

**A CRITICAL ANALYSIS OF BC HYDRO'S DELIVERY MODEL FOR
MEETING THE CLEAN ENERGY ACT'S REQUIREMENTS**

by

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Abstract

On June 3, 2010, the BC Government's Clean Energy Act, Bill 17, became law. This new legislation set out a framework through which the province is to achieve 'electricity self-sufficiency' by the year 2016. BC Hydro is responsible for delivering initiatives within this framework through a series of projects that include building new power generation infrastructure; connecting independent power producers; and promoting energy conservation through demand side management.

This paper provides an analysis of BC Hydro's financial and organizational ability to deliver the requirements mandated by the Act. The utility's resource constraints will be evaluated in terms of building new assets (such as new generation facilities), purchasing power through IPPs and managing energy conservation initiatives. Finally, recommendations for future revenue rate increases and project forecasts are suggested in order for BC Hydro to sustain itself through 2016 and for generations.

Keywords: BC Hydro; Clean Energy Act; Smart Metering Infrastructure; Smart Grid; Independent Power Producer; Site C; Hydroelectric Power Generation; Power Smart; Demand Side Management; Rate Design; Organizational Change

Dedication

This project is dedicated to my wife, Suzanne, whose understanding and support were essential to its completion and to my children, Sarah and Alex, to whom I owe many hours of play time. Thank you all.

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1 Introduction

This project provides a critical analysis of BC Hydro's ability to deliver the requirements mandated by the Clean Energy Act. Delivery options will be considered and recommendations provided through an evaluation of the utility's constraints.

1.1 Background

In 2007, the BC Liberal Government announced their Clean Energy Plan termed, "A Vision for Clean Energy Leadership".¹ This plan focused on the reduction of greenhouse gas emissions from energy production in the province. After several years of public consultation and debate, the key attributes of the Clean Energy Plan were enacted into law and, in 2010, the Clean Energy Act was passed.

This new law includes the reintegration of BCTC into BC Hydro and provides a framework through which the province is to achieve 'electricity self-sufficiency' by 2016. BC Hydro is responsible for delivering programs within this framework that include building new power generation plants; connecting independent power producers to a distribution grid that is continually growing; and promoting energy conservation among customers through demand side management programs.

1.2 Objective

BC Hydro's delivery model will be evaluated against its ability to financially support; the building of new assets (such as new generation facilities), purchasing power through IPPs and managing energy conservation initiatives. This evaluation will involve a look at the Clean Energy Act, the electricity industry, BC Hydro's role in the industry and its ability to influence the industry's development. Finally, alternate recommendations for future project delivery forecasts, managing government requirements and revenue rates are suggested in order for BC Hydro to best meet the requirements of the Clean Energy Act.

¹ The Clean Energy Plan: <http://www.energyplan.gov.bc.ca/bcep/default.aspx?hash=1> (accessed March 14, 2011)

1.3 Organization of Analysis

This project will analyze the options available to BC Hydro for its delivery of the Clean Energy Act. In order to do this, a number of elements must be presented and discussed. These elements include the Clean Energy Act, the electricity industry in British Columbia, BC Hydro's programs and a financial analysis of the program requirements. Finally, a menu of options will be presented from which policy makers can choose desired outcomes in consideration of specific tradeoffs between specific goals and constraints.

Chapter 2 will discuss the Clean Energy Act itself, beginning with a definition of what *clean energy* is. The Clean Energy Act has eight key requirements that will be discussed in detail along with a description of BC Hydro's commitments under each of these requirements. This discussion will define critical timelines, energy capacity constraints and cost factors that BC Hydro must operate within while remaining compliant under the Act.

Chapter 3 will present an analysis of the electricity industry in BC. The growing demand of electricity will be examined along with the sources of supply. How BC manages the gap between demand and supply will be explored along with the process of importing and exporting electricity in BC. This industry framework is important in recognizing how BC Hydro can best operate and deliver its programs. The industry supply chain will be defined along with the roles of each party within this supply chain. Finally, the methods setting electricity rates in BC will be presented along with how energy purchase contracts are awarded. These factors are important to recognizing BC Hydro's role within and influence on the electricity industry and to understand how programs might be developed to meet the requirements of the Clean Energy Act.

Chapter 4 will present the BC Hydro programs designed to implement the requirements of the Clean Energy Act. First, an evaluation of BC Hydro's goals will be presented to understand what the utility must achieve. Second, each of BC Hydro's three key programs will be described in detail including: the demand side management program involving the education program, Power Smart, as well as the electronic metering program currently under implementation; the energy acquisition program through which third party power producers sell electricity to BC Hydro; and the utility's capital program required to build and maintain its aging generation assets. At the end of each section within this chapter, a number of program delivery options will be presented along with an evaluation of how well each option achieves BC Hydro's goals. Third, a summary of program option combinations will be presented by taking the options presented at the end of each section and tabulating them into a menu of delivery choices. This

menu will demonstrate which goals may be achieved under which combinations of options. This table forms the basis of analysis for the final chapter.

Chapter 5 will provide a financial analysis of feasible options available to BC Hydro for best meeting the requirements of the Clean Energy Act. This chapter looks at BC Hydro's historical financing model, the current funding requirements for the delivery of its programs and future projections. First, BC Hydro's financing history will be examined. This will involve an understanding of where the utility gets its revenues and its financing as well as how dividend payments and debt payments are managed. An examination of the company's economic health through sustainable growth will be presented in preparation for forecasting future financial projections. Second, the funding requirements of each program will be calculated in preparation for comparative financial analysis. Third, forecasts are generated including financial statements and pro forma calculations demonstrating various rate requirements for delivering program options. Finally, a summary of tradeoffs and feasible options are presented to help understand how BC Hydro can best meet the requirements of the Clean Energy Act given any flexibility that the government may provide in order to minimize the rate requirements for BC Hydro's delivery of electricity within the province.

2 The Clean Energy Act

This chapter defines the requirements of the Clean Energy Act that are to be delivered by, or are under the direct influence of, BC Hydro. An understanding of these requirements is essential to this project's analysis of whether BC Hydro's delivery model includes programs that sufficiently address all the requirements of the Clean Energy Act, and whether BC Hydro has the resources to deliver them within the prescribed timelines.

The chapter begins with a definition of 'clean energy' and proceeds to describe the key energy objectives of the Clean Energy Act.

2.1 Clean Energy

This section describes how the term 'energy' is used within the Clean Energy Act, how this energy relates to the power generation industry in BC, and provides the Clean Energy Act's definition of 'clean' as it relates to the generation process and the quality of emission by-products produced.

Energy exists in forms such as light (luminous energy), heat (thermal energy) and sound. It also exists in other forms such as magnetic, chemical and nuclear energy. For the purposes of this project and the Clean Energy Act, references to energy will be to energy that exists in the form of electricity (electrical energy).

Power is the rate at which electricity is transferred and, in the metric system, is measured in *Watts*. In practice, (for electrical utility bills for example) we find it more convenient to measure power in kilowatts (or units of 1,000 Watts). When power is measured over time, in convenient units of hours, we multiply power by time to derive units of electrical energy measured in kilowatt-hours (or kWh). *Power* is typically used to measure electricity consumed by a power utility's customers or produced by its generators. *Energy* is typically used to measure how much power is consumed or produced over time. To put these concepts in relative terms, an

average household in BC uses 11,000 kWh per year. A 20-story office tower might use 50,000 kWh per year whereas a pulp mill might use 400,000 kWh per year².

In Canada³, the National Research Council defines clean energy as, “energy that is produced, transmitted, distributed and used with low or zero greenhouse gas (GHG) and other air emissions.” This definition is broad enough to define the clean energy industry in terms of traditional sustainable energy projects as well as emerging technologies that may prove more economical in the future, such as hydrogen fuel cells.

The Renewable Energy & Energy Efficient Partnership (REEEP) defines sustainable energy as the provision of energy that meets the needs of the present without compromising the ability of future generations to meet their needs⁴. This definition involves recognizing the two elements of energy efficiency: the reduction of energy waste, and renewable energy. Reducing energy waste is a function of managing consumer demand. Renewable energy is energy from natural resources that can be replenished. Some natural resources, such as running water, wind and sunlight, are not at risk of depletion through the energy production process. Biomass, renewable organic materials, such as wood, agricultural crops or wastes, and municipal wastes, however, is only considered renewable if its consumption rate does not exceed its regeneration rate. Although it is unlikely that any method of power generation will ever be entirely impact free, those methods of producing renewable energy that involve the least negative changes to the environment are termed to be producing *green energy*. Depending on the jurisdiction in which it is used, green energy may refer to a slightly different subset of renewable energy generation methods. Nuclear Energy is included in this category by some jurisdictions, but its inclusion is controversial and often debated. The most controversial method that is often debated as whether it belongs in this category is that of nuclear power.

2.2 The Clean Energy Act Requirements

On June 3, 2010, the BC Liberal Government’s Clean Energy Act, Bill 17⁵, became law. This new legislation set out a number of initiatives through which the province is to achieve ‘electricity self-sufficiency’⁶ by the year 2016. BC Hydro, a Crown Corporation, is responsible

² BC Hydro Quick Facts:

http://www.bchydro.com/etc/medialib/internet/documents/about/company_information/quick_facts.Par.0001.File.quick_facts.pdf (accessed March 14, 2011)

³ NRC Clean Energy Fund Program: <http://www.nrcan.gc.ca/eneene/science/ceffep-eng.php> (accessed March 14)

⁴ REEEP Glossary of Terms: http://www.reeep.org/file_upload/296_tmpphpXkSxyj.pdf (accessed April 3, 2011)

⁵ Bill 17 – 2011: Clean Energy Act: http://www.leg.bc.ca/39th2nd/3rd_read/gov17-3.htm (accessed March 14, 2011)

⁶ The term ‘electrical self-sufficiency’ is defined under section 6(2) of the Clean Energy Act as holding the rights to electricity in BC that meet the province’s supply obligations.

for delivering these initiatives through a series of projects that essentially fall within three categories: promoting energy efficiency and conservation; connecting independent power producers (IPPs) for the supply of clean energy; and building new power generation infrastructure.

The Clean Energy Act is essentially the accumulation of a series of plans and policies developed over several years to meet the government's commitment to reduce greenhouse gas emissions in the province. This commitment is in compliance with the Federal Government's Greenhouse Gas Regulatory Framework⁷ that in turn was designed to comply with Canada's commitments within the Kyoto Protocol.⁸

The BC government has combined key elements of the Energy Plans from 2002⁹ and 2007¹⁰ with the Climate Action Plan of 2008¹¹ to form the foundation for the generation of clean energy in British Columbia. The government has also designed the Clean Energy Act to focus on generation methods that stimulate growth in the provincial economy.

The government's focus on economic growth is aligned with BC Hydro's Triple Bottom Line (TBL) corporate social responsibility framework. In addition to the financial goal of maximizing economic profits, the TBL analysis accounts for the environmental and social impacts of projects. The TBL approach requires project managers within BC Hydro to consider a number of goals in addition to financial return. These goals include job creation, the development of First Nations and remote communities, energy efficiency, technological development of clean energy opportunities and the reduction of greenhouse gas emissions within the province.

The Clean Energy Act sets out a number of key energy objectives and planning guidelines by which BC Hydro is to deliver its programs. These guidelines include a number of constraints under which the utility must operate while delivering these programs. The Clean Energy Act also places prohibitions on specific existing generation assets and future generation projects including restraints on the sale of property deemed to be *heritage assets*¹². Specific guidelines within the Clean Energy Act identify constraints on power acquisition projects and

⁷ Environment Canada, Government Delivers Details of Greenhouse Gas Regulatory Framework: <http://www.ec.gc.ca/default.asp?lang=En&n=714D9AAE-1&news=B2B42466-B768-424C-9A5B-6D59C2AE1C36> (accessed March 14, 2011)

⁸ Kyoto Protocol: http://en.wikipedia.org/wiki/Kyoto_Protocol (accessed March 14, 2011)

⁹ 2002 Energy Plan: <http://www.bcenergyblog.com/uploads/file/2002%20BC%20Energy%20Plan.pdf> (accessed March 14, 2011)

¹⁰ 2007 Energy Plan: <http://www.energyplan.gov.bc.ca/> (accessed March 14, 2011)

¹¹ 2008 Climate Action Plan: <http://www.env.gov.bc.ca/cas/> (accessed March 14, 2011)

¹² The term 'heritage assets' is defined in Schedule 1 of the Clean Energy Act as a specific set of generation and storage assets (generally hydroelectric facilities).

electricity metering projects while the requirements of a government subsidized First Nations Clean Energy Business Fund (of up to \$5 million) are specified under the Clean Energy Act for the development of electricity generation or transmission projects by First Nations groups.

Finally, the Clean Energy Act defines the parameters by which the two Crown Corporations, BC Hydro and its transmission asset management counterpart, the British Columbia Transmission Corporation (BCTC), are to be reintegrated. This reintegration involves a combination of assets, employee resources and processes designed to comply with energy trading agreements. The Clean Energy Act specifies which governmental parties will have regulatory oversight throughout the implementation of programs carried out in support of the new legislation. The following sections define these parameters in greater detail and explain what BC Hydro's role shall be.

The key energy objectives specified by the Clean Energy Act that affect BC Hydro can be described as follow:

2.2.1 Electricity Self-Sufficiency Timelines

The Province is to achieve electricity self-sufficiency by the year 2016, plus 3,000 GWh of insurance by 2020. Self-sufficiency is defined under the Clean Energy Act as BC Hydro holding the rights to an amount of electricity that meets its electricity supply obligations. The additional insurance capacity requirement in 2020, if generated, could be exported outside the province. Three constraints are set by the Clean Energy Act. First, all electricity must come from generation facilities located within British Columbia. Second, generation facilities cannot be considered to produce electricity levels beyond that determined to be provided under prescribed water conditions (hydrology forecasts). Third, the cogeneration facility, Burrard Thermal¹³, cannot be considered in the supply amounts (as it is to be maintained solely as a stand-by generation plant).

2.2.2 Demand Side Management Targets

The most recent Energy Plan of 2007 proposed that BC Hydro reduce its expected increase in demand for electricity by 2020 by at least 50%. This target has been raised to 66% under the Clean Energy Act. To meet this increased target, BC Hydro must develop more

¹³ A 950 MW thermal plant fuelled by natural gas near Vancouver that supplements BC Hydro's hydroelectric system in years when water inflow is low and provides transmission support and electrical supply security for the Lower Mainland.

aggressive demand side management initiatives to encourage the reduction of electricity usage.¹⁴ The largest project supporting this goal involves the installation of 1.8 million electronic meters called “smart meters” by BC Hydro in 2012.

2.2.3 Electricity Exporting

BC Hydro is to become a net exporter of electricity from clean and renewable resources. These exporting activities will involve trading electricity at rates that are exempt from regulation. The Clean Energy Act does not impose any restrictions on exported electricity rates (as it does for electricity sold to provincial customers). BC Hydro is free to behave as a profit maximizing firm by pricing exported electricity according to supply and demand considerations of the market.

2.2.4 BCUC Exempt Projects

The British Columbia Utilities Commission (BCUC) regulates all energy companies that operate entirely within BC. This regulation typically includes the BCUC’s approval of expenditures on BC Hydro capital projects and the approval of BC Hydro’s proposed electricity rates charged to customers in BC. Specific major electricity projects have been exempted from BCUC regulatory approval of capital spending in that they are considered a requirement of the Clean Energy Act’s key objectives. These include a power line from Skeena to Bob Quinn Lake, BC, known as the Northwest Transmission Line, new turbine unit installations at generation plants Mica and Revelstoke, the proposed Peace River Dam project known as Site C, the Smart Metering program and a number of programs to acquire power from IPPs.

2.2.5 Supply Requirements from IPPs

The IPP programs include a number of ‘calls’ for power. A call is an offer to purchase power under a program within a specified set of rules. These programs include a ‘call for bio-energy’, a ‘call for clean power’, and a ‘standing offer program’. These programs differ by allowable fuel source as well as by time period. The bio-energy and clean calls will be open for a limited period to consider projects producing electricity from wood waste and renewable fuel sources respectively. The standing offer program will be open indefinitely but offer lower rates for electricity than the other calls. Each program varies in terms of the prices paid to IPPs, the sizes of IPP generation capacity permitted and the technologies used by IPPs to generate power. BC Hydro is expected to set targets to acquire up to 1,000 GWh per year through the Bio-energy

¹⁴ BC Hydro defines Demand Side Management (DSM) as actions that modify customer demand for electricity or help to defer the need for new energy and capacity supply additions.

call, up to 5,000 GWh per year through the clean call and additional electricity through the standing offer program (with no minimum target set).

The BCUC is required under the Clean Energy Act to allow BC Hydro to recover the costs associated with becoming self-sufficient. The utility essentially becomes answerable only to the Minister of Energy through rigorous reporting guidelines that have been put in place (called Integrated Resource Plans under the Clean Energy Act). This is a change from the Certificates of Public Convenience and Necessity (CPCN) applications formerly required by the regulator.

A CPCN required BC Hydro's demonstration to the BCUC that the scope of any project submitted for approval was the best means to achieve its objective. The process allowed for private organizations or lobby groups to intervene at a public hearing before the BCUC would render its decision on. This process would often take months or years depending on the complexity of a project. Under the Clean Energy Act, the utility must demonstrate to the Minister that a project is required to meet the self sufficiency goal and then, if approved, would not require further analysis in order for the BCUC to accept the cost as recoverable under the utility's rate structure.

2.2.6 New Renewable Energy Generation Requirements

BC Hydro must generate at least 93% of its electricity in the province from clean or renewable resources and to build the necessary infrastructure to transmit this electricity. This clean energy target is higher than the percentage of clean energy that any electrical utility currently produces anywhere in North America.¹⁵

The environmental impacts of clean energy projects are subject to the requirements of the Canadian Environmental Assessment Agency (CEAA)¹⁶ and must undergo formal environmental assessments under CEAA requirements to obtain a permit from the Agency prior to proceeding. No clean energy projects are permitted on lands defined as parks, ecological reserves or conservation land.

2.2.7 Specific Asset Operation and Ownership

The Clean Energy Act requires BC Hydro to continue to maintain the Burrard Thermal natural gas cogeneration plant. As it is not considered a source of clean energy, however, the

¹⁵ Warren Brazier, the Provincial Government's Green Energy Advisory Task Force, <http://www.bcenergyblog.com/tags/clean-energy-act/> (accessed April 3, 2011)

¹⁶ The Canadian Environmental Assessment Agency is a federal body accountable to the Minister of the Environment with a mandate to eliminate or reduce a project's potential effects on the environment.

plant must not be operated except under specific conditions. These conditions include the provision of transmission support during years of low water inflow to hydroelectric facilities or to assist with transmission system maintenance by reducing the electricity load while the transmission system is under repair.

The sale of *heritage assets* has been prohibited. Heritage assets are defined within a Schedule attached to the act and generally include all generation and storage assets currently owned by BC Hydro. Exceptions to this requirement include disposing of assets that are no longer used or useful for their intended purpose, or assets that are to be replaced.

2.2.8 Structural Reorganization

The Clean Energy Act provides a detailed description of the requirements for the reintegration of BCTC with BC Hydro. In 2003, BCTC was formed under a provincial government mandate to separate the utility's power distribution and generation lines of business from its transmission line of business. At the time, the provincial government believed that the increased independence of transmission would result in the development of regional transmission organizations in the Pacific Northwest. BCTC, a publicly-owned crown corporation was created to help encourage new sources of power generation across the province; this was one of the goals of the Province's 2002 Energy Plan.¹⁷ This view changed in 2007 in response to critics of the Campbell government's energy policies denouncing the growing privatization of electricity in the province. The Clean Energy Act provides clarity on the roles of IPPs while reasserting the government ownership over the electricity transmission and distribution system.

The Clean Energy Act details the requirements for the transfer of property. The dealing of shares and obligations are cross-referenced with other supporting regulatory documents to comply with numerous legal requirements. A procedure is set for resolving any potential legal conflicts that may occur during the transfer of assets. Other details go so far as to define the treatment of employees, their employment terms and their pensions. The great majority of BCTC employees were successfully reintegrated with few redundancies found in the combined organization that currently employs almost 6,000 individuals.

¹⁷ Hoberg, G. (2010), British Columbia's New Clean Energy Act: A Preliminary Analysis: <http://greenpolicyprof.org/wordpress/?p=427> (accessed April 3, 2011)

3 Electricity in BC

This chapter discusses the aspects of the electricity generation industry in British Columbia that are most relevant to BC Hydro and its delivery of the Clean Energy Act's requirements.

The demand and supply of electricity in BC will be discussed along with projected forecasts of future electricity needs in terms of generation sources and overall capacity in order to assess whether the combination of BC Hydro's programs of conservation, acquisition and generation will be sufficient to fill the gap between forecasted demand and supply.

The electricity market will be discussed along with an analysis of its supply chain in order to assess whether BC Hydro's programs are adequately designed to have the influence needed at each stage to meet the Clean Energy Act's requirements.

The roles and responsibilities of the key stakeholders within the electricity generation industry will be described. These stakeholders include the electricity generators, the utilities, and the regulators. Each firm's mandate and the interactions between them are important in assessing the effectiveness of BC Hydro's programs for best meeting the requirements of the Clean Energy Act.

The IPPs will be described along with the interconnection process of IPPs, the award of energy purchase contracts and their rates. Understanding the process of successful connection of IPPs and how the power acquisition rules are set for these power generators is essential to analyzing whether BC Hydro's programs can attract the power required to meet its energy supply requirements under the Clean Energy Act and to determine the effectiveness of each program within BC Hydro's delivery model.

3.1 Demand and Supply of Electricity in BC

3.1.1 Demand of electricity in BC

The demand for electricity in BC is growing.¹⁸ BC Hydro has forecasted that electricity demand within the province will increase by 22-35% over the next 20 years due to several drivers including an expanding population, economic growth, and changes in technology (primarily due to the increased use of electronic devices such as large screen televisions). Statistics Canada has measured the usage of electricity by user group over the four year period of 2003 through 2006 inclusive based on the average consumption of 65,000 GWh per year and has displayed this demand in the following chart. Electricity demand varies according to customer groups which include the three main categories of Industrial, Commercial, and Residential customers. This charts shows that the largest demand for electricity comes from Industrial groups at 43% with Residential groups accounting for 27% and Commercial groups accounting for 20%. The remaining 10% can be attributed to municipal demands such as street lighting and public transit.

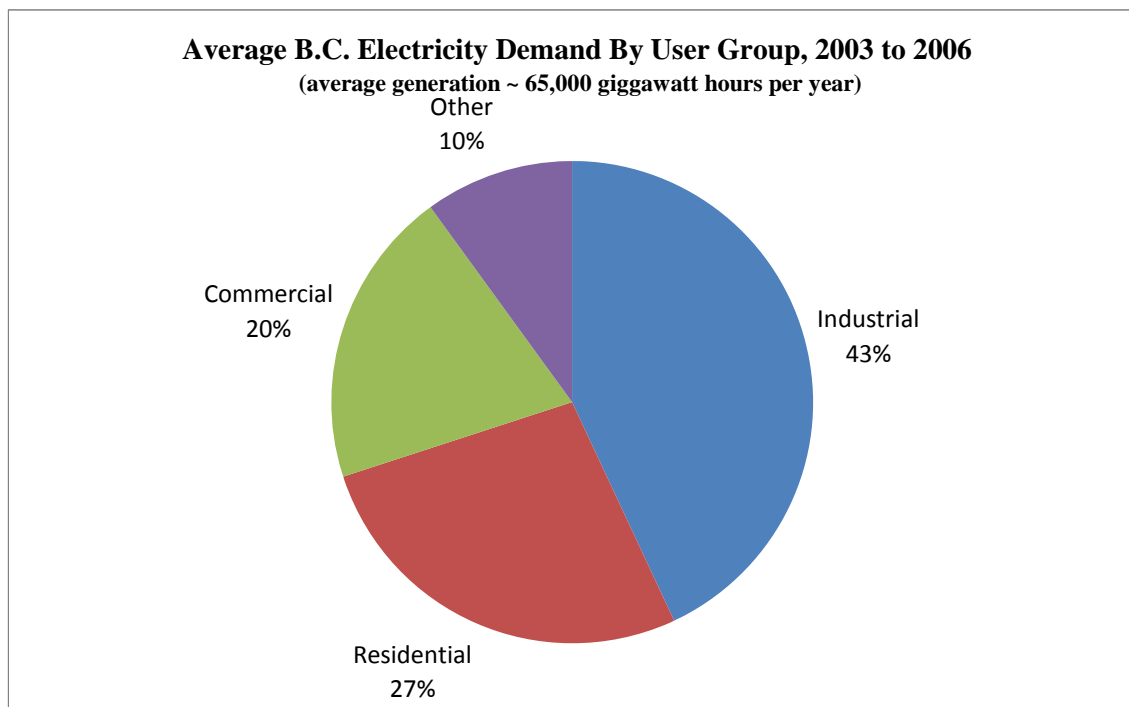


Figure 1: Electricity Demand in BC¹⁹

¹⁸ <http://www.empr.gov.bc.ca/EPD/ELECTRICITY/SUPPLY/Pages/default.aspx> (accessed March 25, 2011)

¹⁹ Source: Statistics Canada

3.1.2 Supply of electricity in BC

Although many countries throughout the world must rely on combustion processes using fossil fuels to produce electricity, British Columbia's electricity supply is predominantly generated through a hydroelectric generation system. The province also has abundant natural gas resources and forest by-products for renewable electricity generation from biomass.²⁰ Diesel and energy heat recovery systems (from industrial plants) are also used for electricity generation.

Statistics Canada has measured the 2009 supply of electricity generation in BC by fuel source. As shown by the following chart 84% of the province's electricity is generated through hydroelectric means, 9% is generated from biomass fuels and 6% from natural gas. Other sources (making up the remaining 1%) include biogas, diesel and heat recovery methods of generation.

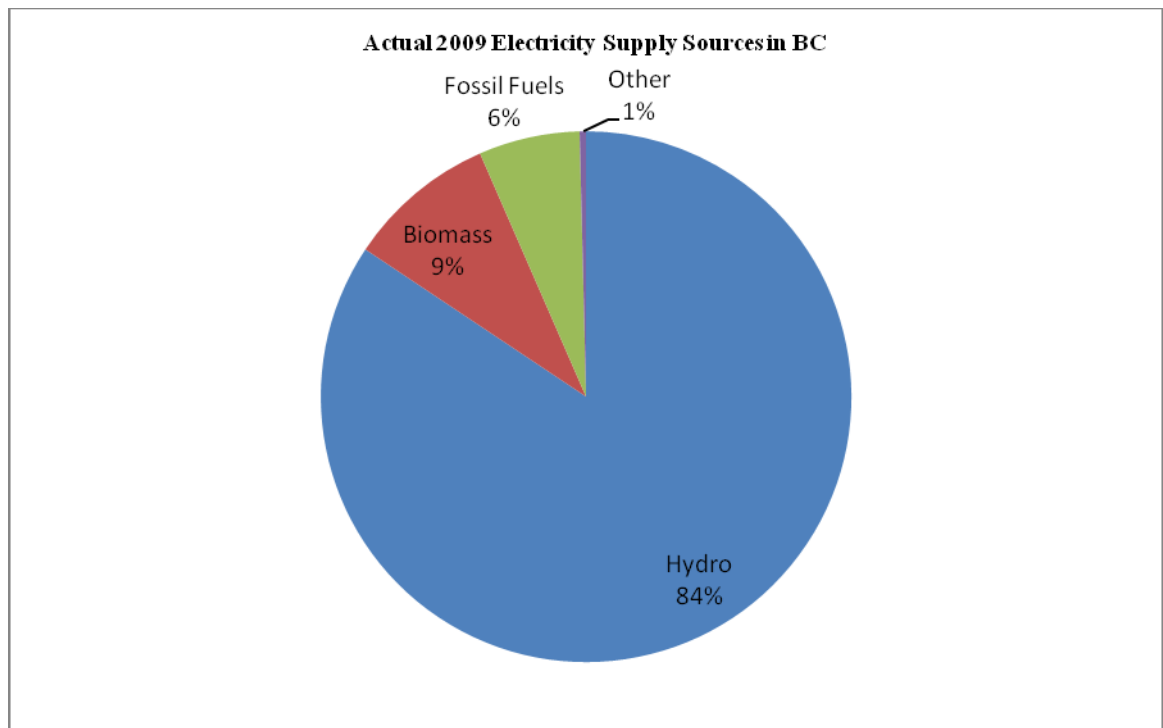


Figure 2: Electricity Supply Sources in BC²¹

²⁰ Biomass fuels includes wood debris from logging, organic residue from pulp mills and timber such as that infested by the mountain pine beetle

²¹ Source: Statistics Canada

Of the 65,000 GWh per year of electricity consumed, BC Hydro generates between 43,000 and 54,000 GWh annually (depending on prevailing water levels) and delivers it to approximately 94% of the province’s population. Included in these estimates of electricity supplied by BC Hydro, is electricity generated by hydroelectric facilities in the US that BC Hydro has rights to under the Columbia River Treaty.²²

3.1.3 The Gap between Supply and Demand

New electricity resources will be required to close the gap between forecasted electricity demand and supply in British Columbia. The following graph shows that BC Hydro’s forecasted customer demand is expected to exceed existing BC Hydro supply by the year 2012. By the year 2016, (not taking into account demand side management) the gap between supply and demand is expected to grow to almost 10,000 GWh and by 2025 the forecasted gap is expected to be approximately 20,000 GWh.²³

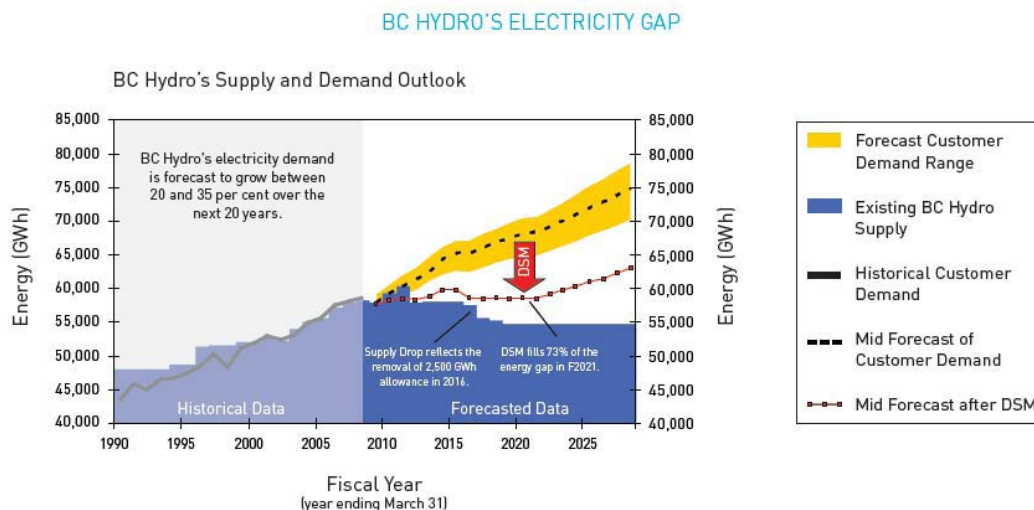


Figure 3: BC Hydro’s Supply & Demand Outlook²⁴

²² This Treaty, signed in 1961, was concerned with flood control between water dams located along the Columbia River both in Canada and the US. The cost of this flood control was to be shared between countries under terms of the Treaty. Canada agreed to sell 60 years of flood control water management to the US for rights to one half of the downstream power benefits (of the water volume managed). Source: The History of the Columbia River Treaty: [http://www.empr.gov.bc.ca/EAED/EPB/Documents/History%20ofColumbiaRiverNov139web\).pdf](http://www.empr.gov.bc.ca/EAED/EPB/Documents/History%20ofColumbiaRiverNov139web).pdf) (accessed April 9, 2011)

²³ <http://www.ippbc.com/EN/10048/> (accessed March 28, 2011)

²⁴ Source: BC Hydro Service Plan 2009/10 – 2011/12 used with permission

The Clean Energy Act's mandate that BC's energy gap be closed by 2016 will require generation solutions from projects that can be built and commissioned in less than five years. The Clean Energy Act also requires that a surplus of electricity be produced beyond this self sufficiency date. The longer term energy requirement (that the utility have 3,000 GWh of additional insurance capacity by 2020) may be met through BC Hydro's more traditional generation projects (i.e. hydroelectric dams).

The Clean Energy Act requires that the sources for this new generation be considered *clean* and that the generation process take place entirely within the province. BC Hydro has assessed the potential electricity generation resource availability in BC. These resource options include over 40,000 GWh of clean supply options as shown in Appendix A.

3.1.4 Importing and Exporting

Although BC Hydro has met its customers' demand in past years, the supply of this electricity has not been entirely generated within the province. In fact, BC Hydro has been a net importer of electricity during every year of since 2001 as shown in Appendix B.

BC Hydro has used importing and exporting of electricity as an economic advantage. Hydroelectric dams can store electricity in the form of water throughout the province and dispatch electricity on demand when the electricity is needed in the US (to power air conditioners during the day for example). BC Hydro exports electricity to meet this demand. The coal and natural gas plants used in the US to generate electricity can not increase their production for daily electricity fluctuations. BC Hydro is able to charge a higher price for this exported electricity during high demand times than it can for electricity exported during low demand times. Much of the imported electricity from Alberta and the U.S. is produced using fossil fuels such as gas and coal – sources that do not meet the Clean Energy Act's definition of those used to produce *clean energy*.

In the evenings, BC Hydro imports electricity from US thermal power plants that cannot be efficiently shut down for short periods. BC Hydro purchases this evening electricity at a much cheaper rate than it sells it for during the day. BC Hydro profits from this daily trading of electricity but the utility still needs to import more electricity each year than it can export to meet provincial customer demands. On average, of the 50,000 GWh of electricity supplied to BC customers each year by BC Hydro, the utility is purchasing 5,000 GWh in net imports annually. The utility forecasts that British Columbia could be relying on imported electricity for almost half

of its energy needs 20 years from now if new sources of generation are not created in the province.²⁵

3.2 The Electricity Market in BC

3.2.1 The History of Electricity in BC

Government control of energy resources in British Columbia began in 1945 after the Second World War with the formation of the BC Power Commission. The Commission acquired small generation and distribution systems while BC Electric, the province's largest privately owned electric utility, enhanced its assets.²⁶ Development of the province's major hydroelectric generation plants occurred throughout the 1950's under public funding through the government owned Peace River Power Development Company. In 1961, this company, BC Electric and the Commission were merged under the Power Development Act into BC Hydro.

A number of deregulation initiatives occurred throughout the 1980's including the sale of BC Hydro's gas division to Inland Natural Gas (the name changed to BC Gas later to Terasen and most recently to FortisBC). Further initiatives throughout the 1990's led to the outsourcing of many of BC Hydro's administrative services to Accenture (a Bermuda based company) and eventually the separation of the utility's transmission asset management group into a new crown corporation know as the British Columbia Transmission Corporation (BCTC). Due to the low electricity rates charged by BC Hydro, privatization of power generation itself, however, was seen by the private sector as unprofitable until the BC Liberal Government introduced its first Energy Plan in 2002. This plan allowed independent power producers to receive profitable rates for their clean energy. Clean and renewable generated power was not cost competitive with coal and natural gas fired generation (the marginal source of power as BC is a net importer) until competitive rates were made available through government policy. In 2007, the BC Liberal Government announced their Clean Energy Plan which went into law as the Clean Energy Act in 2010.

3.2.2 The Electricity Supply Chain in BC

The supply chain for the electrical energy industry is comprised of a series of processes that include power generation, transmission, distribution and consumption with a series of voltage

²⁵ IPPBC, Frequently Asked Questions: <http://www.ippbc.com/EN/10048/> (accessed March 28, 2011)

²⁶ The BC Citizen's Campaign for Public Power: http://www.citizensforpublicpower.ca/issues/bc_hydro (accessed March 12, 2011)

transformation steps in between. In British Columbia, most of the transmission and distribution processes belong to a single owner (the electrical utility) governed by a provincial regulator. The provincial electricity generation process, however, is evolving towards having a larger portion of third power generation. This electricity is being generated both from IPPs (for commercial purposes) and from large industrial customers that generate power (sometimes in excess) for their own business processes. The supply chain can be pictorially represented by the following illustration.

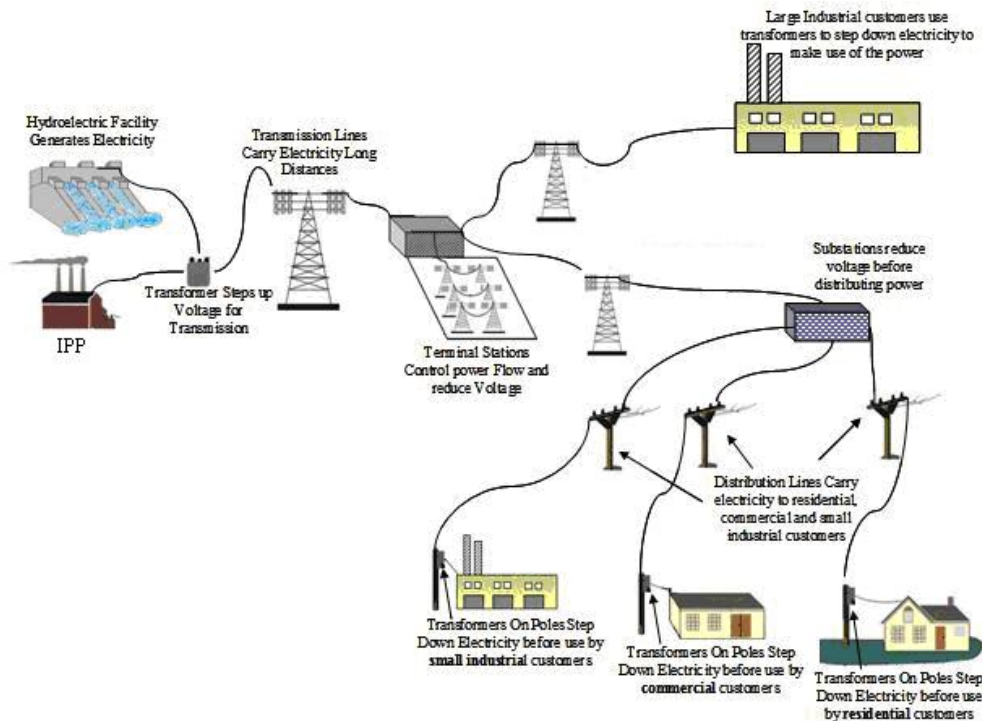


Figure 4: Typical Electrical Industry Supply Chain²⁷

When ownership of the supply chain is shared by IPPs owning the generation assets the supply chain becomes more complex. Defining locations such as the *point of interconnection* (POI) and the *point of metering* (POM) become critical in defining responsibility for operating and maintenance. These terms may also be used by the utility to determine rates paid for power where *line loss* (energy lost through heat as electricity passes through a long conductor) is a determining factor. Governmental regulations and power quality criteria must be carefully

²⁷ Supply Chain Illustration used with permission: <http://tonto.eia.doe.gov/energyexplained/images/transmission.jpg> (accessed March 28, 2010)

managed to ensure that third party producers meet minimum standards (relating to power surges or outage periods).

For energy passed through the electrical energy supply chain to be considered *clean* in British Columbia, the source of fuel must be considered as well as other environmental factors defined by the Clean Energy Act. This requirements result in the Clean Energy Industrial Supply Chain as described by the following processes.

3.2.3 Generation

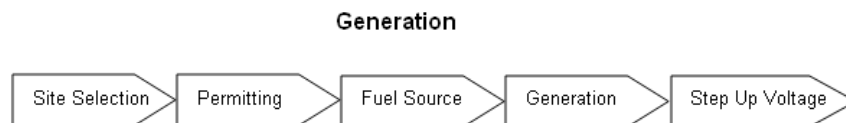


Figure 5: The Generation stage of the Clean Energy Supply Chain²⁸

The Clean Energy Act requires that the fuel used to generate clean energy in British Columbia come from a clean source and that the plant be constructed in accordance with the Canadian Environmental Assessment Act (CEAA). CEAA requires that, in constructing its plant, the IPP take measures to minimize the impact of its facility construction on local plants, birds, animals, fish, and heritage sites. Ecological studies are undertaken to determine wildlife territories and migration routes. Forestry engineering resulting in tree clearing must take into account nesting seasons and endangered bird species. Work near streams must incorporate plans for preserving riparian zones (those areas around waterways where fish food grows – typically plants and insects) during spawning season. Finally, and often most critical to construction schedules, local First Nations bands must be consulted to determine potential impact to reserve land.

Once all of these processes are completed, the supply chain moves through to the production of electricity through a means of generation that has been determined to be clean in accordance with the Clean Energy Act. Finally, the power produced is conducted through a transformer to increase the voltage to Transmission levels. The Clean Energy supply chain for the generation stage of the process is shown above (Figure 5).

²⁸ Source: Author, 2011

3.2.4 Transmission

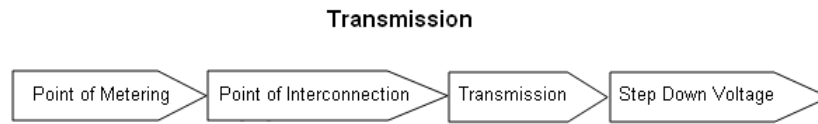


Figure 6: The Transmission stage of the Clean Energy Supply Chain²⁹

Once the generation facilities are energized, transmitting power to the electrical transmission lines requires an interconnection process that must meet specific criteria established by BC Hydro.³⁰ These requirements are designed to protect the utility's assets from faulty operation of the IPP's plant (such as power surges) as well as to protect the reliability of power provided by the utility to BC Hydro's customers in the area. BC Hydro determines a point of metering (POM) in accordance with the rate for which the utility pays the IPP for its power as well as the expected line losses. The metering equipment may reside at the IPP's plant, at the interconnection point or somewhere in between. The point of interconnection (POI) determines the transfer of operating and maintenance responsibility of assets. This point is typically located at a cutout switch (a manual fuse used to link the IPP's line to BC Hydro's line). All assets upstream of the POI are considered property of the IPP to be maintained at the IPP's cost. All assets downstream are owned by BC Hydro. The location of these points has an impact on operating and maintenance costs as more remote IPPs (those further away from BC Hydro's interconnecting power line) will experience higher costs of building and maintaining their private power lines. They will also experience larger line losses over greater distances resulting in the sale of less electricity than that produced.

Once the power is delivered to the transmission line and properly metered, the IPPs responsibility in the supply chain ends and the power (now the property of BC Hydro) is transmitted over a distance to a transformer substation where the voltage is reduced (stepped down) to distribution voltage. This is represented in the above diagram (Figure 6).

²⁹ Source: Author, 2011

³⁰ Some IPPs producing power at low enough levels may connect directly to BC Hydro's distribution system, cutting out the third and fourth steps of the Transmission stage supply chain. The transmission connecting IPP supply chain is shown here for completeness.

3.2.5 Distribution

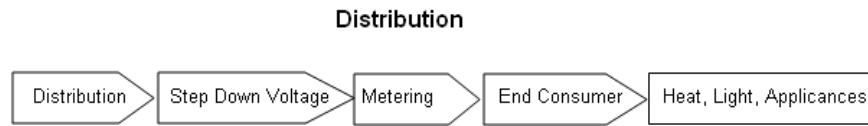


Figure 7: The Distribution stage of the Clean Energy Supply Chain³¹

Distribution power lines feed out of the transmission substations and are either strung along commonly recognized power poles or run through underground duct banks to the customer's location. Power is then conducted through these distribution facilities to a pole-mounted transformer or, in the case of an underground system, a pad mounted transformer (commonly seen in the form of a green box).

Through the transformer, this power is reduced to safe useable levels and fed through a customer meter (owned and calibrated by BC Hydro) after which the downstream connection is left to the customer or developer. Electrical wiring connected to this downstream terminal is then run through homes to connect to lighting, heating or end use appliances in accordance with the BC Electrical Code. This is represented in the above diagram (Figure 7).

3.3 Roles within BC's Electricity Industry

The electrical generation industry in British Columbia is comprised of power producers, utilities, customers and regulators. This section describes the roles of each group.

3.3.1 Independent Power Producers

The Independent Power Producers of BC (IPPBC) is an organization comprised of 48 privately held firms or Independent Power Producers (IPPs) operating entirely within BC. The association states that their mandate is:

"...to develop a viable independent power industry in British Columbia that serves the public interest by providing cost-effective electricity through the efficient and environmentally responsible development of the Province's energy resources."

³¹ Source: Author, 2011

The IPPBC is therefore a governmental lobby group formed to benefit its members through taking advantage of (and influencing the application of) the Clean Energy Act's requirements. The IPPs within the organization are responsible for finding innovative solutions for generating clean energy, complying with regulatory requirements and meeting the power quality and contractual requirements of BC Hydro during the interconnection process.

Together, the member firms within the IPPBC today generate approximately 9% of the province's electricity demand. There are currently no IPPs exporting power outside of BC. The association allows for the exchange of ideas among members related to government policy, interconnection processes, and new technology.

3.3.2 Utilities

The Clean Energy Act has consolidated the electrical utilities within the province. From 2003 to 2010, the transmission assets (transmission power lines, terminal stations, substations and the intermediary voltage regulation equipment) were managed by a separate entity from the power generation and distribution company.

BC Hydro is a Crown Corporation reporting to the BC Ministry of Energy, Mines and Petroleum Resources. The electric utility is the largest in BC and the third largest in Canada serving over 1.8 million customers. The company defines itself as an "entity that plans and delivers the clean energy required to meet British Columbia's growing demand for electricity while fostering job creation throughout the province and helping reduce greenhouse gas emissions." This definition is aligned with the organization's "triple bottom line" of financial, social and environmental management.³² The company's assets are comprised of generation, transmission, distribution and measurement equipment located throughout the province and serving over 94% of the province's population. Among these assets are 30 hydroelectric facilities and 3 natural gas-fueled thermal power plants generating up to 54,000 GWh of electricity each year. All power exported from BC (to the US or to Alberta) is exported by BC Hydro through its wholly owned subsidiary, PowerEx. BC Hydro's other subsidiary, PowerTech Labs, provides equipment testing, consulting and research services to the energy industry.

BCTC was a Crown Corporation formed in 2003 under a government mandate supported by the province's 2002 Energy Plan. The utility's purpose was to manage, operate and maintain the transmission assets within the province as an electricity transportation company operating independently from the electricity generating and distribution company. The decision to operate

³² BC Hydro, Who We Are: <http://www.bchydro.com/about/> (accessed April 4, 2011)

the province’s electricity industry through this model was reversed under the Clean Energy Act in response to IPP lobbyists as the interconnection processes became established. IPPs were claiming that they were experiencing excessive transaction costs due to the bureaucracy of dealing with two firms.

3.3.3 Customers

Electricity customers in BC can generally be separated into the three categories; residential, commercial and industrial. Although the quantity of customers in each category differs greatly, the power consumption of each group is relatively close as shown in the following table.

Table 1: BC Hydro’s customer profile³³

	Residential	Commercial	Industrial
Customers	1,606,156	191,286	162
Consumption (GWh)	17,861	18,265	14,303
Revenues (\$millions)	1,197	1,054	481
Average monthly power bill (\$)	62	459	247,428

Large customers (such as pulp mills) that produce electricity largely for their own consumption but may seasonally contribute power to BC Hydro’s grid are called *Self Generators* and are not considered to be IPPs under the Clean Energy Act.

3.3.4 Regulators

In BC, IPPs, utilities and customers are directly impacted by federal, provincial and municipal regulations. The following regulatory agencies set the permitting requirements of electricity generating facilities built by IPPs in BC.

The federal regulators influencing IPPs and utilities in BC include the Department of Fisheries and Oceans (DFO), the Canadian Environmental Assessment Agency (CEAA), and Environment Canada. Customers (such as developers) designing their facilities connecting to the utilities are also required to comply with the Canadian Electrical Code.

The provincial regulators influencing IPPs and utilities include the British Columbia Utilities Commission (BCUC), the Ministry of the Environment, Land and Parks (also termed

³³ BC Hydro Quick Facts (BC Hydro)

BCParks), and the Ministry of Transportation and Infrastructure (MOTI). MOTI's influence is mostly related to the use of provincially owned land corridors (known as Right-of-Ways) shared between highways and power lines.

Municipal regulators influencing IPPs, utilities and customers include the local city, township or district offices that set local building codes or construction practices within their respective regions.

3.4 Setting Rates and Awarding Contracts

This section describes the pricing method by which electricity acquisition rates are set in BC. The awarding of Energy Purchase Agreements (EPAs) are also discussed in this section along with the interconnection considerations of IPPs. An understanding of these pricing elements is important to assessing the financial obligations of BC Hydro when designing programs for the acquisition of electricity produced by IPPs under the requirements of the Clean Energy Act.

3.4.1 How Electricity Rates in BC are Set

The two most common methods of pricing electricity are market based pricing and cost based pricing.³⁴ Market based pricing involves prices that are determined in an open market system of supply and demand. In a market based pricing environment, prices are set based on agreements made directly between buyers and sellers. Market based prices may recover less or more than full costs depending on how buyers and sellers assess their opportunities and risks.³⁵ Cost based pricing is a method in which a fixed sum or a percentage of the total cost is added (as income or profit) to the cost of the product to arrive at its selling price.³⁶

In BC, a method of cost-based pricing is used. As BC Hydro generates its electricity through the use of large hydroelectric dams built decades ago, electricity prices in BC are very low compared to most other jurisdictions.³⁷ Electricity rates in BC are determined through the

³⁴ Taylor, S., Hoberg, G., (2011), How Electricity Pricing Works in British Columbia: <http://greenpolicyprof.org/wordpress/?p=508> (accessed April 4, 2011)

³⁵ McCracken, M., (2005), Explain Market Based Pricing: http://www.teachmefinance.com/Scientific_Terms/Market-based_pricing.html (accessed April 4, 2011)

³⁶ Business Dictionary, Cost-based pricing: <http://www.businessdictionary.com/definition/cost-based-pricing.html> (accessed April 4, 2011)

³⁷ Taylor, S., Hoberg, G., (2011), How Electricity Pricing Works in British Columbia: <http://greenpolicyprof.org/wordpress/?p=508> (accessed April 4, 2011)

requirements of the BCUC Heritage Contract.³⁸ This Contract is intended to ensure that BC customers benefit from Heritage Assets (defined as BC Hydro's existing generation, transmission and distribution infrastructure). These assets include the large dams built along the Peace and Columbia Rivers throughout the 1960s and 1970s. The purpose of the Heritage Contract is to maintain low rates for customers while maintaining a reliable supply of electricity.³⁹

The Heritage Contract mandates that BC Hydro uses *historical average cost pricing* to determine the price of the guaranteed quantity of electricity to be provided by its Heritage Assets. This method of historical average cost pricing calculates rates charged by the utility as equal to the average cost of producing one unit of electricity over the lifetime of a given generating facility. The average cost is determined by dividing the capital and operating costs of a facility by the total energy that is expected to be generated by the facility over its lifetime.⁴⁰ The early investment in large hydroelectric generating facilities, and this rate structure, is why BC Hydro maintains low electricity rates. Vancouver's residential rates are third lowest in the country, behind only Montreal and Winnipeg.⁴¹ Commercial and industrial customers pay lower rates due to economies of scale in purchased electricity. This is because BC Hydro has lower transmission costs per unit (more electricity is sold through a single power line servicing the customer). Electricity generated by new sources of power in BC will likely be more costly than that produced through Heritage Assets.

When BC Hydro exports electricity across the US or Alberta borders, market based pricing is used. BC Hydro's subsidiary, PowerEx, considers basic supply and demand considerations and factors elements into their pricing such as the availability of water levels behind dams, unforeseen power outages, and seasonal spikes or dips in customer demand. Market prices rise and fall as the balance between supply and demand changes. When BC has a surplus of electricity and import customers are experiencing a shortage, the price for BC Hydro's exported electricity increases. Conversely, when a surplus exists in BC and import customer demand is low, prices decrease. These prices, often quite volatile, are called the spot market prices.

BC Hydro typically buys electricity from IPPs at rates set by the utility under the corresponding Call For Power that exceed spot market prices. This practice has led to criticism

³⁸ BCUC's Heritage Contract: http://www.llbc.leg.bc.ca/public/pubdocs/bcdocs/365469/heritage_recommend.pdf (accessed April 4, 2011)

³⁹ Ibid

⁴⁰ Healey, S. (2010), Peak to Peak, A Primer on Electricity Pricing in BC: http://www.pics.uvic.ca/assets/pdf/futuregrid/Peak%20to%20Peak_Healey.pdf (accessed April 4, 2011)

⁴¹ Hydro Quebec (2010), Comparison of Electricity Prices in Major North American Cities.

that BC Hydro may be overpaying IPPs for electricity. Contracts with IPPs involve prices that are locked in for a long term (in some cases up to 30 years). Over this term, rates paid to IPPs are fixed thereby protecting BC Hydro and the IPPs from the volatility of spot market pricing. Over time, as BC Hydro spends money to maintain its heritage assets and builds new generation facilities, the utility’s cost of producing electricity (as calculated through the method of historical average cost pricing) will increase to rates closer to those paid to IPPs. These are the market considerations behind rates set for IPPs in BC.

There are also technical considerations behind rates paid to IPPs. BC Hydro sets rates paid to IPPs in consideration of the point of interconnection (POI). The utility calculates the cost of this electricity based on the estimated energy lost (through heat dissipation from the conductors) over the distance between the electricity generation supply point and the end consumer demand points. This value is also dependent upon the cost of operating and maintaining the power line infrastructure (the portion owned by BC Hydro) between supply and demand points. Electricity generated closer to regions of higher populations (of electricity consumers) is typically worth more to BC Hydro than electricity generated further away. These considerations vary throughout the province. Prices therefore vary proportionally to the geographic location of the generation facility (Table 1).

Table 2: Base Price by Region set by BC Hydro⁴²

Region of POI	Base Price (\$/MWh)
Vancouver Island	84.23
Lower Mainland	83.86
Kelly/Nicola	80.31
Central Interior	77.53
Peace Region	69.94
North Coast	71.37
South Interior	72.27
East Kootenay	76.05

3.4.2 Qualifying for an Energy Purchase Agreement

The Energy Purchase Agreement (EPA) is a contract to supply electricity between an IPP and BC Hydro. The IPP (as the electricity supplier) applies to obtain an EPA by demonstrating a

⁴² Source: BC Hydro Standing Offer Program, Section 4.1, Fig.3

reliable generation process deemed to be clean under the Clean Energy Act. The application must also be compliant with the terms of the specific Call For Power or power acquisition method under which the IPP requests interconnection. Stringent power quality requirements set by the utility must also be met. Power quality requirements include engineering considerations that measure the IPP's ability to control power surges, maintain levels of generation and limit power outages. This agreement has commercial value to the IPP as the EPA survives the sale of a generating plant (even in mid-construction).

4 BC Hydro's Implementation of the Clean Energy Act

This chapter describes how BC Hydro is currently implementing the requirements of the Clean Energy Act and explores various options. BC Hydro has initiated several programs that, in combination, are designed to meet the Clean Energy Act requirements. These programs essentially fall within the three categories of conserving power, buying power, and building power generation. BC Hydro's goals and evaluation criteria will be established and each program will be analyzed in terms of whether it meets each goal and what alternatives might exist. Finally, a menu of options is presented at the end of the chapter summarizing all combinations of alternatives available. Feasibility of the current implementation as well as the most promising program combinations will be considered in chapter 5.

Conservation programs will be explored in greatest detail within this chapter as BC Hydro expects the success of these programs to be the largest contributor to closing the future gap between electricity supply and demand in the province. This discussion will look at the more traditional Power Smart program in detail as well as BC Hydro's largest demand side initiative, an electronic metering program relying on technology to modify consumer behaviour through access to billing information. Together, these programs are expected to conserve 66% of the forecast increase in demand between now and 2016. This equates to 54% of the gap between the province's forecasted 2016 demand and BC Hydro's forecasted supply after capacity reductions mandated by the Clean Energy Act.

Purchasing power from IPPs has been mandated by the Clean Energy Act. This chapter will discuss the various electricity acquisition programs or "Calls For Power" under which IPPs apply to provide electricity to the utility. A brief analysis of the various procurement methods will be compared against BC Hydro's goals. Currently published acquisition plans as well as future options will be considered. Together, these programs are realistically expected to close BC Hydro's forecasted gap between supply and demand by 25%.

Power generation through BC Hydro's heritage assets will be presented through a discussion of the utility's capital project service plan. This program of maintaining existing plants, upgrading facilities to higher capacity and building new hydroelectric generation will represent the largest expenditure within BC Hydro's overall implementation strategy. Much of

the financial investment required under this program will be factored into any solution to meet requirements as failing to maintain existing generation facilities built many decades ago would ultimately result in equipment failure. Although some projects are required simply to maintain BC Hydro's existing generation capacity, those projects designed to increase capacity are expected to close BC Hydro's forecasted gap between supply and demand by 22%.

4.1 BC Hydro Goals and Project Evaluation

In the delivery of the Clean Energy Act, BC Hydro's goals can be identified in broad terms as *capacity*, *time* and *cost*. The Clean Energy Act requires that the utility become electricity self-sufficient within specific timelines and electricity consumers within the province expect the government to take action to maintain low electricity rates. The three primary goals of the organization will be measured as follows:

Electricity self sufficiency is measured under the Act as BC Hydro having rights to that supply of electricity required to meet the demands of its provincial customers with additional capacity available in the future. Each of BC Hydro's programs will be evaluated against how much they are able to close the gap between electricity supply and demand. The demand side management program will be evaluated against how much reduction in future consumption it can generate through consumer conservation. The electricity purchase and generation programs will be evaluated against how much additional capacity they will provide over specific time periods.

Time milestones are set within the Clean Energy Act. BC Hydro is mandated to implement specific conservation initiatives by 2012, to find a combination of programs that will meet electricity demand with an equal supply by 2016, and to find a means to obtain rights to an additional 'security' capacity of 3000 GWhs by 2020 (about 5% of anticipated 2016 demand, after mandated demand-side reductions). Each of BC Hydro's programs will be evaluated against their ability to meet each of these schedule constraints.

Cost is ultimately the underlining factor of all programs. Although consumers within the province have experienced low rates for electricity in the past, any combination of BC Hydro's programs able to achieve the Clean Energy Act's requirements will require billions of dollars to support. This fact, along with the specific financial constraints which the utility must adhere to is further analyzed in chapter 5. The cost of each program is therefore considered in the evaluation of the any combination of alternatives which meets the government's mandates.

4.2 Demand Side Management

Demand Side Management (DSM) includes all actions that modify customer demand for electricity or help to defer the need for new energy and the addition of capacity supply. The Clean Energy Act has mandated that BC Hydro meet the objective of reducing its expected increase in demand for electricity by at least 66%. This reduction in the 10,000 GWh estimated gap between future demand in 2016 and current supply represents 54% of the reduction between future demand and BC Hydro's expected 2016 supply (taking into account the 2,500 GWh capacity lost from BC Hydro's system after the decommissioning the Burrard Thermal plant in 2016).

Individual DSM expenditures are justified through the value of the energy savings derived from the programs. In order to ensure that BC Hydro is receiving a sufficient benefit from expenditures, the savings achieved are tracked and reported with sufficient accuracy to allow BC Hydro's management to justify such costs to the British Columbia Utilities Commission (BCUC).

This section examines three aspects of DSM. First, a discussion will be provided describing how electricity rates are applied in BC with respect to demand side management. Second, an analysis of BC Hydro's Power Smart program will be presented to explore how it will help achieve the 2016 self-sufficiency goal. Third, an analysis of BC Hydro's delivery model for the Smart Metering program will provide insight into current technology designed specifically to meet the Clean Energy Act requirements. Together, these programs comprise BC Hydro's demand side management program.

4.2.1 Rate Design supporting DSM

Residential, commercial and industrial rates for electricity sold by BC Hydro in BC are applied for by the utility and approved by the BCUC. Rate design applications (RDA) are proposals to update rate structures, rates charged to customer classes, and terms and conditions of service. BC Hydro does not necessarily generate more revenue as a result of an approved RDA, but rather rebalances rates paid by different customer classes.

One purpose of an RDA is to ensure that rates paid by customers reflect the costs of providing service to that customer so that classes of customers do not overly subsidize one another. The other purpose of an RDA is the promotion of energy conservation.

As conservation awareness is increased through Power Smart, and consumers are provided with more electricity conservation data from electronic metering, BC Hydro will begin

to implement 'time of use' rates. Time of use rates are rates charged by BC Hydro to customers that may vary depending on the time of day (usually higher during peak demand periods) and seasonal periods. Such pricing techniques may be used by electric utilities to influence consumer behaviour towards conservation if customers have access to their rate structure details and their electricity usage information as they will through electronic metering.

4.2.2 Power Smart

One of BC Hydro's guiding principles⁴³ is to develop and support a culture of conservation in BC. Power Smart, developed in November of 1990⁴⁴, is BC Hydro's oldest Demand Side Management initiative. It is responsible for leading BC Hydro's conservation and energy efficiency efforts. Power Smart assists customers in conserving energy, thereby saving energy costs and reducing environmental impact. This section describes Power Smart, how the program works and how it will be leveraged in combination with other DSM programs to deliver the requirements of the Clean Energy Act.

4.2.2.1 The Power Smart Program

The Power Smart program is, in its current form, detailed in BC Hydro's Long Term Acquisition Plan.⁴⁵ This plan explains that BC Hydro's influence over customer decisions will involve information and financial assistance. Firms will be influenced through energy prices and regulations that impact business decisions. Changes to market parameters (such as conservation rates or building codes for example) can encourage energy conservation. Communities may also change as a whole where norms and expectations (such as the size of homes) impact energy consumption. These influences have been demonstrated successful through studies performed in similar markets such as California where CALMEC (The California Measurement Advisory Council) has published their Efficiency Evaluation Protocols (measures of electricity consumer behaviour).⁴⁶

⁴³ BC Hydro first published its 15 'guiding principals' within its 2009 annual report.

⁴⁴ BC Hydro Power Pioneers, Chronological Overview: http://www.powerpioneers.com/BC_Hydro_History/1972-1990/chronology.aspx (accessed March 14, 2011)

⁴⁵ Appendix K of BC Hydro's Long term Acquisition Plan : http://hydroweb/etc/medialib/hydroweb/documents/customer_care___conservation/power_smart/quality_assurance/dsm_policy_and_resources/dsm_plan.Par.0001.File.tmp/2008_itap_appendix_k.Par.0001.File.2008_itap_appendix_k.pdf (accessed March 14, 2011)

⁴⁶ CALifornia Measurement Advisory Council (CALMAC), Efficiency Evaluation Protocols: http://www.calmac.org/events/EvaluatorsProtocols_Final_AdoptedviaRuling_06-19-2006.pdf (accessed March 14, 2011)

4.2.2.2 Power Smart Tools to Decrease Demand

Specific examples of Power Smart activities that focus on the individual customer include the Fridge buy-back program and the Team Power Smart program.

The Fridge buy-back program offers residential consumers \$30 for their secondary refrigerators as these appliances often represent the largest consumption of electricity in a customer's home. The older a refrigerator is the less energy efficient it is due to improvements of manufacturing standards over time. On average, these appliances consume 1,200 kWh per year. BC Hydro's Power Smart program has collected 190,000 units since 2002 and estimates another 300,000 secondary fridges are still currently residing in the homes of BC's residents.

Team Power Smart is a program that individual BC Hydro customers can join to learn how electricity conservation can save them money. Members are offered information specific to their electricity consumption uses with an incentive of \$75 if they reduce their consumption by 10% over a one year period. The utility plans to educate these consumers so that their conservation behaviour will continue beyond this period. The program has attracted approximately 300,000 members with an estimated annual energy savings of 330 GWh.

Large industrial customers are assigned a Key Account Manager, an employee of BC Hydro specializing in the customer's industry (such as oil & gas or pulp & paper) to perform annual assessments of the customers facilities to identify areas where energy efficiencies may be improved. Smaller commercial customers and strata properties may take advantage of energy savings assessments performed by private firms to identify where higher efficiency lighting products may be used. The assessing firms then bid on lighting replacement projects for these customers quoting materials subsidized by Power Smart. The most significant savings experienced recently at a typical strata complex in Burnaby⁴⁷ came from the upgrading of fluorescent lighting and exit signs in underground parking areas where lighting is on 24 hours per day.

4.2.2.3 Measuring Success

BC Hydro justifies Power Smart expenditures to its regulator (the BCUC) through energy savings and derived from the individual initiatives. Savings achieved are tracked and reported with sufficient accuracy to meet the needs of the regulator.

⁴⁷ Source: Strata Council President (author), LMS 1789

Power Smart’s mandate is to pursue cost effective demand side measures. A demand side measure is defined as a rate, measure, action or program undertaken to: conserve energy or promote energy efficiency; to reduce the energy demand a public utility must serve; or to shift the use of energy to periods of lower demand. To be cost effective, a demand side measure must produce a benefit that is greater than the cost of the investment in the demand side measure. The benefit that is generally produced through BC Hydro’s demand side measures is primarily related to the avoided costs of new electricity supply (in dollars per kWh saved).

Power Smart energy savings are reported to the regulator after ensuring accuracy and that they are truly attributable to Power Smart. Assessment of the program’s success is done through a series of evaluation, measurement and verification techniques.⁴⁸ There are eight key elements that are taken into account when evaluating the success of a Power Smart initiative. These elements are Cross Effects, Evaluation, Free Riders, Market Effects, Market Transformation, Measurement and Verification, Rebound Effects, and Spillover.⁴⁹ These elements can be graphically illustrated in the savings vs. time graph shown below (Figure 8).

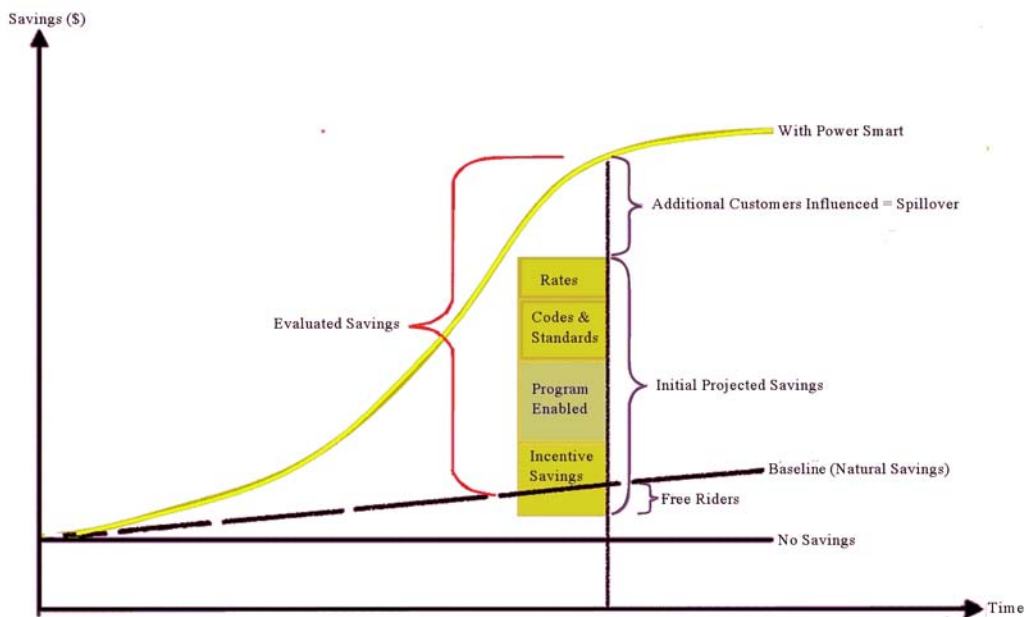


Figure 8: Effectiveness Assessment of Power Smart Initiatives in savings (\$) over time⁵⁰

⁴⁸ BC Hydro Service Plan: Power Smart & Customer Care

⁴⁹ BC Hydro Revenue Requirements Application, Glossary and Abbreviations: http://www.bchydro.com/etc/medialib/internet/documents/info/pdf/revenue_requirements_appendix_a_glossary_and_a_bbreiviatio.Par.0001.File.revenue_requirements_appendix_a_glossary_and_abbreviatio.pdf (accessed March 14, 2011)

⁵⁰ BC Hydro Service Plan: Power Smart & Customer Care

Cross-effects refer to the effect that some energy conservation measures have on other electricity end uses beyond what the Power Smart initiative itself produces. One example is building lighting. As more efficient lighting is installed, less heat is generated by the lighting system. This means that less heat must be removed from the building by the air conditioning system during the cooling season, but more heat needs to be supplied by the heating system during the heating season. Cross-effects need to be assessed at the Power Smart program level to ensure that each initiative's success is accurately identified.

Evaluations are systematic, objective studies are conducted periodically to assess how well a Power Smart initiative is working. The primary intent of evaluations is to determine if adjustments are needed to improve the rate or quality of the initiative relative to the committed resources. Evaluations are carried out for substantial Power Smart initiatives however small, short-term initiatives can be possibly exempt if evaluation costs are determined to exceed their benefit and risk of inefficiency is very low.

Free riders are participants who would have taken the Power Smart initiative's desired action even in its absence. Free riders are accounted for when initiatives are developed and savings are calculated. Estimates may be determined by reviewing evaluations of similar programs, conducting participant surveys, and tracking product sales before and during the rollout of the initiative. In some cases, studies show that energy use increases from developed baselines due to natural conservation and free riders are no longer an issue. Natural conservation refers to improvements in efficiency that occur in the absence of the Power Smart initiative.

Market effects are additional energy efficiency measures undertaken by customers outside of Power Smart initiatives that are attributable to the initiative's impact on overall energy efficiency. Depending on the initiative, market effects can occur at the same time as program activity or in years following a program. Each Power Smart initiative must have a clearly defined intent (in terms of how it will transform the electricity industry) and an established set of goals for transformation that can be measured from an established baseline. A baseline study would document the pre-initiative state and trends of relevant market parameters, such as awareness of electricity rate levels. The study should forecast how market parameters are expected to change in the absence of the Power Smart initiative.

Market Transformations are permanent changes in the functioning of markets. These include more energy efficient behaviour among customers and higher market penetration of energy-efficient products as a result of Power Smart initiatives that increase energy efficiency. Market transformation effects can be large and are therefore best measured through the

establishment of baselines and trends for the particular industry prior to launching the Power Smart initiative. Activity during the initiative can be measured and the savings calculated relative to those measured by the baseline case.

Measurement and Verification savings are determined after one year of post initiative operation and are based upon program effectiveness. These savings are adjusted by effects referred to as direct and indirect rebound effects when determining energy savings. Energy pricing can reduce direct and indirect rebound effects (Sorrell, 2007).⁵¹ These effects are explained as follow:

A direct rebound effect is the increased usage of a device because it is more energy efficient. An examples is when a consumer replaces an incandescent light bulb with a CFL, they may realize that the light now costs less so they will be less concerned about turning it off. For a producer, increased energy efficiency could result in a lower cost of production, increasing the demand for the produced good, resulting in increased output.

An indirect rebound effect is the lower cost of an energy service due to increases in energy efficiency leading to changes in the demand for other goods that consume energy.⁵² Examples include cost savings from a more efficient heating system that may be put towards the purchase of new energy-using electronic equipment. Cost savings obtained by a producer from the installation of more efficient equipment may result in increased output, increasing consumption of other materials or processes which require energy to provide. Examples include the reduced cost of decorative lighting due to LEDs increasing the demand for decorative lighting overall during Christmas.

Spillover (also called free drivers or tag-ons) refers to program participants and non-participants whose energy savings measures occur through actions that are not part of a Power Smart initiative, but which were influenced by the initiative and the market changes resulting from the program. Spillover must be accounted for when Power Smart initiatives are developed and savings are calculated. Prior to implementation, spillover effects can be estimated by reviewing evaluations of similar initiatives and through discussions with market players regarding their intentions should the program proceed. Once a program has been in operation for some time, participant and non-participant surveys can be used to estimate spillover.

⁵¹ Sorrell, S., The Rebound Effect. (2007).
<http://www.ukerc.ac.uk/Downloads/PDF/07/0710ReboundEffect/0710ReboundEffectReport.pdf> (accessed March 14, 2011)

⁵² Greening, L.A., Greene, D.L., Difiglio, C. (2000). Energy Efficiency and Consumption - the rebound effect - a survey:
http://jks-energy.wikispaces.com/file/view/EP_Greening2000EnergyEfficiencyConsumptionReboundEffectSurvey.pdf
(March 14, 2011)

These eight key elements are used to assess the effectiveness of each initiative within the Power Smart program. In combination, these initiatives are mandated to reduce BC's expected increase in demand for electricity by at least 66%. Since its inception, BC Hydro estimates that \$3 in generating costs are saved for every \$1 spent on energy conservation through Power Smart initiatives. The utility expects this level of economic benefit to increase following the introduction of the electronic metering program.

4.2.3 Electronic Metering Installation

This section explores the advantages of applying electronic metering technology at BC Hydro and compares BC Hydro's management of the program to that of similar firms in other jurisdictions, as the effectiveness of the program is greatly dependent upon its implementation schedule. The following analysis demonstrates that electronic metering may be a powerful tool for modifying customer behaviour but that the projected timelines for meeting equipment installations may be overambitious.

4.2.4 Smart Metering and Infrastructure Program

In addition to increasing its generation capacity, BC Hydro's capital delivery plan includes a proposal to automate, modernize and upgrade its electricity distribution grid system through a Smart Metering and Infrastructure (SMI) program. This program includes a series of projects designed to improve the reliability of the distribution grid and provide additional service options for customers in order to facilitate energy conservation behaviour.

BC Hydro anticipates that the program will have a positive net present value, based on expectations that it will improve service and deliver significant benefits to customers in the future (while keeping BC Hydro's electricity rates low). The entire program, when fully rolled out will be comprised of the SMI project itself, a Home Display project, a Theft Detection project and a modernization to the distribution system referred to as Smart Grid. These are described as follows:

4.2.4.1 Smart Metering Project

This stage of the program is scheduled for 2012 at a cost of \$530 million.

BC Hydro will install new digital meters that support two-way communication between the utility and its 1.8 million customers. The SMI project also includes the installation of associated IT systems that, together with the meters, form the foundation for the In Home Display

Project and the Theft Detection Projects. Smart meters will allow BC Hydro to measure and manage electricity supply and demand through new technology that will increase efficiency and allow customers to remotely monitor their energy usage. Customers will have access to new innovative conservation rate structures and benefit from more timely and accurate billing. Service connections and outage detection will also be enhanced.

4.2.4.2 In Home Display Project

This stage of the program is scheduled for 2012 at a cost of \$100 million.

To achieve the Clean Energy Act's target of meeting 66% of incremental load growth through conservation, BC Hydro will be making In Home Displays available to customers. The In Home Display will communicate with Smart Meters via wireless technology so that customers may view their energy consumption and costs directly. BC Hydro anticipates that this timely information will encourage customers to manage their consumption and save money by taking advantage of Power Smart programs discussed above.

4.2.4.3 Theft Detection Project

This stage of the program is scheduled for 2012 at a cost of \$170 million.

The Theft Detection Project involves the installation of specialized devices that will more accurately measure electricity delivered to a specific geographical area. This data will be reconciled with actual customer consumption allowing BC Hydro to identify where theft is occurring and reduce its impact to ratepayers.

4.2.4.4 Smart Grid

This stage of the program is scheduled for 2012 at a cost of \$130 million

Smart Grid is comprised of a series of modernization and infrastructure upgrades planned for implementation within the existing BC Hydro electricity distribution system. This series of initiatives includes upgrades to IT systems that improve efficiencies in operation (such as regulating voltage) and provides support for automation in the system. These automations are expected to decrease restoration time (following an outage), improve reliability and provide more consistent power quality.

These infrastructure upgrades are required to support an increasing number of IPP connections under the requirements of the Clean Energy Act. The distribution grid must be able

to support the acceptance and integration of clean distributed generation (IPPs connecting throughout the province near customer demand). The new infrastructure may eventually enable customers to choose their clean energy supply from a series of options such as solar, wind or biomass.

4.2.4.5 The Advantage of SMI

In summary, BC Hydro has made a commitment to replace 1.8 million conventional meters with digital ‘smart meters’ by the year 2012. The key drivers behind the project include: promoting energy conservation among customers; reducing power theft; and increasing the reliability and management of the power distribution grid. BC Hydro expects the \$930 million project to deliver a positive net present value of approximately \$500 million over the next 20 years.⁵³

Some changes have already begun. CIO, Don Stuckert stated that smart meters have already been installed in the top 300 industrial businesses of BC to better manage electricity use by taking advantage of new pricing programs aimed at encouraging conservation.⁵⁴ Further changes are coming, according to Mr. Stuckert. In addition to the goal of the utility’s customers conserving 66% of the incremental power required under the Clean Energy Act, a 10-20% reduction in theft, the ability to read meters three times faster, and a 10 times decrease in outage response time is expected. Mr. Stuckert explained that, “benchmark consumption and theft monitoring will be measured at 6 month intervals against the plan”. The costs and benefits of BC Hydro’s SMI program are considered critical factors in achieving the firm’s long term goals under the Clean Energy Act.

4.2.4.6 Comparison of SMI among similar firms

Power consumption worldwide is expected to triple by 2050. Over 150 jurisdictions globally (116 utilities in North America) are installing smart meters and smart grids.⁵⁵ BC Hydro’s closest neighbours currently managing SMI programs are Fortis Alberta and Southern California Edison. Fortis is planning to install over 400,000 smart meters by the end of 2010 while Edison plans to deploy 5.3 million smart meters by 2012. Parallels may be drawn between the expected success of BC Hydro’s SMI program and the current success of these firms.

⁵³ Smart Meters Fact Sheet: <http://www.mediaroom.gov.bc.ca/> (accessed March 14, 2011)

⁵⁴ Don Stuckert, CIO, BC Hydro, interview with Jay Buckley for preparation of SFU EMBA Project

⁵⁵ BC Government Fact Sheet, What are other jurisdictions doing?: <http://www.mediaroom.gov.bc.ca/> (accessed March 14, 2011)

Two common challenges found within the published documents of these companies are meeting installation schedules and measuring real versus projected benefits within the programs. Similar economic and labour conditions within Canadian energy industries suggest that BC's installation timelines may be more similar to those of Alberta utilities, whereas benefits from customer conservation behaviour may be more similar to the California market.

Fortis' projected installation schedule and their frequently updated progress is shown on their website⁵⁶. Although they are only slightly behind schedule, their installation targets were much less ambitious than BC Hydro's. Fortis's highest number of smart meter installations planned in a year was 239,000 in 2009. Their website suggests that they achieved about 90% of this amount. They plan to make up the difference by the end of 2011, when they install the remaining 103,000 smart meters. Edison's plan to install 5.3 million meters between 2005 and 2012 (662,500 meters per year) is currently on schedule.

BC Hydro's 2012 timeframe for installing 1.8 million meters, started in the fourth quarter of 2010, requires an installation rate of 800,000 meters per year - over three times that of Fortis. This seems overly-optimistic, even if labour and material resources were as readily available in BC as they are in Alberta's energy market.

Edison's projected benefits⁵⁷ were presented to their Technology Advisory Board on November 9, 2005 while the results from Edison's pilot program are given in their Phase 1 cost benefit analysis report.⁵⁸ Edison's report strongly supports BC Hydro's SMI program justification, in that the numbers strongly support a business case based on behavioural change benefits.

The benefits measured by Edison to justify the cost of their program included three metrics. The first, Net Operating Benefits, includes the ability to detect the location of system outages (due to fallen trees for example). The second, Net Load Control, includes the ability to transfer electric capacity from one distribution circuit to another to optimize system efficiency. The third, Net Price Response, is the customer conservation measurement (in dollars saved) that is most relevant to BC Hydro's DSM projections. Although the actual Net Operating Benefit of \$678 million did not live up to its expected \$860 million in the first year of the program, the

⁵⁶ Fortis Alberta AMI: Deployment Schedule: <http://www.fortisalberta.com/Default.aspx?cid=318&lang=1> (accessed March 14, 2011)

⁵⁷ Southern California Edison, Advanced Metering Infrastructure Program Introduction: <http://www.sce.com/NR/rdonlyres/B5866238-9196-4376-86B1-16B6A258FDEC/0/AMIIIntroTAB11905.pdf> (accessed March 14, 2011)

⁵⁸ Southern California Edison, Volume 1 - Overview of SCE's AMI Deployment Strategy and Objectives: http://www.sce.com/NR/rdonlyres/D93BC247-84B2-43AD-91E1-EEF3898B788AE/0/Vol1_Testimony_AMIPhaseIIApplication.pdf (accessed March 14, 2011)

actual Net Load Control benefit of \$215 million far exceeded its projected \$127 million projection. And, most importantly, the Net Price response from customers generated a very positive \$411 million in benefits – almost double the expected \$222 million value. This latter metric suggests that BC Hydro’s customer conservation behaviour can be greatly influenced through consumer data provided through SMI.

The SMI project’s IT Manager⁵⁹ stated that sourcing the smart meters and having them certified by Measurement Canada will be two of the largest schedule risks. Sourcing smart meters from American vendors who are already challenged to meet production quotas for US firms will be difficult for a Canadian utility. Requiring those same production firms to prioritize meeting Measurement Canada certification requirements in a high demand US market could become an even bigger problem.

Compared to similar power utilities in other jurisdictions, BC Hydro’s energy conservation target, if combined with a strong consumer education program such as Power Smart, seems achievable. BC Hydro’s installation schedule for 1.8 million smart meters by 2012, however, seems difficult to achieve.

4.2.4.7 SMI’s Comparative Outlook

To summarize the comparative analysis above, BC Hydro’s similarity with the Alberta market is in its economic pricing and labour resource strategy, whereas similarity with California markets seems more closely related to the strategy of encouraging the use of ‘clean’ or ‘green’ hydroelectric power over that of fossil fuels. Assuming these factors represent common consumer interests (and assuming other factors are equal),⁶⁰ timelines for metering installation will be closer to those of Fortis while consumer conservation goals will likely be closer to those of Edison.

Multiplying the ratio of BC Hydro’s customers to Edison’s customers by the latter’s Net Price Response, BC Hydro might anticipate a customer decrease in electricity demand of 2090 GWh in its first year (almost 17% of the projected gap between supply and demand in 2016). That year, however, may not be 2012. If BC Hydro’s installation schedule is projected using the

⁵⁹ Dr. Roger Goodwin, IT Manager, SMI Project, February 24, 2011 interview with Jay Buckley for preparation of SFU EMBA Project

⁶⁰ The current value of electricity rates (higher in California than Alberta) also strengthens the argument that the US consumers would be more economically driven towards energy conservation than would their Canadian counterparts

more realistic Fortis rate of meters per year, then BC's meters may not all be in service until the year 2016.

When compared to the performance of SMI programs managed by BC Hydro's neighbours, Fortis and Edison, BC Hydro's SMI program can be seen to have some potential benefits and some challenges. BC Hydro may be required to manage the BC Government's expectations with regard to timelines and emphasize the long term benefit of SMI's influence on motivating customers to conserve. This change in customer behaviour, if developed over a longer period, will lead to higher reductions in the demand of electricity.

4.2.5 Options Considered

If the SMI program is implemented by 2012 and the expected conservation savings are achieved, then BC Hydro will reduce the forecasted 2016 gap between demand and supply by 54%. The remaining excess demand forecast for 2016 would be filled through a combination of IPP and BC Hydro generated electricity in amounts that would depend upon whether other requirements of the Clean Energy Act (such as the self-sufficiency timeline and insurance requirement) are met.

If the Clean Energy Act requirements can be relaxed, the SMI program may be deferred to 2016, its most achievable implementation date (as shown by the above comparative analysis). Although half of the potential conservation benefits over the next ten years would be lost (and reduced to 27%), this timeframe would defer the cost of the program thereby reducing short term capital and operating costs. The resulting gap between supply and demand would be greater than in the first option. This greater excess demand may be met through a combination of IPP and BC Hydro generated electricity in amounts that would again depend on the utility's compliance with the Clean Energy Act's requirements.

Finally, the SMI program could be abandoned altogether, or deferred beyond the 2020 timeline of the Clean Energy Act. Although in violation of the Clean Energy Act, this option would reduce short term expenditures by the cost of the program and may allow BC Hydro to keep short term rates low (while sacrificing the long term benefits of reduced demand due to higher rates). Policy makers may determine that low short term rates are most desirable to their electorate if electricity rates were to become an election issue.

A summary of these demand side management options is provided in the following table and included in the menu of combined options presented at the end of this chapter. Feasibility of

capacity required and overall cost requirements of each combination is analyzed in chapter 5. Net Cost includes the sum of the annual (undiscounted) expenditures on the SMI program from now until 2016 and is reduced by the expected demand side savings associated with implementing the program. Capacity is measured as the percentage reduction in the expected gap between supply and demand of electricity in 2016.

Table 3: Summary of Demand Side Management Program Options⁶¹

	Clean Energy Act (Implementing SMI)	Defer to 2016	Defer beyond 2020
Capacity	54% Reduction	27% Reduction	0% Reduction
Time target	Achieved	Missed	Missed
Net Cost	\$430m	\$680m	\$930m

4.3 Purchasing Power from IPPs

This section describes the methods through which BC Hydro is to acquire power from IPPs within the requirements of the Clean Energy Act. This acquisition program has been designed to acquire at least 3,000 GWh of electricity to help close the gap between BC Hydro’s forecasted gap between electricity demand and supply in 2016 by at least 25%. This gap includes the shortfall in supply due to the decommissioning of the Burrard Thermal plant in 2016.

A number of electricity purchase programs or “Calls For Power” are described under which IPPs apply to provide electricity to the utility. An understanding of these power acquisition methods is essential to analyzing whether BC Hydro’s programs can attract the power required to meet its energy supply requirements under the Clean Energy Act.

A “Call For Power” is a process in which BC Hydro requests offers from IPPs to sell their energy for specific rates. The fuel sources for generating the power and the rates offered by the utility vary and are defined within each Call. If successful, the IPP’s offer is accepted by BC Hydro and the two parties enter into a legal contract known as an Energy Purchase Agreement (EPA). Historically, IPPs have successfully met approximately 30% of the electricity acquisition targets assigned within a Call For Power.

⁶¹ Source: Author, 2011

The Clean Energy Act specifies four power acquisition programs that are to be exempt from regulatory proceedings through the BCUC. These “Calls for Power” include: a Bio-Energy Phase 2 Call to acquire up to 1,000 GWh per year of electricity from generation plants fuelled by wood waste products; a Clean Power Call request for proposals to acquire up to 5,000 GWh per year of electricity from plants generating power from clean or renewable fuel resources; the existing Standing Offer Program offering a longer application term but lower rates; and a Feed-in Tariff Program encouraging new and innovative clean power producing technology. The Clean Energy Act also exempts a number of agreements between BC Hydro and pulp and paper customers in BC that qualify for funding under the Green Transformation Program of Canada.⁶² These customers include businesses that produce their own power but sometimes sell to BC Hydro. These bio-energy based generation firms, in aggregate, may generate up to 1,200 GWh per year of electricity. The Calls for Power, and other electricity purchase processes are all described in the following sections.

4.3.1 Bio-Energy Calls

Bio-Energy Calls are designed to procure bio-energy from projects that utilize wood fibre and biomass fuel sources. These Calls provide attractive rates to IPPs while addressing another provincial concern – the reduction of organic waste in the province. Bio-Energy Calls tend to be open for shorter terms and involve power acquisition limits that are lower than other Calls. Each Call is dependant upon the success of the previous Call and the assessment of future organic waste that may be available in the province. If the current trend continues, this program may provide 300 GWh of electricity by 2016, closing the supply and demand gap by 2%. Currently, the program includes the Bio-Energy Call for Power Phase 1 and Phase 2, the Community-based biomass power call and the Integrated Power Offer.

The Bio-Energy Call for Power Phase 1 was completed in 2009 and resulted in four Electricity Purchase Agreements (EPAs).⁶³ The bio-energy facilities built under this Call used forest-based biomass to generate electricity. This included sawmill residue, logging debris, trees killed by mountain pine beetle, and other residual wood⁶⁴.

⁶² Pulp and Paper Green Transformation Program : <http://cfs.nrcan.gc.ca/subsite/pulp-paper-green-transformation> (accessed March 14, 2011)

⁶³ Bioenergy Phase 1 Call RFP: http://www.bchydro.com/planning_regulatory/acquiring_power/bioenergy_call_for_power/phase_1_rfp.html (accessed March 14, 2011)

⁶⁴ Bioenergy projects given green light to start producing clean, made-in-BC energy: http://www.bchydro.com/news/articles/press_releases/2009/bio_energy_projects.html (accessed March 14, 2011)

The Bioenergy Phase 2 Call for Power involves larger-scale biomass projects, with a target to acquire up to 1,000 GWh per year of cost-effective electricity. Any form of biomass is eligible as long as it meets the Province's clean or renewable electricity definitions⁶⁵. The Bioenergy Phase 2 Call also includes a process designed to minimize transaction costs for proponents and requires that projects be new facilities with at least 5 MW generating capacity.⁶⁶

The Community-Based Biomass Power Call is designed for smaller scale biomass plants. This Call is intended to encourage energy supply solutions within communities using biomass fuel sources. Projects anticipated for submission include underutilized forest-based biomass and other forms of biomass such as crops, aquatic plants, or clean organic material.⁶⁷

The Integrated Power Offer is designed for pulp and paper companies eligible for funding under the federal government's Green Transformation Program.⁶⁸ The Natural Resources Canada's Pulp and Paper Green Transformation Program has offered up to \$1 billion to assist pulp and paper producers in BC, eight of which are already BC Hydro customers.

4.3.2 Standing Offer Call

The Standing Offer Program (SOP) is an open offer with no predetermined end date during which IPPs may apply to provide clean renewable power to BC Hydro for specified rates. If IPPs can not qualify for preferential rates under other Calls, they may be attracted to the SOP. The Program was implemented in 2008 to encourage the development of small and clean or renewable energy projects throughout British Columbia. If IPP interconnections continue at historical rates, the SOP may be expected to provide BC Hydro with 900 GWh of electricity, closing BC Hydro's supply and demand gap by 7%.

Revisions to the Standing Offer Program were made following an analysis of participation, the prices offered for energy and the processes of application, interconnection, and government permitting. BC Hydro also compared their Standing Offer Program to other similar programs across North America. As a result, BC Hydro implemented the set of recommendations

⁶⁵ British Columbia's Clean or Renewable Electricity Definitions
<http://www.empr.gov.bc.ca/EAED/AEPB/Documents/CleanEnergyJune.pdf> (accessed March 14, 2011)

⁶⁶ Bioenergy Phase 2 Call:
http://www.bchydro.com/planning_regulatory/acquiring_power/bioenergy_call_for_power/2009_Phase_II_BP.html
(accessed March 14, 2011)

⁶⁷ Community-Based Biomass Power Call:
http://www.bchydro.com/planning_regulatory/acquiring_power/bioenergy_call_for_power/2009_Phase_II_CBB.html
(accessed March 14, 2011)

⁶⁸ A government program designed to support pulp and paper mills in Canada in their reduction of greenhouse gas emissions while helping them to produce renewable energy from forest biomass. <http://cfs.nrcan.gc.ca/subsite/pulp-paper-green-transformation> (accessed March 14, 2011)

provided in the SOP Review Report⁶⁹ including limits to project size (in terms of MW), eligibility of non-proven technologies and the rates offered for energy. Changes have also been made to the application and interconnection processes.

To be eligible to apply for the Standing Offer Program, the IPP and the project must meet a number of requirements. Requirements include that: the energy must be generated by a facility that generates electricity from clean or renewable resources (excluding nuclear); the projects be located in BC (but outside protected areas defined by in the Clean Energy Act); the project's completion date be within three years of signing the EPA; all material and operational permits have been retained; and First Nations consultation requirements have been completed.⁷⁰

4.3.3 Clean Energy Call

In June of 2008, BC Hydro initiated the Clean Power Call - an offer with a specified end date during which the utility would accept offers from IPPs to sell their electricity under specified fuel source and rate requirements. The call was designed to allow BC Hydro more flexibility in working with IPPs to develop cost-effective contract terms and conditions that address the needs of larger and more complex projects. As a precursor to the Clean Energy Act, the Clean Power Call was designed in alignment with the BC Energy Plan of 2007 which required that at least 90% of all electricity generated in the province must continue to come from clean or renewable sources.⁷¹ This Call is expected to generate 1,500 GWh of electricity and to close BC Hydro's supply and demand gap by 12%.

Some of the key aspects of the Clean Power Call are that: the Call be for clean energy as defined by the province (in 2007) and generated from projects using proven technologies; the acquisition target be set at 5,000 GWh/year of seasonal and hourly firm energy; and the larger projects with extended in-service dates of 2016 or earlier be accommodated. Almost half of the clean energy to be generated under the Clean Power Call is expected to be from wind power projects.⁷²

⁶⁹ Standing Offer Program, Report on the SOP 2-Year Review:
http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/acquiring_power/2011q1/20110125_bc_hydro.Par.0001.File.20110125-BC-Hydro-Report-on-the-SOP-2-Year-Review.pdf (accessed March 14, 2011)

⁷⁰ Who Can Apply:
http://www.bchydro.com/planning_regulatory/acquiring_power/standing_offer_program/who_can_apply.html (accessed March 14, 2011)

⁷¹ Clean Power Call: http://www.bchydro.com/planning_regulatory/acquiring_power/clean_power_call.html (accessed March 14, 2011)

⁷² Press Release:
http://www.bchydro.com/news/articles/press_releases/2010/bch_reaches_clean_energy_milestone.html (accessed March 14, 2011)

4.3.4 Feed-in Tariff

The term "feed-in-tariff" is a literal translation of Germany's law on feeding electricity into the grid. It is a means for encouraging investment in renewable generation from small scale production methods (such as solar panels or small wind turbines) that, at current prices, would not be economical due to their higher costs. Rates paid to these IPPs therefore include implicit subsidies.⁷³ The overall reduction in BC Hydro's supply and demand gap resulting from this program is expected to be less than 1%. The focus of this program is more on the development of innovative technology for future conservation needs.

The Ministry has stated that BC Hydro's program shall cap the size of IPP projects under this program at 5 MW, and limit annual spending on all power acquired under the program to \$25 million above the cost of acquiring the same volume of electricity through BC Hydro's Standing Offer Program.⁷⁴ Another requirement of the Ministry is to limit the term of projects submitted under the program to five years, with the option of securing an EPA with the IPP at the end of the term under the rates published through the current Standing Offer Program. No projections of electricity acquisitions have been made public at this time.

4.3.5 Options Considered

IPPs have been attracted to BC Hydro's Standing Offer Program since 2007 and BC Hydro has designed the new programs using feedback received from the applicants. By attracting an expected 3,000 GWh of electricity, BC Hydro plans to close its forecasted 2016 supply and demand gap by over 25%. Another benefit that BC Hydro receives through acquiring electricity from IPPs is time. BC Hydro could not meet the self-sufficiency requirement of the Clean Energy Act through large scale hydroelectric generation alone due to the long project implementation schedules involved. The cost of acquiring power from IPPs, however, is typically much higher than that produced by BC Hydro's heritage assets.

BC Hydro's options include continuing to attract IPP generated electricity under the requirements of the Clean Energy Act, modifying programs to attract more electricity at potentially lower rates or deferring the program altogether.

When designing new Calls For Power, BC Hydro should consider allowing IPPs to bid for the rates at which they would supply electricity in an EPA. Currently, BC Hydro sets the rates

⁷³ Feed-in Tariff: http://www.bchydro.com/planning_regulatory/acquiring_power/feed_in_tariff.html (accessed March 14, 2011)

⁷⁴ B.C. seeking input on feed-in tariff: <http://www.canadianenergylaw.com/2010/09/articles/electricity/bc-seeking-input-on-feedin-tariff/> (accessed March 14, 2011)

and then requests offers to sell. This creates two risks. First, BC Hydro may set the rates too low, and so risks not receiving enough offers to sell. Second, the utility may set rates too high, risking paying more than would be required. Competitive bidding would eliminate these risks.

As new power acquisition programs, or “Calls For Power” are designed by BC Hydro, new rate considerations might include opportunities for IPPs to bid on EPAs rather than relying on locked-in long term purchase agreements. Competitive pricing may drive cost efficiency and innovative generation technology in the province. BC Hydro could then evaluate energy purchase decisions based on the marginal cost of electricity during importing times.

A summary of these IPP electricity purchase options is provided in the following table and included in the menu of combined options presented at the end of this chapter. Capacity is measured as the reduction in the expected gap between supply and demand of electricity in 2016, and the ability to achieve the 3,000 GWh insurance requirement by 2020. Feasibility of capacity required and overall cost requirements of each combination are analyzed in chapter 5.

Table 4: Summary of IPP Electricity Purchase Program Options⁷⁵

	Clean Energy Act		Defer
	Self-sufficiency by 2016	Gain Insurance by 2020	
Capacity	25%	+3,000 GWh	Variable
Time target	Achieved	Achieved	Missed
Cost ⁷⁶	76.945 \$/MW	76.945 \$/MW	Competitive

4.4 Electricity Generation

BC Hydro has announced its Service Plan for fiscal years 2009 through 2012. The following projects with total capital costs budgeted at \$3.5 billion were approved by the utility’s Board of Directors.⁷⁷ These investments represent the minimum required to maintain BC Hydro’s generation capacity and upgrade existing facilities for BC Hydro to meet the self-sustainability requirements mandated by the Clean Energy Act. These projects are designed to

⁷⁵ Source: Author, 2011

⁷⁶ Average price based on geographic schedule of rates provided BC Hydro’s Service Plan

⁷⁷ BC Hydro Service Plan 2009/10–2011/12:

http://www.bchydro.com/etc/medialib/internet/documents/info/pdf/service_plan.Par.0001.File.service_plan_2009-10-2011-12.pdf (accessed March 14, 2011)

maintain BC Hydro's existing electricity capacity as well as provide an additional 2,800 GWh of electricity to close the utility's supply and demand gap by 22%.

4.4.1 Gordon M. Shrum Units 1 to 4 Stator Replacements

This project is scheduled to complete in 2011 at an approved cost of \$97 million. This upgrade project will add 177 GWh to BC Hydro's capacity closing the gap by about 1%.

The Gordon M. Shrum (GMS) Generating Station is located next to the W.A.C. Bennett Dam on the Peace River near Hudson's Hope. BC Hydro is replacing four stators at the Gordon M. Shrum (GMS) facility that are at risk of failure. The generator stators are the stationary part of the generating unit that converts the mechanical energy of the rotor into electrical energy. These units were built in the 1960s and are due for replacement.

GMS generating units represent 12 per cent of BC Hydro's total electricity producing capacity in the province. This means that overall reliability of the facility has an impact on the security of the province's electricity supply. A secondary benefit of the project will be the improvement in turbine efficiency and capacity.⁷⁸

4.4.2 Revelstoke Unit 5 Project

The project is scheduled to complete in 2012 at an approved cost of \$350 million. This upgrade project will add 2,500 GWh to BC Hydro's capacity, closing the forecast 2016 gap between supply and demand by about 20%.

BC Hydro is installing a fifth generating unit in the Revelstoke plant to provide additional capacity to the BC Hydro system. The Revelstoke Dam and Generating Station represent 21 per cent of BC Hydro's electricity generating capacity. The new generating unit will also provide additional energy, operating flexibility and reserves. Revelstoke was commissioned in 1984 with four generating units but was designed to accommodate six generating units in the future. The four units currently operating have a combined capacity of 1,980 MW. The fifth unit contributes an additional 500 MW of capacity.⁷⁹

⁷⁸ Hydro Electric Power Plants: <http://hydropowerstation.com/?tag=gordon-m-shrum-gms-generating-station> (accessed March 14, 2011)

⁷⁹ Revelstoke Unit 5 Project: http://www.bchydro.com/planning_regulatory/projects/revelstoke_unit_5.html (accessed March 14, 2011)

4.4.3 Cheakamus Spillway Gate Reliability Upgrade

The upgrade is scheduled to be completed in 2012 with an approved cost of \$73 million. This maintenance project will not add to BC Hydro's capacity, but will help ensure the continued operation of the 750 GWh generation facility, which is 1% to the utility's current capacity.

BC Hydro will upgrade spillway gates at the Cheakamus dam. This upgrade has been planned to reduce public and employee safety risk and to ensure flood discharge reliability requirements are met. Spillway gates control the volume of water that can be discharged at any given time from the reservoir. They are used in times of flood to pass high inflows. BC Hydro's recent assessment of the spillway gates revealed various deficiencies concluding that equipment improvements would be required to ensure that they have adequate reliability.⁸⁰

4.4.4 Mica Gas Insulated Switchgear Replacement

This replacement is targeted to be completed in 2014 at an approved cost of \$200 million. This maintenance project will not add to BC Hydro's capacity but help ensure the continued operation of the 8700 GWh generation facility, which is 16% to the utility's current capacity.

BC Hydro will be replacing the switchgear system at the Mica Generating Station. The switchgear system uses two 500 kV circuits (power lines) to conduct the energy from the Mica underground powerhouse to the surface. The electricity is then transmitted to transmission lines which in turn carries the electricity from Mica to BC Hydro's customers. The switchgear system replacement will ensure reliability of this generating station and reduce leakage of SF6 (a greenhouse gas) used in the insulation process of the switchgears.⁸¹

4.4.5 Fort Nelson Generating Station Upgrade

This upgrade is targeted to be completed in 2012 at an approved cost of \$212 million. This upgrade project will add 123 GWh to BC Hydro's capacity closing the forecast 2016 demand-supply gap by about 1%.

As a result of increased industrial activity and households switching to electric heat in the Fort Nelson area, electricity demand has increased by more than 50 per cent in recent years. Electricity supply is a concern in the Fort Nelson area as demand is expected to increase by a

⁸⁰ Hatch, Water Resource Management Projects:

http://www.hatch.ca/Energy/Water_Resources/Projects/bc_hydro_gates.htm (accessed March 14, 2011)

⁸¹ Mica Gas Insulated Switchgear Project: http://www.bchydro.com/planning_regulatory/regulatory/mica_project.html (accessed March 14, 2011)

further 50 to 200 per cent by 2013. BC Hydro will increase the generating capacity at the Fort Nelson Generating Station to meet that demand.⁸²

4.4.6 Gordon M. Shrum Units 1 to 5 Turbine Rehabilitation

The project is scheduled to complete by 2017 at an estimated budget of \$319 million. Although the timeline of this project falls after the 2016 self-sustainability date, it is an important contributor to the BC Hydro's 2020 capacity requirements and will ultimately generate 5,000 GWh of electricity, representing 24% of the gap between 2016 forecasted supply and demand.

The runners and head covers for units 1 to 5 have experienced cracking problems since the units went into service in the late 1960s, and one unit experienced a major failure in the spring of 2008. Units 1 to 5 must be replaced to ensure ongoing reliability and operational availability of these units. The units' replacement will also reduce risk of failure, decrease maintenance costs and improve operational efficiency.⁸³

4.4.7 Upper Columbia Capacity Additions at Mica

The additions of Mica units 5&6 are scheduled for 2016 at a cost of \$1,260 million. This project will not add contribute to closing the gap but will help ensure the continued operation of a 7200 GWh generation facility, which is 13% to the utility's current capacity.

BC Hydro is planning to install two additional 500 MW generating units into existing turbine bays at Mica Generating Station. The facility was originally designed to house six units when it was built with its four existing units in 1977.⁸⁴ Capacity demand now requires BC Hydro to install the two additional units. The project also requires construction of a new series capacitor station near the midpoint of the existing Mica to Nicola 500 kV transmission line needed to ensure the reliable delivery of additional electrical generation at Mica.

4.4.8 Hugh Keenleyside and Stave Falls Spillway Gate Reliability Upgrades

These upgrades are targeted for completion in 2013 at an estimated cost of \$74 million. This maintenance project will not add to BC Hydro's capacity but will help ensure the continued operation of the 925 GWh generation facility, which is 2% of the utility's current capacity.

⁸² Fort Nelson Generating Station Upgrade:
http://www.bchydro.com/planning_regulatory/projects/fort_nelson_generating.html (accessed March 14, 2011)

⁸³ Hydro Power Electric Plants: <http://hydropowerstation.com/?tag=gordon-m-shrum-gms-generating-station>

⁸⁴ Mica Units 5&6 Projects:
http://www.bchydro.com/planning_regulatory/projects/mica_generating_station_upgrade/project_background.html
(accessed March 14, 2011)

Spillway gates will be upgraded at the Hugh Keenleyside and Stave Falls dams to ensure flood discharge reliability requirements are met and to ensure public and employee safety. Other improvements include site to site communications systems, reservoir level monitoring devices, replacement of a debris boom to help clear the water passage and replacement of the gantry crane (used to raise and lower the spillway gates to safely regulate water flow from the reservoir).

4.4.9 Options Considered

The above capital program for maintaining and upgrading the utility’s heritage assets represents the costs of obtaining electricity from BC Hydro’s heritage assets through 2016; after this date, BC Hydro would have to build additional facilities to add capacity. BC Hydro expects this capital program to generate 2,800 GWh of electricity, enough to close the forecast 2016 demand-supply gap by 22%.

If BC Hydro chooses the option of carrying out this plan, then the requirement to purchase (higher cost) electricity from IPPs to meet the requirements of the Clean Energy Act will be minimized. If BC Hydro defers the upgrade program to a later time (after the 2020 Clean Energy Act timeline), then a much greater reliance upon IPPs will be required to meet demand.

Alternatively, if the Clean Energy Act’s self-sufficiency requirements were relaxed to beyond 2016, BC Hydro could continue to be a net importer of electricity until such time as the utility could build additional hydroelectric facilities.

A summary of these electricity generation options is provided in the following table and included in the menu of combined options presented at the end of this chapter. Capacity is measured as the reduction in the expected gap between supply and demand of electricity in 2016. Feasibility of capacity required and overall cost requirements of each combination are analyzed in chapter 5.

Table 5: Summary of BC Hydro’s Electricity Generation Program Options⁸⁵

	Clean Energy Act	Defer
	Self-sufficiency by 2016	
Capacity	22%	Reduced
Time target	Achieved	Missed
Cost	\$3.5 Billion	Deferred

⁸⁵ Source: Author, 2011

4.5 Summary of Option Combinations

The following menu summarizes the various permutations of options presented in this chapter. The combinations of options represent: the three demand side management alternatives of implementing SMI in 2012, in 2016 or not at all; the two options of purchasing power from IPPs to achieve self-sufficiency by 2016 or deferring self-sufficiency until 2020; and the option of upgrading BC Hydro’s heritage assets in 2016 or in 2020. For each of the resulting 12 combinations, the table shows when the programs are implemented, whether the combination results in self-sufficiency by 2016, and whether the goal of 3000 GWhs of “insurance” capacity is achieved by 2020. Capacity and cost constraint analysis will be examined in the next chapter.

Table 6: Combinations of BC Hydro’s Program Options⁸⁶

Option	DSM Program		IPP Program		Generation Program		Time Goals		
	2012	2016	2016	2020	2016	2020	SMI	Self-Suf.	Insurance
1	✓		✓		✓		✓	✓	✓
2	✓		✓			✓	✓	✓	✗
3	✓			✓	✓		✓	✗	✓
4	✓			✓		✓	✓	✗	✗
5		✓	✓		✓		✗	✓	✓
6		✓	✓			✓	✗	✓	✗
7		✓		✓	✓		✗	✗	✓
8		✓		✓		✓	✗	✗	✗
9		✗	✓		✓		✗	✓	✓
10		✗	✓			✓	✗	✓	✗
11		✗		✓	✓		✗	✗	✓
12		✗		✓		✓	✗	✗	✗

⁸⁶ Source: Author, 2011

5 Financial Analysis of BC Hydro's Program Requirements

To achieve its 'electricity self-sufficiency' target mandated by the Clean Energy Act, BC Hydro is responsible for financing a series of initiatives. These initiatives will create some financial challenges. Building new power generation plants and connecting to third party power producers will involve high initial costs whereas energy conservation (convincing customers to use less of the company's product) could lead to lower short term revenues.

These challenges must be financially managed while sustaining an annual dividend payment to the province, maintaining the existing debt to equity ratio and managing a growing debt currently exceeding \$10 billion. Determining required rate increases for various program delivery options will require an analysis of past financing practices and projections for future financing requirements. For simplicity, rate increases suggested in the following sections are calculated as one time rates to be applied immediately and held steady for the forecast period. Rate design (determining strategies for time-of use, stepped rates or variable prices between customer classes) is left to the policy makers.

This section describes the major financial constraints that BC Hydro operates under and explores the history of the power utility's financial performance over the past ten years in order to generate future projections (pro forma statements). This chapter will evaluate the financial requirements of the Clean Energy Act specific to the programs of building new assets, purchasing power through independent producers and managing conservation initiatives. An assessment of BC Hydro's financial requirements is provided in order to determine the minimum rate increase necessary to meet the goal of self-sufficiency by 2016, to maintain its positive dividend payments to the Province and to continue operating within its mandated financial constraints. Finally, should policy makers determine that this rate increase is not acceptable, a menu of options, along with their respective impact on BC Hydro's goals, is presented to illustrate the policy tradeoffs.

5.1 BC Hydro's Historical Financing Model

BC Hydro's purpose statement is to provide, "reliable power, at low cost, for generations". The Crown Corporation's rates are among the lowest in North America (Figure 9).

In order to maintain its standing among the lowest cost power providers, the utility will require effective financial management against a number of constraints.

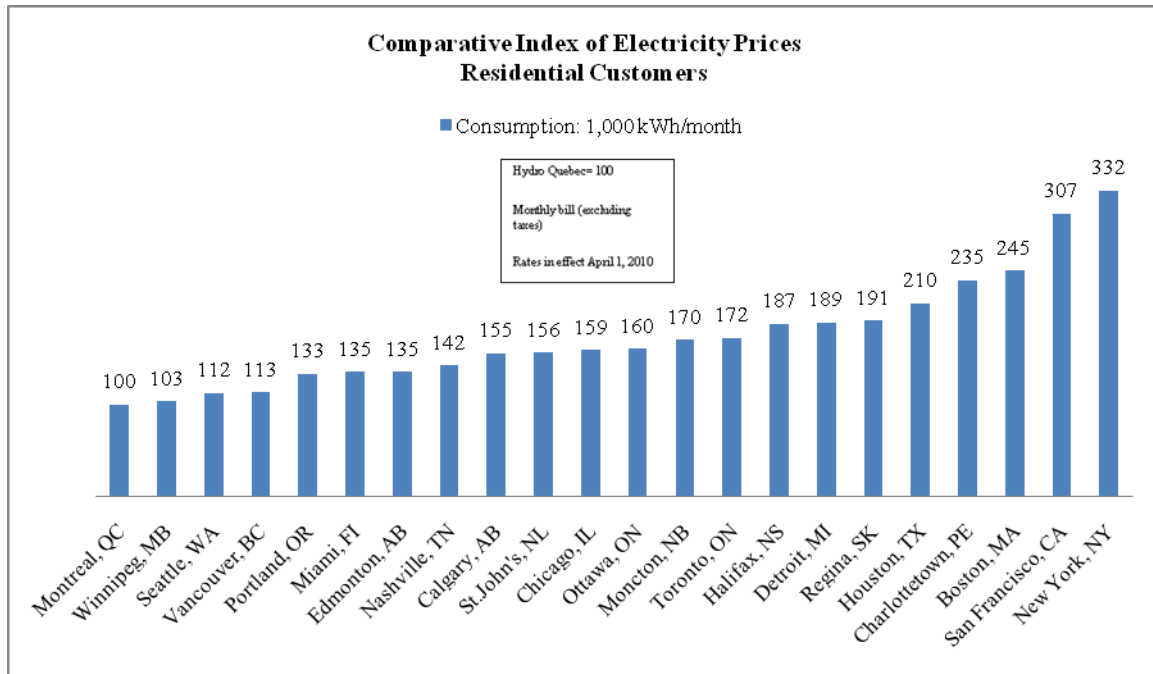


Figure 9: Comparison of Residential Power Rates Across North American Cities (as a % of those in Quebec)⁸⁷

As a Crown Corporation, BC Hydro prepares its financial statements under GAAP and publishes annual reports⁸⁸ to the public. These reports list the amounts of annual payments (similar to dividend payments) that are made to the utility’s sole shareholder, the Government of British Columbia.

Payments to the Province are calculated as 85% of BC Hydro’s ‘distributed surplus’ over the fiscal year. This surplus is calculated as the company’s net income adjusted by finance charges and amortisation, essentially leaving the utility with a retention ratio of 15%.

The government requires BC Hydro to operate within a debt to equity ratio cap of 80:20. Although the equity portion of this ratio is simply the company’s retained earnings, calculating the debt portion is more complex. BC Hydro’s Chief Accounting Officer, Cheryl Yaremko stated

⁸⁷ 2010 Comparison of Electricity Prices in Major North American Cities” (Hydro-Quebec, November, 2010)

⁸⁸ BC Hydro Annual Reports: http://www.bchydro.com/about/company_information/reports/annual_report.html (accessed April 4, 2011)

that the company's debt is calculated as 30% of the sum of long term debt and the current portion of long term debt (net of sinking funds) plus the shareholder's equity less cash.⁸⁹

Another interesting feature of the financial statements was the use of sinking funds (funds created for paying the future principal portion of bonds). Ms. Yaremko explained that, due to recent corporate financial restructuring of debt, BC Hydro has recently been using sinking funds as a source of financing.⁹⁰

The rates that BC Hydro is permitted to charge for power, as well as its maximum allowable return on equity, are set by the British Columbia Utilities Commission (BCUC), the provincial regulating agency for the utility. BC Hydro borrows all funds through the Province of British Columbia. All debt is held or guaranteed by the Province, resulting in a credit rating on long-term debt of Aaa by Moody's and AAA by Standard and Poors.⁹¹

Because the utility's rates are fixed by the BCUC, BC Hydro can not increase its sales revenues faster than its "sustainable"⁹² growth rate" (measured as a percentage of electricity sold) without increasing its debt. This is because the utility's marginal costs rise as it supplies more electricity to customers, and it cannot increase its rates to cover these rising costs. So if it increases its output and sales too fast, its costs rise faster than its revenues, requiring it to issue more debt to cover the shortfall, or to cut its payment to the Province. Figure 10 shows BC Hydro's sustainable and actual annual percentage growth rates of electricity sales revenues. This chart is based on numbers provided from the utility's consolidated financial statements over the last ten years⁹³.

⁸⁹ Cheryl Yaremko, Chief Accounting Officer, Corporate Finance, BC Hydro, interview with Jay Buckley

⁹⁰ Sinking funds (depreciation) may be used as a source of financing. Assuming that a company distributes profit after tax as dividends, depreciation charges reduce the amount of this distribution (as it reduces the profit). The funds that would have been distributed are retained in (and finance) the business.

⁹¹ BC Hydro Service Plan (p.32):

http://www.bchydro.com/etc/medialib/internet/documents/info/pdf/service_plan.Par.0001.File.service_plan_2009-10-2011-12.pdf (accessed April 4, 2011)

⁹² A firm's sustainable growth rate is the maximum growth rate that a firm can finance from its internal sources (increases in retained earnings) without resorting to debt or new stock issue

⁹³ BC Hydro Annual Report Archives: http://www.bchydro.com/about/company_information/reports/annual_report.html (accessed April 4, 2011)

BC Hydro Growth Model

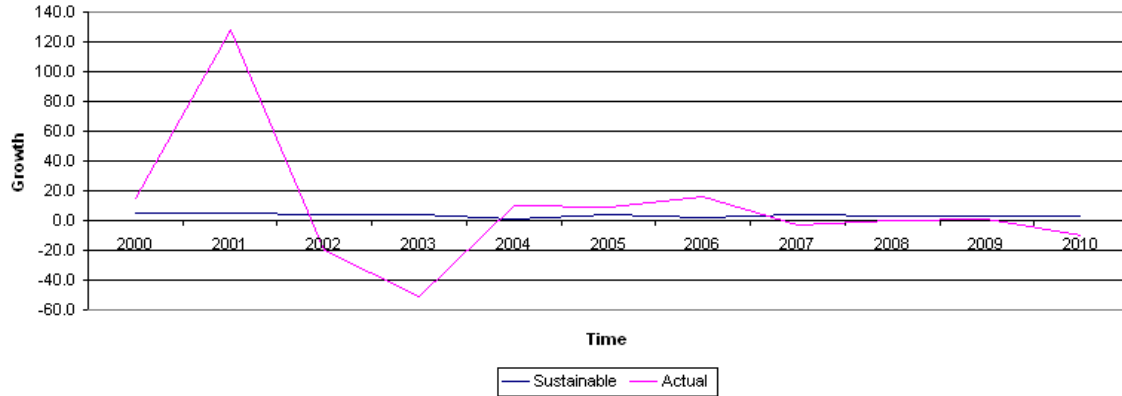


Figure 10: BC Hydro’s Annual % Growth Rates (in Sales Revenue)⁹⁴

This chart demonstrates that the company’s performance has a strong correlation to the economic performance of its customers. For example, in 2001 the utility’s growth of electricity sales experienced a sharp spike as it supplied power during the California energy crisis. A 16% growth in 2006 relates to the strong economic conditions of the time whereas the company’s 10% decline in the fiscal year ending in 2010 reflects the most recent economic crisis. During the three years prior to the recent crisis, BC Hydro operated within its average sustainable growth rate of 3.4% as calculated from the average annual growth rates of BC Hydro over the last 10 years as shown in Table 3.

Table 7: BC Hydro’s Historical Growth Rate Calculations (in Sales)⁹⁵

BC Hydro	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Required ratios:												
Net Income (x \$1,000)	395	416	446	403	418	98	402	266	407	369	365	447
Sales (x \$1000)	3,017	3,457	7,889	6,311	3,107	3,424	3,725	4,311	4,197	4,210	4,269	3,822
Assets (x \$1,000)	11,685	11,596	12,615	11,966	11,924	11,806	12,363	12,704	12,845	14,447	16,368	18,093
Shareholders' equity	1,312	1,385	1,459	1,529	1,609	1,634	1,688	1,707	1,783	1,921	2,189	2,674
Profit margin, P(%)	13.1%	12.0%	5.7%	6.4%	13.5%	2.9%	10.8%	6.2%	9.7%	8.8%	8.6%	11.7%
Retention ratio, R(%)	15	15	15	15	15	15	15	15	15	15	15	15
Asset turnover, A (times)	0.3	0.3	0.6	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2
Financial leverage, T ^a (times)	N/A	8.8	9.1	8.2	7.8	7.3	7.6	7.5	7.5	8.1	8.5	8.3
Sustainable growth rate, g^s (%)	N/A	4.8	4.8	4.1	4.1	0.9	3.7	2.4	3.6	3.1	2.9	3.1
Actual growth rate, g (%)	N/A	14.6	128.2	-20.0	-50.8	10.2	8.8	15.7	-2.6	0.3	1.4	-10.5

⁹⁴ Source: Author, 2011

⁹⁵ Source: Author, 2011

The Provincial Government requires that BC Hydro manage its finances as prudently as do public companies in the power utility sector. Debt to equity levels are managed within prescribed limits and with applicable interest rates that are consistent with their levels of risk. Growth is carefully managed against a cyclical market, financial statements are provided under GAAP, and a healthy dividend payment is expected each year.

5.2 Full Funding Requirements of the Clean Energy Act

In order to meet the Clean Energy Act’s requirements, BC Hydro must build, buy or conserve power in order to meet its electricity self-sustainment goal and to close the forecasted gap between future supply and demand. The following sections explore the costs required to build the new generation assets required, the costs of acquiring power from IPPs and the costs of the demand side management program required to meet conservation efforts needed.

5.2.1 Building new generation assets

BC Hydro mid-point forecast is for its demand is to grow by 27.5% over the next five years. Conservation efforts of Demand Side Management (DSM) are to reduce this forecast demand growth by two thirds, leaving the remaining total growth in annual sales of 9.4% to be filled by new sources of power (Figure 11).

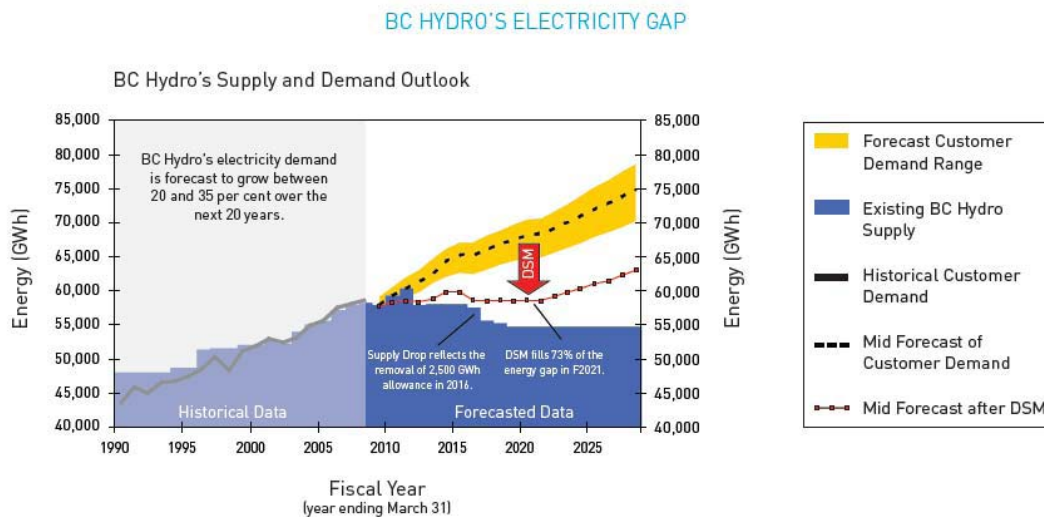


Figure 11: BC Hydro’s Supply & Demand Outlook⁹⁶

⁹⁶ BC Hydro Service Plan (p.13) used with permission:
http://www.bchydro.com/etc/medialib/internet/documents/info/pdf/service_plan.Par.0001.File.service_plan_2009-10-2011-12.pdf (accessed April 4, 2011)

One method of sourcing new power is to build new generation facilities or add capacity to existing facilities. BC Hydro has set out a plan to build over \$3.5 billion in new generation capacity over the next seven years.⁹⁷ For the purposes of this project, cash flow requirements for these major power generation projects, as described in chapter 4, have been provided in Table 4 with expenditures estimated over the expected life of each project. To assist with this project's analysis, these cash flows have been fitted to an 'S' shape distribution curve similar to that of most major construction projects.

Table 8: Cash Flow Projections by Fiscal Year for Major BC Hydro Projects⁹⁸

Capital Project or Program	Projected Cashflow										
	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017
Gordon M. Shrum Units 1 to 4 Stator Replacements		10	78	10							
Revelstoke Unit 5 Project	18	35	123	123	36	19					
Cheakamus Spillway Gate Reliability Upgrade			7	29	30	8					
Mica Gas Insulated Switchgear Replacement			20	40	41	42	44	23			
Fort Nelson Generating Station Upgrade			21	85	87	22					
Gordon M. Shrum Units 1 to 5 Turbine Rehabilitation					16	68	70	72	74	38	20
Upper Columbia Capacity Additions at Mica and Revelstoke				63	260	267	275	284	146	75	
Hugh Keenleyside & Stave Falls Spillway Gate Reliability Upgrades				7	30	31	8				
Infrastructure Upgrades				186	575	197					
Total capital required for new generation infrastructure (\$ million)	18	45	249	543	1076	655	397	378	220	113	20

Note 1: Cash flows assume an "S" curve distribution (rather than an even distribution) more typical of projects of this type

Note 3: Source of total costs and in-service dates: BC Hydro Service Plan (p.37-39)

Debt financing for these new capital expenditures will be subject to the restrictions listed above. BC Hydro must weigh the short term financing requirements of these projects against long term benefits, since the average expected payback period for a new hydroelectric generating facility is over 30 years.

5.2.2 Buying power from IPPs

The Clean Energy Act requires that BC Hydro introduce programs to acquire a portion of its new energy requirements from third party independent power producers⁹⁹. These IPPs may

⁹⁷ BC Hydro Service Plan (pp. 37-39):
http://www.bchydro.com/etc/medialib/internet/documents/info/pdf/service_plan.Par.0001.File.service_plan_2009-10-2011-12.pdf (accessed April 4, 2011)

⁹⁸ Source: Author, 2011

⁹⁹ BC Hydro Service Plan (p. 10):
http://www.bchydro.com/etc/medialib/internet/documents/info/pdf/service_plan.Par.0001.File.service_plan_2009-10-2011-12.pdf (accessed April 4, 2011)

apply to connect their facilities to BC Hydro under a number of ‘Calls For Power’ as outlined in section 4.3 in accordance with a specific set of publicly available rules¹⁰⁰.

The IPP will receive a specific rate for the power it supplies to BC Hydro’s distribution grid. This rate depends on the geographic location of the producer, its generation method and the contractual conditions under the applicable call for power. Although BC Hydro cannot be certain of the number, location or methods through which IPPs will emerge, the utility provides a three year forecast of expected purchases. For analysis purposes of this project, projections have been extended to the self-sufficiency date of 2016. Cash flows for this projected power acquisition profile have been prepared (Table 5) against an assumed average rate that might be expected for these power acquisitions over the next five years (calculated from rates provided in chapter 4).

Table 9: Cash Flow Requirements for Future Energy Purchases From IPPs¹⁰¹

	Forecast (Note 1)			Pro forma projection			
	F2010	F2011	F2012	F2013	F2014	F2015	F2016
Energy Purchases (GWh)	9,173	11,398	11,880	12,480	13,080	13,680	14,280
Required Cashflow (\$million)	\$ 706	\$ 877	\$ 914	\$ 960	\$ 1,006	\$ 1,053	\$ 1,099

Note 1: F2010 through F2012 source: BC Hydro Service Plan, Future projections source: Author

Note 2: Average rate (\$/MWh) from BC Hydro's Standing Offer Program (4.1, Fig.3) = 76.945

Forecasted energy purchases have been provided for the fiscal years ending in 2010, 2011 and 2012 by BC Hydro’s Service Plan. Pro forma purchase costs have been calculated for future years through 2016 and account for contracts currently held between IPPs and BC Hydro.¹⁰² These pro forma statements are based on rates published under BC Hydro’s Standing Offer Program.

5.2.3 Conserving power

Although BC Hydro’s public energy conservation program, Power Smart, will be a key element in promoting conservation attitudes among customers, the cost of the program has already been factored into past and present financial reports. Future financial support of the program has been factored into the utility’s ongoing operating expenses. The most significant

¹⁰⁰ Standing Offer Program Rules, 4.1 Price, Figure 3 (p.9):
http://www.bchydro.com/etc/medialib/internet/documents/info/pdf/info_-_20090224_sop4.Par.0001.File.20090226_SOP_Program_Rules_Clean.pdf (accessed March 14, 2011)

¹⁰¹ Source: Author, 2011, Annual Cashflows = Energy Purchases (GWh) x Average Rate (\$/MWh) x 1,000 MWh (expressed in \$millions)

¹⁰² Source: Author, 2011

cost impact to the conservation effort over the next five years will be the Smart Metering Infrastructure (SMI) program.

BC Hydro has made a commitment to replace 1.8 million conventional meters with digital ‘smart meters’ by the year 2012. The key drivers behind the project include: promoting energy conservation among customers; reducing power theft; and increasing the reliability and management of the power distribution grid. The \$930 million project is expected to deliver a positive net present value of approximately \$500 million over the next 20 years as published on BC Hydro’s Fact Sheet on Smart Meters.¹⁰³

For cash flow purposes, the cost of the Smart Metering Infrastructure program has been built into the new generation infrastructure costs while the anticipated success of the conservation plan will be incorporated into sales growth forecasts by limiting domestic revenue growth to the 9.4% factor calculated above.

BC Hydro’s smart metering infrastructure is the largest demand side management program designed to achieve the utility’s long term goals under the Clean Energy Act. The Act goes so far as to exclude the SMI program from the BCUC’s regulatory review process (if implemented in 2012). Timing of the program’s rollout will be critical to the financial performance of the company in that early energy conservation will translate into a shorter return on investment.

5.3 Financial Projection: Meeting Requirements with No Increase

Given BC Hydro’s financial operating constraints described above, as well as the calculated cash flows generated from the utility’s proposed energy asset building, acquisition and conservation programs, specific financial projections can be developed.

If BC Hydro continues its infrastructure expansion and improvement plans while providing power to its customers at current rate levels, it will require over \$1 billion in debt financing over the next year as demonstrated by Pro Forma 1 (Appendix C). Assuming no other sources of financing are available, the utility could experience a loss in net revenue. Energy sales would likely increase by 9.4% by 2016 (as calculated in section 5.2.1) while energy acquisition costs for domestic power from IPPs would climb as determined by their projected cash flows (as calculated in section 5.2.2). Operating, maintenance and other such expenses could all be

¹⁰³ BC Hydro Fact Sheet, Smart Meters: <http://www.mediaroom.gov.bc.ca/> (accessed March 14, 2011)

assumed to increase proportionally with the new assets built while financing costs would rise to service the resulting debt.

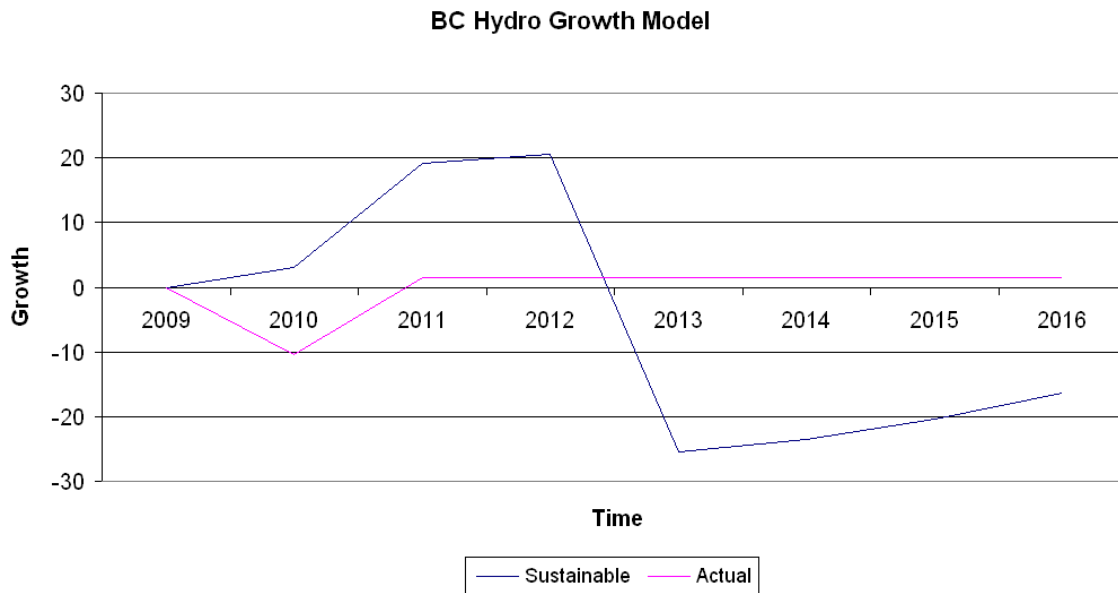


Figure 12: BC Hydro's Forecasted Annual % Growth Rates (in Sales Revenue) Assuming No Rate Increase¹⁰⁴

The projected growth rate chart for this scenario (Figure 12) suggests that, without a rate increase, the company would fail to operate within its sustainable growth rate (calculated in Table 10) and fail to generate positive annual payments to the government as early as the end of 2011.

Table 10: BC Hydro's Forecasted Growth Rate Calculations with no Rate Increase¹⁰⁵

BC Hydro	2009	2010	2011	2012	2013	2014	2015	2016
Required ratios:								
Net Income (x \$million)	365	447	512	550	-681	-628	-544	-439
Sales (x \$million)	4,269	3,822	3,880	3,938	3,998	4,058	4,119	4,182
Assets (x \$million)	16,368	18,093	18,902	19,717	20,221	20,599	20,819	20,932
Shareholders' equity	2,189	2,674	2,674	2,674	2,674	2,674	2,674	2,674
Profit margin, P(%)	8.6%	11.7%	13.2%	14.0%	-17.0%	-15.5%	-13.2%	-10.5%
Retention ratio, R(%)	15	15	100	100	100	100	100	100
Asset turnover, A (times)	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Financial leverage, T ^a (times)	N/A	8.3	7.1	7.4	7.6	7.7	7.8	7.8
Sustainable growth rate, g*(%)	N/A	3.1	19.1	20.6	-25.5	-23.5	-20.4	-16.4
Actual growth rate, g(%)	N/A	-10.5	1.5	1.5	1.5	1.5	1.5	1.5

¹⁰⁴ Source: Author, 2011

¹⁰⁵ Source: Author, 2011

5.4 Financial Projection: Meeting Requirements with a Rate Increase

If BC Hydro were left unconstrained to increase its rates, a second projection could be developed as shown by Pro Forma 2 (Appendix D). The model created above can now be used to apply rate increases until positive Provincial payments are generated. In this case, an immediate 15% rate increase would generate positive net income levels over the next five years.

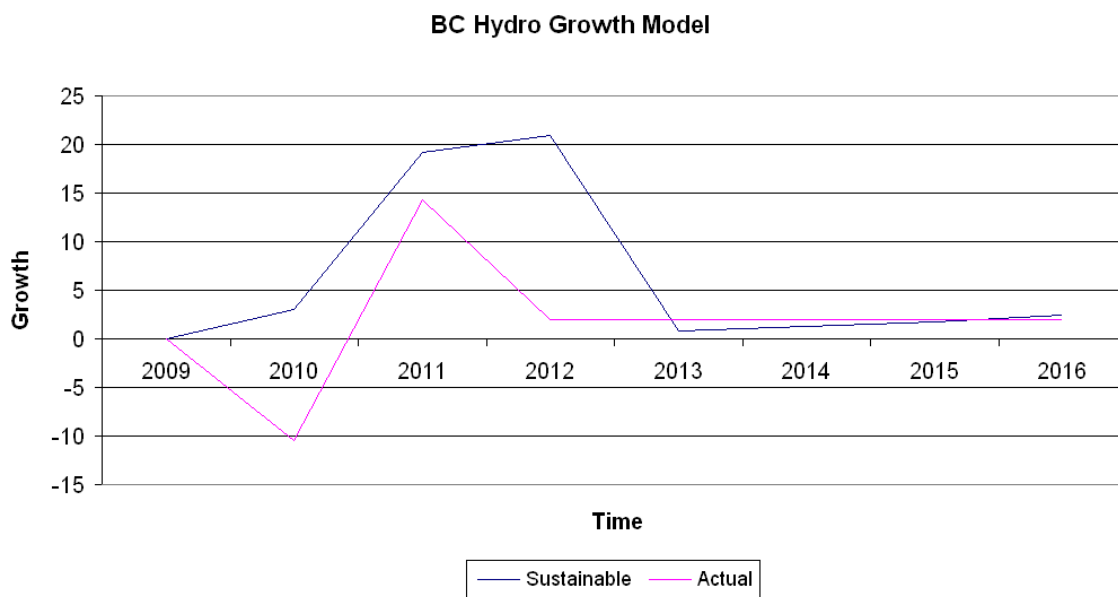


Figure 13: BC Hydro's Forecasted Annual % Growth Rates (in Sales Revenue) with 15% Rate Increase¹⁰⁶

The projected growth rate chart for this scenario (Figure 13) suggests that the company would achieve sustainable growth by 2016, generate healthy returns with positive government payments over the next five years and ultimately achieve sustainable growth (as calculated in Table 11) while operating well within its required debt to equity ratio of 80:20.

¹⁰⁶ Source: Author, 2011

Table 11: BC Hydro’s Forecasted Growth Rate Calculations with a 15% Increase¹⁰⁷

BC Hydro	2009	2010	2011	2012	2013	2014	2015	2016
Required ratios:								
Net Income (x \$million)	365	447	512	550	146	216	316	439
Sales (x \$million)	4,269	3,822	4,369	4,453	4,540	4,628	4,718	4,809
Assets (x \$million)	16,368	18,093	18,902	19,717	20,188	20,588	20,840	21,001
Shareholders' equity	2,189	2,674	2,621	2,629	2,641	2,663	2,695	2,743
Profit margin, P(%)	8.6%	11.7%	11.7%	12.4%	3.2%	4.7%	6.7%	9.1%
Retention ratio, R(%)	15	15	100	100	15	15	15	15
Asset turnover, A (times)	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Financial leverage, T ^a (times)	N/A	8.3	7.1	7.5	7.7	7.8	7.8	7.8
Sustainable growth rate, g*(%)	N/A	3.1	19.1	21.0	0.8	1.2	1.8	2.4
Actual growth rate, g(%)	N/A	-10.5	14.3	1.9	1.9	1.9	1.9	1.9

5.5 Tradeoffs and Feasible Options

If a 15% rate increase is deemed to be unacceptable by the provincial government, a number of alternatives are available for consideration based on the combinations of options presented in chapter 4 (Table 6). The following analysis of each combination of options (listed in Table 12) shows that three feasible alternatives would be available to BC Hydro should the government agree to relax specific requirements of the Clean Energy Act. Two key assumptions are used in the following analysis to reject alternatives. One is that alternatives resulting in higher costs than the full program implementation option (resulting in rate increases greater than 15%) are not acceptable. Another assumption is that alternatives that do not close the demand/supply self-sufficiency gap by 2020 are not acceptable due to their failure to reduce greenhouse gas emissions in BC through clean energy use. Besides showing whether or not an option is acceptable, and what rate increase would be required, the table shows when the programs are implemented, whether the combination results in self-sufficiency by 2016, and whether the goal of 3000 GWh of “insurance” capacity is achieved by 2020. The “D-S Gap” column indicates whether the gap between demand and supply will be closed by 2020 with clean energy produced in BC. Each of the 12 combination of options is discussed below.

¹⁰⁷ Source: Author, 2011

Table 12: Summary of Alternative Combinations of Program Options¹⁰⁸

Option	DSM Program		IPP Program		Generation Program		Time Goals			Capacity	Acceptable	Rate Inc.
	2012	2016	2016	2020	2016	2020	SMI	Self-Suf.	Insurance	D-S Gap	Y/N	%
0	✓		✓		✓		✓	✓	✓	✓	No	0
1	✓		✓		✓		✓	✓	✓	✓	Yes	15.0
2	✓		✓			✓	✓	✓	✗	✗	No	-
3	✓			✓	✓		✓	✗	✓	✓	Yes	4.5
4	✓			✓		✓	✓	✗	✗	✗	No	-
5		✓	✓		✓		✗	✓	✓	✓	No	-
6		✓	✓			✓	✗	✓	✗	✗	No	-
7		✓		✓	✓		✗	✗	✓	✓	Yes	6.0
8		✓		✓		✓	✗	✗	✗	✗	No	-
9		✗	✓		✓		✗	✓	✓	✓	No	-
10		✗	✓			✓	✗	✓	✗	✗	No	-
11		✗		✓	✓		✗	✗	✓	✓	Yes	10.1
12		✗		✓		✓	✗	✗	✗	✗	No	-

5.5.1 Tradeoffs Considered

Option 0 is the status quo. This option represents the financial projection of section 5.3 in which all of BC Hydro’s programs are implemented with no increase in rates. The financial model set up to analyze this option demonstrated that BC Hydro cannot support the proposed set of programs required to deliver the Clean Energy Act requirements without either increasing rates, applying for regulatory changes in how its finances are handled or by asking the government to relax the constraints of the Clean Energy Act.

Option 1 is the full Clean Energy Act implementation plan: This option represents the unconstrained rate increase option presented in section 5.4 through which all programs needed to meet the Clean Energy Act requirements are delivered at their full cost. This option would require a rate increase of 15% to consumers. If this increase is unacceptable to the provincial government, the financial model used to determine this rate may be modified to examine the result of the tradeoff combinations listed as options 2 through 12.

Options 2, 4, 6, 8, 10 and 12 all involve deferring the maintenance and upgrade cost of BC Hydro’s heritage assets and relying on either (in the case of options 2, 6 and 10) considerably more power from IPPs or on (in the case of 4, 8 and 12) substantial increases in imported energy. In the first case, assuming that IPPs could supply sufficient capacity, rates would exceed that of the full implementation plan as projected rates paid to IPPs exceed that paid for power produced by the utility’s heritage assets. In the second case, BC would continue to be a long term net importer of electricity, continue to rely on fossil fuel generated power and fail in its mandate to

¹⁰⁸ Source: Author, 2011

reduce greenhouse gas emissions as required by the Federal Government's Greenhouse Gas Regulatory Framework (designed to comply with Canada's commitments within the Kyoto Protocol).

Options 5 and 9 involve continuing with the IPP Interconnections and BC Hydro's generation capital plan to meet all the Clean Energy Act requirements but also involve either deferring (option 5) or cancelling (option 9) the SMI demand side management program. In order to meet the clean energy requirement without the demand side management reduction, BC Hydro would have to purchase approximately 6,600 GWh of additional electricity from IPPs over the first four years. In the case of option 5, BC Hydro would save the \$930 million implementation cost of the SMI program but pay over \$2 Billion¹⁰⁹ to IPPs to acquire the additional energy required. In the case of option 9, energy acquisition costs would be even higher. Either option would result in an increase in rates above the full program implementation option. These options are therefore considered not feasible on the basis of cost.

5.5.2 Feasible Options

The elimination of the above options leaves BC Hydro with three remaining options that may be feasible should the government agree to relax the 2016 self-sufficiency requirement and (in two cases) the 2012 SMI requirements of the Clean Energy Act. These three options are common in that they all involve deferring the IPP interconnection program for at least four years. This delayed implementation results in lower cost options because electricity purchased from IPPs is replaced by lower cost (and less clean) imported energy. The differences between the options involve the implementation timeline of the SMI program. Later implementation of demand side management programs contributes to less conservation, higher demand for electricity and higher purchase costs. The options are described in detail as follow:

Option 3 requires that BC Hydro ask the government to relax its self-sufficiency timeline of 2016. Deferring the interconnection of IPPs will allow the utility to save the short term costs of acquiring high cost clean energy in favour of importing lower cost energy over the next four years. This option also depends on the successful implementation of the SMI program by the mandated 2012 timeline. Electricity acquisition calculations are based on the assumption that the demand side management program will meet its mandate of decreasing demand by its forecasted amount. If the government relaxed the self-sufficiency timeline of the Clean Energy Act, the utility could achieve electricity self-sufficiency by 2020 after being a net importer for 4 additional

¹⁰⁹ Calculated with the average IPP rate (from Table 9) of \$76.945/MWh and a capacity of 6,600 GW/year over 4 years

years and deliver its programs with a rate increase of 4.5% while meeting its financial requirements as indicated by the financial growth model and the financial statements provided in Appendix E.

Option 7 requires that BC Hydro request two exceptions of the Clean Energy Act. First, that the self-sufficiency timeline is extended by four years and second, that the SMI program is deferred to its more realistic implementation schedule of 2016. If these two concessions are made, the utility could meet self-sufficiency requirements by 2020 but would have to import more energy than it would under option 3 due to later supply of clean energy from IPPs and the negative effect of deferring demand side management programs. Adjusting these timelines, acquisition capacities and rates within the financial model used above leads to the resulting sustainable growth calculation and financial statements provided in Appendix F where a minimum rate increase of 6.0% is predicted.

Option 11 is similar to option 7 in that it assumes BC Hydro is successful in having both the self-sustainability and SMI program requirements of the Clean Energy Act relaxed. This option assumes the same deferral of IPP interconnection but further assumes that the demand side management program is deferred until after 2020. The financial model predicts that the additional capacity of non-conserved energy must be imported by BC Hydro and that cost of higher capacity would result in the sustainable growth calculation and financial statements provided in Appendix G where a minimum forecasted rate increase of 10.1%.

6 Conclusion

This project has described the requirements of the Clean Energy Act, provided an overview of the electrical industry within British Columbia, examined BC Hydro's programs and analyzed the utility's ability to meet the Act's requirements. BC Hydro's options were evaluated against its goals of managing capacity (closing the supply and demand gap), time (self-sufficiency dates) and cost (rates charged to customers). Several program delivery combinations were generated from options available within the programs of Demand Side Management, power acquisition from Independent Power Producers and BC Hydro's capital program to upgrade generation plants. Each combination of alternatives was assessed for feasibility within the Crown Corporation's financial constraints of sustaining a strong annual dividend payment to the provincial government, maintaining its existing debt to equity ratio and meeting the political pressure of maintaining customer rates that are among the lowest in North America.

Any combination of program options designed to deliver the requirements of the Clean Energy Act will involve funding requirements that will most likely result in increased rates to electricity consumers in BC. Within the financial model designed for this project, and the assumptions provided, an immediate minimum 15% increase in rates will be required to meet all the requirements of the Act. This is calculated as a one-time rate applied over the entire duration of the Clean Energy Act's mandate (2011 through 2020). Policy makers may choose to stage this increase over a number of years or differentiate rate increases applied to the customer categories of residential, commercial and industrial. This rate design may also be used to encourage cost conservation through time-of-use variances.

As shown in the following table, policy makers have four feasible options to best meet the requirements of the Clean Energy Act. Although each option allows BC Hydro to operate within its regulated financial constraints, tradeoffs are available to the policy maker should lower rates be preferred over meeting specific requirements of the Clean Energy Act.

Table 13: Summary of Acceptable Options Available to BC Hydro ¹¹⁰

Options	Implement SMI	IPP Interconnection	Generation Upgrades	Tradeoffs
A	2012 Meets the Act	2016 Meets the Act	2016 Meets the Act	Increase Rates by 15.0% Achieve self-sufficiency in 2016 Achieve 2020 Insurance Goal
B	2016 Deferred	2020	2016 Meets the Act	Increase Rates by 6.0% Achieve self-sufficiency in 2020 Achieve 2020 Insurance Goal
C	2012 Meets the Act	2020	2016 Meets the Act	Increase Rates by 4.5% Achieve self-sufficiency in 2020 Achieve 2020 Insurance Goal
D	No Implementation	2020	2016 Meets the Act	Increase Rates by 10.1% Achieve self-sufficiency in 2020 Achieve 2020 Insurance Goal

Option A is the full implementation plan described above. This option requires a 15% rate increase to meet all of the Clean Energy Act's requirements. No tradeoffs are required.

Option B is the most likely alternative available to the policy maker, because the SMI program will likely require additional time to implement (as discussed in the chapter 4 analysis), and BC Hydro customers pay lower rates than those rates required in Option A. This option requires a 6.0% rate increase and will achieve the goal of having 3000 GWhs insurance capacity by 2020. This option does not implement SMI until 2016 and does not achieve self-sufficiency until 2020. Lower rates are possible because imported electricity would replace higher priced clean energy from IPPs for the first four years of the program. The 6.0% rate increase would be required to cover the cost of additional electricity supplies as the DSM program would not have the benefit of SMI, so demand will grow by more.

Option C only requires a 4.5% rate increase, but may not be possible due to the challenging timeline of the SMI program. If SMI can be implemented by 2012, then the only tradeoff required is relaxing the 2016 self-sufficiency requirements. Self-sufficiency would be met in 2020 as would the insurance requirement. A lower rate than Option B is possible because the DSM program would lower electricity demand growth more, and therefore BC Hydro's costs of purchasing electricity as well.

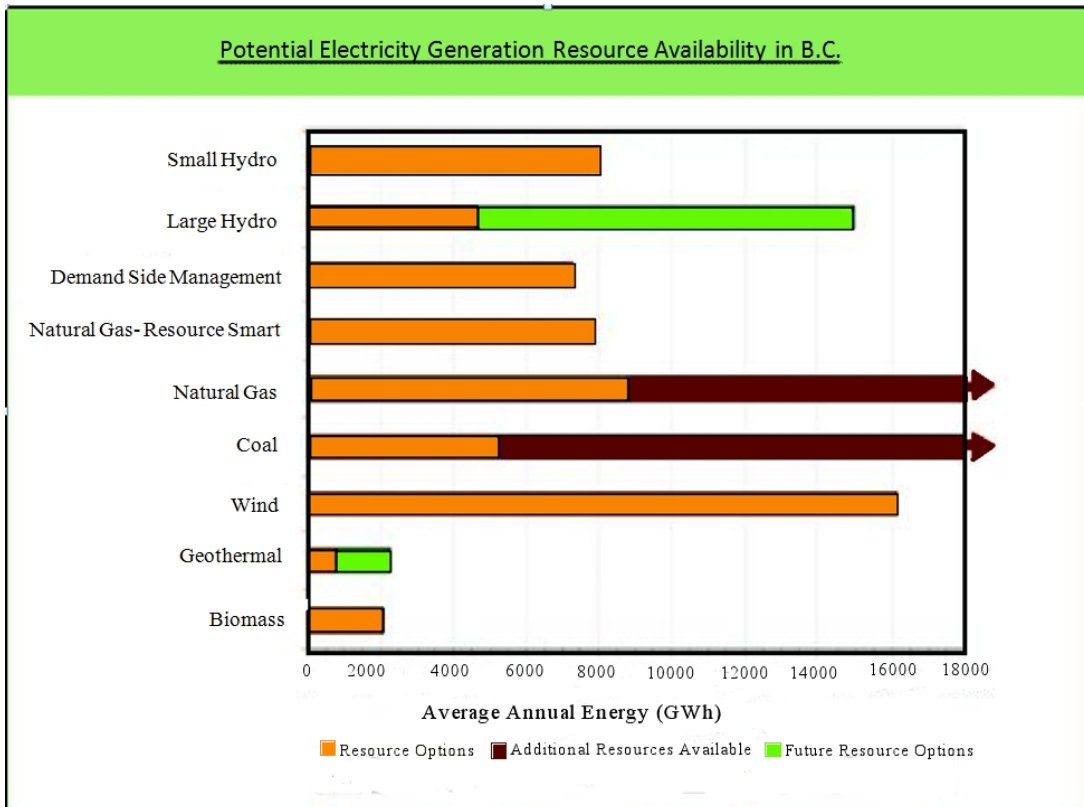
Option D is another feasible option that fits within the utility's financial constraints. This option achieves self-sufficiency in 2020 with a 10.1% rate increase and achieves the 2020 insurance goal. Tradeoffs include deferring the SMI implementation indefinitely and not meeting

¹¹⁰ Source: Author, 2011

the 2016 self-sufficiency timeline. The rate increase is lower than required in Option A as imported electricity would replace higher priced clean energy from IPPs. The rate increase is higher than required in Options B and C because more electricity needs to be purchased than is required with the implementation of the SMI program.

Appendices

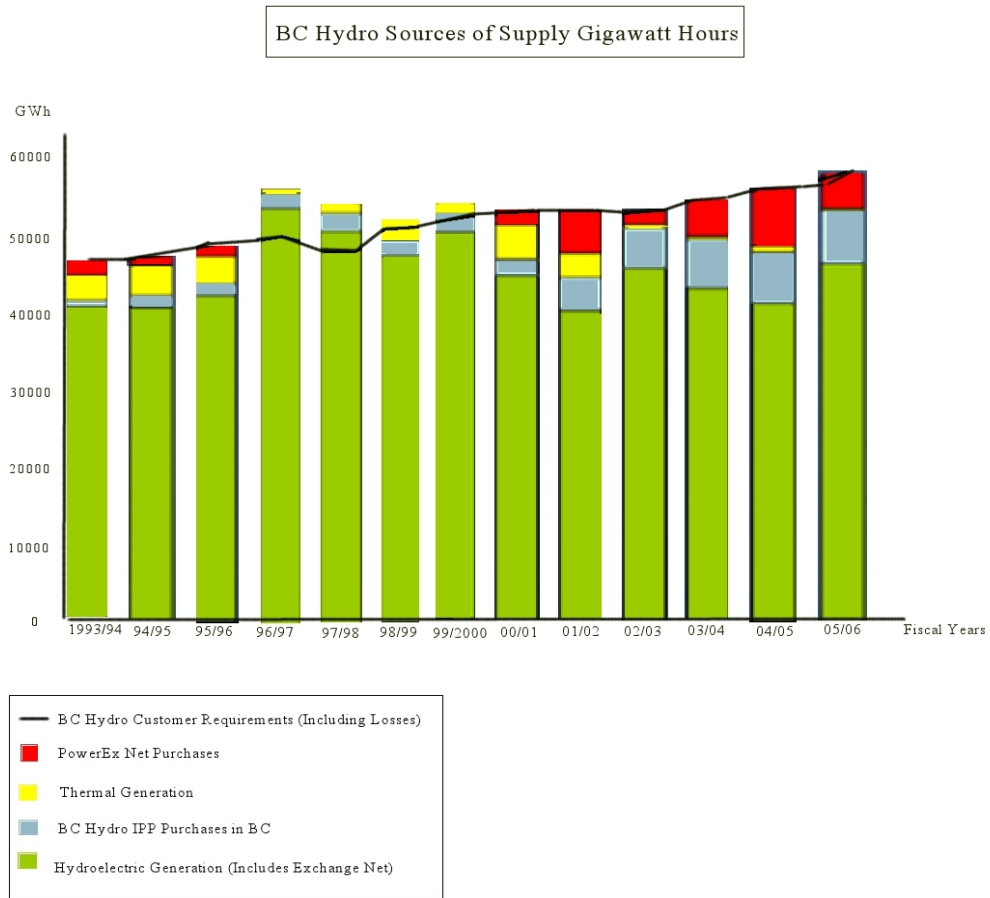
Appendix A



Electricity supply options in BC¹¹¹

¹¹¹ <http://www.ippbc.com/EN/10048/> (accessed March 28, 2011)

Appendix B



BC Hydro has imported electricity to meet demand since 2001 ¹¹²

¹¹² Source: BC Ministry of Energy, Mines and Petroleum Resources

Appendix C

Pro Forma 1: Assume 0% Rate Increase

Financial Statements Pro Forma 1
(assume no rate increase)

Statement of Operations

	2009	2010	2011	2012	2013	2014	2015	2016
Revenues								
Domestic (Note 1)	2814	3090	3380	3698	4046	4426	4842	5297
Trade	1455	732	801	876	958	1049	1147	1255
	4269	3822	4181	4574	5004	5475	5989	6552
Expenses								
Energy Costs								
Domestic (Note 2)	1236	1150	877	914	1145	1376	1607	1837
Trade (Note 3)	1157	635	747	597	448	299	149	0
Operations (Note 4)	395	396	467	533	598	670	743	818
Maintenance (Note 4)	353	628	741	846	949	1063	1178	1298
General Admin	167	225	265	303	340	381	422	465
Taxes	167	173	204	233	261	293	325	358
Amortization	395	445	525	599	672	753	835	920
	3870	3652	3825	4026	4414	4834	5259	5696
Operating Income	399	170	356	549	591	641	731	857
Finance Charges (Note 5)	472	419	954	993	1017	1040	1053	1060
Change in Reg. acct. (Note 6)	438	696	0	0	0	0	0	0
Net Income	365	447	-598	-445	-426	-398	-322	-203
Retained earnings: beginning of year	1856	2221	2621	2023	1579	1152	754	432
Net Income	365	447	-598	-445	-426	-398	-322	-203
Payment to Province	0	47	0	0	0	0	0	0
Retained earnings: end of year	2221	2621	2023	1579	1152	754	432	229

Balance Sheet

	2009	2010	2011	2012	2013	2014	2015	2016
Assets								
Property, Plant & Equip. (Note 7)	11830	13822	14898	15553	15950	16328	16548	16661
Current Assets	2087	1342	1342	1342	1342	1342	1342	1342
Other Assets	2412	2929	2929	2929	2929	2929	2929	2929
	16329	18093	19169	19824	20221	20599	20819	20932
Liabilities								
Long-term Debt	7111	8727	9803	10458	10855	11233	11453	11566
Current Liabilities	4478	3568	3568	3568	3568	3568	3568	3568
Other Liabilities	2561	3124	3124	3124	3124	3124	3124	3124
Shareholders Equity	2179	2674	2674	2674	2674	2674	2674	2674
	16329	18093	19169	19824	20221	20599	20819	20932
Debt: Equity (must be < 4)		2.7	2.8	2.8	2.8	2.8	2.8	2.8

Note 1: Assuming an average increase in sales of 9.4% as per DSM assumptions from 5.2.1

Note 2: Adjusted in accordance with the energy purchase forecast from Table 9

Note 3: Decrease trade to zero over 5 years assuming self-sufficiency is reached

Note 4: Operations and Maintenance. Costs increase proportionally with Property, Plant & Equip. and include the cost of SMI

Note 5: The weighted average effective interest rate of 6.0 per cent applied to long term debt & 5 yr debt expired (BC Hydro Annual Report (p.95))

Note 6: Assume no new regulatory changes to financial structure

Appendix D

Pro Forma 2: Assume 15% Rate Increase

Financial Statements Pro Forma 2
(assume a 15% rate increase)

Statement of Operations

	2009	2010	2011	2012	2013	2014	2015	2016
Revenues								
Domestic (Note 1)	2814	3090	3888	4253	4653	5090	5569	6092
Trade	1455	732	921	1159	1458	1834	2307	2903
	4269	3822	4808	5412	6110	6924	7876	8995
Expenses								
Energy Costs								
Domestic (Note 2)	1236	1150	877	914	1145	1376	1607	1837
Trade (Note 3)	1157	635	747	597	448	299	149	0
Operations (Note 4)	395	396	467	533	598	670	743	818
Maintenance (Note 4)	353	628	741	846	949	1063	1178	1298
General Admin	167	225	265	303	340	381	422	465
Taxes	167	173	204	233	261	293	325	358
Amortization	395	445	525	599	672	753	835	920
	3870	3652	3825	4026	4414	4834	5259	5696
Operating Income	399	170	983	1386	1697	2090	2617	3299
Finance Charges (Note 5)	472	419	954	993	1017	1040	1053	1060
Change in Reg. acct. (Note 6)	438	696	0	0	0	0	0	0
Net Income	365	447	30	393	680	1051	1564	2240
Retained earnings: beginning of year	1856	2221	2621	2625	2684	2786	2944	3179
Net Income	365	447	30	393	680	1051	1564	2240
Payment to Province	0	47	25	334	578	893	1330	1904
Retained earnings: end of year	2221	2621	2625	2684	2786	2944	3179	3515

Balance Sheet

	2009	2010	2011	2012	2013	2014	2015	2016
Assets								
Property, Plant & Equip. (Note 7)	11830	13822	14898	15553	15950	16328	16548	16661
Current Assets	2087	1342	1342	1342	1342	1342	1342	1342
Other Assets	2412	2929	2876	2880	2939	3041	3199	3434
	16329	18093	19116	19775	20231	20711	21089	21437
Liabilities								
Long-term Debt	7111	8727	9803	10458	10855	11233	11453	11566
Current Liabilities	4478	3568	3568	3568	3568	3568	3568	3568
Other Liabilities	2561	3124	3124	3124	3124	3124	3124	3124
Shareholders Equity	2179	2674	2621	2625	2684	2786	2944	3179
	16329	18093	19116	19775	20231	20711	21089	21437

Note 1: Assuming an average increase in sales of 9.4% as per DSM assumptions from 5.2.1

Note 2: Adjusted in accordance with the energy purchase forecast from Table 9

Note 3: Decrease trade to zero over 5 years assuming self-sufficiency is reached

Note 4: Operations and Maintenance. Costs increase proportionally with Property, Plant & Equip. and include the cost of SMI

Note 5: The weighted average effective interest rate of 6.0 per cent applied to long term debt & 5 yr debt expired (BC Hydro Annual Report (p.95))

Note 6: Assume no new regulatory changes to financial structure

Note 7: Assumes average rate increase of 15%

Appendix E

Pro Forma Option 3

**Financial Statements Pro Forma Option 3
(assume a 4.5% rate increase)**

Statement of Operations

	2009	2010	2011	2012	2013	2014	2015	2016
Revenues								
Domestic (Note 1)	2814	3090	3533	3865	4228	4625	5060	5536
Trade	1455	732	837	957	1094	1250	1429	1634
	4269	3822	4369	4821	5322	5876	6490	7170
Expenses								
Energy Costs								
Domestic (Note 2)	1236	1150	0	0	0	0	0	0
Trade (Note 3)	1157	635	747	896	1075	1290	1548	1858
Operations (Note 4)	395	396	427	446	457	468	474	477
Maintenance (Note 4)	353	628	677	707	725	742	752	757
General Admin	167	225	243	253	260	266	269	271
Taxes	167	173	186	195	200	204	207	209
Amortization	395	445	480	501	514	526	533	536
	3870	3652	2759	2997	3230	3496	3783	4108
Operating Income	399	170	1610	1825	2092	2380	2706	3062
Finance Charges (Note 5)	472	419	954	993	1017	1040	1053	1060
Change in Reg. acct. (Note 6)	438	696	0	0	0	0	0	0
Net Income	365	447	657	831	1075	1340	1653	2002
Retained earnings: beginning of year								
	1856	2221	2621	2719	2844	3005	3207	3455
Net Income								
	365	447	657	831	1075	1340	1653	2002
Payment to Province								
	0	47	558	707	914	1139	1405	1702
Retained earnings: end of year								
	2221	2621	2719	2844	3005	3207	3455	3755

Balance Sheet

	2009	2010	2011	2012	2013	2014	2015	2016
Assets								
Property, Plant & Equip. (Note 7)	11830	13822	14898	15553	15950	16328	16548	16661
Current Assets	2087	1342	1342	1342	1342	1342	1342	1342
Other Assets	2412	2929	2876	2974	3099	3260	3462	3710
	16329	18093	19116	19869	20391	20930	21351	21713
Liabilities								
Long-term Debt	7111	8727	9803	10458	10855	11233	11453	11566
Current Liabilities	4478	3568	3568	3568	3568	3568	3568	3568
Other Liabilities	2561	3124	3124	3124	3124	3124	3124	3124
Shareholders Equity	2179	2674	2621	2719	2844	3005	3207	3455
	16329	18093	19116	19869	20391	20930	21351	21713

Note 1: Assuming an average increase in sales of 9.4% as per DSM assumptions from BC Hydro Service Plan p.13

Note 2: Adjusted to defer IPP payments

Note 3: Adjusted to defer self-sufficiency timeline

Note 4: Operations and Maintenance. Costs increase proportionally with Property, Plant & Equip. and include the cost of SMI

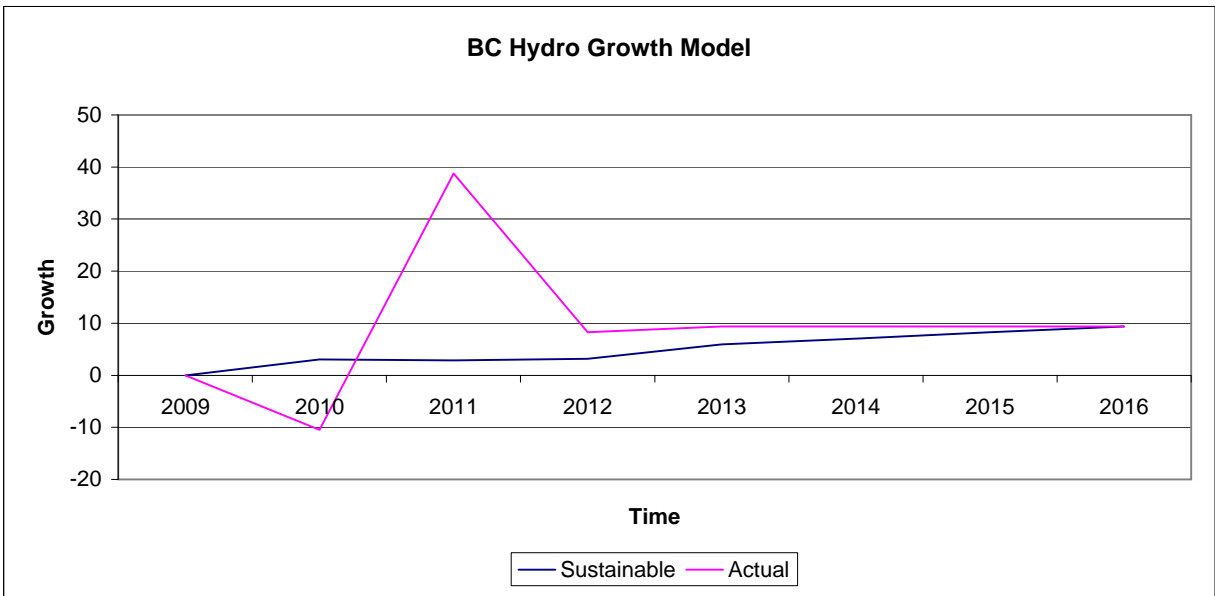
Note 5: The weighted average effective interest rate of 6.0 per cent applied to long term debt & 5 yr debt expired (BC Hydro Annual Report (p.95))

Note 6: Assume no new regulatory changes to financial structure

Note 7: Assumes average rate increase of 4.5%

BC Hydro's Growth Model
 Pro forma Option 3
 (4.5% rate increase)

BC Hydro	2009	2010	2011	2012	2013	2014	2015	2016
Required ratios:								
Net Income (x \$1,000)	365	447	512	550	1,075	1,340	1,653	2,002
Sales (x \$1000)	4,269	3,822	5,304	5,743	6,280	6,867	7,509	8,211
Assets (x \$1,000)	16,368	18,093	18,902	19,717	20,391	20,930	21,351	21,713
Shareholders' equity	2,189	2674	2,621	2,719	2,844	3,005	3,207	3,455
Profit margin, P(%)	8.6%	11.7%	9.7%	9.6%	17.1%	19.5%	22.0%	24.4%
Retention ratio, R(%)	15	15	15	15	15	15	15	15
Asset turnover, A (times)	0.3	0.2	0.3	0.3	0.3	0.3	0.4	0.4
Financial leverage, T^ (times)	N/A	8.3	7.1	7.5	7.5	7.4	7.1	6.8
Sustainable growth rate, g*(%)	N/A	3.1	2.9	3.1	5.9	7.1	8.3	9.4
Actual growth rate, g(%)	N/A	-10.5	38.8	8.3	9.3	9.4	9.3	9.4



Appendix F

Pro Forma Option 7

**Financial Statements Pro Forma Option 7
(assume a 6% rate increase)**

Statement of Operations

	2009	2010	2011	2012	2013	2014	2015	2016
Revenues								
Domestic (Note 1)	2814	3090	3583	3920	4289	4692	5133	5615
Trade	1455	732	849	984	1142	1324	1535	1780
	4269	3822	4432	4904	5430	6015	6668	7395
Expenses								
Energy Costs								
Domestic (Note 2)	1236	1150	0	0	0	0	0	0
Trade (Note 3)	1157	635	747	971	1262	1514	1817	2181
Operations (Note 4)	395	396	410	423	435	446	452	455
Maintenance (Note 4)	353	628	651	672	690	707	717	722
General Admin	167	225	233	241	247	253	257	259
Taxes	167	173	179	185	190	195	197	199
Amortization	395	445	461	476	489	501	508	512
	3870	3652	2681	2967	3312	3615	3948	4327
Operating Income	399	170	1751	1937	2118	2400	2720	3069
Finance Charges (Note 5)	472	419	919	947	971	993	1006	1013
Change in Reg. acct. (Note 6)	438	696	0	0	0	0	0	0
Net Income	365	447	831	991	1148	1407	1713	2055
Retained earnings: beginning of year	1856	2221	2621	2746	2894	3066	3277	3534
Net Income	365	447	831	991	1148	1407	1713	2055
Payment to Province	0	47	707	842	975	1196	1456	1747
Retained earnings: end of year	2221	2621	2746	2894	3066	3277	3534	3843

Balance Sheet

	2009	2010	2011	2012	2013	2014	2015	2016
Assets								
Property, Plant & Equip. (Note 7)	11830	13822	14323	14781	15178	15556	15776	15889
Current Assets	2087	1342	1342	1342	1342	1342	1342	1342
Other Assets	2412	2929	2876	3001	3149	3321	3532	3789
	16329	18093	18541	19124	19669	20219	20650	21020
Liabilities								
Long-term Debt	7111	8727	9228	9686	10083	10461	10681	10794
Current Liabilities	4478	3568	3568	3568	3568	3568	3568	3568
Other Liabilities	2561	3124	3124	3124	3124	3124	3124	3124
Shareholders Equity	2179	2674	2621	2746	2894	3066	3277	3534
	16329	18093	18541	19124	19669	20219	20650	21020

Note 1: Assuming an average increase in sales of 9.4% as per DSM assumptions from BC Hydro Service Plan p.13

Note 2: Operations and Maintenance. Costs increase proportionally with Property, Plant & Equip. and do not include the cost of SMI

Note 3: Decrease trade to zero over 5 years assuming self-sufficiency is reached

Note 4: Operations and Maintenance. Costs increase proportionally with Property, Plant & Equip. and include the cost of SMI

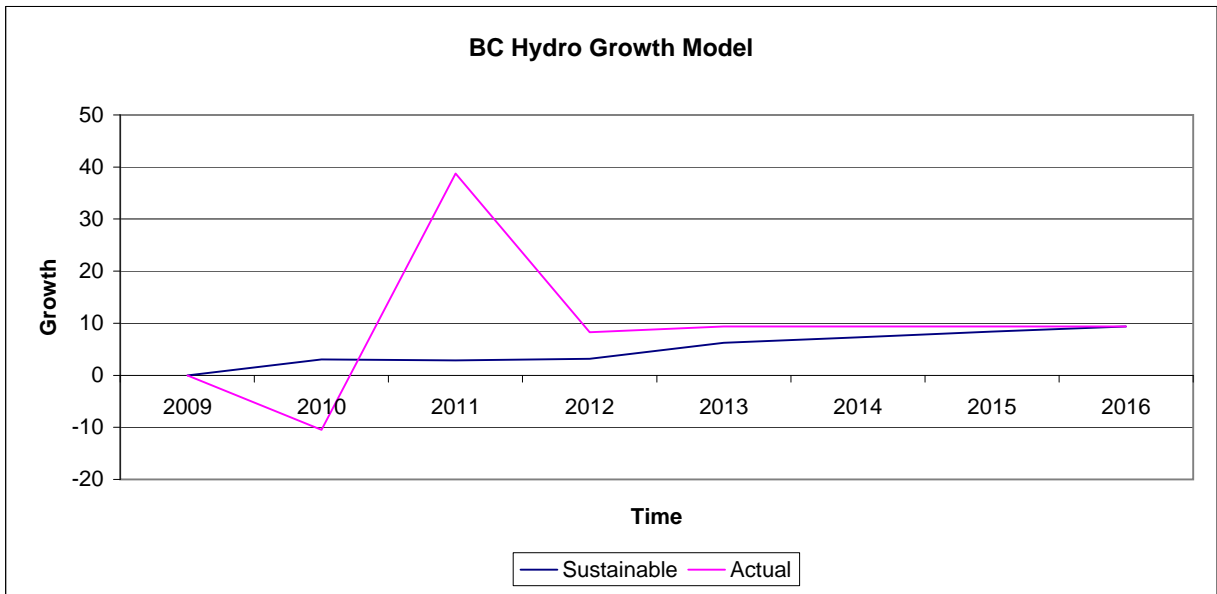
Note 5: The weighted average effective interest rate of 6.0 per cent applied to long term debt & 5 yr debt expired (BC Hydro Annual Report (p.95))

Note 6: Assume no new regulatory changes to financial structure

Note 7: Assumes average rate increase of 6.0%

BC Hydro's Growth Model
 Pro forma Option 7
 (6% rate increase)

BC Hydro	2009	2010	2011	2012	2013	2014	2015	2016
Required ratios:								
Net Income (x \$1,000)	365	447	512	550	1,148	1,407	1,713	2,055
Sales (x \$1000)	4,269	3,822	5,304	5,743	6,280	6,867	7,509	8,211
Assets (x \$1,000)	16,368	18,093	18,902	19,717	19,669	20,219	20,650	21,020
Shareholders' equity	2,189	2,674	2,621	2,746	2,894	3,066	3,277	3,534
Profit margin, P(%)	8.6%	11.7%	9.7%	9.6%	18.3%	20.5%	22.8%	25.0%
Retention ratio, R(%)	15	15	15	15	15	15	15	15
Asset turnover, A (times)	0.3	0.2	0.3	0.3	0.3	0.3	0.4	0.4
Financial leverage, T^ (times)	N/A	8.3	7.1	7.5	7.2	7.0	6.7	6.4
Sustainable growth rate, g*(%)	N/A	3.1	2.9	3.1	6.3	7.3	8.4	9.4
Actual growth rate, g(%)	N/A	-10.5	38.8	8.3	9.3	9.4	9.3	9.4



Appendix G

Pro Forma Option 11

**Financial Statements Pro Forma Option 11
(assume a 10.1% rate increase)**

Statement of Operations

	2009	2010	2011	2012	2013	2014	2015	2016
Revenues								
Domestic (Note 1)	2814	3090	3722	4072	4454	4873	5331	5832
Trade	1455	732	882	1062	1279	1541	1856	2235
	4269	3822	4604	5134	5734	6414	7187	8068
Expenses								
Energy Costs								
Domestic (Note 2)	1236	1150	0	0	0	0	0	0
Trade (Note 3)	1157	635	747	971	1262	1640	2133	2772
Operations (Note 4)	395	396	410	423	435	446	452	455
Maintenance (Note 4)	353	628	651	672	690	707	717	722
General Admin	167	225	233	241	247	253	257	259
Taxes	167	173	179	185	190	195	197	199
Amortization	395	445	461	476	489	501	508	512
	3870	3652	2681	2967	3312	3742	4263	4919
Operating Income	399	170	1922	2167	2422	2672	2924	3149
Finance Charges (Note 5)	472	419	919	947	971	993	1006	1013
Change in Reg. acct. (Note 6)	438	696	0	0	0	0	0	0
Net Income	365	447	1003	1220	1451	1679	1917	2136
Retained earnings: beginning of year								
	1856	2221	2621	2771	2954	3172	3424	3712
Net Income								
	365	447	1003	1220	1451	1679	1917	2136
Payment to Province								
	0	47	852	1037	1233	1427	1630	1816
Retained earnings: end of year								
	2221	2621	2771	2954	3172	3424	3712	4032

Balance Sheet

	2009	2010	2011	2012	2013	2014	2015	2016
Assets								
Property, Plant & Equip. (Note 7)	11830	13822	14323	14781	15178	15556	15776	15889
Current Assets	2087	1342	1342	1342	1342	1342	1342	1342
Other Assets	2412	2929	2876	3026	3209	3427	3679	3967
	16329	18093	18541	19149	19729	20325	20797	21198
Liabilities								
Long-term Debt	7111	8727	9228	9686	10083	10461	10681	10794
Current Liabilities	4478	3568	3568	3568	3568	3568	3568	3568
Other Liabilities	2561	3124	3124	3124	3124	3124	3124	3124
Shareholders Equity	2179	2674	2621	2771	2954	3172	3424	3712
	16329	18093	18541	19149	19729	20325	20797	21198

Note 1: Assuming an average increase in sales of 9.4% as per DSM assumptions from BC Hydro Service Plan p.13

Note 2: Adjusted to reflect deferred IPP payments

Note 3: Defer electricity self-sustainment goal

Note 4: Operations and Maintenance. Costs increase proportionally with Property, Plant & Equip. and do not include the cost of SMI

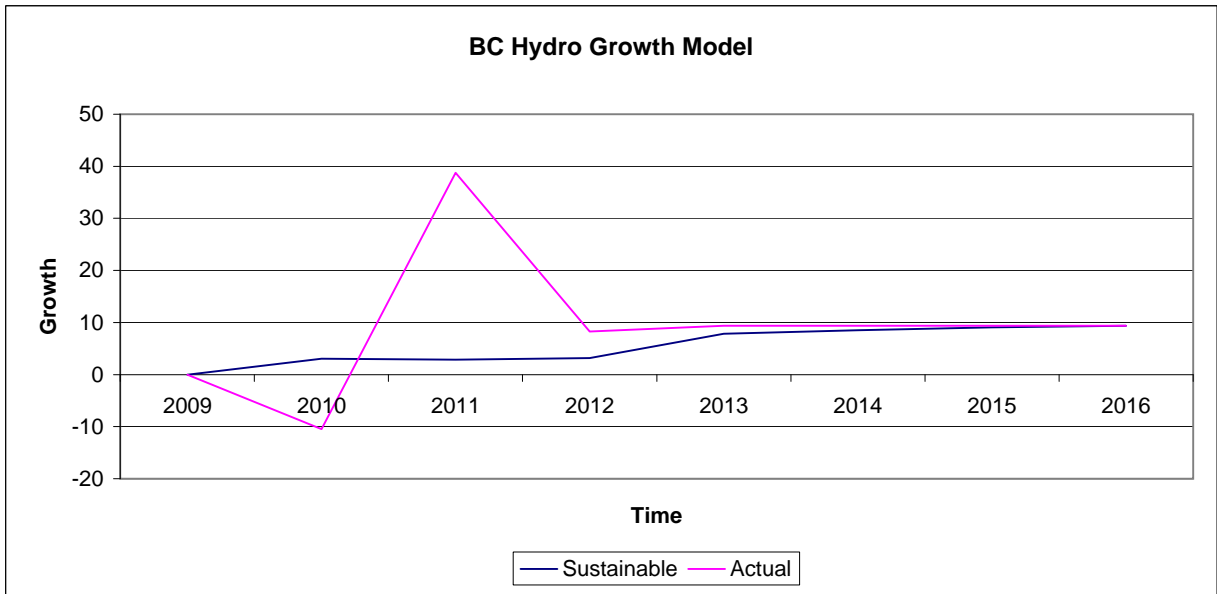
Note 5: The weighted average effective interest rate of 6.0 per cent applied to long term debt & 5 yr debt expired (BC Hydro Annual Report (p.95))

Note 6: Assume no new regulatory changes to financial structure

Note 7: Assumes average rate increase of 10.1%

BC Hydro's Growth Model
 Pro forma Option 11
 (10.1% rate increase)

BC Hydro	2009	2010	2011	2012	2013	2014	2015	2016
Required ratios:								
Net Income (x \$1,000)	365	447	512	550	1,451	1,679	1,917	2,136
Sales (x \$1000)	4,269	3,822	5,304	5,743	6,280	6,867	7,509	8,211
Assets (x \$1,000)	16,368	18,093	18,902	19,717	19,729	20,325	20,797	21,198
Shareholders' equity	2,189	2674	2,621	2,771	2,954	3,172	3,424	3,712
Profit margin, P(%)	8.6%	11.7%	9.7%	9.6%	23.1%	24.5%	25.5%	26.0%
Retention ratio, R(%)	15	15	15	15	15	15	15	15
Asset turnover, A (times)	0.3	0.2	0.3	0.3	0.3	0.3	0.4	0.4
Financial leverage, T [^] (times)	N/A	8.3	7.1	7.5	7.1	6.9	6.6	6.2
Sustainable growth rate, g*(%)	N/A	3.1	2.9	3.1	7.9	8.5	9.1	9.4
Actual growth rate, g(%)	N/A	-10.5	38.8	8.3	9.3	9.4	9.3	9.4



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