.T.	N.W.T.	Nun.	Canada
Refurbishment/ repowering	2,955	26,427	7,639	1,410	18,926	10,814	2,776	283	2,621	345	14	1	18	74,229
Retirement	342	677	3	0	3,711	0	135	11	205	0	0	0	0	5,085
New construction	16,131	16,914	2,782	8,647	37,214	17,916	3,151	1,314	11,911	299	35	35	0	116,348
Subtotal	**19,428**	**44,019**	**10,423**	**10,057**	**59,851**	**28,730**	**6,062**	**1,608**	**14,736**	**644**	**49**	**36**	**18**	**195,662**

Source: The Conference Board of Canada.

CHAPTER 5

Transmission Investments

Chapter Summary

- Canada has a north–south transmission network that connects with the United States Canada–U.S. interconnections play an important role in the electricity trade between the two countries and, currently, there are three major interconnections under development.
- The transmission investments identified in this report are likely to be underestimated, as only a few public documents identify the transmission investment plans, and some transmission requirements associated with new generation projects have not been identified. Overall, Canada faces $36 billion (in 2010 dollars) in transmission investments, with Alberta having the highest investments at almost $17 billion; Ontario, the second highest at $5 billion; and British Columbia, the third at $4 billion.

Canada's high voltage electricity transmission grid (see Exhibit 1) is really a collection of provincial grids that are linked together through varying levels of intertie capacity. Provincial and interstate transmission systems are linked together as regional transmission systems. British Columbia, Manitoba, Ontario, and Quebec have the largest external connections, and they serve interconnected regional U.S. markets more than neighbouring provinces. This north–south orientation of the transmission grid, or at least the absence of significant east–west capacity, has long been a subject of discussion and suggestions for change. This report does not examine the potential for east–west developments beyond projects already identified and planned by the transmission companies themselves. The investment potential described in this chapter is therefore conservative in the event that east–west transmission capacity development emerges in future.

Canadian provincial and U.S. interstate transmission systems are linked together as regional transmission systems.

Each provincial transmission system that interconnects with U.S. markets must be open access—any party that meets the technical and financial standards must be able to move power through the system. The system operator is responsible for the complex process of coordinating power flows in real time. The entity that acts as system operator depends on the market structure in each province. Ontario and Alberta both have a totally independent entity; in most other provinces the operator also owns transmission assets. The process of planning for future transmission requirements also depends on market structure, government policy, and the nature of regulatory oversight. The planning horizons and projection methods vary widely.

Exhibit 1
Canada's High-Voltage Electricity Transmission Grid

Source: www.electricity.ca.

U.S.–Canada interconnections play an important role in the electricity trade market between the two countries. New York, Washington, Michigan, and Minnesota/North Dakota represent some of the top importers and exporters of Canadian electricity. Currently, there are three new U.S.–Canada interconnections under development: Montana-Alberta Tie Ltd., NU-NSTAR-Hydro-Québec, and Champlain Hudson Power Express.[1] The market is of significant importance to both countries, with many economic benefits achieved due to this trade market. To further improve the system, governments must develop open and effective communication; and regulatory processes must be streamlined to avoid lengthy and costly processes. In addition, governments must focus on ensuring security of the system, while the U.S. government must coordinate with Canada with respect to the new legislation for the electricity grid.[2]

1 Canadian Electricity Association, "U.S. and Canada."

2 Ibid.

Table 8 presents a summary of the investments identified for this report. The broad range of planning horizons makes projections of total investments for Canada difficult. Further, the transmission investments summarized here are only those that have been identified and quantified by the transmission companies in public documents. The transmission investments that will be required beyond the end of the planning horizons identified in Table 8 will be significant, but are beyond the scope of this report to estimate. The investments shown in the table do not align completely with the generation investments identified in Chapter 5. In particular, the incremental investments required to integrate additional large volumes of renewable generation, or the investments to integrate large generation projects beyond 2010, are not clearly identified for some provinces. For example, Ontario's Long-Term Energy Plan identifies a total transmission investment of \$9 billion between now and 2030, whereas Table 8 captures only \$5.5 billion of that total. This is a result of the timing of the IPSP and the lack of public investment plans.

Similarly, the $3.8 billion shown for Quebec relates to a very short planning horizon. The transmission investments required to accommodate longer-term capacity additions have not been published. Finally, the generation assumptions for Atlantic Canada include the Lower Churchill project in Newfoundland and Labrador, whereas the transmission investment projected for Newfoundland and Labrador is not included in the long-term capital plan shown in Table 8 ($5 billion for the island link and on-land transmission combined).

This report relies entirely on data gathered from public sources. The $35.8 billion in transmission investment identified likely understates significantly the investment that will be required, given that only Newfoundland and Labrador shows expenditures beyond 2020 with any detail regarding the projects that are included. For British Columbia and Quebec, there are current expectations that additional transmission capacity will be required as domestic demand and exports continue to grow. Provinces with significant coal-fired generation

Table 8
Transmission Investments
(2010 $ millions)

Province	Total investments identified	Information sources	Time horizon
British Columbia	4,330	BCTC Transmission System Capital Plan F2009–F2018 Fortis BC 2005–2024 T&D System Development Plan British Columbia Utilities Commission decision reports	2010–18 2011–24 2011
Alberta	16,654	AESO Long-Term Transmission System Plan AUC decisions and pending applications	2010–20 2010–15
Saskatchewan	—	Project costs not published	—
Manitoba	3,535	Manitoba Hydro 2010/2011 and 2011/2012 Rate Application, Tab 6	2010–18
Ontario	5,481	Hydro One Capital Plan IPSP Section E Long-Term Energy Plan	2010–12 2010–20 2010–30
Quebec	3,805	Hydro-Québec TransÉnergie 2009–2013 strategic plan	2009–13
Nova Scotia	1,700	Nova Scotia Power 10-year system outlook	2010–15
New Brunswick	88	Long-term capital plan	2010–18
Newfoundland and Labrador	244	Long-term capital plan	2010–30
Prince Edward Island	—	Project costs not published	—
Total announced investment	**35,838**		

Source: The Conference Board of Canada.

capacity (Alberta and Saskatchewan in particular) face pending federal emissions regulations that will influence future generation requirements. Although the impact on generation investments is examined in Chapter 4, the transmission implications are not included in the investment plans presented here. Ontario is currently addressing the requirement for enabler lines to make transmission capacity available for renewable generation projects identified under the Feed-in Tariff (FIT) program. These investments have not yet been quantified and are not represented in Table 8.[3] Similarly, the transmission investments to make power from Lower Churchill are likely not fully captured in the long-term capital plans presented.

The transmission investments can also be segmented between those required to maintain and replace existing facilities (typically referred to as investments in sustaining capacity), and investments required for anticipated system growth. Most companies show only the total investment in transmission, and those that separate investments to sustain capacity from investments to accommodate growth typically do so for only the very near-term outlook. However, based on the transmission investment plans reviewed for this report, a useful rule of thumb might be that at least one-third of the total investment is to sustain the existing transmission system and the remainder to accommodate anticipated growth. This separation is arbitrary given that even new transmission lines, intended primarily to accommodate growth, will contribute to the overall system.

Provinces with significant coal-fired generation capacity face pending federal emissions regulations that will influence the future generation requirements.

Given the partial time horizon for which data are available and the range of investment needs identified above that may not be reflected in the public data, it is reasonable to conclude that the $35.8 billion in transmission investment identified in the table understates the capital that will likely be spent between 2010 and 2030.

3 The Long-Term Energy Plan indicates that the Ontario investment could be as high as $9 billion. Table 8 is built from published data for individual projects identified in the sources shown.

CHAPTER 6

Distribution Investments

Chapter Summary

- Overall, Canada faces distribution investments of $62 billion (2010 dollars) over the next 20 years. Quebec has the highest requirement at $22 billion, Ontario faces $21 billion, and Alberta is third at $11 billion.
- Increasing levels of distributed generation use, smart grid developments, and changing electricity requirements will all affect future distribution investments.

Canada is served by a large number of electricity distributors, whose function is to transmit energy from an interconnection with a high-voltage transmission line to a retail consumer. Some of these distributors are investor owned, others are owned by the municipality they serve, and yet others are cooperatives. Some distributors are a business unit of a larger company that also provides transmission or generation services. Some distribution companies are required to provide access to their facilities network to transport power on behalf of end customers that choose to purchase power from a third party. This complex range of market structures, service offerings, and ownership structures is the background against which investment requirements must be estimated.

Investments by electricity distributors can be conveniently separated between sustaining investments and growth investments. The sustaining investments are those made to maintain the existing network, provide a consistent level of service quality, and adjust to a changing marketplace. Growth investments are those that are made to accommodate growing loads from existing customers, changing load characteristics (for example the pending introduction of electric vehicles), an increasing number of customers within the service area, and perhaps even an expanding service area.

Some distribution companies must provide access to their facilities network to transport power on behalf of end customers choosing to buy power from a third party.

Electricity distributors face some form of oversight or regulation, particularly with respect to rates and finances. Part of the oversight is setting depreciation rates that closely match the useful life of the assets being depreciated. Based on the assumption that assets are replaced as they reach the end of their useful life, an examination of cumulative investment, cumulative depreciation, the annual rate of depreciation, and inflationary factors provides a starting point for estimating the sustaining investments required, going forward.

Investments to accommodate growth can be estimated based on growth in provincial electricity demand and an assumption regarding the investment required per GWh of energy delivered. Such estimates implicitly assume a level of investment that will provide a similar level of service in the future as compared with the past. The estimates abstract from any changing circumstances or characteristics of future markets.

The distribution investments required for sustaining and growth purposes are shown in Table 9. These are substantial investments, totalling $62.3 billion over the 20-year period examined. The substantial total is to maintain the current system in terms of service availability and quality, and to expand to meet future requirements represented in the demand outlook employed. Very few distribution companies provide long-term capital plans, and it is anticipated that the estimated numbers will grow through time. The estimates are in real terms; hence, the impacts of inflation are not considered.

Table 9
Projected Distribution Investments
(2010 $ millions)

	Sustaining	Growth	Total
British Columbia	2,536	1,540	4,076
Alberta	8,016	2,745	10,761
Saskatchewan	631	22	652
Manitoba	2,122	317	2,439
Ontario	16,636	3,966	20,602
Quebec	19,298	2,371	21,669
Nova Scotia	428	240	668
New Brunswick	618	284	902
Newfoundland and Labrador	357	61	418
Prince Edward Island	44	22	66
Yukon	12	5	18
Northwest Territories	24	16	40
Nunavut	5	1	6
Canada	**50,727**	**11,590**	**62,316**

Source: The Conference Board of Canada.

There are three major market trends that will influence future distribution costs and that are not reflected in Table 9. The first is the investments that will be required as a result of increasing levels of distributed generation based on renewable energy technologies. The second is investments associated with the development of a smart grid. Both are highly uncertain and have been excluded from the analysis on that basis. The third is changing electricity requirements.

The growing focus on distributed generation, and small or micro renewable generation downstream of the transmission grid, will change the way the grid is operated, and will require investment.

Distributed generation refers broadly to generation assets that are downstream of transmission and major distribution transformer stations. Most provinces in Canada now require that the distributor make two-way metering available so that customers who choose to invest in micro generation facilities can sell excess power back to a service provider or to the grid. In addition to the facilities required to accept the power, the distributor must develop or enhance the ability to predict how much power will flow in each direction and when. Given that most distributed generation is based on solar or wind power, this implies a requirement to adjust demand forecasts and to forecast variable supplies. Any issues related to power quality must also be anticipated and appropriate investments made to ensure a reliable, high-quality electricity service to all customers.

There has also been only very preliminary consideration of the investments that would be required to facilitate future development of a smart grid. At its broadest level, a smart grid could be a self-healing network that integrates generation, transmission, and distribution management in a highly automated environment. Smart grid initiatives to date have focused primarily on the retail customer. Ontario has installed smart meters for all residential and small commercial customers and other provinces are moving forward as well. The growing focus on distributed generation and small or micro renewable generation downstream of the transmission grid will change the way the grid is operated, and will require investment. Time-of-use meters are being deployed and time-of-use rates are in the early stage of development. Ontario has taken the lead in this transition, with time-of-use rates more broadly available. Load management devices are a logical next step downstream of the meter, although very few small customers have taken this step to date. One of the primary immediate implications of smart grid development for electricity distributors is the need to manage a much larger volume of data from the meter, ensure that meters are secure (both physically and with respect to any data transmitted), and ensure that the customer has secure access to near-real-time data as required to manage loads.

There are also trends, such as electric vehicles, that could reshape future distribution investment requirements. As consumers become more aware of their energy profile and as their energy consumption decisions change, distribution companies will be required to make adjustments, including investment. The electric vehicle provides perhaps the strongest example. To the extent that such vehicles reach the market, they will change the electricity consumption characteristics of the residences or other locations where they are charged. The potential for load spikes as vehicles are connected for charging can be a significant requirement for distribution system upgrades. They could also trigger investments in transmission upgrades and would influence generation requirements. Such investments are not reflected in this report.

CHAPTER 7

Closing the Gap: Summary and Recommendations

Chapter Summary

- Two-thirds of the $293.8 billion in invesments required over the next 20 years will be used to replace or repower generating stations.
- Transmission investments are only 12 per cent of the total, but are likely understated.
- Replacing aging generation, transmission, and distribution assets at the same time as integrating more distributed generation and renewable energy creates opportunities at all levels of the electric power system. The key challenge is to manage the costs to consumers.

This report has examined the spectrum of future investment plans and opportunities for electric energy in Canada. Electricity has long served as a reliable and economical source of energy for Canadian homes and businesses. Historically, we have relied strongly on generation sources that are low in pollutant emissions, although some provinces are exceptions to that rule. With an overall 67.8 per cent of current operating capacity that is low emission, Canada performs well compared with most OECD nations. However, there are initiatives under way both federally and provincially to further increase our reliance on renewable energy and reduce emissions from electricity production.

The report identifies a total of $293.8 billion of required investments in electricity infrastructure between 2010 and 2030. Two-thirds of this investment will be in generation assets to replace or repower aging stations, add to renewable generation capability, and accommodate market growth. The transmission investments identified represent 12 per cent of the total, and are understated given that available investment plans do not cover the entire period examined. The remaining investments will be required to maintain service quality and expand distribution systems.

This report identifies required investments of $293.8 billion in electricity infrastructure between 2010 and 2030.

One of the questions investigated is whether there is an infrastructure deficit in the electricity sector. This is a hypothetical question, given that future infrastructure investments will accommodate market growth in addition to maintaining or replacing existing assets. Chapter 2 of this report examined the historical investment performance of the electricity sector. Based on published data, the average annual investment in electricity infrastructure in Canada has been somewhat variable. In constant dollars—hence, with inflation adjusted for—the investment averaged $10.5 billion per year in the 1970s and 1980s, $9.2 billion per year in the 1990s, and $10.8 billion per year from 2000 to 2010. There was a significant pause in investment in the mid-1990s, which coincides with the period in which restructuring was being discussed and initiated. The investment requirements of $293.8 billion, identified in this report, average just under $15 billion per year, a level that is substantially higher than in the five previous decades. Improving and expanding infrastructure, increasing the availability of small-scale generation from renewable sources, and reducing greenhouse gas emissions from fossil fuel stations are among the reasons for this accelerated investment pace. The relative contribution of an infrastructure gap has not been decomposed from the total.

The historical north–south focus of transmission investments appears poised to continue into the future.

Generation investments top the list at an estimated $195.7 billion. These investments are to replace or repower assets at the end of their useful life and to add new capacity. New capacity additions, projected at 39.4 gigawatts (GW), are estimated to require $116.4 billion of investment (60 per cent of total generation investments), with repowering or retirements accounting for the remainder. Ontario faces the largest required investments in new generation capacity because it has the largest internal market, the largest installed capacity, and the strongest commitment to replace fossil fuel technologies with smaller and less-centralized renewable energy capacity. Quebec's investment in new generation capacity appears to be driven by anticipated export growth. Alberta ranks third for new generation, primarily because of continued oil sands and economic expansion. Repowering and retirement investments are significantly higher in Alberta than any other province, primarily because of coal-fired generation assets that are nearing the end of their life and must be repowered to meet stricter emissions standards or replaced with other technologies. This investment will likely place a significant burden on Alberta electricity generators and consumers. Ontario faces significant expenses to retire the remaining coal stations, refurbish additional nuclear facilities, and in the long term, refurbish the wind capacity that has recently come into service. The Lower Churchill development represents the largest projected investment in Atlantic Canada, and would provide an opportunity to reduce the historical role of fossil fuel generation in that region.

Ontario, Alberta, Saskatchewan, Nova Scotia, and New Brunswick all face the challenge of either retiring coal-fired stations, or repowering them to meet emissions standards. Ontario will retire coal units by 2014 and has committed to replacing the capacity primarily from renewable energy sources. This brings an overall system cost, both because of the investment in new capacity and because of the investments required to maintain system reliability and expand reserve capacity—with the latter costs very difficult to quantify. Alberta must meet this challenge during a period of internal market growth, primarily driven by industrial expansion related to oil sands production. The investment also comes during a period when natural gas prices have been volatile and natural gas production in Alberta is not expected to grow. This makes the generation technology choice a difficult one. Much of the investment in repowering or refurbishment will come as a result of initiatives to reduce reliance on fossil fuels or reduce related emissions without adding to generating capacity. Such investments must be carefully managed to limit rate increases to consumers.

New capacity additions, projected at 39.4 gigawatts, are estimated to require $116.4 billion of investment (60 per cent of total generation investments), with repowering or retirements accounting for the remainder.

The transmission investments identified understate future requirements. Most of the projects identified were either to improve transmission capacity within the province (Alberta and Manitoba, for example) or to improve internal capacity, as well as increase export capability (British Columbia, Quebec, and Newfoundland and Labrador). Transmission investments have become more controversial with market restructuring—particularly in Alberta, where market participants have been unable to achieve consensus with respect to the best mix of generation options and transmission additions, including those aimed at export markets. The historical north–south focus of transmission investments appears poised to continue into the future. Significant east–west capacity additions are relatively few in the investment plans examined. Development of a stronger east–west system within Canada is supported by many, although additional costs would need to be incurred.

The electricity distribution market segment is emerging as a key focus for infrastructure renewal and advancement. Distributed generation is becoming a priority, particularly in Ontario where the micro-FIT program encourages generation investments in communities and even households. Smart meter installations and pilot projects are expanding. Although the consumer benefits remain to be demonstrated conclusively, these trends will impact distribution system investments and must be carefully managed. The objective is to ensure that where costs are incurred there are commensurate benefits. The timing for these developments is opportune where distribution infrastructure needs renewal, but inopportune where economic conditions are unfavourable or where electricity rates are rising to accommodate generation or transmission investments.

All of the investments profiled are also occurring at a time when environmental regulations are expanding the oversight of project development. Application and approval processes, both federally and provincially, are beginning to focus more carefully on cumulative impacts, alternative land uses, and environmental protection. This can contribute to a push-pull environment for investment. It is important to recognize that environmental processes protect environmental resources. It is also important to ensure that required projects are reviewed in a timely manner.

APPENDIX A

Provincial Summaries

BRITISH COLUMBIA

There are four primary power utilities in British Columbia that buy and generate power: BC Hydro, Fortis BC, Columbia Power, and Nelson Power. There is a relatively small group of independent power producers. Taking into account the partnerships BC Hydro has with Rio Tinto/Alcan and Tech Cominco, as well as power contract purchases, BC Hydro has access to about 94 per cent of the total existing B.C. capacity. Fortis, Columbia Power, and Nelson Power have most of the balance. BC Hydro is the key buyer of B.C. electric power.

British Columbia is preferentially located between three major markets: California, Pacific Northwest, and Alberta through interconnected tie-lines. The flexibility of the hydro system and tie-line capacity to link these markets is substantial,[1,2] allowing B.C. to maximize its profitability across the markets—a competitive advantage it exploits effectively through its trading arm, Powerex.

BC Hydro takes a collaborative integrated approach to planning power needs through its "Integrated Resource Plan." BC Hydro's 2011 Integrated Resource Plan (IRP) is a 20-year plan that will describe how to meet future growth in demand for electricity through energy conservation and clean energy generation. The 2011 IRP will also include an evaluation of the export markets for clean electricity, as well as the supporting transmission requirements for the next 30 years.

There are four primary power utilities in British Columbia that buy and generate power.

BC Hydro has had three Calls for Power from independent power producers—one in 2002–03, where it has 2,842 MW on existing contracted power; the 2006 Call for Power, where it contracted 1,439 MW (not including Columbia Power's Brilliant Expansion); and its recent Clean Power Call, where 1,168 MW were successful.

FUTURE GENERATION CAPACITY

British Columbia is overwhelmingly hydro based. Of the 15,679 MW installed capacity, 87 per cent is hydro, with natural gas a distant second at 9 per cent. The economics of large-scale hydro will do little to change that

1 Flows between British Columbia and Alberta: The Western Electricity Coordinating Council's (WECC) approved path rating for the B.C. to Alberta path (i.e., west to east) is 1,200 MW. Conversely, the WECC-approved path rating for the flow of electricity from the Alberta to B.C. intertie (i.e., west to east) is 1,000 MW. Normally, the total actual allowable transfer capacity is significantly less than this.

2 Flows between British Columbia and the U.S.: The WECC-approved path rating from B.C. to the U.S. is 3,150 MW, a combined limit for the Eastside and Westside tie, with maximum flow limited to 2,850 MW on the 500 kilovolt (kV) Westside Intertie. The Boundary–Nelway 230 kV line has a limit of 400 MW. The WECC-approved path rating from the U.S. to B.C. is 2,000 MW, a combined limit for the east and west-side ties, with maximum flow limited to 2,000 MW on the 500 kV Westside Intertie. The Boundary–Nelway 230 kV line has a limit of 400 MW.

direction unless there is a policy or political change in British Columbia. At the time of writing, an additional 1,734 MW of new plants are under construction, with 495 MW under development and 6,361 MW of proposed projects. Of the projects under construction, 78 per cent are large-scale hydro and about 14 per cent are wind. The predominance of proposed projects are wind projects at 63 per cent, followed by large-scale hydro projects at 31 per cent. The detailed projects are listed in Table 1. The province has a strong commitment to maintain or increase its reliance on renewable electricity generation as expressed in the provincial energy plan. This commitment is evidenced in the proposed capacity additions, as no fossil fuel stations are proposed.

ALBERTA

In Alberta, any customer—residential, commercial, or industrial—can elect to purchase power from authorized retailers. Notably, while Service Alberta and the Utilities Consumer Advocate each provide additional market rules and regulations to protect small retail customers, retailers must primarily demonstrate only the ability to exchange data with the utilities, along with the required credit support.

Table 1
British Columbia Generation Projects, by Energy Source and Status

Primary energy source	Stations existing or under construction	Installed capacity (MW)	Energy generated 2010 (TWh)	Stations planned or proposed	Capacity planned or proposed (MW)
Coal	0	0.0		0	0.0
Coal/biomass	0	0.0		2	240.0
Nuclear	0	0.0		0	0.0
Large hydro	62	14,979.7		32	2,315.5
Storage hydro	0	0.0		1	31.0
Natural gas	6	1,449.0		0	0.0
Natural gas/diesel	1	46.0		0	0.0
Biomass	9	353.0		2	140.0
Landfill or biogas	1	1.4		0	0.0
Diesel	0	0.0		0	0.0
Off-grid diesel	9	46.1		0	0.0
Fuel oil	0	0.0		0	0.0
Off-grid hydro	1	2.0		0	0.0
Small hydro	37	170.6		12	81.4
Waste heat	2	12.0		1	11.0
Wind	4	354.0		16	3,442.2
Wind, offshore	0	0.0		0	0.0
Geothermal	0	0.0		1	100.0
Solar	0	0.0		0	0.0
Other/unknown fuel	0	0.0		0	0.0
Total	**132**	**17,413.8**	**67.7**	**67**	**6,361.1**

Source: The Conference Board of Canada.

The Alberta Electric System Operator (AESO) ensures safe, reliable operation of the interconnected electric system and provides its economic plans. The AESO also provides open and non-discriminatory access to the grid for generation and distribution companies and large industrial consumers of electricity. What is notably absent from this mandate—or any mandate in Alberta—is that there is little accountability to ensure that the customer's demand is met beyond the instantaneous demand in real time. Utilities do carry the responsibility to ensure that people are not cut off during winter months. While the AESO does evaluate and present the short- and long-term demand and supply balance to signal reliability of the market, and must ensure adequate transmission capability, it stops short of holding responsibility for ensuring customers have the power they want over time.

Given the strength of Alberta's coal-fired assets, and their age, the province's generators face important decisions with respect to future generation technologies.

Another notable factor about how power is purchased in Alberta is the contract. Most consumers do not purchase power under long-term contracts beyond three years, and only about 25 to 30 per cent enter into contracts. This is true for all customer categories except retailers.

Another issue of note in Alberta is the reliance of an energy-only, spot market known as the Power Pool. There is no capacity market that would provide a fixed payment to a generator to build. All generator revenues are ultimately linked to the energy market—as generators either sell into the Pool and get the hourly settled price or use contracts that ultimately tie to the Pool price. Some contracts include fixed-capacity payments but, as mentioned, there are not significant buyers in the market for long-term contracts, and these contracts would now have the additional requirement of a fixed payment.

A material consideration in the Alberta Power Pool is the allowance of scarcity pricing, up to the price cap of $1,000 per hour. Much debated, it was ultimately decided that scarcity pricing would be allowed in order to offer companies a material opportunity to reward their risk-taking and signal new players in the market. This is not to be misconstrued as unbounded, as Alberta's Market Surveillance Administrator has provided guidance in its recent *Offer Behaviour Enforcement Guidelines* posted on the MSA website, which clarify how this type of pricing will be overseen. While spot market volatility can be more profitable than a long-term fixed contract, it lacks the certainty.

FUTURE GENERATION CAPACITY

Alberta's electricity generation is predominately fossil fuel based, given its significant fossil fuel resource base. Several decades ago, Alberta was predominately reliant on coal, but today natural gas is a significant component of the fuel supply. Hydro systems are relatively minor relative to its neighbour B.C., owing to smaller river systems and the very dry southern half of the province. Wind is a significant resource in the windy bottom third of the province.

Alberta's electricity policy supports any generation technology that can penetrate the market. As a result, there are no policies or programs in place to give renewable energy an advantage, or to subsidize costs. The provincial policy does, however, permit retailers to "brand" renewable energy and sell it at a price premium if consumers agree to purchase.

Given the strength of Alberta's coal-fired assets, together with their age, the province's generators face important decisions with respect to future generation technologies, including the treatment of coal-fired assets as they reach the end of their Power Purchase Arrangement (PPA) or service life.

At the time of writing, an additional 735 MW of new plants are under construction, with 13,798 MW under development or proposed. Seventy-five per cent of the projects under development are natural gas—with wind, hydro, and steam making up the balance. In contrast, almost half of the proposed projects are wind, with nuclear, coal, and several natural gas facilities making up the balance. The detailed projects are listed in Table 2.

Table 2
Alberta Generation Projects, by Energy Source and Status

Primary energy source	Stations existing or under construction	Installed capacity (MW)	Energy generated 2010 (TWh)	Stations planned or proposed	Capacity planned or proposed (MW)
Coal	18	6,232.0		4	1,232.0
Nuclear	0	0.0		1	4,000.0
Large hydro	10	1,040.0		1	100.0
Natural gas	56	5511.0		14	2,289.0
Biomass	8	266.0		3	82.0
Landfill or biogas	0	0.0		0	0.0
Diesel	0	0.0		0	0.0
Fuel oil	0	0.0		0	0.0
Off-grid hydro	0	0.0		0	0.0
Small hydro	2	10.0		0	0.0
Waste heat	0	0.0		0	0.0
Wind	21	1,189.0		32	5,390.0
Wind, offshore	0	0.0		0	0.0
Geothermal	0	0.0		0	0.0
Solar	0	0.0		0	0.0
Steam	1	100.0		1	135.0
Other/unknown fuel	0	0.0		7	570.0
Total	**116**	**14,348.0**	**67.8**	**63**	**13,798.0**

Source: The Conference Board of Canada.

SASKATCHEWAN

Saskatchewan's electricity consumers have their power purchased for them by SaskPower, which is a regulated utility. Municipal, commercial, and industrial customers can, however, make alternate power purchasing arrangements or build and operate their own generating systems. SaskPower has 3,371 MW of generating capacity and purchases 700 MW from independent power producers (IPPs).

Saskatchewan's electricity generation is predominately fossil fuel-based with coal and natural gas. In early 2009, SaskPower had two requests for proposals, one for peaking and the other for baseload generation. Northland Power won both and is building two natural gas facilities in Saskatachewan. Later that same year, SaskPower launched the Green Options Plan to procure 175 MW of wind power from IPPs; in September 2010, it received bids from the IPPs qualified to participate in the process.

FUTURE GENERATION CAPACITY

There are 346 MW of new plants under construction; 25 MW under development; and 707 MW of proposed projects, of which 300 MW are wind. The majority of the existing projects are coal or natural gas. The detailed projects are listed in Table 3.

Table 3
Saskatchewan Generation Projects, by Energy Source and Status

Primary energy source	**Stations existing or under construction**	**Installed capacity** (MW)	**Energy generated 2010** (TWh)	**Stations planned or proposed**	**Capacity planned or proposed** (MW)
Coal	3	1,682.0		0	0.0
Nuclear	0	0.0		0	0.0
Large hydro	5	840.0		1	250.0
Natural gas	15	1,869.0		0	0.0
Biomass	0	0.0		1	182.0
Landfill or biogas	0	0.0		0	0.0
Diesel	0	0.0		0	0.0
Fuel oil	0	0.0		0	0.0
Off-grid hydro	0	0.0		0	0.0
Small hydro	2	12.8		0	0.0
Waste heat	0	0.0		0	0.0
Wind	3	172.2		3	300.0
Wind, offshore	0	0.0		0	0.0
Geothermal	0	0.0		0	0.0
Solar	0	0.0		0	0.0
Other/unknown fuel	0	0.0		0	0.0
Total	**28**	**4,576.0**	**17.5**	**5**	**732.0**

Source: The Conference Board of Canada.

MANITOBA

Manitoba Hydro is a Crown corporation and Manitoba's major energy utility. About 2 per cent of the total installed capacity is purchased from an IPP.

Exporting power has a material impact on Manitoba's financial results. According to the 2010 Annual Report, out of the $1.6 billion in revenues for 2010, $427 million, or 27 per cent of the revenues, related to net exports. Exports are viewed as a mechanism to keep Manitoba Hydro's electricity rates for its customers among the lowest in North America.[3]

The province supports wind development through its Energy Development Initiative and originally committed to 1,000 MW by 2015.[4] Proponents can go to the government with their projects and demonstrate the project economics. Like other provinces, there are tax incentives for green energy technologies. Manitoba Hydro will enter into power purchase agreements with successful candidates.

3 Manitoba Hydro, "Electricity."

4 Manitoba Innovation, Energy and Mines, "Wind Energy."

Unfortunately, Manitoba's first major wind farm required a $250 million bailout to Pattern Energy to complete the project and keep rates where Manitoba Hydro wanted.[5] Since that experience, there has been no stated continued commitment to build the 1,000 MW by 2015.

Under this initiative, 242 MW of wind projects have been installed. There do not appear to be any projects that have advanced beyond getting a license to build the facilities to get a PPA contract from Manitoba Hydro.

FUTURE GENERATION CAPACITY

Like B.C. and Quebec, Manitoba relies almost exclusively on its vast hydro resources, as 88 per cent of the installed capacity is at 14 hydro generating stations. There are two wind farms and one coal plant.

At the time of writing, an additional 895 MW of new plants are under construction, with 1,885 MW under development and 495 MW proposed projects. The predominance of proposed projects are hydro and wind. The detailed projects are listed in Table 4.

ONTARIO

Ontario has a rich and diverse resource base and an extremely large population of customers to serve, and all of the issues a diverse fuel and customer base can impart. From aging infrastructure, nuclear waste disposal, deregulation, customer requirements, emissions reduction, trade—Ontario has the a plethora of issues.

Table 4
Manitoba Generation Projects, by Energy Source and Status

Primary energy source	Stations existing or under construction	Installed capacity (MW)	Energy generated 2010 (TWh)	Stations planned or proposed	Capacity planned or proposed (MW)
Coal	0	0.0		0	0.0
Coal/natural gas	1	339.0		0	0.0
Nuclear	0	0.0		0	0.0
Large hydro	16	5,938.0		1	1,485.0
Natural gas	1	129.0		0	0.0
Biomass	0	0.0		0	0.0
Landfill or biogas	0	0.0		0	0.0
Diesel	0	0.0		0	0.0
Off-grid diesel	4	10.0		0	0.0
Fuel oil	0	0.0		0	0.0
Off-grid hydro	0	0.0		0	0.0
Small hydro	0	0.0		0	0.0
Waste heat	0	0.0		0	0.0
Wind	3	242.0		9	894.6
Wind, offshore	0	0.0		0	0.0
Geothermal	0	0.0		0	0.0
Solar	0	0.0		0	0.0
Other/unknown fuel	0	0.0		0	0.0
Total	**25**	**6,658.0**	**36.4**	**10**	**2,379.6**

Source: The Conference Board of Canada.

5 Welch, "Hydro Bailout."

Decision-making for generation investment is not entirely market driven: several organizations contribute to the decision-making. The Ontario government, through the Ministry of Energy, sets overall policies for electricity. The Ontario Power Authority (OPA) is responsible for supply procurement and develops the Integrated Power System Plan (IPSP). Until the IPSP is approved by the Ontario Energy Board (the target date is 2012), procurements will continue to be authorized by formal directives from the Minister of Energy.

Ontario's electric power industry did not make a transition to a deregulated market to the same extent as Alberta, and there remain elements of organization planning for generation investments that are important to highlight. The Ontario government has laid out detailed plans for the electric power industry in terms of generation, transmission, and distribution investments in its report *Ontario's Long-Term Energy Plan: Building Our Clean Energy Future*, including initiatives that will help Ontario consumers use less energy.

In 2004, the government established the Ontario Power Authority as the province's long-term planner, with responsibilities that include activities that facilitate load management and energy conservation.

The Independent Electricity System Operator (IESO) is a not-for-profit corporate entity established in 1998 by the *Electricity Act of Ontario*. The IESO is the short-term wholesale market for electricity, directing all flows in Ontario across the province's transmission lines.

Ontario's Feed-in Tariff (FIT) program provides:

> . . . guaranteed pricing structure for renewable electricity production. It offers stable prices under long-term contracts for energy generated from renewable sources, including: biomass, biogas , landfill gas, on-shore wind, solar photovoltaic (PV), and hydropower. The FIT Program was enabled by the *Green Energy and Green Economy Act, 2009* which was passed into law on May 14, 2009. The Ontario Power Authority is responsible for implementing the program.[6]

6 Ontario Power Authority, "Renewable Energy."

There are currently 2,421 MW that have been offered FIT contracts and 6,531 MW that are awaiting certification.

In the past, non-utility generators (NUGs) entered into contracts with the former Ontario Hydro. The contracts with NUGs are currently held by the Ontario Electricity Financial Corporation, an agency of the Ministry of Finance. These contracts were developed in the early 1990s and will begin to expire. Many of these are natural gas-fired and contribute up to 1,550 MW of clean power to the system.

Over the next two decades, Ontario will need to make choices as to which facilities—that are at the end of their useful lives—to retire and which to refurbish.

As the contracts expire, IESO and OPA will determine if the generation is still required to help ensure reliability. The government will direct OPA to design contracts that will encourage NUGs to operate during periods when it would most benefit the electricity system. The OPA will be authorized to enter into new contracts where this generation is needed and will negotiate to get the best value for consumers.

FUTURE GENERATION CAPACITY

In terms of coal, the Ontario government has committed to cease the burning of coal in its facilities by 2014.[7] That will include an investigation of converting Atikokan to biomass and Thunder Bay to natural gas and shutting down all currently operating coal plants.

With respect to nuclear, the government is committed to the continued use of the nuclear fleet for about 50 per cent of the total energy supply. However, over the next two decades, Ontario will be faced with facilities that are at the end of their useful lives, so will need to make choices as to which facilities to retire and which to refurbish. This is in addition to several facilities that have been refurbished, or are in the process of being refurbished.

7 Ontario Ministry of Energy and Infrastructure, *Ontario's Long-Term Energy Plan*.

Meeting growth, while shutting down current capacity, will be done by growing its hydro capacity to 9,000 MW and its wind, solar, and bioenergy to 10,700 MW by 2018. Natural gas will continue to provide peaking capacity. There is also to be a heavy mix of demand reduction and peak shifting, as the government has set the objective of reducing demand by 7,000 MW by 2030.

The current 37,591 MW of installed capacity in the province consists of 34 per cent nuclear, roughly 25 per cent natural gas and hydro, and 12 per cent coal. There are 2,800 MW under construction and almost 13,000 MW at various stages of planning. Solar represents the majority of the proposed projects, at 1,421 MW. The detailed projects are listed in Table 5.

QUEBEC

Hydro-Québec is the dominate player in planning, generating, and buying electric power in Quebec. Hydro-Québec does procure some of its power needs from independent power producers, but it is overwhelmingly the most significant player in resource development.

Like B.C., Hydro-Québec is ideally situated for trading power between Ontario, the Maritimes, and the United States. The trading volumes between Newfoundland and Labrador, Quebec, Ontario, and the U.S. are the highest in Canada. In 2009, Quebec's provincial receipts were 30,953 GWh and deliveries to the U.S. were 18,637 GWh. To put this in context, electric power sales within the province were 170 terawatt hours (TWh)—so this amounts to a significant portion of the volumes of electric power.

Table 5
Ontario Generation Projects, by Energy Source and Status

Primary energy source	**Stations existing or under construction**	**Installed capacity** (MW)	**Energy generated 2010** (TWh)	**Stations planned or proposed**	**Capacity planned or proposed** (MW)
Coal	3	3,277.0		0	0.0
Coal/biomass	1	950.0		0	0.0
Nuclear	18	12,856.0		0	0.0
Large hydro	71	8,839.3		6	152.0
Natural gas	37	9,612.3		5	2,450.0
Digester gas	1	1.6		0	0.0
Biomass	5	160.5		9	135.4
Landfill or biogas	1	5.3		17	56.3
Diesel	0	0.0		0	0.0
Off-grid diesel	0	0.0		0	0.0
Fuel oil	0	0.0		0	0.0
Off-grid hydro	0	0.0		0	0.0
Small hydro	72	271.3		75	297.8
Waste heat	0	0.0		0	0.0
Wind	37	1,441.3		203	8,436.2
Wind, offshore	0	0.0		0	0.0
Geothermal	0	0.0		0	0.0
Solar	7	176.5		155	1,421.1
Other/unknown fuel	0	0.0		0	0.0
Total	**253**	**37,591.1**	**154.9**	**470**	**12,948.8**

Note: The projects shown here do not include the projects awaiting ECT under the FIT program or the projects offered FIT contracts on February 24, 2011.
Source: The Conference Board of Canada.

Hydro-Québec's business objectives, as stated in *Strategic Plan 2009–2013* for its power production and procurement, are to increase generating capacity and exports.[8] The first objective is to increase hydro-electric generating capacity, for which 2,469 MW are currently under construction. Part of that objective is to also develop additional projects, for which 3,000 MW have been identified, costing more than $10 billion. The Northern Plan also includes wind and emerging renewable projects, of which 500 MW are being investigated for Northern Quebec.

Stepping up exports to Ontario, New England, and New York will occur through increased transmission. The third aspect of the objective is to enhance the performance of the generating assets. To do this, Hydro-Québec will exploit new monitoring technologies, robotics, operational changes, and spend over $4 billion to refurbish generating facilities.

Hydro-Québec purchases power from independent power producers as set out in the strategic plans. The current Northern Plan offers opportunities for IPPs to build wind and hydro facilities in the North.

FUTURE GENERATION CAPACITY

Quebec, like Manitoba and B.C., takes advantage of its access to the relatively inexpensive hydro capability.

Table 6
Quebec Generation Projects, by Energy Source and Status

Primary energy source	**Stations existing or under construction**	**Installed capacity** (MW)	**Energy generated 2010** (TWh)	**Stations planned or proposed**	**Capacity planned or proposed** (MW)
Coal	0	0.0		0	0.0
Coal/natural gas	0	0.0		0	0.0
Nuclear	1	675.0		0	0.0
Large hydro	67	37,736.6		13	3,082.4
Natural gas	4	1,402.0		0	
Biomass	3	51.5		6	52.9
Landfill or biogas	0	0.0		0	0.0
Diesel	24	65.9		0	0.0
Off-grid diesel	0	0.0		0	0.0
Fuel oil	1	66.0		0	0.0
Off-grid hydro	0	0.0		0	0.0
Small hydro	5	26.3		5	23.5
Waste heat	0	0.0		0	0.0
Wind	11	839.5		27	2,552.5
Wind, offshore	0	0.0		0	0.0
Geothermal	0	0.0		0	0.0
Solar	0	0.0		0	0.0
Steam	1	660.0		0	0.0
Other/unknown fuel	0	0.0		0	0.0
Total	**117**	**41,522.8**	**203.4**	**51**	**5,711.3**

Source: The Conference Board of Canada.

8 Hydro-Québec, *Strategic*.

Hydro-Québec's installed capacity is 90 per cent hydro. Including refurbishments, there are 2,692 MW under construction, 2,600 under development, and 3,112 proposed facilities, with a healthy balance of both hydro and wind options. The detailed projects are listed in Table 6.

NOVA SCOTIA

Nova Scotia Power Inc. (NSPI), a subsidiary of Halifax-based Emera, is the public utility in charge of the generation, transmission, and distribution of electricity in Nova Scotia. It was privatized in 1992.

As part of the provincial government's Renewable Electricity plan, Nova Scotia will soon have a community feed-in tariff (COMFIT) for renewable energy projects, including biomass, wind, and tidal power. Like Ontario's program, companies and individuals can sell their power at a set rate under a long-term contract.

FUTURE GENERATION CAPACITY

Nova Scotia Power operates the only tidal generating station in Canada, the Annapolis Royal Tidal Generating Station. Its primary base fuels for the base generating system are coal, hydro, fuel oil, and natural gas. The situation has quite a substantial portion of wind resources. Going forward, there are 74 MW under construction, with 696 MW of facilities in various stages of planning. The detailed projects are listed in Table 7.

Table 7
Nova Scotia Generation Projects, by Energy Source and Status

Primary energy source	Stations existing or under construction	Installed capacity (MW)	Energy generated 2010 (TWh)	Stations planned or proposed	Capacity planned or proposed (MW)
Coal	3	1,061.0		0	0.0
Coal/fuel oil	1	171.0		0	0.0
Nuclear	0	0.0		0	0.0
Large hydro	6	342.0		0	0.0
Natural gas	0	0.0		0	0.0
Biomass	1	27.0		2	120.0
Landfill or biogas	0	0.0		0	0.0
Diesel	0	0.0		0	0.0
Off-grid diesel	0	0.0		0	0.0
Fuel oil	3	222.0		0	0.0
Fuel oil/natural gas	1	415.0		0	0.0
Off-grid hydro	0	0.0		0	0.0
Small hydro	10	56.0		0	0.0
Waste heat	1	50.0		0	0.0
Wind	30	358.8		13	576.1
Wind, offshore	0	0.0		0	0.0
Geothermal	0	0.0		0	0.0
Solar	0	0.0		0	0.0
Tidal	1	20.0		0	0.0
Other/unknown fuel	0	0.0		0	0.0
Total	**57**	**2,722.8**	**12.7**	**15**	**696.1**

Source: The Conference Board of Canada.

NEW BRUNSWICK

New Brunswick Power is a utility wholly owned by the Government of New Brunswick. In 2003, the *Electricity Act* was amended. The company's distribution, transmission, and nuclear power's monopolies were maintained, but competition was supported in generation. To accommodate this, New Brunswick has an independent system operator to manage the electricity flows within the province and to and from outside markets.

FUTURE GENERATION CAPACITY

With the coal, diesel, fuel oil, natural gas, hydro, and nuclear plants, New Brunswick's generating capacity is about 4,656 MW. The fleet of coal, diesel, fuel oil, and nuclear facilities are old. The nuclear plant is currently being refurbished. There are 45 MW of wind being constructed and 1,540 MW of planned capacity in the works. The detailed projects are listed in Table 8.

NEWFOUNDLAND AND LABRADOR

Newfoundland and Labrador Hydro (Hydro) is a provincial Crown corporation that generates and delivers electricity for Newfoundland and Labrador, Quebec, and the northeastern areas of the United States.

Ninety-five per cent of Newfoundland and Labrador's 7,484 MW of generating capacity is owned either directly or indirectly by Nalcor, which owns Churchill Falls (Labrador) Corporation and Newfoundland and Labrador Hydro. Newfoundland Power and Kruger Energy have an equal share of the market, and there is a handful of other IPPs.

Table 8
New Brunswick Generation Projects, by Energy Source and Status

Primary energy source	Stations existing or under construction	Installed capacity (MW)	Energy generated 2010 (TWh)	Stations planned or proposed	Capacity planned or proposed (MW)
Coal	2	516.0		0	0.0
Nuclear	2	675.0		1	1,085.0
Large hydro	7	931.5		0	0.0
Natural gas	2	348.0		0	0.0
Biomass	1	44.5		1	5.0
Landfill or biogas	0	0.0		1	10.0
Diesel	3	527.0		0	0.0
Off-grid diesel	0	0.0		0	0.0
Fuel oil	3	1,387.0		0	0.0
Off-grid hydro	0	0.0		0	0.0
Small hydro	3	18.0		1	4.1
Waste heat	0	0.0		0	0.0
Wind	4	294.0		6	436.5
Wind, offshore	0	0.0		0	0.0
Geothermal	0	0.0		0	0.0
Solar	0	0.0		0	0.0
Other/unknown fuel	0	0.0		0	0.0
Total	**27**	**4,741.0**	**16**	**10**	**1,540.6**

Source: The Conference Board of Canada.

On November 18, 2010, Newfoundland and Labrador and Nova Scotia announced their $6.2 billion energy plan at the Lower Churchill. Newfoundland and Labrador's provincially owned Nalcor and Nova Scotia's private electric company, Emera, will implement the project. Nalcor will contribute $5 billion and Emera, $1.2 billion. Emera will own 20 per cent of the generated power, Newfoundland and Labrador will own 40 per cent, and the remaining 40 per cent can be sold to potential buyers through Nalcor.

At the time of writing, there were 7,484 MW of installed capacity, with the majority belonging to hydro projects. They also dominate the proposed projects, with hydro projects planned to bring another 3,470 MW of capacity to the province. The detailed projects are listed in Table 9.

PRINCE EDWARD ISLAND

Almost half of Prince Edward Island's needs come from New Brunswick Power Corporation through submarine cables connected to the mainland.[9] Nowhere in Canada is there a larger portion of wind in the installed capacity. Wind makes up 48 per cent of the total native installed capacity on the island. Fuel oil and diesel from imported sources makes up the rest.

Self-sufficiency is an important goal within the government's energy policy document, *Prince Edward Island Energy Strategy: Securing our Future—Energy Efficiency and Conservation.*[10] Currently, utilities on P.E.I. must meet at least 15 per cent of their electrical energy sales from procuring power from renewable

Table 9
Newfoundland and Labrador Generation Projects, by Energy Source and Status

Primary energy source	Stations existing or under construction	Installed capacity (MW)	Energy generated 2010 (TWh)	Stations planned or proposed	Capacity planned or proposed (MW)
Coal	0	0.0		0	0.0
Nuclear	0	0.0		0	0.0
Large hydro	12	6,630.4		5	3,153.0
Natural gas	2	81.0		2	192.5
Biomass	1	15.0		0	0.0
Landfill or biogas	0	0.0		0	0.0
Diesel	6	55.7		0	0.0
Off-grid diesel	0	0.0		0	0.0
Fuel oil	2	554.0		0	0.0
Off-grid hydro	0	0.0		0	0.0
Small hydro	26	94.6		0	0.0
Waste heat	0	0.0		0	0.0
Wind	2	54.0		0	0.0
Wind, offshore	0	0.0		0	0.0
Wind, diesel, hydrogen	1	0.3		0	0.0
Geothermal	0	0.0		0	0.0
Solar	0	0.0		0	0.0
Steam	0	0.0		1	125.0
Other/unknown fuel	0	0.0		0	0.0
Total	**52**	**7,485.0**	**43.9**	**8**	**3,470.5**

Source: The Conference Board of Canada.

9 www.gov.pe.ca/photos/original/env_snergystr.pdf.

10 Prince Edward Island, Department of Environment, Energy and Forestry, *Prince Edward Island.*

resources. To further reduce the reliance on imported oil and gas, the province wants to bring 500 MW of wind online by 2013 and an additional 10 MW in biomass generation. To bring about this goal, the provincial government will double its renewable energy portfolio standard from 15 to 30 per cent by 2013. The P.E.I. government currently owns North Cape and East Point wind farms.

FUTURE GENERATION CAPACITY

There are about 350 MW of planned wind capacity for which the P.E.I. government is an active participant. Currently, there are 346 MW of installed capacity—with the majority being wind facilities that bring in 167 MW of power. The detailed projects are listed in Table 10.

THE NORTH: YUKON, NORTHWEST TERRITORIES, AND NUNAVUT

The Northern territories have a rather diverse fuel source for their generating capacity. Yukon is almost exclusively hydro based, with another 10 MW of hydro capacity planned. Nunavut's electricity system is diesel based, with plans to develop an additional 5 MW of capacity. The Northwest Territories has an approximately equal mix of diesel and small-hydro facilities. Its growth in capacity is double that of Yukon and Nunavut together, with 10 MW under construction and 23 MW proposed hydro projects.

Table 10
Prince Edward Island Generation Projects, by Energy Source and Status

Primary energy source	Stations existing or under construction	Installed capacity (MW)	Energy generated 2010 (TWh)	Stations planned or proposed	Capacity planned or proposed (MW)
Coal	0	0.0		0	0.0
Nuclear	0	0.0		0	0.0
Large hydro	0	0.0		0	0.0
Natural gas	0	0.0		0	0.0
Biomass	0	0.0		0	0.0
Landfill or biogas	0	0.0		0	0.0
Diesel	2	67.0		0	0.0
Off-grid diesel	0	0.0		0	0.0
Fuel oil	1	112.0		0	0.0
Off-grid hydro	0	0.0		0	0.0
Small hydro	0	0.0		0	0.0
Waste heat	0	0.0		0	0.0
Wind	8	166.6		3	350.0
Wind, offshore	0	0.0		0	0.0
Geothermal	0	0.0		0	0.0
Solar	0	0.0		0	0.0
Other/unknown fuel	0	0.0		0	0.0
Total	**11**	**345.6**	**0.7**	**3**	**350.0**

Source: The Conference Board of Canada.

Yukon Energy is a Crown corporation and takes its guidance from the government's energy strategy. In this respect, its goal is to increase the renewable energy supply by 20 per cent by 2020. At this time, it can be described as being in the planning stages.

Northwest Territories Power Corporation, either directly or through affiliates, provides power to all communities in the Northwest Territories without the aid of the transmission infrastructure of Southern communities. Thus, it builds generating systems near demand at the cheapest cost possible.

Qulliq Energy is a Crown corporation that supplies, transmits, and distributes power throughout Nunavut.

There are very few planned electricity projects for the Northern provinces and territories. Current projects in Yukon are mainly hydro; Nunavut's electricity comes entirely from diesel; and the Northwest Territories has a mix of diesel and hydro as their current energy sources. The detailed projects are listed in tables 11, 12, and 13.

Table 11
Yukon Generation Projects, by Energy Source and Status

Primary energy source	Stations existing or under construction	Installed capacity (MW)	Energy generated 2010 (TWh)	Stations planned or proposed	Capacity planned or proposed (MW)
Coal	0	0.0		0	0.0
Nuclear	0	0.0		0	0.0
Large hydro	3	80.0		0	0.0
Natural gas	0	0.0		0	0.0
Biomass	0	0.0		0	0.0
Landfill or biogas	0	0.0		0	0.0
Diesel	0	0.0		0	0.0
Off-grid diesel	0	0.0		0	0.0
Fuel oil	0	0.0		0	0.0
Off-grid hydro	0	0.0		0	0.0
Small hydro	2	6.3		0	0.0
Waste heat	0	0.0		0	0.0
Wind	1	0.9		0	0.0
Wind, offshore	0	0.0		0	0.0
Geothermal	0	0.0		0	0.0
Solar	0	0.0		0	0.0
Other/unknown fuel	0	0.0		0	0.0
Total	**6**	**87.2**	**0.3**	**0**	0.0

Source: The Conference Board of Canada.

Table 12
Northwest Territories Generation Projects, by Energy Source and Status

Primary energy source	**Stations existing or under construction**	**Installed capacity** (MW)	**Energy generated 2010** (TWh)	**Stations planned or proposed**	**Capacity planned or proposed** (MW)
Coal	0	0.0		0	0.0
Nuclear	0	0.0		0	0.0
Large hydro	1	10.0		1	18.0
Natural gas	1	7.7		0	0.0
Biomass	0	0.0		0	0.0
Landfill or biogas	0	0.0		0	0.0
Diesel	27	65.0		0	0.0
Off-grid diesel	0	0.0		0	0.0
Fuel oil	0	0.0		0	0.0
Off-grid hydro	0	0.0		0	0.0
Small hydro	6	55.0		1	5.0
Waste heat	0	0.0		0	0.0
Wind	0	0.0		0	0.0
Wind, offshore	0	0.0		0	0.0
Geothermal	0	0.0		0	0.0
Solar	0	0.0		0	0.0
Other/unknown fuel	0	0.0		0	0.0
Total	**35**	**137.7**	**0.6**	**2**	**23.0**

Source: The Conference Board of Canada.

Table 13
Nunavut Generation Projects, by Energy Source and Status

Primary energy source	**Stations existing or under construction**	**Installed capacity** (MW)	**Energy generated 2010** (TWh)	**Stations planned or proposed**	**Capacity planned or proposed** (MW)
Coal	0	0.0		0	0.0
Nuclear	0	0.0		0	0.0
Large hydro	0	0.0		0	0.0
Natural gas	0	0.0		0	0.0
Biomass	0	0.0		0	0.0
Landfill or biogas	0	0.0		0	0.0
Diesel	25	53.6		1	5.0
Off-grid diesel	0	0.0		0	0.0
Fuel oil	0	0.0		0	0.0
Off-grid hydro	0	0.0		0	0.0
Small hydro	0	0.0		1	5.0
Waste heat	0	0.0		0	0.0
Wind	0	0.0		0	0.0
Wind, offshore	0	0.0		0	0.0
Geothermal	0	0.0		0	0.0
Solar	0	0.0		0	0.0
Other/unknown fuel	0	0.0		0	0.0
Total	**25**	**53.6**	**0.15**	**2**	**10.0**

Source: The Conference Board of Canada.

APPENDIX B

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The Centre for Clean Energy

Clean energy is emerging as one of the major issues of the 21st century. The Centre for Clean Energy (CCE) has been created to find the best means of designing and managing the transition toward clean-energy systems that operate in a practical, profitable, and sustainable manner, and to find ways to develop global clean-energy industries in Canada.

Key Objectives

- Define pathways for fostering economic growth through the production and trade of energy services and clean-energy technologies, while facilitating the prudent exploitation and use of Canada's rich fossil, renewable, and nuclear resources.
- Build a community of leaders sharing the goal of a sustainable energy future for Canada. Mobilize these leaders to develop, discuss, and report on pathways for the transition to a clean-energy system for Canada.

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- Participation in, and access to, Conference Board executive briefings (on topics such as building a sustainable energy future for Canada, financing the transition, and the economic spinoffs).

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Membership in CCE is ideal for executives in all energy sectors—including energy supply, energy demand, governments, municipalities, academia, and environmental non-governmental organizations (ENGOs).

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