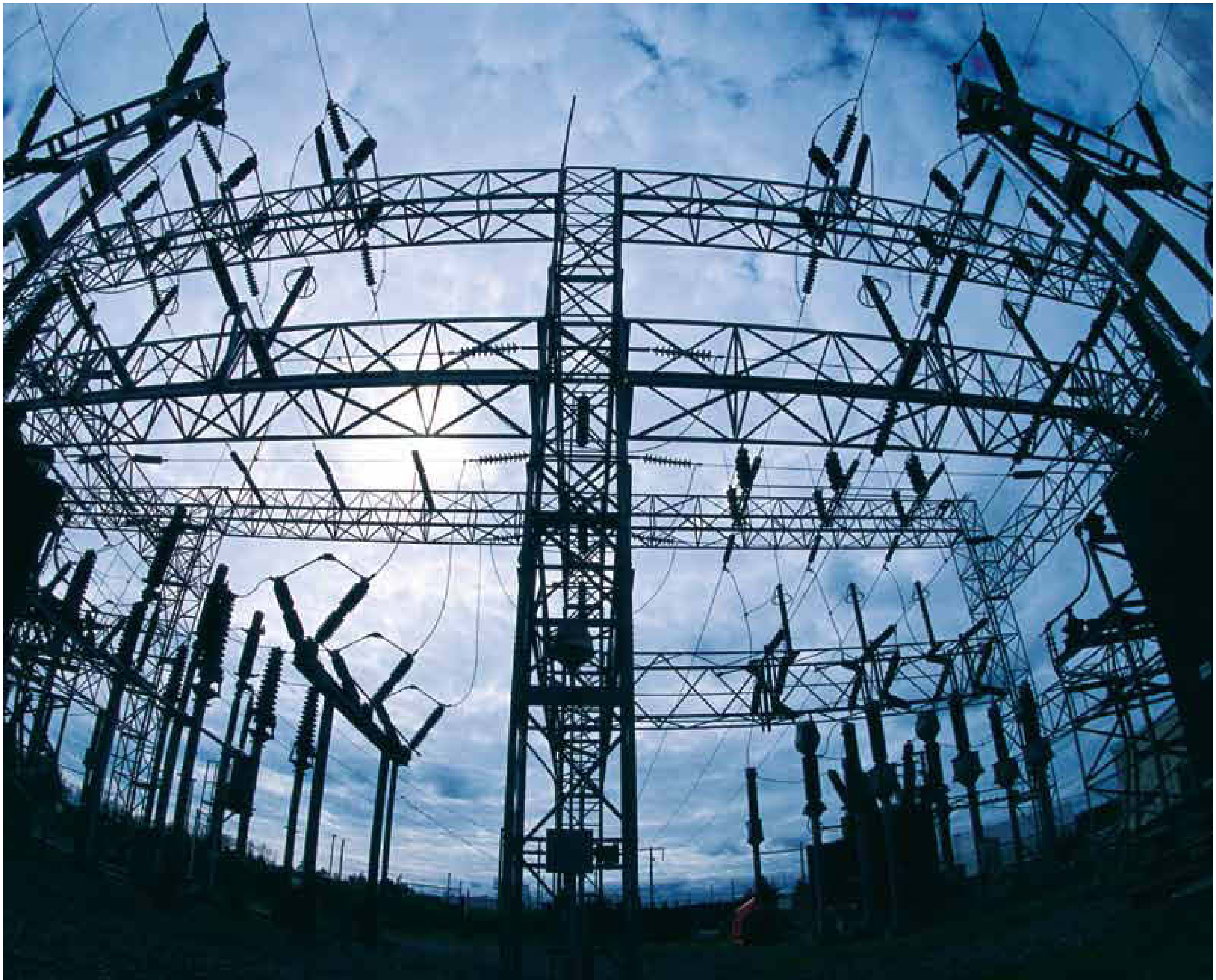


BC HYDRO ANNUAL REPORT 2013

BC hydro
FOR GENERATIONS

BRITISH COLUMBIA

TABLE OF CONTENTS

Table of Contents

LETTER FROM THE CHAIR TO THE MINISTER

Stephen Bellringer
Chair, BC Hydro

On behalf of the Board of Directors, the Executive Team and employees, I am pleased to submit BC Hydro's fiscal 2013 annual report, which was prepared under the Board's direction in accordance with the *Budget Transparency and Accountability Act* and the BC Reporting Principles. The Board is accountable for the contents of the report, including what has been included in the report and how it was reported.

The information presented reflects the actual performance of BC Hydro for the 12 months ended March 31, 2013 in relation to the 2012/13-2014/15 Service Plan. The Board is responsible for ensuring internal controls are in place to ensure information is measured and reported accurately and in a timely fashion.

All significant assumptions, policy decisions, events and identified risks, as of March 31, 2013, have been considered in preparing the report. The report contains estimates and interpretive information that represent the best judgment of management. Any changes in mandate direction, goals, strategies, measures or targets made since the 2012/13-2014/15 Service Plan was released and any significant limitations in the reliability of data are identified in the report.

INVESTING IN OUR CLEAN ENERGY FUTURE

This past year BC Hydro continued to focus on investing in our electricity system, so that we can reliably and safely serve our customers, now and in the future. We are balancing this investment with our responsibility to keep rates competitive for British Columbians.

In February 2013, the British Columbia Utilities Commission approved the replacement of the John Hart Generating Station on Vancouver Island, a project that will address seismic, reliability, and environmental issues. We are also adding transmission infrastructure to the system. Construction is underway on the Northwest Transmission Line, which will provide a reliable supply of clean power to future industrial developments in Northern B.C., as well as the Interior to Lower Mainland Transmission Line, which will improve our capability to serve domestic load in the Lower Mainland.

Part of our planning for the long term, the Site C Clean Energy Project is a proposed third dam and hydroelectric generating station on the Peace River in Northeast B.C. This year the project reached an important milestone, as BC Hydro submitted the Environmental Impact Statement as part of the federal and provincial review process. Site C would be a source of clean, reliable and cost-effective electricity for more than 100 years, and could power the equivalent of about 450,000 homes per year.

We are modernizing our system through the Smart Metering Program, which is enhancing the safety and reliability of the electricity system, enabling greater customer choice and control over their usage, and creating the foundation for new uses of electricity such as electric vehicles and customer generation. As of the end of fiscal 2013, new meter installations are nearly complete and most customers can now access comprehensive information about their hourly energy use through MyHydro, a secure online account. In addition to introducing these new conservation tools, we also met our conservation and environmental targets this year.

Our relationships with customers, communities, stakeholders and suppliers remains critical to how we do our business. A challenge in early fiscal 2013 was higher than normal seasonal call volumes. Customer care strategies, such as improved online tools, helped us achieve our customer satisfaction targets and address our call volumes, however we did not meet our first call resolution target. We did achieve a gold-level designation for best practices in aboriginal relations as measured by the Canadian Council for Aboriginal Relations' Progressive Aboriginal Relations program.

Looking to the future to address growing demand for electricity, BC Hydro's Integrated Resource Plan will provide a full picture of how we propose to meet our customers' needs in a cost-effective, and clean and reliable way. We will be submitting the Integrated Resource Plan to the Province of B.C. in August 2013.

SAFELY POWERING BRITISH COLUMBIA

Safety is BC Hydro's top priority and a core value. BC Hydro's most recent employee fatality in 2010 reinforced statistics that showed BC Hydro was experiencing a fatality or serious injury on average every six months. This tragic loss of life caused the organization to pause and reflect and BC Hydro's Executive Team and partnering unions to take a closer look at the organization to find solutions to dramatically improve safety at BC Hydro. In response, the BC Hydro Safety Taskforce was established in 2010. We are currently working to roll out their recommendations in phases over a three to five year period to permanently transform BC Hydro's safety culture. Despite our best efforts, last year we did not meet our safety objectives, but we know changing a culture takes time and we are on a path towards continuous improvement. Our reliability performance results, on the other hand, exceeded all of our targets in fiscal 2013.

The spring freshet in late fiscal 2013 presented unprecedented safety and operational challenges for BC Hydro, as we worked with agencies and communities to manage high water levels and mitigate flood impacts. We spilled at all of our major facilities because of high inflows. Clean energy generation was well above the Government's requirement that at least 93 per cent of electricity generation in the province come from clean or renewable resources.

An engaged workforce is required to achieve our goals. In September 2012, nearly 70 per cent of our employees participated in an employee-wide engagement survey, which provided an opportunity for employees to provide candid comments and suggestions. The overall engagement score was 78 per cent and a performance target of 80 per cent for employee engagement has been set for next fiscal year as we work to focus on improving this score with more visible and active leadership and a more focused approach to career development.

KEEPING RATES COMPETITIVE FOR CUSTOMERS

BC Hydro is balancing the investment in our electricity system with a continued focus on running our business in a streamlined and efficient way utilizing technology. British Columbia's electricity rates are among the lowest in North America, in large part because of the legacy of our hydroelectric generating facilities that were built between the 1950s and 1980s. It is important to keep BC Hydro rates affordable for all customers, including the businesses and industries that grow B.C.'s economy.

As of the end of fiscal 2013, we completed 44 of the 50 recommendations from the 2011 Government Panel Review of BC Hydro, and we are on track to achieving a cumulative cost savings of $391 million over three years. We are continuing to find ways to accelerate cost savings and reduce expenditures, while maintaining our commitment to safety and reinvesting in our system. We have a major effort underway in our Transmission and Distribution group to implement people and process changes to drive operational excellence. We are also bringing in technology to improve our service and operations.

BC Hydro's net income in fiscal 2013 was $509 million, which was within one per cent of our plan of $514 million. Our operating costs came in right on target at $705 million.

At the end of the day, our business is about people. It is about engaging communities, and using feedback from our stakeholders to inform our business. It is about ensuring that our employees are empowered to work safely, and that the public can depend on the safety of our operations. At our core, it is about continuing to provide clean, reliable power to British Columbians for years to come.

Sincerely,

Steve Bellringer

Stephen Bellringer

ORGANIZATIONAL OVERVIEW

BC Hydro was created to generate and deliver clean, reliable and competitively priced electricity to British Columbia's homes and businesses. The electricity generated by our dams and delivered by our transmission and distribution infrastructure has powered B.C.'s economy and quality of life for generations.

OUR VISION, VALUES & STRATEGIC OBJECTIVES

BC Hydro's vision is: "Powering B.C. with clean, reliable electricity for generations" and there are six core values that are essential to our success: accountability, integrity, safety, service, teamwork and ingenuity.

We also have six Strategic Objectives that guide our actions. These are each supported by corresponding strategies, performance measures and targets. Each performance measure is supported by a definition and rationale, as well as benchmarking measures, where available.

Vision: POWERING B.C. WITH CLEAN, RELIABLE ELECTRICITY FOR GENERATIONS

Values: ACCOUNTABILITY | INGENUITY | INTEGRITY | SAFETY | SERVICE | TEAMWORK

Strategic Objectives:

SAFELY KEEP THE LIGHTS ON
Reliably meet the electricity needs of our customers through integrated planning, technology and safely operating, maintaining and advancing our system.

SUCCEED THROUGH RELATIONSHIPS
Gain support for our work by building trusted relationships with customers, suppliers, First Nations and the communities we serve.

MIND OUR FOOTPRINT
Create a sustainable energy future in B.C. by carefully managing our impacts on the environment and fostering an energy conservation and efficiency culture.

FOSTER ECONOMIC DEVELOPMENT
Foster economic development opportunities across B.C. through our projects, practices and advancement of the clean energy sector.

MAINTAIN COMPETITIVE RATES
Deliver value for British Columbia and maintain competitive rates by efficiently and responsibly managing our business.

ENGAGE A SAFE AND EMPOWERED TEAM
Empower a team that is innovative, prepared for the future and committed to safety.

ENABLING LEGISLATION

As a Provincial Crown corporation, the owner and sole Shareholder of BC Hydro is the Province of British Columbia. BC Hydro reports to the B.C. Government through the Minister of Energy, Mines and Natural Gas and the Government's expectations are expressed through legislation, policy and instructions. The *BC Hydro Public Power Legacy and Heritage Contract Act* ensures public ownership of BC Hydro's heritage resources, which include BC Hydro's transmission and distribution systems, and all of BC Hydro's existing generation and storage assets. The Province's 2007 BC Energy Plan lays out the general energy policies BC Hydro is required to follow and the 2010 *Clean Energy Act* updated several elements and targets included in that plan and provided further guidance for how BC Hydro is to meet the Province's energy objectives.

This Annual Report outlines how BC Hydro met the Shareholder's expectations over the last year on page 18. To read the Government's Letter of Expectations for 2012/13, go to: **www.bchydro.com/about/accountability_reports/openness_accountability.html**

HOW WE POWER BRITISH COLUMBIA

BC Hydro is one of the largest electric utilities in Canada, serving 95 per cent of B.C.'s population and delivering electricity safely and reliably at competitive rates to approximately 1.9 million customers. Nearly 90 per cent of customer accounts are residential, with the remainder either commercial or industrial. Each of these three groups consumes roughly one third of the total electricity supplied; however, the industrial sector is growing the fastest given unprecedented developments in the oil and gas sector in Northern B.C.

BC Hydro operates 31 hydroelectric facilities and three thermal generating plants, totaling approximately 12,000 MW of installed generating capacity. The existing hydroelectric system, with inflows managed through the use of reservoir storage, is capable of providing between 43,000 and 56,000 GWh per year of energy with an average 48,000 GWh per year. BC Hydro's own generation is supplemented by additional electricity purchased from independent power producers in the province to meet customers' annual needs.

Over 95 per cent of the electricity generated by BC Hydro comes from hydroelectric facilities, which are located throughout the Peace, Columbia and Coastal regions of B.C. Three thermal generating plants produce the remainder. BC Hydro delivers electricity to customers through a network of nearly 76,000 kilometres of transmission and distribution lines. This system also includes approximately 300 substations, approximately one million utility poles and 325,000 individual transformers. The transmission network connects with transmission systems in Alberta and Washington State, which both improves the overall reliability of the system and provides opportunities for trade.

OVERVIEW OF BC HYDRO SYSTEM

REGIONAL OFFICES
Castlegar
Cranbrook
Nanaimo
Prince George
Revelstoke
Vancouver
Vernon

HYDRO DAMS AND GENERATING STATIONS

Aberfeldie	ABN
Alouette	ALU
Ash River	ASH
Bridge River 1&2	BR 1&2
Buntzen	LB 1
Cheakamus	CMS
Clowhom	COM
Elko	ELK
Falls River	FLS
G.M. Shrum	GMS
John Hart	JHT
Jordan River	JOR
Kootenay Canal	KCL
La Joie	LAJ
Ladore	LDR
Mica	MCA
Peace Canyon	PCN
Puntledge	PUN
Revelstoke	REV
Ruskin	RUS
Seton	SON
Seven Mile	SEV
Shuswap	SHU
Spillimacheen	SPN
Stave Falls	SFN
Strathcona	SCA
Wahleach	WAH
Walter Hardman	WHN
Whatshan	WGS
Waneta (1/3 BCH)	WAN

HYDRO DAMS – NO GENERATING STATIONS

Bear Creek	BEC
Clayton Falls	CLA
Coquitlam	CQD
Duncan	DDM
Herber	HEB
Hugh Keenleyside	HLK
Diversion	DIV
Quinsam	QSM
Salmon River	SAR
Sugar	SGR

THERMAL GENERATING STATIONS

Burrard	BGS
Fort Nelson	FNG
Prince Rupert	RPG

DIESEL GENERATING STATIONS

Ah-Sin-Heek	ASK
Anahim Lake	AHM
Atlin	ATL
Bella Bella	BEL
Dease Lake	DLK
Eddontenajon	EDD
Elhateese	ELH
Kwatacha	KWA
Masset	MAS
McBridge	MCB
Sandspit	SPT
Telegraph Creek	TCK
Toad River	TDR
Tsay Key Dene	TKD

SERIES CAPACITOR STATIONS

American Creek	AMC
Chapmans	CHP
Creekside	CRK
Guichon	GUI
Kennedy	KDY
Mcleese	MLS

230 KV SUBSTATIONS

Arnott	ARN
Nelway	NLY
Pike Lake	PIK
Vancouver Island	VIT

287 KV SUBSTATIONS

Minette	MIN
Rupert	RUP

500 KV SUBSTATIONS

Ashton Creek	ACK
Cheekye	CKY
Clayburn	CBN
Cranbrook	CBK
Dunsmuir	DMR
Glenannan	GLN
Ingledow	ING
Kelly Lake	KLY
Kennedy	KDS
Malaspina	MSA
Meridian	MDN
Nicola	NIC
Selkirk	SEL
Skeena	SKA
Telkwa	TKW
Vaseux Lake	VAS
Williston	WSN

SAFETY ABOVE ALL

Improving employee, contractor and public safety is critical to BC Hydro, and we continue to work hard to transform our safety culture. We have begun to implement the recommendations put forward by the Safety Taskforce, which was established in 2010. As part of this process, this year we adopted Life Saving Rules focusing on high risk activities with the greatest threat of serious injury or death. In conjunction with these rules, we rolled out the Just Culture principles and adjusted our investigation approach to reflect these principles in order to encourage reporting of all incidents and learning from them. It is important that we create an environment of risk awareness and accountability, where employees know that their voices will be heard. The Life Saving Rules and Just Culture principles support BC Hydro's focus on addressing hazards that have the potential to result in a loss of life or a permanently disabling injury, in alignment with our performance measure of Zero Fatality and Serious Injury. Once we have addressed these hazards, we can focus on those hazards that have the potential to result in lost time or medical aid injuries.

Key to transforming our safety culture will be embedding safety and health in our business processes and information technology systems as well as having the entire company working within an aligned management system. The Safety Health & Environment Management System provides the overall framework to enable us to proactively manage issues, achieve compliance and integrate a risk-based approach to safety, health and environment improvement initiatives.

Ensuring that BC Hydro employees have a solid knowledge base when it comes to safety is one of the means to achieve better safety performance. Our operations training works to ensure employees are complying with requirements and orders related to such safety issues as asbestos training, driving, and safe work practices, job planning, limits of approach, fall protection and confined space. To support planning, a company-wide Safety Training Needs Assessment was launched in fiscal 2013. This will allow us to better deploy resources and provide training that is relevant and impactful at the local level. In addition, a new Trades Training Centre opened in the spring. The facility is designed to provide the safest learning environment possible for BC Hydro's frontline workforce. It's expected that with a new facility and updated curriculum, trades training at BC Hydro will reach the next level of safety excellence.

In fiscal 2013, to augment the training being rolled out to the plants and field, we held three successful senior leader and senior managers sessions providing Life Saving Rules, Just Culture and Courage to Intervene training. These sessions clarified the roles and responsibilities of senior leaders for demonstrating their support and commitment to safety as the Safety Taskforce recommendations are rolled out. More than 600 leaders attended this training.

Smart meters are helping to make the electricity grid safer for our communities. Meter installers have found and repaired more than 2,000 cases of pre-existing damage to customers' meter sockets at no charge, reducing the risk of electrical problems for these customers. The new meters also provide improved surge protection, and will notify BC Hydro if we need to upgrade our grid equipment to ensure that it is delivering electricity safely. Starting in the fall of 2013, smart meters will automatically detect power outages, so BC Hydro can get the lights back on faster and safer.

MAINTAIN COMPETITIVE RATES

BC Hydro's electricity rates are among the lowest in North America, in large part due to the past investments in infrastructure that help us generate and deliver cost-effective, clean energy. According to Hydro Québec's 2012 survey comparing electricity prices, BC Hydro's rates overall are the 4th lowest among the 22 North American utilities surveyed.

BC Hydro's challenge is to balance the need to invest in revitalizing our system with the need to manage the pressure on rates and keep rates competitive for our customers. This means that BC Hydro is focusing on carefully managing costs and operating in an efficient and cost-effective manner and striving to ensure that projects are delivered on time, and within both scope and budget.

Following a 2011 Government Panel Review of BC Hydro, a report was released containing 50 recommendations to BC Hydro, and we continue to make progress on these recommendations, having completed 44 of the 50, to date, with the remaining six recommendations expected to be completed by the end of fiscal 2014. One of these recommendations was related to managing our workforce, and in fiscal 2013 we met our goal to maintain our headcount equivalent below the fiscal 2013 target through management of attrition and headcount levels throughout the year. The operating cost savings we committed to for fiscal 2012 and 2013 have been achieved and we are on track to deliver a cumulative cost savings of $391 million by the end of fiscal 2014.

Our focus on procurement activities continued in fiscal 2013. Last year, BC Hydro established 42,000 contracts totaling more than $2 billion to support BC Hydro's capital and operating programs. We did so while working hard to build positive relationships with our suppliers with initiatives to, among other things, consistently pay suppliers on time. A new, industry-supported construction contract was implemented in fiscal 2013 that will enable a more balanced approach to contractual rights and obligations, assign risks to the party that can best manage them, as well as increase the number of bids and strengthen our relationships with suppliers. This contract paves the way for more efficient and effective project delivery.

We also completed the implementation of the contract for transactional services for Customer Care, Human Resources, Accounts Payable and Office Services, and the contract for Facilities Management. Through these agreements, BC Hydro has already realized significant savings and service improvements in our operations and we are positioned for further benefits in the years to come. Information technology and telecommunication services were successfully transitioned to a multi-vendor service delivery model prior to the March 31, 2013 expiration of our previous 10-year outsourcing agreement with Accenture to provide an extensive range of business services.

We have a major effort underway in our Transmission and Distribution (T&D) group to implement people and process changes to drive operational excellence. We are also bringing in technology that together with the people and process changes will build a safer, more modern, cost-effective, efficient and customer-focused utility. Work is underway to build and implement tools for work allocation, scheduling, and dispatch, which along with supply chain and integrated asset and work management systems will create the future foundation for delivery of work and information analytics. In fiscal 2013, BC Hydro completed a number of key milestones in T&D, including bundling more work packages for contractors to improve efficiency, introducing a new customer program for underground residential interconnections, and new integrated asset management planning processes.

CONSERVATION AND EFFICIENCY

Power Smart, BC Hydro's Demand Side Management (DSM) initiative, is a recognized leader in promoting conservation and efficiency. DSM is an important part of BC Hydro's plan to meet future supply needs. It has little to no environmental impact, and defers BC Hydro's need for investment in new generation. It is a flexible resource and can be adjusted depending on short-term and long-term energy needs. DSM continues to be B.C.'s lowest cost resource option. The more customers conserve, the less BC Hydro needs to build new infrastructure to meet growing demand. The average resource cost of DSM is significantly below the British Columbia clean and renewable electricity supply cost.

BC Hydro's investment in DSM saves customers money on their electricity bills, which increases the disposable income of residential customers and improves the competitiveness of business customers. In addition, it creates jobs across the province and provides BC Hydro with an opportunity to engage customers and enhance relationships.

BC Hydro's Power Smart programs are designed to increase the awareness of energy conservation and identify opportunities to reduce consumption, improve the availability of energy efficiency products and services, and provide capital incentives to motivate customers to invest in conservation and efficiency. BC Hydro has a wide-ranging approach to DSM, involving retailers, distributors, service providers and manufacturers to maximize Power Smart's reach, manage costs, and support the adoption of energy efficient products in B.C.

MINDING OUR FOOTPRINT

BC Hydro is working to create a sustainable energy future in B.C. and an important aspect of this is carefully managing our impact on the environment. Towards this goal, last year we made investments in vulnerable species recovery, applied climate adaptation research, and continued to reduce energy use and greenhouse gas emissions across our operations.

Protecting fish and fish habitat is always a major aspect of our capital build and operational plans. Last year, as part of our Fish & Wildlife Compensation Program partnership with the Columbia White Surgeon Recovery Initiative, we released approximately 4,000, ten-month-old juvenile white sturgeon into the Columbia River.

Four years of research with academic partners into projected changes to runoff in three key provincial watersheds resulted in a publication on the potential impacts of climate change on BC Hydro-managed water resources. The scenarios to 2050 are being incorporated into long-term resource planning as well as regulatory applications for the John Hart Replacement Project and the environmental assessment for Site C.

BC Hydro is carbon neutral in our corporate operations and successfully passed an independent review of our program in fiscal 2013. We continue to pursue operational savings by building and retrofitting facilities to energy-efficiency standards and managing our vehicle fleet. This year, we decommissioned 30 IT servers and installed 12 new virtual host servers, avoiding the installation of 142 new IT servers and thereby saving 437,000 kilowatt hours of electricity per year.

Meanwhile, thanks to a marketing campaign and improved online services, paperless bill adoption continues to rise and was at approximately 25 per cent of total bills at the end of fiscal 2013.

PLANNING TO MEET FUTURE DEMAND

Ensuring we can provide affordable, clean and reliable electricity for years to come is the foundation of BC Hydro's long range planning activities. We must consider drivers that increase electricity needs such as industrial growth and economic activity, population increases, electrification and new consumer technologies.

Meeting future need in a reliable, low-cost and low-impact way involves continuing to pursue conservation and energy efficiency programs, maintaining existing generation resources and transmission infrastructure and exploring future options for additional resources should they be needed.

The Integrated Resource Plan (IRP) will be BC Hydro's plan for meeting B.C.'s electricity needs over the coming decades. Guided by Government policy direction contained in the *Clean Energy Act*, BC Hydro consulted with First Nations, the public and stakeholders on its draft IRP in the spring of 2012. In fall 2012, the B.C. Government extended the deadline for BC Hydro's IRP to August 3, 2013, to allow more time to assess and better understand the future electricity requirements of the Liquefied Natural Gas (LNG) industry.

BC Hydro continues to complete its IRP based on expected electricity from existing and already planned generation resources and our growing understanding of the future needs of the LNG industry.

Based on BC Hydro's updated Load Resource Balance, BC Hydro expects to have enough resources to be electricity self-sufficient over the next five to 10 years. While demand for electricity continues to grow, along with population increases and economic expansion, BC Hydro expects planned conservation and efficiency measures, combined with new energy acquisitions already set to come online, will address forecast growth in electricity demand over this period. Meanwhile, we continue to pursue plans for additional resources, such as Site C, to address growth in demand over the longer term.

INVESTING TO ENSURE RELIABILITY

Many of BC Hydro's assets were built before 1970—over 40 years ago—and their aging and deteriorating state must be addressed if we are to continue to provide electricity reliably. That's why BC Hydro is upgrading its aging dams, generating stations, transmission and distribution substations and lines, as well as increasing maintenance work to ensure electricity continues to be provided reliability. Capital spending is also underway that directly supports the business, such as vehicles and information technology. Meanwhile, BC Hydro is building new substations and transmission lines to ensure customers continue to receive reliable power and future electricity demand is met.

These projects span the entire system, and provide economic and business development opportunities in communities and regions across the province. Timely investments in the system—such as with the Site C Clean Energy Project, the Northwest Transmission Line and the fifth and sixth turbine installations at Mica Generation Station—will enhance long-term reliability.

The Smart Metering Program along with the advanced technology platform represents another major investment in our system. Smart meters are helping us modernize our electricity system, keep rates amongst the lowest in North America, and deliver new tools to customers to help them save energy and money. MyHydro, a new online tool made possible by smart meters, is enabling customers to track their energy use, compare energy use to outside temperature, view cost-to-date, and explore Power Smart tips and tools.

The new metering system will also help to restore power faster during outages, reduce electricity theft, and reduce wasted electricity by enabling the right amount of electricity to be delivered to customers when and where it is needed. As of the end of fiscal 2013, 95 per cent of meters installations were complete. The Province has extended the deadline in the Smart Meter and Smart Grid Regulations under the *Clean Energy Act* to December 2013 to allow BC Hydro more time to work with customers that do not yet have a new meter.

Three pipelines from John Hart Dam lead towards the 90-metre tall surge towers and the generating station downstream.

CAPITAL PROJECTS

The following two lists highlight the key projects we completed in fiscal 2013 exceeding $50 million, as well as ongoing and planned projects expected to exceed $50 million. Some of the cost ranges may be large, particularly for projects still in definition phase, as scope, final costs and completion dates are still to be determined. The projects to follow have been approved by the Board of Directors.

For more information on project details, timelines and risks, visit **bchydro.com/regeneration**.

RECENTLY COMPLETED PROJECTS

COLUMBIA VALLEY TRANSMISSION PROJECT (CVT)	OCT 2012 In-Service	$112 Total cost ($ millions)

Constructed a new 230 kV transmission line from the existing Invermere substation to a new substation (called Kicking Horse) built on the west side of the Columbia River near the town of Golden; constructed a new 69 kV transmission line between the new Kicking Horse substation and the existing Golden substation; expanded Golden and Invermere substations and modified the Cranbrook substation—all to meet load growth in the Columbia Valley area. CVT project is now in close out phase.

STAVE FALLS SPILLWAY GATE REPLACEMENT	MAR 2013 In-Service	$46 Total cost ($ millions)

Upgraded the spillway gates[3] at the Stave Falls dam to increase public and employee safety and ensure the gates meet flood discharge reliability requirements. The project is now in close out phase.

ONGOING AND PLANNED

1. SMART METERING & INFRASTRUCTURE PROGRAM	F2015 Targeted completion	$840–930 Total cost[1,4] ($ millions)	$583 LTD cost ($ millions)[2]

The Smart Metering and Infrastructure Program (SMI) includes the installation of 1.9 million smart meters in homes and businesses across the province, optional conservation tools, an advanced telecommunications infrastructure to support electricity system management and customer applications, and information technology to support customer billing, load forecasting and outage management systems. The SMI Program plays a key role in modernizing BC Hydro's electricity grid. All customers will benefit from more choice and control over their electricity usage, and operational efficiencies.

2. VANCOUVER CITY CENTRAL TRANSMISSION (VCCT)	F2014 Targeted completion	$160–201 Total cost[1] ($ millions)	$138 LTD cost[2] ($ millions)

Build an enclosed 230/12 kV substation in the Mt. Pleasant area of Vancouver and two new underground 230 kV transmission lines connecting the new substation to the existing transmission network to serve growing loads in the Mt. Pleasant/False Creek area and maintain a reliable supply of electricity to other areas of Vancouver.

3. MICA GAS INSULATED SWITCHGEAR (GIS) REPLACEMENT PROJECT	F2014 Targeted completion	$199 Total[1] cost ($ millions)[2]	$140 LTD cost[2] ($ millions)

Replace the switchgear system at the Mica Generating Station to ensure the reliability of this key generating station and reduce SF_6 (a greenhouse gas) leakage. The switchgear system uses 500 kV circuits to conduct the energy from the Mica underground powerhouse to the surface, where it transitions to transmission lines.

4. SEYMOUR ARM SERIES CAPACITOR STATION (SASC)	F2015 Targeted completion	$49–58 Total cost[1] ($ millions)	$13 LTD cost[2] ($ millions)

Construct a 500 kV series capacitor station adjacent to the existing transmission lines 5L71 and 5L72, which run between Mica Generating Station and the Nicola Substation near Merritt. The capacitor station will increase the transmission capacity of the lines and allow the Mica Generating Station to securely deliver its full station output with the new generating units 5 and 6 in place.

5. DAWSON CREEK / CHETWYND AREA TRANSMISSION (DCAT)	F2015 Targeted completion	$220–255 Total cost[1] ($ millions)	$24 LTD cost[2] ($ millions)

The project will expand the Peace Region 230 kV transmission system to the Dawson Creek-Chetwynd Area to supply the high area load growth. The project will include the construction of new 230 kV lines between Dawson Creek (DAW) and Bear Mountain (BMT), and from BMT to a new station called Sundance (SLS), located approximately 19 km east of Chetwynd.

6. NORTHWEST TRANSMISSION LINE PROJECT (NTL)	F2015 Targeted completion	$736–746 Total cost[1] ($ millions)	$340 LTD cost[2] ($ millions)

Construct a 344 km, 287 kV transmission line between Skeena substation near Terrace and a new substation to be built near Bob Quinn Lake to ensure a reliable supply of clean power to potential industrial developments in the area; provide a secure interconnection point for clean generation projects; and potentially help certain northwest communities access their power from the electricity grid rather than diesel generators.

** Total cost range represents the gross cost of the project and has not been netted for contributions, which total $220 million from the Federal Government and a customer. The LTD cost has not been netted for $23.4 million in contributions received from the Federal Government.*

7. INTERIOR TO LOWER MAINLAND (ILM)	F2015 Targeted completion	$690–725 Total cost[1] ($ millions)	$251 LTD cost[2] ($ millions)

Construct a new 500 kV transmission line, approximately 248 km in length, between the Nicola substation near Merritt and the Meridian substation in Coquitlam and build a new series capacitor station at Ruby Creek near Agassiz to help meet domestic load growth in the Lower Mainland.

8. MERRITT AREA TRANSMISSION PROJECT (MAT)	F2015 Targeted completion	$58–66 Total cost[1] ($ millions)	$5 LTD cost[2] ($ millions)

Construct a new 138 kV radial transmission line from the existing Highland Substation to a new substation in Merritt to meet the increased demand for power in the Merritt area.

9. UPPER COLUMBIA CAPACITY ADDITIONS AT MICA—UNITS 5&6	F2015–F2016 Targeted completion	$627–714 Total cost[1] ($ millions)	$284 LTD cost[2] ($ millions)

Install two additional 500 MW generating units into existing turbine bays at the Mica Generating Station. The new units are similar to the four existing units, but with more efficient turbines. Includes construction of a series capacitor station located near the mid-point on the existing Mica-Nicola 500 kV transmission lines.

10. HUGH KEENLEYSIDE SPILLWAY GATE RELIABILITY UPGRADE	F2016 Targeted completion	$116–123 Total cost[1] ($ millions)	$45 LTD cost[2] ($ millions)

Upgrade the spillway gates[3] at the Hugh Keenleyside dam to increase public and employee safety and ensure the gates meet flood discharge reliability requirements.

11. G.M. SHRUM UNITS 1 TO 5 TURBINE REPLACEMENT	F2016 Targeted completion	$197–272 Total cost[1] ($ millions)	$70 LTD cost[2] ($ millions)

Replace the turbines for Units 1 to 5 to reduce the risk of runner failure, decrease maintenance costs and improve operating efficiency.

12. ISKUT EXTENSION PROJECT	F2016 Targeted completion	$167–180 Total cost[1] ($ millions)	$0 LTD cost[2] ($ millions)

Construction of a 92 km, 287 kV transmission extension, plus a 16 km distribution line from Bob Quinn substation. The transmission line would terminate at a new substation at Tatooga Lake and a 16 km, 25 kV distribution line continuing to Iskut.

** The total cost range represents the gross cost of the project and has not been netted to reflect contributions of $39.6 million from a customer.*

13. SURREY AREA SUBSTATION PROJECT	F2016 Targeted completion	$76–94 Total cost[1] ($ millions)	$1 LTD cost[2] ($ millions)

Construct a new 200 MVA 230/25 kV Substation in the Fleetwood area of Surrey. The supply to the station will be from circuit 2L75 and will allow for increased station capacity of 400 MVA.

14. RUSKIN DAM SAFETY AND POWERHOUSE UPGRADE	F2018 Targeted completion	$626–748 Total cost[1] ($ millions)	$145 LTD cost[2] ($ millions)

This project upgrade will meet modern safety and seismic requirements and replace the powerhouse equipment, which is in poor condition. It is expected to take six years to complete and includes: reinforcement of the right bank; seismic upgrade of the dam and water intakes; powerhouse upgrades; and, relocation of the switchyard. Once completed, the upgraded facility will be reliable and safe and will produce enough electricity to serve more than 33,000 homes.

15. JOHN HART REPLACEMENT	F2019 Targeted completion	$1,004–1,149 Total cost[1] ($ millions)	$81 LTD cost[2] ($ millions)

Replace the existing six units, 126 MW generating station (in operation since 1947) and add integrated emergency bypass capability to ensure reliable long-term generation, mitigate earthquake risk and reduce environmental risk to fish and fish habitat. In February 2013, BC Hydro received a Certificate of Public Convenience and Necessity from the BCUC for the project.

16. SITE C CLEAN ENERGY PROJECT	2023* Targeted completion	$7,900 Total cost[1] ($ millions)	$258 (deferred capital) LTD cost[2] ($ millions)

Site C is a proposed third dam and 1,100 MW hydroelectric generating station on the Peace River approximately seven kilometres southwest of Fort St. John. It will be capable of producing approximately 5,100 gigawatt-hours of electricity annually and will deliver firm electricity with a high degree of flexibility. The Site C project is currently in Stage 3—environmental and regulatory review, which includes an independent federal and provincial environmental assessment. Subject to environmental certification, construction will take about seven years and Site C would provide clean, reliable power to B.C. for more than 100 years.

** Planned in-service date for all units. This timeline reflects the projects current regulatory schedule and is subject to change based on a review of the construction schedule.*

1 *Total capital expenditure amounts do not include dismantling or asset retirement costs.*
2 *Life to date (LTD) costs to March 31, 2013.*
3 *Spillway gates control the amount of water that can be discharged from the reservoir. They are generally used in times of flood to pass high inflows.*
4 *Smart Metering & Infrastructure (SMI) Program amount includes both capital costs and operating expenditures subject to regulatory deferral.*

CONTEMPLATED PROJECTS OVER $50 MILLION

BC Hydro is contemplating the following projects over $50 million during fiscal 2014 to fiscal 2016, listed in alphabetical order. These projects are in the Early Identification or Definition Phases; scope, final costs and completion dates are still to be determined. The projects below have not yet been approved by the Board of Directors.

BIG BEND SUBSTATION

The South Burnaby, Big Bend area requires a new greenfield, 100 MVA, 69/12 kV Substation to meet local residential and commercial load growth.

BRIDGE RIVER 2 UNITS 5 AND 6 REHABILITATION

Restore Bridge River 2 Units 5 and 6 (commissioned over 60 years ago) to "as-new condition". This would address known major component deficiencies and enable units to run at full capacity (currently derated from 70 MW to 60 MW).

CHEAKAMUS UNIT 1 AND UNIT 2 GENERATOR REPLACEMENT

Replace the two units at Cheakamus generating station (commissioned over 50 years ago) and ancillary equipment to address the condition and known deficiencies of major components.

DOWNTOWN VANCOUVER REDEVELOPMENT PROGRAM

Upgrade and expand the transmission and distribution network serving downtown Vancouver over the next 20 to 30 years. The project includes the addition of a new transmission cable coming into the downtown core, the construction of a new substation, and the refurbishment and/or replacement of the existing substations. The project also includes converting the existing distribution system from a 12 kV dual radial system to a 25 kV open-loop system to feed off the new transmission system.

G.M. SHRUM G1-G10 CONTROL SYSTEM UPGRADE

The existing legacy controls for GMS U1-10 do not meet BC Hydro's current standards. Unit 1 to 10 controls are becoming unreliable, have increased maintenance requirements, are difficult to troubleshoot and are lacking spare parts.

JOHN HART DAM SEISMIC UPGRADE

Upgrade the John Hart Dam to reliably withstand moderate to severe earthquake loadings and meet normal operations criteria post-earthquake.

LA JOIE SEISMIC IMPROVEMENTS

Upgrade the La Joie Dam (a rock filled structure completed in 1955) to address ongoing seepage and seismic withstand deficiencies, ensure dam and public safety and maintain reliability of supply.

LONG BEACH AREA TRANSMISSION

Expansion of Long Beach (LBH) and Great Central Lake (GCL) substations with two new transformers at each and capacitor banks at LBH to support the load growth and provide voltage support in the area.

PEACE REGION ELECTRIC SUPPLY

Increase transmission capacity to the South Peace area by providing a second 230 kV supply to Dawson Creek in response to the significant load growth in the area, mainly from the gas production industry.

PRINCE GEORGE TERRACE CAPACITY UPGRADE

The Prince George to Terrace capacitors project will increase the capacity of the 500 kV circuit supplying the north coast areas. This will increase the transfer capacity by approximately 60 per cent through the addition of reactive compensation. This additional capacity is required to provide capacity for industrial loads expected to interconnect to the Northwest Transmission Line. The timing of the PGTC project is linked to the interconnection of Apache's Kitimat Liquefied Natural Gas plant (phase 2) that is scheduled for March 2016.

REVELSTOKE UNIT 6 INSTALLATION

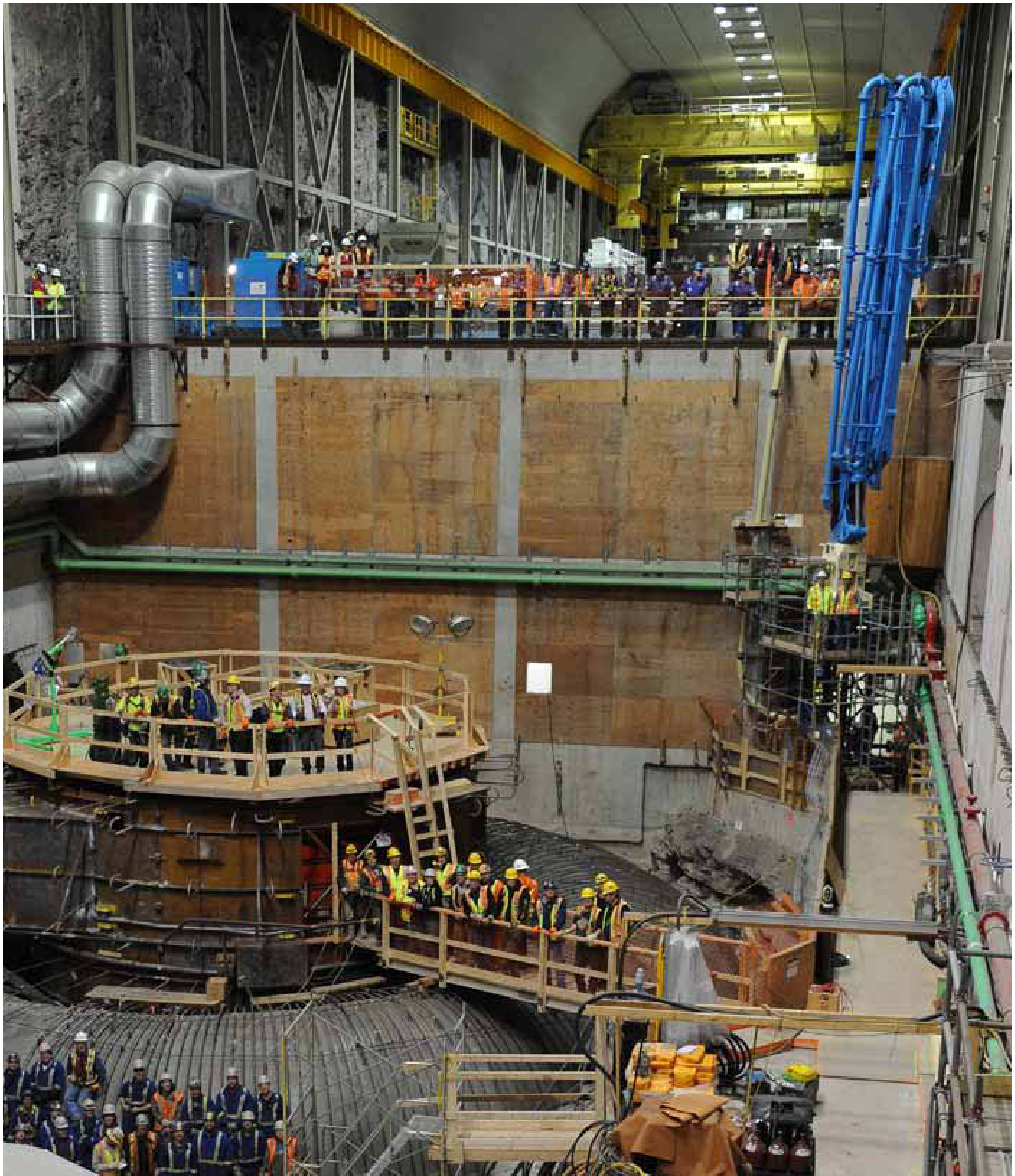
Supply and install an approximately 500 MW unit in the existing empty Unit 6 bay at Revelstoke Generating station to add capacity to the BC Hydro system.

W.A.C BENNETT DAM IMPROVEMENTS

Improve BC Hydro's ability to manage the performance risks at W.A.C. Bennett Dam by gathering, reviewing, and updating all existing information on the performance of the dam; along with the evaluation, development, and application of new technologies for monitoring and improvement of dam performance. Implement necessary upgrades to ensure ongoing safe performance of the embankment dam.

W.A.C. BENNETT DAM RIP-RAP UPGRADE

The W.A.C. Bennett Dam Rip-rap has functionally degraded since its completion in 1968. The project will rebuild the upstream slope to ensure there is adequate protection and shielding to the embankment dam from the wind generated waves.



At Mica Generating Station, the BC Hydro team, the Peter Kiewit team, the Andritz Hydro team and F&M Installations Ltd. assembled for a group photo in March 2013 to celebrated a milestone – the Unit 5 spiral case being embedded by concrete to the half way mark. Unit 6 is enclosed in white plastic in the foreground. It will be in service about six months after Unit 5.

SUBSIDIARIES

POWEREX CORPORATION

Powerex Corp. is a wholly owned subsidiary of BC Hydro and a key participant in energy markets across North America, buying and supplying wholesale power, renewable energy, natural gas, ancillary services, and financial energy products and services. Established in 1988, its export, marketing and trade activities help optimize BC Hydro's electric system resources and provide significant economic benefits to British Columbia. Powerex supports BC Hydro's electric system requirements through importing and exporting energy as required in addition to meeting its own trade commitments. Powerex also markets, on behalf of the Province, the Canadian Entitlement to the Downstream Benefits of the Columbia River Treaty.

The Chief Executive Officer (CEO) of Powerex reports directly to the Board of Directors of Powerex through the Chair of Powerex and works closely with the President & CEO of BC Hydro as a member of the Executive Team. The Chair of the Powerex Board, the Powerex CEO and BC Hydro's CEO ensure the Board of BC Hydro is informed of Powerex's key strategies and business activities. Powerex's Directors are Larry Blain, Chair, Stephen Bellringer and James Brown. Powerex's senior management includes Teresa Conway, President & CEO, Janette Lyons, Chief Financial Officer, and John Irving, Chief Legal Officer.

Powerex operates in complex and volatile energy markets, which can cause net income in any given year to vary significantly. Over the previous five years, Powerex income has ranged from $8 million to $244 million. Powerex's net income for fiscal 2013 was $98 million. Market and economic conditions, reduced BC Hydro system flexibility, income timing differences and the strength of the Canadian dollar can materially impact Powerex net income. For more information, visit **powerex.com**.

Energy traders at Powerex.

POWERTECH LABS INC.

Powertech Labs, a wholly owned subsidiary of BC Hydro, has been providing consulting and testing services to utilities, gas companies, automotive manufacturers and others since its inception in 1979. Operating as a separate commercial entity, Powertech provides research and development, standards and certifications and technical services to the international energy community including BC Hydro. Powertech's Directors are John Knappett (Chair), Brenda Eaton, and Nancy Olewiler. Powertech's senior management includes President and CEO Don Stuckert and Managing Director, Raymond Lings.

Powertech is located on an 11-acre campus in Surrey. It is a multidisciplinary facility that incorporates 21 laboratories and employs approximately 130 full-time employees. In the last five years, Powertech's technical expertise and consulting services have helped to increase gross revenue from $26.8 million to $29.3 million. Over the last five years, Powertech's net income has ranged from $0.5 million to $2.9 million. In fiscal 2013, Powertech's net income was $2.9 million. For more information, visit **powertechlabs.com**.

OTHER SUBSIDIARIES

Over the years, BC Hydro has created a number of other subsidiaries to help it manage risk in developing projects and/or contracting with third parties or other legal reasons. Where necessary, these entities have been retained. The Boards and management of these subsidiaries are made up of BC Hydro employees, whom perform these duties without additional remuneration.

STRATEGIC PARTNERSHIPS

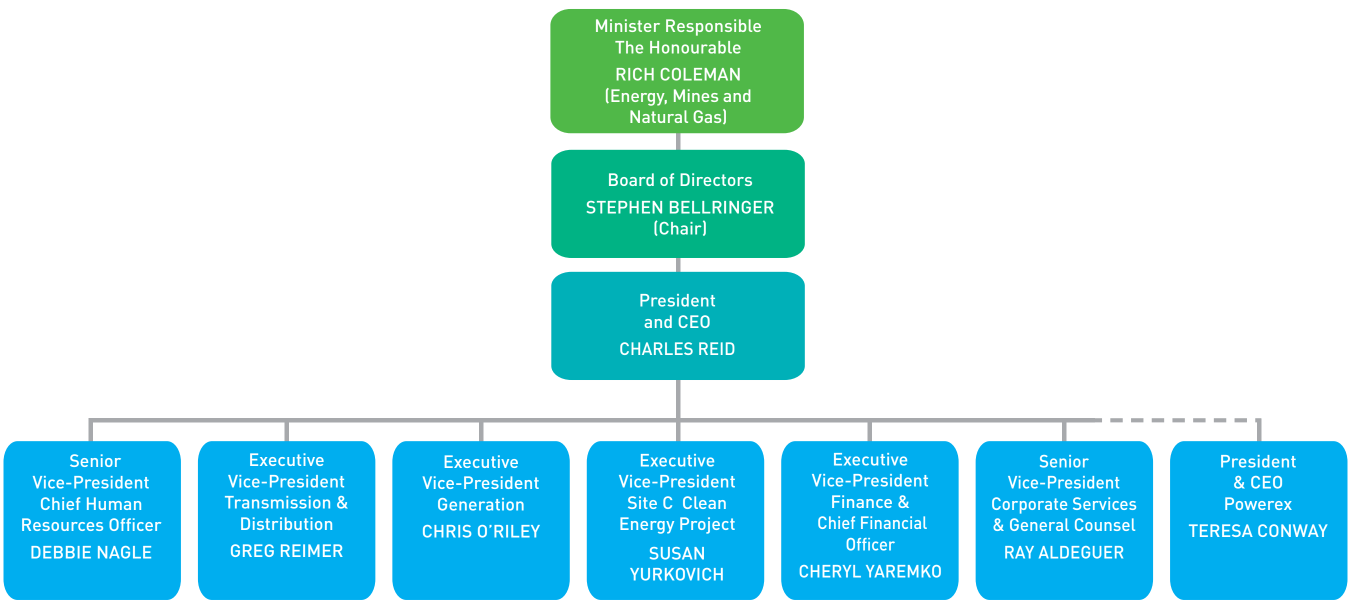
- Accenture Business Services of British Columbia (Accenture) provides transactional services for customer care, human resources, accounts payable and office services under a seven-year outsourcing agreement that came into effect in 2011.
- TELUS provides data centre operations and help desk services under a five-year outsourcing agreement that came into effect in 2012.
- SNC Lavalin Operations & Maintenance Inc. provides facilities management services under a five-year outsourcing agreement that came into effect in 2011.
- Fujitsu provides information technology application services under a five-year outsourcing agreement that came into effect in 2012.
- Independent power producers provided 10,675 GWh of energy to our system in fiscal 2013, or about 20 per cent of total domestic supply. They will continue to play a significant role in helping us provide reliable, clean and cost-effective electricity supply for many years to come.
- The Canadian Entitlement provided to Canada by the United States varies from year to year, and is currently about 4,400 GWh per year of firm energy and about 1,320 MW of capacity (scheduling rights). This entitlement is half of the extra power capability at generation facilities in the U.S. that results from the improved water regulation made available by the Columbia River Treaty. The Canadian Entitlement is owned by the Province of B.C. and is marketed on its behalf by Powerex. The Columbia River Treaty has no expiration date, but either the U.S. or Canada can terminate most of the treaty provisions in 2024, provided written notice is given a minimum of 10 years in advance.

CORPORATE GOVERNANCE

EXECUTIVE OF BC HYDRO

BC Hydro's organizational structure is designed to ensure we deliver on our strategic objectives and the mandate of the *Clean Energy Act*; and facilitates coordination among business functions. BC Hydro regularly reviews and updates the governance framework to ensure business needs are met.

The following chart shows the current organizational structure of the Executive Team.



BC Hydro is committed to best practices in corporate governance. Strong corporate governance practices provide for greater public accountability and transparency.

BC Hydro's practices and policies meet the "Best Practice Guidelines on Governance and Disclosure" for public sector organizations, which was issued by the B.C. Provincial Government in February 2005.

The governance framework is reviewed regularly to ensure it meets BC Hydro's ongoing business needs, while being consistent with the government's guidelines.

The links below provide further information about our Board of Directors and our Corporate Code of Conduct:

http://www.bchydro.com/about/who_we_are/board_of_directors.html; and,

http://www.bchydro.com/about/who_we_are/corporate_citizenship/code_of_conduct/corporate_governance.html

BC HYDRO BOARD OF DIRECTORS

The BC Hydro Board of Directors oversees the conduct of business and supervises management, which in turn is responsible for the day-to-day operations of BC Hydro. Directors are appointed by the B.C. Cabinet to bring special skills and experience to the Board's deliberations.

CHAIR: **Stephen Bellringer**

MEMBERS: **Kim Baird, Brad Bennett, Larry Blain, James Brown, James Hatton** (appointed Jan. 17, 2013) **John Knappett, Tracey McVicar, Janine North, John Ritchie**

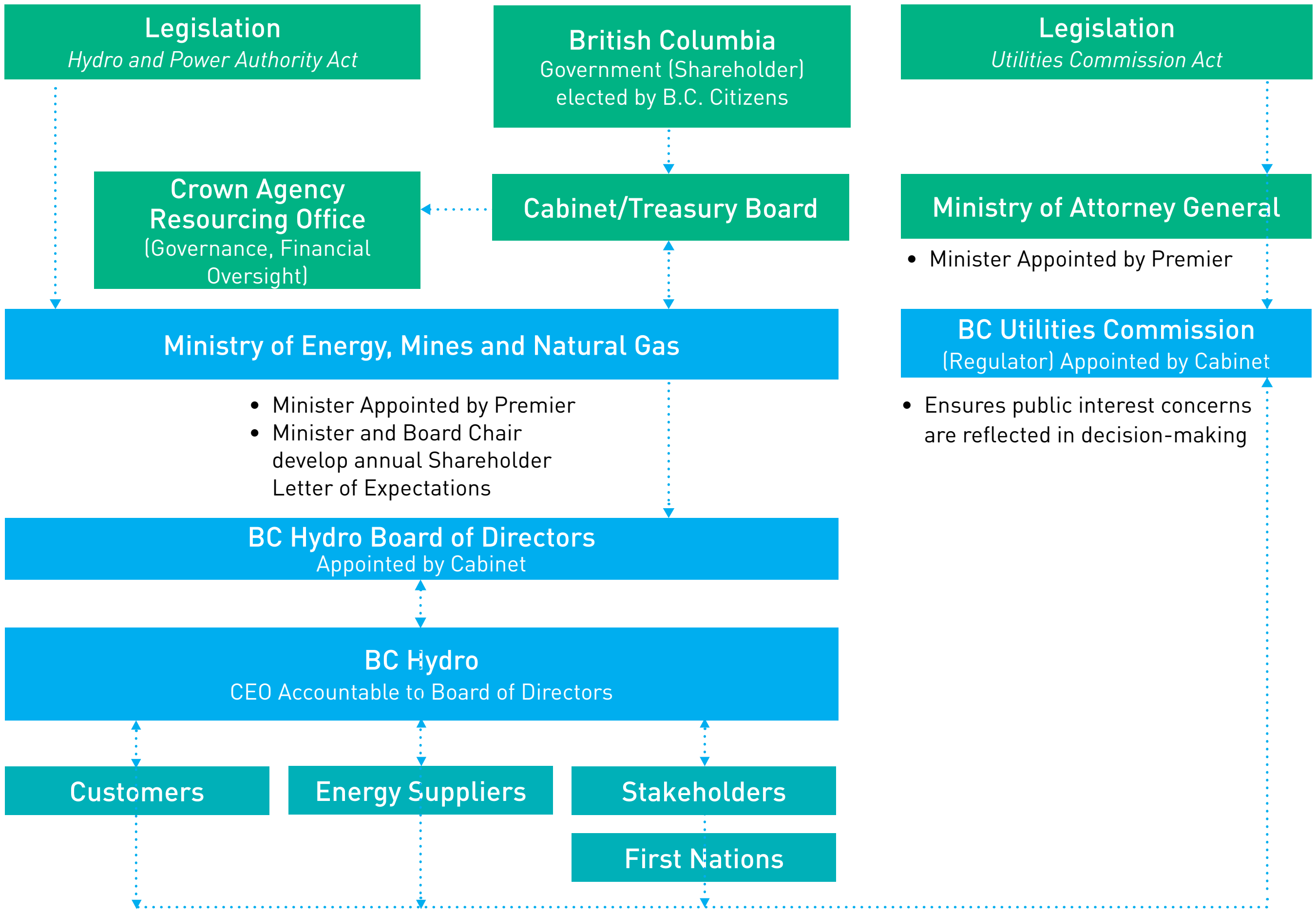
The Board's broad set of responsibilities includes:

- Ensuring there is a strategic and business planning process, and then reviewing, validating and endorsing a strategy for the Corporation and monitoring its implementation.
- Ensuring that effective controls and appropriate governance are in place as part of its oversight of management.
- Having a continuing understanding of the principal risks associated with the Corporation's business and ensuring that the appropriate processes and systems are in place to mitigate that risk.
- The Board acts in accordance with the Best Practices Guidelines Governance and Disclosure Guidelines for Governing Boards of B.C. Public Sector Organizations, which can be found at: fin.gov.bc.ca/brdo/governance/index.asp. More information on the Board can be found at bchydro.com/about/company_information/board_committees.html.

AUDIT AND FINANCE COMMITTEE* CHAIR: Tracey McVicar MEMBERS: Larry Blain, Jamie Brown	**Purpose:** The Audit and Finance Committee assists the Board in fulfilling its obligations and oversight responsibilities relating to the audit process, financial reporting, information technology and telecommunications, the system of corporate controls and governance of the Corporation's pension plans. The Committee is also responsible for ensuring that principal risks associated with these issues are appropriately identified, monitored and managed.
CAPITAL PROJECTS COMMITTEE* CHAIR: John Ritchie MEMBERS: Brad Bennett, John Knappett	**Purpose:** The Capital Projects Committee assists the Board of Directors in fulfilling its obligations and oversight responsibilities relating to the Corporation's long-term capital plans, capital budgets and capital projects, including dam safety, aboriginal relations and negotiations, and transmission projects. The Committee is also responsible for ensuring that principal risks associated with these issues are appropriately identified, monitored and managed.
CONSERVATION AND CLIMATE ACTION COMMITTEE* CHAIR: Janine North MEMBERS: Kim Baird, Tracey McVicar	**Purpose:** The Conservation and Climate Action Committee assists the Board by monitoring and directing the environmental performance of the Corporation and monitoring and supporting the implementation of an energy conservation strategy as described in the BC Energy Plan. The Committee also provides guidance and direction to management and makes recommendations to the Board regarding initiatives and programs related to meeting the Corporation's environmental goals. The Committee is also responsible for ensuring that principal risks associated with these issues are appropriately identified, monitored and managed.
CORPORATE GOVERNANCE COMMITTEE CHAIR: Stephen Bellringer MEMBERS: All Directors	**Purpose:** The Corporate Governance Committee is structured as a Committee of the Whole. This means that its membership includes all Directors. Nonetheless, the Committee has independent Terms of Reference and is responsible for ensuring that BC Hydro and its Board develops and implements an effective approach to corporate governance which enables the business and affairs of the Corporation to be carried out, directed and managed with the objective of enhancing shareholder value. The Committee is also responsible for ensuring that principal risks associated with these issues are appropriately identified, monitored and managed.
EXECUTIVE COMMITTEE CHAIR: Stephen Bellringer MEMBERS: Kim Baird, Larry Blain, Janine North, Tracey McVicar John Ritchie	**Purpose:** The Executive Committee only meets in special circumstances. It has the full powers of the Board to act in situations when, for timing reasons, a Board meeting cannot be scheduled.
ENERGY PLANNING AND PROCUREMENT COMMITTEE* CHAIR: Larry Blain MEMBERS: Brad Bennett, Janine North John Ritchie	**Purpose:** The Energy Planning and Procurement Committee provides advice and direction to the Corporation on both its strategic direction relating to resource planning, export strategy, economic development and energy procurement activities, and its execution of related initiatives. In addition, the Committee provides advice and support to the Board Chair in his or her dealings with government pertaining to these issues. The Committee is also responsible for ensuring that principal risks associated with these issues are appropriately identified, monitored and managed.
HUMAN RESOURCES AND SAFETY COMMITTEE CHAIR: Kim Baird MEMBERS: Janine North, Stephen Bellringer	**Purpose:** The Human Resources and Safety Committee assists the Board in fulfilling its obligations relating to human resources and compensation issues, related specifically to senior management and generally to the Corporation. The Committee also monitors safety performance. The Committee is also responsible for ensuring that principal risks associated with these issues are appropriately identified, monitored and managed.

*The Board Chair is an ex-officio member of all committees.

SHAREHOLDER-REGULATORY RELATIONSHIP FRAMEWORK



GOVERNMENT'S LETTER OF EXPECTATIONS

The B.C. Government's Letter of Expectations describes the relationship between BC Hydro and the Province, and sets out objectives that the Shareholder wishes BC Hydro to achieve. The letter is the basis for the development of BC Hydro's Service Plans and Annual Reports, and is reviewed annually and updated as required. Shareholder Direction to BC Hydro outlined in the 2012/13 letter focused on cost savings, economic development, supplying Liquefied Natural Gas, Site C, and the Integrated Resource Plan.

BC HYDRO WILL:

Implement the recommendations of the 2011 Panel Review of BC Hydro and continue to provide progressive reports to the Shareholder on its implementation.

BC HYDRO ACTION:

BC Hydro has committed to implementing all of the Panel's recommendations and is providing regular progress reports to the Shareholder. We are making good progress on all of the recommendations and have completed 44 of the 50 recommendations directed to BC Hydro. By the end of fiscal 2014, BC Hydro is expecting to complete the remaining six recommendations.

BC HYDRO WILL:

Work in collaboration with the Shareholder to ensure that adequate supplies of electricity are available to support new investments in liquefied natural gas and mines, consistent with Canada Starts Here: The BC Jobs Plan.

BC HYDRO ACTION:

BC Hydro is working with the Shareholder to understand the future needs of the liquified natural gas and mining sectors, and to ensure an adequate reliable electricity supply can be available to them.

BC HYDRO WILL:

Advance Site C through the environmental assessment process, including consultation and input by the public, Aboriginal groups, communities, property owners and stakeholders. BC Hydro led consultations for Site C will be coordinated with other Natural Resource Sector consultations being undertaken by the Shareholder.

BC HYDRO ACTION:

The Site C Clean Energy Project is in the early stages of a harmonized environmental assessment process by federal and provincial regulatory agencies, which includes a joint review panel. The environmental assessment for Site C will be thorough and independent. In addition, there will be multiple opportunities for timely and meaningful consultation and input by the public, Aboriginal groups, communities, property owners and stakeholders.

BC HYDRO WILL:

Complete the Integrated Resource Plan, meeting the newly legislated timeline.

BC HYDRO ACTION:

BC Hydro will submit the Integrated Resource Plan to Government on August 3, 2013 for review and approval.

BC HYDRO WILL:

Implement the capital projects necessary to address the aging infrastructure as outlined in the Service Plan, subject to any necessary modifications to meet the requirements of the BC Hydro Review Panel Report and BC Hydro's Integrated Resource Plan.

BC HYDRO ACTION:

BC Hydro is carrying out extensive capital projects in accordance to the Service Plan and also subject to any necessary modifications to meet the requirements of the BC Hydro Review Panel Report and BC Hydro's Integrated Resource Plan.

BC Hydro has nearly completed smart meter installations in B.C. In December 2012, the Province extended the deadline in the Smart Meter and Smart Grid Regulations under the *Clean Energy Act* to December 2013.

BC HYDRO WILL:

Deliver value for British Columbia and maintain competitive rates by efficiently and responsibly managing the business.

BC HYDRO ACTION:

BC Hydro continues to provide British Columbians with clean, reliable electricity for generations, while responsibility managing costs by, for example, completing the recommendations in the Government Review Panel report, and continuing to supply some of the most competitively priced electricity in North America.

REPORT ON PERFORMANCE

BC Hydro met or exceeded 17 of 21 reported Service Plan performance metrics in fiscal 2013.

GUIDING PRINCIPLES	PERFORMANCE MEASURE	F2011 Actual	F2012 Actual	F2013 Target	F2013 Actual	Status	F2014 Target[1]	F2015 Target[1]	F2016 Target[1]
SAFELY KEEP THE LIGHTS ON	**Zero Fatality & Serious Injury** (Loss of life or the injury has resulted in a permanent disability)	3	0	0	1	🔴	0	0	0
	Severity (Number of calendar days lost due to injury per 200,000 hours worked)	22.2	27.4	18.0	45.1	🔴	27.0[2]	26.0[2]	25.0[2]
	All Injury Frequency (Number of employee injury incidents per 200,000 hours worked)	1.7	1.7	1.4	2.1	🔴	1.7[3]	1.6[3]	1.5[3]
	CAIDI[4] (hours) – Average Interruption in hours per interrupted customer	2.20	2.27	2.35	2.12	🟢	2.30	2.25	2.20
	SAIFI[4] (frequency) – Number of sustained disruptions per year	1.49	1.58	1.50	1.29	🟢	1.45	1.40	1.40
	CEMI-4[4] (%) – Customers experiencing four or more outages	13.56	12.50	12.00	9.10	🟢	11.00	11.00	11.00
	Winter Generation Availability Factor (%)	94.4	96.8	96.4	98.1	🟢	96.4	96.4	96.4
SUCCEED THROUGH RELATIONSHIPS	**CSAT Index** (% of customers satisfied or very satisfied)—Customer Satisfaction Index	89	87	85	86	🟢	85	86	87
	Billing Accuracy (% of accurate bills)	98.5	98.4	98.2	98.5	🟢	98.4	98.4	98.4
	First Call Resolution (% of customer calls resolved first time)	73.0	74.2	72.0	68.0	🔴	72.0	73.0	74.0
	Progressive Aboriginal Relations Designation	Silver	Silver	Gold	Gold	🟢	Gold	Gold	Gold
MIND OUR FOOTPRINT	**Demand Side Management**[5] (GWh/year)	2,322	3,424	4,400	4,460	🟢	5,100	7,100	8,300
								SUBJECT TO CHANGE	
	Electricity Production GHG Emissions (kilotonnes CO_2e)	1,074	560[6]	930[6]	631[6]	🟢	710[6,7]	710[6,7]	710[6,7]
	Carbon Neutral Program Emissions (kilotonnes CO_2e)	29.5	30.0[6]	30.0[6]	28.8[6]	🟢	30.0[6]	29.0[6]	29.0[6]
	Clean Energy (%)	95.0	98.1	93.0	98.2	🟢	93.0	93.0	93.0
FOSTER ECONOMIC DEVELOPMENT	**BC Hydro Capital Spend**[8] ($ millions within B.C.)	1,468	1,853	2,082[9]	1,865	🟢	1,963	2,364	2,375

🟢 *Target met* 🔴 *Target not met*

GUIDING PRINCIPLES	PERFORMANCE MEASURE	F2011 Actual	F2012 Actual	F2013 Target	F2013 Actual	Status	F2014 Target	F2015 Target	F2016 Target
MAINTAIN COMPETITIVE RATES	Competitive Rates	1st Quartile	1st Quartile	1st Quartile	1st Quartile	●	1st Quartile	1st Quartile	1st Quartile
	Net Income ($ million)	589	558	514[10]	509	●	545	611	684
	Operating Costs[11] ($ million)	695	665	705	705	●	699	706	713
	Debt to Equity (%)	80/20	80/20	80/20	80/20	●	80/20	80/20	80/20
ENGAGE A SAFE & EMPOWERED TEAM	Employee Engagement[12] (%)	—	—	—	78	●	80	80	80

Notes:

1 *Fiscal 2014 to fiscal 2016 performance targets as published in the revised BC Hydro 2013/14–2015/16 Service Plan.*

2 *Compared to the 2012/13–2014/15 Service Plan, the severity targets have increased by 10. The targets in the 2013/14–2015/16 Service Plan are more realistic as they are based on a four-year severity average (the most recent four-year average is 24.2). In addition, the revised targets take into account reductions in corporate and administrative staff while the number of operational roles has increased slightly. The previous Service Plan targets were based on an unusually good result of 17.9 in fiscal 2010.*

3 *Compared to the 2012/13–2014/15 Service Plan, the All Injury Frequency (AIF) targets have increased slightly. The targets in the 2013/14–2015/16 Service Plan are seen to be more realistic as they are based on a four-year AIF average (the most recent four-year average is 1.5). In addition, the revised targets take into account reductions in corporate and administrative staff while the number of operational roles has increased slightly. The previous Service Plan targets were based on an unusually good results in fiscal 2010 and fiscal 2011.*

4 *Performance within + / - 10 per cent is considered acceptable for the reliability targets given the wide range of potential disruptions to the electrical system. BC Hydro measures reliability under normal circumstances, which excludes major events. A major event is defined as an uncontrollable event (e.g. windstorm or forest fire) that results in more than 70,000 customer hours lost.*

5 *BC Hydro's energy savings are drawn from its DSM plan presented in its fiscal 2012–fiscal 2013 DSM Expenditure Application in the fiscal 2012–fiscal 2014 RRA. Numbers are presented in cumulative run rate savings since fiscal 2008. As BC Hydro is required to seek BCUC approval for DSM expenditures beyond fiscal 2013, the energy savings targets over the period of fiscal 2014–fiscal 2016 are initial planned estimates only and subject to change. BC Hydro intends to establish its future DSM targets to align with its Integrated Resource Plan, to be submitted to Government on August 3, 2013.*

6 *Starting in fiscal 2012, BC Hydro is reporting its GHG emissions by calendar year instead of fiscal year to align with GHG emissions reports filed under the* Canadian Environmental Protection Act, *1999, the B.C. Reporting Regulation and the B.C. Carbon Neutral Reporting Regulation.*

7 *The Electricity Production GHG Emissions targets have been lowered from 930 kt to 710 kt per year, based on projected reduction of thermal generation within the Service Plan horizon.*

8 *BC Hydro capital spending in British Columbia is the total capital spend adjusted for estimated spend within British Columbia.Targets for Capital Spend in B.C. in BC Hydro's Service Plan are set based on total forecast BC Hydro capital expenditures adjusted to exclude estimates of major capital purchases from outside of B.C. However, targets, in this case, are more of an indicator of economic development in B.C. versus a true "target" that we are aspiring to achieve. BC Hydro makes every effort to make purchases within B.C. where goods are available and it makes economic sense, but doesn't seek to achieve spending targets within B.C. in isolation of overall business decisions on capital expenditures. Accordingly, when total capital expenditures are less than plan due to prudent business decisions or circumstances, BC Hydro does not consider itself to be off track on Capital Spend within B.C. as long as purchases are made from within B.C. when economically viable. Due to challenges in setting appropriate targets and accurately measuring results for this measure, BC Hydro is assessing opportunities to revise and improve its Economic Development measure.*

9 *A fiscal 2013 target of $2,282 million was used in the 2013/14-2015/16 Service Plan; however, prior to the beginning of fiscal 2013 mainly due to delays on major projects we amended our capital plan and, in turn, our target to $2,082 million.*

10 *Following the filing of the 2012/13-14/15 Service Plan, the Government issued Special Direction No.3 to the BCUC which included, among other things, the lowering of BC Hydro's allowed rate of return on deemed equity from 12.75 per cent to 11.73 per cent. The net income target was reduced from $566 million to $514 mainly as a result of this change.*

11 *Operating costs are defined as personnel, materials and external services expenses included in income, that are incurred in the day-to-day operation of BC Hydro's electric utility, net of recoveries, capitalized costs and reclassification adjustment.*

12 *The new sustainable engagement score indicates the level to which employees connect with the organization, whether or not they feel the company provides the tools and resources to work effectively, and whether or not they feel that the company cares about their personal well-being.*

SAFELY KEEP THE LIGHTS ON

STRATEGIES IN THE 2012/13-2014/15 SERVICE PLAN*

- Continue to implement the Safety Taskforce recommendations.
- Design and commence implementation of the integrated safety, health and environment management system building on the Four Pillar Safety Plan and linking to the Safety Taskforce recommendations.
- Systematically include identification of hazards and barriers in all work-planning activities and work procedure development.
- Increase integration of job-safety planning into day-to-day work for all operating facilities and all operational activities.
- Participate in regional planning initiatives to identify opportunities to increase regional transmission capacity and advance work on major transmission infrastructure projects.
- Continue implementation of a comprehensive, long-term reliability strategy to improve the system and customer reliability.
- Invest in projects that utilize new technologies that support safe and reliable operations, such as: the Smart Metering and Smart Grid Program, Distribution Management System, Enterprise Geographic Information system, and other Business Intelligence solutions.
- Continue to effectively manage dam safety issues, risks and regulatory requirements.

SAFETY PERFORMANCE

WHY WE MEASURE ZERO FATALITY AND SERIOUS INJURY, SEVERITY & ALL INJURY FREQUENCY

To underscore our commitment to ensuring no serious incidents occur, BC Hydro established the zero fatality or serious injury target. The target is a testament of our commitment to eliminating "Level 1 injury incidents." These involve incidents where there has either been a loss of life or the injury has resulted in a permanent disability (and a disability pension has been received or is expected).

The measure of serious injury is unique to BC Hydro and thus is not benchmarked against other Canadian Electricity Association (CEA) member utilities. However, the CEA does report on fatalities. BC Hydro has the highest number of fatalities among CEA members for the five-year period from 2008 to 2012. We also have had eight on the job fatalities since 1999.

BC Hydro also measures Severity and All Injury Frequency, which are standard CEA measures. Severity is defined as the number of calendar days lost due to injury per 200,000 hours worked. The Severity metric does not include data on fatal incidents; however, one or two injuries can have a major impact on Severity. All Injury Frequency is defined as total number of employee Medical Aids and Lost Time Injuries per 200,000 hours worked. Medical Aid injuries are those where a medical practitioner has rendered services beyond

**The 2012/13-2014/15 Service Plan safety performance strategies highlighted a "Safety Action Plan," which was an interim measure in response to an employee fatality in 2010. Strategies reflected in our fiscal 2013 Annual Report reflect the evolution of a long-term safety strategy involving the implementation of the Safety Taskforce recommendations and an integrated Safety, Health and Environment management system.*

the level defined as "first aid" and the employee has not been absent from work after the day of injury. Lost Time Injuries are those where the employee is absent beyond the day of injury.

Both Severity and All Injury Frequency measures are, as defined in the CEA Standard, generally harmonized with the U.S. Occupational Safety and Health Administration Standards for safety statistics. On average, over 90 per cent of the Severity results are related to incidents that occur in operational groups and 86 per cent of all injuries occur in operational groups.

The data source for all safety performance metrics are incidents reported through the Incident Management System. To ensure accuracy and reliability of the data, each incident is reviewed to ensure that it meets the CEA reporting criteria, the correct level and type has been assigned, and the appropriate calendar days lost have been assigned to lost time injuries. This approach does exclude a small number of accepted WorkSafeBC claims that do not meet the CEA reporting criteria.

FISCAL 2013 SAFETY PERFORMANCE

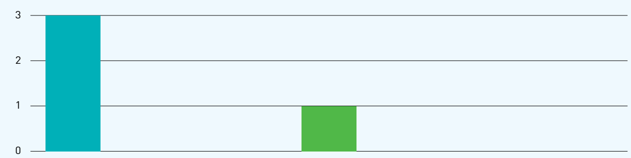
In fiscal 2013, BC Hydro did not meet our safety performance targets; however, we know that improving our safety performance will be a multi-year journey and we are committed to long-term success. BC Hydro reported zero fatalities and one serious injury last year—an electrical contact incident near Duncan in August. This is above the Service Plan target of zero and unfavorable compared to BC Hydro's fiscal 2012 performance. There were also two other incidents in fiscal 2013 that could have resulted in more serious injury—an apprentice power line technician falling from a pole and a utility task vehicle rollover incident.

BC Hydro's Severity rate of 45.1 for fiscal 2013 is considerably above the Service Plan target of 18 and is unfavorable compared to the fiscal 2012 result of 27.4. Of the 50 injuries in fiscal 2013 resulting in lost time, eight of the injured workers have yet to return to work. Seventeen of the 50 lost time injuries resulted in 30 or more calendar days lost and represent 88 per cent of the Severity rate results. Of these 17 lost time injuries resulting in 30 or more calendar days lost, the three most serious incidents account for over 20 per cent of the Severity rate. A further 50 per cent of the Severity rate is due to 11 of the 17 incidents, all of which relate to injuries from body mechanics (slips, trips and falls, lifting, pushing and pulling, and sprains, strains or ruptures from voluntary or involuntary bodily motions). BC Hydro's All Injury Frequency result of 2.1 for fiscal 2013 is above our target of 1.4 and above the fiscal 2012 result of 1.7.

PERFORMANCE MEASURES

ZERO FATALITY & SERIOUS INJURY

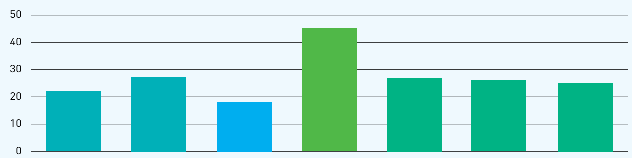
There has either been a loss of life or an injury resulting in a permanent disability.



F2011 ACTUAL	F2012 ACTUAL	F2013 TARGET	F2013 ACTUAL	F2014 TARGET	F2015 TARGET	F2016 TARGET
3	0	0	1	0	0	0

SEVERITY

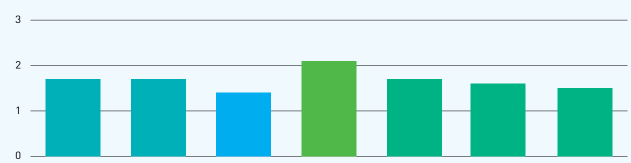
Number of days lost due to injury per 200,000 hours, based on actual hours worked *(lower is better)*



F2011 ACTUAL	F2012 ACTUAL	F2013 TARGET	F2013 ACTUAL	F2014 TARGET	F2015 TARGET	F2016 TARGET
22.2	27.4	18.0	45.1	27.0	26.0	25.0

ALL INJURY FREQUENCY

Number of injuries per 200,000 hours, based on actual hours worked *(lower is better)*



F2011 ACTUAL	F2012 ACTUAL	F2013 TARGET	F2013 ACTUAL	F2014 TARGET	F2015 TARGET	F2016 TARGET
1.7	1.7	1.4	2.1	1.7	1.6	1.5

It is important to note that with over half of our medical aid and lost time injuries being the result of body mechanics, the factors that influence our Severity and All Injury Frequency results are not the same as those influencing our results for fatalities and serious injuries.

BC Hydro benchmarks its Severity and All Injury Frequency performance against available CEA composite results. For the 2012 calendar year, the CEA composite Severity result was 15.49, and the CEA Group 1 utilities (utilities with greater than 1,500 employees) composite result was 15.73, compared to BC Hydro's 2012 calendar year result of 48.94. BC Hydro consistently has results in the fourth quartile compared to other CEA Group 1 utilities. For the 2012 calendar year, the CEA composite All Injury Frequency result was 1.77, and the CEA Group 1 utilities composite result was 1.79, compared to BC Hydro's 2012 calendar year result of 2.53. BC Hydro's result for 2012 was in the fourth quartile compared to other CEA Group 1 utilities. However, in previous years, BC Hydro's results were usually in alignment with other CEA Group 1 utilities, with results in the second quartile.

BC Hydro's leadership has committed to its employees to deliver on the Safety Taskforce vision and recommendations. The implementation of the recommendations is staged to ensure that change can be sustained, and especially so that the frontline is not overwhelmed by too many initiatives rolling out at one time. Work started in fiscal 2012 by dedicated implementation teams and we expect to have all the recommendations complete in fiscal 2017. Experience with recent incidents and investigations have confirmed that we are on the right track with the recommendations. As with every culture change, this will take time, persistence and unwavering support and leadership. As Just Culture becomes entrenched, and as employees trust that they will be fairly dealt with and see that underlying system conditions are being fixed, BC Hydro expects to see more reporting of incidents and near misses. This will ensure that BC Hydro has as much information as possible to improve the systems to support and improve worker and process safety. However, in the short term, this increase in reporting may have a negative impact on Severity and All Injury Frequency performance.

RELIABILITY PERFORMANCE

WHY WE MEASURE CAIDI, SAIFI AND CEMI-4

CAIDI is a CEA standard measure that is the average interruption in hours per interrupted customer; SAIFI is a CEA standard measure of how many sustained interruptions (longer than one minute) an average customer will experience over the course of a year; and, CEMI-4 is the percentage of customers experiencing four or more outages over the course of a fiscal year. CEMI is not benchmarked externally as utilities are at varying stages in their development of this metric.

Improving reliability requires a long-term investment strategy and commitment. It also requires short-term strategies such as outage notification and early restoration capabilities. Annually, circuits are benchmarked to prioritize reliability investment for sustained reliability improvement on the worst performing circuits. On a monthly basis, the most significant outages are reviewed to ensure accuracy of data, effectiveness of restoration actions, and to better understand vulnerabilities. As a second check for accuracy, trends in recent performance measures are compared against past results and forecast performance. Senior management reviews the annual and monthly performance measures and takes action when actual performance deviates from forecast. Operational staff are sometimes limited in their ability to capture the exact timing and number of customers restored when they are busy responding to large storms; however, since major uncontrollable events are excluded from the performance calculations, these errors have minimal impact on the reported measures.

The data gathered to measure our three reliability measures—CAIDI, SAIFI & CEMI-4—is collected and validated in a process that starts with operational staff who record the start and end time of each power outage as well as the cause. Based on the location of the outage, the number of customers impacted is calculated automatically. This information is collected in a centralized database that allows outage records to be reviewed by managers each day to ensure accuracy. Outages that impact a significant number of customers or involve lengthy repair times require a formal outage report to be written by an engineer and approved by management. As BC Hydro completes the implementation of the Smart Metering Program, outage data will be collected from the new meters enabling performance measures to be calculated automatically.

BC Hydro measures reliability under normal circumstances, because major events are not predictable and largely uncontrollable. Annually, BC Hydro participates in Transmission and Distribution benchmarking surveys conducted by First Quartile Consulting and the Distribution Service Continuity survey conducted by the CEA. Our reliability targets are based on specific values; however performance within 10 per cent is considered acceptable given the wide range of variations in weather patterns and other uncontrollable elements that can significantly disrupt the electrical system.

FISCAL 2013 RELIABILITY PERFORMANCE

Reliability is a challenge given the size of our service area, predominantly overhead distribution system, abundance of trees and rough terrain. BC Hydro has two to three times as many trees per overhead pole kilometer as the North American average, and trees, together with adverse weather, account for half of the annual lost customer hours. These constraints significantly affect our ability to achieve higher levels of reliability while balancing the need to continue to provide competitively priced power.

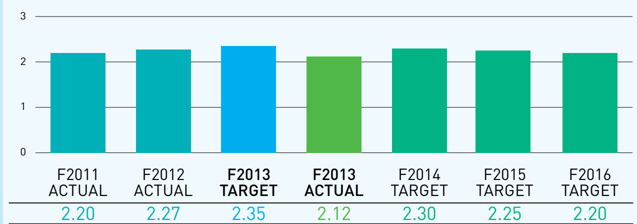
Nevertheless, we met all of our reliability targets in fiscal 2013, with our CAIDI, SAIFI and CEMI-4 all performing better than plan. Past investments in reliability have led to a lower than historical average number of outages caused by adverse weather, trees, and equipment failure contributing to the favorable reliability performance for the quarter. There were two major events in the fourth quarter, resulting in 290,000 customer hours lost, and eleven major events in fiscal 2013, resulting in over 1.9 million customer hours lost.

Continuing these reliability improvements requires a continued commitment to the overall investment strategy. Some of the reliability-focused programs in fiscal 2013 that contributed to meeting our reliability targets include our vegetation management hazard tree program, prioritized investment in the worst performing circuits, and further integration of distribution reclosers. Monitoring of CEMI-2 and CEMI-3 customers who were at risk of becoming CEMI-4 customers also contributed to a better performance for this metric and we hope this will translate into improved customer satisfaction.

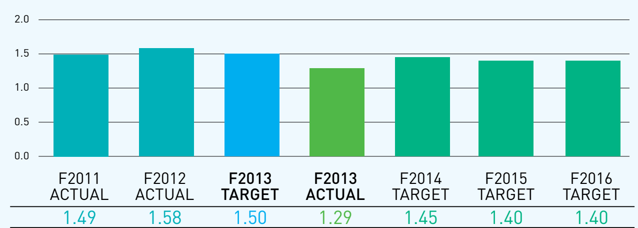
BC Hydro's short-term and medium-term strategies for addressing improvements in reliability performance will continue to focus on targeting the worst performing circuits by implementing a distribution automation program, improving circuit tie points, the distribution vegetation management hazard tree program and continued transmission right-of-way control and maintenance. Long-term strategies include leveraging the smart metering infrastructure and our demand management system to increase efficiencies and the level of automation for development of a more flexible distribution system. The completion of initiatives that are driven by the need to address load growth, energy conservation, and end-of-life asset replacement, is also expected to improve customer reliability.

PERFORMANCE MEASURES

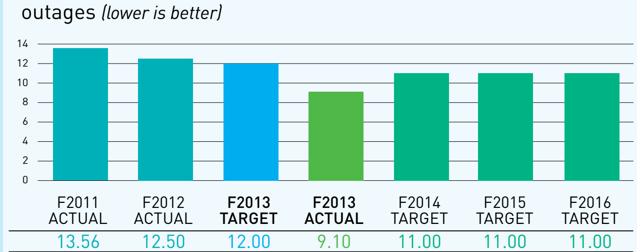
CAIDI—Average interruption in hours per interrupted customer *(lower is better)*



SAIFI—Number of interruptions per customer per year *(lower is better)*



CEMI-4 (%)—Percentage of customers experiencing 4 or more outages *(lower is better)*



WINTER GENERATION AVAILABILITY FACTOR

WHY WE MEASURE THIS

BC Hydro focuses on Winter Generation Availability Factor to manage the availability of generation during the critical winter period when customer loads are most likely to reach their annual peaks, and to ensure all BC Hydro generating units will remain in-service barring a forced outage or urgent maintenance.

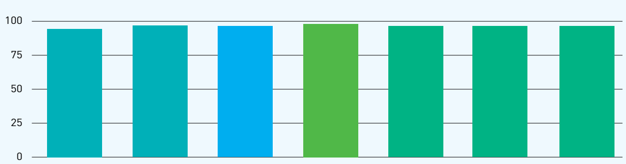
Winter Generation Availability Factor is a percentage of Heritage Asset units in the system greater than 20 MW and available to generate electricity (total hours available for service/total hours), excluding certain planned capital and maintenance outages, during the critical peak load period of November 15 to February 15. BC Hydro is not aware of any external benchmarks suitable for comparison with the Winter Generation Availability Factor, and instead uses historical trend information to track performance.

FISCAL 2013 PERFORMANCE

The actual Winter Generation Availability Factor for fiscal 2013 was 98.1 per cent, which is higher than the 96.4 per cent target. Although there were minor forced outages at several of our facilities throughout the winter months, the remainder of the hydro generation units performed very well throughout the winter period. There were also a number of planned capital and maintenance outages throughout the system, which we exclude from the Winter Generation Availability Factor calculation.

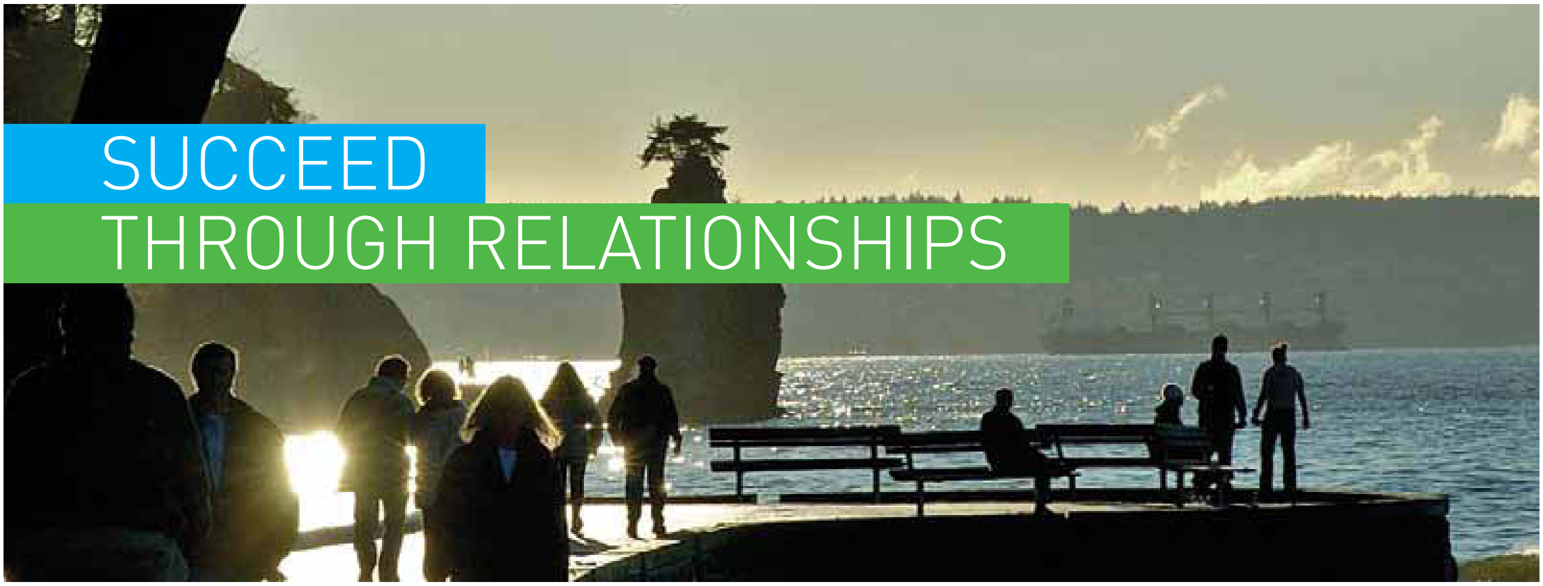
PERFORMANCE MEASURE

WINTER GENERATION AVAILABILITY FACTOR (%)
Heritage Asset units >20 MW available to generate electricity, excluding certain planned capital and maintenance outages
(higher is better)



F2011 ACTUAL	F2012 ACTUAL	F2013 TARGET	F2013 ACTUAL	F2014 TARGET	F2015 TARGET	F2016 TARGET
94.4	96.8	96.4	98.1	96.4	96.4	96.4

Maintenance and Operations Manager Dennean Gould by the Revelstoke Generating Station penstock.



SUCCEED THROUGH RELATIONSHIPS

STRATEGIES IN THE 2012/13-2014/15 SERVICE PLAN

- Undertake consultation where activities may have an impact on Aboriginal rights and title and where appropriate, accommodate First Nations' interests. Continue to build longer-term relationships with First Nations.
- Strengthen BC Hydro's understanding of customers' needs and expectations through customer engagement, targeted segmentation and benchmarking.
- Increase the efficiency, consistency and quality of customer experiences through integration of all customer channels.
- Educate, support and encourage regional districts, municipalities and large-scale developers in creating integrated, community-wide energy strategies.
- Implement recommendations from our supplier engagement review to improve how we engage and transact business with our suppliers.

CUSTOMER SATISFACTION (CSAT)

WHY WE MEASURE THIS

CSAT is the percentage of customers— residential, small and medium-sized businesses and key accounts—who are satisfied or very satisfied with BC Hydro (as measured on a four-point verbal scale) in five equally weighted areas: providing reliable electricity, value for money, commitment to customer service, acting in the best interests of British Columbians, and efforts to communicate with customers and communities.

BC Hydro maintains a minimum threshold target of 85 per cent for CSAT to ensure we have strong customer support. BC Hydro benchmarks against leading regional service providers and other electric utilities in an effort to better understand our performance relative to customer perceptions and understand what is needed to be a leader in our industry and the province. Benchmarking results to date demonstrate BC Hydro compares well against both non-electric utility service providers and other electric utilities.

FISCAL 2013 PERFORMANCE

Customer Satisfaction experienced downward pressure in early fiscal 2013 related to higher than normal seasonal call volumes. The 12-month rolling average satisfaction score reached a low point of 85 per cent in the middle of fiscal 2013. Customer care strategies, such as improved online tools, helped us achieve our customer satisfaction targets and address the call volumes. The Customer Satisfaction score was 86 per cent at the end of the fiscal, slightly above the plan target of 85 per cent.

We improved our customers' online experience by redesigning the homepage and other aspects of our website, bchydro.com. We also improved customer service online with a major upgrade to our content management system. To further support customer inquiries related to energy consumption, usage and bills, a new energy visualization tool and improved self-serve functionality became available to more than one million customers during the fourth quarter. The number of customers utilizing paperless billing increased steadily during the year and the fiscal year ended with one out of every four customers on paperless billing.

BILLING ACCURACY

WHY WE MEASURE THIS

Billing Accuracy is the percentage of invoices that are accurately calculated based on the customer's consumption and do not require adjustment or rebilling. This is a core expectation of customers. BC Hydro has therefore set targets to deliver consistently high performance. Billing accuracy is affected by items such as incorrect meter reads and various adjustments, such as correction to rate applied.

FISCAL 2013 PERFORMANCE

This metric was tracking below plan in the early part of the year due to higher than normal billing exceptions and backlogs. However, as an increased number of bills began to be generated through automated reads, billing accuracy improved and the average achieved for the year was above plan. Close to one million bills per month are now being issued using automated reads from smart meters. Bills issued from automated reads improve billing accuracy and customer service by reducing the percentage of estimates required as well as lowering the number of bills requiring rework compared to bills that are issued from non-automated reads.

FIRST CALL RESOLUTION

WHY WE MEASURE THIS

First Call Resolution (FCR) measures the percentage of calls that are resolved during the first contact with a call centre agent. This is a measure that assesses customer service operations as a whole in terms of accurate and timely information flow, agent capability and quality, and a satisfying customer experience at a transaction level. BC Hydro utilizes a post call customer survey conducted by a leading North American call center industry research firm to measure FCR. The accuracy of our FCR results could be influenced by customer sentiment, since a customer may associate call resolution with arriving at their desired end result, as opposed to the accurate result. For example, someone who wants to see their bill lowered may respond negatively to the survey if the call ends without that particular result being achieved, regardless of how they are treated during the call or the accuracy of the information related to their inquiry.

FISCAL 2013 PERFORMANCE

First Call Resolution was below plan mainly as a result of increased high bill calls and wait times experienced throughout the spring as customers called to question their winter consumption. Customers continue to indicate that their issues are not being resolved on the first call. The Customer Care team continues to work with their service providers to identify and implement improvement opportunities in order to increase performance in this area.

PROGRESSIVE ABORIGINAL RELATIONS

WHY WE MEASURE THIS

Building collaborative relationships for generations is an important vision that guides BC Hydro's goal to establish relationships with First Nations built on mutual respect and that appropriately reflect the interest of First Nations. The Canadian Council for Aboriginal Relations' Progressive Aboriginal Relations (PAR) program is an externally verified certification program that measures an organization's success in the areas of Aboriginal employment, business development, capacity development and community engagement. The gold-level standard is an indication of sustained excellence in all four areas.

FISCAL 2013 PERFORMANCE

In September 2012, BC Hydro earned PAR gold-level certification, the highest level of achievement, for best practices in Aboriginal Relations from the Canadian Council for Aboriginal Business' Progressive Aboriginal Relations program. This achievement demonstrates BC Hydro's commitment to the prosperity of Aboriginal communities, businesses, and individuals.

BC Hydro continues to strengthen its collaborative relationships. Fiscal 2013 marked the second year of BC Hydro's long-term relationship agreement with St'at'imc, where progress has been made in the areas of contracting, education and training, and key other initiatives, including environmental and archaeological work.

We continued to consult First Nations on our generation and transmission projects, and provide procurement, training and other economic opportunities. This year, BC Hydro reached agreements with We Wai Kai, Wei Wai Kum and K'omoks First Nations related to the John Hart Generating

Station Replacement Project, which will see them directly involved in the preservation and enhancement of salmon stocks within the Campbell River System.

In addition, off-grid communities such as Kwadacha First Nation's community of Fort Ware in northern B.C. and the Uchucklesaht Tribe's community of Elhlateese on Vancouver Island were provided with reliable and affordable electricity through new modular generating stations and distribution systems. Meanwhile, BC Hydro met our target of hiring 35 Aboriginal employees, launched our Aboriginal Employee Network and procured $96 million in goods and services from Aboriginal vendors.

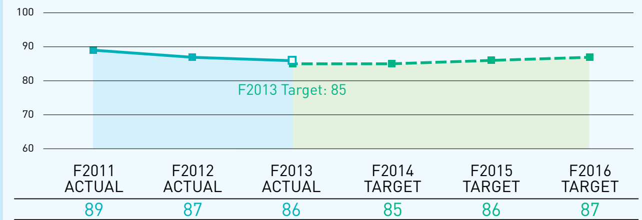
BC Hydro also provides financial and in-kind support to Aboriginal events and organizations. This year, BC Hydro participated in the Truth and Reconciliation Commission of Canada's regional event in Victoria where 20 senior leaders volunteered and served as witnesses as residential school survivors recounted their experiences and the impacts this has had on their lives and the generations that have followed.

Above: JP Gladu, President and CEO of the Canadian Council for Aboriginal Business, left, appears with Greg Reimer, Executive Vice-President, Transmission & Distribution, Charles Reid, President and CEO and Terry Goodtrack, President and CEO, Aboriginal Financial Officers Association of Canada, following the presentation of the gold-level certification in Progressive Aboriginal Relations, September 27, 2012.

PERFORMANCE MEASURES

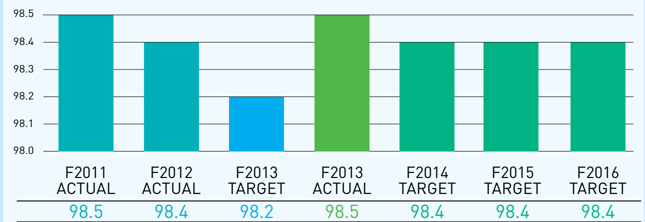
CUSTOMER SATISFACTION INDEX (CSAT) (%)

(higher is better)



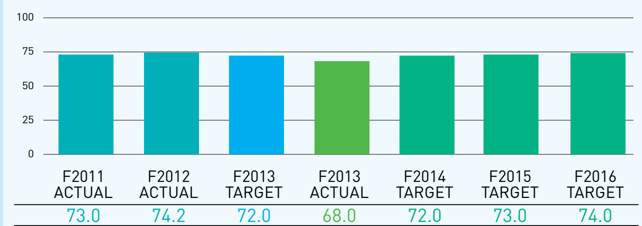
BILLING ACCURACY (%)

(higher is better)

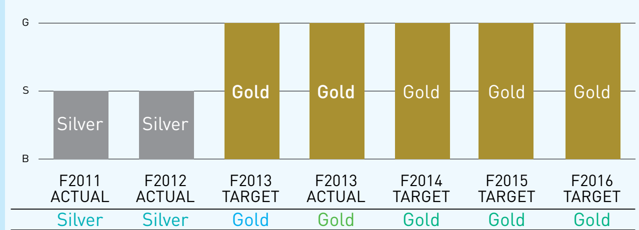


FIRST CALL RESOLUTION (%)

(higher is better)



PROGRESSIVE ABORIGINAL RELATIONS DESIGNATION



MIND OUR FOOTPRINT

STRATEGIES IN THE 2012/13–2014/15 SERVICE PLAN*

- Continue to implement the DSM plan, including Power Smart programs and conservation rate structures, supporting new energy efficiency regulations, and fostering an energy conservation and efficiency culture.
- Manage the impact on the environment from BC Hydro operations and new developments by applying an avoiding, minimizing and offsetting approach.
- Meet all new regulatory requirements for GHG emissions from emission sources. This includes ensuring operations are carbon neutral under the *B.C. Greenhouse Gas Reduction Targets Act*.
- Continue to purchase power from independent power producers (IPPs) that use clean or renewable resources.
- Continue implementing the PCB electrical equipment phase out strategy, and develop a long-term strategy for the handling, decontamination and disposal of PCB contaminated equipment and materials.

DEMAND SIDE MANAGEMENT

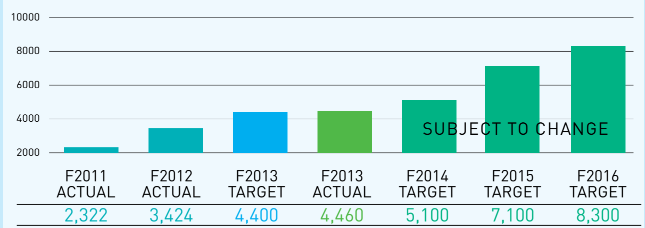
WHY WE MEASURE THIS

Demand Side Management (DSM) is an important part of BC Hydro's plan to meet future supply needs. DSM performance is measured in the cumulative rate of annual electricity savings (GWh/yr) resulting from DSM activities, including programs, codes and standards and rate structures and reflects savings that were initiated since fiscal 2008, following the 2007 BC Energy Plan. BC Hydro developed its annual cumulative DSM targets as part of long-term DSM and resource planning using the results from a Conservation Potential Review, market experience and research. BC Hydro's DSM plan compares well against other leading DSM jurisdictions in North America.

BC Hydro undertakes a comprehensive approach to estimating DSM electricity savings. Depending on the DSM initiative, there can be up to four distinct areas of activity that ultimately contribute to the confirmation of DSM savings estimates: technical reviews of programs and energy conservation projects; site inspections on a sample of projects; measurement and verification of project performance; and evaluation of programs, conservation rates, building codes and product standards.

PERFORMANCE MEASURE

DEMAND SIDE MANAGEMENT (GWh/year)
Cumulative annual electricity savings since 2008 *(higher is better)*



FISCAL 2013 PERFORMANCE

For fiscal 2013, BC Hydro's cumulative energy savings of 4,460 GWh/year exceeded the Service Plan target of 4,400 GWh/year. Our energy savings targets were achieved through various programs with capital incentives for businesses, industry and everyday British Columbians to

**BC Hydro has removed "preparing to participate in emissions trading under the B.C. Cap and Trade Act" from our GHG emissions strategies in the 2012/13-2014/15 Service Plan since the development of a B.C. cap-and-trade system would come into force by issue of a government regulation and there has not yet been a final decision as to whether to institute a cap-and-trade program.*

conserve energy; conservation rates that provide an incentive to use less electricity and save money; and by working with governments to encourage improvements to building codes and product standards to increase the efficiency of buildings and the goods people and businesses use. Our encouraging fiscal 2013 performance can be attributed to the strong relationships BC Hydro has built and maintained across all customer segments—from providing our low-income customers with free energy savings kits, to working with many of our largest commercial and industrial customers to assist them in identifying and completing energy conservation projects.

ELECTRICITY PRODUCTION GREENHOUSE GAS (GHG) EMISSIONS

WHY WE MEASURE THIS

The Electricity Production GHG Emissions measure quantifies the direct GHG emissions associated with electricity generation, from BC Hydro-owned generating stations and from our IPPs in B.C., and the fugitive SF_6 releases from our transmission and distribution system. Electricity Production GHG Emissions are reported by calendar year rather than fiscal year to ensure consistency with GHG emissions reports filed under the *Canadian Environmental Protection Act*, 1999 and the B.C. Reporting Regulation.

The Electricity Production GHG Emissions targets are based on the forecasted need to run the generating stations, taking into account hydrology, reliability, system needs and market conditions, including the expected price of carbon emissions. We have recalibrated the targets for Electricity Production GHG Emissions from the 2013/14–2015/16 Service Plan to reflect updates to the forecast. GHG emissions from BC Hydro-owned generating stations and fugitive SF_6 releases are calculated using methods required under the B.C. Reporting Regulation. The reported emissions are subject to mandatory third-party verification by an accredited verifier. GHG emissions from IPPs are estimated based on information supplied by the IPPs.

FISCAL 2013 PERFORMANCE

The calendar year 2012 Electricity Production GHG emissions were 631 kilotonnes CO_2e, which is 32 per cent below the target of 930 kilotonnes CO_2e. Emissions were lower than forecasted for the Island Generation IPP, which ran for less than three weeks in 2012 for reliability, system support and trade, and for the Burrard Generating Station, which only ran for test purposes and steam generation for a third party. Emissions were also lower than forecasted for the Fort Nelson Generating Station, because it was rarely called upon for Transmission Must Run capacity in 2012.

When compared to other Canadian hydroelectric utilities, BC Hydro's 2012 Electricity Production GHG Emissions of 631 kilotonnes CO_2e (for about 63,000 GWh generated and purchased from IPPs) were higher than Manitoba Hydro's reported 2011 total emissions of 157 kilotonnes CO_2e (for about 33,000 GWh generated) and Hydro-Québec's reported 2011 electricity generation and CH_4/SF_6 fugitive emissions of 247 kilotonnes CO_2e (for about 169,000 GWh generated). Our performance relative to Manitoba Hydro and Hydro-Québec reflects the higher proportions of hydroelectric generation in the resource mix for those utilities. The GHG intensity of electricity generated by BC Hydro and our IPPs in B.C. has ranged from about 10 to 30 tonnes per GWh in recent years, which is significantly lower than the average electricity generation intensity of 160 to 200 tonnes per GWh for Canadian provinces and territories, many of which do not have a resource mix so favourable towards hydroelectricity.

CARBON NEUTRAL PROGRAM EMISSIONS

WHY WE MEASURE THIS

BC Hydro became carbon neutral in our operations in 2010, along with the entire B.C. public sector. This means that we measure the GHG emissions from our vehicle fleet, buildings (energy used for heating, cooling, lighting, and IT equipment) and paper use, in accordance with the Province's guidelines for public sector organizations. We also implement measures to reduce those emissions and report on these reduction measures in our annual Carbon Neutral Action Report, which is published at www.livesmartbc.ca. Finally, we offset any remaining emissions from these sources through investments in the Pacific Carbon Trust.

Carbon Neutral Program Emissions are reported by calendar year rather than fiscal year to ensure consistency with GHG emissions reports filed under the B.C. Carbon Neutral Government Regulation. The Carbon Neutral Program Emissions targets are based on a forecast of emissions, taking into account emission reduction initiatives that are planned or underway. Carbon Neutral Program emissions are calculated using the Province's SMARTTool, based on BC Hydro's reported fuel, electricity and paper use. Small sources of emissions such as boats, snowmobiles and all-terrain vehicles, estimated to comprise one per cent or less of total Carbon Neutral

Program Emissions, are excluded from reporting in accordance with provincial guidelines. All public sector organizations are required to certify and confirm the accuracy and completeness of the data submitted into SMARTTool by completing self-certification. In addition, a representative sample of public sector organizations is selected for independent verification of their GHG emissions reporting procedures.

FISCAL 2013 PERFORMANCE

The calendar year 2012 Carbon Neutral Program Emissions were 28.8 kilotonnes CO_2e, which is four per cent below the target of 30 kilotonnes CO_2e. Vehicle fleet emissions, which account for almost three-quarters of Carbon Neutral Program Emissions, were three per cent lower in 2012 than in the previous calendar year. This reduction is largely the result of BC Hydro's new transportation model, implemented in the fall of 2011, which transferred the transportation of materials and equipment from our vehicle fleet to contracted transportation vendors that demonstrated fuel saving measures and green business practices. We do not track vehicle emissions from our vendors. Emissions from heating, cooling, lighting and IT equipment in buildings were almost six per cent lower than in calendar year 2011. This reduction can be attributed to a combination of energy use reduction initiatives within our building portfolio and warmer average temperatures in 2012.

Due to the distinctive nature of our operations, it is difficult to compare BC Hydro's Carbon Neutral Program Emissions to those of other public sector organizations. BC Hydro is unique in that we require a relatively large vehicle fleet to support our province-wide operations. In 2010 and 2011, BC Hydro reported the eighth highest emissions among the public sector organizations (2012 results are not yet available for benchmarking). In 2010, BC Hydro's emissions per full-time equivalent employee were less than ten per cent above the average for Crown corporations.

CLEAN ENERGY

WHY WE MEASURE THIS

The Clean Energy target aligns with the objectives set forth in the 2010 *Clean Energy Act*. The Clean Energy measure represents a minimum threshold generation target in accordance with the B.C. Government's requirement that at least 93 per cent of electricity generation in the province be from clean or renewable resources—i.e., from biogas, biomass, energy recovery generation, geothermal, hydro, solar, tidal, wave, wind or other potential clean or renewable electricity sources recognized by the B.C. Government.

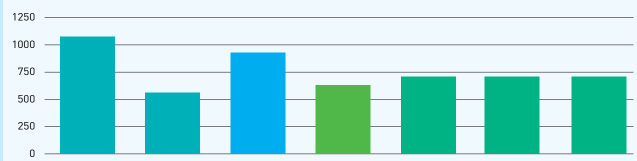
Consistent with B.C. regulation, this measure does not include electricity to serve demand from facilities that liquefy natural gas for export by ship. BC Hydro does not compare its results for this performance measure against other utilities. The measure uses actual historical generation data obtained from BC Hydro and IPPs. The generation data is reviewed and verified internally at BC Hydro for reliability, consistency and data integrity.

FISCAL 2013 PERFORMANCE

For fiscal 2013, Clean Energy generation was higher than plan due to increased large hydro generation largely related to very high inflows throughout B.C. during the 2012 spring/summer period and favourable market conditions (prices) in the fourth quarter of fiscal 2013.

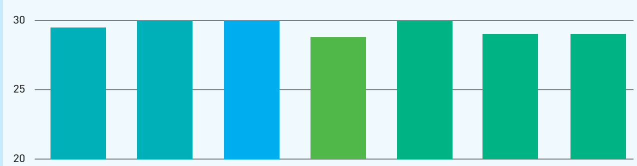
PERFORMANCE MEASURES

ELECTRICITY PRODUCTION GHG EMISSIONS (kt) Carbon dioxide equivalent metric kilotonnes from electricity production *(lower is better)*



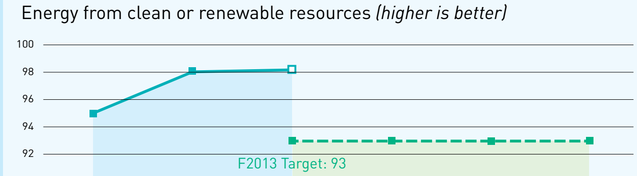
F2011 ACTUAL	C2011 ACTUAL	C2012 TARGET	C2012 ACTUAL	C2013 TARGET	C2014 TARGET	C2015 TARGET
1,074	560	930	631	710	710	710

CARBON NEUTRAL PROGRAM EMISSIONS (kt) Carbon dioxide equivalent metric kilotonnes from building energy use and vehicles *(lower is better)*



F2011 ACTUAL	C2011 ACTUAL	C2012 TARGET	C2012 ACTUAL	C2013 TARGET	C2014 TARGET	C2015 TARGET
29.5	30.0	30.0	28.8	30.0	29.0	29.0

CLEAN ENERGY (%) Energy from clean or renewable resources *(higher is better)*



F2011 ACTUAL	F2012 ACTUAL	F2013 ACTUAL	F2014 TARGET	F2015 TARGET	F2016 TARGET
95.0	98.1	98.2	93.0	93.0	93.0

FOSTER ECONOMIC DEVELOPMENT

STRATEGIES IN THE 2012/13-2014/15 SERVICE PLAN

- Continue to develop best-in-class energy-procurement practices and strengthen relationships with energy suppliers.
- Integrate economic development principles into decision-making tools, business cases and corporate policies.
- Ensure appropriate tariff/rate structures are in place to enable the expansion of business activity across B.C.
- Develop new business models to enable new energy projects that make sense from a longer-term, provincial perspective while minimizing customer impacts.
- Help expand and retain current customers by fostering business competition through Power Smart programs and the delivery of clean, reliable energy.

CAPITAL SPENDING IN BRITISH COLUMBIA

WHY WE MEASURE THIS

By virtue of our business, BC Hydro has always been and will continue to be a major contributor to economic development in B.C. The "BC Hydro Capital Spending in British Columbia" measure was introduced in the fiscal 2012/13–2014/15 Service Plan to serve as a measure of BC Hydro's contribution to economic development in B.C. The measure is calculated as total capital spend per BC Hydro's financial system adjusted to exclude estimates of major capital purchases from outside B.C, as these expenditures do not directly contribute to economic activity in B.C.

The adjustment to total expenditures is based on major equipment imports in fiscal 2010 identified by a consultant as part of their 2011 analysis of the economic impact of BC Hydro's activities. In fiscal 2010, the adjustment represented 3.3 per cent of total capital expenditures. In the absence of better information, the targets in the fiscal 2013/14–2015/16 Service Plan and actuals for fiscal 2013 are based on total capital spend, adjusted by 3.3 per cent of total capital expenditures each year. With the change in composition of BC Hydro's total capital spending since fiscal 2010, this calculation may not be a reasonable estimate of BC Hydro's spending in B.C. It would require a substantial amount of effort to identify actual in-province expenditures on an annual basis. Accordingly, we are currently assessing opportunities to improve this measure to more effectively reflect the goal of fostering economic development in future years.

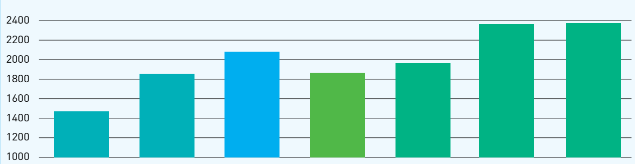
FISCAL 2013 PERFORMANCE

BC Hydro continues to invest significantly to refurbish its aging infrastructure and build new assets for future growth. In fact, we are forecasting capital expenditures of almost $7 billion over the next three years. Capital expenditures for the twelve months ended March 31, 2013 were $1,929 million, with $1,865 million calculated to be B.C. spend, which was slightly below our plan of $2,153 million and our B.C. spend target of $2,082 million. We came below target primarily due to major project schedule delays and some cost savings on projects, such as the Columbia Valley Transmission Line.

Targets for this measure are more of an indicator of economic development in B.C. versus a true "target" that we are aspiring to achieve. BC Hydro makes every effort to make purchases within B.C. where goods are available and it makes economic sense, but doesn't seek to achieve spending targets within B.C. in isolation of overall business decisions on capital expenditures. Accordingly, when total capital expenditures are less than plan due to prudent business decisions or circumstances, BC Hydro does not consider itself to be off track on Capital Spend within B.C. as long as purchases are made from within B.C. when economically viable. Due to challenges in setting appropriate targets and accurately measuring results for this measure, BC Hydro is assessing opportunities to revise and improve its Economic Development measure.

PERFORMANCE MEASURE

BC HYDRO CAPITAL SPENDING IN B.C.
($ millions)



F2011 ACTUAL	F2012 ACTUAL	F2013 TARGET	F2013 ACTUAL	F2014 TARGET	F2015 TARGET	F2016 TARGET
1,468	1,853	2,082	1,865	1,963	2,364	2,375

Some of the new transmission towers along the Northwest Transmission Line route taken by Bruce Barrett, Vice-President, Project & Program Delivery in late April.

MAINTAIN COMPETITIVE RATES

STRATEGIES IN THE 2012/13-2014/15 SERVICE PLAN

- Implement recommendations from the June 2011 Government Panel Review of BC Hydro to realize cost-savings and efficiencies.
- Increase focus on management and control of its cost structure.
- Continue with IT system and process improvements in the areas of human resources, supply chain, and work management.
- Effectively deliver on BC Hydro's capital investment program, including process and procurement improvements.
- Optimize BC Hydro's balance sheet and cost of capital.
- Realize value through innovative procurement strategies, strategic sourcing and by building mutually strong supplier relationships.
- Manage the cost of energy to customers by: implementing a 20-year Demand-Side Management plan; procuring and/or building new electricity supply at competitively benchmarked costs; making careful short-term generate and buy decisions; and using BC Hydro's ability to use the flexibility of its heritage assets.

COMPETITIVE RATES

WHY WE MEASURE THIS

BC Hydro's electricity rates are among the most competitive in North America, in large part due to the past investments in infrastructure that help us generate and deliver cost-effective, clean energy. Our competitive rates measure compares BC Hydro's rates against other utilities across North America for three types of power classes: a typical residential customer with an estimated monthly consumption of 1,000 kWh; a medium customer with an estimated monthly consumption of 400,000 kWh; and, a large customer with an estimated monthly consumption of 30,600 MWh.

Pursuant to Rate Comparison Regulation under the *Clean Energy Act*, issued on June 28, 2011, BC Hydro provides an Electricity Rate Comparison Annual Report to the Minister of Energy, Mines and Natural Gas and to the BCUC. This is based on survey information taken from the Hydro Québec report, Comparison of Electricity Prices in Major North American Cities, which compiles monthly bill and average prices for 12 Canadian utilities and 10 U.S. utilities.

FISCAL 2013 PERFORMANCE

Based on the 2012 Hydro Québec Study "Comparison of Electricity Prices in North American Cities," which was issued in October, BC Hydro achieved a 1st Quartile rating as targeted. The study also found BC Hydro to have the 4th lowest rates overall among the 22 North American utilities surveyed.

It is in large part due to the development of our large generating facilities built between the 1950s and 1980s that our rates are so competitive. We also work hard to carefully manage our costs and operate in an efficient and cost-effective manner, and strive to ensure that projects deliver benefits and are on time, and within scope and budget.

We are on track to meeting our target of $391 million in operating cost savings in the three-year period between fiscal 2012 and fiscal 2014, as we committed to in our response to the recommendations following the 2011 Government Panel Review of BC Hydro. In fiscal 2013, we met our goal to maintain our headcount equivalent below the fiscal 2013 target through proactive management of attrition and headcount levels throughout the year. Meanwhile, we've been working hard to realize significant cash savings through our procurement activities and strategic partnerships, including with SNC Lavalin, Accenture, Fujitsu and TELUS.

We have a major effort underway in our Transmission and Distribution (T&D) group to implement people and process changes to drive operational excellence. We are also bringing in technology that together with the people and process changes will build a safer, more modern, cost-effective, efficient and customer-focused utility. Work is underway to build and implement tools for work allocation, scheduling, and dispatch, which along with supply chain and integrated asset and work management systems will create the future foundation for delivery of work and information analytics. In fiscal 2013, BC Hydro completed a number of key milestones in T&D, including bundling more work packages for contractors to improve efficiency, introducing a new customer program for underground residential interconnections, and new integrated asset management planning processes.

NET INCOME

WHY WE MEASURE THIS

BC Hydro bases net income targets on the latest financial forecast. The targets are based on BC Hydro's allowed return on equity and reflect expected rate increases required to enable BC Hydro to cover its costs.

BC Hydro ensures the integrity of its financial data by maintaining robust systems of financial internal controls. The financial statements are also audited annually by an independent external accounting firm.

FISCAL 2013 PERFORMANCE

Consolidated net income for fiscal 2013 was $509 million, $5 million or just one per cent below plan net income of $514 million, which is considered to be on target. This was primarily due to some unplanned write-offs of cancelled projects and higher than planned mass asset retirements.

OPERATING COSTS

WHY WE MEASURE THIS

Operating costs are defined as personnel, materials and external services expenses included in income, that are incurred in the day-to-day operation of BC Hydro's electric utility, net of recoveries, capitalized costs and reclassification adjustment. Operating costs are impacted by such things as the age of assets and maintenance requirements, inflation and other cost increases for materials and supplies, growth in the customer base, and changes in environmental and regulatory standards.

FISCAL 2013 PERFORMANCE

It continues to be challenging to meet our operating costs targets due to needed investments in aging infrastructure, an increase in the number of customers we serve, and the increasing costs of fuel and materials. Nevertheless, we met our targets in fiscal 2013, realizing operating costs on our target of $705 million.

DEBT TO EQUITY

WHY WE MEASURE THIS

Debt to Equity is defined as the ratio of debt to the sum of the total of debt and equity. This is of interest to sector analysts, rating agencies, and finance providers. It is commonly used in the financial community. It measures the leverage in the company and is used in the regulation of electricity companies in some jurisdictions.

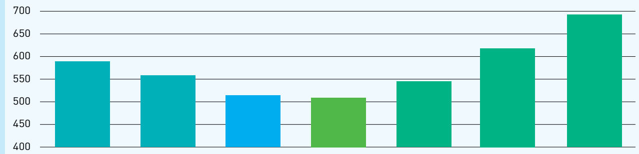
FISCAL 2013 PERFORMANCE

The debt to equity ratio of 80/20 is on target. BC Hydro's payment to the province is equal to 85 per cent of BC Hydro's net income if the debt to equity ratio, after deducting the payment, is not greater than 80:20. Based on fiscal 2013 results, the dividend to be paid to the province is $215 million, which is 42 per cent of net income. This was below the 85 per cent payment due to the 80:20 debt to equity ratio cap.

PERFORMANCE MEASURES

NET INCOME

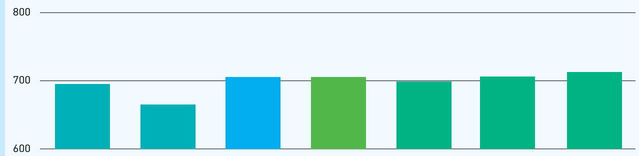
($ million)



F2011 ACTUAL	F2012 ACTUAL	F2013 TARGET	F2013 ACTUAL	F2014 TARGET	F2015 TARGET	F2016 TARGET
589	558	514	509	545	611	684

OPERATING COSTS

($ million)



F2011 ACTUAL	F2012 ACTUAL	F2013 TARGET	F2013 ACTUAL	F2014 TARGET	F2015 TARGET	F2016 TARGET
695	665	705	705	699	706	713

COMPETITIVE RATES

1st Quartile

- ACTUAL F2011, F2012 & F2013
- TARGET F2013, F2014, F2015 & F2016

DEBT TO EQUITY (%)

80/20

- ACTUAL F2011, F2012 & F2013
- TARGET F2013, F2014, F2015 & F2016

ENGAGE
A SAFE AND EMPOWERED TEAM

STRATEGIES IN THE 2012/13-2014/15 SERVICE PLAN

- Continue to adapt the organizational structure to prudently manage staffing levels; ensure the optimal complement of new recruits, skilled, experienced and high-performing employees; and leverage contracted and outsourced service providers in an efficient manner.
- Support leaders to engage employees so they are highly motivated to work together safely and effectively.
- Identify key skill shortages in critical roles and create recruitment and development plans to ensure a readily available talent pool for critical roles.
- Provide an appropriate balance of competitive, cost-efficient compensation and flexible benefits, and work/life programs that serve to attract the best possible candidates, retain top performers and enhance employees' well-being.

EMPLOYEE ENGAGEMENT

WHY WE MEASURE THIS

The Employee Sustainable Engagement Score is BC Hydro's annual measure of employee engagement through an all-employee survey. The approach to the employee engagement survey was changed significantly from the last survey in 2009. In fiscal 2013, BC Hydro and its external survey provider, Towers Watson, updated the survey tool to provide an efficient process that could be administered annually based on leading practice. New baseline measures and targets were set in anticipation of the fiscal 2014 survey.

The new sustainable engagement score indicates the level to which employees connect with the organization, whether or not they feel the company provides the tools and resources to work effectively, and whether or not they feel that the company cares about their personal well-being. BC Hydro's results are benchmarked against a number of Towers Watson indicators, including their Global Utilities Norm and their Canada National Norm. Our annual target is to meet or exceed the Towers Watson Global Utilities norm for sustainable engagement. This target is adjusted annually to benchmark against shifts in the norms within the utilities industry.

FISCAL 2013 PERFORMANCE

After the 2009 survey, BC Hydro took time to assess the alignment of the survey in support of the business. In 2012, the survey instrument was redesigned based on leading practice and the frequency changed from biennial to annual administration. This provides better line of sight to employee perception of the workplace in a time of significant change, and informs BC Hydro's continuous improvement measures. The company-wide participation rate was 69 per cent and we achieved a "sustainable engagement" score of 78 per cent.

BC Hydro's fiscal 2013 results are slightly below the new external benchmark of Towers Watson Global Utilities Norm of 80 per cent. While we were very close to the benchmarked norm, many employees shared concerns about the pace and extent of change and their perception of the impacts of increased financial constraints on career opportunities and workplace conditions.

Based on the survey results and employee comments, the company has identified two priority areas for action. First, leadership and integrity, which involves communicating a clear vision for the future and demonstrating follow-up on issues raised and improving the dialogue about objectives and decisions between senior leaders and employees; second, career development, which involves continuing to develop our workforce by leveraging internal recruitment and training opportunities and supporting employees in developing their careers at BC Hydro.

As part of this effort, BC Hydro constructed a new Trades Training Centre in fiscal 2013 that centralized all technical and trades training development and delivery so that our training programs are now managed and delivered by BC Hydro employees on our own equipment, resulting in an improved training experience that better supports safe work practices.

At the end of fiscal 2013, a new action tracking process launched to ensure a cycle of continuous improvement and that BC Hydro is successful at continuing to engage employees.

PERFORMANCE MEASURE

EMPLOYEE SUSTAINABLE ENGAGEMENT SCORE
(% Favourable)

F2011 ACTUAL	F2012 ACTUAL	F2013 TARGET	F2013 ACTUAL	F2014 TARGET	F2015 TARGET	F2016 TARGET
—	—	—	78	80	80	80


Opening day at the new Trades Training Centre.

BC HYDRO & POWER AUTHORITY MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) reports on British Columbia Hydro and Power Authority's (BC Hydro or the Company) consolidated results and financial position for the year ended March 31, 2013 (fiscal 2013) and should be read in conjunction with the Audited Consolidated Financial Statements and related notes of the Company for the years ended March 31, 2013 and 2012.

Effective April 1, 2012, the Company changed its financial reporting framework from Canadian generally accepted accounting principles (CGAAP) to the standards as prescribed by the Province of British Columbia ("the Province") which applies the accounting principles of International Financial Reporting Standards (IFRS) except that the Company applies regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980, *Regulated Operations* (ASC 980) ("Prescribed Standards"). All financial information is expressed in Canadian dollars unless otherwise specified, and prior year amounts have been restated to conform to the Prescribed Standards. For more information on the Company's transition to the Prescribed Standards, please see the "Explanation of Transition to the Prescribed Standards" section of this MD&A and Notes 2 and 22 of the Audited Consolidated Financial Statements for the year ended March 31, 2013.

This report contains forward-looking statements, including statements regarding the business and anticipated financial performance of the Company. These statements are subject to a number of risks and uncertainties that may cause actual results to differ from those contemplated in the forward-looking statements.

HIGHLIGHTS

- Net income after regulatory transfers for the year ended March 31, 2013 was $509 million, $49 million below the prior fiscal year net income of $558 million. The decrease from the prior year was primarily due to the reduction in the allowed return on equity (ROE). Key variances included higher amortization and depreciation expense of $160 million as a result of higher assets in service and higher regulatory account amortization, higher finance charges of $41 million due primarily to higher overall debt levels in fiscal 2013 to fund capital expenditures, partially offset by higher revenues of $168 million.

- Revenues for the year were $4.9 billion, $168 million higher than the prior year due to higher domestic revenues of $290 million due to higher average customer rates and surplus energy sales, partially offset by lower trade revenues of $122 million due primarily to lower net gas revenues due to lower gas prices.

- Usable system inflows for fiscal 2013 were 109 per cent of average, comparable to 108 per cent of average in fiscal 2012. At March 31, 2013, the combined system storage in the Company's reservoirs was 103 per cent of average compared to 110 per cent of average at March 31, 2012. As a result of the high inflows during the summer months, the Company sold a significant volume of surplus energy during fiscal 2013, an increase of over 5,000 GWh as compared to surplus energy sales in fiscal 2012. The high inflows also resulted in both the Williston and Kinbasket reservoirs spilling substantial volumes of surplus water in the summer of 2012, with the result that usable system inflows for fiscal 2013 were significantly less than total system inflows.

- Capital expenditures for the year ended March 31, 2013 were $1,929 million, a $226 million increase over prior fiscal year capital expenditures of $1,703 million. The increase reflects the Company's ongoing investment to refurbish its aging infrastructure and build new assets for future growth, including Mica Units 5 & 6 Project, Northwest Transmission Line Project, G.M. Shrum Units 1 to 5 Turbine Rehabilitation, Ruskin Dam and Powerhouse Upgrade, Smart Metering and Infrastructure (SMI) program, Interior to Lower Mainland Transmission Project, and Vancouver City Central Transmission Project.

CONSOLIDATED RESULTS OF OPERATIONS

for the years ended March 31 (in millions)	2013	2012	Change
Total Assets	**$ 23,782**	$ 21,900	$ 1,882
Total Revenues	**$ 4,898**	$ 4,730	$ 168
Shareholders' Equity	**$ 3,500**	$ 3,219	$ 281
Net Income	**$ 509**	$ 558	$ (49)
Accrued Payment to the Province	**$ 215**	$ 230	$ (15)
Property, Plant and Equipment Expenditures	**$ 1,929**	$ 1,703	$ 226
Debt to Equity Ratio	**80:20**	80:20	–
Number of Domestic Customers	**1,892,685**	1,872,891	19,794
GWh Sold (Domestic)	**57,012**	52,197	4,815
Total Reservoir Storage (GWh)	**13,261**	14,061	(800)

REVENUES

Total revenue for the year ended March 31, 2013 was $4,898 million, an increase of $168 million or four per cent compared to the prior fiscal year primarily due to higher domestic revenues resulting from an increase in average customer rates and increased other energy sales (primarily surplus energy sales). These increases were partially offset by lower trade energy sales as a result of decreases in average natural gas and electricity prices.

	(in millions)		*(gigawatt hours)*	
for the years ended March 31	**2013**	2012	**2013**	2012
Domestic				
Residential	**$ 1,612**	$ 1,581	**17,703**	18,395
Light industrial and commercial	**1,436**	1,327	**18,384**	18,005
Large industrial	**642**	598	**13,508**	13,522
Other energy sales	**322**	236	**7,417**	2,275
Total Domestic Revenue Before Regulatory Transfer	**4,012**	3,742	**57,012**	52,197
Domestic rate smoothing and load variance regulatory transfer	**26**	6	**–**	–
Total Domestic	**$ 4,038**	$ 3,748	**57,012**	52,197
Trade				
Electricity – Gross	**$ 914**	$ 993	**30,975**	26,908
Less: forward electricity purchases[1]	**(187)**	(281)	**–**	–
Electricity – Net	**727**	712	**–**	–
Gas – Gross	**817**	1,010	**28,982**	27,640
Less: forward gas purchases[1]	**(684)**	(740)	**–**	–
Gas – Net	**133**	270	**–**	–
Total Trade[2]	**$ 860**	$ 982	**59,957**	54,548
Total Revenues	**$ 4,898**	$ 4,730	**116,969**	106,745

[1] *Forward purchases include derivatives which are deducted from gross sales in accordance with the Prescribed Standards.*
[2] *Trade revenue regulatory transfer is netted with the trade cost of energy transfer to reflect a trade margin transfer.*

DOMESTIC REVENUES

Total domestic revenues after regulatory transfers for the year ended March 31, 2013 were $4,038 million, an increase of $290 million or eight per cent over the prior fiscal year. The increase was due mainly to higher average customer rates, increased consumption by light industrial and commercial customers and higher other energy sales. High water inflows during primarily the summer months of fiscal 2013 resulted in surplus energy in excess of load requirements which must be either sold into the market or spilled. This resulted in an increase in the volume of Other energy sales compared to the prior year but at significantly lower prices.

Average customer rates were higher in fiscal 2013, reflecting an average rate increase of 3.91 per cent approved by the British Columbia Utilities Commission (BCUC) for fiscal 2013 and a Deferral Account Rate Rider (DARR) of 5 per cent for fiscal 2013 compared to a DARR of 2.5 per cent in effect in fiscal 2012.

Variances between actual and planned load are deferred to the Non-Heritage Deferral Account (NHDA) and variances between actual and planned other energy sales are deferred to either the Heritage Deferral Account (HDA) or NHDA.

TRADE REVENUES

Powerex, a wholly owned subsidiary of the Company, is a key participant in energy markets across North America, buying and supplying wholesale power, natural gas, ancillary services, financial energy products, and environmental products with an expanding list of trade partners.

The Company's electricity system is interconnected with systems in Alberta and the Western United States, facilitating sales and purchases of electricity outside of British Columbia. Powerex's trade activities help the Company balance its system by being able to import energy to meet domestic demand when there is a supply shortage and exporting energy when there is a supply surplus. Exports are made only after ensuring domestic demand requirements can be met.

Gross trade revenue for the year ended March 31, 2013 was $1,731 million, a decrease of $272 million compared with the same period in the prior year due to a decrease in gross gas revenue of $193 million and a decrease in gross electricity revenue of $79 million. The decrease in gross gas revenue was primarily driven by a 19 per cent decrease in the average gas price reflecting overall lower natural gas prices in North America following continued high shale gas production. The decrease in gross electricity revenue was primarily driven by a 12 per cent decrease in the average electricity sales price over the same period in the prior year, primarily due to lower Pacific Northwest prices as a result of higher hydro and wind generation. Deducted from gross trade revenues are forward purchases, which decreased by a net $150 million compared with the same period in the prior year, primarily due to a decrease in electricity and natural gas prices. Forward transactions are reported on a net basis in accordance with the Prescribed Standards. Variances between actual and planned trade income are deferred to the Trade Income Deferral Account (TIDA).

OPERATING EXPENSES

For the year ended March 31, 2013, total operating expenses of $3,849 million were $176 million higher than in the prior fiscal year. The increase over the prior year is due primarily to higher amortization and depreciation expense, higher expenditures on materials and services, lower capitalization of overhead costs and higher other operating costs.

COST OF ENERGY

Energy costs are comprised of electricity and gas purchases for domestic and trade customers, water rentals and transmission and other charges. Energy costs are influenced primarily by the volume of energy consumed by customers, the mix of sources of supply and market prices of energy. The mix of sources of supply is influenced by variables such as the current and forecast market prices of energy, water inflows, reservoir levels, energy demand, and environmental and social impacts.

Total energy costs, after regulatory account transfers, for the year ended March 31, 2013 were $1,806 million, $70 million or four per cent lower than in the prior fiscal year. The decrease was primarily due to lower trade energy purchases as a result of lower average natural gas and electricity prices. Energy costs are comprised of the following sources of supply:

	(in millions)		*(gigawatt hours)*		*($ per MWh)*	
for the years ended March 31	**2013**	2012	**2013**	2012	**2013**[3]	2012[3]
Domestic						
Water rental payments (hydro generation)[1]	**$ 348**	$ 357	**52,143**	49,784	**$ 7.15**	$7.16
Purchases from Independent Power Producers	**760**	749	**10,675**	10,827	**71.23**	69.22
Other electricity purchases - Domestic	**10**	18	**359**	840	**28.00**	21.92
Gas for thermal generation	**29**	32	**122**	143	**237.69**	224.92
Transmission charges and other expenses	**12**	5	**113**	110	**–**	–
Non-treaty storage	**(57)**	–	**–**	–	**–**	–
Allocation (to) from trade energy	**(21)**	(132)	**(883)**	(3,993)	**22.51**	31.07
Total Domestic Cost of Energy Before Regulatory Transfers	**1,081**	1,029	**62,529**	57,711	**17.29**	17.84
Domestic cost of energy regulatory transfers	**42**	71	**–**	–	–	–
Total Domestic	**$ 1,123**	$ 1,100	**62,529**	57,711	**$ 17.96**	$ 19.07
Trade						
Electricity - Gross	**$ 539**	$ 486	**29,824**	22,890	**$ 18.07**	$ 21.23
Less: forward electricity purchases[2]	**(187)**	(281)	**–**	–	**–**	–
Electricity - Net	**352**	205	**–**	–	**–**	–
Remarketed gas - Gross	**793**	972	**29,198**	27,976	**27.16**	34.74
Less: forward gas purchases[2]	**(684)**	(740)	**–**	–	**–**	–
Remarketed gas - Net	**109**	232	**–**	–	**–**	–
Transmission charges and other expenses	**209**	192	**–**	–	**–**	–
Allocation from (to) domestic energy	**21**	132	**883**	3,993	**22.51**	31.07
Total Trade Cost of Energy Before Regulatory Transfers	**691**	761	**59,905**	54,859	**13.31**	17.97
Trade net margin regulatory transfer	**(8)**	15	**–**	–	**–**	–
Total Trade	**$ 683**	$ 776	**59,905**	54,859	**$ 13.17**	$ 18.24
Total Energy Costs	**$ 1,806**	$ 1,876	**122,434**	112,570	**$ 15.62**	$ 18.67

[1] *Total GWh is net of storage exchange.*
[2] *Other electricity purchases in dollars include purchases for trade activities shown net of derivatives. Gigawatt hours (GWh) and $ per Megawattt hour (MWh) are shown at gross cost.*
[3] *Total cost per MWh includes other electricity purchases at gross cost.*

Domestic Energy Costs

Domestic energy costs before regulatory transfers of $1,081 million for the year ended March 31, 2013 were $52 million or five per cent higher than in the prior fiscal year primarily because of lower allocation to trade due to reduced net trade energy exports. With reduced net trade energy exports, higher inflows, lower load, and to manage risk of spill and reservoir levels, significantly higher hydro energy was generated and sold as surplus energy.

Independent Power Producer (IPP) volumes were lower as existing IPPs under-delivered due to outages or were subject to curtailment and dispatch agreements. Costs were higher as new IPPs came on line at higher contracted rates. With surplus energy, fewer market purchases were required in fiscal 2013 as compared to the prior fiscal year.

The Company has an agreement with Bonneville Power Administration (BPA) to operate Non-Treaty space at Mica. Under the agreement, when the Company releases water from its portion of non-treaty storage it is entitled to the value of additional energy flowing through the U.S. Federal Columbia River, as determined by the market price of energy at that time. As a result of renegotiation of the agreement in April 2012, the Company was entitled to $57 million for net releases from September 1, 2011 to April 1, 2012, and the current year net releases of water, which were reflected as a reduction to cost of energy.

Variances between actual and planned domestic cost of energy are transferred to the HDA and NHDA.

Trade Energy Costs

Gross trade energy costs for the year ended March 31, 2013 were $1,562 million, a decrease of $220 million compared with the same period in the prior year primarily due to a $179 million decrease in gross gas purchase costs and a $111 million decrease in the allocation from domestic energy, partly offset by a $53 million increase in gross trade electricity purchases. The decrease in gross gas purchases was due to a 22 per cent decrease in the average gas price, consistent with the decrease in gross gas revenue.Trade electricity purchase costs increased due to a 30 per cent increase in physical purchase volumes. Deducted from gross trade energy costs are forward purchases, which decreased by a net $150 million compared with the same period in the prior year, primarily due to a decrease in electricity and natural gas prices. Forward purchases are netted against forward sales within gross revenue in accordance with the Prescribed Standards. Variances between actual and planned trade income (which includes trade energy costs) are deferred to the Trade Income Deferral Account (TIDA).

Water Inflows

Usable system inflows for fiscal 2013 were 109 per cent of average, with inflows to the Williston Reservoir on the Peace River system at 111 per cent and the Kinbasket Reservoir on the Columbia River system at 112 per cent of average. Usable system inflows were approximately 108 per cent of average in fiscal 2012. During the summer of 2012, both Williston and Kinbasket reservoirs spilled substantial volumes of surplus water as a result of the high inflows, with the result that usable system inflows for fiscal 2013 were significantly less than total system inflows.

The Company's reservoirs have been managed such that the combined system storage at March 31, 2013 was 103 per cent of average (average for 1986 – 2011), with the Williston and Kinbasket reservoirs at 108 per cent and 82 per cent of average, respectively. In comparison, combined system storage at March 31, 2012 was 110 per cent of average.

PERSONNEL EXPENSES

Personnel costs for the year ended March 31, 2013 were $527 million as compared to $521 million in fiscal 2012. Personnel expenses include labour, benefits and post employment benefits for employees of the Company and were relatively consistent with the prior year end.

MATERIALS AND EXTERNAL SERVICES

Expenditures on materials and external services for the year ended March 31, 2013 of $606 million were $20 million higher than in the prior fiscal year, primarily the result of higher maintenance and other operational activities, including environmental risk management projects, repairs and maintenance of generation, transmission and distribution assets, and information technology expenditures.

CAPITALIZED COSTS

Capitalized costs are overhead costs incurred to support capital expenditures and are transferred from operating costs to property, plant and equipment. Under the Prescribed Standards there are less costs eligible for capitalization resulting in a decrease in property, plant and equipment and a corresponding increase in operating costs. The impact of this increase in operating costs in fiscal 2012 resulting from the application of the Prescribed Standards was $215 million. This amount was transferred to the IFRS Property, Plant and Equipment regulatory account and is being amortized over 40 years. In addition, the ongoing impact of this change is being smoothed into rates over a ten year period through transfers to the IFRS Property, Plant and Equipment regulatory account. As such, each year 1/10 more of ineligible costs will be charged to operating costs such that by the end of year ten, all ineligible costs will be charged to operating costs. Capitalized costs to either property, plant and equipment or the associated regulatory accounts for the year ended March 31, 2013 were $259 million, $22 million lower than capitalized costs of $281 million in the same period in the prior fiscal year.

AMORTIZATION AND DEPRECIATION

Amortization and depreciation expense includes the depreciation of property, plant and equipment, intangible assets, and the amortization of certain regulatory assets and liabilities. For the year ended March 31, 2013, amortization and depreciation expense was $953 million, $160 million or 20 per cent higher than in the prior fiscal year. The increase was primarily due to higher assets in service in the current year and higher net regulatory account amortization.

Increased net regulatory account amortization resulted primarily from higher recovery of energy deferral account balances due to the DARR of 5 per cent in effect in fiscal 2013 ($180 million recovery for the fiscal year) as compared to the DARR of 2.5 per cent in effect in fiscal 2012 ($88 million recovery for the fiscal year).

GRANTS AND TAXES

As a Crown Corporation, the Company is exempt from paying federal and provincial income taxes, but pays local government taxes and grants in lieu to municipalities and regional districts, and school tax to the Province on certain assets. Total grants and taxes for the year ended March 31, 2013 of $196 million, were comparable to total grants and taxes of $184 million in the prior fiscal year.

OTHER COSTS (RECOVERIES)

Other costs (recoveries) primarily include gains and losses on the disposal of assets and certain cost recoveries classified as operating costs. For the year ended March 31, 2013, other costs net of recoveries were $26 million higher than in the prior fiscal year. The increase was primarily due to higher losses incurred on asset disposals and retirements in the current fiscal year.

FINANCE CHARGES

Finance charges after net regulatory transfers for the year ended March 31, 2013 of $540 million were $41 million or 8 per cent higher than in the prior fiscal year. The increase is primarily due to higher planned volume of debt levels, higher planned lease charges, and lower planned recoveries primarily due to lower interest rate swap income and net higher planned regulatory charges in fiscal 2013 compared to the prior fiscal year. The increase was partially offset by higher capitalized interest during construction.

REGULATORY TRANSFERS

The Company presents its results and financial position under the Prescribed Standards. Under the Prescribed Standards, the Company applies the principles of IFRS plus ASC 980 to reflect the rate-regulated environment in which the Company operates. These Prescribed Standards allow for the deferral of costs and recoveries that under IFRS would otherwise be included in the determination of comprehensive income in the year the amounts are incurred. The deferred amounts are either recovered or refunded through future rate adjustments.

The use of regulatory accounts is common amongst regulated utility industries throughout North America. BC Hydro uses various regulatory accounts, in compliance with BCUC orders, in order to better match costs and benefits for different generations of customers, smooth out the rate impact of large non-recurring costs, and defer to future periods differences between forecast and actual costs or revenues. Regulatory accounts allow the Company to defer certain types of revenue and cost variances through transfers to and from the accounts which would otherwise be included in net income or other comprehensive income. The deferred amounts are then included in customer rates in future periods, subject to approval by the BCUC.

Net regulatory account transfers are comprised of the following:

for the years ended March 31 (in millions)	**2013**	2012
Variances between forecast and actual costs		
Energy deferral accounts	**$ (7)**	$ 24
Finance Charges	**(48)**	(26)
Non-Current Pension Cost	**184**	322
Other	**(4)**	10
	125	330
Deferral of costs for future recovery in rates		
Demand Side Management (DSM)	**148**	182
Site C	**67**	71
Smart Metering and Infrastructure (SMI)	**93**	56
Environmental Provisions	**52**	54
First Nations (payments/settlements)	**17**	151
IFRS Property, Plant and Equipment	**197**	246
Other	**7**	11
	581	771
Rate Smoothing Account	**(41)**	(70)
Amortization of regulatory accounts	**(321)**	(188)
Interest on regulatory accounts	**55**	48
Net change in regulatory accounts	**$ 399**	$ 891

Net regulatory account balances were as follows:

as at March 31 (in millions)	2013	2012
Energy Accounts		
Heritage Deferral Account	$ 70	$ 244
Non-Heritage Deferral Account	467	429
Trade Income Deferral Account	190	205
	727	878
Capital Accounts		
DSM	733	638
Site C	258	181
Capital Project Investigation Costs	40	45
SMI	192	92
	1,223	956
Forecast Variance Accounts		
Rate Smoothing Account	(111)	(70)
Non-Current Pension Cost	544	377
Foreign Exchange Gains and Losses	(100)	(103)
Contributions in Aid of Construction (CIA) Amortization	75	68
Finance Charges	1	49
Other Forecast Variance Accounts	73	103
	482	424
Non-Cash Accounts		
First Nation Negotiations, Litigation and Settlement Costs	553	543
Environmental Provisions	367	322
Future Removal and Site Restoration Costs	(88)	(104)
	832	761
IFRS Accounts		
IFRS Pension & Other Post Employment Benefits	723	762
IFRS Property, Plant and Equipment	447	254
	1,170	1,016
Total Regulatory Account Balance	$ 4,434	$ 4,035

For the year ended March 31, 2013, net additions after amortization to the Company's regulatory accounts were $399 million compared to prior year net additions of $891 million. The net asset balance in the regulatory asset and liability accounts as at March 31, 2013 was an asset of $4,434 million compared to an asset of $4,035 million at March 31, 2012.

Significant net additions to the regulatory accounts during the year ended March 31, 2013 included:

- Costs incurred on large projects deferred for future recovery in rates including DSM projects which support energy conservation, Site C, and SMI;
- Transfers to the Environmental Provisions regulatory account which reflect increases required to asbestos and PCB contamination provisions;
- Transfers to the IFRS Property, Plant and Equipment regulatory account to smooth the rate impact of overhead costs eligible for capitalization under CGAAP but not eligible under the Prescribed Standards as they are not considered directly attributable to the construction of capital assets;
- Transfers to the Non-Current Pension Cost regulatory account include variances that arise between forecast and actual non-current pension and other post employment benefit costs, which would otherwise be included in operating expenses as well as actuarial gains and losses, which are primarily driven by changes in the year over year discount rates.

Significant net decreases in the regulatory accounts during the period included:

- Transfers from the energy deferral accounts primarily due to the rate rider which is amortized pro rata to the Heritage Deferral Account, Non Heritage Deferral Account and the Trade Income Deferral account, partially offset by interest;
- Transfers from the Finance Charges regulatory account due to favourable variances to the forecast;
- Transfers from the Rate Smoothing regulatory account to smooth the rate increases over the three years covered by the Amended F2012-F2014 Revenue Requirements Application. The balance of the Rate Smoothing regulatory account will be fully drawn down by the end of fiscal 2014.

COMPARISON WITH SERVICE PLAN

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each February. BC Hydro's Service Plan for fiscal 2013 was filed in February 2012 (February 2012 Service Plan) and forecast net income at $566 million. Subsequent to the February 2012 Service Plan, on May 22, 2012 the Government issued Direction No. 3 to the BCUC which included, among other things, the setting of the interim rate increase for fiscal 2013 of 3.91 per cent as final and lowering the allowed rate of return on deemed equity for fiscal 2013 from 12.75 per cent to 11.73 per cent, which resulted in a reduced net income forecast for fiscal 2013. A revised Service Plan was filed in February 2013 (February 2013 Service Plan) with a net income of $516 million.

Domestic revenues were higher than the February 2013 Service Plan primarily due to higher other energy sales reflecting the higher surplus sales resulting from the high water inflows in fiscal 2013, partially offset by lower domestic load. The lower domestic load was principally due to less activity in the large industrial customer class resulting from the effect of low natural gas prices on the oil and gas sector, operational shutdowns in the mining sector and less activity in the wood manufacturing sector due to the slow U.S. housing market and lower demand from China. The favourable domestic revenue variance was partially offset by higher than forecast energy costs.

Higher than forecast trade revenue was offset by higher than forecast trade energy costs, resulting in a trade gross margin comparable to the February 2013 Service Plan.

Personnel, materials and external services expenditures, net of capitalized overhead costs, were comparable to the February 2013 Service Plan, as were amortization expense and grants and taxes and finance charges. Other expense was higher than the February 2013 Service Plan primarily due to unplanned write-offs of certain capital assets.

The table below provides an overview of BC Hydro's fiscal 2013 financial performance results, relative to its February 2012 Service Plan forecast and the February 2013 Service Plan. The results and forecasts form the basis upon which key performance targets are set.

Consolidated Statement of Operations[1,2]

(in millions)	Actual			February 2012 Service Plan	February 2013 Service Plan	Variance to February 2013 Service Plan	Forecast[5]		
	2011[3]	2012	2013	2013	2013		2014	2015	2016
Revenues									
Domestic	$ 3,438	$ 3,748	$ 4,038	$ 3,900	$ 3,971	$ 67	$ 4,214	$ 4,710	$ 5,122
Trade	578	982	860	1,320	689	171	711	775	783
	4,016	4,730	4,898	5,220	4,661	239	4,925	5,485	5,904
Expenses									
Operating Costs									
Cost of energy	1,415	1,876	1,806	2,209	1,578	(228)	1,687	1,966	2,077
Other operating expenses									
Personnel expenses, materials and external services[4]	834	801	840	849	843	3	851	875	920
Amortization	533	793	953	842	952	(1)	1,003	1,121	1,172
Finance Charges	435	499	540	525	541	1	597	661	788
Grants and taxes	184	184	196	195	195	(1)	205	212	220
Other	26	19	54	33	35	(19)	37	40	42
	3,427	4,172	4,389	4,653	4,145	(245)	4,380	4,874	5,220
Net Income	$ 589	$ 558	$ 509	$ 566	$ 516	$ (7)	$ 545	$ 611	$ 684

1 *Table may not add due to minor rounding.*
2 *F2012 to F2016 information was prepared in accordance with the Prescribed Standards and 2012 information has been restated to Prescribed Standards for comparative purposes. Financial information for F2011 was prepared in accordance with Canadian GAAP.*
3 *F2011 is not comparable to future years as it includes the integration of BCTC as at July 1, 2010. Therefore only 9 months of the integrated company are included in F2011.*
4 *These amounts are net of capitalized overhead and recoveries.*
5 *Revised BC Hydro Service Plan 2013/14 - 2015/16.*

PAYMENT TO THE PROVINCE

Under a Special Directive from the Province, the Company is required to make an annual payment to the Province (the Payment) on or before June 30 of each year. The Payment is equal to 85 per cent of the Company's net income for the most recently completed fiscal year unless the debt to equity ratio, as defined by the Special Directive, after deducting the Payment, is greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment is the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. The Payment accrued for the year ended March 31, 2013 is $215 million which is below 85 per cent of the Company's net income due to the 80:20 cap.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the year ended March 31, 2013, was $888 million, compared with cash flow provided by operating activities of $816 million in the prior fiscal year. The increase was primarily due to an increase in net income before regulatory transfers due to higher revenues and lower operating costs, partially offset by higher energy costs. The increase in cash flows was primarily offset by a reduction in working capital due to timing.

The long-term debt balance net of sinking funds at March 31, 2013 was $14.0 billion, compared with $12.8 billion at March 31, 2012. The increase was mainly as a result of net long-term bond issues totaling $1.3 billion ($1.2 billion par value). The increase was partially offset by a decrease in revolving borrowings of $110 million and net gains on economic hedging activities of $44 million.

PROPERTY, PLANT AND EQUIPMENT EXPENDITURES

Property, plant and equipment expenditures were as follows:

for the years ended March 31 (in millions)	**2013**	2012	Change
Distribution improvements and expansion	**$ 309**	$ 295	$ 14
Generation replacements and expansion	**421**	422	(1)
Transmission lines and substation replacements & expansion	**758**	533	225
Smart Metering and Infrastructure program	**258**	234	24
General, including computers and vehicles	**183**	219	(36)
Total Property, Plant and Equipment Expenditures	**$ 1,929**	$ 1,703	$ 226

Total property, plant and equipment expenditures presented in this table are different from the expenditures in the Consolidated Statement of Cash Flows due to the effect of accruals related to these expenditures. To reflect BC Hydro's transition to the Prescribed Standards in fiscal 2013, the March 31, 2012 total property, plant and equipment expenditures have been restated to $1,703 million from $1,917 million.

Distribution capital expenditures for the year ended March 31, 2013 were $14 million higher than the prior fiscal year. The increase is primarily due to more assets replaced in fiscal 2013 and more customer driven projects, offset by lower expenditures in system expansion and improvements.

Transmission capital expenditures for the year ended March 31, 2013 were $225 million higher compared to the prior fiscal year. The increase is primarily attributable to higher expenditures on several projects due to schedule advancements and other new projects added, partially offset by lower spend in fiscal 2013 on other projects, primarily the Vancouver City Central transmission project and the Columbia Valley Transmission (CVT) due to cost savings.

SMI capital expenditures were $24 million higher for the year ended March 31, 2013 compared to the prior fiscal year. The increase is due to the project being in full implementation phase in fiscal 2013 for all six delivery releases, whereas in fiscal 2012 it was focused on release 1 to 3. The purchase and installation of more expensive demand and energy meters starting in April 2012 also contributed to higher costs in fiscal 2013 compared to fiscal 2012.

General capital expenditures for the year ended March 31, 2013 were $36 million lower than the prior fiscal year due to decreases in spend on vehicle purchases and energy storage project costs incurred in fiscal 2012, partially offset by higher costs for the Surrey Trade Training Center Project, Transformation and Supply Chain information technology costs and interior space renovations.

ACCOUNTING CHANGES

EXPLANATION OF TRANSITION TO THE PRESCRIBED STANDARDS

On April 1, 2012, the Company adopted the financial reporting provisions prescribed by the Province pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* (BTAA) and Section 9.1 of the *Financial Administration Act* (FAA). The Company prepared its consolidated financial statements for the year ended March 31, 2013 in accordance with the principles of IFRS, except that in accordance with the aforementioned legislation, it applies regulatory accounting in accordance with ASC 980. The application of ASC 980 results in the Company recognizing in the statement of financial position the deferral and amortization of certain costs and recoveries that have been approved by the BCUC for inclusion in future customer rates. Absent the application of ACS 980, such costs and recoveries would otherwise be included in the determination of comprehensive income in the year the amounts are incurred. The comparative periods included in these financial statements have been restated to the Prescribed Standards. The Company's previously issued interim and annual financial statements prior to and including the year ended March 31, 2012 were prepared in accordance with CGAAP.

LEGAL PROCEEDINGS

Since 2000, Powerex has been named, along with other energy providers, in lawsuits and U.S. federal regulatory proceedings which seek damages and/or contract rescissions based on allegations that, during part of 2000 and 2001, the California wholesale electricity markets were unlawfully manipulated and energy prices were not just and reasonable. Powerex has obtained dismissals of all but one of the lawsuits. In the remaining lawsuit, the California Department of Water Resources (CDWR) has claimed that it was forced under duress to enter into numerous transactions with Powerex in 2001. Powerex has obtained an indefinite stay of the remaining lawsuit pending resolution of related proceedings before the Federal Energy Regulatory Commission (FERC).

FERC has approved a settlement agreement between FERC staff and Powerex that acknowledged that there was no evidence that Powerex engaged in any gaming or other improper practices with any other market participants, and further noted that Powerex was a valuable and reliable supplier to the California market throughout the energy crisis. FERC's approval of this settlement is currently being challenged by various California parties.

FERC decided earlier in the proceedings that certain market-wide refunds will have to be paid by energy providers to various California parties. The precise amount has not been determined and the timing of the refunds is unknown. FERC commenced an inquiry in April 2012 to consider whether individual sellers engaged in unlawful market activity during the summer of 2000, and if so, whether the unlawful activity affected the market clearing price. An initial decision unfavourable to Powerex and other respondents which is advisory only and has no force or effect was issued by a FERC trial judge in February 2013. Powerex and the other respondents will ask the FERC Commission to reject the initial decision in its entirety on the basis that it failed to provide the legal and factual analysis required by the Commission. The FERC Commission has complete discretion as to how it treats the decision and will likely issue a final order during calendar year 2014.

A FERC trial judge has determined that in the event Powerex and other energy providers improperly reported transactional data to FERC in 2000 and 2001, those reports did not hide an accumulation of market power which resulted in unreasonably high energy prices. The FERC Commission has issued a final order upholding the trial judge's decision. The California Parties are seeking a rehearing from FERC and if they are unsuccessful, it is likely they will commence appeal proceedings.

A FERC hearing will commence in August 2013 on the California parties' allegations of market manipulation by Powerex and other respondents in the Pacific Northwest (PNW) between January 2000 and June 2001, and to consider whether there should be refunds for PNW bilateral contract transactions.

Two other FERC proceedings involving allegations of wrongdoing against Powerex were dismissed by the FERC Commission in May 2011, and the California Parties filed requests for rehearing in both those proceedings. FERC has denied the rehearing request in both proceedings and the California Parties have appealed the dismissal and denial orders to the Ninth Circuit Court.

At March 31, 2013, Powerex was owed US $265 million (CDN $269 million) plus interest by the California Power Exchange (Cal Px) and the California Independent System Operator (CAISO) related to Powerex's electricity trade activities in California during the period covered by the lawsuits. As a result of defaults by a number of California utilities, the Cal Px and CAISO were unable to pay these amounts to Powerex. It is expected those receivables will be offset against any refunds that Powerex is required to pay.

Due to the ongoing nature of the regulatory and legal proceedings against Powerex, management cannot predict the outcomes of the claims against Powerex. Powerex has recorded provisions for uncollectible amounts and legal costs associated with the California energy crisis. These provisions are based on management's best estimates, and are intended to adequately provide for any exposure. However, the amounts that are ultimately collected or paid may differ from management's current estimates. Management has not disclosed the provision amounts or ranges of expected outcomes due to the potentially adverse effect on the process.

RATE REGULATION

In the process of regulating and setting rates for BC Hydro, the BCUC must ensure that the rates are sufficient to allow BC Hydro to provide reliable electricity service, meet its financial obligations, comply with government policy and achieve an annual rate of return on deemed equity (ROE). The annual rate of return is equal to the pre-income tax annual rate of return allowed by the BCUC to the most comparable investor-owned energy utility regulated under the *Utilities Commission Act*. This is in accordance with Heritage Special Direction No. HC2. The allowed rate of return for fiscal 2013 is 11.73 per cent, and is lower than the prior year's allowed rate of 14.38 per cent due to the expiration of the addition of 1.63 per cent to the allowed ROE as per OIC No. 074, which expired on March 31, 2012, and changes to the effective tax rate for FortisBC Energy Inc. upon which BC Hydro's rate of return is based.

On February 28, 2012, the BCUC initiated a Generic Cost of Capital (GCOC) Proceeding in order to review the setting of an appropriate rate of return on equity for a benchmark low-risk utility, among other issues. An oral hearing was held in December 2012 and on May 10, 2013 the BCUC issued its decision. The BCUC determined that the annual rate of return on equity for the benchmark low-risk utility (FortisBC Energy Inc.) should be reduced from 9.50 per cent to 8.75 per cent, effective January 1, 2013. The GCOC would normally directly affect BC Hydro's allowed annual rate of return for fiscal 2014, as the ROE of FortisBC Energy Inc., as noted above, is the basis for the calculation of BC Hydro's rate of return. However, the Province has requested that BC Hydro contribute to ongoing balanced budgets by maintaining its net income from the February 2013 budget, subject to minor adjustments to reflect year end actuals as of March 31, 2013.

DAWSON CREEK/CHETWYND AREA TRANSMISSION UPGRADE PROJECT

On July 11, 2011, the Company filed an application with the BCUC for a Certificate of Public Convenience and Necessity (CPCN) for the Dawson Creek/Chetwynd Area Transmission (DCAT) Upgrade Project. This project proposes to address electricity supply constraints in the southern Peace region of the province and meet significant forecasted load growth in that region attributable to the development of the Montney natural gas field. The project involves the construction of a new substation, a new 230 kV transmission line and the expansion of an existing substation at an estimated cost of approximately $250 million. The BCUC issued its Decision on the project on October 12, 2012 and agreed that the project as described in the application is needed, but it delayed issuing a CPCN until evidence of further consultation with the West Moberly First Nations had been undertaken. BC Hydro filed evidence of further consultation with the West Moberly First Nations on April 8, 2013, and the West Moberly First Nations issued a letter supporting BC Hydro's submissions. The additional consultation requirement for the project has resulted in an approximately twelve to fourteen month delay of the in-service date to Spring, 2015. On April 26, 2013, the BCUC issued CPCN Order No. C-5-13 in which it determined that the duty to consult the West Moberly First Nations had been adequately met and approving the CPCN for the project.

JOHN HART GENERATING STATION REPLACEMENT PROJECT

On May 25, 2012, BC Hydro filed an application for a CPCN for the John Hart Generating Station Replacement Project. This project involves replacing the existing three 1.8-kilometre long penstocks with a 2.1-kilometre tunnel through bedrock, constructing a replacement generating station beside the existing station, constructing a replacement water intake at the John Hart Spillway Dam, and building a new water bypass facility. Following a thorough review of the application, the project was found to be the most cost-effective long term solution and was approved by the BCUC on February 8, 2013, at an expected cost of $940 million. The first replacement generating unit is expected to be in service by 2017 with project completion by the end of 2018.

INDUSTRIAL ELECTRICITY POLICY REVIEW

Following a commitment to launch a public process on the retail access provisions of the Transmission Service Rate for industrial electricity customers made in November 2011, the Province committed to undertake an Industrial Electricity Policy Review over the next two years.

The Review was officially launched in late January 2013 when a three person panel was appointed by the Province. The main issue to be reviewed is with regard to changes to transmission voltage rates, or the regulatory framework within which those rates are established, and which could be made to advance the objectives of electricity conservation, economic development and take into account the current environmental policy. The panel is currently seeking comments from stakeholders, including BC Hydro, on the main issues under consideration. The final report with recommendations will be presented to Government no later than July 31, 2013.

RISK MANAGEMENT

BC Hydro is exposed to numerous risks, which can be broadly classified as either “Operating” or “Strategic” in nature. Operating risks arise from the construction, ownership, operation and decommissioning of the Company’s assets. The consequences of operating risks include safety, environmental, financial, reliability and reputational impacts and can range in scale from minor to catastrophic. Significant strategic risks include both long term and short term load/resource balance, exposure to commodity and financial market prices, stakeholder relationships and access to adequate funding. The potential consequences of these risks are similar to those of operating risks and can vary from minor to significant.

The Company strives to manage all the risks it faces on a cost effective basis, taking into account the potential reward to be gained in return for acceptance of the risk. The Company also strives to manage significant risks in conformity with the provisions of the international standard ISO 31000, “*Risk Management – Principles and Guidelines*”, or in conformity with the provisions of other externally recognized standards appropriate to the risk being managed.

The Board of Directors is accountable for all risks incurred by the Company and its subsidiaries. Authority for risk management is delegated to the Chief Executive Officer. The Chief Risk Officer is charged with the development of the enterprise risk management framework across all of the Company, which provides the basis for consistent application of risk management practices. The Board of Directors and management regularly review and discuss the risk profile of the organization and consider the nature and amount of risk incurred in the pursuit of the organization’s objectives.

OPERATING RISKS

The generation, transmission and distribution of electricity inherently results in certain safety risks to both the Company’s workers and the public. To manage worker, contractor and public safety, the Company invests in compliance with occupational safety and health regulations, education and training to support awareness and culture, safe asset design, barrier installation, safe work procedures, safety practice regulations and communications. The Company also prepares emergency response plans to limit injury and loss to life and to restore electric service on a timely basis.

Significant risks to the reliability of the Company's system include aging infrastructure, severe weather and natural disasters such as earthquakes. Reliability risks could also result from either a lack of available generation supply or the associated transmission capacity to meet customer demand. The Company manages these risks through long-term planning, asset maintenance and replacement programs, emergency response programs, a diverse supply of energy options, and through cooperative support arrangements with neighbouring utilities.

Dam Safety

The large dams, spillways and water passages represent potentially extreme consequence but low probability risks in terms of life, safety, financial, environmental and reputation loss. These risks are managed through a comprehensive dam safety management system involving dam safety professionals and experts. Dams are continually monitored and conditions compared against national and international best practices. Interim risk management plans and capital upgrade programs are initiated as required.

Environment

The Company is exposed to the risk of non-compliance with environmental regulations when there are impacts to fish and wildlife and their habitats, risks related to releases to the environment, such as hazardous materials, and risks related to not meeting regulatory administrative requirements, such as greenhouse gas reporting regulations. These risks are managed through the Company's environmental management systems, regulatory agreements, work procedures and a variety of site specific environmental risk management strategies.

STRATEGIC RISKS

Load/Energy Resource Balance

Variations in system inflows, market prices, and domestic load can significantly influence cost of energy. The system inflow energy for fiscal 2013 was 9 per cent above average, with unusually high water conditions and some flooding impacts during the spring and summer of 2012. The system inflow energy for fiscal 2014 is forecast to be about 1 per cent above normal. Net market sales for fiscal 2013 were approximately 6,500 GWh (equivalent to 12 per cent of our domestic load). For fiscal 2014, the current forecast of net market sales is 2,100 GWh (equivalent to 4 per cent of our domestic load).

Several factors constrain the Company's ability to use its stored system energy to meet load throughout the year. These factors include generating unit outages at major plants (forced outages and capital projects) as well as water management constraints which limit generation at the major plants during some periods. Even when the system has annual net energy sales, some electricity purchases are likely required during constrained periods of the year (e.g. late fall, winter, early spring), while electricity sales may be unavoidable during other periods to minimize spill from system reservoirs. The value of these purchases and sales is subject to market price risk.

Electricity demand is generally increasing as B.C.'s population increases. However, this demand can be variable for large industrial customers due to variability in export markets and world commodity prices, and the potential for major new loads such as Liquefied Natural Gas (LNG). The Company has been and continues to work closely with the Government and LNG project proponents on plans to meet these potentially very large demands. The Company regularly models the projected supply-demand balance of the system over the short term to plan optimum system operations and over the medium term to cost-effectively meet demand.

Relationships

First Nation traditional territories encompass the entire Province of British Columbia. The Canadian Constitution, in its most recent amendment of 1982, recognizes and affirms existing Aboriginal rights. While the Constitution refers to existing not new rights, it does not define these rights nor has it set out where these rights exist. These rights have also not been clearly defined by the Courts. The B.C. Treaty process is helping to create certainty with respect to Aboriginal rights; however, while there are 203 First Nations there are only a few modern day and historic treaties in the province. The Company's assets are all situated on First Nation traditional territories, reserve and/or treaty settlement lands. The Company has a comprehensive aboriginal relations program to ensure the organization understands and can proactively respond to First Nation communities priorities. Failure to do so could result in project delays, increased costs and could ultimately create operational issues.

Organizational Risk

The Company's voluntary attrition continues to be a concern among employees in trades and specialized technical roles. Project structures have been established to provide focused attraction and retention strategies for priority roles where voluntary attrition is a concern: Engineers, CPC Technologists, Power Line Technicians, Cable Splicers, Station Electricians, and Field Managers. The Company continues work on a strategic workforce plan for fiscal 2015 to fiscal 2024 to align with the Company's 10-Year Capital Plan and assess the potential gaps between long-term labour demand and supply, and propose strategies to close these gaps.

FINANCIAL RISKS

In meeting its financial performance targets, the Company faces many risks including uncertain economic conditions, variable costs and revenues as driven by energy costs, energy demand, interest and foreign exchange rates, pension obligations and energy trading results. Of these, risks associated with energy costs – specifically water inflows and energy market prices – are the largest. Tariff rates are set based upon the Company's cost forecast and allowed return on deemed equity. Many financial risks (differences between forecast and actual costs) associated with uncontrollable costs are mitigated through regulatory accounts. Increasing costs due to aging infrastructure, the modernization and refurbishment of the electricity system, the need for new supply and the need to manage environmental impacts create challenges for the Company in maintaining competitive rates. Regulatory accounts assist in matching costs and benefits for different generations of customers and to smooth the impact of large, non-recurring costs. However, the magnitude of these accounts poses a risk that our regulator will require an accelerated recovery of these deferred costs which would place further pressure on current operating and capital cost constraints if our rates are to remain competitive.

The Company satisfies its borrowing requirements through the Province of British Columbia. Through established policies and procedures the Company maintains a percentage of its debt portfolio subject to variable interest rate exposure (short-term debt). The Company has established a commercial paper facility with the province that is used to help manage the variability of forecasted cash flows, interest costs and liquidity risk. In addition, the Company uses fixed-for-floating interest rate swaps to assist in maintaining the exposure of variable interest rates to within the established risk limits. As a result, the Company has decreased the variable interest rate exposure as a percentage of the overall debt portfolio so as to help mitigate the interest rate risk associated with growing debt. In addition, management has increased the weighted average term to maturity of the portfolio and tries, when possible, to diversify the maturity schedule so as to reduce the amount of refinancing in any one year. While these steps assist in managing the risk in the near term, BC Hydro's ability to execute its capital plans over the long term is dependent on the ability to obtain financing on acceptable terms.

The Company's energy trading subsidiary, Powerex, is exposed to the risk of variable market prices and counterparties who might not meet their obligations. Powerex manages these risks by operating through defined limits that are regularly reviewed by both the Powerex and BC Hydro Boards of Directors.

FUTURE OUTLOOK

The Company's earnings can fluctuate significantly due to various non-controllable factors such as the level of water inflows, customer load, market prices for electricity and natural gas, weather, temperatures, interest rates and foreign exchange rates. The impact to net income of these non-controllable factors is largely mitigated through the use of regulatory accounts. The forecast for fiscal 2014 assumes average water inflows (100 per cent of average), customer load of 52,701 GWh, average market energy prices of US $29.23/MWh, short-term interest rates of 1.39 per cent, a U.S. dollar exchange rate of US $1.0119, a return on equity of 11.84 per cent, and an approved rate increase of 1.44 per cent for fiscal 2014.

EARNINGS SENSITIVITY

The following table shows the effect on earnings of changes in some key variables. The analysis is based on business conditions and production volumes forecast for fiscal 2014. Each separate item in the sensitivity analysis assumes the others are held constant. While these sensitivities are applicable to the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitude of changes.

The volatility between BC Hydro's plan and actual results are mostly mitigated through the use of BCUC-approved regulatory accounts.

Factor	Change	Approximate change in earnings before regulatory account transfers (in millions)	5 year high	5 year low	Fiscal 2013
Hydro generation[1]	1,000 GWh	$ 25	52,114 GWh	39,303 GWh	52,114 GWh
Electricity trade margins	+/-10%	20	n/a	n/a	n/a
Interest rates	+/- 1%	50	2.50%[2]	0.45%[2]	1.30%[2]
Exchange rates (US/ CDN)	$0.01	5	$1.01[3]	$0.89[3]	$1.00[3]
Weather	1°C change in average temperature	20	1.0°C[4]	-1.5 °C[4]	0.3°C[4]

[1] *Assumes change in hydro generation is offset by corresponding change in energy imports (i.e. increase in hydro generation is offset by decrease in energy imports).*

[2] *Interest rates are the average Canadian short-term interest rates (3-month Canadian Dollar Offered Rate).*

[3] *Exchange rates are the average US Dollar noon rates for F2009 to F2013.*

[4] *Weather high and low numbers represents the variance in degrees Celsius from the normal temperatures over the winter months November to March from 2008/09 to 2012/13. (-1.5 degrees lower than normal to 1.0 degrees higher than normal – normal is the 10-year rolling average).*

MANAGEMENT REPORT

The consolidated financial statements of British Columbia Hydro and Power Authority (BC Hydro) are the responsibility of management and have been prepared in accordance with the financial reporting provisions prescribed by the Province of British Columbia pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* and Section 9.1 of the *Financial Administration Act* (see Note 2(a)). The preparation of financial statements necessarily involves the use of estimates which have been made using careful judgement. In management's opinion, the consolidated financial statements have been properly prepared within the framework of the accounting policies summarized in the consolidated financial statements and incorporate, within reasonable limits of materiality, all information available at May 23, 2013. The consolidated financial statements have also been reviewed by the Audit & Finance Committee and approved by the Board of Directors. Financial information presented elsewhere in this Annual Report is consistent with that in the consolidated financial statements.

Management maintains systems of internal controls designed to provide reasonable assurance that assets are safeguarded and that reliable financial information is available on a timely basis. These systems include formal written policies and procedures, careful selection and training of qualified personnel and appropriate delegation of authority and segregation of responsibilities within the organization. An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit & Finance Committee.

The consolidated financial statements have been examined by independent external auditors. The external auditors' responsibility is to express their opinion on whether the consolidated financial statements, in all material respects, fairly present BC Hydro's financial position, comprehensive income and cash flows in accordance with financial reporting provisions prescribed by the Province of British Columbia pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* and Section 9.1 of the *Financial Administration Act* (see Note 2(a)). The Auditors' Report, which follows, outlines the scope of their examination and their opinion.

The Board of Directors, through the Audit & Finance Committee, is responsible for ensuring that management fulfills its responsibility for financial reporting and internal controls. The Audit & Finance Committee, comprised of directors who are not employees, meets regularly with the external auditors, the internal auditors and management to satisfy itself that each group has properly discharged its responsibility to review the financial statements before recommending approval by the Board of Directors. The Audit & Finance Committee also recommends the appointment of external auditors to the Board of Directors. The internal and external auditors have full and open access to the Audit & Finance Committee, with and without the presence of management.

Charles Reid
President and Chief Executive Officer

Cheryl Yaremko
Executive VP Finance & Chief Financial Officer

Vancouver, Canada
May 23, 2013

INDEPENDENT AUDITORS' REPORT

The Minister of Energy and Mines, Province of British Columbia and the Board of Directors of British Columbia Hydro and Power Authority:

We have audited the accompanying consolidated financial statements of British Columbia Hydro and Power Authority, which comprise the consolidated statements of financial position as at March 31, 2013, March 31, 2012 and April 1, 2011, the consolidated statements of comprehensive income, changes in equity and cash flows for the years ended March 31, 2013 and March 31, 2012, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with the financial reporting provisions prescribed by the Province of British Columbia pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* and Section 9.1 of the *Financial Administration Act* (see Note 2(a)), and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgement, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of British Columbia Hydro and Power Authority as at March 31, 2013, March 31, 2012 and April 1, 2011, and its consolidated financial performance and its consolidated cash flows for the years ended March 31, 2013 and March 31, 2012 in accordance with the financial reporting provisions prescribed by the Province of British Columbia pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* and Section 9.1 of the *Financial Administration Act* (see Note 2(a)).

KPMG LLP

Chartered Accountants

Vancouver, Canada

May 23, 2013

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

for the years ended March 31 (in millions)	**2013**	2012
Revenues		
Domestic	**$ 4,038**	$ 3,748
Trade	**860**	982
	4,898	4,730
Expenses		
Operating Expenses (Note 4)	**3,849**	3,673
Finance Charges (Note 5)	**540**	499
Net Income	**509**	558
Other Comprehensive Income (Loss):		
Effective portion of changes in fair value of derivatives designated as cash flow hedges	**(5)**	7
Reclassification to income on derivatives designated as cash flow hedges	**(10)**	(12)
Foreign currency translation gains	**2**	15
Other Comprehensive Income (Loss)	**(13)**	10
Total Comprehensive Income	**$ 496**	$ 568

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(in millions)	**As at March 31 2013**	As at March 31 2012	As at April 1 2011
ASSETS			
Current Assets			
Cash and cash equivalents (Note 7)	**$ 60**	$ 12	$ 27
Accounts receivable and accrued revenue (Note 8)	**721**	595	569
Inventories (Note 9)	**173**	142	126
Prepaid expenses	**201**	147	156
Current portion of derivative financial instrument assets (Note 18)	**83**	140	198
	1,238	1,036	1,076
Non-Current Assets			
Property, plant and equipment (Note 10)	**17,226**	15,991	15,019
Intangible assets (Note 11)	**438**	412	335
Regulatory assets (Note 12)	**4,741**	4,314	3,419
Sinking funds (Note 13)	**112**	105	97
Derivative financial instrument assets (Note 18)	**27**	42	27
	22,544	20,864	18,897
	$ 23,782	$ 21,900	$ 19,973
LIABILITIES AND EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities (Notes 14 and 19)	**$ 1,544**	$ 1,423	$ 1,594
Current portion of long-term debt (Note 15)	**3,288**	2,888	2,803
Current portion of derivative financial instrument liabilities (Note 18)	**172**	123	165
	5,004	4,434	4,562
Non-Current Liabilities			
Long-term debt (Note 15)	**10,846**	10,062	8,909
Regulatory liabilities (Note 12)	**307**	279	275
Derivative financial instrument liabilities (Note 18)	**94**	189	212
Contributions in aid of construction	**1,196**	1,106	1,012
Post employment benefits (Note 17)	**1,396**	1,182	845
Other long-term liabilities (Note 19)	**1,439**	1,429	1,277
	15,278	14,247	12,530
Shareholder's Equity			
Contributed surplus	**60**	60	60
Retained earnings	**3,369**	3,075	2,747
Accumulated other comprehensive income	**71**	84	74
	3,500	3,219	2,881
	$ 23,782	$ 21,900	$ 19,973

Commitments and Contingencies (Note 20)

See accompanying Notes to Consolidated Financial Statements.

Approved on Behalf of the Board:

Stephen Bellringer
Chairman

Tracey L. McVicar
Chair, Audit & Finance Committee

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(in millions)	Cumulative Translation Reserve	Unrealized Gains/(Losses) on Cash Flow Hedges	Total Accumulated Other Comprehensive Income	Contributed Surplus	Retained Earnings	Total
Balance, April 1, 2011	$ –	$ 74	$ 74	$ 60	$ 2,747	$ 2,881
Payment to the Province	–	–	–	–	(230)	(230)
Comprehensive Income (Loss)	15	(5)	10	–	558	568
Balance, March 31, 2012	$ 15	$ 69	$ 84	$ 60	$ 3,075	$ 3,219
Balance, April 1, 2012	$ 15	$ 69	$ 84	$ 60	$ 3,075	$ 3,219
Payment to the Province	–	–	–	–	(215)	(215)
Comprehensive Income (Loss)	2	(15)	(13)	–	509	496
Balance, March 31, 2013	$ 17	$ 54	$ 71	$ 60	$ 3,369	$ 3,500

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

for the years ended March 31 (in millions)	2013	2012
Operating Activities		
Net income	$ 509	$ 558
Regulatory account transfers	(720)	(1,079)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 12)	321	188
Amortization and depreciation expense	615	570
Unrealized gains on mark-to-market	(16)	(34)
Interest accrual	633	617
Other items	34	(9)
	1,376	811
Changes in:		
Accounts receivable and accrued revenue	(121)	(25)
Prepaid expenses	(54)	9
Inventories	(30)	(14)
Accounts payable, accrued liabilities and other long-term liabilities	210	514
Contributions in aid of construction	128	128
	133	612
Interest paid	(621)	(607)
Cash provided by operating activities	888	816
Investing Activities		
Property, plant and equipment and intangible asset expenditures	(1,810)	(1,610)
Cash used in investing activities	(1,810)	(1,610)
Financing Activities		
Long-term debt:		
Issued	1,535	1,372
Retired	(200)	(450)
Receipt of revolving borrowings	6,061	5,109
Repayment of revolving borrowings	(6,172)	(4,756)
Payment to the Province (Note 16)	(230)	(463)
Other items	(24)	(33)
Cash provided by financing activities	970	779
Increase (decrease) in cash and cash equivalents	48	(15)
Cash and cash equivalents, beginning of year	12	27
Cash and cash equivalents, end of year	$ 60	$ 12

See accompanying Notes to Consolidated Financial Statements.

NOTE 1: REPORTING ENTITY

British Columbia Hydro and Power Authority (BC Hydro) was established in 1962 as a Crown corporation of the Province of British Columbia (the Province) by enactment of the *Hydro and Power Authority Act*. As directed by the *Hydro and Power Authority Act*, BC Hydro's mandate is to generate, manufacture, conserve and supply power. BC Hydro owns and operates electric generation, transmission and distribution facilities in the province of British Columbia.

The consolidated financial statements of BC Hydro include the accounts of BC Hydro and its principal wholly-owned operating subsidiaries Powerex, Powertech Labs Inc., and Columbia Hydro Constructors Ltd., (collectively with BC Hydro, "the Company") including BC Hydro's one third interest in the Waneta Dam and Generating Facility (Waneta), a joint operation. All intercompany transactions and balances are eliminated upon consolidation.

The Company accounts for its one third interest in Waneta as a joint operation. The consolidated financial statements include the Company's proportionate share in Waneta, including its share of any liabilities and expenses incurred jointly with Teck Metals Ltd. and its revenue from the sale of the output in relation to Waneta.

NOTE 2: BASIS OF PRESENTATION

(a) Basis of Accounting

These consolidated financial statements have been prepared in accordance with the significant accounting policies as set out in Note 3. These policies have been established based on the financial reporting provisions prescribed by the Province pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* (BTAA) and Section 9.1 of the *Financial Administration Act* (FAA). In accordance with the directive issued by the Province's Treasury Board, BC Hydro is to prepare these consolidated financial statements in accordance with the accounting principles of International Financial Reporting Standards (IFRS), except that BC Hydro is to continue to apply regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980 (ASC 980), *Regulated Operations* (collectively the "Prescribed Standards"). The application of ASC 980 results in BC Hydro recognizing in the statement of financial position the deferral and amortization of certain costs and recoveries that have been approved by the British Columbia Utilities Commission (BCUC) for inclusion in future customer rates. Such costs and recoveries would otherwise be included in the determination of comprehensive income in the year the amounts are incurred.

BC Hydro's accounting policies with respect to its regulatory accounts are disclosed in Note 3(a) and the impact of the application of ASC 980 on these consolidated financial statements is described in Note 12. The accounting policies adopted under the Prescribed Standards have been applied consistently to all periods presented in these financial statements and by all subsidiaries of BC Hydro.

These are the Company's first consolidated financial statements prepared in accordance with the Prescribed Standards. In prior years, these financial statements were prepared in compliance with Canadian Generally Accepted Accounting Principles (CGAAP). In preparing these statements, management has amended certain accounting methods previously applied in the CGAAP consolidated financial statements to comply with the Prescribed Standards. The comparative figures for the prior year were restated to reflect these amendments. An explanation of how the transition to the Prescribed Standards has affected the reported financial position, financial performance and cash flows of the Company is provided in Note 22.

Certain amounts in the prior year's comparative figures have been reclassified to conform to the current year's presentation.

These consolidated financial statements were approved by the Board of Directors on May 23, 2013.

(b) Basis of Measurement

The consolidated financial statements have been prepared on the historical cost basis except for financial instruments that are accounted for according to the financial instrument categories as defined in Note 3(j) and the post employment benefits obligation as described in Note 3(n).

(c) Functional and Presentation Currency

The functional currency of BC Hydro and all of its subsidiaries, except for Powerex, is the Canadian dollar. Powerex's functional currency is the U.S. dollar. These consolidated financial statements are presented in Canadian dollars and financial information has been rounded to the nearest million.

(d) Key Assumptions and Significant Judgements

The preparation of financial statements in conformity with the Prescribed Standards requires management to make judgements, estimates and assumptions in respect of the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from those judgements, estimates, and assumptions.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized in the period in which the estimates are revised and in any future periods affected. Information about significant areas of judgement, estimates and assumptions in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements is as follows:

(i) Retirement Benefit Obligation

BC Hydro operates a defined benefit statutory pension plan for its employees which is accounted for in accordance with IAS 19, *Employee Benefits*. Actuarial valuations are based on key assumptions which include employee turnover, mortality rates, discount rates, earnings increases and expected rate of return on retirement plan assets. Judgement is exercised in determining these assumptions. The assumptions adopted are based on prior experience, market conditions and advice of plan actuaries. Future results are impacted by these assumptions including the accrued benefit obligation and current service cost. See Note 17 for significant benefit plan assumptions.

(ii) Provisions and Contingencies

Management is required to make judgements to assess if the criteria for recognition of provisions and contingencies are met, in accordance with IAS 37, *Provisions, Contingent Liabilities and Contingent Assets*. IAS 37 requires that a provision be recognized where there is a present obligation as a result of a past event, it is probable that transfer of economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Key judgements are whether a present obligation exists and the probability of an outflow being required to settle that obligation.

Key assumptions in measuring recorded provisions include the timing and amount of future payments and the discount rate applied in valuing the provision.

The Company and its subsidiary Powerex, are currently defending certain lawsuits where management must make judgements, estimates and assumptions about the final outcome, timing of trial activities and future costs as at the period end date. Management has obtained the advice of its external counsel in determining the likely outcome and estimating the expected costs associated with these lawsuits; however, the ultimate outcome or settlement costs may differ from management's estimates.

(iii) Financial Instruments

The Company enters into financial instrument arrangements which require management to make judgements to determine if such arrangements are derivative instruments in their entirety or contain embedded derivatives, including whether those embedded derivatives meet the criteria to be separated from their host contract, in accordance with IAS 39, *Financial Instruments: Recognition and Measurement*. Key judgements are whether certain non-financial items are readily convertible to cash, whether similar contracts are routinely settled net in cash or delivery of the underlying commodity taken and then resold within a short period, whether the value of a contract changes in response to a change in an underlying rate, price, index or other variable, and for embedded derivatives, whether the economic risks and characteristics are not closely related to the host contract and a separate instrument with the same terms would meet the definition of a derivative on a standalone basis.

Valuation techniques are used in measuring the fair value of financial instruments when active market quotes are not available. Valuation of the Company's financial instruments is based in part on forward prices which are volatile and therefore the actual realized value may differ from management's estimates.

(iv) Leases

The Company enters into long-term energy purchase agreements that may be considered to be, or contain a lease. In making this determination, judgement is required to determine whether the fulfillment of an arrangement is dependent on the use of a specific asset, and whether the arrangement conveys a right to use the asset. For those arrangements considered to be, or contain, an embedded lease, further judgement is required to determine whether to account for the agreement as either a finance or operating lease by assessing whether substantially all of the significant risks and rewards of ownership are transferred to the Company or remain with the counterparty to the agreement. The measurement of finance leases requires the estimate of the amount and timing of future cash flows and the determination of an appropriate discount rate.

NOTE 3: SIGNIFICANT ACCOUNTING POLICIES

(a) Rate Regulation

BC Hydro is regulated by the BCUC and both entities are subject to directives and directions issued by the Province. BC Hydro operates under a cost of service regulation as prescribed by the BCUC. Orders in Council from the Province establish the basis for determining BC Hydro's equity for regulatory purposes, as well as its allowed return on equity and the annual Payment to the Province. Calculation of its revenue requirements and rates charged to customers are established through applications filed with and approved by the BCUC.

BC Hydro applies the principles of ASC 980, which differs from IFRS, to reflect the impacts of the rate-regulated environment in which BC Hydro operates (see Note 12). Generally, this results in the deferral and amortization of costs and recoveries to allow for adjustment of future customer rates. In the absence of rate-regulation, these amounts would otherwise be included in the determination of comprehensive income in the year the amounts are incurred. BC Hydro capitalizes as a regulatory asset all or part of an incurred cost that would otherwise be charged to expense or other comprehensive income if it is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes and the future rates and revenue approved by the BCUC will permit recovery of that incurred cost. Regulatory liabilities are recognized for certain gains or other reductions of net allowable costs for adjustment of future rates as determined by the BCUC.

These accounting policies support BC Hydro's rate regulation and regulatory accounts have been established through ongoing application to, and approval by, the BCUC. When a regulatory account has been or will be applied for, and, in management's estimate, acceptance of deferral treatment by the BCUC is considered probable, BC Hydro defers such costs in advance of a final decision of the BCUC. If the BCUC subsequently denies the application for regulatory treatment, the remaining deferred amount is recognized immediately in comprehensive income.

(b) Revenue

Domestic revenues comprise sales to customers within the province of British Columbia and sales of firm energy outside the province under long-term contracts that are reflected in the Company's domestic load requirements. Other sales outside the province are classified as trade.

Revenue is recognized at the time energy is delivered to the Company's customers, the amount of revenue can be measured reliably and collection is reasonably assured. Revenue is determined on the basis of billing cycles and also includes accruals for electricity deliveries not yet billed.

Energy trading contracts that meet the definition of a financial or non-financial derivative are accounted for at fair value whereby any realized gains and losses and unrealized changes in the fair value are recognized in trade revenues in the period the change occurred.

Energy trading and other contracts which do not meet the definition of a derivative are accounted for on an accrual basis whereby the realized gains and losses are recognized as revenue as the contracts are settled. Such contracts are considered to be settled when, for the sale of products, the significant risks and rewards of ownership transfer to the buyer, and for the sale of services, those services are rendered.

(c) Finance Income and Charges

Finance income comprises income earned on sinking fund investments held for the redemption of long-term debt, the expected return on defined benefit plan assets, foreign exchange gains and realized hedging instrument gains that are recognized in the statement of comprehensive income, excluding energy trading contracts.

Finance charges comprise interest expense on borrowings, accretion expense on provisions and other long-term liabilities, interest on defined benefit obligations, interest on finance lease liabilities, foreign exchange losses and realized hedging instrument losses that are recognized in the statement of comprehensive income. All borrowing costs are recognized using the effective interest rate method.

Finance costs exclude borrowing costs attributable to the construction of qualifying assets, which are assets that take more than six months to prepare for their intended use.

(d) Foreign Currency

Foreign currency transactions are translated into the respective functional currencies of BC Hydro and its subsidiaries, using the exchange rates prevailing at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies at the reporting date are re-translated to the functional currency at the exchange rate in effect at that date. The foreign currency gains or losses on monetary items is the difference between the amortized cost in the functional currency at the beginning of the period, adjusted for effective interest and payments during the period, and the amortized cost in the foreign currency translated at the exchange rate at the end of the reporting period. Non-monetary items that are measured in terms of historical cost in a foreign currency are translated using the exchange rate at the date of the transaction.

For purposes of consolidation, the assets and liabilities of Powerex, whose functional currency is the US dollar, are translated to Canadian dollars using the rate of exchange in effect at the reporting date. Revenue and expenses of Powerex are translated to Canadian dollars at exchange rates at the date of the transactions. Foreign currency differences resulting from translation of the accounts of Powerex are recognized directly in other comprehensive income and are accumulated in the cumulative translation reserve.

Foreign exchange gains or losses arising from a monetary item receivable from or payable to Powerex, the settlement of which is neither planned nor likely in the foreseeable future and which in substance is considered to form part of a net investment in Powerex by BC Hydro, are recognized directly in other comprehensive income in the cumulative translation reserve.

(e) Property, Plant and Equipment

(i) Recognition and measurement

Property, plant and equipment in service are measured at cost less accumulated depreciation and accumulated impairment losses.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials, direct labor and any other costs directly attributable to bringing the asset into service. The cost of dismantling and removing an item of property, plant and equipment and restoring the site on which it is located is estimated and capitalized only when, and to the extent that, the Company has a legal or constructive obligation to dismantle and remove such asset. Property, plant and equipment in service include the cost of plant and equipment financed by contributions in aid of construction. Borrowing costs that are directly attributable to the acquisition or construction of a qualifying asset are capitalized as part of the cost of the qualifying asset. Upon retirement or disposal, any gain or loss is recognized in the statement of comprehensive income.

Government grants related to assets are deducted from the carrying value of the related asset. Government grants include contributions arising from the Columbia River Treaty related to three dams built by the Company in the mid-1960s to regulate the flow of the Columbia River. The contributions were made to assist in financing the construction of the dams. The contributions were deducted from the carrying value of the related dams.

Unfinished construction consists of the cost of property, plant and equipment that is under construction or not ready for service. Costs are transferred to property, plant and equipment in service when the constructed asset is capable of operation in a manner intended by management.

(ii) Subsequent costs

The cost of replacing a component of an item of property, plant and equipment is recognized in the carrying amount of the item if it is probable that the future economic benefits embodied within the component will flow to the Company, and its cost can be measured reliably. The carrying amount of the replaced component is derecognized. The costs of property, plant and equipment maintenance are recognized in the statement of comprehensive income as incurred.

(iii) Depreciation

Property, plant and equipment in service are depreciated over the expected useful lives of the assets, using the straight-line method. When major components of an item of property, plant and equipment have different useful lives, they are accounted for as separate items of property, plant and equipment.

The expected useful lives, in years, of the Company's main classes of property, plant and equipment are:

Generation	15 – 100
Transmission	20 – 65
Distribution	20 – 60
Buildings	5 – 60
Equipment & Other	3 – 35

The expected useful lives and residual values of items of property, plant and equipment are reviewed annually.

Depreciation of an item of property, plant and equipment commences when the asset is available for use and ceases at the earlier of the date the asset is classified as held for sale and the date the asset is derecognized.

(f) Intangible Assets

Intangible assets are recorded at cost less accumulated amortization and accumulated impairment losses. Land rights associated with statutory rights of way acquired from the Province that have indefinite useful lives and are not subject to amortization. Intangible assets with finite useful lives are amortized over their expected useful lives on a straight line basis. These assets are tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset value may not be fully recoverable. The expected useful lives, in years, are as follows:

Software	2 – 10
Sundry	10 – 20

Amortization of intangible assets commences when the asset is available for use and ceases at the earlier of the date that the asset is classified as held for sale and the date that the asset is derecognized.

(g) Asset Impairment

(i) Financial assets

Financial assets, other than those measured at fair value, are assessed at each reporting date to determine whether there is impairment. A financial asset is impaired if evidence indicates that a loss event has occurred after the initial recognition of the asset, and that the loss event had a negative effect on the estimated future cash flows of that asset that can be estimated reliably.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the asset's original effective interest rate. An impairment loss in respect of an available-for-sale financial asset is calculated by reference to its fair value.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in net income. Any cumulative loss in respect of an available-for-sale financial asset previously recognized in other comprehensive income and presented in unrealized gains/losses on available-for-sale financial assets in equity is transferred to net income.

An impairment loss is reversed if the reversal can be related to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost and available-for-sale financial assets that are debt securities, the reversal is recognized in net income.

(ii) Non-financial assets

The carrying amounts of the Company's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. For intangible assets that have indefinite useful lives or that are not yet available for use, the recoverable amount is estimated annually.

For the purpose of impairment testing, assets that cannot be tested individually are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit, or CGU"). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. All of BC Hydro's assets form one CGU for the purposes of testing for impairment.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in net income. Impairment losses recognized in respect of a CGU are allocated to reduce the carrying amounts of the assets in the CGU on a pro-rata basis.

Impairment losses recognized in prior periods are assessed at the reporting date for any indications that the loss has decreased or no longer exists. Impairment reversals are recognized immediately in net income when the recoverable amount of an asset increases above the impaired net book value, not to exceed the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized for the asset in prior years.

(h) Cash and Cash Equivalents

Cash and cash equivalents include unrestricted cash and units of a money market fund that are redeemable on demand and are carried at amortized cost.

(i) Inventories

Inventories are comprised primarily of natural gas, materials, and supplies. Inventories are valued at the lower of cost determined on a weighted average basis and net realizable value. The cost of inventories comprises all costs of purchase, costs of conversion and other directly attributable costs incurred in bringing the inventories to their present location and condition. Net realizable value is the estimated selling price in the ordinary course of business, less the estimated selling expenses.

(j) Financial Instruments

(i) Financial Instruments – Recognition and Measurement

All financial instruments are required to be measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods depends on which of the following categories the financial instrument has been classified as: fair value through profit or loss, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities as defined by the standard. Transaction costs are expensed as incurred for financial instruments classified or designated as fair value through profit or loss. For other financial instruments, transaction costs are included in the carrying amount. All regular-way purchases or sales of financial assets are accounted for on a settlement date basis.

Financial assets and financial liabilities classified as fair value through profit or loss are subsequently measured at fair value with changes in those fair values recognized in net income. Financial assets classified as available-for-sale are subsequently measured at fair value, with changes in those fair values recognized in other comprehensive income until realized. Financial assets classified as held-to-maturity, loans and receivables, and financial liabilities classified as other financial liabilities are subsequently measured at amortized cost using the effective interest method of amortization less any impairment. Derivatives, including embedded derivatives that are not closely related to the host contract and are separately accounted for are generally classified as fair value through profit or loss and recorded at fair value in the consolidated statement of financial position.

The following table presents the classification of financial instruments in the various categories:

Category	Financial Instruments
Financial assets and liabilities at fair value through profit or loss	Short-term investments Designated long-term debt Derivatives not in a hedging relationship
Held to Maturity	US dollar sinking funds
Available for sale financial assets	US dollar sinking funds held in units of a money market fund
Loans and receivables	Cash Accounts receivable and other receivables
Other financial liabilities	Accounts payable and accrued liabilities Revolving borrowings Long-term debt (including current portion due in one year) Finance lease obligations and First Nations liabilities presented in other long-term liabilities

(ii) Fair Value

The fair value of financial instruments reflects changes in the level of commodity market prices, interest rates, foreign exchange rates and credit risk. Fair value is the amount of consideration that would be agreed upon in an arm's length transaction between knowledgeable willing parties who are under no compulsion to act.

Fair value amounts reflect management's best estimates considering various factors including closing exchange or over-the-counter quotations, estimates of future prices and foreign exchange rates, time value of money, counterparty and own credit risk, and volatility. The assumptions used in establishing fair value amounts could differ from actual prices and the impact of such variations could be material. In certain circumstances, Powerex uses valuation inputs that are not based on observable market data and internally developed valuation models which are based on models and techniques generally recognized as standard within the energy industry.

The fair values of financial instruments are classified as Level 1, 2 or 3 as defined below:

Level 1 values are quoted prices (unadjusted) in active markets for identical assets and liabilities.

Level 2 inputs are those other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, as of the reporting date.

Level 3 inputs are those that are not based on observable market data.

(iii) Derivative Financial Instruments

The Company uses derivative financial instruments to manage interest rate and foreign exchange risks related to debt and to manage risks related to electricity and natural gas commodity transactions.

Interest rate and foreign exchange related derivative instruments that are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded at fair value as either an asset or liability with changes in fair value recognized in net income. For liability management activities, the related gains or losses are included in finance charges. For foreign currency exchange risk associated with electricity and natural gas commodity transactions, the related gains or losses are included in domestic revenues. The Company's policy is to not utilize interest rate and foreign exchange related derivative financial instruments for speculative purposes.

Derivative financial instruments are also used by Powerex to manage economic exposure to market risks relating to commodity prices. Derivatives used for energy trading activities that are not designated as hedges are recorded using the market-to-market method of accounting whereby instruments are recorded at fair value as either an asset or liability with changes in fair value recognized in net income. Gains or losses are included in trade revenues.

(iv) Hedges

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for unrealized gains or losses attributable to the hedged risk and recognized in net income. Changes in the fair value of the hedged item attributed to the hedged risk, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net income. When hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to net income over the remaining term of the original hedging relationship, using the effective interest method of amortization.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income. The ineffective portion is recognized in net income. The amounts recognized in accumulated other comprehensive income are reclassified to net income in the periods in which net income is affected by the variability in the cash flows of the hedged item. When hedge accounting is discontinued the cumulative gain or loss previously recognized in accumulated other comprehensive income remains there until the forecasted transaction occurs. When the hedged item is a non-financial asset or liability, the amount recognized in accumulated other comprehensive income is transferred to the carrying amount of the asset or liability when it is recognized. In other cases the amount recognized in accumulated other comprehensive income is transferred to net income in the same period that the hedged item affects net income.

Hedge accounting is discontinued prospectively when the derivative no longer qualifies as an effective hedge, the hedging relationship is discontinued, or the derivative is terminated or sold, or upon the sale or early termination of the hedged item.

(k) Investments Held in Sinking Funds

Investments held in sinking funds are held as individual portfolios and are classified as held to maturity. Securities included in an individual portfolio are recorded at cost, adjusted by amortization of any discounts or premiums arising on purchase, on a yield basis over the estimated term to settlement of the security. Realized gains and losses are included in sinking fund income.

(l) Deferred Revenue – Skagit River Agreement

Deferred revenue consists principally of amounts received under the agreement relating to the Skagit River, Ross Lake and the Seven Mile Reservoir on the Pend d'Oreille River (collectively, "the Skagit River Agreement").

Under the Skagit River Agreement, the Company has committed to deliver a predetermined amount of electricity each year to the City of Seattle for an 80-year period ending in fiscal 2066 in return for two annual payments of approximately US$22 million per year for a 35 year period ending in 2021 and US$100,000 (adjusted for inflation) per year for the 80-year period ending in 2066. The amounts received under the agreement are deferred and included in income on an annuity basis over the electricity delivery period ending in fiscal 2066.

(m) Contributions in Aid of Construction

Contributions in aid of construction are amounts paid by certain customers toward the cost of property, plant and equipment required for the extension of services to supply electricity. These amounts are recognized into revenue over the expected useful life of the related assets, as the associated contracts do not have a finite period over which service is provided.

(n) Post Employment Benefits

The cost of pensions and other post employment benefits earned by employees is actuarially determined using the projected accrued benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. The expected long-term rate of return on plan assets is used to calculate the income on plan assets. The obligations are discounted using a market interest rate at the end of the year on high-quality corporate debt instruments that match the timing and amount of expected benefit payments.

Past service costs are recognized as an expense on a straight-line basis over the average period until the benefits become vested. If the benefits have already vested, immediately following the introduction of, or changes to, a defined benefit plan, past service costs are recognized in earnings immediately.

A plan curtailment will result if the Company has demonstrably committed to a significant reduction in the expected future service of active employees or a significant element of future service by active employees no longer qualifies for benefits. A curtailment is recognized when the event giving rise to the curtailment occurs.

The expected return on plan assets and the interest cost on the defined benefit plan liabilities arising from the passage of time are included in finance income and finance costs, respectively. The Company recognizes actuarial gains and losses immediately in other comprehensive income. The amount recognized in other comprehensive income is subsequently transferred to a regulatory asset account for inclusion in future rates.

(o) Provisions

A provision is recognized if the Company has a present legal or constructive obligation as a result of a past event, it is probable that an outflow of economic benefits will be required to settle the obligation and a reliable estimate of the obligation can be determined. For obligations of a long-term nature, provisions are measured at their present value by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability except in cases where future cash flows have been adjusted for risk.

Decommissioning Obligations

Decommissioning obligations are legal and constructive obligations associated with the retirement of long-lived assets. A liability is recorded at the present value of the estimated future costs based on management's best estimate. When a liability is initially recorded, the Company capitalizes the costs by increasing the carrying value of the asset. The increase in net present value of the provision for the expected cost is included in finance costs as accretion (interest) expense.

Adjustments to the provision made for changes in timing, amount of cash flow and discount rates are capitalized and amortized over the useful life of the associated asset. Actual costs incurred upon settlement of a decommissioning obligation are charged against the related liability. Any difference between the actual costs incurred upon settlement of the decommissioning obligation and the recorded liability is recognized in net income at that time.

Environmental Expenditures and Liabilities

Environmental expenditures are expensed as part of operating activities, unless they constitute an asset improvement or act to mitigate or prevent possible future contamination, in which case the expenditures are capitalized and amortized to income. Environmental liabilities arising from a past event are accrued when it is probable that a present legal or constructive obligation will require the Company to incur environmental expenditures.

Legal

The Company is currently defending certain lawsuits where the final outcome and costs are not able to be determined as at period end. Management obtains the advice of its external counsel in determining the likely outcome and estimating the expected costs associated with lawsuits. Further information regarding lawsuits in progress is disclosed in Note 20, Commitments and Contingencies.

(p) Leases

Embedded Leases

The Company may enter into an arrangement that does not take the legal form of a lease but conveys a right to use an asset in return for a payment or series of payments. Arrangements in which a party conveys a right to the Company to use an asset may in substance be, or contain, a lease that should be accounted for as either a finance or operating lease. Determining whether an arrangement is, or contains, a lease requires an assessment of whether fulfilment of the arrangement is dependent on the use of a specific asset; and whether the arrangement conveys a right to use the asset. The right to use an asset is conveyed if the right to operate or control physical access to the underlying asset is provided or if the Company consumes substantially all of the output of the asset and the price paid for the output is neither contractually fixed per unit of output nor equal to the current market price.

Finance Leases

Leases where substantially all of the benefits and risk of ownership rest with the Company are accounted for as finance leases. Finance leases are recognized as assets and liabilities at the lower of the fair value of the asset and the present value of the minimum lease payments at the date of acquisition. Finance costs represent the difference between the total leasing commitments and the fair value of the assets acquired. Finance costs are charged to net income over the term of the lease at interest rates applicable to the lease on the remaining balance of the obligations. Assets under finance leases are depreciated on the same basis as property, plant and equipment or over the term of the relevant lease, whichever is shorter.

Operating Leases

Leases where substantially all of the benefits and risk of ownership remain with the lessor are accounted for as operating leases. Rental payments under operating leases are expensed to net income on a straight-line basis over the term of the relevant lease. Benefits received and receivable as an incentive to enter into an operating lease are recognized as an integral part of the total lease expense and are recorded on a straight-line basis over the term of the lease.

(q) Taxes

The Company pays local government taxes and grants in lieu to municipalities and regional districts. As a Crown corporation, the Company is exempt from Canadian federal and provincial income taxes.

(r) Jointly Controlled Assets

The Company has joint ownership of assets which are jointly controlled with a third party. A jointly controlled asset exists when there is a joint ownership and control of one or more assets to obtain benefits for the venturers. Each venture takes a share of the output from the assets for its own exclusive use. These consolidated financial statements include the Company's share of the jointly controlled assets. The Company also records its share of any liabilities and expenses incurred jointly with the third party and any revenue from the sale or use of its share of the output in relation to the assets.

(s) New Standards and Interpretations Not Yet Adopted

A number of new standards, and amendments to standards and interpretations, are not yet effective for the year ended March 31, 2013, and have not been applied in preparing these consolidated financial statements. In particular, the following new and amended standards become effective for the Company's annual periods beginning on or after the dates noted below:

- IFRS 9, *Financial Instruments* (effective April 1, 2015)
- IFRS 10, *Consolidated Financial Statements* (effective April 1, 2013)
- IFRS 11, *Joint Arrangements* (effective April 1, 2013)
- IFRS 12, *Disclosure of Interests in Other Entities* (effective April 1, 2013)
- IFRS 13, *Fair Value Measurement* (effective April 1, 2013)
- Amendments to IAS 1, *Presentation of Financial Statements* (effective April 1, 2013)
- Amendments to IAS 19, *Employee Benefits* (effective April 1, 2013)
- IAS 28, *Investments in Associates and Joint Ventures* (effective April 1, 2013)
- Amendments to IAS 32 and IFRS 7, *Offsetting Financial Assets and Liabilities* (effective April 1, 2014 and April 1, 2013, respectively)

The Company does not have any plans to early adopt any of the new or amended standards. It is anticipated that the standards effective for the Company's fiscal 2014 will not have a material effect on the consolidated financial statements, except for the Amendments to IAS 19, *Employee Benefits*, which may have a material effect on the measurement of employee benefit costs. The impacts of the Amendments to IAS 19 on the measurement of employee benefit costs are expected to be mitigated by the application of regulatory accounting for fiscal 2014. The extent of the impact has not been determined.

NOTE 4: OPERATING EXPENSES

(in millions)	2013	2012
Electricity and gas purchases	$ 1,291	$ 1,382
Water rentals	352	346
Transmission charges	163	148
Personnel expenses	527	521
Materials and external services	606	586
Amortization and depreciation (Note 6)	953	793
Grants and taxes	196	184
Capitalized costs	(259)	(281)
Other costs (recoveries)	20	(6)
Total	$ 3,849	$ 3,673

NOTE 5: FINANCE CHARGES

(in millions)	2013	2012
Interest on long-term debt	$ 647	$ 612
Interest on finance lease liabilities	27	23
Interest on defined benefit plan obligations	197	189
Less: capitalized interest	(73)	(49)
Total finance costs	798	775
Expected return on defined benefit plan assets	(183)	(176)
Other costs (recoveries)	(75)	(100)
Total	$ 540	$ 499

Capitalized interest presented in the table above is net of regulatory transfers. Actual interest capitalized to property, plant and equipment and intangible assets was $68 million (2012 - $53 million). The effective capitalization rate used to determine the amount of borrowing costs eligible for capitalization was 4.7% (2012: 4.8%).

NOTE 6: AMORTIZATION AND DEPRECIATION

(in millions)	2013	2012
Depreciation of property, plant and equipment	$ 556	$ 515
Amortization of intangible assets	59	55
Amortization of regulatory accounts	338	223
Total	$ 953	$ 793

NOTE 7: CASH AND CASH EQUIVALENTS

	March 31		April 1
(in millions)	2013	2012	2011
Cash	$ 38	$ –	$ –
Short-term investments	22	12	27
Total	$ 60	$ 12	$ 27

NOTE 8: ACCOUNTS RECEIVABLE AND ACCRUED REVENUE

	March 31		April 1
(in millions)	**2013**	2012	2011
Trade receivables	**$ 528**	$ 425	$ 433
Accrued revenue	**95**	85	39
Other	**98**	85	97
Total	**$ 721**	$ 595	$ 569

Accrued revenue represents revenue for electricity delivered and not yet billed. Trade receivables includes a restricted cash balance of $70 million at March 31, 2013 (March 31, 2012 - $31 million, April 1, 2011 - $40 million).

NOTE 9: INVENTORIES

	March 31		April 1
(in millions)	**2013**	2012	2011
Materials and supplies	**$ 108**	$ 91	$ 83
Natural gas trading inventories	**65**	51	43
Total	**$ 173**	$ 142	$ 126

During the year ended March 31, 2013, an impairment reversal of $20 million (2012 – impairment of $32 million) was charged to cost of energy to adjust the recorded value of natural gas inventories as a result of an increase in market prices. As at March 31, 2013, $41 million (March 31, 2012 - $50 million, April 1, 2011 - $21 million) of the value of natural gas inventories was valued at net realizable value.

Inventories recognized as an expense during the year amounted to $32 million (2012 - $27 million).

NOTE 10: PROPERTY, PLANT AND EQUIPMENT

(in millions)	Generation	Transmission	Distribution	Land & Buildings	Equipment & Other	Unfinished Construction	Total
Cost							
Balance at April 1, 2011	$ 5,554	$ 3,435	$ 3,830	$ 330	$ 428	$ 1,598	$ 15,175
Additions	424	287	496	89	69	214	1,579
Disposals and retirements	(8)	(8)	(24)	(12)	(7)	(8)	(67)
Balance at March 31, 2012	5,970	3,714	4,302	407	490	1,804	16,687
Additions	289	400	536	45	98	478	1,846
Disposals and retirements	(8)	(11)	(95)	(11)	(11)	(13)	(149)
Balance at March 31, 2013	$ 6,251	$ 4,103	$ 4,743	$ 441	$ 577	$ 2,269	$ 18,384
Accumulated Depreciation							
Balance at April 1, 2011	$ (119)	$ (7)	$ (10)	$ (14)	$ (6)	$ –	$ (156)
Depreciation expense	(168)	(134)	(175)	(14)	(56)	–	(547)
Disposals and retirements	2	2	3	–	–	–	7
Balance at March 31, 2012	(285)	(139)	(182)	(28)	(62)	–	(696)
Depreciation expense	(178)	(138)	(173)	(16)	(59)	–	(564)
Disposals and retirements	4	7	72	11	8	–	102
Balance at March 31, 2013	$ (459)	$ (270)	$ (283)	$ (33)	$ (113)	$ –	$ (1,158)
Net carrying amounts							
At April 1, 2011	$ 5,435	$ 3,428	$ 3,820	$ 316	$ 422	$ 1,598	$ 15,019
At March 31, 2012	$ 5,685	$ 3,575	$ 4,120	$ 379	$ 428	$ 1,804	$ 15,991
At March 31, 2013	$ 5,792	$ 3,833	$ 4,460	$ 408	$ 464	$ 2,269	$ 17,226

(i) As at March 31, 2013, the Company has included its one-third interest in Waneta with a net book value of $777 million in Generation assets.

(ii) Included within Distribution assets are the Company's portion of utility poles with a net book value of $734 million (2012 - $690 million) that are jointly owned with a third party.

(iii) During fiscal 2013, the Company received government contributions of $23 million for the construction of a new transmission line and has deducted the grant received from the cost of the asset.

(iv) The Company has contractual commitments to spend $1,180 million on major property, plant and equipment projects (individual projects greater than $50 million) as at March 31, 2013.

LEASED ASSETS

Property, plant and equipment under finance leases of $388 million (2012- $388 million, April 1, 2011 - $388 million), net of accumulated amortization of $146 million (2012- $132 million, April 1, 2011 - $118 million), are included in the total amount of property, plant and equipment above.

NOTE 11: INTANGIBLE ASSETS

(in millions)	Land Rights	Internally Developed Software	Purchased Software	Other	Work in Progress	Total
Cost						
Balance at April 1, 2011	$ 158	$ 7	$ 157	$ 11	$ 12	$ 345
Additions	19	25	66	–	19	129
Balance at March 31, 2012	177	32	223	11	31	474
Additions	5	16	66	–	(4)	83
Retirements	–	–	(9)	–	–	(9)
Balance at March 31, 2013	$ 182	$ 48	$ 280	$ 11	$ 27	$ 548
Accumulated Amortization						
Balance at April 1, 2011	$ –	$ –	$ (10)	$ –	$ –	$ (10)
Amortization expense	–	(3)	(46)	(3)	–	(52)
Balance at March 31, 2012	–	(3)	(56)	(3)	–	(62)
Amortization expense	–	(6)	(49)	(2)	–	(57)
Retirements	–	–	9	–	–	9
Balance at March 31, 2013	$ –	$ (9)	$ (96)	$ (5)	$ –	$ (110)
Net carrying amounts						
At April 1, 2011	$ 158	$ 7	$ 147	$ 11	$ 12	$ 335
At March 31, 2012	$ 177	$ 29	$ 167	$ 8	$ 31	$ 412
At March 31, 2013	$ 182	$ 39	$ 184	$ 6	$ 27	$ 438

(i) Land rights consist primarily of statutory rights of way acquired from the Province in perpetuity. These land rights have indefinite useful lives and are not subject to amortization. These land rights are tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset value may not be recoverable.

NOTE 12: RATE REGULATION

REVENUE REQUIREMENTS APPLICATION

On June 20, 2012, the BCUC issued its decision on BC Hydro's F2012 to F2014 Revenue Requirements Application (RRA). Results for the year ended March 31, 2013 reflect this decision and all other decisions and directives issued by the BCUC during the year which affect fiscal 2013 results.

REGULATORY ACCOUNTS

The following regulatory assets and liabilities have been established through rate regulation. In the absence of rate regulation, these amounts would be reflected in operating results in the year in which they are incurred. For the year ended March 31, 2013, the impact of regulatory accounting has resulted in an increase to net income of $208 million (2012 - $569 million) and other comprehensive income of $191 million (2012 – $322 million increase). For each regulatory account, the amount reflected in the Net Change column in the following regulatory tables represents the impact on comprehensive income for the applicable year. Under rate regulated accounting, a net decrease in a regulatory asset or a net increase in a regulatory liability results in a decrease to comprehensive income.

(in millions)	*March 31 2012 CGAAP*	*Transition to Prescribed Standards (Note 22)*	*April 1 2012*	*Addition (Reduction)*	*Amortization*	*Net Change*	*March 31 2013*
Regulatory Assets							
Heritage Deferral Account	$ 244	$ -	$ 244	$ (118)	$ (56)	$ (174)	$ 70
Non-Heritage Deferral Account	367	62	429	122	(84)	38	467
Trade Income Deferral Account	175	30	205	25	(40)	(15)	190
Demand-Side Management Programs	646	(8)	638	148	(53)	95	733
First Nation Negotiations, Litigation & Settlement Costs	543	-	543	17	(7)	10	553
Non-Current Pension Cost	55	322	377	184	(17)	167	544
Site C	181	-	181	77	-	77	258
CIA Amortization Variance	68	-	68	7	-	7	75
Environmental Provisions	234	88	322	53	(8)	45	367
Smart Metering and Infrastructure	92	-	92	100	-	100	192
Finance Charges	6	43	49	(48)	-	(48)	1
IFRS Pension & Other Post Employment Benefits	-	762	762	-	(39)	(39)	723
IFRS Property, Plant and Equipment	-	254	254	197	(4)	193	447
Other Regulatory Accounts	150	-	150	1	(30)	(29)	121
Total Regulatory Assets	2,761	1,553	4,314	765	(338)	427	4,741
Regulatory Liabilities							
Future Removal and Site Restoration Costs	120	(16)	104	-	(16)	(16)	88
Rate Smoothing	70	-	70	41	-	41	111
Foreign Exchange Gains and Losses	103	-	103	(2)	(1)	(3)	100
Other Regulatory Accounts	2	-	2	6	-	6	8
Total Regulatory Liabilities	295	(16)	279	45	(17)	28	307
Net Regulatory Asset	$ 2,466	$ 1,569	$ 4,035	$ 720	$ (321)	$ 399	$ 4,434

(in millions)	*March 31 2011 CGAAP*	*Transition to Prescribed Standards (Note 22)*	*April 1 2011*	*Transfers*	*Addition (Reduction)*	*Amortization*	*Net Change*	*March 31 2012*
Regulatory Assets								
Heritage Deferral Account	$ 247	$ –	$ 247	$ 45	$ (21)	$ (27)	$ (48)	$ 244
Non-Heritage Deferral Account	362	59	421	–	48	(40)	8	429
Trade Income Deferral Account	188	14	202	–	24	(21)	3	205
Demand-Side Management Programs	506	–	506	(8)	182	(42)	140	638
First Nation Negotiations, Litigation & Settlement Costs	399	–	399	–	151	(7)	144	543
Non-Current Pension Cost	72	–	72	–	322	(17)	305	377
Site C	104	–	104	–	77	–	77	181
CIA Amortization Variance	59	–	59	–	9	–	9	68
Environmental Provisions	231	45	276	–	54	(8)	46	322
Smart Metering and Infrastructure	34	–	34	–	58	–	58	92
Finance Charges	6	69	75	–	(26)	–	(26)	49
GM Shrum Unit 3	43	–	43	(45)	2	–	2	–
Procurement Enhancement Initiative	38	–	38	–	2	(40)	(38)	–
IFRS Pension & Other Post Employment Benefits	–	796	796	–	–	(34)	(34)	762
IFRS Property, Plant and Equipment	–	–	–	8	246	–	246	254
Other Regulatory Accounts	147	–	147	–	14	(11)	3	150
Total Regulatory Assets	2,436	983	3,419	–	1,142	(247)	895	4,314
Regulatory Liabilities								
Future Removal and Site Restoration Costs	140	(1)	139	–	–	(35)	(35)	104
Rate Smoothing	–	–	–	–	70	–	70	70
Foreign Exchange Gains and Losses	106	–	106	–	(3)	–	(3)	103
Other Regulatory Accounts	30	–	30	–	(4)	(24)	(28)	2
Total Regulatory Liabilities	276	(1)	275	–	63	(59)	4	279
Net Regulatory Asset	$ 2,160	$ 984	$ 3,144	$ –	$ 1,079	$ (188)	$ 891	$ 4,035

HERITAGE DEFERRAL ACCOUNT (HDA)

Under a Special Directive issued by the Province, BCUC was directed to authorize the Company to establish the HDA. This account is intended to mitigate the impact of certain variances between the forecasted costs in a revenue requirements application and actual costs of service associated with the Heritage Resources by adjustment of net income. These deferred variances will be recovered in rates through the rate rider. The closing balance of $45 million as of March 31, 2012 in the GM Shrum Unit 3 regulatory account was transferred to the HDA as approved by the BCUC.

NON-HERITAGE DEFERRAL ACCOUNT (NHDA)

Under a Special Directive issued by the Province, BCUC approved the establishment of the NHDA, which is intended to mitigate the impact of certain cost variances between the forecasted costs in a revenue requirements application and actual costs related to energy acquisition and maintenance of the Company's distribution assets by adjustment of net income. These deferred variances will be recovered in rates through the rate rider.

TRADE INCOME DEFERRAL ACCOUNT

Established under a Special Directive issued by the Province, this account is intended to mitigate the uncertainty associated with forecasting the net income of the Company's trade activities. The impact is to defer the difference between the Trade Income forecast in the revenue requirements application and actual Trade Income. In May 2012, the Province amended the Heritage Special Direction No. 2 to change the definition of Trade Income and remove the $200 million cap. Trade Income is now defined as the greater of (a) the amount that is equal to BC Hydro's consolidated net income, less BC Hydro's non-consolidated net income, less the net income of the BC Hydro's subsidiaries except Powerex, less the amount that BC Hydro's consolidated net income changes due to foreign currency translation gains and losses on intercompany balances between BC Hydro and Powerex; and (b) zero. The difference between the Trade Income forecast and actual Trade Income is deferred except for amounts arising from a net loss in Trade Income. The removal of the $200 million cap on Powerex income allows ratepayers to benefit from all of Powerex's income. Any losses incurred by Powerex will not impact rates.

DEMAND-SIDE MANAGEMENT ACTIVITIES (DSM)

Amounts incurred for DSM are deferred and amortized on a straight-line basis over the anticipated 15 year period of benefit of the program. DSM programs are designed to reduce the energy requirements on the Company's system. DSM costs include materials, direct labour and applicable portions of support costs, equipment costs, and incentives, the majority of which are not eligible for capitalization. Costs relating to identifiable tangible assets that meet the capitalization criteria are recorded as property, plant and equipment.

FIRST NATION NEGOTIATIONS, LITIGATION AND SETTLEMENT COSTS

The First Nations Negotiations, Litigation and Settlement Costs consist primarily of settlement costs related to agreements reached with various First Nations groups. These agreements address settlements related to the construction and operation of the Company's existing facilities and provide compensation associated with past, present and future impacts. Provisions for and costs incurred with respect to First Nation negotiations, litigation and settlements are deferred and costs incurred are amortized on a straight-line basis over a period of 10 years.

Costs relating to identifiable tangible assets that meet the capitalization criteria are recorded as property, plant and equipment.

NON-CURRENT SERVICE PENSION COST

Variances that arise between forecast and actual non-current pension and other post employment benefit costs are deferred. In the absence of rate regulation and the application of ASC 980, these cost variances would be included in operating results, which would have resulted in a $7 million increase in net income for the year (2012 - $nil million).

In addition, actuarial gains and losses related to post employment benefit plans are also deferred. In the absence of rate regulation, these actuarial gains and losses would be included in other comprehensive income in the year in which they are incurred, which would have resulted in a $191 million decrease in other comprehensive income (2012 - $322 million decrease). The net impact of the deferral of the non-current service pension costs variances and the actuarial losses is $184 million.

The amortization of the Non-Current Service Pension cost regulatory asset is recorded in operating results. In the absence of rate regulation, this amortization expense would not exist which would result in a $17 million increase in net income (2012 - $17 million increase).

SITE C

Site C expenditures incurred in fiscal 2007 through fiscal 2013 have been deferred.

CONTRIBUTIONS IN AID OF CONSTRUCTION (CIA) AMORTIZATION VARIANCE

This account captures the difference in revenue requirement impacts of the 45 year amortization period the Company uses as per a depreciation study and the 25 year amortization period determined by the BCUC.

ENVIRONMENTAL PROVISIONS

A liability provision and offsetting regulatory asset has been established for environmental compliance and remediation arising from the costs that will likely be incurred to comply with the Federal Polychlorinated Biphenyl (PCB) Regulations enacted under the *Canadian Environmental Protection Act*, the Asbestos requirements of the Occupational Health and Safety Regulations under the jurisdiction of WorkSafe BC and the remediation of environmental contamination at a property occupied by a predecessor company.

SMART METERING AND INFRASTRUCTURE (SMI)

Operating costs incurred by the Company with respect to the SMI Program are being deferred. Costs relating to identifiable tangible and intangible assets that meet the capitalization criteria are being recorded as property, plant and equipment or intangible assets respectively. The SMI net operating costs, amortization of capital assets, and finance charges have been deferred.

FINANCE CHARGES

Variances that arise between forecast (in the RRA) and actual finance charges are deferred.

IFRS PENSION & OTHER POST-EMPLOYMENT BENEFITS

Unamortized experience gains and losses on the pension and other post-employment benefit plans recognized at the time of transition to the Prescribed Standards were deferred to this regulatory account to allow for recovery in future rates. The account balance is amortized over the expected average remaining service life of the employees.

IFRS PROPERTY, PLANT & EQUIPMENT

The fiscal 2012 impacts due to componentization, mass asset retirements, overhead capitalization and interest during construction described in Note 22 are included in this account. In addition, an annual overhead expenditure deferral equal to the fiscal 2012 overhead deferral amount less a ten year phase in adjustment will be included in the account. The annual deferred amount will be amortized over 40 years beginning the year following the expenditures.

FUTURE REMOVAL AND SITE RESTORATION COSTS

This account was established by a one-time transfer of $251 million from retained earnings for liabilities previously recorded in excess of amounts required as decommissioning obligations. The costs of dismantling and disposal of property, plant and equipment will be applied to this regulatory liability if they do not otherwise relate to an asset retirement obligation.

RATE SMOOTHING

The Rate Smoothing regulatory account was established in order to smooth out annual rate increases applied for in the Amended F2012-F2014 Revenue Requirements Application.

FOREIGN EXCHANGE GAINS AND LOSSES

Foreign exchange gains and losses from the translation of specified foreign currency financial instruments are deferred.

OTHER REGULATORY ACCOUNTS

Other regulatory asset accounts with individual balances less than $45 million include the following: Arrow Water Systems, Capital Project Investigation Costs, Home Purchase Option Plan, Return on Equity Adjustment, and Waneta.

Other regulatory liability accounts with individual balances less than $10 million include the following: Amortization of Capital Additions, and Storm Damage.

NOTE 13: INVESTMENTS HELD IN SINKING FUNDS

Investments held in sinking funds are held by the Trustee (the Minister of Finance for the Province) for the redemption of long-term debt. The sinking fund balances at the statement of financial position date are accounted for as held to maturity, and include the following investments:

(in millions)	**March 31 2013**		March 31 2012		April 1 2011	
	Carrying Value	**Weighted Average Effective Rate[1]**	Carrying Value	Weighted Average Effective Rate[1]	Carrying Value	Weighted Average Effective Rate[1]
Province and BC Crown Corporation bonds	**$ 72**	**3.2%**	$ 65	3.2%	$ 60	4.6%
Federal and other provincial government securities	**40**	**3.3%**	40	3.5%	37	4.7%
Total	**$ 112**		$ 105		$ 97	

[1] *Rate calculated on market yield to maturity.*

Effective December, 2005, all sinking fund payment requirements on all new and outstanding debt were removed.

NOTE 14: ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

(in millions)	**March 31 2013**	2012	April 1 2011
Trade payables	**$ 328**	$ 252	$ 245
Accrued liabilities	**838**	767	712
Current portion of other long-term liabilities (Note 19)	**98**	127	124
Dividend payable	**215**	230	463
Other	**65**	47	50
Total	**$ 1,544**	$ 1,423	$ 1,594

NOTE 15: LONG-TERM DEBT AND DEBT MANAGEMENT

The Company's long-term debt comprises bonds and revolving borrowings obtained under an agreement with the Province.

The Company has a commercial paper borrowing program with the Province which is limited to $4.0 billion, and includes revolving borrowings. This limit increased to $4.5 billion effective April 1, 2013. At March 31, 2013, the outstanding amount under the borrowing program was $2,573 million (2012 - $2,683 million, 2011 - $2,333 million).

During fiscal 2013, the Company issued bonds with a par value of $1,393 million (2012 – $1,350 million) a weighted average effective interest rate of 3.3 per cent (2012 – 4.3 per cent) and a weighted average term to maturity of 25.4 years (2012 – 31.2 years).

Long-term debt, expressed in Canadian dollars, is summarized in the following table by year of maturity:

($ amounts in millions of Canadian dollars)	**March 31, 2013**				March 31, 2012				April 1, 2011			
	Canadian	**US**	**Total**	**Weighted Average Interest Rate[1]**	Canadian	US	Total	Weighted Average Interest Rate[1]	Canadian	US	Total	Weighted Average Interest Rate[1]
Maturing in fiscal:												
2012	**$ –**	**$ –**	**$ –**	**–**	$ –	$ –	$ –	–	$ 450	$ –	$ 450	6.1
2013	**–**	**–**	**–**	**–**	200	–	200	4.8	200	–	200	4.8
2014	**500**	**203**	**703**	**6.6**	500	200	700	6.6	500	194	694	6.6
2015	**325**	**–**	**325**	**5.5**	325	–	325	5.5	325	–	325	5.5
2016	**150**	**–**	**150**	**5.2**	150	–	150	5.2	150	–	150	5.2
2017	**–**	**–**	**–**	**–**	–	–	–	–	–	–	–	–
2018	**40**	**–**	**40**	**4.8**	–	–	–	–	–	–	–	–
1-5 years	**1,015**	**203**	**1,218**	**6.0**	1,175	200	1,375	5.9	1,625	194	1,819	6.0
6-10 years	**3,331**	**203**	**3,534**	**6.3**	2,871	200	3,071	6.2	2,345	194	2,539	5.9
11-15 years	**110**	**508**	**618**	**6.9**	410	499	909	7.7	936	486	1,422	7.7
16-20 years	**1,610**	**–**	**1,610**	**5.0**	1,300	–	1,300	5.4	500	–	500	5.0
21-25 years	**–**	**305**	**305**	**7.4**	–	300	300	7.4	800	–	800	5.5
26-30 years	**3,273**	**–**	**3,273**	**4.3**	1,250	–	1,250	4.9	1,250	292	1,542	5.3
Over 30 years	**680**	**–**	**680**	**4.2**	1,820	–	1,820	4.4	470	–	470	4.7
Bonds	**10,019**	**1,219**	**11,238**	**5.4**	8,826	1,199	10,025	5.7	7,926	1,166	9,092	6.0
Revolving borrowings	**1,926**	**647**	**2,573**	**0.9**	1,835	848	2,683	0.8	2,261	72	2,333	1.2
	11,945	**1,866**	**13,811**		10,661	2,047	12,708		10,187	1,238	11,425	
Adjustments to carrying value resulting from hedge accounting	**45**	**22**	**67**		83	30	113		127	34	161	
Unamortized premium, discount, and issue costs	**267**	**(11)**	**256**		140	(11)	129		137	(11)	126	
	$12,257	**$ 1,877**	**$14,134**		$10,884	$ 2,066	$12,950		$10,451	$ 1,261	$11,712	
Less: Current portion	**(2,437)**	**(851)**	**(3,288)**		(2,040)	(848)	(2,888)		(2,731)	(72)	(2,803)	
Long-term debt	**$ 9,820**	**$ 1,026**	**$10,846**		$ 8,844	$ 1,218	$10,062		$ 7,720	$ 1,189	$ 8,909	

[1] The weighted average interest rate represents the effective rate of interest on fixed-rate bonds and the current interest rate in effect at March 31 for floating-rate debt, all before considering the effect of derivative financial instruments used to manage interest rate risk.

The following interest rate contracts were in place at March 31, 2013 in an asset position of $4 million (2012 – asset of $10 million, April 1, 2011 – asset of $20 million). Floating rates are based on the effective rates at the statement of financial position date and vary over time. Such contracts are used to hedge the impact of interest rate changes on debt.

	March 31		April 1
(in millions)	**2013**	2012	2011
Receive fixed, pay floating rate swaps			
Notional amount[1]	**$ 553**	$ 750	$ 1,194
Weighted average receive rate	**4.15%**	3.53%	3.66%
Weighted average pay rate	**0.93%**	1.08%	1.14%
Weighted terms	**< 1 year**	1 year	2 years
Receive floating, pay fixed rate swaps			
Notional amount[1]	**$ 290**	$ 290	$ 290
Weighted average receive rate	**1.45%**	1.44%	1.47%
Weighted average pay rate	**4.90%**	4.90%	4.90%
Weighted terms	**< 1 year**	1 year	2 years

[1] Notional amount for a derivative instrument is defined as the contractual amount on which payments are calculated.

The following foreign currency contracts were in place at March 31, 2013 in a liability position of $157 million (2012 – liability of $175 million and April 1, 2011 – liability of $179 million). Such contracts are primarily used to hedge foreign dollar principal and interest payments.

	March 31		April 1
(in millions)	**2013**	2012	2011
Cross- Currency Swaps			
United States dollar to Canadian dollar - notional amount[1]	**US $ 200**	US $ 200	US $ 200
United States dollar to Canadian dollar - weighted average contract rate	**1.45**	1.45	1.45
Weighted remaining term	**< 1 year**	1 year	2 years
Foreign Currency Forwards			
United States dollar to Canadian dollar - notional amount[1]	**US $1,462**	US $1,698	US $ 897
United States dollar to Canadian dollar - weighted average contract rate	**1.12**	1.11	1.18
Weighted remaining term	**8 years**	8 years	14 years

[1] Notional amount for a derivative instrument is defined as the contractual amount on which payments are calculated.

For more information about the Company's exposure to interest rate, foreign currency and liquidity risk, see Note 18.

NOTE 16: CAPITAL MANAGEMENT

Orders in Council from the Province establish the basis for determining the Company's equity for regulatory purposes, as well as the annual Payment to the Province. Capital requirements are consequently managed through the retention of equity subsequent to the Payment to the Province and a limit on the Payment to the Province if it would cause the debt to equity ratio to exceed 80:20.

The Company monitors its capital structure on the basis of its debt to equity ratio. For this purpose, the applicable Order in Council defines debt as revolving borrowings and interest-bearing borrowings less investments held in sinking funds and cash and cash equivalents. Equity comprises retained earnings, accumulated other comprehensive income (loss) and contributed surplus.

During the period, there were no changes in the approach to capital management.

The debt to equity ratio at March 31, 2013, March 31, 2012 and April 1, 2011 was as follows:

(in millions)	**As at March 31 2013**	As at March 31 2012	As at April 1 2011
Total debt, net of sinking funds	**$ 14,022**	$ 12,845	$ 11,615
Less: Cash and cash equivalents	**(60)**	(12)	(27)
Net Debt	**$ 13,962**	$ 12,833	$ 11,588
Retained earnings	**$ 3,369**	$ 3,075	$ 2,747
Contributed surplus	**60**	60	60
Accumulated other comprehensive income	**71**	84	74
Total Equity	**$ 3,500**	$ 3,219	$ 2,881
Net Debt to Equity Ratio	**80 : 20**	80 : 20	80 : 20

PAYMENT TO THE PROVINCE

The Company is required to make an annual Payment to the Province (the Payment) on or before June 30 of each year. The Payment is equal to 85 per cent of the Company's net income for the most recently completed fiscal year unless the debt to equity ratio, as defined by the Province, after deducting the Payment, is greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment is the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. The Payment accrued to date at March 31, 2013 is $215 million (March 31, 2012 - $230 million, April 1, 2011 - $463 million), which is included in accounts payable and accrued liabilities and is less than 85 per cent of the net income due to the 80:20 cap.

NOTE 17: EMPLOYEE BENEFITS – POST EMPLOYMENT BENEFIT PLANS

The Company provides a defined benefit statutory pension plan to substantially all employees, as well as supplemental arrangements which provide pension benefits in excess of statutory limits. Pension benefits are based on years of membership service and highest five-year average pensionable earnings. Annual cost-of-living increases are provided to pensioners to the extent that funds are available in the indexing fund. Employees make basic and indexing contributions to the plan funds based on a percentage of current pensionable earnings. The Company contributes amounts as prescribed by the independent actuary. The Company is responsible for ensuring that the statutory pension plan has sufficient assets to pay the pension benefits upon retirement of employees. The supplemental arrangements are unfunded. The most recent actuarial funding valuation for the statutory pension plan was performed at December 31, 2009. The next valuation for funding purposes is being prepared as of December 31, 2012, and the results will be available in September 2013.

The Company also provides post-employment benefits other than pensions including medical, extended health and life insurance coverage for retirees who have at least 10 years of service and qualify to receive pension benefits. Certain benefits, including the short-term continuation of health care and life insurance, are provided to terminated employees or to survivors on the death of an employee. These post-employment benefits other than pensions are not funded. Post-employment benefits include the pay-out of benefits that vest or accumulate, such as banked vacation.

Information about the benefit plans, post-employment benefits and post-employment benefits other than pensions is as follows:

(a) The expense for the Company's benefit plans at March 31, is recognized in the following line items in the statement of comprehensive income prior to any capitalization of employment costs attributable to property, plant and equipment and intangible asset additions:

	Pension Benefit Plans		Other Benefit Plans	
(in millions)	**2013**	2012	**2013**	2012
Current service costs charged to personnel operating costs	**$ 71**	$ 61	**$ 10**	$ 9
Charged/(credited) to finance costs:				
Interest on defined benefit plan obligations	**188**	160	**15**	15
Expected return on plan assets	**(196)**	(161)	**n/a**	n/a
Total charge/(credit) to finance costs	**(8)**	(1)	**15**	15
Total post employment benefit plan expense	**$ 63**	$ 60	**$ 25**	$ 24

Actual return on defined benefit plan assets for the year ended March 31, 2013 is $246 million (2012 - $117 million).

Actuarial gains and losses recognized in other comprehensive income is nil (2012 – nil). As per Notes 12 and 22, in accordance with Prescribed Standards and as approved by the BCUC, actuarial gains and losses are deferred to the Non-Current Pension Cost regulatory account.

(b) Information about the Company's benefit plans at March 31, in aggregate, is as follows:

	Pension Benefit Plans			Other Benefit Plans		
	March 31		April 1	March 31		April 1
(in millions)	**2013**	2012	2011	**2013**	2012	2011
Accrued benefit obligation of funded plans	**$ 3,575**	$ 3,241	$ 2,911	**$ –**	$ –	$ –
Accrued benefit obligation of unfunded plans	**127**	124	108	**361**	320	285
Fair value of plan assets	**2,667**	2,503	2,459	**–**	–	–
Plan deficit	**$ (1,035)**	$ (862)	$ (560)	**$ (361)**	$ (320)	$ (285)

The Company determined that there was no minimum funding requirement adjustment required in fiscal 2013 and fiscal 2012 in accordance with IFRIC 14 *The Limit on Defined Benefit Asset, Minimum Funding Requirements and Their Interaction*.

(c) Movement of defined benefit obligations and defined benefit plan assets during the year:

	Pension Benefit Plans		Other Benefit Plans	
(in millions)	**2013**	2012	**2013**	2012
Present value of accrued benefit obligation				
Opening present value	**$ 3,365**	$ 3,020	**$ 320**	$ 285
Current service cost	**71**	61	**10**	9
Interest cost	**188**	160	**15**	15
Benefits paid	**(162)**	(154)	**(11)**	(11)
Employee contributions	**26**	26	**–**	–
Actuarial (gains) losses[1]	**214**	252	**27**	22
Closing present value	**3,702**	3,365	**361**	320
Fair value of plan assets				
Opening fair value	**2,503**	2,459	**n/a**	n/a
Expected return on plan assets	**196**	161	**n/a**	n/a
Employer contributions	**49**	49	**n/a**	n/a
Employee contributions	**26**	26	**n/a**	n/a
Benefits paid	**(157)**	(148)	**n/a**	n/a
Actuarial gains (losses)[1]	**50**	(44)	**n/a**	n/a
Closing fair value	**2,667**	2,503	**–**	–
Plan deficit	**(1,035)**	(862)	**(361)**	(320)
Accrued benefit asset (liability)	**$ (1,035)**	$ (862)	**$ (361)**	$ (320)

[1] *Actuarial gains/losses are included in the Non-Current Pension Cost regulatory account*

(d) The significant assumptions adopted in measuring the Company's accrued benefit obligations as at each March 31 year end are as follows:

	Pension Benefit Plans		Other Benefit Plans	
(in millions)	**2013**	2012	**2013**	2012
Discount rate				
Benefit cost	**4.62%**	5.42%	**4.55%**	5.35%
Accrued benefit obligation	**4.00%**	4.62%	**4.20%**	4.55%
Expected long term rate of return on plan assets	**7.30%**	7.30%	**n/a**	n/a
Rate of compensation increase				
Benefit cost	**3.70%**	3.70%	**n/a**	n/a
Accrued benefit obligation	**3.70%**	3.70%	**n/a**	n/a
Health care cost trend rates				
Weighted average health care cost trend rate	**n/a**	n/a	**5.72%**	5.00%
Weighted average ultimate health care cost trend rate	**n/a**	n/a	**4.38%**	3.90%
Year ultimate health care cost trend rate will be achieved	**n/a**	n/a	**2026**	2015

The valuation cost method for the accrued benefit is the projected accrued benefit pro-rated on service.

(e) Asset allocation of the defined benefit statutory pension plan as at the measurement date:

		Target Range		March 31		April 1
	Target Allocation	**Min**	**Max**	**2013**	2012	2011
Equities	59%	41%	77%	**66%**	65%	62%
Fixed interest investments	30%	19%	39%	**24%**	25%	29%
Real estate	10%	5%	15%	**10%**	10%	9%
Infrastructure	1%	0%	10%	**0%**	0%	0%

Plan assets are re-balanced within ranges around target applications. The expected return on plan assets is determined by considering long-term historical returns, future estimates of long-term investment returns and asset allocations.

(f) Other information about the Company's benefit plans is as follows:

	Pension Benefit Plans		Other Benefit Plans	
(in millions)	**2013**	2012	**2013**	2012
Employer contributions	**$ 49**	$ 49	**$ –**	$ –
Employee contributions	**26**	26	**–**	–
Benefits paid	**148**	140	**11**	11
Settlement payments	**14**	14	**–**	–

The Company's contributions to be paid to its funded defined benefit plan in 2014 is expected to amount to $49 million. The expected benefit payments to be paid in fiscal 2014 in respect to the unfunded defined benefit plan is $19 million.

Assumed healthcare cost trend rates have a significant effect on the amounts recognized in net income. A one percentage point change in assumed healthcare cost trend rates would have the following effects:

	One percentage point increase 2013	One percentage point decrease 2013
Effect on current service costs	$ 3	$ (2)
Effect on defined benefit obligation	42	(34)

The impact on the Pension Benefit Plan liabilities of changing certain of the major assumptions is as follows:

		2013	
	Increase/ decrease in assumption	Effect on accrued benefit obligation	Effect on current service costs
Discount rate	1%	$ +/- 378	$ +/- 18
Longevity	1 year	+/- 134	+/- 2

(g) Historical information

	March 31		April 1
(in millions)	**2013**	2012	2011
Present value of defined benefit obligation	**$ 3,702**	$ 3,365	$ 3,019
Fair value of plan assets	**2,667**	2,503	2,459
Surplus (Deficit) in the plan	**$ (1,035)**	$ (862)	$ (560)
Experience adjustments arising on plan liabilities (loss)	**$ (214)**	$ (252)	n/a
Experience adjustments arising on plan assets (loss)	**$ 50**	$ (44)	n/a

NOTE 18: FINANCIAL INSTRUMENTS

FINANCIAL RISKS

The Company is exposed to a number of financial risks in the normal course of its business operations, including market risks resulting from fluctuations in commodity prices, interest rates and foreign currency exchange rates, as well as credit risks and liquidity risks. The nature of the financial risks and the Company's strategy for managing these risks has not changed significantly from the prior period.

The following discussion is limited to the nature and extent of risks arising from financial instruments, as defined under IFRS 7 *Financial Instruments: Disclosures*. However, for a complete understanding of the nature and extent of risks the Company is exposed to, this note should be read in conjunction with the Company's discussion of Risk Management found in the Management's Discussion and Analysis section of the 2013 Annual Report.

(a) Credit Risk

Credit risk refers to the risk that one party to a financial instrument will cause a financial loss for a counterparty by failing to discharge an obligation. The Company is exposed to credit risk related to cash and cash equivalents, sinking fund investments, and derivative instruments. It is also exposed to credit risk related to accounts receivable arising from its day to day electricity and natural gas sales in and outside British Columbia. Maximum credit risk with respect to financial assets is limited to the carrying amount presented on the statement of financial position with the exception of US dollar sinking funds classified as held-to-maturity and carried on the statement of financial position at amortized cost of $112 million. The maximum credit risk exposure for these US dollar sinking funds as at March 31, 2013 is its fair value of $135 million. The Company manages this risk through Board-approved credit risk management policies which contain limits and procedures to the selection of counterparties. Exposures to credit risks are monitored on a regular basis.

(b) Liquidity Risk

Liquidity risk refers to the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. The Company manages liquidity risk by forecasting cash flows to identify financing requirements and by maintaining committed credit facilities. The Company's long-term debt comprises bonds and revolving borrowings obtained under an agreement with the Province. Cash from operations reduces the Company's liquidity risk. The Company does not believe that it will encounter difficulty in meeting its obligations associated with financial liabilities.

(c) Market Risks

Market risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: currency risk, interest rate risk, and price risk, such as changes in commodity prices and equity values. The Company monitors its exposure to market fluctuations and may use derivative contracts to manage these risks, as it considers appropriate. Other than in its energy trading subsidiary Powerex, the Company does not use derivative contracts for trading or speculative purposes.

i. Currency Risk

Currency risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in foreign exchange rates. The Company's currency risk is primarily with the U.S. dollar.

The majority of the Company's currency risk arises from long-term debt in the form of U.S. dollar denominated bonds. Energy commodity prices are also subject to currency risk as they are primarily denominated in U.S. dollars. As a result, the Company's trade revenues and purchases of energy commodities, such as electricity and natural gas, and associated accounts receivable and accounts payable, are affected by the Canadian/U.S. dollar exchange rate. In addition, all commodity derivatives and contracts priced in U.S. dollars are also affected by the Canadian/U.S. dollar exchange rate.

The Company actively manages its currency risk through a number of Board-approved policy documents. The Company uses cross currency swaps and forward foreign exchange purchase contracts to achieve and maintain the Board-approved U.S. dollar exposure targets.

ii. Interest Rate Risk

Interest rate risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Company is exposed to changes in interest rates primarily through its variable rate debt and the active management of its debt portfolio including its related sinking fund assets and temporary investments. The Company's Board-approved debt management strategies include maintaining a percentage of variable interest rate debt within a certain range. The Company enters into interest rate swaps to achieve and maintain the target range of variable interest rate debt.

iii. Commodity Price Risk

The Company is exposed to commodity price risk as fluctuations in electricity prices and natural gas prices could have a materially adverse effect on its financial condition. Prices for electricity and natural gas fluctuate in response to changes in supply and demand, market uncertainty, and a variety of other factors beyond the Company's control.

The Company enters into derivative contracts to manage commodity price risk. Risk management strategies, policies and limits are designed to ensure the Company's risks and related exposures are aligned with the Company's business objectives and risk tolerance. Risks are managed within defined limits that are regularly reviewed by the Board of Directors.

CATEGORIES OF FINANCIAL INSTRUMENTS

The following table provides a comparison of carrying values and fair values for non-derivative financial instruments as at March 31, 2013 and March 31, 2012:

	2013		2012		April 1, 2011		Interest Income (Expense) recognized in Finance Charges	Interest Income (Expense) recognized in Finance Charges
(in millions)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value	Carrying Value	Fair Value	**2013**	2012
Financial Assets and Liabilities at Fair Value Through Profit or Loss:								
Short-term investments	**$ 22**	**$ 22**	$ 12	$ 12	$ 27	$ 27	**$ –**	$ –
Designated long-term debt	**(565)**	**(565)**	(799)	(799)	(1,287)	(1,287)	**(39)**	(48)
Loans and Receivables:								
Accounts receivable and accrued revenue	**721**	**721**	595	595	569	569	**–**	–
Cash	**38**	**38**	–	–	–	–	**–**	–
Held to Maturity:								
Sinking funds – US	**112**	**135**	104	126	97	103	**3**	3
Available for Sale:								
Sinking funds – US	**–**	**–**	1	1	–	–	**–**	–
Other Financial Liabilities:								
Revolving borrowings - CAD	**(1,926)**	**(1,926)**	(1,835)	(1,835)	(2,261)	(2,261)	**(32)**	(29)
Revolving borrowings - US	**(647)**	**(647)**	(848)	(848)	(72)	(72)	**–**	–
Accounts payable and accrued liabilities	**(1,544)**	**(1,544)**	(1,423)	(1,423)	(1,594)	(1,594)	**–**	–
Long-term debt (including current portion due in one year)	**(10,996)**	**(13,073)**	(9,468)	(11,565)	(8,092)	(9,088)	**(576)**	(535)
First Nations liability (long-term portion only)	**(374)**	**(1,125)**	(377)	(537)	(244)	(487)	**–**	–
Finance Lease Obligation (long-term portion only)	**(275)**	**(275)**	(285)	(285)	(301)	(301)	**(27)**	(23)

For non-derivative financial assets and liabilities classified as financial assets and liabilities at fair value through profit or loss, a $37 million gain (2012 - $35 million gain) has been recognized in net income for the period relating to changes in fair value. For short-term investments, loans and receivables, and accounts payable and accrued liabilities, the carrying value approximates fair value due to the short duration of these financial instruments. For available-for-sale financial assets, no amount has been recorded in other comprehensive income and no amount was removed from other comprehensive income and reported in net income for the period.

The fair value of derivative instruments designated and not designated as hedges, was as follows:

	2013		2012		April 1, 2011	
(in millions)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value	Carrying Value	Fair Value
Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:						
Foreign currency contracts (cash flow hedges for $US denominated long-term debt)	**$ (160)**	**$ (160)**	$ (162)	$ (162)	$ (178)	$ (178)
Interest rate swaps (fair value hedges for debt)	**4**	**4**	12	12	23	23
	(156)	**(156)**	(150)	(150)	(155)	(155)
Non-Designated Derivative Instruments:						
Foreign currency contracts	**3**	**3**	(15)	(15)	(4)	(4)
Commodity derivatives	**(3)**	**(3)**	35	35	7	7
	–	**–**	20	20	3	3
Total	**$ (156)**	**$ (156)**	$ (130)	$ (130)	$ (152)	$ (152)

Information related to the foreign currency and interest rate swaps contracts is presented in Note 15.

The derivatives are represented on the statement of financial position as follows:

	2013	2012	April 1, 2011
Current portion of derivative financial instrument assets	**$ 83**	$ 140	$ 198
Current portion of derivative financial instrument liabilities	**(172)**	(123)	(165)
Derivative financial instrument assets, long-term	**27**	42	27
Derivative financial instrument liabilities, long-term	**(94)**	(189)	(212)
Total	**$ (156)**	$ (130)	$ (152)

For the year ended March 31, 2013, a loss of $1 million (2012 – loss of $1 million) was recognized in finance charges related to the ineffective portion of designated cash flow hedges. For designated cash flow hedges for the year ended March 31, 2013, a loss of $5 million (2012 – gain of $16 million) was recognized in other comprehensive income. For the year ended March 31, 2013, $9 million (2012 – $26 million) was removed from other comprehensive income and reported in net income, offsetting foreign exchange losses (2012 – losses) recorded in the year.

For derivative instruments not designated as hedges, a gain of $2 million (2012 – loss of $3 million) was recognized in finance charges for the year ended March 31, 2013 with respect to foreign currency contracts for cash management purposes. For the year ended March 31, 2013, a loss of $9 million (2012 – loss of $23 million) was recognized in finance charges with respect to foreign currency contracts for U.S. short-term borrowings. These economic hedges offset $5 million of foreign exchange revaluation gains (2012 – gain of $21 million) recorded with respect to U.S. short-term borrowings. A net loss of $3 million (2012 – gain of $223 million) was recorded in trade revenue for the year ended March 31, 2013 with respect to commodity derivatives.

COMMODITY DERIVATIVES

Additional information related to the fair value of the commodity derivatives is as follows:

As at March 31, 2013	Notional Quantity of Natural Gas (in TJ)	Notional Quantity of Electricity (in GWh)	Carrying Value	Fair Value	Maximum Term (in months)
Current assets	22,371	6,896	$ 71	$ 71	12
Long term assets	451	374	21	21	66
Current liabilities	46,598	6,296	(80)	(80)	12
Long-term liabilities	2,100	186	(15)	(15)	79
Total			$ (3)	$ (3)	

As at March 31, 2012	Notional Quantity of Natural Gas (in TJ)	Notional Quantity of Electricity (in GWh)	Carrying Value	Fair Value	Maximum Term (in months)
Current assets	37,139	8,635	$ 123	$ 123	12
Long term assets	12,346	2,529	32	32	91
Current liabilities	15,421	8,241	(97)	(97)	12
Long-term liabilities	9,051	1,995	(23)	(23)	21
Total			$ 35	$ 35	

As at April 1, 2011	Notional Quantity of Natural Gas (in TJ)	Notional Quantity of Electricity (in GWh)	Carrying Value	Fair Value	Maximum Term (in months)
Current assets	9,493	6,960	$ 169	$ 169	12
Long term assets	3,246	638	19	19	90
Current liabilities	5,231	4,829	(152)	(152)	12
Long-term liabilities	5,022	258	(29)	(29)	103
Total			$ 7	$ 7	

Notional quantities in the above tables are presented on a net basis and do not necessarily represent the amounts to be exchanged by the parties to the instruments. Furthermore, the magnitude of the notional amounts does not necessarily correlate to the carrying value or fair value of the commodity derivatives.

CREDIT RISK

DOMESTIC ELECTRICITY RECEIVABLES

A customer application and a credit check are required prior to initiation of services. For customers with no BC Hydro credit history, call center agents ensure accounts are secured either by a credit bureau check, a cash security deposit, or a credit reference letter.

The value of domestic and trade accounts receivable, by age and the related provision for doubtful accounts are presented in the following tables.

DOMESTIC AND TRADE ACCOUNTS RECEIVABLE NET OF ALLOWANCE FOR DOUBTFUL ACCOUNTS

	March 31		April 1
(in millions)	**2013**	2012	2011
Current	**$ 489**	$ 404	$ 412
Past due (30-59 days)	**30**	24	21
Past due (60-89 days)	**10**	6	5
Past due (More than 90 days)	**5**	5	4
	534	439	442
Allowance for doubtful accounts	**(6)**	(14)	(9)
Total	**$ 528**	$ 425	$ 433

At the end of each reporting period a review of the provision for doubtful accounts is performed. It is an assessment of the potential amount of domestic and trade accounts receivable which will not be paid by customers after the statement of financial position date. The assessment is made by reference to age, status and risk of each receivable, current economic conditions, and historical information. There was an $8 million decrease in the allowance for doubtful accounts during the year.

FINANCIAL ASSETS ARISING FROM THE COMPANY'S TRADING ACTIVITIES

A substantial majority of the Company's counterparties associated with its trading activities are in the energy sector. This industry concentration has the potential to impact the Company's overall exposure to credit risk in that the counterparties may be similarly affected by changes in economic, regulatory, political, and other factors. The Company manages credit risk by authorizing trading transactions within the guidelines of the Company's risk management policies, by monitoring the credit risk exposure and credit standing of counterparties on a regular basis, and by obtaining credit assurances from counterparties to which they are entitled under contract.

The Company regularly uses standard master netting agreements that allow for netting of exposures and often include margining provisions. In addition, the Company has credit loss insurance that covers most credit exposure associated with transactions that are delivered in the United States.

With respect to these financial assets, the Company assigns credit limits for counterparties based on evaluations of their financial condition, net worth, regulatory environment, cost recovery mechanisms, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically and a detailed credit analysis is performed at least annually. Further, the Company has tied a portion of its contracts to master agreements that require security in the form of cash or letters of credit if current net receivables and replacement cost exposure exceed contractually specified limits. The following table outlines the distribution, by credit rating, of financial assets that are neither past due nor impaired:

As at March 31, 2013	Investment Grade %	Unrated %	Non-Investment Grade %	Total %
Accounts receivable	91	3	6	100
Assets from trading activities	100	0	0	100

As at March 31, 2012	Investment Grade %	Unrated %	Non-Investment Grade %	Total %
Accounts receivable	93	4	3	100
Assets from trading activities	100	0	0	100

As at April 1, 2011	Investment Grade %	Unrated %	Non-Investment Grade %	Total %
Accounts receivable	94	2	4	100
Assets from trading activities	89	11	0	100

The outstanding amount of collateral received from customers at March 31, 2013 was $2 million (2012 - nil).

LIQUIDITY RISK

The following table details the remaining contractual maturities at March 31, 2013 of the Company's non-derivative financial liabilities and derivative financial liabilities, which are based on contractual undiscounted cash flows. Interest payments have been computed using contractual rates or, if floating, based on rates current at March 31, 2013. In respect of the cash flows in U.S. dollars, the exchange rate as at March 31, 2013 has been used.

(in millions)	Carrying Value	Fiscal 2014	Fiscal 2015	Fiscal 2016	Fiscal 2017	Fiscal 2018	Fiscal 2019 and thereafter
Non-Derivative Financial Liabilities							
Total trade and other payables (excluding interest accruals and current portion of lease obligations and other long-term liabilities)	$ 1,351	$ (1,351)	$ –	$ –	$ –	$ –	$ –
Long-term debt (including interest payments)	14,297	(3,889)	(899)	(716)	(558)	(597)	(17,173)
Lease obligations	292	(81)	(82)	(84)	(85)	(87)	(897)
Other long-term liabilities	387	(13)	(14)	(14)	(16)	(13)	(886)
		(5,334)	(995)	(814)	(659)	(697)	(18,956)
Derivative Financial Liabilities							
Interest rate swaps used for hedging	1	(5)	–	–	–	–	–
Cross currency swaps used for hedging	87						
Cash outflow		(292)	–	–	–	–	–
Cash inflow		203	–	–	–	–	–
Forward foreign exchange contracts used for hedging	79						
Cash outflow	–	–	–	–	–	–	(923)
Cash inflow	–	–	–	–	–	–	785
Other forward foreign exchange contracts designated at fair value	3						
Cash outflow		(376)	–	–	–	–	–
Cash inflow		371	–	–	–	–	–
Financially settled commodity derivative liabilities designated at fair value	81	(75)	(6)	–	–	–	–
Physically settled commodity derivative liabilities designated at fair value	14	17	(2)	–	–	–	–
		(157)	(8)	–	–	–	(138)
Total Financial Liabilities		(5,491)	(1,003)	(814)	(659)	(697)	(19,094)
Derivative Financial Assets							
Financially settled commodity derivative assets designated at fair value	(85)	47	7	1	–	–	–
Physically settled commodity derivative assets designated at fair value	(7)	38	29	4	4	5	9
Net Financial Liabilities[1]		$ (5,406)	$ (967)	$ (809)	$ (655)	$ (692)	$ (19,085)

[1] *The Company believes that the liquidity risk associated with commodity derivative financial liabilities needs to be considered in conjunction with the profile of payments or receipts arising from commodity derivative financial assets. It should be noted that cash flows associated with future energy sales and commodity contracts which are not considered financial instruments under IAS 39 are not included in this analysis, which is prepared in accordance with IFRS 7.*

MARKET RISKS

(a) Currency Risk

Sensitivity Analysis

A $0.01 strengthening or weakening of the US dollar against the Canadian dollar at March 31, 2013 would have an impact of $2 million, but as a result of regulatory accounting would have no impact on net income and would have an immaterial impact on other comprehensive income. The regulatory account that captures all variances from forecasted finance charges as described in Note 12 eliminates any impact on net income. This analysis assumes that all other variables, in particular interest rates, remain constant.

This sensitivity analysis has been determined assuming that the change in foreign exchange rates had occurred at March 31, 2013 and been applied to each of the Company's exposures to currency risk for both derivative and non-derivative financial instruments in existence at that date, and that all other variables remain constant. The stated change represents management's assessment of reasonably possible changes in foreign exchange rates over the period until the next statement of financial position date.

(b) Interest Rate Risk

Fair value sensitivity analysis for fixed rate non-derivative instruments

The Company accounts for certain fixed rate financial assets and liabilities as financial assets and liabilities at fair value through profit or loss. A change in interest rates at March 31, 2013 would not affect net income and would have no impact on other comprehensive income with respect to these fixed rate instruments. The regulatory account that captures all variances from forecasted finance charges as described in Note 12 eliminates any impact on net income. This analysis assumes that all other variables, in particular foreign exchange rates, remain constant.

Sensitivity analysis for variable rate non-derivative instruments and derivative instruments

An increase or decrease of 100-basis points in interest rates at March 31, 2013 would have an impact of $30 million, but as a result of regulatory accounting would have no impact on net income and would have no material impact on other comprehensive income. The Finance Charges regulatory account that captures all variances from forecasted finance charges as described in Note 12 eliminates any impact on net income. This analysis assumes that all other variables, in particular foreign exchange rates, remain constant.

This sensitivity analysis has been determined assuming that the change in interest rates had occurred at March 31, 2013 and been applied to each of the Company's exposure to interest rate risk for both derivative and non-derivative financial instruments in existence at that date, and that all other variables remain constant. The stated change represents management's assessment of reasonably possible changes in interest rates over the period until the next statement of financial position date.

(c) Commodity Price Risk

Sensitivity Analysis

Commodity price risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in commodity prices.

BC Hydro's subsidiary Powerex trades and delivers energy and associated products and services throughout North America. As a result, the Company has exposure to movements in commodity prices for commodities Powerex trades, including electricity, natural gas and associated derivative products. Prices for these commodities fluctuate in response to changes in supply and demand, market uncertainty, and other factors beyond the Company's control.

The Company manages these exposures through its Board-approved risk management policies, which limit components of and overall market risk exposures, pre-define approved products and mandate regular reporting of exposures.

The Company's risk management policy for trading activities defines various limits and controls, including Value at Risk ("VaR") limits, mark-to-market limits, and various transaction specific limits which are monitored on a daily basis. VaR estimates the pre-tax forward trading loss that could result from changes in commodity prices, with a specific level of confidence, over a specific time period. Powerex uses an industry standard Monte Carlo VaR model to determine the potential change in value of its forward trading portfolio over a 10-day holding period, within a 95 per cent confidence level, resulting from normal market fluctuations.

VaR as an estimate of price risk has several limitations. The VaR model uses historical information to determine potential future volatility, assuming that price movements in the recent past are indicative of near-future price movements. It cannot forecast unusual events which can lead to extreme price movements. In addition, it is sometimes difficult to appropriately estimate the VaR associated with illiquid or non-standard products. As a result, Powerex uses additional measures to supplement the use of VaR to estimate price risk. These include the use of a Historic VaR methodology, stress tests and notional limits for illiquid or emerging products.

Powerex's VaR, calculated under this methodology, was approximately $11 million at March 31, 2013 (2012 - $11 million).

FAIR VALUE HIERARCHY

The following provides an analysis of financial instruments that are measured subsequent to initial recognition at fair value, grouped based on the lowest level of input that is significant to that fair value measurement.

The inputs used in determining fair value are characterized by using a hierarchy that prioritizes inputs based on the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

Level 1 values are quoted prices (unadjusted) in active markets for identical assets and liabilities.

Level 2 inputs are those other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, as of the reporting date.

Level 3 inputs are those that are not based on observable market data.

The following tables present the financial instruments measured at fair value for each hierarchy level as at March 31, 2013 and 2012:

As at March 31, 2013	Level 1	Level 2	Level 3	Total
Short-term investments	$ 22	$ –	$ –	$ 22
Revolving borrowings	–	(2,573)	–	(2,573)
Derivatives designated as hedges	–	(156)	–	(156)
Derivatives not designated as hedges	(12)	(22)	34	–
	$ 10	$ (2,751)	$ 34	$ (2,707)

As at March 31, 2012	Level 1	Level 2	Level 3	Total
Short-term investments	$ 12	$ –	$ –	$ 12
Revolving borrowings	–	(2,683)	–	(2,683)
Derivatives designated as hedges	–	(150)	–	(150)
Derivatives not designated as hedges	4	(31)	47	20
	$ 16	$ (2,864)	$ 47	$ (2,801)

As at April 1, 2011	Level 1	Level 2	Level 3	Total
Short-term investments	$ 27	$ –	$ –	$ 27
Revolving borrowings	–	(2,333)	–	(2,333)
Derivatives designated as hedges	–	(155)	–	(155)
Derivatives not designated as hedges	(1)	(23)	27	3
	$ 26	$ (2,511)	$ 27	$ (2,458)

There were no transfers between Levels 1 and 2 during the year.

The following table reconciles the changes in the balance of financial instruments carried at fair value on the statement of financial position, classified as Level 3, for the years ended March 31, 2013 and 2012:

(in millions)	
Balance at April 1, 2011	**$ 27**
Cumulative impact of net gain recognized	74
New transactions	16
Transfer from level 2 to level 3	2
Existing transactions settled	(72)
Balance at March 31, 2012	**$ 47**
Cumulative impact of net gain recognized	24
New transactions	10
Existing transactions settled	(47)
Balance at March 31, 2013	**$ 34**

A net loss of $2 million recognized in net income during the year ended March 31, 2013 relates to Level 3 financial instruments held at March 31, 2013. The net loss is recognized in operating expenses.

The Company believes that the use of reasonable alternative valuation input assumptions in the calculation of Level 3 fair values would not result in significantly different fair values.

NOTE 19: OTHER LONG-TERM LIABILITIES

(in millions)	**March 31 2013**	March 31 2012	April 1 2011
Provisions			
Environmental liabilities	**$ 340**	$ 326	$ 282
Decommissioning obligations	**52**	68	50
Other	**43**	43	30
Total Provisions	**435**	437	362
First Nations liabilities	**387**	392	303
Finance lease obligations	**292**	309	325
Deferred revenue - Skagit River Agreement	**423**	418	411
	1,537	1,556	1,401
Less: Current portion, included in accounts payable and accrued liabilities	**(98)**	(127)	(124)
Total	**$ 1,439**	$ 1,429	$ 1,277

Changes in each class of provision during the financial year are set out below:

	Environmental	Decommissioning	Other	Total
Balance at March 31, 2012	$ 326	$ 68	$ 43	$ 437
Made during the period	23	–	–	23
Used during the period	(40)	(10)	–	(50)
Reversed during the period	(1)	–	–	(1)
Changes due to changes in estimate	26	(7)	–	19
Accretion	6	1	–	7
Balance at March 31, 2013	$ 340	$ 52	$ 43	$ 435

ENVIRONMENTAL LIABILITIES

The Company has recorded a liability for the estimated future expenditures associated with the removal and destruction of PCB-contaminated insulating oils and related electrical equipment and for the assessment and remediation of chemically contaminated lands. The Company's recorded liability is based on management's best estimate of the present value of the future expenditures expected to be required to comply with existing regulations. The current present value of PCB remediation expenditures is $291 million. Of this total, $257 million was recorded as an environmental liability and $34 million was recorded as a decommissioning obligation.

The Company has recorded a liability for the estimated future expenditures associated with the remediation of asbestos containing materials installed in some of its facilities, equipment and infrastructure. The current present value of the estimated future asbestos remediation expenditures is $44 million. In addition, the Company has recorded $39 million for other environmental remediation expenditures not associated with PCB and asbestos.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of cash flows may differ significantly from the Company's current assumptions. In addition, for the PCB program, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

The undiscounted cash flow related to the Company's environmental liabilities, which will be incurred between fiscal 2014 and 2045, is approximately $435 million and was determined based on current cost estimates. A range of discount rates between 1.0 to 2.6 per cent were used to calculate the net present value of the obligations.

As described in Note 12, the Company has recorded a regulatory asset in relation to the environmental liabilities.

DECOMMISSIONING OBLIGATIONS

The Company's decommissioning obligation provision consists of estimated removal and destruction costs associated with certain PCB contaminated assets, certain submarine cables and decommissioning costs associated with a small dam. The Company has determined its best estimate of the undiscounted amount of cash flows required to settle remediation obligations at $89 million (2012 – $107 million), which will be settled between fiscal 2014 and 2054. The undiscounted cash flows are then discounted by a range of discount rates between 1.0 to 2.6 per cent were used to calculate the net present value of the obligations. The obligations are re-measured at each period end to reflect changes in estimated cash flows and discount rates.

FIRST NATIONS LIABILITIES

The First Nations liabilities consist primarily of settlement costs related to agreements reached with various First Nations groups. First Nations liabilities are recorded as financial liabilities and are measured at fair value on initial recognition with future contractual cash flows being discounted at rates ranging from 4.4 percent to 5.0 percent. These liabilities are measured at amortized cost and not re-measured for changes in discount rates. The First Nations liabilities are non-interest bearing.

FINANCE LEASE LIABILITIES

The finance lease obligations are related to long-term energy purchase agreements. The present value of the lease obligations were discounted at rates ranging from 7.9 percent to 9.3 percent with contract terms of 25 years expiring from 2018 until 2036. Finance lease liabilities are payable as follows:

(in millions)	**Future minimum lease payments 2013**	**Interest 2013**	**Present value of minimum lease payments 2013**	Future minimum lease payments 2012	Interest 2012	Present value of minimum lease payments 2012	Future minimum lease payments 2011	Interest 2011	Present value of minimum lease payments 2011
Less than one year	**$ 40**	**$ 24**	**$ 16**	$ 42	$ 26	$ 16	$ 40	$ 27	$ 13
Between one and five years	**181**	**96**	**85**	200	105	95	202	113	89
More than five years	**353**	**162**	**191**	375	177	198	418	195	223
Total minimum lease payments	**$ 574**	**$ 282**	**$ 292**	$ 617	$ 308	$ 309	$ 660	$ 335	$ 325

DEFERRED REVENUE – SKAGIT RIVER AGREEMENT

Deferred revenue consists principally of amounts received under the agreement relating to the Skagit River, Ross Lake, and the Seven Mile Reservoir on the Pend d'Orielle River. Under the agreement, the Company has committed to deliver a pre-determined amount of electricity each year to the City of Seattle for an 80 year period ending in fiscal 2066 in return for two annual payments of approximately US$22 million per year for 35 years ending in 2012 and US$100,000 (adjusted for inflation) per year for the 80-year period.

NOTE 20: COMMITMENTS AND CONTINGENCIES

ENERGY COMMITMENTS

BC Hydro (excluding Powerex) has long-term energy purchase contracts to meet a portion of its expected future domestic electricity requirements. The expected obligations to purchase energy under these contracts have a total value of approximately $52,407 million of which approximately $869 million relates to the purchase of natural gas and natural gas transportation contracts, at market prices over 30 years. The remaining commitments are at predetermined prices. Included in the total value of the long-term energy purchase agreements are $574 million accounted for as obligations under capital leases. The total BC Hydro combined payments are estimated to be approximately $1,043 million for less than one year, $5,632 million between one and five years, and $45,732 million for more than five years.

Powerex has energy purchase commitments with an estimated minimum payment obligation of $2,585 million extending to 2024. The total Powerex energy purchase commitments are estimated to be approximately $533 million for less than one year, $912 million between one and five years, and $1,140 million for more than five years. Powerex has energy sales commitments of $878 million extending to 2024 with estimated amounts of $532 million for less than one year, $296 million between one and five years, and $50 million for more than five years.

LEASE AND SERVICE AGREEMENTS

The Company has entered into various agreements to lease facilities or assets treated as operating leases, or to purchase business support services. The agreements cover periods of up to 10 years, and the aggregate minimum payments are approximately $525 million. Payments are $129 million for less than 1 year, $344 million between one and five years, and $51 million for more than five years.

LEGAL CONTINGENCIES

a) Since 2000, Powerex has been named, along with other energy providers, in lawsuits and U.S. federal regulatory proceedings which seek damages and/or contract rescissions based on allegations that, during part of 2000 and 2001, the California wholesale electricity markets were unlawfully manipulated and energy prices were not just and reasonable. Powerex has obtained dismissals of all but one of the lawsuits. In the remaining lawsuit, the California Department of Water Resources (CDWR) has claimed that it was forced under duress to enter into numerous transactions with Powerex in 2001. Powerex has obtained an indefinite stay of this remaining lawsuit pending resolution of related proceedings before the Federal Energy Regulatory Commission (FERC).

   FERC has approved a settlement agreement between FERC staff and Powerex that acknowledged that there was no evidence that Powerex engaged in any gaming or other improper practices with any other market participants, and further noted that Powerex was a valuable and reliable supplier to the California market throughout the energy crisis. FERC's approval of this settlement is currently being challenged by various California parties.

   FERC decided earlier in the proceedings that certain market-wide refunds will have to be paid by energy providers to various California parties. The precise amount has not been determined and the timing of the refunds is unknown. FERC commenced an inquiry in April 2012 to consider whether individual sellers engaged in unlawful market activity during the summer of 2000, and if so, whether the unlawful activity affected the market clearing price. An initial decision unfavourable to Powerex and other respondents which is advisory only and has no force or effect was issued by a FERC trial judge in February 2013. Powerex and the other respondents will ask the FERC Commission to reject the initial decision in its entirety on the basis that it failed to provide the legal and factual analysis required by the Commission. The FERC Commission has complete discretion as to how it treats the decision and will likely issue a final order during the calendar year 2014.

A FERC trial judge has determined that in the event Powerex and other energy providers improperly reported transactional data to FERC in 2000 and 2001, those reports did not hide an accumulation of market power which resulted in unreasonably high energy prices. The FERC Commission has issued a final order upholding the trial judge's decision. The California Parties are seeking a rehearing from FERC and if they are unsuccessful, it is likely they will commence appeal proceedings.

A FERC hearing will commence in August 2013 on the California parties' allegations of market manipulation by Powerex and other respondents in the Pacific Northwest (PNW) between January 2000 and June 2001, and to consider whether there should be refunds for PNW bilateral contract transactions.

Two other FERC proceedings involving allegations of wrongdoing against Powerex were dismissed by the FERC Commission in May 2011, and the California Parties filed requests for rehearing in both those proceedings. FERC has denied the rehearing request in both proceedings and the California Parties have appealed the dismissal and denial orders to the Ninth Circuit Court.

At March 31, 2013, Powerex was owed US $265 million ($269 million) plus interest by the California Power Exchange (Cal Px) and the California Independent System Operator (CAISO) related to Powerex's electricity trade activities in California during the period covered by the lawsuits. As a result of defaults by a number of California utilities, the Cal Px and CAISO were unable to pay these amounts to Powerex. It is expected those receivables will be offset against any refunds that Powerex is required to pay.

Due to the ongoing nature of the regulatory and legal proceedings against Powerex, management cannot predict the outcomes of the claims against Powerex. Powerex has recorded provisions for uncollectible amounts and legal costs associated with the California energy crisis. These provisions are based on management's best estimates, and are intended to adequately provide for any exposure. However, the amounts that are ultimately collected or paid may differ from management's current estimates. Management has not disclosed the provision amounts or ranges of expected outcomes due to the potentially adverse effect on the process.

b) Facilities and Rights of Way: the Company is subject to existing and pending legal claims relating to alleged infringement and damages in the operation and use of facilities owned by the Company. These claims may be resolved unfavourably with respect to the Company and may have a significant adverse effect on the Company's financial position. For existing claims in respect of which settlement negotiations have advanced to the extent that potential settlement amounts can reasonably be predicted, management has recorded a liability for the potential costs of those settlements. For pending claims, management believes that any loss exposure that may ultimately be incurred may differ materially from management's current estimates. Management has not disclosed the ranges of expected outcomes due to the potentially adverse effect on the negotiation process for these claims.

c) Due to the size, complexity and nature of the Company's operations, various other legal matters are pending. It is not possible at this time to predict with any certainty the outcome of such litigation. Management believes that any settlements related to these matters will not have a material effect on the Company's consolidated financial position or results of operations.

d) The Company and its subsidiaries have outstanding letters of credit totalling $389 million, of which there is US $115 million (2012 – US $110 million).

NOTE 21: RELATED PARTY TRANSACTIONS

SUBSIDIARIES

The principal subsidiaries of BC Hydro are Powerex Corporation (Powerex), Powertech Labs Inc. (Powertech), and Columbia Hydro Constructors Ltd. (Columbia).

All companies are wholly owned and incorporated in Canada and all ownership is in the form of common shares. Powerex is involved in the marketing and trading of power and gas in Canada and the United States. Powertech offers services to solve technical problems with power equipment and systems in Canada and throughout the world. Columbia provides construction services in support of certain BC Hydro capital programs.

All intercompany transactions and balances are eliminated upon consolidation.

RELATED PARTIES

As Crown corporations of the Province, the Company and the Province are considered related parties. All transactions between the Company and its related parties are considered to possess commercial substance and are consequently recorded at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The related party transactions are summarized below:

(in millions)	**2013**	2012	2011
Balance sheet			
Accounts receivable	**$ 109**	$ 88	$ 105
Accounts payable and accrued liabilities	**274**	281	514
Amounts incurred/accrued during the year include:			
Water rental fees	**348**	357	298
Cost of energy sales	**89**	110	131
Taxes	**123**	116	120
Interest	**628**	611	487
Payment to the Province	**215**	230	463

The Company's debt is either held or guaranteed by the Province (see Note 15). Under an agreement with the Province, the Company indemnifies the Province for any credit losses incurred by the Province related to interest rate and foreign currency contracts entered into by the Province on the Company's behalf. At March 31, 2013, the aggregate exposure under this indemnity totaled approximately $20 million (2012 - $29 million, April 1, 2011 - $43 million). The Company has not experienced any losses to date under this indemnity.

As Crown corporations of the Province, the Company and British Columbia Investment Management Corporation ("bcIMC") are both related parties. The Company has responsibility for administration of the British Columbia Hydro and Authority Pension Plan and uses internal and external service providers for this purpose. It has engaged bcIMC to manage investments on behalf of the plan. bcIMC uses internal and external investment managers for this purpose.

Refer to Note 17 for the Company contributions to the pension plan for 2013 and 2012.

KEY MANAGEMENT PERSONNEL AND BOARD COMPENSATION

Key management personnel and board compensation includes compensation to the Company's executive officers, executive vice presidents, senior vice presidents and board of directors.

(in millions)	**2013**	2012
Short-term employee benefits	$ **3**	$ 3
Post-employment benefits	**1**	1
Termination benefits	**–**	1
Other long-term benefits	**–**	–

NOTE 22: EXPLANATION OF TRANSITION TO THE PRESCRIBED STANDARDS

As stated in Note 2, these are the Company's first consolidated financial statements prepared in accordance with the Prescribed Standards.

The accounting policies set out in Note 3 have been applied in preparing the financial statements for the year ended March 31, 2013, the comparative information presented in these financial statements for the year ended March 31, 2012 and in preparation of an opening statement of financial position at April 1, 2011 (the Company's date of transition).

In adopting the Prescribed Standards, the Company has applied the recognition, measurement, presentation and disclosure principles of IFRS 1 in preparing its transitional adjustments and financial statements. The principles of IFRS 1 generally require that first-time adopters of a new set of accounting policies retrospectively apply all effective standards and interpretations in effect as at the reporting date. However IFRS 1 also provides for certain optional exemptions and certain mandatory exemptions to full retrospective application. In adopting the Prescribed Standards, the Company has elected to apply the following mandatory and optional exemptions available under IFRS 1:

(a) IFRS Mandatory Exceptions

(i) Hedge Accounting

Hedging relationships that do not qualify for hedge accounting in accordance with IAS 39, *Financial Instruments: Recognition and Measurement* are not reflected in the opening statement of financial position. Hedge accounting has therefore been discontinued for those transactions that no longer meet the conditions under IAS 39 on a prospective basis. No transactions entered into before the date of transition to the Prescribed Standards have been retrospectively designated as hedges.

ii) Estimates

The Company's estimates under the Prescribed Standards at the date of transition were consistent with estimates made under CGAAP. Estimates previously made were not revised for changes under the Prescribed Standards except to reflect any difference in accounting policies.

(b) Optional Exceptions

(i) Fair Value as Deemed Cost

Entities that hold items of property, plant and equipment or intangible assets used in operations subject to rate regulation are permitted under IFRS 1 to elect to use their carrying amounts as deemed cost at the date of transition to the Prescribed Standards. The carrying amount of such items may include amounts that were recorded under CGAAP but do not qualify for capitalization in accordance with the Prescribed Standards. The Company has elected to apply this exemption except for assets impacted by elections (ii) and (vi) in this section.

(ii) Leases

IFRS 1 allows entities to apply the transitional provisions in IFRIC 4 – *Determining whether an Arrangement contains a Lease*, which allows the Company to determine whether an arrangement existing at the date of transition to the Prescribed Standards contains a lease on the basis of facts and circumstances existing at that date. This election has been applied to the assessment of energy purchase contracts that were previously grandfathered under EIC-150, *Determining Whether an Arrangement Contains a Lease*.

(iii) Employee Benefits

IFRS 1 allows entities to recognize all cumulative unrecognized actuarial gains and losses at the date of transition to the Prescribed Standards. This election has been applied to all employee benefit plans.

(iv) Cumulative Translation Differences

IAS 21, *The Effects of Changes in Foreign Exchange Rates* requires an entity to recognize foreign exchange differences arising on translation of subsidiaries with a different functional currency in other comprehensive income and accumulate these in a separate component of equity. However, IFRS 1 allows entities to not comply with these requirements for cumulative translation differences that existed at the date of transition to the Prescribed Standards. This election has been applied to the operations of Powerex with all related cumulative translation differences deemed to be zero at the date of transition.

(v) Designation of Previously Recognized Financial Instruments

IFRS 1 permits an entity to designate a previously recognized financial liability as a financial liability at fair value through profit or loss. The Company has discontinued fair value hedge accounting with respect to a number of its Canadian dollar denominated debt issues and has applied this exemption to the underlying debt under the discontinued hedging relationship.

(vi) Decommissioning Liabilities Included In the Cost of Property, Plant and Equipment

IFRIC 1, *Changes in Existing Decommissioning, Restoration and Similar Liabilities* requires specified changes in a decommissioning, restoration or similar liability to be adjusted against the cost of the asset to which it relates with the adjusted amount depreciated prospectively over its remaining useful life. IFRS 1 provides an exemption from complying with these requirements for changes in such liabilities that occurred before the date of transition to the Prescribed Standards. The Company has applied this exemption to existing asset retirement obligations recognized under CGAAP and to new obligations recognized on transition to the Prescribed Standards.

(vii) Fair Value Measurement of Financial Assets or Financial Liabilities at Initial Recognition

For transactions which are recognized as financial instruments at fair value under IFRS, but were not recognized at fair value under CGAAP, IFRS 1 permits an entity to avoid retrospectively applying certain measurement guidance in IAS 39 for the term of the transaction prior to the Prescribed Standards transition. This exemption is only available for transactions which were entered into prior to the date of the Prescribed Standards transition. The Company has applied this exemption to all eligible transactions as at the date of transition.

In preparing its opening statement of financial position, the Company has adjusted amounts reported previously in financial statements prepared in accordance with CGAAP. An explanation of how the transition from CGAAP to the Prescribed Standards has affected the Company's financial position, financial performance and cash flows is set out in the following tables and the notes that accompany the tables:

Reconciliation of the Consolidated Statement of Financial Position Prepared According to the Prescribed Standards

		April 1, 2011			March 31, 2012		
(in millions)	Note	Canadian GAAP	Effect of Transition	Prescribed Standards	Canadian GAAP	Effect of Transition	Prescribed Standards
ASSETS							
Current Assets							
Cash and cash equivalents		$ 27	$ –	$ 27	$ 12	$ –	$ 12
Accounts receivable and accrued revenue		569	–	569	595	–	595
Inventories		128	(2)	126	142	–	142
Prepaid expenses		156	–	156	147	–	147
Current portion of derivative financial instrument assets	n	198	–	198	140	–	140
		1,078	(2)	1,076	1,036	–	1,036
Non-Current Assets							
Property, plant and equipment	a-e,g,o	15,211	(192)	15,019	16,420	(429)	15,991
Intangible assets		335	–	335	412	–	412
Regulatory assets	t	2,436	983	3,419	2,761	1,553	4,314
Sinking funds		97	–	97	105	–	105
Employee future benefits	h	296	(296)	–	272	(272)	–
Derivative financial instrument assets	n	26	1	27	41	1	42
		18,401	496	18,897	20,011	853	20,864
		$ 19,479	$ 494	$ 19,973	$ 21,047	$ 853	$ 21,900
LIABILITIES AND EQUITY							
Current Liabilities							
Accounts payable and accrued liabilities	n,o	$ 1,589	$ 5	$ 1,594	$ 1,393	$ 30	$ 1,423
Current portion of long-term debt	j	2,793	10	2,803	2,886	2	2,888
Current portion of derivative financial instrument liabilities	n	159	6	165	116	7	123
		4,541	21	4,562	4,395	39	4,434
Non-Current Liabilities							
Long-term debt	j,l	8,851	58	8,909	10,026	36	10,062
Regulatory liabilities	t	276	(1)	275	295	(16)	279
Derivative financial instrument liabilities		212	–	212	189	–	189
Contibutions in aid of construction	c	1,012	–	1,012	1,110	(4)	1,106
Post employment benefits	h	345	500	845	370	812	1,182
Other long-term liabilities	f-g,o,r	1,362	(85)	1,277	1,464	(35)	1,429
		12,058	472	12,530	13,454	793	14,247
Shareholder's Equity							
Contributed surplus		60	–	60	60	–	60
Retained earnings	b-h,j-o,r	2,747	–	2,747	3,075	–	3,075
Accumulated other comprehensive income	k,m,r	73	1	74	63	21	84
		2,880	1	2,881	3,198	21	3,219
		$ 19,479	$ 494	$ 19,973	$ 21,047	$ 853	$ 21,900

For presentation purposes, the current portion of other long-term liabilities has been reclassified and included in accounts payable and accrued liabilities in the comparative periods under CGAAP, increasing accounts payable and accrued liabilities and decreasing other long-term liabilities by $74 million at April 1, 2011 and $49 million at March 31, 2012.

Reconciliation of the Consolidated Statement of Comprehensive Income

		For the year ended March 31, 2012		
(in millions)	Note	Canadian GAAP	Effect of Transition	Prescribed Standards
Revenues				
Domestic	c,n,p	$ 3,709	$ 39	$ 3,748
Trade	t	975	7	982
		4,684	46	4,730
Expenses				
Operating Expenses	b-d,f-i,o-q	3,643	30	3,673
Finance Charges	e,f,i-m,o,q	483	16	499
Net Income		$ 558	$ –	$ 558
Other Comprehensive Income (Loss):				
Effective portion of changes in fair value on derivatives designated as cash flow hedges	k,m	$ 16	$ (9)	$ 7
Reclassification to income on derivatives designated as cash flow hedges	m	(26)	14	(12)
Foreign currency translation gains	r	–	15	15
Other Comprehensive Income (Loss)		$ (10)	$ 20	$ 10
Total Comprehensive Income		$ 548	$ 20	$ 568

NOTES TO THE RECONCILIATION OF THE CONSOLIDATED STATEMENT OF FINANCIAL POSITION AND CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME PREPARED ACCORDING TO THE PRESCRIBED STANDARDS:

The following explanations disclose the key impacts arising on transition from CGAAP to the Prescribed Standards. The net transitional impacts to retained earnings, contributed surplus and actuarial losses in accumulated other comprehensive income as at April 1, 2011 and for the year ended March 31, 2012 have been deferred to regulatory assets and liabilities on the statement of financial position for regulatory accounting purposes. As identified in the Company's Amended fiscal 2012-2014 Revenue Requirements Application (Amended RRA), the Company has requested approval to defer the retained earnings impacts resulting from the application of the principles of IFRS that are not within the current scope of existing regulatory deferral accounts. Refer to Note 12 for further information on regulatory accounts.

(a) Fair Value as Deemed Cost

With the application of the deemed cost exemption, the net book value of property, plant and equipment and intangible assets for BC Hydro entities subject to rate regulation at April 1, 2011 have become the opening cost of property, plant and equipment and intangible assets under the Prescribed Standards except for finance leases and asset retirement obligation assets.

(b) Componentization

CGAAP permits component accounting for property, plant and equipment but does not require componentization of assets. The principles of IFRS require the componentization of significant parts of an asset where the useful life or the depreciation method of the part of the asset differs from the remainder of the asset. In addition certain expenditures under CGAAP are eligible for capitalization and are considered asset components under the Prescribed Standards. The impact of componentization as at and for the year ended March 31, 2012 was a decrease in property, plant and equipment of $7 million and a corresponding increase in depreciation expense of $7 million due to the reduction in the useful life of the component assets compared to the life of the parent asset.

(c) Mass Asset Retirements

Under CGAAP, the Company did not record any gains or losses for assets that are tracked on a pooled basis except when entire pools or a substantial portion of an asset pool is retired prior to being fully amortized. The principles of IFRS require that gains and losses on disposal of assets be recognized immediately in income, and not charged or credited to accumulated amortization. The impact as at and for the year ended March 31, 2012 was a loss of $29 million recognized for the retirement of pooled assets offset by recognition of associated deferred contributions in aid into revenue in the amount $4 million.

(d) Capital Overhead

Under CGAAP, there are expenditures allocated to capital that are associated with capital programs that are no longer eligible for capitalization under the principles of IFRS as they are not considered directly attributable to the construction of the asset. The effect of this difference as at and for the year ended March 31, 2012 was a decrease in property, plant and equipment and a corresponding increase in operating costs in the amount of $206 million.

(e) Interest During Construction

Under CGAAP, the Company capitalized interest on all capital projects regardless of project duration period. Under the principles of IFRS, interest costs are only capitalized in relation to an asset that takes a "substantial period of time" to prepare for their intended use. The Company considers a substantial period of time to be in excess of six months; therefore interest costs that relate to capital projects with less than six months duration to prepare for their intended use are no longer eligible for capitalization and must be expensed in the period incurred. The effect as at and for the year ended March 31, 2012 was a decrease in property, plant and equipment and a corresponding increase in finance charges of $7 million.

(f) New Provisions

Measurement requirements for provisions under the principles of IFRS have a lower recognition threshold than CGAAP and as a result, upon transition to the Prescribed Standards, a provision has been estimated in connection with asbestos at various facilities. This resulted in an increase in total provisions of $26 million and a corresponding decrease in retained earnings as at April 1, 2011. The accretion adjustment for the year ended March 31, 2012 was an increase of $1 million in finance charges and a corresponding increase to the environmental liability.

A provision has also been estimated in connection with the decommissioning of a specific facility due to the identification of a constructive obligation under the principles of IFRS. The amount recognized as at and for the year ended March 31, 2012 was a $15 million environmental obligation offset by a corresponding increase in provision expense.

(g) Provision Re-Measurement

Under CGAAP, there was no requirement to re-measure provisions for changes in discount rates. Under IAS 37, *Provisions, Contingent Liabilities and Contingent Assets*, provisions are reviewed at the end of each reporting period and adjusted to reflect the current best estimate, including a reassessment in discount rates where the present value of a provision has been calculated. The revaluation of these provisions to reflect the appropriate discount rates at the end of each reporting period resulted in an increase in total provisions of $26 million and a corresponding decrease in retained earnings as at April 1, 2011. There was an increase in provisions and provision expense for the year ended March 31, 2012 of $42 million.

The Company elected to use an exemption allowing decommissioning related assets to be re-measured on a simplified approach at the transition date rather than perform a full detailed calculation. At the transition date, the re-measurement increased decommissioning liabilities by $6 million, increased property, plant and equipment by $4 million and decreased retained earnings by $2 million. In addition to the transition date adjustment, the re-measurement increased the decommissioning liabilities and property, plant and equipment by $2 million for the year ended March 31, 2012.

(h) Actuarial Gains and Losses Recognition

Under CGAAP, the Company recognized actuarial gains and losses in net income over the employees' remaining service period. Under the principles of IFRS, the Company's policy is to recognize all actuarial gains and losses in other comprehensive income. As permitted by IFRS 1, the Company has elected to recognize all previously unrecognized actuarial gains and losses that existed at the date of transition in opening retained earnings for all of its employee post-employment and defined benefit plans. IAS 19 requires all vested past service costs to be recognized immediately. Under CGAAP, the Company recognized past service costs over the expected average remaining service life of the employees. On the date of transition, the Company recognized all vested past service costs into opening retained earnings with a resulting decrease in the post retirement benefit liability.

The effect as at the date of the transition resulted in a decrease to the defined benefit asset of $296 million, an increase in the defined benefit obligation of $500 million and a decrease in opening retained earnings of $796 million. The reversal of amortization previously recognized under CGAAP resulted in a decrease of $34 million to the pension benefit obligation and expense for the year ended March 31, 2012. For the year ended March 31, 2012, actuarial gains and losses recognized in other comprehensive income amounted to a loss of $322 million.

In accordance with the Prescribed Standards, the transition date adjustment impacts net of the reversal of the fiscal 2012 amortization recognized under CGAAP has been deferred to the IFRS Pension & Other Post Employment Benefits regulatory account. The fiscal 2012 actuarial gains and losses recognized in other comprehensive income have been deferred to the Non-Current Pension Cost regulatory account.

(i) Interest Reclassification

Under the principles of IFRS, interest on defined benefit obligations and interest on defined benefit plan assets are classified as finance charges rather than as operating costs under CGAAP. The effect was a reclassification of net interest expense on the plan obligations and assets from operating costs to finance charges of $13 million for the year ended March 31, 2012.

(j) Designation of Previously Recognized Financial Instruments

As permitted by IFRS 1, the Company has elected to designate a number of previously recognized liabilities as a financial liability at fair value through the profit or loss at the date of transition. The Company has discontinued fair value hedge accounting with respect to a number of its Canadian denominated debt issues and has applied this exemption to the underlying debt under the discontinued hedging relationship. This increased the current portion of long term debt by $10 million, increased long term debt by $53 million and decreased opening retained earnings by $63 million as at April 1, 2011. There was an additional decrease in long-term debt of $28 million and a corresponding decrease in finance charges for the year ended March 31, 2012.

The carrying value of these debt issues at March 31, 2011 was $1,225 million and the fair value at April 1, 2011, the date of transition, was $1,288 million.

(k) Ineffectiveness of Cash Flow Hedges

Certain methods to assess hedge effectiveness under CGAAP are no longer permitted under IFRS. The resulting transitional adjustment recorded to reflect the hedge ineffectiveness that would have been realized under the principles of IFRS in prior years as at the date of transition was less than $1 million. The impact at transition was eliminated in the year ended March 31, 2012.

(l) Fair Value of Debt Issuance

Certain previous Canadian debt issues were issued to the Province of B.C. at yields that were higher or lower than market yields (off market rates). This was allowed under CGAAP under the related parties guidance. The principles of IFRS require all debt to be recorded at its fair value at inception. This adjustment is required to reflect the accounting standards under the principles of IFRS for off market debt issues. This transitional adjustment results in an increase to debt of $5 million, an increase to contributed surplus of $11 million, and a decrease to retained earnings of $16 million as at April 1, 2011.The amortization of this transitional adjustment for the year ended March 31, 2012 resulted in a decrease to finance charges and long-term debt of $2 million.

(m) De-Designation of Cash Flow Hedging Relationship as at April 1, 2011

This transitional adjustment reverses the mark-to-market adjustment from other comprehensive income to finance charges for the comparative period due to the de-designation of specific hedges. The effect is an increase in other comprehensive income and finance charges for the year ended March 31, 2012 of $3 million.

There was an additional adjustment recorded for the amortization of accumulated other comprehensive income amounts due to the de-designation of hedge accounting on April 1, 2011 for transition to the Prescribed Standards. The amortization adjustment resulted in an increase in finance charges and accumulated other comprehensive income for the year ended March 31, 2012 of $2 million.

(n) New Derivatives

Under the principles of IFRS, the lack of a specified notional quantity does not preclude a contract from meeting the criteria for classification as a derivative financial instrument, as is the case under CGAAP. As a result, on transition to the Prescribed Standards, a number of transactions previously recognized by the Company as an executory contract under CGAAP are now recognized on a fair value basis under the principles of IFRS. The impact on the date of transition was a decrease of $3 million to retained earnings offset by an increase for both derivative financial instrument assets and liabilities of $1 million and $6 million, respectively and a decrease in accounts payable and accrued liabilities of $2 million.

There was an increase of $2 million and $1 million in accounts payable and accrued liabilities and derivative financial instrument liabilities respectively, offset by a decrease in revenue for the year ended March 31, 2012.

(o) Leases

On the date of transition to the Prescribed Standards, an energy purchase agreement was assessed as containing an embedded lease under IFRIC 4. The arrangement was subsequently assessed under IAS 17, *Leases* and was classified as a finance lease. Adjustments were also made to two energy purchase agreements that were classified as finance leases under CGAAP. One agreement was reclassified from a finance lease to an operating lease. Another agreement was re-measured using the interest rate implicit in the agreement.

The following table summarizes the impact of the adjustments:

	Incremental Increase (Decrease)	
(in millions)	As at April 1, 2011	For the year ended March 31, 2012
Property, plant and equipment	$ (196)	$ 11
Lease obligation liability	(137)	8
Accounts payable and accrued liabilities	-	6
Retained earnings	(59)	-
Finance charges	-	6
Operating costs	-	(3)

(p) Contributions in Aid

Contributions that are received by the Company to fund customer connections to the ongoing supply of electricity will continue to be recorded as deferred revenue as in the case under CGAAP. Under the principles of IFRS, amortization of the deferred revenue will be recorded as revenue, rather than as depreciation expense under CGAAP. The effect for the year ended March 31, 2012 was a reclassification from depreciation expense to revenue of $39 million.

(q) Accretion Expense Reclassification

Under the principles of IFRS, accretion expense is classified as finance charges rather than as operating costs under CGAAP. The reclassification adjustment from operating costs to finance charges was $2 million for the year ended March 31, 2012.

(r) Functional Currency

In accordance with IFRS 1, the Company elected to deem all foreign currency translation differences arising on consolidation of Powerex to be nil at the date of transition, April 1, 2011. The foreign currency translation adjustment was a gain of $15 million, recognized in other comprehensive income for the year ended March 31, 2012. The impact of foreign currency translation on consolidation is not deferred for regulatory purposes.

In addition, as a result of the change in Powerex's functional currency, Powerex recorded adjustments to its foreign exchange gains and losses as at April 1, 2011 and for the year ended March 31, 2012. The impact of these adjustments was to decrease retained earnings by $3 million at April 1, 2011 and to record a foreign exchange loss of $14 million for the year ended March 31, 2012. The impact of these differences has been deferred for regulatory purposes in the Trade Income Deferral Account.

(s) Change in Classification of Cash Flows

The following table is a reconciliation of the change in classification of cash flows arising from the transition to the Prescribed Standards for the year ended March 31, 2012:

(in millions)	Canadian GAAP	Effect of Transition to Prescribed Standards	Prescribed Standards
Net cash provided by operating activities	$ 975	$ (159)	$ 816
Net cash used in investing activities	(1,769)	159	(1,610)
Net cash provided by financing activities	779	–	779

The adjustments to the cash flow classification arise primarily as a result of reclassification of contributions in aid of construction receipts and reclassification of certain property, plant and equipment expenditures not eligible for capitalization under the principles of IFRS.

(t) Deferral of Transitional Impacts

The transitional impacts resulting from the application of the principles of IFRS to retained earnings, contributed surplus and actuarial losses in accumulated other comprehensive income have been deferred for regulatory purposes. The changes have increased (decreased) regulatory assets and liabilities as follows:

(in millions)		Incremental Increase (Decrease)	
	Note	As at April 1, 2011	For the year ended March 31, 2012
Componentization	b	$ –	$ 7
Mass Asset Retirements	c	–	25
Capital Overhead	d	–	206
Interest During Construction	e	–	7
New Provisions	f	26	16
Provision Re-Measurement	g	28	42
Actuarial Gains and Losses Recognition	h	796	288
Designation of Previously Recognized Financial Instruments	j	63	(28)
Ineffectiveness of Cash Flow Hedges	k	1	–
Fair Value of Debt Issuance	l	5	(2)
De-Designation of Cash Flow Hedging Relationship	m	–	3
New Derivatives	n	3	4
Leases	o	59	3
Foreign Exchange	r	3	14
Incremental increase for the period		984	585
Total cumulative increase as at the balance date		$ 984	$ 1,569
Regulatory assets		$ 983	$ 1,553
Regulatory liabilities		(1)	(16)
Net regulatory increase		$ 984	$ 1,569

The regulatory transfer impact on trade income resulted in a $7 million increase in trade revenue and operating expenses for the year ended March 31, 2012.

FINANCIAL STATISTICS

for the years ended or as at March 31 (millions of dollars)	2013	2012	2011[6]	2010[6]	2009[6]
Revenues	**$ 4,898**	$ 4,730	$ 4,016	$ 4,028	$ 4,269
Expenses					
Energy costs	**1,806**	1,876	1,415	1,621	2,393
Other operating expenses[1]	**894**	820	860	795	915
Amortization	**953**	793	533	487	395
Taxes	**196**	184	184	178	167
Finance charges	**540**	499	435	500	472
	4,389	4,172	3,427	3,581	4,342
Income Before Regulatory Account Transfers	**509**	558	589	447	(73)
Regulatory Transfers[2]	**–**	–	–	–	438
Net Income	**$ 509**	$ 558	$ 589	$ 447	$ 365
Property, Plant and Equipment & Intangible Assets					
At cost[3]	**$18,932**	$ 17,161	$ 23,334	$ 21,300	$ 19,418
Less: Accumulated depreciation[3]	**1,268**	758	7,788	7,305	7,319
Net Book Value	**$17,664**	$ 16,403	$ 15,546	$ 13,995	$ 12,099
Property, Plant & Equipment and Intangible Asset Additions					
Sustaining	**$ 1,009**	$ 956	$ 865	$ 948	$ 664
Growth	**920**	747	654	1,458	733
Total Property, Plant & Equipment and Intangible Asset Additions[4]	**$ 1,929**	$ 1,703	$ 1,519	$ 2,406	$ 1,397
Net Long-Term Debt[5]	**$13,962**	$ 12,833	$ 11,520	$ 10,696	$ 9,135
Retained Earnings	**$ 3,369**	$ 3,075	$ 2,747	$ 2,621	$ 2,221
Debt to Equity Ratio	**80:20**	80:20	80:20	80:20	81:19

1 *Personnel, materials & external services, capitalized costs and other costs.*

2 *In F2011, BC Hydro changed its presentation of the impact of regulation on its statement of comprehensive income. Regulatory Transfers were previously a single line item whereas in F2011 to F2013, they are netted against the corresponding expense or revenue line item. F2010 was restated to conform to the current presentation.*

3 *F2012 to F2013 information was prepared in accordance with the Prescribed Standards. Arising on transition from Canadian Generally Accepted Accounting Principles (GAAP) to the Prescribed Standards and with the application of the deemed cost exemption, the net book value of property, plant and equipment and intangible assets for BC Hydro entities subject to rate regulation at April 1, 2011 have become the opening cost of property, plant and equipment and intangible assets under the Prescribed Standards except for finance leases and asset retirement obligation assets.*

4 *Total property, plant and equipment and intangible asset expenditures include non-cash items.*

5 *Consists of long-term debt, including the current portion, net of sinking funds and cash and cash equivalents.*

6 *F2012 to F2013 information was prepared in accordance with the Prescribed Standards and F2012 information has been restated to Prescribed Standards for comparative purposes. Financial information for F2009 to F2011 was prepared in accordance with Canadian GAAP.*

OPERATING STATISTICS

for the years ended or as at March 31	**2013**	2012	2011	2010	2009
Generating Capacity (megawatts)					
Hydroelectric[1]	**10,927**	10,923	10,923	10,259	10,242
Thermal	**1,120**	1,117	1,096	1,086	1,088
Total	**12,047**	12,040	12,019	11,345	11,330
Peak One-Hour Demand					
Integrated System (megawatts)	**9,153**	9,929	9,790	9,847	10,010
Customers					
Residential	**1,689,050**	1,671,412	1,654,079	1,633,558	1,606,156
Light industrial and commercial	**199,981**	197,821	195,402	193,522	191,286
Large industrial	**172**	168	166	163	162
Other	**3,482**	3,490	3,490	3,455	3,434
Trade	**249**	264	269	287	290
Total	**1,892,934**	1,873,155	1,853,406	1,830,985	1,801,328
Average number of customers per employee	**330**	317	317	311	305
Electricity Sold (gigawatt-hours)					
Residential	**17,703**	18,395	17,797	17,593	17,861
Light industrial and commercial	**18,384**	18,005	18,052	17,811	18,265
Large industrial	**13,508**	13,522	13,164	13,020	14,303
Other	**7,417**	2,275	1,647	1,809	2,083
Domestic	**57,012**	52,197	50,660	50,233	52,512
Trade[2]	**59,957**	54,548	49,615	48,842	50,799
Total	**116,969**	106,745	100,275	99,075	103,311
Total electricity sold per employee (gigawatt-hours)	**15.43**	13.46	13.25	13.43	14.55
Revenues (millions)					
Residential	**$ 1,622**	$ 1,531	$ 1,366	$ 1,272	$ 1,197
Light industrial and commercial	**1,382**	1,321	1,243	1,192	1,054
Large industrial	**731**	680	590	590	481
Other energy sales	**303**	216	239	235	82
Domestic	**4,038**	3,748	3,438	3,289	2,814
Trade[2]	**860**	982	578	739	1,455
Total	**$ 4,898**	$ 4,730	$ 4,016	$ 4,028	$ 4,269

OPERATING STATISTICS
(CONTINUED)

for the years ended or as at March 31	**2013**	2012	2011	2010	2009
Average Revenue (per kilowatt-hour)					
Residential	**9.2 ¢**	8.3 ¢	7.7 ¢	7.2 ¢	6.7 ¢
Light industrial and commercial	**7.5**	7.3	6.9	6.7	5.8
Large industrial	**5.4**	5.0	4.5	4.5	3.4
Other	**4.1**	9.5	14.5	13.0	3.9
Trade[2]	**3.1**	4.0	4.0	4.4	6.6
Average Annual Kilowatt-Hour Use Per Residential Customer	**10,534**	11,067	10,818	10,857	11,258
Lines In Service					
Distribution (kilometres)	**58,115**	57,914	57,648	57,278	56,780
Transmission (circuit kilometres)	**19,163**	18,864	18,764	18,603	18,531
Full Time Equivalent (FTE)[3]	**5,702**	5,875	5,805	5,687	5,416

[1] *Maximum sustained generating capacity.*
[2] *The method used to calculate the trade revenue per kilowatt hour is based on gross electricity and gas revenues.*
[3] *Regular FTEs (the productive hours of work for one employee) for BC Hydro, excluding subsidiaries.*

TOTAL REQUIREMENTS FOR ELECTRICITY AND SOURCES OF SUPPLY

for the years ended March 31

	2013			2012			2011			2010			2009		
	Generating Capacity (Megawatts)	Gigawatt-Hours	%	Generating Capacity (Megawatts)	Gigawatt-Hours	%	Generating Capacity (Megawatts)	Gigawatt-Hours	%	Generating Capacity (Megawatts)	Gigawatt-Hours	%	Generating Capacity (Megawatts)	Gigawatt-Hours	%
Requirements															
Domestic	**12,047**	**57,012**	**65.4**	12,040	52,197	62.2	12,019	50,660	62.1	11,345	50,233	60.3	11,330	52,512	58.0
Electricity trade		**30,975**	**35.6**		26,908	32.1		26,253	32.2		28,210	33.9		32,504	36.0
		87,987	**101.0**		79,105	94.3		76,913	94.3		78,443	94.2		85,016	94.0
Line loss and system use		**(861)**	**(1.0)**		4,783	5.7		4,648	5.7		4,840	5.8		5,391	6.0
		87,126	**100.0**		83,888	100.0		81,561	100.0		83,283	100.0		90,407	100.0
Sources Of Supply															
Hydroelectric generation															
Gordon M. Shrum	**2,730**	**15,878**	**18.2**	2,730	14,447	17.2	2,730	10,015	12.3	2,730	14,756	17.7	2,730	15,287	17.0
Revelstoke	**2,480**	**9,760**	**11.2**	2,480	8,756	10.4	2,480	7,155	8.8	1,980	7,061	8.5	1,980	6,955	7.7
Mica	**1,805**	**7,873**	**9.0**	1,805	7,943	9.5	1,805	6,294	7.7	1,805	6,549	7.9	1,805	5,695	6.3
Kootenay Canal	**583**	**3,595**	**4.1**	583	3,108	3.7	583	2,924	3.6	583	2,255	2.7	583	2,507	2.8
Peace Canyon	**694**	**3,902**	**4.5**	694	3,613	4.3	694	2,591	3.2	694	3,709	4.4	694	3,801	4.2
Seven Mile	**805**	**3,176**	**3.6**	805	3,491	4.2	805	3,210	3.9	805	2,870	3.4	805	3,306	3.7
Bridge River	**478**	**2,626**	**3.0**	478	2,732	3.3	478	2,631	3.2	478	1,948	2.3	478	2,360	2.6
Other	**1,352**	**5,304**	**6.1**	1,348	5,743	6.9	1,348	4,483	5.5	1,184	4,059	4.9	1,167	3,901	4.3
	10,927	**52,115**	**59.8**	10,923	49,833	59.5	10,923	39,303	48.2	10,259	43,207	51.8	10,242	43,812	48.6
Thermal generation															
Burrard	**950**	**25**	**0.0**	950	19	0.0	950	58	0.1	950	233	0.3	950	116	0.1
Other	**170**	**97**	**0.1**	167	124	0.1	146	193	0.2	136	315	0.4	138	347	0.4
Purchases under long-term commitments		**15,003**	**17.2**		15,317	18.3		15,427	18.9		13,403	16.1		12,359	13.6
Purchases under short-term commitments		**19,858**	**22.8**		18,640	22.2		26,208	32.1		27,217	32.7		33,237	36.7
Exchange net		**28**	**0.0**		(45)	(0.1)		372	0.4		(1,092)	(1.3)		536	0.6
	12,047	**87,126**	**100.0**	12,040	83,888	100.0	12,019	81,561	100.0	11,345	83,283	100.0	11,330	90,407	100.0

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For more information about BC Hydro's Annual Report, visit BC Hydro's website at **bchydro.com**

***Above:** The Gordon M. Shrum (GMS) Generating Station is a cornerstone of BC Hydro's system, supplying about 24 per cent of all of BC Hydro's installed generation capacity. Located next to the W.A.C. Bennett Dam on the Peace River near Hudson's Hope, several projects are either underway or planned to start soon that will renew aging equipment at GMS. The most substantial projects involve the replacement of turbines in five units.*

GDS13-134