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Rob - example of conservation discontinuing? Refrigeration buy back program.

Risk to public seen as not helping with conservation? Will investing 375m over three years. Different programs. Haven't lost focus on conservation.

Tom - electric cars and incentives. What's your load forecast on electric vehicles? 6 or 7 thousand. Could increase to 40 or 50 over 20 years.

Vaughn - charts deferred accounts for original and dark blue revised (slide 17) at front end getting worse every year. Hoping to make up at the end. On regulatory accounts

Rates smoothing account, sadjustments had to be made in future years with projects we could reschdule.

On regulatory accounts, unknowns

Trajectories built into rate smoothing plan. Meant to capture variances.

Dirk - job loses? No layoff program to meet these targets.

Les - two more years of dividend? Three more years.

Keith - site c, committed number for contratcs? 4.1 billion committed.

Almost half project committed? Yes.

Federal permit, fed signed off? Two. 1) fisheries act authorization.

How many more? Pretty much done.

Sent from my BlackBerry 10 smartphone on the TELUS network.

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BC Hydro
Power smart

CONFIDENTIAL

Event: Background briefing for RRA filing

Contacts: Simi Heer, Media Relations, BC Hydro 604-375-2746
Mora Scott, Media Relations, BC Hydro 604-880-3863

Date: Thursday, July 28

Time: 1 p.m.

Location: Galiano Room, Hotel Grand Pacific
463 Belleville Street, Victoria, B.C.

Security: Hotel security available; event deemed low risk (invite only); not advertised in lobby

Speakers: Jessica McDonald, President & CEO
Chris O'Riley, Deputy CEO
Cheryl Yaremko, Executive Vice-President Finance and CFO

Media: Legislative reporters (briefing)
News media province wide (news release)

Legislative reporters (invited):
- Keith Baldrey, Global TV
- Bhinder Sajan, CTV
- Tom Fletcher, Black Press
- Dirk Meissner, Canadian Press
- Rob Shaw, Vancouver Sun
- Vaughn Palmer, Vancouver Sun
- Richard Zussman, CBC BC
- Andrew McLeod, The Tyee
- Justine Hunter, Globe & Mail
- Les Leyne, Victoria Times Colonist
- Sophie Rousseau, Radio Canada
- Mike Smyth, The Province
- Lindsay Kines, Victoria Times Colonist
- Mary Griffin, CHEK TV

Format

- In-person technical briefing followed by facilitated Q&A with Jessica with support from Chris & Cheryl.
- Province-wide rollout of media material followed by one-on-one interviews by Jessica (if requested)

Set-up

Holding area
- Space for speakers (Saltspring room) is located directly next to presentation room (available first thing in the morning)

Presentation area
- Smaller, intimate room
- Table at front for all speakers with classroom style set up for reporters (two people per table)
- 70-inch LED screen to display PowerPoint to the right of the speaker table
- No microphones, speakers or telephone lines

Media tactics

• Media calls/invites	Tuesday
• Presentation & speaking notes	Thursday
• News release	Thursday
• Social media (news release, facts)	Thursday
• Media take away material: news release, presentation	Thursday

Timeline

Technical briefing		
11 a.m.	set up of Galiano room	Simi, Mora
12:00 p.m.	pre-brief, practice in Saltspring room	Jessica, Chris O, Cheryl, Chris S.
12:45 p.m.	media arrive	
12:55 p.m.	speakers take their seats	Jessica, Chris O, Cheryl
1 p.m.	briefing begins	Jessica, Chris O, Cheryl, Simi
1:20 p.m.	Q&A	Jessica, Chris O, Cheryl, Simi
1:35 p.m.	event concludes; speakers to holding area	Jessica, Chris O, Cheryl
Announcement		
2 p.m.	RRA filed & posted to .com (TBC)	Regulatory, Leela
2 p.m.	news release distributed; social media push	Kevin, Leela
2:30 - 3 p.m.	media interviews	Jessica

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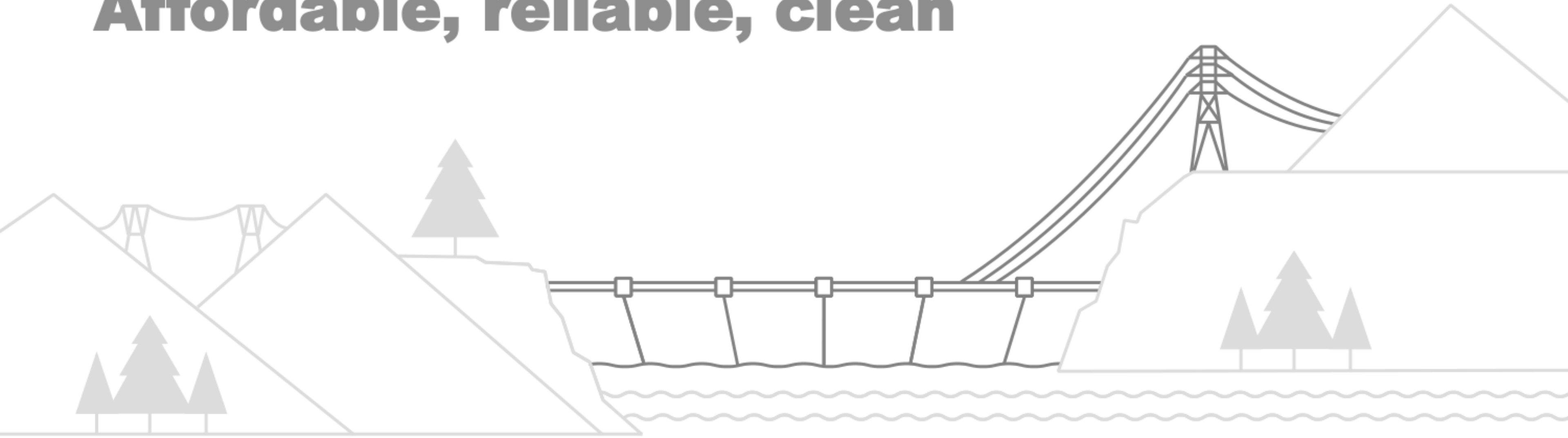
Protecting B.C.'s energy advantage

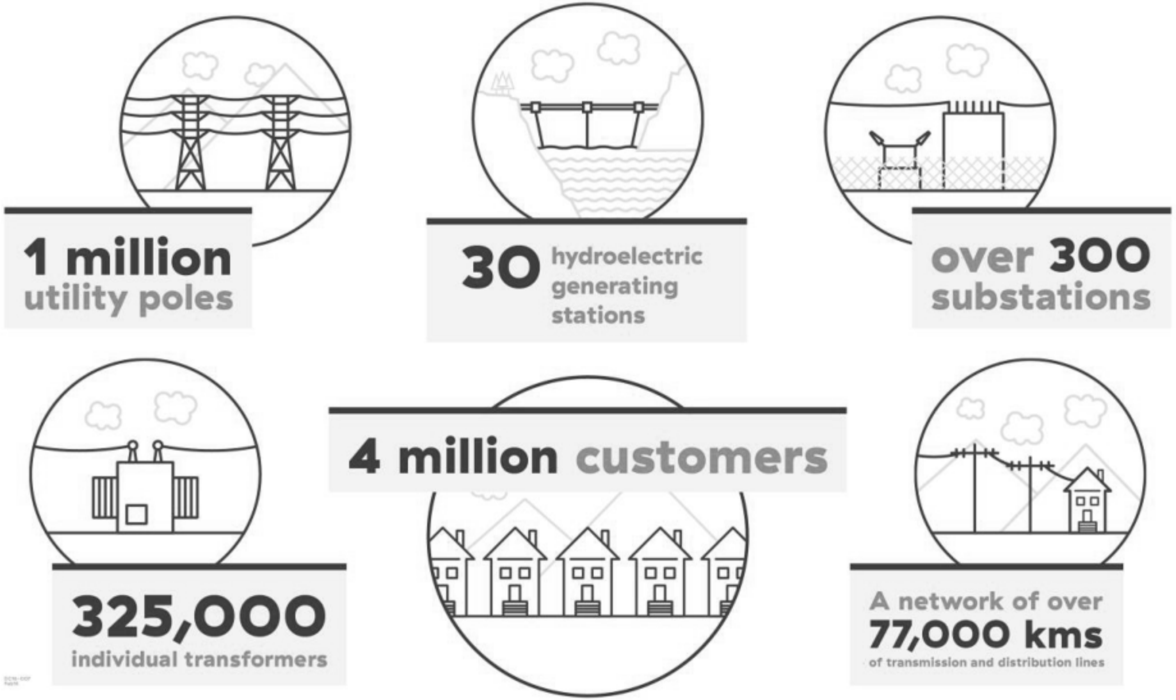
Affordable, reliable, clean



BC Hydro

BC Hydro's system

We have a large and complex system serving 95% of the province's population and 4 million customers.



BC Hydro

BC Hydro today

BC Hydro is here to deliver affordable, reliable, clean electricity to our customers, safely.

Affordable, reliable, clean

Our rates are among the lowest in North America.

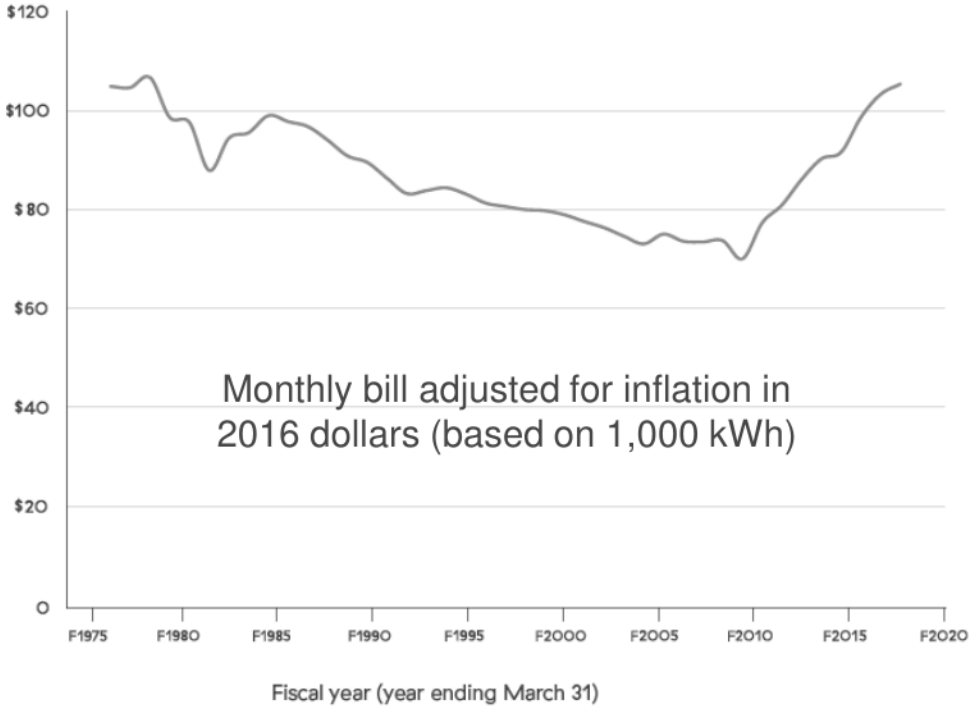
An average residential customer pays **$203** each month for their **phone, TV, and internet services**, compared to **$91** per month on **electricity**.

*based on 830 kWh/month

BC Hydro

Affordable, reliable, clean

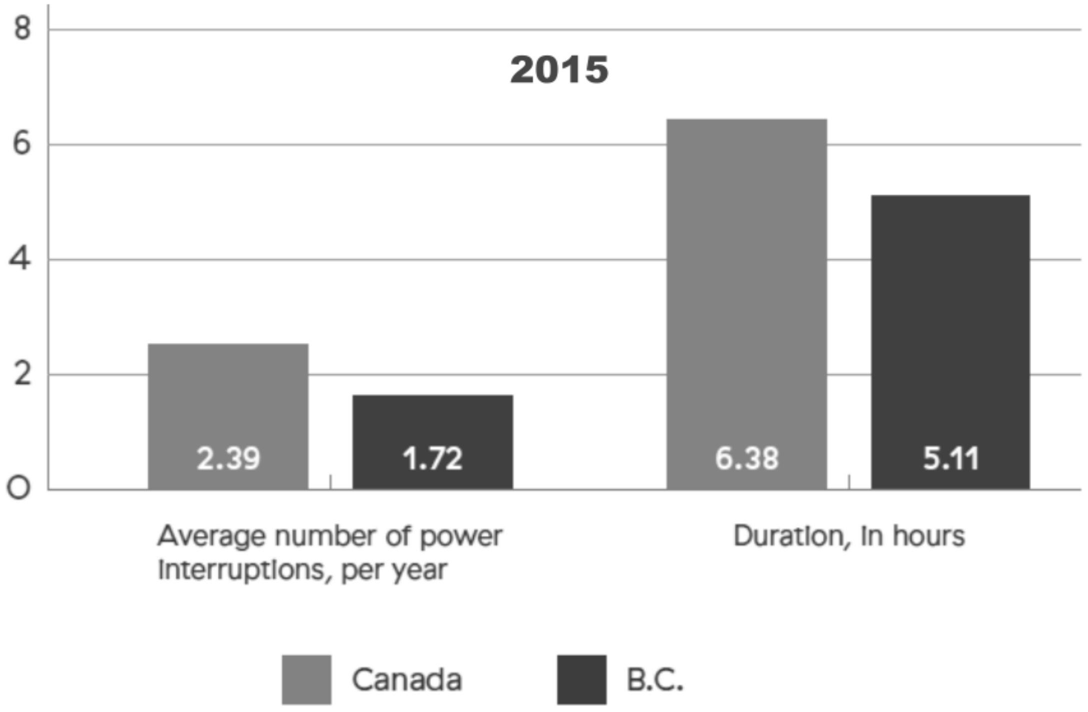
Adjusting for inflation, electricity costs about the same today as it did back in 1976.



Inflation-adjusted average monthly residential bills	
1976	$104.55
2016	$107.05

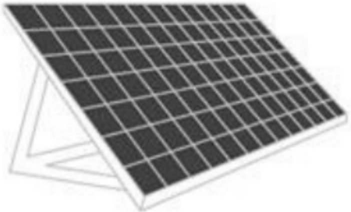
Affordable, reliable, clean

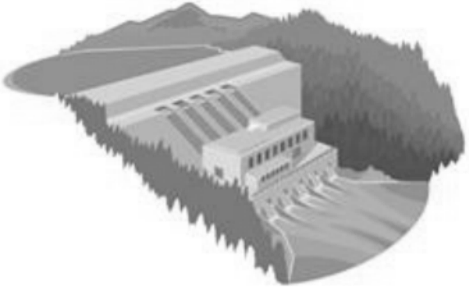
B.C.'s power supply is more reliable than the Canadian average.



Affordable, reliable, clean

Last year, 98% of the electricity generated in B.C. was from clean or renewable sources.





We're doing everything we can to keep rates low for our customers

BC Hydro
Power smart

Warm winter reduced energy sales

Ski hills in Alberta, B.C. suffering from unusually warm weather

Mountain resorts across Western Canada are struggling to provide good snow for skiers, snowboarders

By Kyle Bakx, CBC News   Posted: Feb 17, 2015 7:00 PM ET | Last Updated: Feb 18, 2015 10:33 AM ET

IN DEPTH | El Niño forecasts warm winter for West Coast

A strong El Niño means warmer than normal trend continues — but what does that mean for skiers?

By Johanna Wagstaffe, CBC News   Posted: Oct 22, 2015 1:19 PM PT | Last Updated: Oct 24, 2015 1:59 PM PT

Drought forces Howe Sound pulp mill to close one operation in hopes of saving two others

THE CANADIAN PRESS   JULY 24, 2015

Warm winter causes headaches for seasonal businesses

JACOB SEREBRIN
Special to The Globe and Mail
Published Monday, Feb. 29, 2016 5:00AM EST
Last updated Monday, Feb. 29, 2016 12:07PM EST

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Commodity prices reduced forecasts

Natural Gas

	2013	2016	% Change
Gas ($/mmBtu)	2.8	2.1	↓24%
LNG ($/mmBtu)	16.2	8.4	↓48%

Mining

	2013	2016	% Change
Coal (metallurgical) ($/mt)	130	68	↓48%
Copper ($/lb)	3.6	2.2	↓39%

Pulp & Paper

	2013	2016	% Change
Kraft pulp ($/tonne)	660	610	↓8%
Thermo-mechanical pulp ($/tonne)	550	380	↓31%
Paper, newsprint ($/tonne)	640	520	↓19%
Lumber ($/m fbm)	300	280	↓7%

Forecasting approximately **$3.5 billion (or 7%) less revenue** over the duration of the 10 Year Rates Plan compared to the assumptions at the time the plan was announced in 2013.

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Power smart

Staying on track

By continuing to find operational savings that are reinvested in priority areas.

✓ This year, we’ve identified a further **$33 million** in cost reductions.

✓ We’ve limited base operating cost increases to an average of **only 1.2% per year** for 2017 to 2019.

By locking in low interest rates.

✓ We’ve put in place a debt management strategy to lock in low interest rates, which we expect will achieve approximately **$45 million** in savings over the next three years.

BC Hydro
Power smart

Staying on track

By working hard to manage our costs.

- ✓ We've replaced contractors with internal staff where it reduces costs, generating an overall capital savings of **$20 million** over the next three years.
- ✓ We've prioritized our capital spending, reducing planned expenditures by about **$380 million** over the next 3 years.
- ✓ We've updated our conservation programs, reducing the average program cost to **$22 per megawatt hour.**
- ✓ Over the past 5 years, we've completed **563 capital projects** at a total cost of **$6.48 billion** which is about **$12 million under budget overall.**

Staying on track

By optimizing our energy resources.

- ✓ We're renewing contracts with independent power producers at **prices less** than what they are currently paid, recognizing that those producers have typically recovered most of their capital costs over their original contract terms.
- ✓ We're reviewing the Standing Offer Program to reflect the **declining cost** of new power technology and to better meet system needs.

Staying on track

By spending money where it matters most.

- Over the next three years, we're re-deploying operational savings in the following priority areas:
    - ✓ Safety
    - ✓ Customer service
    - ✓ Storm response
    - ✓ Maintenance
    - ✓ Capital project planning

2013 10 Year Rates Plan update

We're on track to meet the targets in the 2013 10 Year Rates Plan, while making investments to safely provide reliable, clean electricity to our customers.

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10 Year Rates Plan

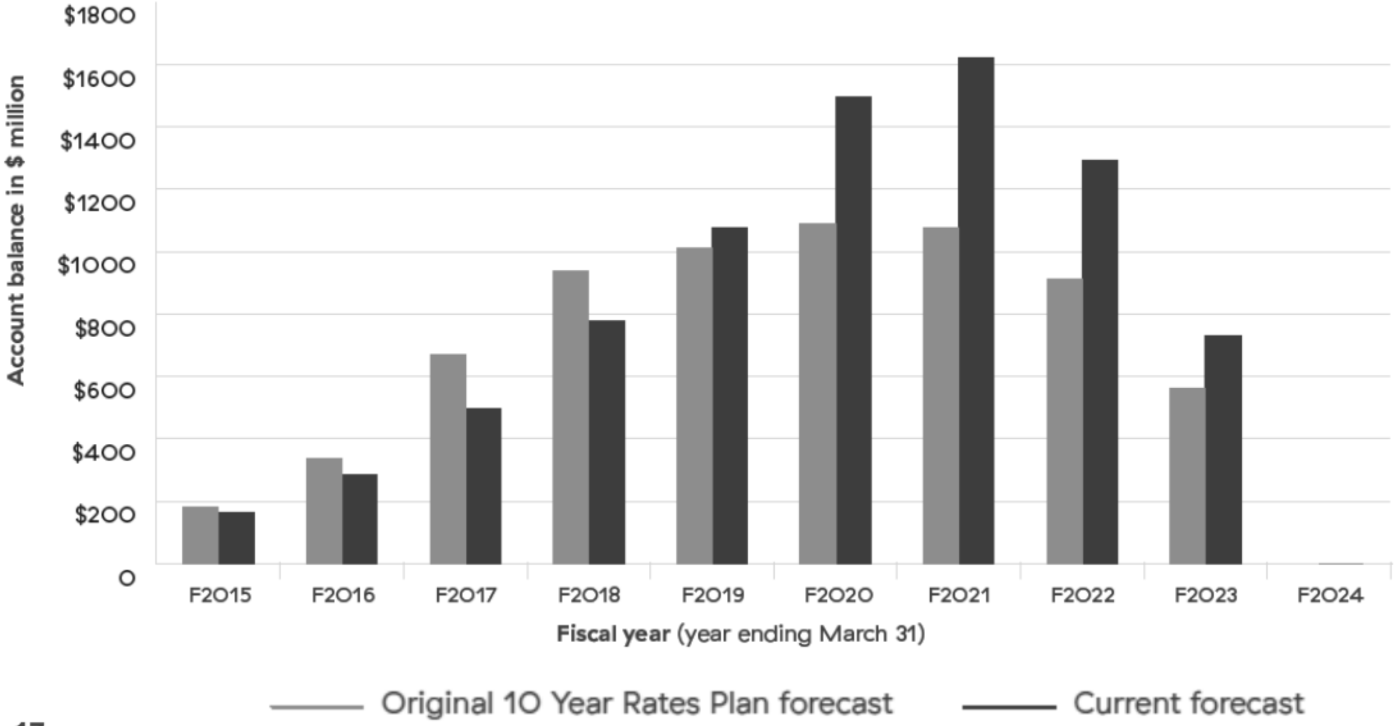
- The plan targets average rate increases of 2.6% in the last 5 years:

	Set by Government		Capped			Targets (to be set by the BC Utilities Commission)				
Year	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024
Increase	9%	6%	4%	3.5%	3%	2.6%	2.6%	2.6%	2.6%	2.6%

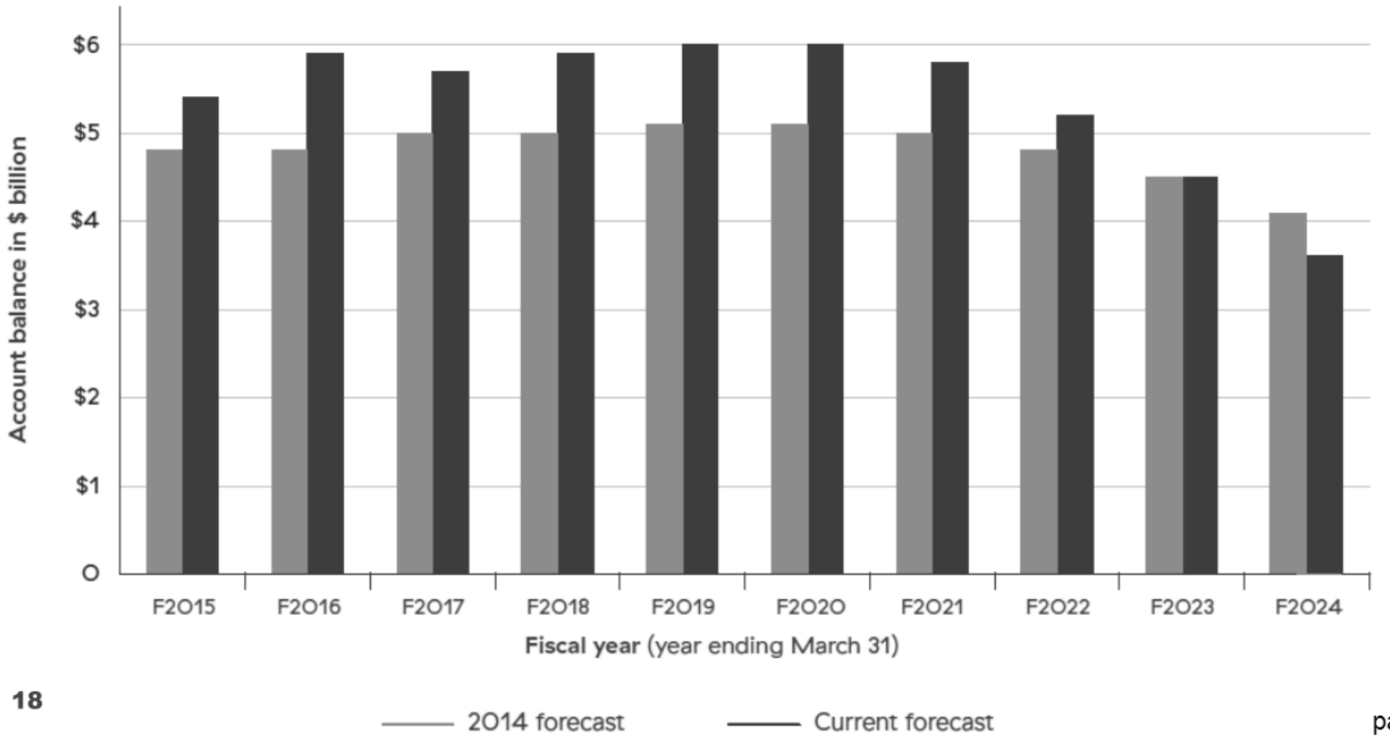
- This includes full recovery of the balance in the Rate Smoothing Account (which shifts costs from earlier years to later years of the 10 Year Rates Plan):

Rate Smoothing Account – (Additions) / Recoveries in millions											
Year	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	Total
Original Forecast	(181)	(158)	(333)	(268)	(70)	(78)	13	161	354	560	0
Latest Forecast	(166)	(121)	(210)	(286)	(299)	(408)	(99)	304	553	733	0

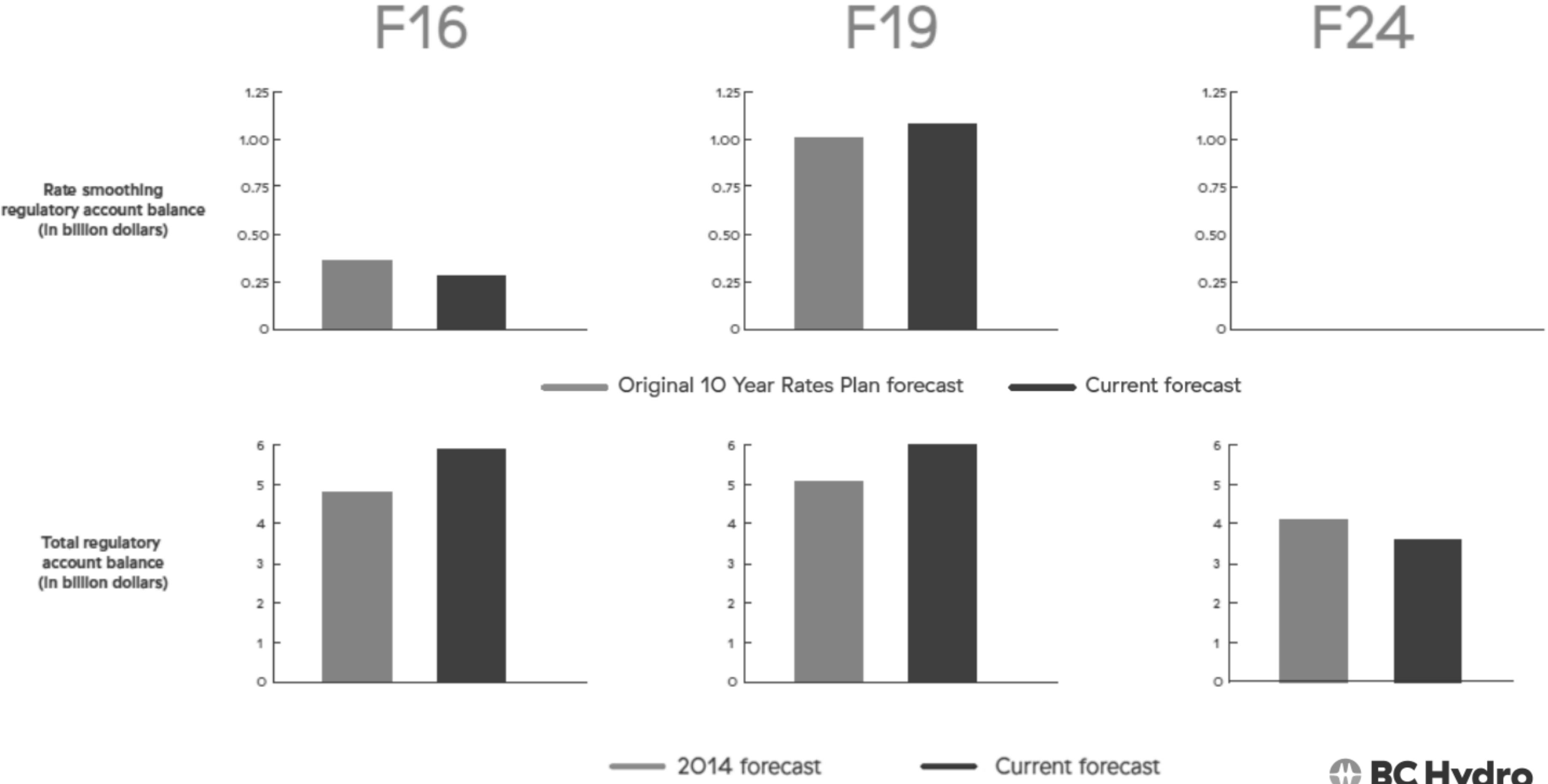
Rate Smoothing Account balance is on track to reach zero by 2024



We're paying down regulatory accounts by almost 40% by 2024



BC Hydro



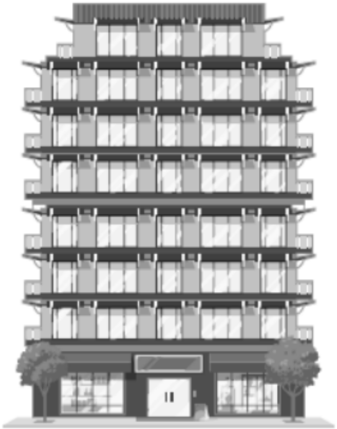
F16
F19
F24
Rate smoothing regulatory account balance (in billion dollars)
1.25
1.00
0.75
0.50
0.25
0
Original 10 Year Rates Plan forecast
Current forecast
Total regulatory account balance (in billion dollars)
6
5
4
3
2
1
0
2014 forecast
Current forecast

BC Hydro

A 4% rate increase means...

$4.65

extra per month
for a family of four
living in a single-family
detached home.



$1.37

extra per month
for a single person
living in an apartment.

$2.88

extra per month
for a couple
living in a townhouse.

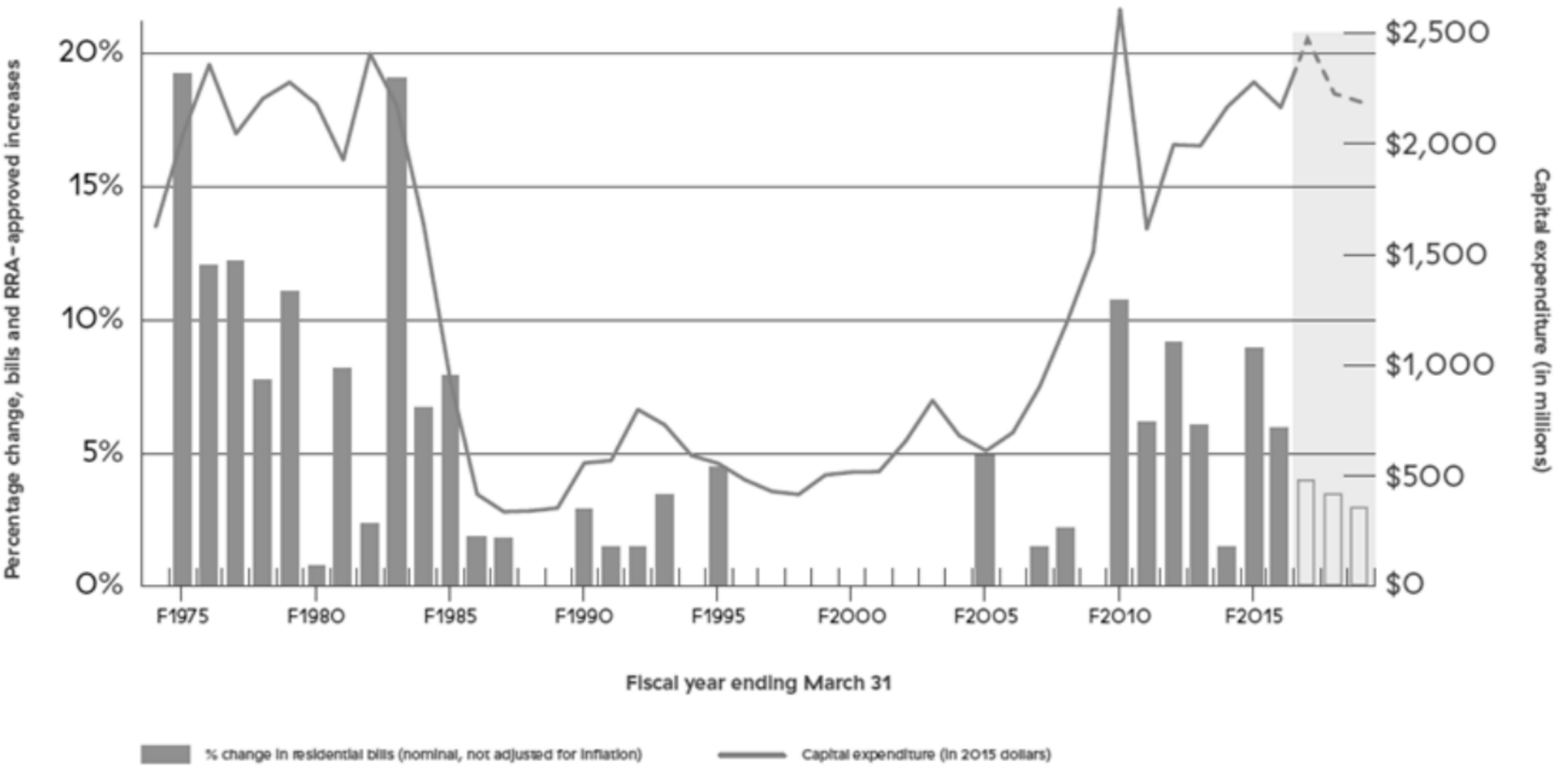
Investing in our system to keep it reliable and clean

As our province grows, further investment is needed to meet growing demand and ensure reliable power for years to come.

We are investing over $2 billion per year to upgrade aging assets and build new infrastructure.

BC Hydro
Power smart

Residential bill increases and capital expenditures (1973 to 2018)

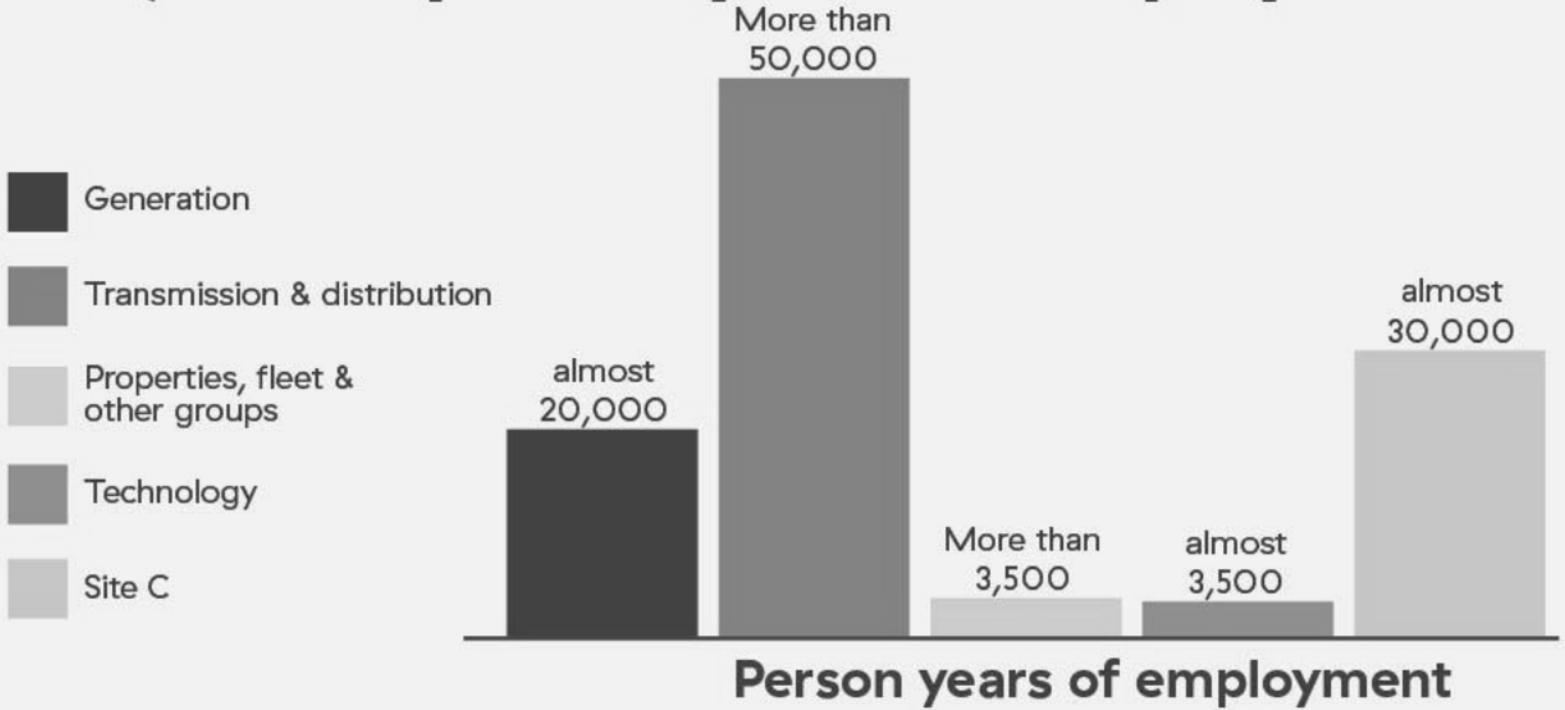


Our hydroelectric assets are over 45 years old on average.


Over 400,000 transmission and distribution
assets need remediation or replacement
within the next 10 years.

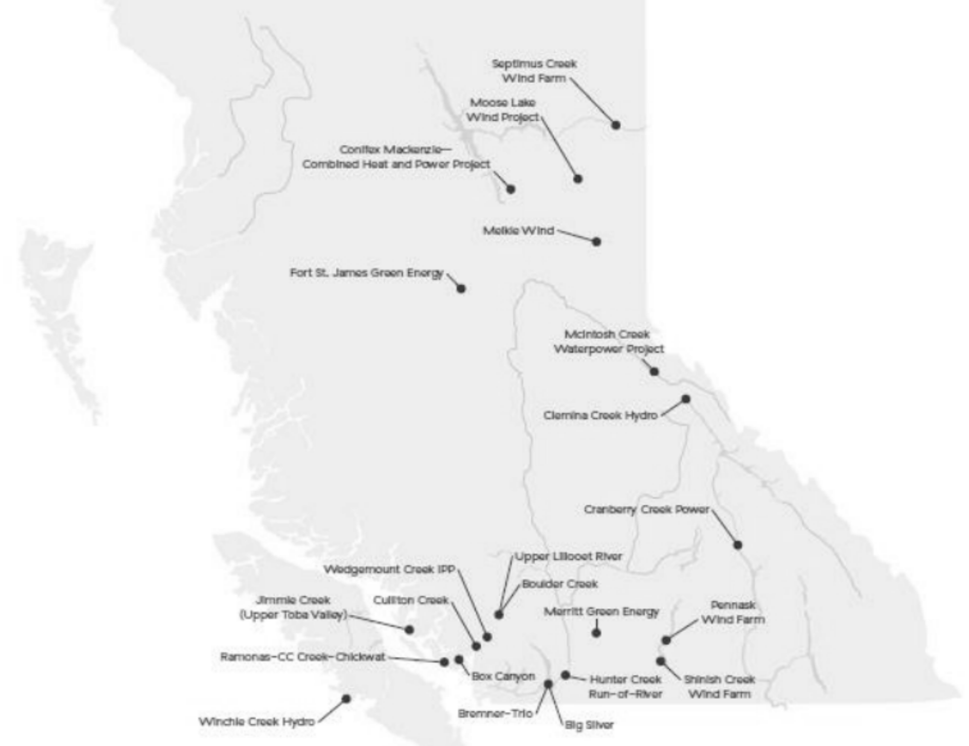

Lower Mainland, Dawson Creek, Kamloops
and other areas are experiencing
substantial growth.

100,000+ person years of employment



Over 20 new clean power projects will be complete in the next three years

Independent Power Producers provide about 25% of supply.



Meeting long-term growth

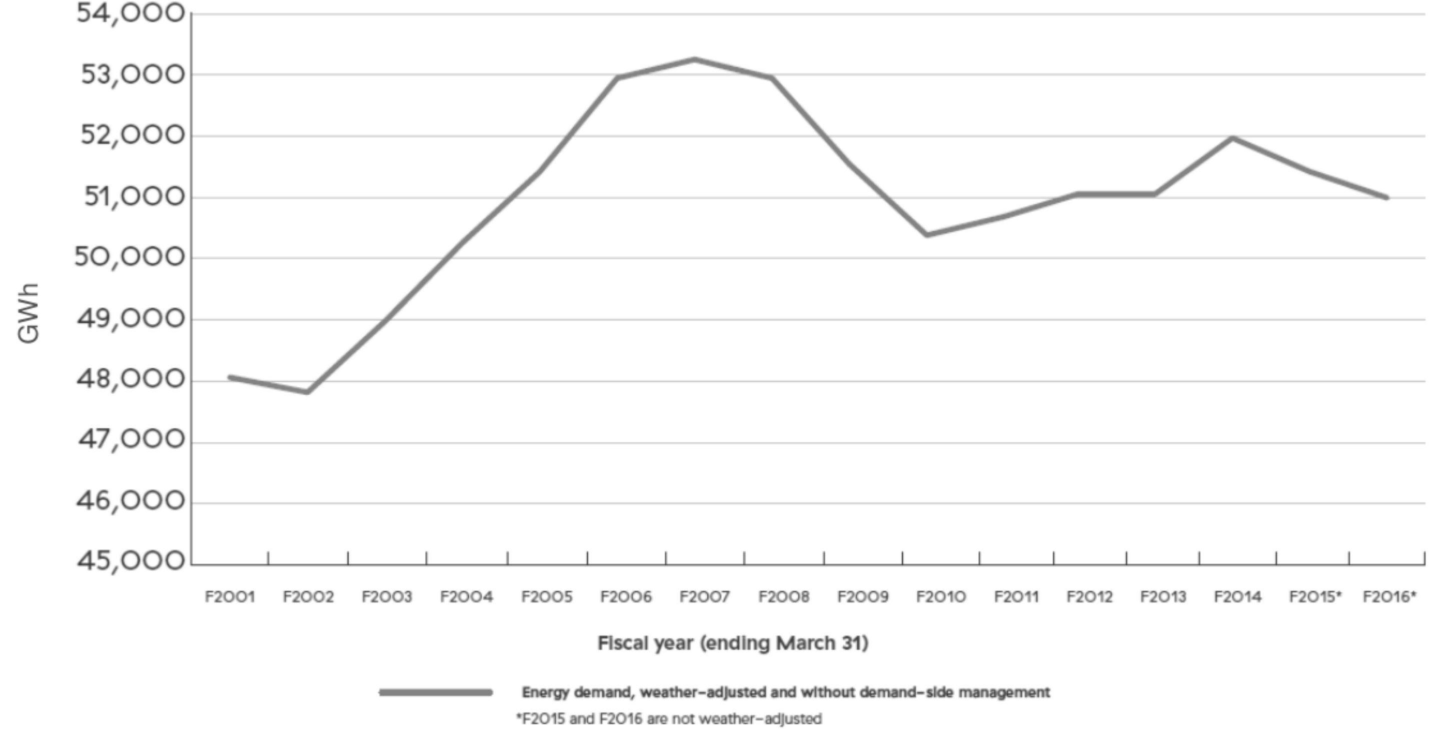
The 2013 Integrated Resource Plan forecasted demand growth of 40% over the next 20 years, before LNG.

With the shift in commodity markets since 2013, BC Hydro is now forecasting growth of 34% before LNG and 39% with LNG.

This means an average growth rate of 1.4% per year, after conservation.

BC Hydro
Power smart

Energy demand since 2002



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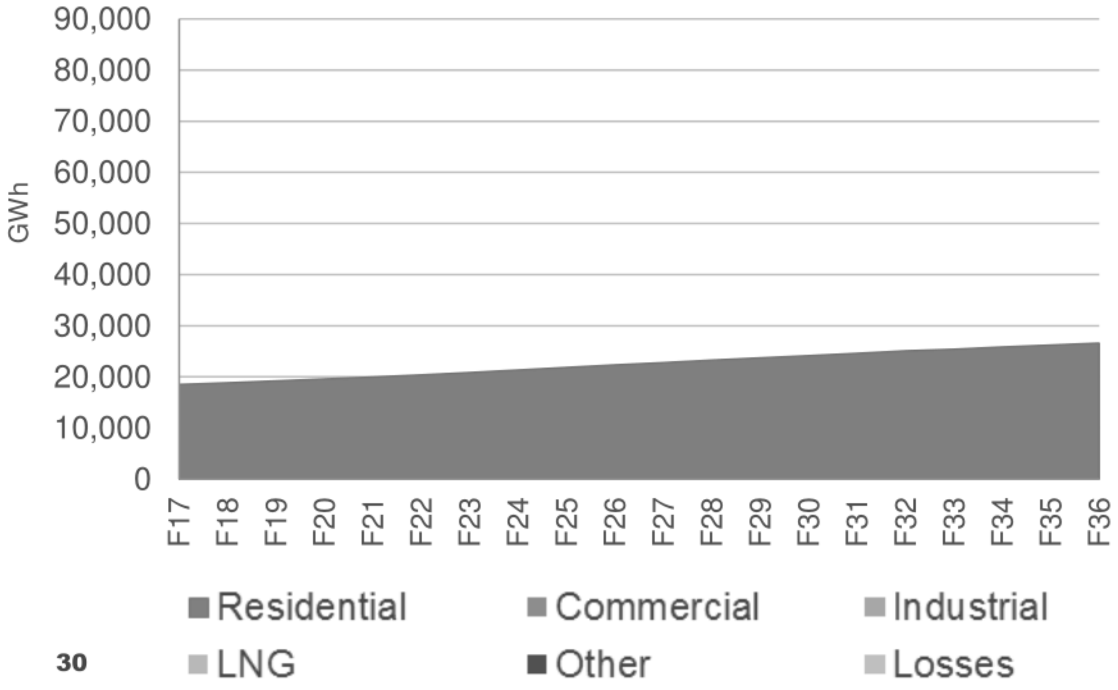
Demand is growing – residential

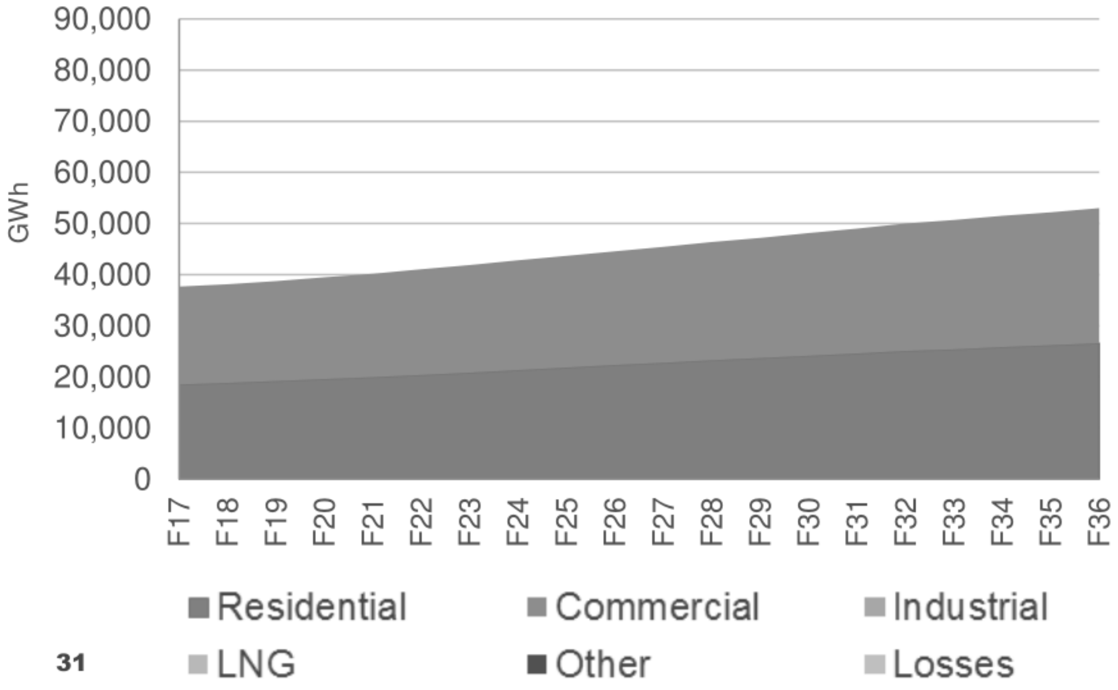
We continue to forecast significant long-term growth for all customer sectors.



- B.C.'s population is forecast to grow by over **1 million people** to 5.8 million by 2035.
- Declining trend in residential use per account due to gains in appliance efficiency has softened sales.

Demand is growing – commercial

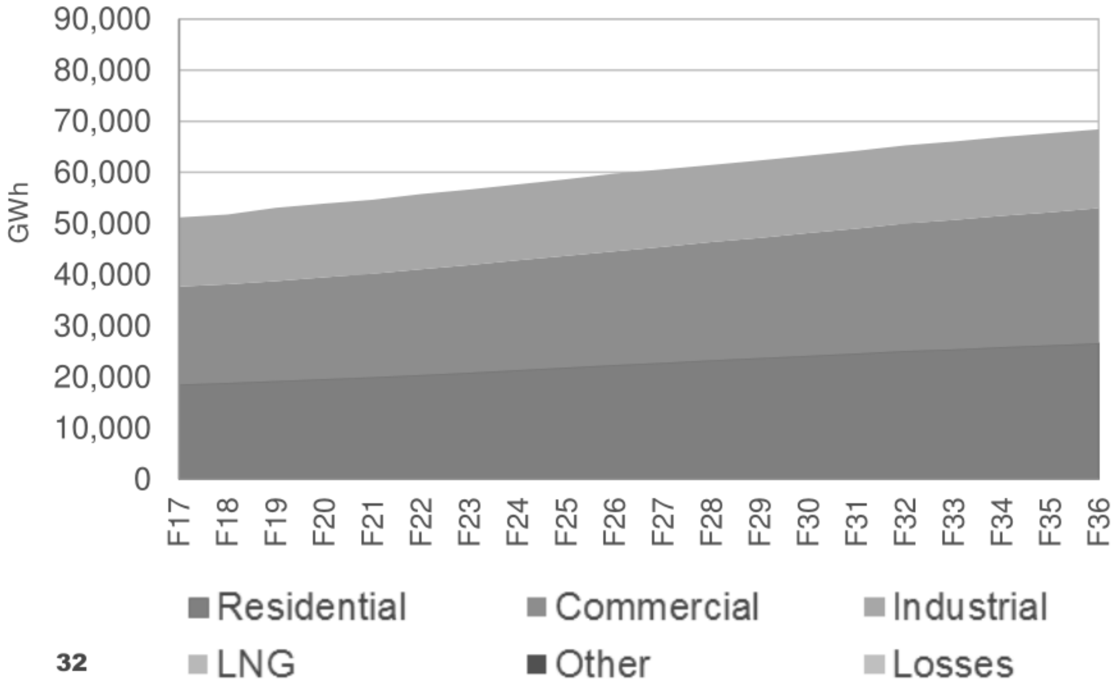
We continue to forecast significant long-term growth for all customer sectors.



- B.C.'s GDP growth is forecast at a lower rate than in 2013 but still expected to lead the country at 2.3% on average, from 2017 to 2019.

Demand is growing – industrial

We continue to forecast significant long-term growth for all customer sectors.

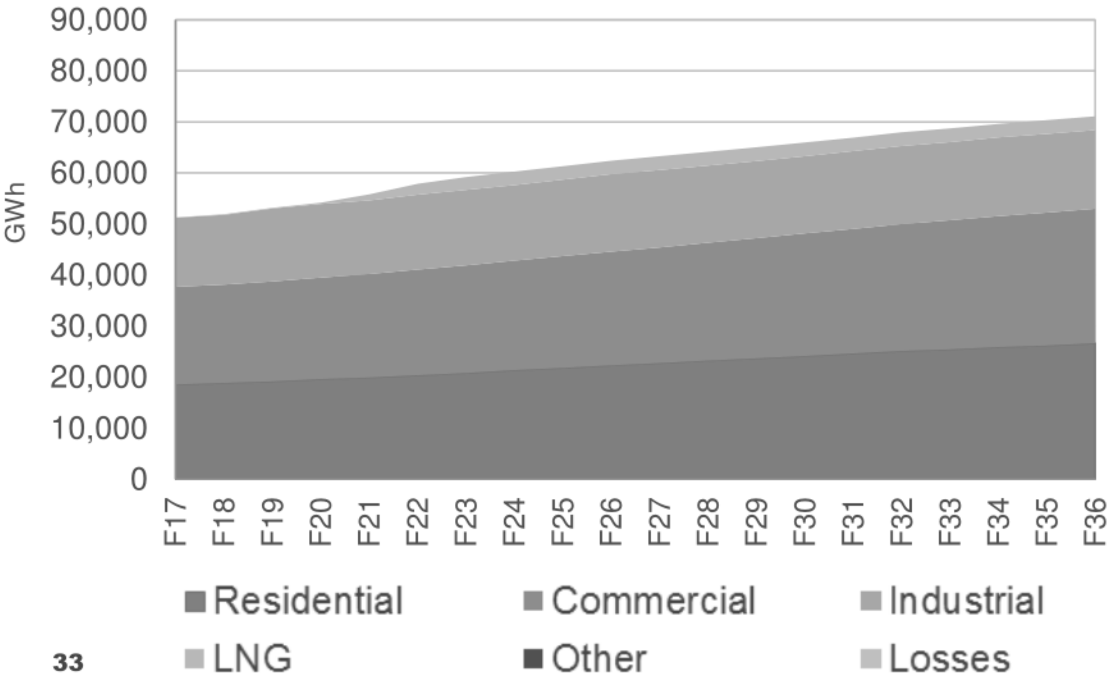


- Declining commodity prices have led to a lower forecast rate of industrial load growth.
- Average annual year over year industrial load growth over the next 20 years is about 1.3% (with LNG).

BC Hydro

Demand is growing – LNG

We continue to forecast significant long-term growth for all customer sectors.

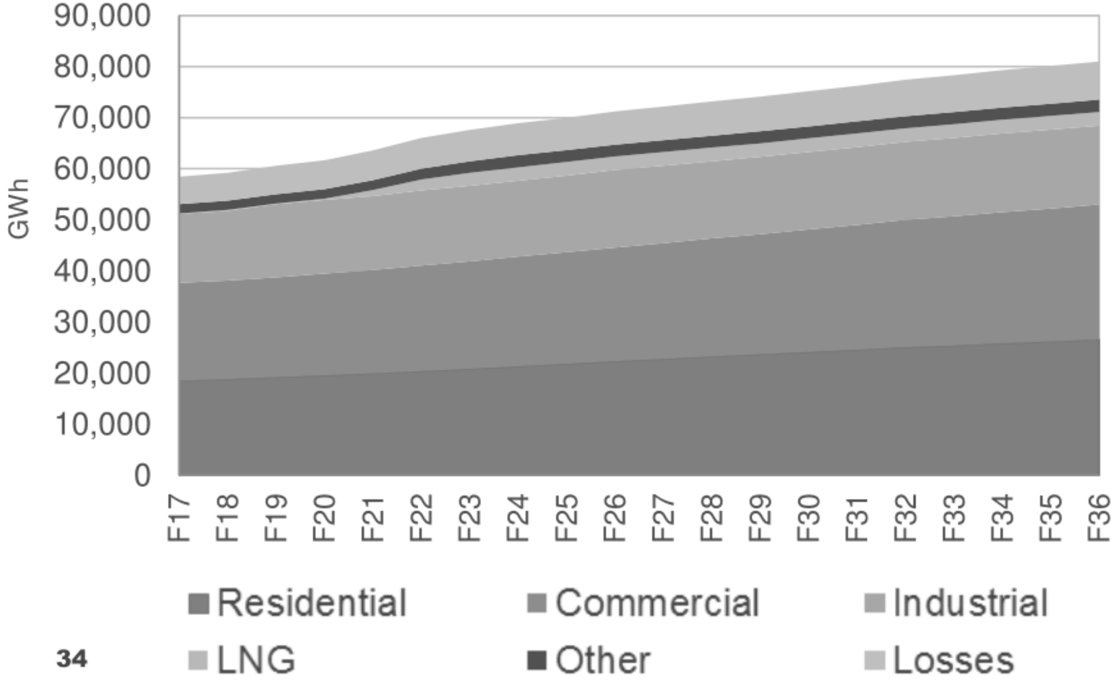


- Fortis Tilbury, LNG Canada and Woodfibre LNG have confirmed their intent to take service from BC Hydro.

- Delays to final investment decisions have pushed out in-service dates.

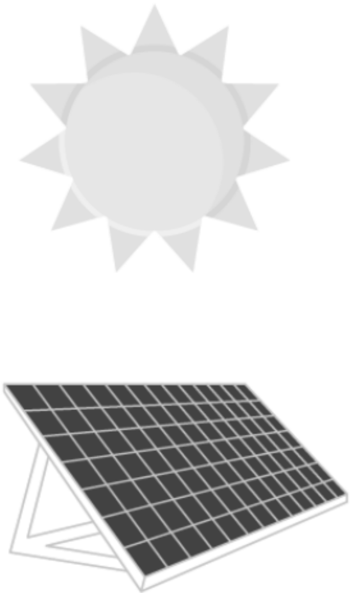
Demand is growing

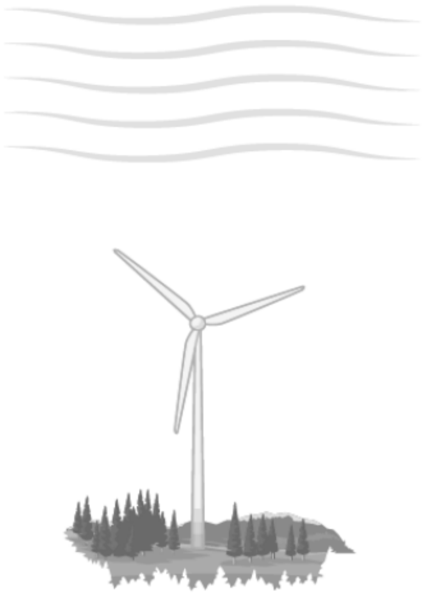
We continue to forecast significant long-term growth for all customer sectors.



- Line losses & other

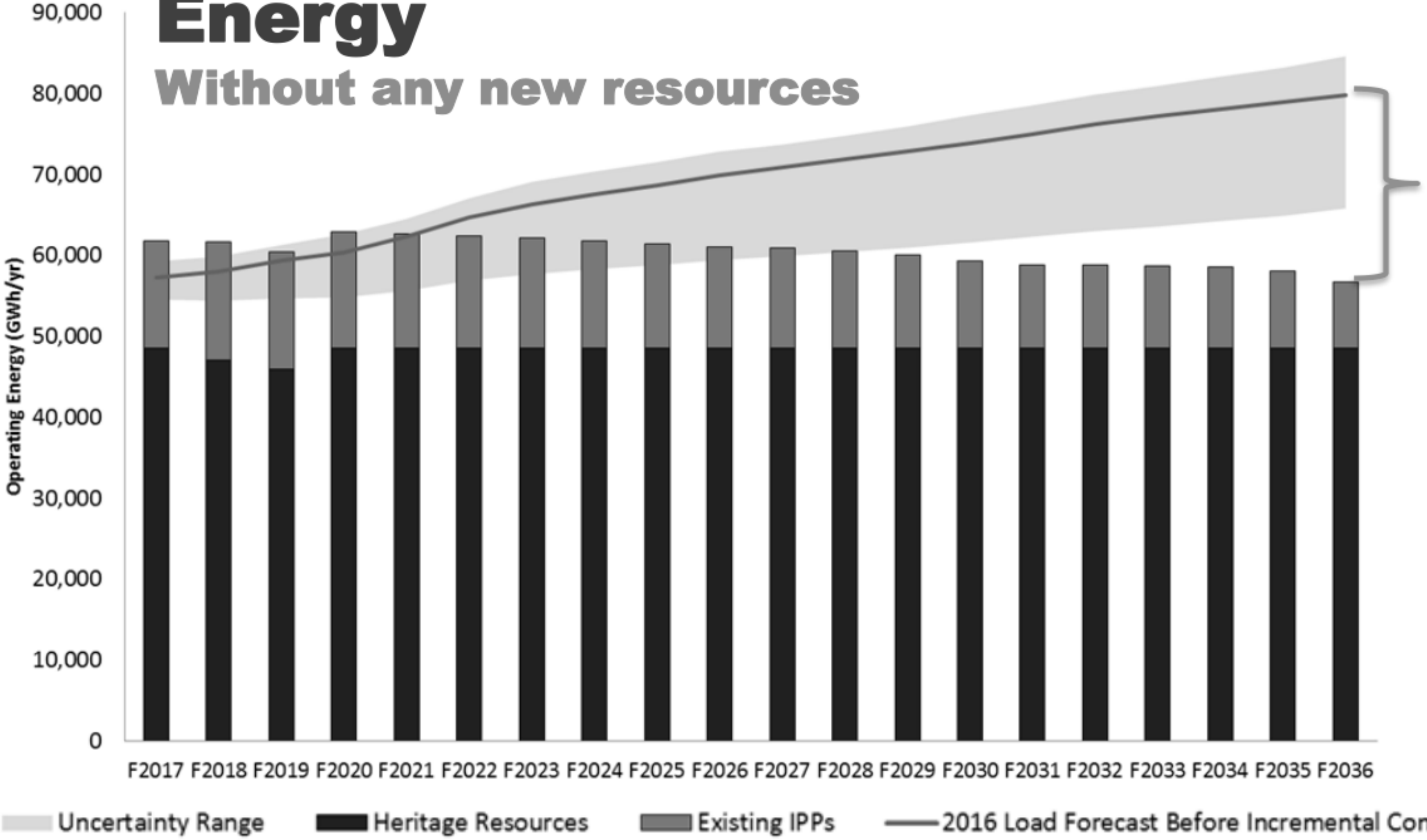
Energy vs. Capacity





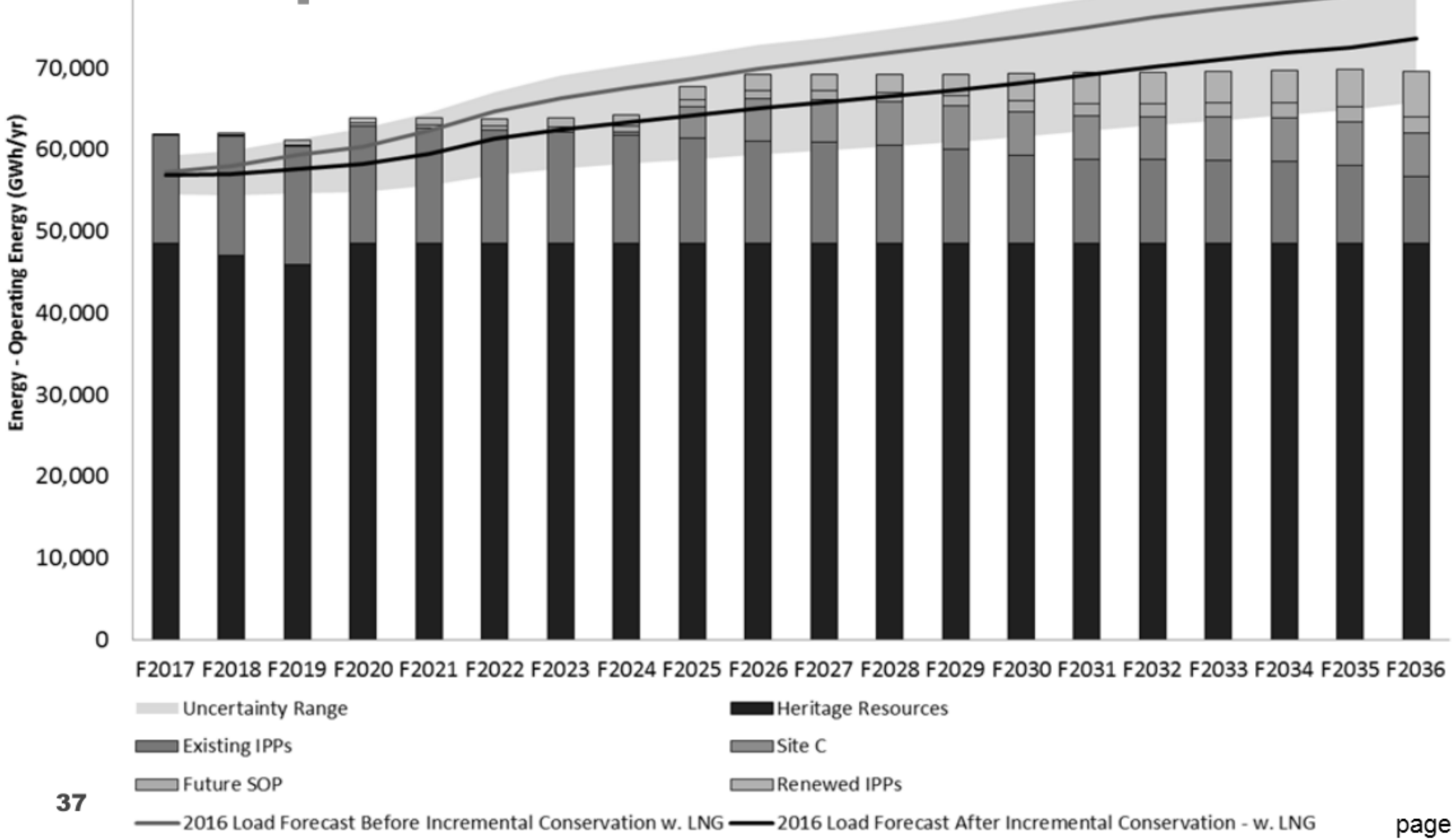
Energy

Without any new resources



By 2036, B.C. would have an energy supply gap of **23,000 GWh** – equivalent to the power needs of over **2 million homes**.

Energy
With planned new resources



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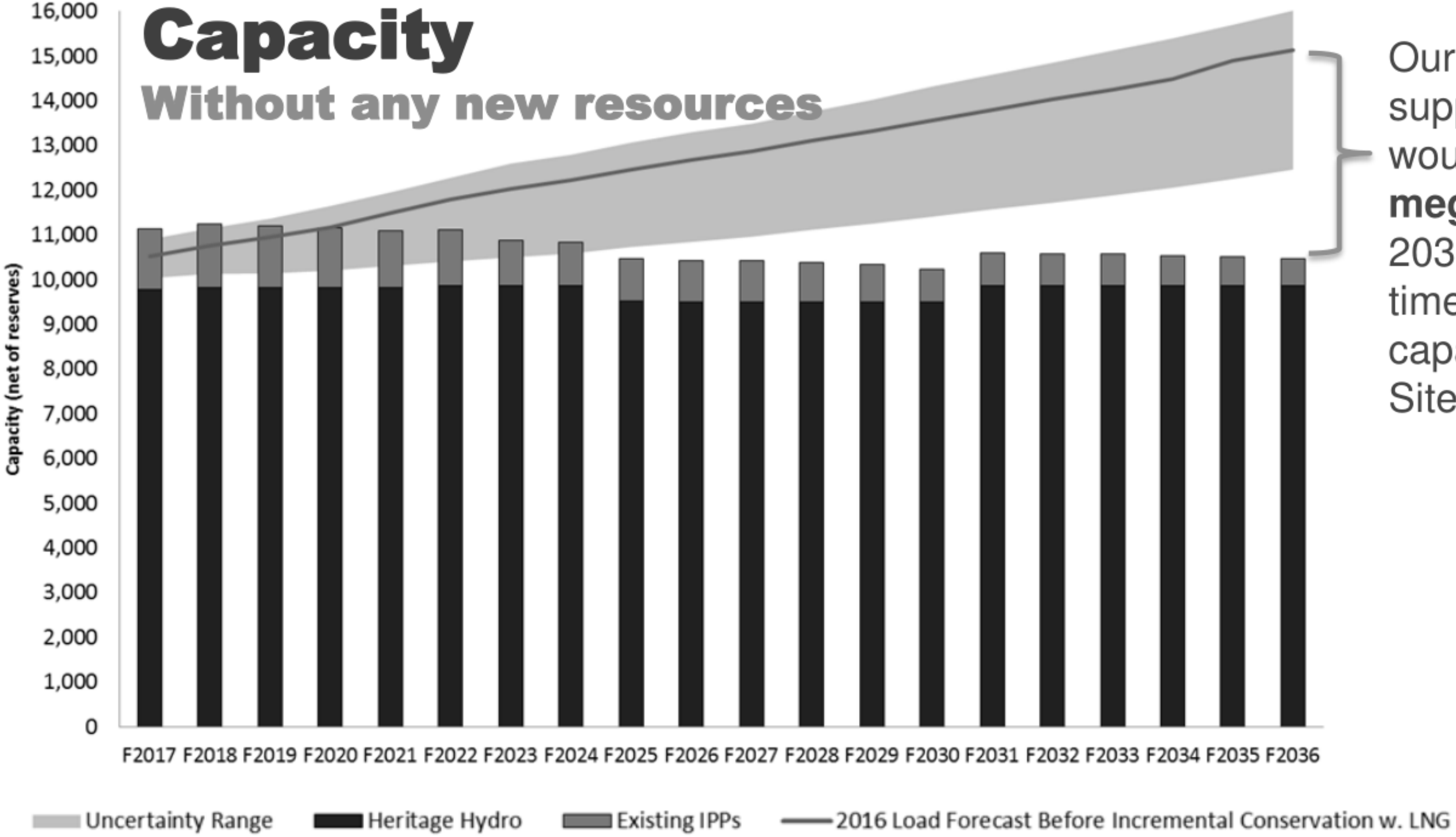
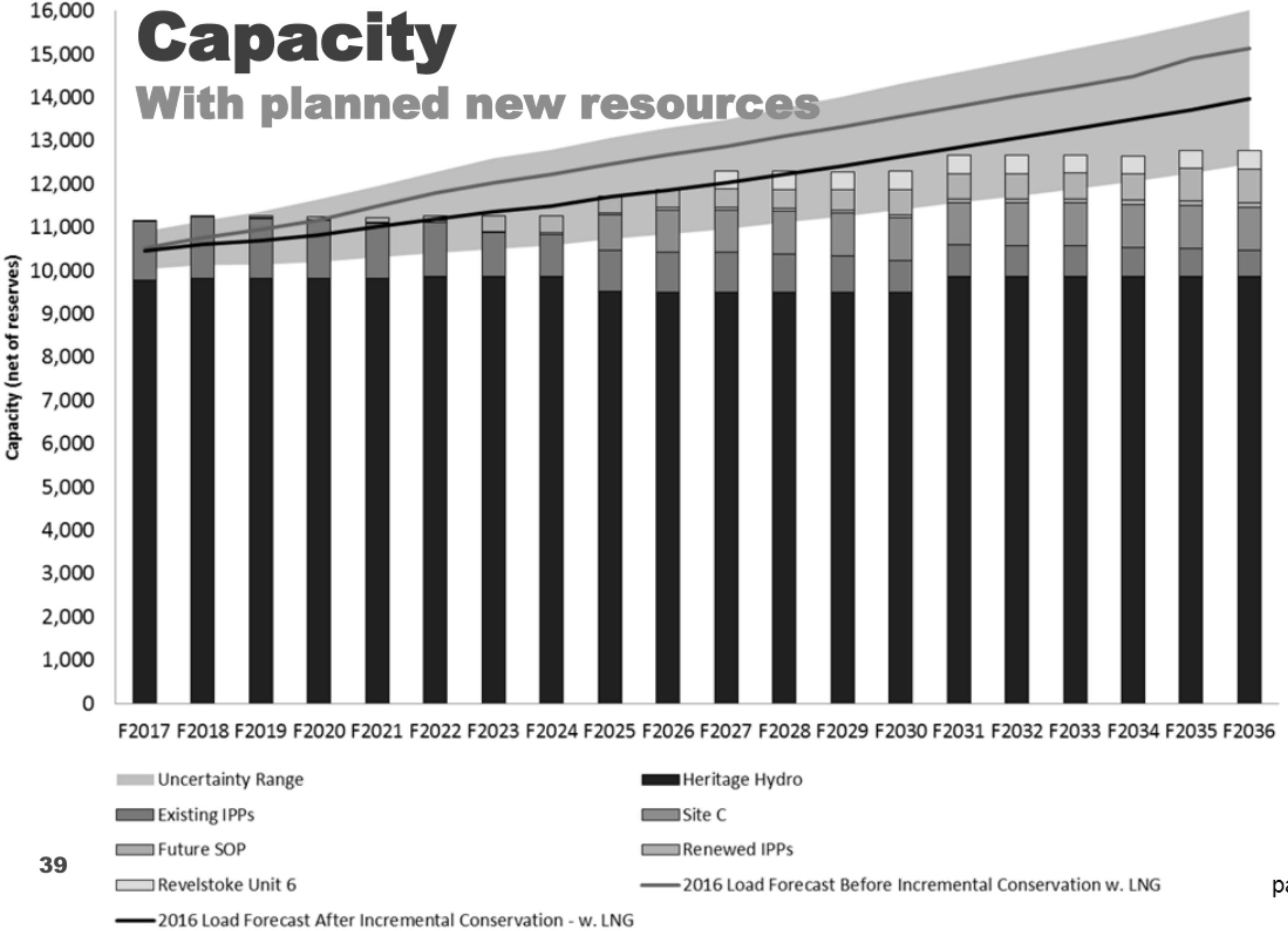
Capacity

Without any new resources



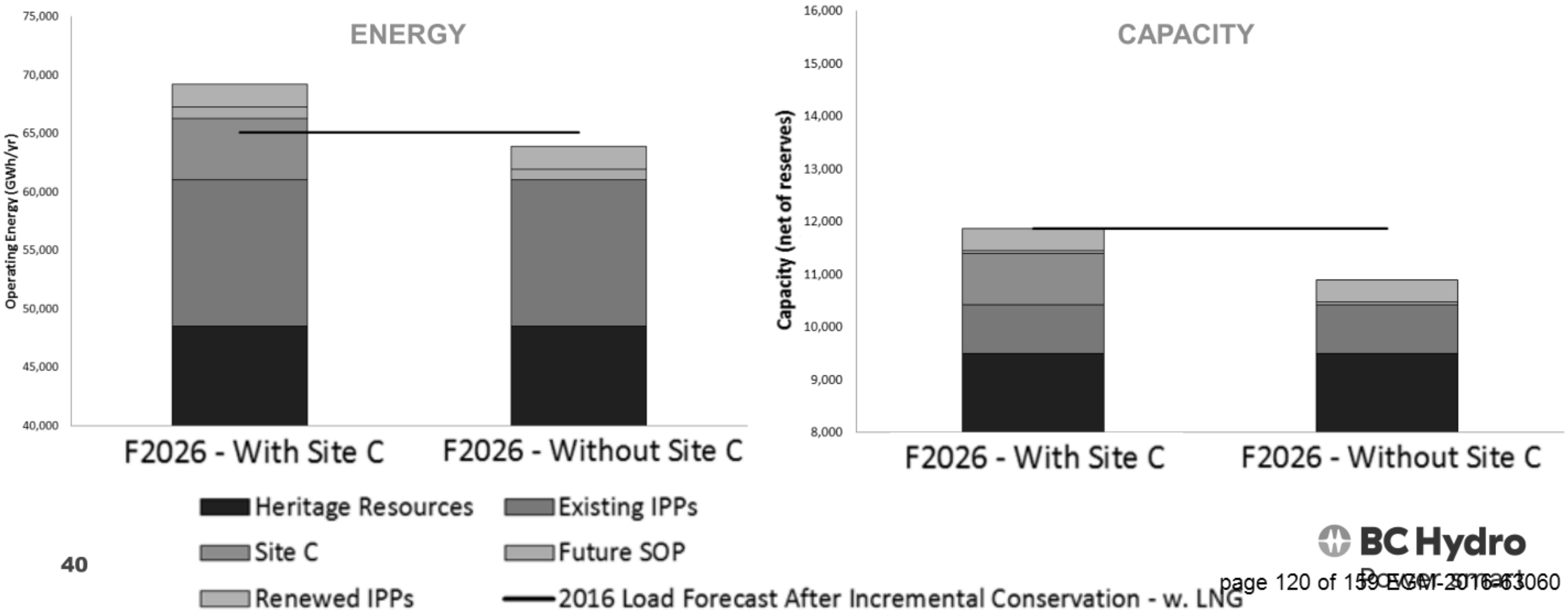
Our capacity supply gap would be **4,600 megawatts** in 2036 – over 4 times the capacity of Site C.


Capacity
With planned new resources
16,000
15,000
14,000
13,000
12,000
11,000
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
Capacity (net of reserves)
F2017 F2018 F2019 F2020 F2021 F2022 F2023 F2024 F2025 F2026 F2027 F2028 F2029 F2030 F2031 F2032 F2033 F2034 F2035 F2036
Uncertainty Range
Heritage Hydro
Existing IPPs
Site C
Future SOP
Renewed IPPs
Revelstoke Unit 6
2016 Load Forecast Before Incremental Conservation w. LNG
2016 Load Forecast After Incremental Conservation - w. LNG

BC Hydro

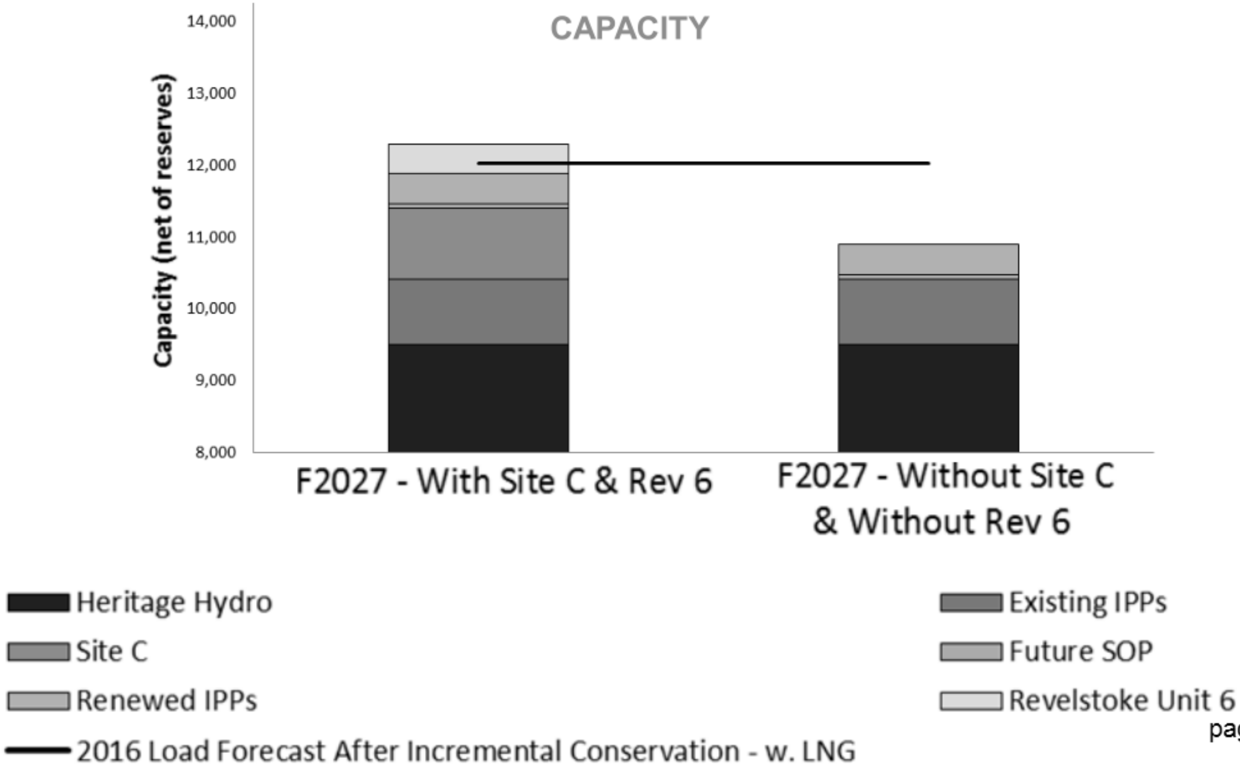
Without Site C, British Columbia would have a capacity deficit of over 950 MW (8%) and an energy deficit of over 1,100 GWh (2%) in 10 years

This is equivalent to the power needs of 100,000 homes



BC Hydro

In 2027, without Site C and Revelstoke 6, British Columbia would have a capacity deficit of over 1,100 MW (9%)



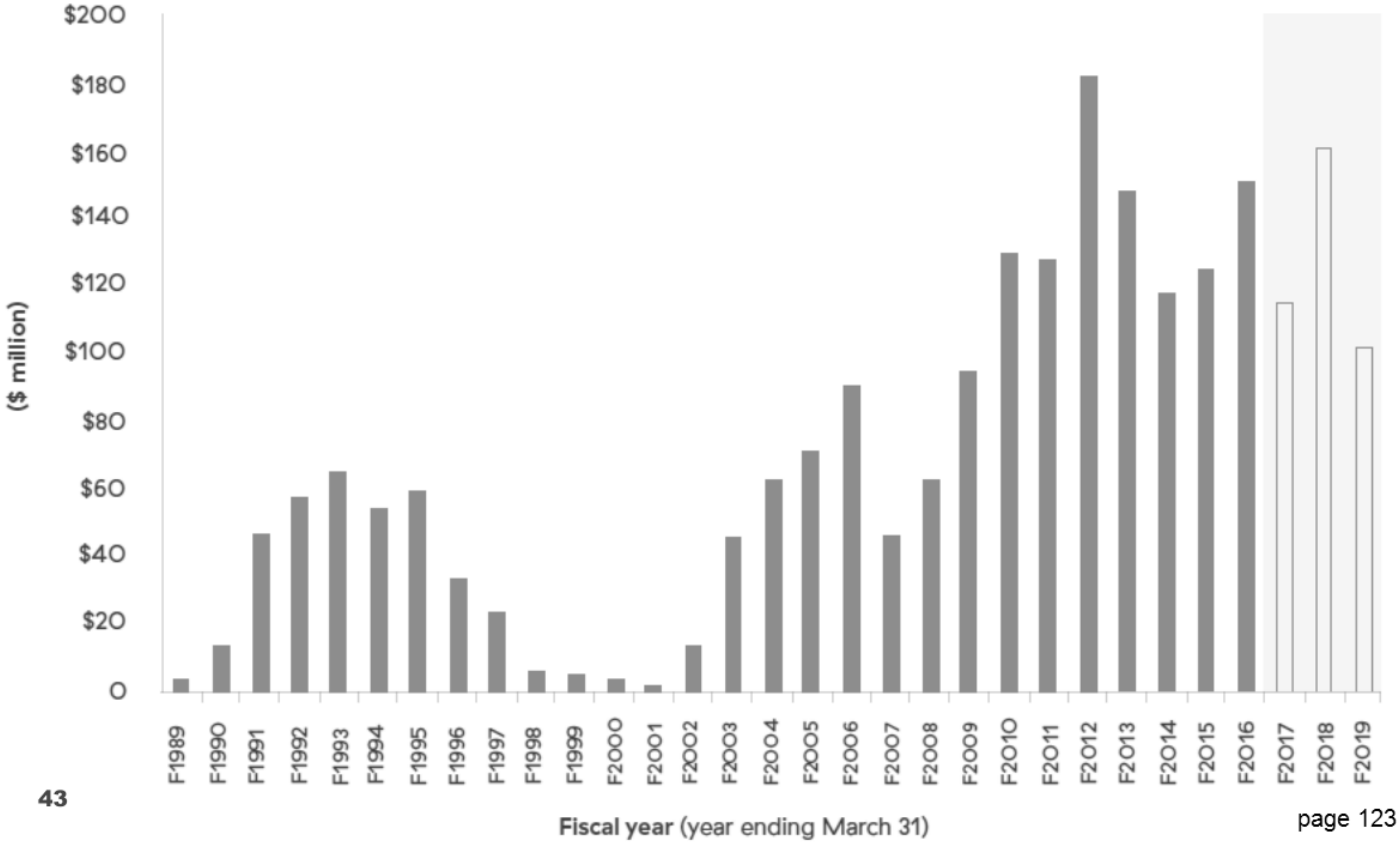
Investing in conservation

Since 2003, BC Hydro has invested $1.3 billion in conservation (an average of $100 million per year).

Our conservation programs achieved cumulative energy savings of 5,091 gigawatt hours from 2008 to 2016 – that's equal to the amount of power that will be produced by Site C.

BC Hydro
Power smart

Conservation investment 1989 to 2019



BC Hydro

Our conservation plan

On track to exceed the *Clean Energy Act* target.

- ✓ Invest $375 million over the next three years, including $7.8 million on low income programs.
- ✓ Re-focus programs, adjust and discontinue programs that are not cost effective, reducing average cost to $22 per megawatt hour.
- ✓ Use new tools, information and technologies to help customers make smart choices about energy consumption.
- ✓ Retain and expand programs that align with customer and system needs.

BC Hydro
Power smart

Frankl, Dave MEM:EX

From: Bennett, Bill MEM:EX
Sent: Wednesday, July 20, 2016 3:59 PM
To: Chris.Sandve@bchydro.com
Cc: Wallace-Deering, Eric MEM:EX
Subject: RRA Chapters 1, 3, 4_MEM Briefing
Attachments: RRA Chapters 1, 3, 4_MEM Briefing.pdf; ATT00001.txt

s.12,s.13

Bill

Annotations in the attached document can be seen with Acrobat Reader on the computer. To view annotations on iOS device, use compatible app like PDF Expert.

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Electricity Purchase Agreements that reached commercial operations (COD) in F2016 or expected to reach COD in F17 – F19

Call Process	Project	Location
2006 Call	Cranberry Creek Power	Revelstoke
2010 Standing Offer Program	McIntosh Creek Waterpower Project	McBride
	SunMine	Kimberly
	Tolko Kelowna Cogeneration	Kelowna
	Wedgemount Creek IPP	Whistler
	Shinish Creek Wind Farm	Summerland
	Pennask Wind Farm	Westbank
	Septimus Creek Wind Farm	Taylor
	Moose Lake Wind Project	Tumbler Ridge
	Winchie Creek Hydro	Ucluelet
	Hunter Creek Run-of-River	Hope
	Clemina Creek Hydro	Valemont
2010 Call	Castle Creek (formerly Benjamin Creek)	McBride
	Big Silver - Shovel Creek	Harrison Hot Springs
	Boulder Creek	Pemberton
	Box Canyon	Port Mellon
	Bremner - Trio	Harrison Hot Springs
	Ramonas - CC Creek - Chickwat	Sechelt
	Culliton Creek	Squamish
	Dasque - Middle	Terrace
	Meikle Wind	Tumbler Ridge
	Tretheway Creek	Mission
	Upper Lillooet River	Pemberton
	Jimmie Creek (Upper Toba Valley)	Powell River
2010 Bio Energy II	Fort St. James Green Energy	Fort St. James
	Merritt Green Energy	Merritt
	Chetwynd Biomass	Chetwynd
Negotiated Electricity Purchase Agreement	Conifex Green Energy	Mackenzie
	McLymont Creek	Stewart
	Houweling Nurseries (Delta) Cogeneration	Delta
	Conifex Mackenzie - Combined Heat and Power Project	Mackenzie
	Quesnel River Pulp	Quesnel

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Page 148 to/à Page 159

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Explanation Continued

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British Columbia Hydro and Power Authority

2015/16
ANNUAL SERVICE PLAN REPORT

BRITISH
COLUMBIA

For more information on BC Hydro contact:

333 Dunsmuir Street

Vancouver, BC

V6B 5R3

Lower Mainland

604 BCHYDRO

(604 224 9376)

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BC Hydro's Annual Service Plan Report can be found online at:
http://www.bchydro.com/about/accountability_reports/financial_reports/annual_reports.html

Chair, Board of Directors Accountability Statement

BC Hydro is a provincial Crown Corporation, owned by the people of British Columbia. We operate an integrated system of generation, transmission and distribution infrastructure to deliver reliable, affordable and clean electricity to our four million customers, safely. As an organization, we have a huge impact on the lives of the people of British Columbia and we are working together to uphold this responsibility and become the most trusted, innovative utility company in North America - smart about power in all we do.

The 2015/16 Annual Service Plan Report outlines BC Hydro's performance on the strategies and measures set out in our 2015/16 – 2017/18 Service Plan. It details how we are meeting the objectives in the Government Mandate Letter and aligning with the Taxpayer Accountability Principles.

This report was prepared under the Board's direction in accordance with the *Budget Transparency and Accountability Act* and the B.C. Reporting Principles. The Board and Management are accountable for the contents of the report, including what has been included and how it has been reported.

The information presented reflects the actual performance of BC Hydro for the year ended March 31, 2016, in relation to the 2015/16 - 2017/18 Service Plan. The Board is responsible for ensuring internal controls are in place to measure information and report accurately and in a timely fashion.

All significant assumptions, policy decisions, events and identified risks, as of March 31, 2016 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 2015/16 - 2017/18 Service Plan was released and any significant limitations in the reliability of the information are identified in the report.

The BC Hydro 2015/16 Annual Service Plan Report compares the corporation's actual results to the expected results identified in the 2015/16 - 2017/18 Service Plan. I am accountable for those results as reported.

W.J. Brad Bennett, O.B.C.
Chair, Board of Directors

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Chair, Board of Directors and Chief Executive Officer Letter

On behalf of the Board of Directors and all BC Hydro employees, we are pleased to submit BC Hydro's Annual Service Plan Report for the year ending March 31, 2016.

This past year we began construction on the Site C Clean Energy project which is one of the largest infrastructure projects ever undertaken in British Columbia. Construction is well underway and the job fairs we have held in the surrounding communities have attracted thousands of people. We are investing $2.3 billion per year for the next 10 years to maintain and upgrade our aging assets as well as develop new power infrastructure to ensure we reliably meet our customer's current and future electricity needs. We have made advancements in the services we provide to our customers and this will continue to be a focus for us in the coming year. In January 2016, BC Hydro was named the most influential brand in B.C. for 2015 by B.C. Business Magazine. With this honour comes the responsibility to maintain the trust and respect of our customers and stakeholders. While fluctuating commodity prices and other economic shifts have created challenges, we are on target to meet the 10 Year Rates Plan set out by government to help keep rates low and predictable for our customers as a result of prudent actions to reduce costs and become a more focused organization.

BC Hydro works closely with the Ministry of Energy and Mines to ensure alignment with government policy expectations through regular meetings and updates. These are held between the Executive, the Minister and his staff and the Board Chair, as appropriate, to discuss progress on achievement of the 10 Year Rates Plan and actions identified in the Government Mandate Letter (highlights in *Appendix C: Crown Corporations Mandate and Actions Summary*). Regular updates are provided to the Board of Directors each quarter through a Taxpayer Accountability Report which documents actions to support the Taxpayer Accountability Principles. With respect to organizational governance and shareholder engagement, the development and responsibilities of Directors and the Executive are outlined in *Appendix B: Additional Information.*

We're proud of this year's accomplishments. We will continue to work together to deliver reliable, affordable and clean electricity to our customers, and to ensure that everyone gets home safely every day.

W.J. Brad Bennett, O.B.C.
Chair, Board of Directors

Jessica McDonald
President and Chief Executive Officer

Purpose of the Organization

BC Hydro's mission is to provide our customers with reliable, affordable and clean electricity throughout British Columbia, safely. We are one of the largest energy suppliers in Canada, generating and delivering electricity to 95 per cent of the population of British Columbia. We operate an integrated system backed by 30 hydroelectric and two thermal generating stations as well as79,000 kilometres of transmission and distribution lines. We are proud of our partnership with the independent power sector in British Columbia which operates over 100 projects across the province including biomass, hydro, wind, solar and more.

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 and Mines and the Government's expectations are expressed through the following legislation, policy and instructions:

- *The Hydro and Power Authority Act*
- *The Utilities Commission Act*
- *The BC Hydro Public Power Legacy and Heritage Contract Act*
- The Province's 2007 BC Energy Plan
- *The 2010 Clean Energy Act (CEA)*

The Hydro and Power Authority Act gives BC Hydro its mandate to generate, manufacture, conserve, supply, acquire, and dispose of power and related products.

Powerex Corp. (Powerex) and Powertech Labs Inc. (Powertech) are two wholly-owned subsidiaries of BC Hydro. Powerex is a key participant in energy markets across North America, buying and selling wholesale power, renewable and low-carbon energy and products, natural gas, ancillary services, and financial energy products. Powertech is internationally recognized for providing research and development, testing, technical services, and advanced technology services to clients around the world, including BC Hydro. For more information on Powerex, Powertech, or other active and inactive subsidiaries, see *Appendix A: Subsidiaries and Operating Segments.*

Strategic Direction and Context

British Columbia has the third lowest electricity rates in North America for residential customers, the fourth lowest for commercial customers and the fifth lowest for industrial customers. The 10 Year Rates Plan sets out a framework to keep rates as low as possible while BC Hydro makes investments in aging assets and new infrastructure to modernize the province's electricity system and support British Columbia's growing population and economy.

BC Hydro continues to forecast long-term load growth across all customer classes. While our customer base is growing, we also have an aging electricity system which was largely built in the 1960s, 1970s and 1980s and needs to be rebuilt and upgraded to meet current and future needs. That's why, to maintain our system's reliability and support the growth of the province over the next decade, BC Hydro is investing an average of $2.3 billion each year on capital projects. From fiscal 2012-2016, BC Hydro completed 563 capital projects at a total cost of $6.48 billion which is 0.18 percent under budget overall.

BC Hydro is managing its capital portfolio to emphasize cost consciousness, respect the environment and communities in which we work, and strengthen our relationships with First Nations to ensure economic and social benefits for ratepayers. Over the next decade, BC Hydro's capital projects are expected to generate a total provincial economic impact of $13 billion and create 110,000 person-years of employment[1]. During 2015/16, capital additions were $2.8 billion and several notable projects were completed including:

- Two new units, adding 1,000 megawatts of capacity, at the Mica Generating Station,
- The Interior to Lower Mainland Transmission project, a 247 kilometre, 500 kilovolt line, that will reliably deliver power from the Peace and Columbia systems to customers in our major load centers,
- The Gordon M. Shrum Units 1-5 Turbine Replacement project to upgrade 1960s-era turbines at BC's largest generating station,
- The completion of our Smart Metering program to modernize our 1950s-era grid and provide customers with the information they need to make smart energy choices; and
- The new Dawson Creek/Chetwynd Area Transmission Project which will increase capacity in the region to provide oil and gas producers with reliable, clean power, support economic development and reduce provincial greenhouse gas emissions.

BC Hydro's Site C Clean Energy Project will help meet the future electricity needs of British Columbia's growing population and economy. Site preparation and construction has commenced with vegetation clearing, building of access roads, a construction bridge, and worker accommodations. Procurement activities have resulted in the award of many small and large contracts with commitments totaling approximately $3.8 billion as at March 31, 2016. Thousands of people have attended Site C job fairs and the number of on-site workers peaked at 691 this past year, of which 492 were from British Columbia. Specific to aboriginal business opportunities and employment, in fiscal 2016 $90 million in procurement commitments have been made to First Nations companies, and joint ventures including First Nations companies, and more than 50 First Nations employees and contractors are working on the project.

BC Hydro renewed its customer service strategy this past year with the goal of making it easier for customers to do business with us. This has prompted process improvements and training including simplifying bills, and sharing information in a relevant and timely way. BC Hydro also continues to help customers manage their electricity consumption through our conservation and energy management programs and through new tools such as smart meters, which provide customers with the information they need to make smart energy choices.

At BC Hydro, we are constantly striving to keep rates affordable and predictable for our customers, to support the achievement of the 10 Year Rates Plan and protect British Columbia's competitive advantage of having amongst the lowest electricity rates in North America. A key component of these efforts is the prudent management of our operating costs. In 2015/16, we initiated a workforce optimization program to convert external contractors to internal staff in cases where it reduces costs or improves outcomes, and continued our Work Smart program, an employee-led program to identify process efficiencies across the business. As part of that program, our Transmission, Distribution and Customer Service business group identified 16

[1] *Economic Impact Assessment of BC Hydro's 10-Year Capital Plan.* Deetken Group September 2015.

projects ranging from trouble response process improvements to vegetation management tools implementation. We also conducted a review of our conservation programs and identified opportunities to reduce costs and take advantage of innovative technologies, such as smart meters, to better respond to customer and system needs. The savings from these types of initiatives over the next few years will continue to help fund important investments in priority areas like customer service, safety, maintenance and capital project planning.

This past year, BC Hydro developed a debt management strategy and one component, a Debt Management Regulatory Account, was approved by the BC Utilities Commission (Commission), which will lock-in low long-term interest rates to protect customers from the risk of rising interest rates. We filed our first Rate Design Application since 2007, which reflects extensive stakeholder and customer feedback on our current rate designs, and on potential rate design options. We also filed and received approval for an interim Revenue Requirements Application with the Commission, requesting a four percent rate increase for fiscal 2017, in alignment with the 10 Year Rates Plan. After updating our forecasts to account for recent events in the mining and liquefied natural gas sectors, BC Hydro will file a full Revenue Requirements Application in July 2016, consistent with the rate caps set out in the 10 Year Rates Plan.

In 2015/16, domestic revenues before regulatory transfers were lower than planned due to the loss of large industrial load related to declining market conditions including low commodity prices, and a warmer than normal winter affecting residential customers. BC Hydro has responded to these events through prudent management of its operating and capital expenditures to maintain low rates for its customers. In addition, we are implementing the Province's direction to allow eligible mining customers, under certain circumstances, to postpone payment of their electricity bills with deferred bill amounts to be repaid in full, with interest, as commodity prices recover.

Last August, we experienced the largest single day outage event in our history. Approximately 700,000 Lower Mainland and Vancouver Island customers were without power due to a severe windstorm. Despite the amount of damage and number of customers left without power, BC Hydro employees and our contractors performed a commendable job restoring power. The vast majority of customers were restored to service within 48 hours, and all customers were restored within five days. This required a massive effort including the replacement of 200 power poles, 500 broken cross-arms on pole tops, 10,000 meters of wire and more than 1,200 pieces of electrical equipment, as well as the repair of 25 transmission circuits. Compared with previous large-scale restoration efforts, this was the safest, fastest and most cost-effective large scale restoration on record. Delivering electricity safely is critical to our workers and the public, especially during storm events and importantly, no safety incidents occurred during this service restoration. In 2015/16, BC Hydro had no fatalities or serious injuries and our goal continues to be that, every day, all workers go home safe.

Report on Performance

BC Hydro continues to focus on achieving the objectives outlined in the Government Mandate Letter and aligning with the Taxpayer Accountability Principles. For specific details on fulfillment of the Government Mandate Letter, please refer to *Appendix C: Crown Corporations Mandate and Action Summary.*

Under the Taxpayer Accountability Principles, BC Hydro has implemented its action plan with regular communications between the CEO, Board Chair, the Minister and Deputy Minister; quarterly reporting to the Board of Directors; and, alignment of its Service Plan and Annual Service Plan Report with the spirit and intent of the Taxpayer Accountability Principles. Examples of specific outcomes this year include:

- Implementing the Work Smart process improvement program to identify efficiencies and service enhancements in areas like vegetation management, asbestos management and our customer build program where we work with developers in the design and construction of residential developments,
- Implementing the Province's compensation guidelines for public sector employees,
- Being ranked the #1 employer in Canada in an independent survey by Forbes,
- Initiating a process to optimize the Standing Offer Program by identifying ways to better reflect future system needs and considering technological improvements that have led to declining development costs,
- Implementing a new customer strategy to improve service outcomes; and
- Developing BC Hydro's Statement of Aboriginal Principles to guide our relationships with First Nations.

BC Hydro's values align with the Taxpayer Accountability Principles and employees will continue to identify opportunities that reflect Cost Consciousness, Accountability, Appropriate Compensation, Service, Respect, and Integrity across our business.

Goals, Strategies, Measures and Targets

In 2015/16, BC Hydro updated its mission: ***To provide our customers with reliable, affordable, clean electricity throughout B.C., safely.*** We have continued to implement our strategies to achieve our six goals and 21 performance measures as set out in the 2015/16 - 2017/18 Service Plan; however, these have since been updated to better align with our new mission. The new goals and performance measures are reflected in our new Service Plan for 2016/17 - 2018/19. The goals and measures below track our progress on delivering the identified priorities for 2015/16. BC Hydro management is responsible for measuring performance against targets, and results are reported to the Board on a quarterly basis and publicly in the Annual Service Plan Report. The BC Hydro 2015/16 Annual Service Plan Report compares the corporation's 2015/16 actual results to the expected results in the 2015/16 - 2017/18 Service Plan. The fiscal 2017 and fiscal 2018 targets presented below are based on the recent 2016/17 - 2018/19 Service Plan.

Goal 1: Safely Keep The Lights On

Safely and reliably meet the electricity needs of our customers through integrated planning and technology, and in the operation, maintenance and advancement of our system.

Strategies

Safety

BC Hydro is implementing its five year safety strategy, and in 2015/16, the following was achieved:

- Trained and assessed the competency of our powerline technicians and electricians associated with BC Hydro's Life Saving Rules. This work was initiated this year and will be completed in 2016/17.
- Implemented an improved process to identify critical hazards and ensure multiple safeguards are in place to protect workers.
- Continued work to reduce hazards associated with arc flash, working in confined spaces and with asbestos.
- Implemented a knife cut reduction program by distributing new cutting tools and cut resistant gloves to our employees.
- Made significant progress developing our contractor safety management program, field access to safety information and safety management system improvements.
- Used safety data analytics to assess the safety performance across the organization to identify areas for improvement, and to establish safety priorities and initiatives.

Reliability

BC Hydro continues to ensure the reliability of the system by effectively implementing capital and maintenance programs to manage overall asset health:

- This past year, the focused vegetation management program helped to manage the frequency of outages caused by tree contacts.
- Continued deployment of the automatic recloser program has improved customer interruption impact by reducing sustained outages.
- The longer term implementation of the distribution automation strategy through smart meters and other technologies help to improve system flexibility in outage management.
- BC Hydro continues to effectively manage dam safety issues and risks and is focused on implementing the action plan that was identified through a probabilistic seismic hazard analysis completed in 2014/15. This plan calls for $1.9 billion in investment over the next 10 years in dam safety and seismic upgrades. This work is also driving a similar analysis of resiliency for our transmission and distribution system assets and informs our comprehensive emergency management and security plans.

Performance Measures 1-8[1]

Performance Measures	Actual 2012/13	Actual 2013/14	Actual 2014/15	Target 2015/16	**Actual 2015/16**	Target 2016/17	Target 2017/18
Zero Fatality & Serious Injury[2] [Loss of life or the injury has resulted in a permanent disability]	2[3]	0	1[4]	0	**0**	0	0
Severity[2] [Number of calendar days lost due to injury per 200,000 hours worked]	45.1[5]	28.9	23.3	25.0	**30.0**	N/A[6]	N/A[6]

Performance Measures	Actual 2012/13	Actual 2013/14	Actual 2014/15	Target 2015/16	**Actual 2015/16**	Target 2016/17	Target 2017/18
Lost Time Injury Frequency[2] [Number of employee injury incidents resulting in lost time (beyond the day of the injury) per 200,000 hours worked]	1.0	1.1[7]	1.0	1.0	**1.1**	1.0	0.9
CAIDI (duration)[8] [customer average interruption duration index-hours per interrupted customer]	2.12	2.30	2.36	2.30	**2.02**	N/A[6]	N/A[6]
SAIDI (duration)[8] [system average interruption duration index – total outage duration (in hours) experienced by an average customer in a year] (excluding major events)	2.73	3.59[9]	3.07	3.22	**3.01**	3.22	3.20
SAIFI (frequency)[8] [system average interruption frequency index - number of sustained interruptions per year] (excluding major events)	1.29	1.56	1.30	1.40	**1.48**	1.40	1.35
CEMI-4 (%)[8] [customer experienced multiple interruptions - four or more outages]	9.10	12.35	9.23	11.00	**12.60**	N/A[6]	N/A[6]
Winter Generation Availability (%)	98.1	96.8	97.4	96.4	**96.5**	N/A[6]	N/A[6]

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance.
[2] BC Hydro's safety performance measures do not include contractor or public safety injuries or fatalities.
[3] Neither of the incidents in fiscal 2013 resulted in a fatality.
[4] The fiscal 2015 results reflect a serious injury from an electrical contact that occurred in November 2014.
[5] The fiscal 2013 Severity result of 45.1 is unusually high compared to other years. Over 40 per cent of the result is due to five injuries, each of which had considerable time loss (180 days or more). Traditionally, we only experience one or two injuries in a year resulting in this amount of time loss.
[6] This measure was removed from the 2016/17 – 2018/19 Service Plan; therefore, targets are not included.
[7] Prior years' results have been calculated based on the latest available data and may be different than previously stated.
[8] Annual targets are based on a number of factors including long-term historic reliability trending, current year performance, previous years' investments and future years' investment plans.
[9] Actual 2013/14 actuals were updated based upon revised data and may be different than previously stated.
Note: 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 uncontrollable elements that can significantly disrupt the electrical system. BC Hydro measures reliability under normal circumstances, because major events are not predictable and largely uncontrollable. The reliability measures are therefore based on data that excludes major events. BC Hydro reviews performance during major events and takes the performance into consideration in reliability improvement initiatives.

Discussion

- In 2015/16, BC Hydro had no fatalities or serious injuries. BC Hydro missed the targets for lost time injury frequency and severity but our performance has remained relatively stable over the past five years. Preventing injuries such as those resulting from slips, trips and falls and cuts through our knife injury reduction program should support future positive results.
- With regards to reliability, CAIDI and SAIDI were better than the annual targets meaning the average system customer interruption duration and the average outage duration of the impacted customers were lower than expected. SAIFI, which represents the average number of times that a customer experiences an outage during the year, remained within the 10 percent range of the target. CEMI-4 exceeded the annual target by more than 10 percent mainly due to multiple weather related outages affecting the same customers four or more times, mostly in the Lower Mainland and Vancouver Island areas.

Goal 2: Succeed Through Relationships

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

Strategies

- In 2015/16, we started the implementation of a comprehensive Customer Strategy. With a renewed focus on the customer across the organization, along with execution of some specific initiatives to help make it easy for customers to do business with us, we were able to exceed our Customer Satisfaction Survey (CSAT) target by two percent. Some highlights include:
    - Call centre training focussing on soft skills to find out what we can do to help our customers, as well as improvements to our planned outage process and our communications to listen to customer concerns and reduce any negative impacts.
    - With the installation of smart meters, billing accuracy consistently high due to the nature and accuracy of daily registered reads. For non-smart metered premises, manual meter reading has continued with a quality assurance process to maintain accuracy.
    - First call resolution improved this past year from 71 percent to 73.5 percent.
- BC Hydro once again earned a gold-level certification for best practices from the Canadian Council for Aboriginal Business' Progressive Aboriginal Relations (PAR) program. Key activities we undertook this year to support program sustainment include:
    - Engaging with First Nations earlier in the project planning cycle to improve transparency for First Nations to better incorporate their interests into the delivery of our capital programs, as well as enhance opportunities for collaboration.
    - Supporting business development and employment by investing approximately $100 million for work undertaken by aboriginal businesses. An example is our contract with a Skeetchestn-owned company to provide gravel for a resurfacing project at our Kelly Lake Substation.
    - Advancing training and employment plans with First Nations, educators and service providers in the Northeast, Okanagan, and Lower Mainland regions.
    - Awarding $50,000 in scholarships and bursaries to aboriginal students who are working toward BC Hydro careers.
    - Focusing our efforts on building support with aboriginal people in areas where BC Hydro has a large operating footprint and where our infrastructure footprint is expected to grow. For example, we are collaborating on a five year work plan with the Okanagan Nation Alliance.

Performance Measure 9 - 12[1]

Performance Measures	Actual 2012/13	Actual 2013/14	Actual 2014/15	Target 2015/16	**Actual 2015/16**	Target 2016/17	Target 2017/18
CSAT Index [Customer Satisfaction Index: % of customers satisfied or very satisfied]	86.0	85.0	86.0	85.0	**87.0**	85.0	85.0
Billing Accuracy [% of accurate bills]	98.5	99.1	99.5	99.0	**99.5**	N/A[2]	N/A[2]
First Call Resolution [% of customer calls resolved first time]	68.0	71.0	71.0	71.0	**73.5**	N/A[2]	N/A[2]
Progressive Aboriginal Relations Designation[3]	Gold	Gold	Gold	Gold	**Gold**	Gold	Gold

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance.
[2] This performance measure was removed from the 2016/17 – 2018/19 Service Plan; therefore, targets are not included
[3] BC Hydro attained a gold-level designation from the Canadian Council for Aboriginal Business in 2015/16 which is valid for a three year period. In fiscal 2019, BC Hydro will apply for the next certification.

Goal 3: 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.

Strategies

In 2015/16, BC Hydro continued to:

- Implement its conservation plan which is forecast to exceed the *Clean Energy Act* objective to meet at least two-thirds of future demand growth through conservation by 2020. This includes energy management programs and conservation rate structures, supporting new energy efficiency codes and standards, and maintaining an energy conservation and efficiency culture.
- Meet the 93 per cent clean energy objective in the *Clean Energy Act* by building Site C, completing electricity purchase agreements for new wind, solar and run-of-river projects, and exploring the development of zero-emission capacity resources.
- Meet regulatory requirements related to greenhouse gas emissions reporting and verification for our electricity generation, transmission and distribution operations.
- Contribute to meeting the Province's goal of achieving carbon neutrality in the public sector by purchasing offsets to reach net zero greenhouse gas emissions from our buildings, vehicles and paper use.
- Facilitate the electrification of transportation in B.C. through the establishment of a new electric vehicle office and customer service strategy; obtaining approval from the Commission for a new shore power rate for ocean vessels to access grid power while in port; and providing leadership support to Plug In BC, an initiative empowered to lay the groundwork for plug-in electric vehicles and related electric charging infrastructure in B.C.
- Manage the impact on the environment from BC Hydro's new developments and retrofits of existing facilities by incorporating an "avoid, minimize and offset" approach to project design, planning and implementation.

- Implement environmental studies and projects related to water licence requirements under BC Hydro's Water Use Plans, to confirm the suitability of operational controls and infrastructure at our facilities.
- Implement the polychlorinated biphenyl (PCB) electrical equipment phase-out strategy, and the long-term strategy for the handling, decontamination and disposal of PCB contaminated equipment and materials.

Performance Measures 13 - 16[1]

Performance Measures	Actual 2012/13	Actual 2013/14	Actual 2014/15	Target 2015/16	**Actual 2015/16**	Target 2016/17	Target 2017/18
Demand Side Management (DSM) (GWh/year)[2]	4,460	4,776	4,334	5,000	**5,091**	N/A[3]	N/A[3]
Clean Energy (%)[4]	98.2	97.1	97.9	93.0	**98.3**	93.0	93.0
Electricity Production GHG Emissions (kilotonnes CO_2e)[5,6]	631	730	667	1,100	**606**[7]	N/A[8]	N/A[8]
Carbon Neutral Program Emissions (kilotonnes CO_2e)[5,9]	28.8	27.0	26.6	28.0	**27.3**[10]	N/A[8]	N/A[8]

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance.

[2] Target numbers are rounded values presented as cumulative run-rate savings since 2008 and include energy savings from energy conservation programs as well as from codes/standards and rate structures. The conservation program results were within one percent of Plan. This was due to efforts in codes & standards, commercial new construction, load displacement, transmission service rates and our Commercial Leaders in Energy Management program.

[3] This performance measure was changed in the 2016/17 – 2018/19 Service Plan; therefore, the F2017 and F2018 targets are not applicable. The new Energy Conservation Portfolio performance measure will be New Incremental Energy Savings (GWh/yr). The targets for this new measure are 700 GWh/yr in F2017 and 700 GWh/yr in F2018.

[4] The Clean Energy Target represents the 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. BC Hydro's forecast is based on actual resource use and is consistent with previous years. This year's actual was the highest BC Hydro has achieved in a decade.

[5] All actuals, forecast and targets for Electricity Production GHG Emissions and Carbon Neutral Program Emissions are presented on a calendar year basis, not fiscal year. For Electricity Production, this is to ensure consistency with GHG emissions reports filed under *the Canadian Environmental Protection Act, 1999* and the B.C. Reporting Regulation. For Carbon Neutral this is to ensure consistency with the B.C. Carbon Neutral Government Regulation.

[6] The Electricity Production GHG Emissions measure includes emissions from electricity generation, electricity purchased from B.C. Independent Power Producers (IPP), and fugitive SF_6 releases.

[7] Electricity Production GHG emissions were 606 kilotonnes CO_2e, which is 45 percent below the plan of 1,110 kilotonnes CO_2e. Emissions were lower than forecasted for the Island Generation IPP, Burrard Generating Station, and Fort Nelson Generating Station. Fugitive SF_6 releases were also lower than forecasted.

[8] This performance measure was removed from the 2016/17 – 2018/19 Service Plan; therefore, targets are not included.

[9] The Carbon Neutral Program Emissions measures are based on emissions from BC Hydro's vehicle fleet, buildings and paper use.

[10] Carbon Neutral Program Emissions were 27.3 kilotonnes CO_2e, which is a favorable result and three percent below the target of 28.0 kilotonnes CO_2e. The Carbon Neutral Program Emissions were almost three percent higher in 2015 than in the previous calendar year. This is due to a seven percent increase in vehicle fleet fuel consumption that was partially mitigated by a reduction in building energy use and paper use.

Goal 4: Foster Economic Development

Foster economic development opportunities across B.C. through our projects, practices and advancement of the energy efficiency and clean energy sectors.

Strategies

Many of BC Hydro's operating, capital and procurement activities support provincial economic development and create local employment. Several are noted in *Appendix C: Crown Corporations Mandate and Actions Summary*. In addition, this past year:

- BC Hydro received Commission approval for a tariff that would allow indirect interconnection service for transmission voltage customers. This will facilitate economic development by allowing customers to connect to BC Hydro through other customer-owned transmission infrastructure.

- BC Hydro's conservation programs help create jobs by fostering B.C.'s energy efficiency industry made up of contractors, engineers and suppliers, while helping customers lower their energy bills and utilize new technologies, to improve the competitiveness of their businesses.

Goal 5: Maintain Competitive Rates

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

Strategies

BC Hydro prudently manages its operating and capital expenditures to maintain competitive rates for our customers. For example, from fiscal 2012-2016, BC Hydro completed 563 capital projects managed by the Project Delivery group at a total cost of $6.48 billion and came in at 0.18 percent under budget overall. Additional accomplishments this past year include:

- Operational improvements including the introduction of a weather forecasting service to provide localized and detailed weather information to assist with pre-deployment of transmission and distribution crews and resources to deliver a faster and more efficient restoration of service to our customers during storms.
- A Distribution Work Scheduling tool to provide a single view of all provincial distribution-related work which has supported better and more efficient work scheduling.
- Implementation of supply chain strategies to deliver improved operational performance and efficiencies which have supported improvements to the supplier model for safety clothing resulting in a greater than 20 percent improvement in the total life cycle cost.
- New regional optimized contracts which are achieving higher than forecasted savings, as well as improved contractor safety and quality performance.

Performance Measures 17 - 20[1]

Performance Measures	Actual 2012/13	Actual 2013/14	Actual 2014/15	Target 2015/16	**Actual 2015/16**	Target 2016/17	Target 2017/18
Competitive Rates[2]	1st quartile	1st quartile	1st quartile	1st quartile	**1st quartile**	1st quartile	1st quartile
Net Income[3] ($ million)	509	549	581	653	**655**	N/A[4]	N/A[4]
Operating Costs[3,5] ($ million)	705	702	710	713	**715**	N/A[4]	N/A[4]
Project Budget to Actual Cost[6]	+0.83% on $3.29 billion	-4.75% on $3.33 billion	-1.83% on $3.94 billion	Within +5% to -5% of budget excluding project reserve amounts	**-0.18% on $6.49 billion**	Within +5% to -5% of budget excluding project reserve amounts	Within +5% to -5% of budget excluding project reserve amounts

[1] Performance Measure definitions, rationales, data sources, and benchmarking information are available at www.bchydro.com/performance.
[2] Based on the annual HydroQuebec Report on Electricity Rates in North America.
[3] Performance within (+/-) 0.5 per cent is considered acceptable.
[4] This performance measure was removed from the 2016/17 – 2018/19 Service Plan; however, the information is available in the Finance section of the Annual Service Plan Report.
[5] 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 adjustments.
[6] Project Budget to Actual Cost metric is new for 2015/16. The data includes Generation, Substation and Transmission Line projects managed by the Project Delivery groups in Generation, and Transmission and Distribution. Annually, BC Hydro reflects the past five years' performance in delivering capital projects. This is a five year rolling data set of actual costs compared to original approved full scope implementation budgets not including project reserve amounts, for capital projects that were put into service during the period. Distribution projects (including Smart Metering and Infrastructure) and property projects (including the Nanaimo Office) that went into service in 2015/16 are included in the F2016 five year rolling average. Distribution and properties were not included in previous five year rolling averages.

Goal 6: Engage a Safe and Empowered Team

Empower a team that is committed to safety, innovative and prepared for the future.

Strategies

In 2015/16, BC Hydro implemented:

- Targeted campaigns to address workforce gaps which have provided a readily available talent pool for specialized and critical roles.
- A new workforce plan to ensure the appropriate labour mix with the skills required to safely design, operate and maintain our system while seeking opportunities to adjust our labour mix (new staff, specific skills, and, contracted or outsourced service providers) in areas where costs or business risks can be reduced.

***Note:** For information on how BC Hydro is working to ensure the safety of employees, contractors and the public see Goal 1.*

Performance Measure 21[1]

Performance Measures	Actual 2012/13	Actual 2013/14	Actual 2014/15	Target 2015/16	**Actual 2015/16**	Target 2016/17	Target 2017/18
Employee Engagement (%)[2]	78 Global Utility Index score was 79	79 Global Utility Index score was 79	82 Global Utility Index score was 79	Meet or exceed Towers Watson's Global Utilities Index	**83** **Global Utility Index score was 81**	N/A[3]	N/A[3]

[1] Performance Measure definitions, rationales, data sources, and benchmarking information are available at www.bchydro.com/performance.
[2] The target is for BC Hydro's favourable score to meet or exceed the industry benchmark. The benchmark is the Towers Watson Global Utilities Companies Norm, which is calculated annually. Performance and engagement results continue to trend upward and particularly reflect employee willingness to contribute their discretionary effort to achieving organizational priorities.
[3] This performance measure was removed from the 2016/17 – 2018/19 Service Plan; therefore, targets are not included.

FINANCIAL REPORT

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, 2016 (fiscal 2016) and should be read in conjunction with the Audited Consolidated Financial Statements and related notes of the Company for the years ended March 31, 2016 and 2015.

The Company applies accounting standards as prescribed by the Province of British Columbia (the Province) which combines the accounting principles of International Financial Reporting Standards (IFRS) with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980, *Regulated Operations* (ASC 980) (collectively, the Prescribed Standards). All financial information is expressed in Canadian dollars unless otherwise specified.

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 for the year ended March 31, 2016 was $655 million, $74 million higher than the prior fiscal year net income of $581 million. The increase from the prior year was primarily due to higher domestic revenues mainly due to higher average customer rates reflecting a British Columbia Utilities Commission (BCUC) approved rate increase of 6 per cent for fiscal 2016. This was partially offset by higher finance charges primarily due to higher planned volume of long-term debt borrowings, higher planned lease charges related to electricity purchase agreements, and higher planned short-term interest rates, as well as higher amortization and depreciation expenses primarily due to an increase in assets in service.

- Inflows to the system during fiscal 2016 were 97 per cent of average, compared to 102 per cent of average for the prior fiscal year. Actual inflows to Williston and Kinbasket reservoirs were 102 per cent and 110 per cent of average, respectively, compared to 93 per cent and 112 per cent respectively in the prior fiscal year. The lower inflows in fiscal 2016 were due to lower than average inflows in the Kootenay and Pend-d'Oreille basins and at most of BC Hydro's smaller plants.

- Capital expenditures, before contributions in aid of construction, for the year ended March 31, 2016 were $2,306 million, a $137 million increase over the prior fiscal year. BC Hydro continues to invest significantly in capital projects to refurbish its ageing infrastructure and build new assets for future growth, including the Site C Clean Energy project, John Hart Generating Station Replacement project, Ruskin Dam Safety and Powerhouse Upgrade project, Interior to Lower Mainland Transmission project, Dawson Creek/Chetwynd Area Transmission project, and the Upper Columbia Capacity Additions at Mica – Units 5 & 6 project.

CONSOLIDATED RESULTS OF OPERATIONS

for the years ended March 31 ($ in millions)	**2016**	2015	Change
Total Revenues	**$ 5,657**	$ 5,748	$ (91)
Net Income	**$ 655**	$ 581	$ 74
Capital Expenditures	**$ 2,306**	$ 2,169	$ 137
GWh Sold (Domestic)	**57,300**	51,213	6,087

as at March 31 ($ in millions)	**2016**	2015	Change
Total Assets	**$ 30,034**	$ 27,753	$ 2,281
Shareholder's Equity	**$ 4,500**	$ 4,170	$ 330
Accrued Payment to the Province	**$ 326**	$ 264	$ 62
Retained Earnings	**$ 4,397**	$ 4,068	$ 329
Debt to Equity	**80 : 20**	80 : 20	n/a
Number of Domestic Customer Accounts	**1,960,555**	1,935,068	25,487
Total Reservoir Storage (GWh)	**16,518**	19,565	(3,047)

REVENUES

Total revenues after regulatory account transfers for the year ended March 31, 2016 were $5,657 million, a decrease of $91 million or 2 per cent compared to the prior fiscal year. The decrease was primarily due to lower trade revenues mainly due to a decrease in the average natural gas price and decreases in volumes of physical gas and electricity sold, partially offset by higher domestic revenues primarily due to higher average customer rates and higher surplus energy sales.

	(in millions)		*(gigawatt hours)*		*($ per MWh)* [2]	
for the years ended March 31	**2016**	2015	**2016**	2015	**2016**	2015
Domestic						
Residential	**$ 1,842**	$ 1,712	**17,331**	17,047	**$ 106.28**	$ 100.43
Light industrial and commercial	**1,685**	1,597	**18,421**	18,564	**91.47**	86.03
Large industrial	**766**	748	**13,669**	14,020	**56.04**	53.35
Other energy sales	**464**	280	**7,879**	1,582	**58.89**	176.99
Total Domestic Revenue Before Regulatory Transfer	**4,757**	4,337	**57,300**	51,213	**83.02**	84.69
Rate smoothing and load variance regulatory transfer	**299**	492	-	-	-	-
Total Domestic	**$ 5,056**	$ 4,829	**57,300**	51,213	**$ 88.24**	$ 94.29
Trade						
Electricity - Gross	**$ 643**	$ 989	**14,732**	21,928	**$ 43.65**	$ 45.10
Less: forward electricity purchases	**(183)**	(214)	-	-	-	-
Electricity - Net	**460**	775	-	-	-	-
Gas - Gross	**462**	886	**17,042**	21,637	**27.11**	40.95
Less: forward gas purchases	**(321)**	(742)	-	-	-	-
Gas - Net	**141**	144	-	-	-	-
Total Trade [1]	**$ 601**	$ 919	**31,774**	43,565	**$ 18.91**	$ 21.09
Total	**$ 5,657**	$ 5,748	**89,074**	94,778	**$ 63.51**	$ 60.65

[1] *Trade revenue regulatory transfer is netted with the trade cost of energy transfer to reflect a trade margin transfer and this is reflected in the cost of energy table.*

[2] *The Trade $/MWh figures are based on total gross sales which includes physical and financial transactions whereas the volumes only include physical transactions.*

Domestic Revenues

Total domestic revenues after regulatory account transfers for the year ended March 31, 2016 were $5,056 million, an increase of $227 million or 5 per cent compared to the prior fiscal year. Domestic revenues before regulatory account transfers of $4,757 million were $420 million or 10 per cent higher than the prior fiscal year. The increase compared to the prior fiscal year was primarily due to higher average customer rates and higher other energy sales.

Average customer rates were higher in fiscal 2016 compared to the prior fiscal year, reflecting an average rate increase as approved by the British Columbia Utilities Commission of 6 per cent effective April 1, 2015.

Other energy sales were higher as a result of more surplus energy sold into the market as compared to the prior fiscal year (6,277 GWh for fiscal 2016 and 14 GWh for fiscal 2015). Surplus energy sales were required to reduce spill risk, as a result of higher reservoir levels at the start of the fiscal year resulting from increased storage through the fall and winter of the prior year due to low market prices. In addition, increased generation at Mica was required in the current year to maintain downstream Arrow reservoir levels and to meet Columbia River Treaty obligations which contributed to increased surplus energy sales. Surplus sales vary year to year based on level and timing of inflows, risk of spill, and market conditions.

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 the Heritage Deferral Account (HDA) and NHDA.

Trade Revenues

Powerex, a wholly owned subsidiary of the Company, is an active participant in western energy markets, buying and selling wholesale power, natural gas, ancillary services, clean and renewable power, and environmental products.

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.

Total trade revenues for the year ended March 31, 2016 were $601 million, a decrease of $318 million or 35 per cent compared to the prior fiscal year. The decrease in revenue was primarily due to a 34 per cent decrease in the average natural gas sales price and a 21 per cent decrease in the volume of physical gas sold, as well as a 33 per cent decrease in the volume of physical electricity sold. The decrease in the average natural gas sales price was reflective of an increase in production in the U.S. and mild temperatures in Eastern North America in the current year resulting in lower than normal demand. The decrease in the volume of physical gas sold was primarily due to lower gas trading opportunities following decreased demand as a result of warmer temperatures. The decrease in the volume of physical electricity sold for trade was primarily due to higher volumes of surplus energy sold for domestic purposes as well as an outage for a key third party transmission line to California.

Variances between actual and planned trade revenues are transferred to the Trade Income Deferral Account (TIDA).

OPERATING EXPENSES

For the year ended March 31, 2016, total operating expenses of $4,250 million were $285 million lower than the prior fiscal year. The decrease over the prior fiscal year was primarily due to lower expenditures for trade electricity and gas purchases. In addition, there were lower domestic energy costs, partially offset by higher amortization and depreciation expense.

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 transfers for the year ended March 31, 2016 were $1,852 million, $351 million or 16 per cent lower than the prior fiscal year. The decrease over the prior fiscal year was primarily due to lower trade electricity and gas purchases.

	(in millions)		*(gigawatt hours)*		*($ per MWh)* [2]	
for the years ended March 31	**2016**	2015	**2016**	2015	**2016**	2015
Domestic						
Water rental payments (hydro generation)[1]	**$ 327**	$ 334	**48,376**	41,318	**$ 6.62**	$ 8.11
Purchases from Independent Power Producers	**1,229**	1,064	**14,319**	13,377	**85.82**	79.54
Other electricity purchases - Domestic	**3**	6	**122**	207	**22.66**	28.76
Gas for thermal generation	**29**	34	**215**	213	**134.64**	157.36
Transmission charges and other expenses	**24**	2	**111**	115	**-**	-
Non-treaty storage / Libby Coordination Agreement	**(15)**	14	**-**	-	**-**	-
Allocation from (to) trade energy	**-**	16	**(6)**	512	**24.79**	33.51
Total Domestic Cost of Energy Before Regulatory Transfers	**1,597**	1,470	**63,137**	55,742	**25.30**	26.37
Domestic cost of energy regulatory transfers	**(172)**	(12)	**-**	-	**-**	-
Total Domestic	**$ 1,425**	$ 1,458	**63,137**	55,742	**$ 22.57**	$ 26.15
Trade						
Electricity - Gross	**$ 362**	$ 617	**14,602**	22,397	**$ 24.79**	$ 27.55
Less: forward electricity purchases	**(183)**	(214)	**-**	-	**-**	-
Electricity - Net	**179**	403	**-**	-	**-**	-
Remarketed gas - Gross	**401**	842	**17,296**	21,812	**23.18**	38.60
Less: forward gas purchases	**(321)**	(742)	**-**	-	**-**	-
Remarketed gas - Net	**80**	100	**-**	-	**-**	-
Transmission charges and other expenses	**215**	248	**-**	-	**-**	-
Allocation (to) from domestic energy	**-**	(16)	**6**	(512)	**24.79**	33.51
Total Trade Cost of Energy Before Regulatory Transfers	**474**	735	**31,904**	43,697	**20.58**	21.73
Trade net margin regulatory transfer	**(47)**	10	**-**	-	**-**	-
Total Trade	**$ 427**	$ 745	**31,904**	43,697	**$ 19.10**	$ 21.96
Total Energy Costs	**$ 1,852**	$ 2,203	**95,041**	99,439	**$ 21.41**	$ 24.31

[1] *Total GWh is net of storage exchange.*

[2] *Total cost per MWh includes other electricity purchases at gross cost.*

Domestic Energy Costs

Total domestic energy costs after regulatory transfers for the year ended March 31, 2016 were $1,425 million, $33 million or 2 per cent lower than the prior fiscal year. Domestic energy costs before regulatory transfers of $1,597 million for the year ended March 31, 2016 were $127 million or 9 per cent higher than the prior fiscal year. The increase in costs, before regulatory transfers, was primarily due to higher Independent Power Producer costs as more Independent Power Producers were in operation during the current year. The increase was also due to higher domestic transmission costs, as a result of increased surplus sales in the current year. This was partially offset by lower energy costs from water transactions related to the Non-Treaty Storage Agreement and Libby Coordination Agreement and a lower allocation from trade energy.

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

Trade Energy Costs

Total trade energy costs after regulatory account transfers for the year ended March 31, 2016 were $427 million, a decrease of $318 million or 43 per cent compared with the prior fiscal year. Trade energy costs before regulatory account transfers for the year ended March 31, 2016 were $474 million, a decrease of $261 million or 36 per cent compared with the prior fiscal year. The decrease was primarily due to a 40 per cent decrease in the average gas purchase price and a 21 per cent decrease in the volume of physical gas purchased, as well as a 35 per cent decrease in the volume of physical electricity purchased. The decrease in the average gas purchase price was primarily reflective of an increase in production in the U.S. and mild temperatures in Eastern North America in the current year resulting in lower than normal demand. The decrease in volume of physical electricity and physical gas purchased was consistent with the decrease in physical electricity and physical gas sold, respectively.

Variances between actual and planned trade cost of energy are transferred to the TIDA.

Water Inflows

Water inflows to the system during fiscal 2016 were 97 per cent of average, compared to 102 per cent of average for the prior fiscal year. Actual inflows to Williston and Kinbasket reservoirs were 102 per cent and 110 per cent of average, respectively, compared to 93 per cent and 112 per cent respectively in the prior fiscal year. The lower inflows in fiscal 2016 were due to lower than average inflows in the Kootenay and Pend-d'Oreille basins and at most of BC Hydro's smaller plants.

The Williston and Kinbasket reservoirs have been managed such that system energy storage on March 31, 2016 was 14,900 GWh, or 2,100 GWh above the 10 year historic average. This was 2,900 GWh lower than the system energy storage of 17,800 GWh recorded one year earlier. The Williston and Kinbasket reservoir energy contents were 11,200 GWh (1,800 GWh above the 10 year historic average) and 3,700 GWh (300 GWh above the 10 year historic average), respectively, with Williston the same as the prior fiscal year and Kinbasket 2,900 GWh lower than the prior fiscal year. The relative imbalance between the Williston and Kinbasket reservoir operations during this period was due to running Mica to support Arrow reservoir levels while meeting Arrow releases obligated under the Columbia River Treaty. The higher than average levels of Williston storage at the end of the fiscal year are a culmination of lower than forecast system loads and market prices, unit outages at the Gordon M. Shrum generating station, and more restrictive than normal ice constraints.

Personnel Expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the year ended March 31, 2016 were $527 million, comparable to personnel expenses of $534 million in the prior fiscal year.

Materials and External Services

Expenditures on materials and external services for the year ended March 31, 2016 were $605 million, $12 million higher than the prior fiscal year, primarily due to increased expenditures on electricity purchase agreements accounted for as finance leases and a recovery from a third party recognized in the prior year, lowering that year's expenses.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment (PP&E), amortization of intangible assets, and the amortization of certain regulatory assets and liabilities. For the year ended March 31, 2016, amortization and depreciation expense was $1,241 million, $36 million or 3 per cent higher than the prior fiscal year primarily due to an increase in depreciation of property, plant and equipment due to an increase in assets in service.

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, 2016 were $220 million, comparable to total grants and taxes of $209 million in the prior fiscal year.

Capitalized Costs

Capitalized costs consist of overhead costs directly attributable to capital expenditures that are transferred from operating costs to PP&E. Certain overhead costs not eligible for capitalization under IFRS are transferred from operating costs to the IFRS PP&E regulatory account. These transfers are amortized over 40 years which approximates the composite average life of the PP&E. In addition, starting fiscal 2013, the ongoing impact of this change is being smoothed into rates over a 10-year period through transfers to the IFRS PP&E regulatory account as approved by the BCUC. As such, each year, 1/10th 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 for the year ended March 31, 2016 were $203 million, $21 million lower than capitalized costs of $224 million in the prior fiscal year. The reduction in capitalized costs was primarily due to the annual reduction of the transfer of operating costs to the IFRS PP&E account.

FINANCE CHARGES

Finance charges for the year ended March 31, 2016 were $752 million, $120 million or 19 per cent higher than the prior fiscal year. The increase was primarily due to higher planned volume of long-term debt borrowings, higher planned lease charges related to electricity purchase agreements, and higher planned short-term interest rates.

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 combined with 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 total comprehensive income in the year the amounts are incurred or would be reflected in rates. 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 are then included in customer rates in future periods, subject to approval by the BCUC and have the effect of adjusting net income.

Net regulatory account transfers are comprised of the following:

for the years ended March 31 (in millions)	**2016**	2015
Energy Deferral Accounts		
Heritage Deferral Account	$ **(152)**	$ 82
Non-Heritage Deferral Account	**483**	238
Trade Income Deferral Account	**51**	(10)
	382	310
Forecast Variance Accounts		
Total Finance Charges	**(158)**	(120)
Rate Smoothing Account	**121**	166
Non-Current Pension Cost	**142**	317
Other	**18**	25
	123	388
Capital-Like Accounts		
Demand-Side Management	**145**	125
Site C	**-**	65
Smart Metering & Infrastructure	**20**	26
IFRS Property, Plant & Equipment	**134**	157
	299	373
Non-Cash Accounts		
Environmental Provisions & Costs	**51**	69
First Nations Provisions & Costs	**14**	12
Other	**6**	6
	71	87
Amortization of regulatory accounts	**(472)**	(491)
Interest on regulatory accounts	**72**	67
Net change in regulatory accounts	$ **475**	$ 734

For the year ended March 31, 2016, net additions to the Company's regulatory accounts after interest and amortization were $475 million compared to prior year net additions of $734 million. The net asset balance in the regulatory asset and liability accounts as at March 31, 2016 was an asset of $5,908 million compared to an asset of $5,433 million as at March 31, 2015.

Net additions to the regulatory accounts during the year ended March 31, 2016 included:

- Increases of $382 million to the energy deferral accounts primarily due to lower domestic revenues, higher Independent Power Producer costs, and lower trade income, partially offset by higher surplus sales;
- Planned expenditures of $145 million on Demand-Side Management projects, which support energy conservation;
- Transfers of $142 million to the Non-Current Pension Cost regulatory account for 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 other

comprehensive income. The increase was primarily due to a change in the mortality assumption incorporating future mortality improvement, and by a lower rate of return on plan assets, partially offset by an increase in the discount rate used to value defined benefit obligations;

- Transfers of $134 million to the IFRS PP&E regulatory account for smoothing the rate impact of overhead costs not eligible for capitalization under IFRS as they are not considered directly attributable to the construction of capital assets;

- Increases of $121 million to the Rate Smoothing regulatory account for smoothing the rate impacts of the rate increases in the 10 Year Rates Plan;

- Interest on regulatory accounts of $72 million; and

- Transfers of $51 million to the Environmental Provisions & Costs regulatory account reflecting increases required to asbestos and polychlorinated biphenyls (PCBs) contamination provisions.

These net additions were partially offset by:

- Net amortization of $472 million which is the regulatory mechanism to recover the regulatory account balances in rates; and

- Transfers of $158 million to the Total Finance Charges regulatory liability account due to lower interest rates, lower volume of borrowings, and higher capitalization of interest during construction.

Net regulatory account balances are as follows:

as at March 31 (in millions)	**2016**	2015
Energy Deferral Accounts		
Heritage Deferral Account	**$ (24)**	$ 165
Non-Heritage Deferral Account	**917**	524
Trade Income Deferral Account	**249**	244
	1,142	933
Capital-Like Accounts		
Demand-Side Management	**908**	842
Site C	**436**	419
Capital Project Investigation Costs	**25**	30
Smart Metering & Infrastructure	**283**	283
IFRS Property, Plant & Equipment	**872**	758
	2,524	2,332
Forecast Variance Accounts		
Rate Smoothing Account	**287**	166
Non-Current Pension Cost	**691**	564
Foreign Exchange Gains and Losses	**(69)**	(71)
CIA Amortization	**92**	87
Total Finance Charges	**(305)**	(173)
Other Forecast Variance Accounts	**44**	32
	740	605
Non-Cash Accounts		
First Nations Provisions & Costs	**541**	564
Environmental Provisions & Costs	**358**	382
Future Removal & Site Restoration Costs	**(9)**	(33)
IFRS Pension	**612**	650
	1,502	1,563
Total Regulatory Account Balance	**$ 5,908**	$ 5,433

BC Hydro has regulatory mechanisms in place to collect 24 of 26 regulatory accounts in use or with balances at March 31, 2016, which represent approximately 88 per cent of the total net regulatory account balance, in rates over various periods.

COMPARISON WITH SERVICE PLAN

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each year. BC Hydro's Service Plan for fiscal 2015/16-2017/18 was filed in February 2015 and forecast net income for fiscal 2016 at $653 million.

The table below provides an overview of BC Hydro's fiscal 2016 financial performance results, relative to its February 2015 Service Plan forecast.

Consolidated Statement of Operations

(in millions)	Actual 2015	Actual 2016	2016 Service Plan 2016	Variance to 2016 Service Plan
Revenues				
Domestic	$ 4,829	$ 5,056	5,057	$ (1)
Trade	919	601	1,029	(428)
	5,748	5,657	6,086	(429)
Expenses				
Operating Costs				
Cost of energy	2,203	1,852	2,280	428
Other operating expenses				
Personnel expenses, materials and external services [1]	868	905	900	(5)
Amortization	1,205	1,241	1,254	13
Finance charges	632	752	751	(1)
Grants and taxes	209	220	218	(2)
Other	50	32	30	(2)
	5,167	5,002	5,433	431
Net Income	$ 581	$ 655	$ 653	$ 2

[1] *These amounts are net of capitalized overhead and recoveries.*

Trade revenue and trade cost of energy amounts were both lower than the forecast by $428 million; however, the trade gross margin was on Plan. Variances to the February 2015 Service Plan for trade revenue and trade cost of energy are both deferred through the TIDA.

Overall, domestic revenues and expenses and net income were comparable to the Service Plan forecast.

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, 2016 was $326 million which was 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, 2016 was $1,060 million, which is comparable to cash flow provided by operating activities of $1,018 million in the prior fiscal year.

The long-term debt balance net of sinking funds at March 31, 2016 was $18,046 million, compared with $16,721 million at March 31, 2015. The increase was mainly as a result of an increase in long-term bond issues totaling $2,641 million ($2,691 million par value) and net foreign exchange losses of $24 million. These increases were partially offset by a decrease in revolving borrowings of $1,171 million and long-term bond redemptions totaling $150 million par value. Long-term debt increased primarily to fund capital expenditures.

CAPITAL EXPENDITURES

Capital expenditures include property, plant and equipment and intangible assets. The capital expenditures, before contributions in aid of construction, were as follows:

for the years ended March 31 (in millions)	**2016**	2015
Transmission lines and substations replacements & expansion	$ **612**	$ 1,003
Generation replacements and expansion	**498**	526
Distribution system improvements and expansion	**464**	399
General, including technology, vehicles and buildings	**243**	216
Site C Clean Energy project	**489**	25
Total Capital Expenditures	**$ 2,306**	$ 2,169

Total capital expenditures presented in this table are different from the amount of property, plant and equipment and intangible asset expenditures in the Consolidated Statement of Cash Flows due to the effect of accruals related to these expenditures.

Transmission lines and substation capital expenditures includes expenditures on the Interior to Lower Mainland Transmission Line project, Dawson Creek/Chetwynd Area Transmission project, Surrey Area Substation project, Big Bend Substation project, the Transmission Wood Structure Replacement program, Arnott Capacity Upgrade project, Horsey to George Tripp Substation 230kV Cable project, Meikle Wind Energy interconnection project, and Merritt Area Transmission project.

Generation capital expenditures include expenditures for John Hart Generating Station Replacement project, Ruskin Dam Safety and Powerhouse Upgrade project, Upper Columbia Capacity Additions at Mica – Units 5 & 6 project, Hugh Keenleyside Spillway Gate Reliability project and G.M. Shrum Units 1-5 Turbine Rehabilitation project.

Distribution capital expenditures include expenditures on customer driven work, end of life asset replacements, system expansion and improvements, and the Smart Metering & Infrastructure program.

General capital expenditures include expenditures on various technology projects, building development programs, and vehicles.

Site C Clean Energy project expenditures incurred after the provincial government's positive investment decision in December 2014 are recorded as capital and include expenditures in support of construction which started in July 2015.

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).

BC Hydro 10 Year Rates Plan

In November 2013, the Government announced a 10 Year Rates Plan for BC Hydro. On March 6, 2014, the Government issued Directions No. 6 and 7 to the BCUC to implement the 10 Year Rates Plan. Direction No. 6 set BC Hydro's rate increase at 9 per cent for fiscal 2015 and 6 per cent for fiscal 2016 and also specifies the amounts to be amortized from BC Hydro's regulatory accounts in those years. BC Hydro rate increases for fiscal 2017, fiscal 2018, and fiscal 2019 are subject to BCUC review but are capped at 4.0 per cent, 3.5 per cent, and 3.0 per cent pursuant to Direction No. 7. The BCUC will also set the rates for the final five years of the plan. In addition, Direction No. 7 sets the return on equity at 11.84 per cent for fiscal 2015, fiscal 2016 and fiscal 2017. Furthermore, the Deferral Account Rate Rider will remain at 5 per cent for fiscal 2016 and future years. Commencing in fiscal 2018, the dividend will be reduced by $100 million per year until it reaches zero and will thereafter remain at zero until BC Hydro achieves a 60:40 debt to equity ratio. Allowed net income for fiscal 2018 and future years will increase by the forecast growth in the B.C. consumer price index.

BC Hydro Request for Fiscal 2017 Interim Rates

In February 2016, BC Hydro filed a rate application with the BCUC requesting an interim general rate increase of 4.0 per cent effective April 1, 2016 (fiscal 2017). In March 2016, the BCUC issued Order No. G-40-16, approving the interim rate increase.

BC Hydro Fiscal 2017-2019 Revenue Requirements Application

BC Hydro plans to file a three-year Revenue Requirements Application with the BCUC in July 2016 for the test period covering fiscal 2017-2019. This application will seek to finalize the interim rate increase of 4.0 per cent approved for fiscal 2017 by BCUC Order No. G-40-16, and request approval of further rate increases of 3.5 per cent in fiscal 2018, and 3.0 per cent in fiscal 2019, consistent with the 10 Year Rates Plan. The BCUC will likely issue its decision on the Application in calendar 2017.

BC Hydro 2015 Rate Design Application

In September 2015, BC Hydro filed Module 1 of its 2015 Rate Design Application with the BCUC. Among the various approvals sought in Module 1 of the 2015 Rate Design Application, BC Hydro is seeking approval to simplify its commercial rates, retain the inclining block structure for residential customers and introduce a new rate for transmission service customers that would provide market pricing during the freshet period (May to July) for incremental consumption. A final decision by the BCUC on the Rate Design Application is expected late in calendar 2016. Changes in rate design are designed to be revenue neutral to BC Hydro.

Debt Management Regulatory Account Application

In December 2015, BC Hydro filed an Application with the BCUC seeking approval to establish a new regulatory account to capture mark-to-market gains and losses of financial contracts that hedge long-term future debt. This new account will assist BC Hydro in mitigating risks of increasing interest rates while borrowing to support its capital plan. The Commission approved BC Hydro's Application on March 30, 2016 (Order No. G-42-16).

RISK MANAGEMENT

BC Hydro is exposed to numerous risks, which can result in safety, environmental, financial, reliability and reputational impacts. This section of the MD&A discusses risks that impacted financial performance in the year.

The impact of many financial risks associated with uncontrollable external influences on BC Hydro's net income is mitigated through the use of regulatory accounts. Regulatory accounts assist in matching costs and benefits for different generations of customers, to smooth the impact of large, non-recurring costs and to defer for future recovery in rates the differences between planned and actual costs or revenues that arise due to uncontrollable events. BC Hydro has a documented plan for the recovery of its regulatory accounts which it filed with the F15-F16 RRRA.

In addition, information on risks and opportunities that could significantly impact BC Hydro meeting its objectives are outlined at www.bchydro.com/serviceplan.

Significant Financial Risks

The largest sources of variability in BC Hydro's financial performance are typically domestic and trade revenue and cost of energy. Both revenues and cost of energy are influenced by several elements, which generally fall into the following four categories:

- Generation available from BC Hydro-dispatched hydro plants;
- Domestic demand for energy;
- Energy market prices; and,
- Deliveries from electricity purchase agreement contracts.

Neither a high nor a low value of any of these individual drivers is intrinsically positive or negative for BC Hydro's financial results. It is the specific combination of these drivers in any given year which has an impact.

While meeting domestic demand, environmental regulations and treaty obligations, BC Hydro attempts to operate the system to take maximum advantage of market energy prices – buying from the markets when prices are low and selling when prices are high. In doing so, BC Hydro attempts to optimize the combined effects of these elements and reduce the net cost of energy for our customers.

Energy Availability

The amount of generation available influences BC Hydro's financial results through both changing the amount of energy we have available to export (or need to import to meet domestic load) and through changing our ability to take advantage of short-term market price variations. The amount of available generation is driven primarily by hydrology - the amount and timing of inflows into BC Hydro-dispatched plants. The range of historic inflows is significant, with over 15,000 GWh (or approximately 25 per cent of current domestic demand) separating the wettest years from the driest in the most recent 43 years of data in BC Hydro's records. To a less significant extent, the amount of available generation is also impacted by the availability of both BC Hydro and Independent Power Producer generating assets and by BC Hydro's operation of the system.

The financial forecast in the Service Plan assumes that inflows into BC Hydro-dispatched plants will be the average of the most recent 43 years of data in BC Hydro's records.

The system inflow energy for fiscal 2016 was 97 per cent of average, compared to the system inflow energy for fiscal 2015 at 102 per cent of average. Due to a number of contributing factors, energy in storage at the beginning of fiscal 2016 was 5,000 GWh above the 10 year average, reducing the flexibility of the system to absorb above average inflows. Above average system inflows were not observed, so over the course of fiscal 2016 storage was drawn down, although still 2,100 GWh above the 10 year average on March 31, 2016. This net drawdown was a result of a very dry summer (Q2 fiscal 2016 inflows were 79 per cent of average), but somewhat offset by higher fall and early winter inflows (Q3 fiscal 2016 at 111 per cent of average).

Domestic Demand for Energy

Electricity demand is generally increasing as B.C.'s population and gross domestic product increases; however, short-term fluctuations in electricity demand can be experienced due to large industrial loads and weather impacts. Large industrial customers can have significant variability in load as a result of changing supply and demand balances in world commodity markets and related commodity prices. Weather can have a significant impact on particularly residential load with colder years resulting in higher demand for electrical heating than in average or warm years.

The amount of electricity demand from BC Hydro's customers combined with the variable inflow of water into BC Hydro's large hydro reservoirs determines the volume of BC Hydro's market energy purchases and sales. To the extent there is a mismatch between the amount of available generation and domestic demand, BC Hydro will be either a net importer or net exporter of energy in a given year. However, even in high inflow years, BC Hydro may need to make some purchases during periods of the year when generation availability is low because of either water management requirements or maintenance outages (generally late fall, winter, and early spring). Similarly, even in low water years, electricity sales may be advantageous during certain periods either to minimize spill from large reservoirs or to take advantage of market price fluctuations. The value of all of these transactions is subject to market price risk.

In fiscal 2016, domestic revenues before regulatory transfers were lower than planned due to lower domestic loads resulting from the loss of large industrial load related to declining market conditions including low commodity prices, and a warmer than normal winter. This resulted in annual load being 3,351 GWh below plan (excluding surplus sales). The energy that would have gone to serving load will be sold to the market, at prices that are between 10 and 50 per cent of what would have been received had it been sold to domestic customers. More information can be found in the discussion on Domestic Revenues.

Energy Market Prices

The cost of energy, the revenue from trade market activity, and the market opportunities available to Powerex all depend on a combination of system surplus or deficit energy, system flexibility and gas and electricity market fundamentals. Both domestic loads and market prices in fiscal 2016 were materially lower than forecast in the Service Plan. Nonetheless, significantly greater than forecast net market electricity sales were made in fiscal 2016 to manage the generation within the province that is surplus to load and the above average system storage energy content.

Deliveries from Electricity Purchase Agreement Contracts

Energy delivered under electricity purchase agreement contracts has a different cost than both energy generated by BC Hydro and energy purchased or sold in energy markets. Therefore, as the proportion of electricity purchase agreement contract energy changes BC Hydro's average cost of energy changes. BC Hydro's portfolio of electricity purchase agreement contracts includes a significant portion of hydro resources and the amount of generation under these contracts is driven by hydrology and other operational factors that impact deliveries, which may vary significantly from year to year. In fiscal 2016, there was greater than forecast energy delivered from hydro Independent Power Producers, primarily due to changes in operations at a large Independent Power Producer. However, this was partially offset by lower than forecast deliveries for several Independent Power Producers due to delays in achieving their commercial operations date and lower than planned thermal generation.

Finance Charges

Interest expense on borrowings is a significant component of Finance Charges. Variability in interest expense on borrowings is influenced by both the volume of debt BC Hydro requires and the interest rate paid on that debt. A portion of BC Hydro's existing debt is subject to changes to interest rates (variable rate debt) which results in variability in interest expense. BC Hydro accepts this variability in return for the savings obtained from normally lower short-term rates.

As of March 31, 2016, approximately 13 per cent of existing debt had a maturity of one year or less and is recognized as variable rate debt. BC Hydro has steadily reduced its allocation of variable rate debt over the last few years in response to historically low long-term interest rates and rising debt levels. The majority of BC Hydro's foreign denominated debt is hedged with long-term foreign exchange derivative contracts and as a result is not a significant risk variable.

In an effort to further reduce variability in interest expense, BC Hydro intends to hedge a portion of long-term future debt issuances.

The actual fiscal 2016 financial results compared to the Service Plan can be found in the previous Comparison with Service Plan discussion.

FUTURE OUTLOOK

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each year. BC Hydro's Service Plan filed in February 2016 forecasted net income for fiscal 2017 at $692 million.

The Company's earnings can fluctuate significantly due to various non-controllable factors such as the level of water inflows, domestic sales 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 2017 assumes average water inflows (100 per cent of average), domestic sales of 56,692 GWh, average market energy prices of US $24.15/MWh, short-term interest rates of 0.68 per cent and a US dollar exchange rate of US $0.7646.

EARNINGS SENSITIVITY

The following table shows the estimated effect on earnings of changes in some key variables, before regulatory account transfers. The analysis is based on business conditions and production volumes forecast for fiscal 2017. 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 2016
Hydro generation [1]	+/-1%	10	52,114 GWh	41,226 GWh	49,262 GWh
Electricity trade margins[5]	+/-10%	20	$206	$174	$174
Interest rates	+/- 100 basis points	40	1.30% [2]	0.87% [2]	0.87% [2]
Exchange rates (US/ CDN)	+/- $0.01	5	$1.01 [3]	$0.76 [3]	$0.76 [3]
Weather	10% change in normal degree days	35	2,261 degree days [4]	1,944 degree days [4]	2,008 degree days [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 annual daily average Canadian short-term interest rates (3-month Canadian Dollar Offered Rate).

[3] Exchange rates are the annual daily average US Dollar noon rates.

[4] The high and low degree days represent the highest degree days in the past five years and the lowest degree days in the past five years for the five winter months (November to March) on sales weighted basis for the BC Hydro Domestic System. A degree day is calculated by the difference between the daily average temperature for the day and 18 Degrees Celsius. As such, if the daily average temperature is below 18 Degree Celsius, by one degree, then there is one degree day for that day. For fiscal 2016, the actual degree days on sales weighted basis is reported as a total for the five winter months.

[5] Trade revenues less trade cost of energy (in millions).

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 judgment. 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 June 1, 2016. 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 Service Plan 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.

Jessica McDonald
President and Chief Executive Officer

Cheryl Yaremko
Executive Vice-President, Finance & Supply Chain
and Chief Financial Officer

Vancouver, Canada
June 1, 2016

INDEPENDENT AUDITORS' REPORT

The Minister of Energy and Mines and Minister Responsible For Core Review, 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 statement of financial position as at March 31, 2016, the consolidated statements of comprehensive income, changes in equity and cash flows for the year then ended, 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 audit. We conducted our audit 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 judgment, 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 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, 2016 and its consolidated financial performance and its consolidated cash flows for the year then ended 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 Professional Accountants
Vancouver, Canada
June 1, 2016

AUDITED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

for the years ended March 31 (in millions)	**2016**	2015
Revenues		
Domestic	**$ 5,056**	$ 4,829
Trade	**601**	919
	5,657	5,748
Expenses		
Operating expenses (Note 5)	**4,250**	4,535
Finance charges (Note 6)	**752**	632
Net Income	**655**	581
OTHER COMPREHENSIVE INCOME (LOSS)		
Items Reclassified Subsequently to Net Income		
Effective portion of changes in fair value of derivatives designated as cash flow hedges (Note 19)	**12**	81
Reclassification to income of derivatives designated as cash flow hedges (Note 19)	**(21)**	(127)
Foreign currency translation gains	**10**	34
Other Comprehensive Income (Loss)	**1**	(12)
Total Comprehensive Income	**$ 656**	$ 569

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

as at March 31 (in millions)	2016	2015
ASSETS		
Current Assets		
Cash and cash equivalents (Note 8)	**$ 44**	$ 39
Accounts receivable and accrued revenue (Note 9)	**669**	627
Inventories (Note 10)	**155**	122
Prepaid expenses	**202**	211
Current portion of derivative financial instrument assets (Note 19)	**137**	152
	1,207	1,151
Non-Current Assets		
Property, plant and equipment (Note 11)	**21,385**	19,933
Intangible assets (Note 12)	**609**	547
Regulatory assets (Note 13)	**6,324**	5,714
Derivative financial instrument assets (Note 19)	**92**	97
Other non-current assets (Note 14)	**417**	311
	28,827	26,602
	$ 30,034	$ 27,753
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities (Note 15)	**$ 1,816**	$ 1,708
Current portion of long-term debt (Note 16)	**2,376**	3,698
Current portion of derivative financial instrument liabilities (Note 19)	**143**	85
	4,335	5,491
Non-Current Liabilities		
Long-term debt (Note 16)	**15,837**	13,178
Regulatory liabilities (Note 13)	**416**	281
Derivative financial instrument liabilities (Note 19)	**27**	38
Contributions in aid of construction	**1,669**	1,583
Post-employment benefits (Note 18)	**1,657**	1,498
Other non-current liabilities (Note 20)	**1,593**	1,514
	21,199	18,092
Shareholder's Equity		
Contributed surplus	**60**	60
Retained earnings	**4,397**	4,068
Accumulated other comprehensive income	**43**	42
	4,500	4,170
	$ 30,034	$ 27,753

Commitments and Contingencies (Notes 11 and 21)

See accompanying Notes to the Consolidated Financial Statements.

Approved on behalf of the Board:

W. J. Brad Bennett, O.B.C.
Chair, Board of Directors

Tracy Redies
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, 2014	$ 33	$ 21	$ 54	$ 60	$ 3,751	$ 3,865
Payment to the Province (Note 17)	-	-	-	-	(264)	(264)
Comprehensive Income (Loss)	34	(46)	(12)	-	581	569
Balance, March 31, 2015	67	(25)	42	60	4,068	4,170
Payment to the Province (Note 17)	-	-	-	-	(326)	(326)
Comprehensive Income (Loss)	10	(9)	1	-	655	656
Balance, March 31, 2016	$ 77	$ (34)	$ 43	$ 60	$ 4,397	$ 4,500

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

for the years ended March 31 (in millions)	**2016**	2015
Operating Activities		
Net income	**$ 655**	$ 581
Regulatory account transfers (Note 13)	**(947)**	(1,225)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 13)	**472**	491
Amortization and depreciation expense (Note 7)	**745**	691
Unrealized losses (gains) on mark-to-market	**75**	(53)
Employee benefit plan expenses	**110**	84
Interest accrual	**717**	670
Other items	**69**	96
	1,896	1,335
Changes in:		
Accounts receivable and accrued revenue	**(47)**	465
Prepaid expenses	**9**	-
Inventories	**(33)**	1
Accounts payable, accrued liabilities and other non-current liabilities	**(73)**	(202)
Contributions in aid of construction	**98**	89
Other non-current assets	**(79)**	-
	(125)	353
Interest paid	**(711)**	(670)
Cash provided by operating activities	**1,060**	1,018
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(2,102)**	(1,928)
Cash used in investing activities	**(2,102)**	(1,928)
Financing Activities		
Long-term debt:		
Issued	**2,641**	1,565
Retired	**(150)**	(325)
Receipt of revolving borrowings	**7,761**	8,112
Repayment of revolving borrowings	**(8,927)**	(8,326)
Payment to the Province (Note 17)	**(264)**	(167)
Other items	**(14)**	(17)
Cash provided by financing activities	**1,047**	842
Increase (decrease) in cash and cash equivalents	**5**	(68)
Cash and cash equivalents, beginning of year	**39**	107
Cash and cash equivalents, end of year	**$ 44**	$ 39

See accompanying Notes to the 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 Corp. (Powerex), Powertech Labs Inc. (Powertech), and Columbia Hydro Constructors Ltd. (Columbia), (collectively with BC Hydro, the Company) including BC Hydro's one third interest in the Waneta Dam and Generating Facility (Waneta). All intercompany transactions and balances are eliminated on consolidation.

The Company accounts for its one third interest in Waneta as a joint operation. BC Hydro has classified Waneta as a joint operation on the basis that fundamental operating and investing decisions relating to Waneta require unanimous approval by each co-owner. 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 4. 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), combined with 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 regulatory costs and recoveries would be included in the determination of comprehensive income unless recovered in rates in the year the amounts are incurred.

BC Hydro's accounting policies with respect to its regulatory accounts are disclosed in Note 4(a) and the impact of the application of ASC 980 on these consolidated financial statements is described in Note 13.

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 June 1, 2016.

(b) Basis of Measurement

The consolidated financial statements have been prepared on the historical cost basis except for natural gas inventories in Note 4(j), financial instruments that are accounted for according to the financial instrument categories as defined in Note 4(k) and the post-employment benefits obligation as described in Note 4(o).

(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 Judgments

The preparation of financial statements in conformity with the Prescribed Standards requires management to make judgments, 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 judgments, 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 judgment, 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. Judgment 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 18 for significant benefit plan assumptions.

(ii) Provisions and Contingencies

Management is required to make judgments 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 judgments 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 is currently defending certain lawsuits where management must make judgments, 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 judgments 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 judgments 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, judgment 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 leases, or which contain an embedded lease, further judgment 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 estimations of the amounts and timing of future cash flows and the determination of an appropriate discount rate.

NOTE 3: CHANGES IN ACCOUNTING POLICIES

Effective April 1, 2015, the Company adopted Amendments to IAS 19, *Employee Benefits*, which had no impact on the consolidated financial statements.

NOTE 4: 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 13). 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 comprehensive income unless recovered in rates 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 of change.

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 Costs and Recoveries

Finance costs comprise interest expense on borrowings, accretion expense on provisions and other long-term liabilities, net interest on net 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.

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

(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 U.S. 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 labour 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.

The Company recognizes government grants when there is reasonable assurance that any conditions attached to the grant will be met and the grant will be received. Government grants related to assets are deducted from the carrying amount of the related asset and recognized in profit or loss over the life of the related asset.

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. Other intangible assets include California carbon allowances which are not amortized because they are used to settle obligations arising from carbon emissions regulations. 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
Other	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 identifiable 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 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 (short-term investments) that are redeemable on demand and are carried at amortized cost and fair value, respectively.

(i) Restricted Cash

Restricted cash includes cash balances which the Company does not have immediate access to as they have been pledged to counterparties as security for investments or trade obligations. These balances are available to the Company only upon settlement of the trade obligations for which they have been pledged as security.

(j) Inventories

Inventories are comprised primarily of natural gas, materials and supplies. Natural gas inventory is valued at fair value less costs to sell and included in Level 2 of the fair value hierarchy (Note 19: Financial Instruments – Fair Value Hierarchy). Materials and supplies inventories are valued at the lower of cost determined on a weighted average basis and net realizable value. The cost of materials and supplies 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.

(k) Financial Instruments

(i) Financial Instruments – Recognition and Measurement

All financial instruments are 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 in the period of change. 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 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 Derivatives not in a hedging relationship
Held to maturity	US dollar sinking funds
Loans and receivables	Cash Restricted 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, First Nations liabilities and other 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, valuation inputs are used 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.

(iii) Inception Gains and Losses

In some instances, a difference may arise between the fair value of a financial instrument at initial recognition, as defined by its transaction price, and the fair value calculated by a valuation technique or model (inception gain or loss). In addition, the Company's inception gain or loss on a contract may arise as a result of embedded derivatives which are recorded at fair value, with the remainder of the contract recorded on an accrual basis. In these circumstances, the unrealized inception gain or loss is deferred and amortized into income over the full term of the underlying financial instrument. Additional information on deferred inception gains and losses is disclosed in Note 19, Financial Instruments.

(iv)Derivative Financial Instruments

The Company may use 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 in the period of change. 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.

(v) 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.

(l) 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.

(m) 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 annual payments of approximately US$22 million for a 35 year period ending in 2021 and US$100,000 (adjusted for inflation) for the remaining 45 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.

(n) 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 term of the agreement with the customer or over the expected useful life of the related assets, if the associated contracts do not have a finite period over which service is provided.

(o) 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 mortality, salary escalation, retirement ages of employees and expected health care costs. The net interest for the period is determined by applying the same market discount rate used to measure the defined benefit obligation at the beginning of the annual period to the net defined benefit asset or liability at the beginning of the annual period, taking into account any changes in the net defined benefit asset or liability during the period as a result of current service costs, contributions and benefit payments. The market discount rate is determined based on the 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 arising from plan amendments and curtailments are recognized in net income 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 net interest cost on the net defined benefit plan liabilities arising from the passage of time are included in finance charges. The Company recognizes actuarial gains and losses immediately in other comprehensive income.

(p) 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 recognizes legal claims as a provision when it is probable that the claim will be settled against the Company and the amount of the settlement can be reasonably measured. 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, that have not been recognized, is disclosed in Note 21, Commitments and Contingencies.

(q) 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.

(r) 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.

(s) Jointly Controlled Operations

The Company has joint ownership and control over certain assets with third parties. A jointly controlled operation exists when there is a joint ownership and control of one or more assets to obtain benefits for the joint operators. The parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, related to the arrangement. Each joint operator 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 third parties and any revenue from the sale or use of its share of the output in relation to the assets.

(t) 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, 2016, 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:

- Amendments to IFRS 10, *Consolidated Financial Statements* (April 1, 2016)
- Amendments to IFRS 11, *Joint Arrangements* (April 1, 2016)
- Amendments to IFRS 12, *Disclosure of Interests in Other Entities* (April 1, 2016)
- Amendments to IAS 1, *Presentation of Financial Statements* (April 1, 2016)
- Amendments to IAS 16, *Property, Plant and Equipment* (April 1, 2016)
- Amendments to IAS 38, *Intangible Assets* (April 1, 2016)
- Amendments to IAS 7, *Statement of Cash Flows* (April 1, 2017)
- IFRS 9, *Financial Instruments* (April 1, 2018)
- IFRS 15, *Revenue From Contracts With Customers* (April 1, 2018)
- IFRS 16, *Leases* (April 1, 2019)

The Company does not have any plans to early adopt any of the new or amended standards. It is expected that the standards effective for the Company's 2017 fiscal year will not have a material effect on the consolidated financial statements. The Company continues to assess the impact of adopting standards that become effective for the Company's fiscal years commencing April 1, 2017 and later.

IFRS 14, *Regulatory Deferral Accounts*, effective for fiscal years beginning on or after January 1, 2016, has been issued; however, the Company currently does not intend to adopt IFRS 14 as it applies the Prescribed Standards, not IFRS, and accounts for its regulatory accounts in accordance with ASC 980.

NOTE 5: OPERATING EXPENSES

(in millions)	**2016**	2015
Electricity and gas purchases	$ **1,345**	$ 1,707
Water rentals	**366**	358
Transmission charges	**141**	138
Personnel expenses	**527**	534
Materials and external services	**605**	593
Amortization and depreciation (Note 7)	**1,241**	1,205
Grants and taxes	**220**	209
Capitalized costs	**(203)**	(224)
Other costs, net of recoveries	**8**	15
	$ **4,250**	$ 4,535

NOTE 6: FINANCE CHARGES

(in millions)	**2016**	2015
Interest on long-term debt	$ **771**	$ 685
Interest on finance lease liabilities	**94**	77
Less: Other recoveries	**(52)**	(61)
Capitalized interest	**(61)**	(69)
	$ **752**	$ 632

Capitalized interest presented in the table above is after regulatory transfers. Actual interest capitalized to property, plant and equipment and intangible assets before regulatory transfers was $81 million (2015 - $89 million). The effective capitalization rate used to determine the amount of borrowing costs eligible for capitalization was 4.1 per cent (2015 - 4.1 per cent).

NOTE 7: AMORTIZATION AND DEPRECIATION

(in millions)	**2016**	2015
Depreciation of property, plant and equipment	$ **678**	$ 626
Amortization of intangible assets	**67**	65
Amortization of regulatory accounts	**496**	514
	$ **1,241**	$ 1,205

NOTE 8: CASH AND CASH EQUIVALENTS

(in millions)		**2016**		2015
Cash	**$**	**33**	$	28
Short-term investments		**11**		11
	$	**44**	$	39

NOTE 9: ACCOUNTS RECEIVABLE AND ACCRUED REVENUE

(in millions)		**2016**		2015
Accounts receivable	**$**	**390**	$	411
Accrued revenue		**128**		89
Restricted cash		**62**		31
Other		**89**		96
	$	**669**	$	627

Accrued revenue represents revenue for electricity delivered and not yet billed.

NOTE 10: INVENTORIES

(in millions)		**2016**		2015
Materials and supplies	**$**	**119**	$	110
Natural gas trading inventories		**36**		12
	$	**155**	$	122

There were no materials and supplies inventory impairments during the years ended March 31, 2016 and 2015. Natural gas inventory held in storage is measured at fair value less costs to sell and therefore, not subject to impairment testing.

Inventories recognized as an expense during the year amounted to $30 million (2015 - $69 million).

NOTE 11: PROPERTY, PLANT AND EQUIPMENT

(in millions)	Generation	Transmission	Distribution	Land & Builidings	Equipment & Other	Unfinished Construction	Total
Cost							
Balance at March 31, 2014	$ 6,516	$ 4,552	$ 5,057	$ 504	$ 661	$ 2,940	$ 20,230
Net additions (transfers)	479	1,096	349	77	85	(9)	2,077
Disposals and retirements	(6)	(8)	(28)	(3)	(11)	(26)	(82)
Balance at March 31, 2015	6,989	5,640	5,378	578	735	2,905	22,225
Net additions (transfers)	535	1,465	418	72	165	(487)	2,168
Disposals and retirements	(6)	(34)	(31)	-	(34)	(8)	(113)
Balance at March 31, 2016	$ 7,518	$ 7,071	$ 5,765	$ 650	$ 866	$ 2,410	$ 24,280
Accumulated Depreciation							
Balance at March 31, 2014	$ (645)	$ (411)	$ (433)	$ (51)	$ (165)	$ -	$ (1,705)
Depreciation expense	(198)	(161)	(165)	(24)	(64)	-	(612)
Disposals and retirements	3	6	6	1	9	-	25
Balance at March 31, 2015	(840)	(566)	(592)	(74)	(220)	-	(2,292)
Depreciation expense	(211)	(177)	(171)	(23)	(72)	-	(654)
Disposals and retirements	3	8	8	-	32	-	51
Balance at March 31, 2016	$ (1,048)	$ (735)	$ (755)	$ (97)	$ (260)	$ -	$ (2,895)
Net carrying amounts							
At March 31, 2015	$ 6,149	$ 5,074	$ 4,786	$ 504	$ 515	$ 2,905	$ 19,933
At March 31, 2016	$ 6,470	$ 6,336	$ 5,010	$ 553	$ 606	$ 2,410	$ 21,385

(i) The Company includes its one-third interest in Waneta with a net book value of $715 million (2015 - $735 million) in Generation assets. Depreciation expense on the Waneta asset for the year ended March 31, 2016 was $20 million (2015 - $20 million).

(ii) Included within Distribution assets are the Company's portion of utility poles with a net book value of $911 million (2015 - $842 million) that are jointly owned with a third party. Depreciation expense on jointly owned utility poles for the year ended March 31, 2016 was $23 million (2015 - $21 million).

(iii) The Company received government grants 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 grants were made to assist in financing the construction of the dams. The grants were deducted from the carrying amount of the related dams. In addition, the Company received government grants for the construction of a new transmission line and has deducted the grants received from the cost of the asset. Government grants received in fiscal 2016 were $13 million (2015 - $nil).

(iv) The Company has contractual commitments to spend $3,710 million on major property, plant and equipment projects (individual projects greater than $50 million) as at March 31, 2016.

Leased assets

Property, plant and equipment under finance leases of $388 million (2015 - $388 million), net of accumulated amortization of $186 million (2015 - $173 million), are included in the total amount of property, plant and equipment above.

NOTE 12: INTANGIBLE ASSETS

(in millions)	Land Rights	Internally Developed Software	Purchased Software	Other	Work in Progress	Total
Cost						
Balance at March 31, 2014	$ 183	$ 85	$ 334	$ 19	$ 46	$ 667
Net additions	15	34	32	21	17	119
Disposals and retirements	-	-	-	(9)	(4)	(13)
Balance at March 31, 2015	198	119	366	31	59	773
Net additions	42	30	73	7	1	153
Disposals and retirements	-	-	(2)	(19)	(2)	(23)
Balance at March 31, 2016	$ 240	$ 149	$ 437	$ 19	$ 58	$ 903
Accumulated Amortization						
Balance at March 31, 2014	$ -	$ (21)	$ (129)	$ (8)	$ -	$ (158)
Amortization expense	-	(17)	(48)	(3)	-	(68)
Balance at March 31, 2015	-	(38)	(177)	(11)	-	(226)
Amortization expense	-	(21)	(48)	-	-	(69)
Disposals and retirements	-	(4)	5	-	-	1
Balance at March 31, 2016	$ -	$ (63)	$ (220)	$ (11)	$ -	$ (294)
Net carrying amounts						
At March 31, 2015	$ 198	$ 81	$ 189	$ 20	$ 59	$ 547
At March 31, 2016	$ 240	$ 86	$ 217	$ 8	$ 58	$ 609

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 13: RATE REGULATION

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 total comprehensive income unless the Company sought recovery through rates in the year in which they are incurred. For the year ended March 31, 2016, the impact of regulatory accounting has resulted in a net increase to total comprehensive income of $475 million (2015 - $734 million) which is comprised of an increase to net income of $403 million (2015 - $470 million) and an increase to other comprehensive income of $72 million (2015 – $264 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, unless otherwise recovered through rates. 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.

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(in millions)	*April 1 2015*	*Addition (Reduction)*	*Interest*	*Amortization*	*Net Change*	*March 31 2016*
Regulatory Assets						
Heritage Deferral Account	$ 165	$ (137)	$ 1	$ (29)	$ (165)	$ -
Non-Heritage Deferral Account	524	483	28	(118)	393	917
Trade Income Deferral Account	244	51	9	(55)	5	249
Demand-Side Management	842	145	-	(79)	66	908
First Nations Provisions & Costs	564	14	6	(43)	(23)	541
Non-Current Pension Cost	564	142	-	(15)	127	691
Site C	419	-	17	-	17	436
CIA Amortization	87	5	-	-	5	92
Environmental Provisions & Costs	382	51	-	(75)	(24)	358
Smart Metering & Infrastructure	283	20	11	(31)	-	283
IFRS Pension	650	-	-	(38)	(38)	612
IFRS Property, Plant & Equipment	758	134	-	(20)	114	872
Rate Smoothing Account	166	121	-	-	121	287
Other Regulatory Accounts	66	30	1	(19)	12	78
Total Regulatory Assets	5,714	1,059	73	(522)	610	6,324
Regulatory Liabilities						
Heritage Deferral Account	-	15	1	8	24	24
Future Removal & Site Restoration Costs	33	-	-	(24)	(24)	9
Foreign Exchange Gains and Losses	71	(3)	-	1	(2)	69
Total Finance Charges	173	158	-	(26)	132	305
Other Regulatory Accounts	4	14	-	(9)	5	9
Total Regulatory Liabilities	281	184	1	(50)	135	416
Net Regulatory Asset	$ 5,433	$ 875	$ 72	$ (472)	$ 475	$ 5,908

(in millions)	*April 1 2014*	*Addition (Reduction)*	*Interest*	*Amortization*	*Net Change*	*March 31 2015*
Regulatory Assets						
Heritage Deferral Account	$ 105	$ 82	$ 4	$ (26)	$ 60	$ 165
Non-Heritage Deferral Account	362	238	15	(91)	162	524
Trade Income Deferral Account	324	(10)	11	(81)	(80)	244
Demand-Side Management	788	125	-	(71)	54	842
First Nations Provisions & Costs	589	12	7	(44)	(25)	564
Non-Current Pension Cost	280	317	-	(33)	284	564
Site C	338	65	16	-	81	419
CIA Amortization	81	6	-	-	6	87
Environmental Provisions & Costs	383	69	3	(73)	(1)	382
Smart Metering & Infrastructure	277	26	11	(31)	6	283
IFRS Pension	688	-	-	(38)	(38)	650
IFRS Property, Plant & Equipment	617	157	-	(16)	141	758
Rate Smoothing Account	-	166	-	-	166	166
Other Regulatory Accounts	96	15	1	(46)	(30)	66
Total Regulatory Assets	4,928	1,268	68	(550)	786	5,714
Regulatory Liabilities						
Future Removal & Site Restoration Costs	56	-	-	(23)	(23)	33
Foreign Exchange Gains and Losses	89	(18)	-	-	(18)	71
Total Finance Charges	79	120	-	(26)	94	173
Other Regulatory Accounts	5	8	1	(10)	(1)	4
Total Regulatory Liabilities	229	110	1	(59)	52	281
Net Regulatory Asset	$ 4,699	$ 1,158	$ 67	$ (491)	$ 734	$ 5,433

RATE REGULATION

In March 2014, the Province issued Directions No. 6 and 7 to the BCUC that, among other things, requires the Company to amortize specific amounts prescribed for a majority of BC Hydro's regulatory accounts, in each of fiscal 2015 and fiscal 2016.

HERITAGE DEFERRAL ACCOUNT

Under a Special Direction issued by the Province, the BCUC was directed to authorize the Company to establish the Heritage Deferral Account. This account is intended to mitigate the impact of certain variances between the forecast costs in a revenue requirements application and actual costs of service associated with the Company's hydroelectric and thermal generating facilities by adjustment of net income. These deferred variances are recovered in rates through the Deferral Account Rate Rider (DARR). The DARR, currently at 5 per cent, is an additional charge on customer bills and is used to recover the balances in the energy deferral accounts.

NON-HERITAGE DEFERRAL ACCOUNT

Under a Special Direction issued by the Province, the BCUC approved the establishment of the Non-Heritage Deferral Account, which is intended to mitigate the impact of certain cost variances between the forecast costs in a revenue requirements application and actual costs related to items including all non-heritage energy costs (e.g. costs related to power acquisitions from Independent Power Producers), load (i.e. customer demand), and certain unplanned major capital and maintenance expenditures. These deferred variances are recovered in rates through the DARR.

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. These deferred variances are recovered in rates through the DARR.

Trade Income is 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.

DEMAND-SIDE MANAGEMENT

Amounts incurred for Demand-Side Management are deferred and amortized on a straight-line basis over the anticipated 15 year period of benefit of the program. Demand-Side Management programs are designed to reduce the energy requirements on the Company's system. Demand-Side Management 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 NATIONS PROVISIONS & COSTS

The First Nations Costs regulatory account includes the present value of future payments 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 for associated impacts. Annual settlement costs paid pursuant to these settlements are transferred to the First Nations Costs regulatory account. In addition, annual negotiation costs and current year interest costs are deferred to the First Nations Costs regulatory account.

Also, pursuant to the Company's fiscal 2015-2016 Revenue Requirements Rate Application, lump sum settlement payments are to be amortized over 10 years and, in fiscal 2015 and fiscal 2016, annual negotiation costs, annual settlement payments, and current year interest will be expensed from the First Nations Costs regulatory account in the year incurred.

NON-CURRENT PENSION COST

Variances that arise between forecast and actual non-current pension and other post-employment benefit costs are deferred. In addition, actuarial gains and losses related to post employment benefit plans are also deferred. The account is amortized over the average remaining service life of the employee group. In September 2015, the BCUC issued order G-148-15, approving the Company's transfer of the operating cost variance between the fiscal 2015-2016 Revenue Requirements Rate Application plan amount and actual fiscal 2016 post-employment benefits current service costs. The deferral for fiscal 2016 was $17 million.

SITE C

Site C expenditures incurred in fiscal 2007 through the third quarter of fiscal 2015 have been deferred. In December 2014, the Provincial Government approved a final investment decision for the Site C project, resulting in expenditures being capitalized in property, plant and equipment starting in the fourth quarter of fiscal 2015. BC Hydro plans to seek BCUC approval to begin amortizing the balance of the Site C regulatory account once the assets are in service.

CONTRIBUTIONS IN AID (CIA) OF CONSTRUCTION AMORTIZATION

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 & COSTS

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. The regulatory asset for PCB remediation is amortized based on actual expenditures incurred during the year.

Balances related to non-PCB environmental regulatory provisions are not amortized – amounts are transferred to environmental cost regulatory assets based on actual expenditures incurred attributable to the provision. Environmental cost regulatory assets are amortized over the term covered by the Company's next revenue requirements filing.

SMART METERING & INFRASTRUCTURE

Net operating costs incurred by the Company in fiscal 2015 and fiscal 2016 with respect to the Smart Metering & Infrastructure program were deferred through the end of fiscal 2016 when the project was completed. Costs relating to identifiable tangible and intangible assets that meet the capitalization criteria were recorded as property, plant and equipment or intangible assets respectively. The Smart Metering & Infrastructure costs incurred prior to fiscal 2015, including net operating costs, amortization of capital assets, and finance charges have been deferred and commenced amortization, based on the fiscal 2014 ending balance, over 15 years starting in fiscal 2015. Furthermore, per Direction 6, net operating costs incurred in fiscal 2015 and fiscal 2016 were deferred. Pursuant to Direction 7 to the BCUC, the BCUC may not disallow recovery in rates of the costs deferred to the Smart Metering & Infrastructure regulatory account.

IFRS PENSION

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 20 years on a straight-line basis beginning in fiscal 2013.

IFRS PROPERTY, PLANT & EQUIPMENT

This account includes the fiscal 2012 incremental earnings impacts due to the application of the accounting principles of IFRS to Property, Plant & Equipment to the comparative fiscal year for the adoption of the Prescribed Standards. In addition, the account includes an annual deferral of overhead costs, ineligible for capitalization under the accounting principles of IFRS, equal to the fiscal 2012 overhead deferral amount less a ten year phase-in adjustment. The annual deferred amounts are amortized over 40 years beginning the year following the deferral of the expenditures.

RATE SMOOTHING ACCOUNT

As part of the 10 Year Rates Plan, the Rate Smoothing regulatory account was established with the objective of smoothing rate increases over a 10 year period so that there is less volatility from year to year. The account balance will be fully amortized by the end of the 10 Year Rates Plan.

FUTURE REMOVAL & 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 may be applied to this regulatory liability if they do not otherwise relate to an asset retirement obligation. This account is estimated to be fully depleted during fiscal 2017.

FOREIGN EXCHANGE GAINS AND LOSSES

Foreign exchange gains and losses from the translation of specified foreign currency financial instruments are deferred. Foreign exchange gains and losses are subject to external market forces over which BC Hydro has no control. The account balance is amortized using the straight-line pool method over the weighted average life of the related debt.

TOTAL FINANCE CHARGES

This account is intended to mitigate the impact of certain variances that arise between the forecast finance costs in a revenue requirements application and actual finance charges incurred. Variances incurred during the current test period are recovered over the next test period. A test period refers to the period covered by a revenue requirements application filing (the current test period is fiscal 2015-2016).

OTHER REGULATORY ACCOUNTS

Other regulatory asset and liability accounts with individual balances less than $30 million include the following: Storm Restoration, Capital Project Investigation, Real Property Sales, Arrow Water Provision, Minimum Reconnection Charge, Arrow Water Divestiture Costs and Amortization on Capital Additions.

NOTE 14: OTHER NON-CURRENT ASSETS

(in millions)	**2016**	2015
Non-current receivables	**$ 171**	$ 156
Sinking funds	**167**	155
Other	**79**	-
	$ 417	$ 311

Non-Current Receivables

Included in the non-current receivables balance is a $152 million (2015 - $156 million) receivable for contributions in aid of the construction of the Northwest Transmission Line (NTL). The contributions will be received in annual payments of approximately $11 million, adjusted for inflation. The fair value of the receivable was initially measured using an estimated inflation rate and a 4.6 per cent discount rate. The current portion of the NTL receivable is $11 million (2015 - $10 million) and has been recorded within accounts receivable and accrued revenue.

Included in the non-current receivables balance is an $8 million receivable from certain mining customers. In February 2016, the Province of British Columbia issued a direction to the BCUC to establish the Mining Customer Payment Plan, which allows the operators of applicable B.C. mines to defer payment of a portion of electricity purchases for a period of up to five years. The direction also allows BC Hydro to establish a regulatory account in which BC Hydro would transfer the impact of any defaults on these deferred payments to allow recovery in future rates.

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)	**2016**		2015	
	Carrying Value	**Weighted Average Effective Rate**[1]	Carrying Value	Weighted Average Effective Rate[1]
Province of BC bonds	**$ 107**	**2.9 %**	$ 100	3.0 %
Other provincial government and crown corporation bonds	**60**	**3.1 %**	55	3.1 %
	$ 167		$ 155	

[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 15: ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

(in millions)		**2016**		2015
Accounts payable	**$**	**265**	$	294
Accrued liabilities		**1,031**		945
Current portion of other long-term liabilities (Note 20)		**122**		129
Dividend payable (Note 17)		**326**		264
Other		**72**		76
	$	**1,816**	$	1,708

NOTE 16: 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 $4,500 million, and is included in revolving borrowings. At March 31, 2016, the outstanding amount under the borrowing program was $2,376 million (2015 - $3,547 million).

During fiscal 2016, the Company issued bonds with a par value of $2,691 million (2015 – $1,665 million) a weighted average effective interest rate of 2.5 per cent (2015 – 3.4 per cent) and a weighted average term to maturity of 20.2 years (2015 – 26.4 years).

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

(in millions)	2016					2015			
	Canadian	**US**	**Euro**	**Total**	**Weighted Average Interest Rate[1]**	Canadian	US	Total	Weighted Average Interest Rate[1]
Maturing in fiscal:									
2016	$ -	$ -	$ -	$ -	-	$ 150	$ -	$ 150	5.2
2017	-	-	-	-	-	-	-	-	-
2018	40	-	-	40	4.8	40	-	40	4.8
2019	1,030	259	-	1,289	4.4	1,030	254	1,284	4.6
2020	175	-	-	175	5.3	175	-	175	5.3
2021	1,100	-	-	1,100	7.5	-	-	-	-
1-5 years	2,345	259	-	2,604	5.8	1,395	254	1,649	4.7
6-10 years	2,136	649	390	3,175	4.9	2,336	-	2,336	7.3
11-15 years	1,000	-	-	1,000	3.7	800	634	1,434	5.2
16-20 years	1,110	-	-	1,110	5.0	1,110	-	1,110	5.0
21-25 years	1,250	389	-	1,639	5.5	-	380	380	7.4
26-30 years	4,588	-	-	4,588	3.9	5,838	-	5,838	4.1
Over 30 years	1,730	-	-	1,730	3.5	530	-	530	4.4
Bonds	14,159	1,297	390	15,846	4.6	12,009	1,268	13,277	5.0
Revolving borrowings	1,605	771	-	2,376	0.6	2,623	924	3,547	0.7
	15,764	2,068	390	18,222		14,632	2,192	16,824	
Adjustments to carrying value resulting from hedge accounting	23	24	-	47		27	25	52	
Unamortized premium, discount, and issue costs	(39)	(12)	(5)	(56)		13	(13)	-	
	15,748	2,080	385	18,213		14,672	2,204	16,876	
Less: Current portion	(1,605)	(771)	-	(2,376)		(2,774)	(924)	(3,698)	
Long-term debt	$ 14,143	$ 1,309	$ 385	$ 15,837		$ 11,898	$ 1,280	$ 13,178	

[1] *The weighted average interest rate represents the effective rate of interest on fixed-rate bonds.*

The following foreign currency contracts were in place at March 31, 2016 in a net asset position of $18 million (2015 – asset of $76 million). Such contracts are primarily used to hedge foreign currency long-term debt principal and U.S. commercial paper borrowings.

(in millions)	**2016**	2015
Cross- Currency Swaps		
Euro dollar to Canadian dollar - notional amount[1]	**€ 264**	€ -
Euro dollar to Canadian dollar - weighted average contract rate	**1.48**	-
Weighted remaining term	**10 years**	-
Foreign Currency Forwards		
United States dollar to Canadian dollar - notional amount[1]	**US$ 1,450**	US$ 1,542
United States dollar to Canadian dollar - weighted average contract rate	**1.28**	1.22
Weighted remaining term	**6 years**	6 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 19.

NOTE 17: 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 (see below). 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 and contributed surplus.

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

The debt to equity ratio at March 31, 2016, and March 31, 2015 was as follows:

(in millions)	**2016**	2015
Total debt, net of sinking funds	**$ 18,046**	$ 16,721
Less: Cash and cash equivalents	**(44)**	(39)
Net Debt	**$ 18,002**	$ 16,682
Retained earnings	**$ 4,397**	$ 4,068
Contributed surplus	**60**	60
Accumulated other comprehensive income	**43**	42
Total Equity	**$ 4,500**	$ 4,170
Net Debt to Equity Ratio	**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 at March 31, 2016 is $326 million (March 31, 2015 - $264 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 18: 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. The plan also provides pensioners a conditional 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, 2012. The next valuation for funding purposes is being prepared as at December 31, 2015, and the results will be available in September 2016.

The Company also provides post-employment benefits other than pensions including limited medical, extended health, dental 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 pension benefit plans and post-employment benefits other than pensions is as follows:

(a) The expense for the Company's benefit plans for the years ended at March 31, 2016 and 2015 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 and prior to the application of regulatory accounting:

	Pension Benefit Plans		Other Benefit Plans	
(in millions)	**2016**	2015	**2016**	2015
Current service costs charged to personnel operating costs	**$ 97**	$ 77	**$ 16**	$ 13
Net interest costs charged to finance costs	**40**	38	**17**	17
Total post-employment benefit plan expense	**$ 137**	$ 115	**$ 33**	$ 30

Actuarial gains and losses recognized in other comprehensive income are $nil (2015 – $nil). As per Note 13, in accordance with Prescribed Standards and as approved by the BCUC, actuarial gains and losses, as summarized in Note 18(c) below, are deferred to the Non-Current Pension Cost regulatory account.

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

	Pension Benefits Plans		Other Benefits Plans	
(in millions)	**2016**	2015	**2016**	2015
Defined benefit obligation of funded plans	**$ (4,228)**	$ (4,202)	**$ -**	$ -
Defined benefit obligation of unfunded plans	**(157)**	(155)	**(441)**	(432)
Fair value of plan assets	**3,169**	3,291	**-**	-
Plan deficit	**$ (1,216)**	$ (1,066)	**$ (441)**	$ (432)

The Company determined that there was no minimum funding requirement adjustment required in fiscal 2016 and fiscal 2015 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)	**2016**	2015	**2016**	2015
Defined benefit obligation				
Opening defined benefit obligation	**$ 4,357**	$ 3,784	**$ 432**	$ 374
Current service cost	**97**	77	**16**	13
Interest cost on benefit obligations	**115**	230	**17**	17
Benefits paid[1]	**(171)**	(175)	**(12)**	(12)
Employee contributions	**28**	27	**-**	-
Actuarial (gains) losses[2]	**(41)**	414	**(12)**	40
Defined benefit obligation, end of year	**4,385**	4,357	**441**	432
Fair value of plan assets				
Opening fair value	**3,291**	2,985	n/a	n/a
Interest income on plan assets[3]	**74**	192	n/a	n/a
Employer contributions	**66**	66	n/a	n/a
Employee contributions	**28**	27	n/a	n/a
Benefits paid[1]	**(165)**	(169)	n/a	n/a
Actuarial (losses) gains[2,3]	**(125)**	190	n/a	n/a
Fair value of plan assets, end of year	**3,169**	3,291	**-**	-
Accrued benefit liability	**$ (1,216)**	$ (1,066)	**$ (441)**	$ (432)

[1] *Benefits paid under Pension Benefit Plans include $13 million (2015 - $20 million) of settlement payments.*

[2] *Actuarial gains/losses are included in the Non-Current Pension Cost regulatory account and for fiscal 2016 are comprised of $125 million of experience losses on return of plan assets and $53 million of net experience gains on the benefit obligations due to discount rate changes and experience gains, partially offset by a change in the mortality assumption incorporating future mortality improvement.*

[3] *Actual loss on defined benefit plan assets for the year ended March 31, 2016 was $51 million (2015 - $382 million income).*

(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	
	2016	2015	**2016**	2015
Discount rate				
Benefit cost	**3.51%**	4.37%	**3.79%**	4.59%
Accrued benefit obligation	**3.81%**	3.51%	**3.72%**	3.79%
Rate of return on plan assets	**3.51%**	4.37%	**n/a**	n/a
Rate of compensation increase				
Benefit cost	**3.35%**	3.35%	**n/a**	n/a
Accrued benefit obligation	**3.35%**	3.35%	**n/a**	n/a
Health care cost trend rates				
Weighted average health care cost trend rate	**n/a**	n/a	**5.10%**	5.47%
Weighted average ultimate health care cost trend rate	**n/a**	n/a	**4.29%**	4.39%
Year ultimate health care cost trend rate will be achieved	**n/a**	n/a	**2026**	2026

The valuation cost method for the accrued benefit obligation 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 Allocation	Target Range Min	Target Range Max	2016	2015
Equities	57%	41%	76%	**60%**	62%
Fixed interest investments	29%	19%	39%	**30%**	28%
Real estate	10%	5%	15%	**8%**	9%
Infrastructure	4%	0%	10%	**2%**	1%

Plan assets are re-balanced within ranges around target applications. The Company's 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:

The Company's contribution to be paid to its funded defined benefit plan in fiscal 2017 is expected to amount to $57 million. The expected benefit payment to be paid in fiscal 2017 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:

(in millions)	One percentage point increase 2016	One percentage point decrease 2016
Effect on current service costs	$ 4	$ (3)
Effect on defined benefit obligation	57	(46)

The impact on the defined benefit obligation for the Pension Benefit Plans of changing certain of the major assumptions is as follows:

		2016	
($ in millions)	Increase/ decrease in assumption	Effect on accrued benefit obligation	Effect on current service costs
Discount rate	1% increase	$ -463	$ -24
Discount rate	1% decrease	+ 531	+ 29
Longevity	1 year	+/- 134	+/- 3

NOTE 19: 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 financial 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 2016 Annual Service Plan 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, restricted cash, 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 U.S. dollar sinking funds classified as held-to-maturity and carried on the statement of financial position at amortized cost of $167 million. The maximum credit risk exposure for these U.S. dollar sinking funds as at March 31, 2016 is its fair value of $194 million. The Company manages this risk through Board-approved credit risk management policies which contain limits and procedures related to the selection of counterparties. Exposures to credit risks are monitored on a regular basis. In addition, the Company has credit loss insurance that covers most credit exposures with U.S. counterparties or transactions delivered in the U.S.

(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 a commercial paper borrowing program under an agreement with the Province (Note 16 – Long-Term Debt and Debt Management). 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. During the year, the Company issued a European currency denominated bond and simultaneously entered into a cross currency swap hedging the principal and interest payments of the bond against movements in the Euro, thereby effectively converting it into a Canadian bond.

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 may enter 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 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

Finance charges, including interest income and expenses, for financial instruments disclosed in the following note, are prior to the application of regulatory accounting for the years ended March 31, 2016 and 2015.

The following table provides a comparison of carrying values and fair values for non-derivative financial instruments as at March 31, 2016 and 2015. The non-derivative financial instruments, where carrying value differs from fair value, would be classified as Level 2 of the fair value hierarchy.

	2016		2015		**2016**	2015
(in millions)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value	**Interest Income (Expense) recognized in Finance Charges**	Interest Income (Expense) recognized in Finance Charges
Financial Assets and Liabilities at Fair Value Through Profit or Loss:						
Cash equivalents - short-term investments	**$ 11**	**$ 11**	$ 11	$ 11	**$ 1**	$ 1
Loans and Receivables:						
Accounts receivable and accrued revenue	**669**	**669**	627	627	**-**	-
Non-current receivables	**171**	**171**	156	162	**7**	5
Cash	**33**	**33**	28	28	**-**	-
Held to Maturity:						
Sinking funds – US	**167**	**194**	155	184	**8**	7
Other Financial Liabilities:						
Accounts payable and accrued liabilities	**(1,816)**	**(1,816)**	(1,708)	(1,708)	**-**	-
Revolving borrowings - CAD	**(1,605)**	**(1,605)**	(2,623)	(2,623)	**(14)**	(33)
Revolving borrowings - US	**(771)**	**(771)**	(924)	(924)	**(2)**	-
Long-term debt (including current portion due in one year)	**(15,837)**	**(18,684)**	(13,329)	(16,799)	**(701)**	(638)
First Nations liabilities (non-current portion)	**(378)**	**(547)**	(391)	(758)	**(17)**	(9)
Finance lease obligations (non-current portion)	**(219)**	**(219)**	(240)	(240)	**(21)**	(23)
Other liabilities	**(147)**	**(153)**	(81)	(86)	**-**	-

The carrying value of cash equivalents, loans and receivables, and accounts payable and accrued liabilities approximates fair value due to the short duration of these financial instruments.

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

(in millions)	**2016 Fair Value**	2015 Fair Value
Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:		
Foreign currency contracts (cash flow hedges for $US denominated long-term debt)	**$ 57**	$ 45
Foreign currency contracts (cash flow hedges for €Euro denominated long-term debt)	**(5)**	-
	52	45
Non-Designated Derivative Instruments:		
Foreign currency contracts	**(34)**	31
Commodity derivatives	**41**	50
	7	81
Net asset	**$ 59**	$ 126

The carrying value of derivative instruments designated and not designated as hedges was the same as the fair value.

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

(in millions)	**2016**	2015
Current portion of derivative financial instrument assets	**$ 137**	$ 152
Current portion of derivative financial instrument liabilities	**(143)**	(85)
Derivative financial instrument assets, non-current	**92**	97
Derivative financial instrument liabilities, non-current	**(27)**	(38)
Net asset	**$ 59**	$ 126

For designated cash flow hedges for the year ended March 31, 2016, a gain of $12 million (2015 - $81 million gain) was recognized in other comprehensive income. For the year ended March 31, 2016, $21 million (2015 - $127 million) was removed from other comprehensive income and reported in net income, offsetting foreign exchange losses (2015 – losses) recorded in the year.

For derivative instruments not designated as hedges, a gain of $2 million (2015 - $8 million gain) was recognized in finance charges for the year ended March 31, 2016 with respect to foreign currency contracts for cash management purposes. For the year ended March 31, 2016, a gain of $58 million (2015 - $22 million gain) was recognized in finance charges with respect to foreign currency contracts for U.S. short-term borrowings. These economic hedges offset $61 million of foreign exchange revaluation losses (2015 - $24 million loss) recorded with respect to U.S. short-term borrowings for the year ended March 31, 2016. A net gain of $9 million (2015 - $76 million gain) was recorded in trade revenue for the year ended March 31, 2016 with respect to commodity derivatives.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

(in millions)	**2016**	2015
Deferred inception loss, beginning of the year	**$ 70**	$ 50
New transactions	**(14)**	22
Amortization	**(8)**	(2)
Deferred inception loss, end of the year	**$ 48**	$ 70

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 table.

Domestic and Trade Accounts Receivable Net of Allowance for Doubtful Accounts

(in millions)		**2016**		2015
Current	$	**362**	$	381
Past due (30-59 days)		**27**		26
Past due (60-89 days)		**6**		6
Past due (More than 90 days)		**3**		6
		398		419
Allowance for doubtful accounts		**(8)**		(8)
Total	$	**390**	$	411

At the end of each reporting year, 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.

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 enters into derivative transactions under International Swaps and Derivatives Association (ISDA) and Western Systems Power Pool (WSPP) or similar master netting agreements and presents these transactions on a gross basis under derivative commodity assets/liabilities in the statement of financial position. These master netting agreements do not meet the criteria for offsetting as the Company does not have the legally enforceable right to offset recognized amounts. The right to offset is enforceable only on the occurrence of future events such as a credit default.

Under the Company's trading agreements, the amounts owed by each counterparty that are due on a single day in respect of all transactions outstanding in the same currency under the same agreement are aggregated into a single net amount being payable by one party to the other. Such receivable or payable amounts meet the criteria for offsetting and are presented as such on the Company's statement of financial position.

The following table sets out the carrying amounts of recognized financial instruments that are subject to the above agreements:

	2016		
(in millions)	Gross Derivative Instruments Presented in Statement of Financial Position	Related Instruments That Are Not Offset	Net Amount
Derivative commodity assets	$ 165	$ 5	$ 160
Derivative commodity liabilities	124	5	119

	2015		
(in millions)	Gross Derivative Instruments Presented in Statement of Financial Position	Related Instruments That Are Not Offset	Net Amount
Derivative commodity assets	$ 165	$ 1	$ 164
Derivative commodity liabilities	115	1	114

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 associated with our trading activities that are neither past due nor impaired:

	Investment Grade	Unrated	Non-Investment Grade	Total
As at March 31, 2016	%	%	%	%
Accounts receivable	92	2	6	100
Assets from trading activities	100	0	0	100

	Investment Grade	Unrated	Non-Investment Grade	Total
As at March 31, 2015	%	%	%	%
Accounts receivable	86	1	13	100
Assets from trading activities	100	0	0	100

LIQUIDITY RISK

The following table details the remaining contractual maturities at March 31, 2016 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, 2016. In respect of the cash flows in foreign currencies, the exchange rate as at March 31, 2016 has been used.

(in millions)	Carrying Value	Fiscal 2017	Fiscal 2018	Fiscal 2019	Fiscal 2020	Fiscal 2021	Fiscal 2022 *and thereafter*
Non-Derivative Financial Liabilities							
Total accounts payable and other payables (excluding interest accruals and current portion of lease obligations and other long-term liabilities)	$ 1,573	$ (1,573)	$ -	$ -	$ -	$ -	$ -
Long-term debt (including interest payments)	18,404	(3,109)	(769)	(2,007)	(838)	(1,726)	(21,708)
Lease obligations	240	(40)	(40)	(21)	(21)	(21)	(312)
Other long-term liabilities	556	(15)	(12)	(41)	(31)	(31)	(1,551)
Total Non-Derivative Financial Liabilities	20,773	(4,737)	(821)	(2,069)	(890)	(1,778)	(23,571)
Derivative Financial Liabilities							
Cross currency swaps used for hedging	5						
Cash outflow		(10)	(10)	(10)	(10)	(10)	(439)
Cash inflow		3	3	3	3	3	407
Forward foreign exchange contracts used for hedging	5						
Cash outflow		-	-	-	-	-	(337)
Cash inflow		-	-	-	-	-	337
Other forward foreign exchange contracts designated at fair value	36						
Cash outflow		(847)	(21)	-	-	-	-
Cash inflow		811	21	-	-	-	-
Financially settled commodity derivative liabilities designated at fair value	104	(95)	(12)	(2)	-	-	-
Physically settled commodity derivative liabilities designated at fair value	20	(30)	2	-	-	-	-
Total Derivative Financial Liabilities	170	(168)	(17)	(9)	(7)	(7)	(32)
Total Financial Liabilities	20,943	(4,905)	(838)	(2,078)	(897)	(1,785)	(23,603)
Derivative Financial Assets							
Forward foreign exchange contracts used for hedging	(62)						
Cash outflow		-	-	(204)	-	-	(382)
Cash inflow		-	-	259	-	-	406
Other forward foreign exchange contracts designated at fair value	(2)						
Cash outflow		(44)	-	-	-	-	-
Cash inflow		46	-	-	-	-	-
Financially settled commodity derivative liabilities designated at fair value	(90)	68	6	2	-	-	-
Physically settled commodity derivative liabilities designated at fair value	(75)	182	30	8	4	-	-
Total Derivative Financial Assets	(229)	252	36	65	4	-	24
Net Financial Liabilities[1]	**$ 20,714**	**$ (4,653)**	**$ (802)**	**$(2,013)**	**$ (893)**	**$(1,785)**	**$ (23,579)**

[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 (weakening) of the U.S. dollar against the Canadian dollar at March 31, 2016 would have a negative (positive) impact of $2 million on net income 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 Finance Charges regulatory account that captures all variances from forecasted finance charges as described in Note 13 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, 2016 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

Sensitivity analysis for variable rate non-derivative instruments
An increase (decrease) of 100-basis points in interest rates at March 31, 2016 would have a negative (positive) impact on net income of $28 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 Finance Charges regulatory account that captures all variances from forecasted finance charges as described in Note 13 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, 2016 and been applied to each of the Company's exposure to interest rate risk for 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 prices for commodities Powerex trades, including electricity, natural gas and associated derivative products. Prices for electricity and natural gas 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 and correlation, 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 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 $10 million at March 31, 2016 (2015 - $5 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, 2016 and 2015:

As at March 31, 2016 *(in millions)*	Level 1	Level 2	Level 3	Total
Short-term investments	$ 11	$ -	$ -	$ 11
Derivatives designated as hedges	-	62	-	62
Derivatives not designated as hedges	75	30	62	167
Total financial assets carried at fair value	$ 86	$ 92	$ 62	$ 240
Derivatives designated as hedges	$ -	$ (10)	$ -	$ (10)
Derivatives not designated as hedges	(108)	(46)	(6)	(160)
Total financial liabilities carried at fair value	$ (108)	$ (56)	$ (6)	$ (170)

As at March 31, 2015 *(in millions)*	Level 1	Level 2	Level 3	Total
Short-term investments	$ 11	$ -	$ -	$ 11
Derivatives designated as hedges	-	53	-	53
Derivatives not designated as hedges	72	77	47	196
Total financial assets carried at fair value	$ 83	$ 130	$ 47	$ 260
Derivatives designated as hedges	$ -	$ (8)	$ -	$ (8)
Derivatives not designated as hedges	(76)	(31)	(8)	(115)
Total financial liabilities carried at fair value	$ (76)	$ (39)	$ (8)	$ (123)

The Company determines Level 2 fair values for debt securities and derivatives using discounted cash flow techniques, which use contractual cash flows and market-related discount rates.

Level 2 fair values for energy derivatives are determined using inputs other than unadjusted quoted prices that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices). Level 2 includes bilateral and over-the-counter contracts valued using interpolation from observable forward curves or broker quotes from active markets for similar instruments and other publicly available data, and options valued using industry-standard and accepted models incorporating only observable data inputs.

For year ended March 31, 2016, energy derivatives with a carrying amount of $14 million were transferred from Level 2 to Level 1 as the Company now uses published price quotations in an active market.

Powerex holds congestion products and structured power transactions that require the use of unobservable inputs when observable inputs are unavailable. Congestion products are valued using forward spreads at liquid hubs that include adjustments for the value of energy at different locations relative to the liquid hub as well as other adjustments that may impact the valuation. Option pricing models are used when the congestion product is an option. Structured power transactions are valued using standard contracts at a liquid hub with adjustments to account for the quality of the energy, the receipt or delivery location, and delivery flexibility where appropriate. Significant unobservable inputs include adjustments for the quality of the energy and the transaction location relative to the reference standard liquid hub.

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, 2016 and 2015:

(in millions)		
Balance at March 31, 2014	**$**	**43**
Cumulative impact of net gain recognized		38
New transactions		(3)
Existing transactions settled		(39)
Balance at March 31, 2015		**39**
Cumulative impact of net gain recognized		21
New transactions		(4)
Balance at March 31, 2016	**$**	**56**

Level 3 fair values for energy derivatives are determined using inputs that are based on unobservable inputs. Level 3 includes instruments valued using observable prices adjusted for unobservable basis differentials such as delivery location and product quality, instruments which are valued by extrapolation of observable market information into periods for which observable market information is not yet available, and instruments valued using internally developed or non-standard valuation models.

During the year, unrealized gains of $22 million (2015 - $42 million gain) were recognized on Level 3 derivative commodity assets still on hand at year end. During the year, unrealized gains of $3 million (2015 - $8 million loss) were recognized on Level 3 derivative commodity liabilities still on hand at year end. These gains and losses are recognized in trade revenues.

Methodologies and procedures regarding Powerex's energy trading Level 3 fair value measurements are determined by Powerex's Risk Management group. Level 3 fair values are calculated within Powerex's Risk Management policies for trading activities based on underlying contractual data as well as observable and non-observable inputs. Development of non-observable inputs requires the use of judgment. To ensure reasonability, Level 3 fair value measurements are reviewed and validated by Powerex's Risk Management and Finance departments on a regular basis.

NOTE 20: OTHER NON-CURRENT LIABILITIES

(in millions)	**2016**	2015
Provisions		
Environmental liabilities	$ **390**	$ 368
Decommissioning obligations	**56**	53
Other	**10**	27
	456	448
First Nations liabilities	**409**	414
Finance lease obligations	**240**	259
Other liabilities	**147**	81
Deferred revenue - Skagit River Agreement	**463**	441
	1,715	1,643
Less: Current portion, included in accounts payable and accrued liabilities	**(122)**	(129)
	$ **1,593**	$ 1,514

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

	Environmental	Decommissioning	Other	Total
Balance at March 31, 2015	$ **368**	$ **53**	$ **27**	$ **448**
Made during the period	-	-	4	4
Used during the period	(27)	(4)	(21)	(52)
Changes in estimate	45	6	-	51
Accretion	4	1	-	5
Balance at March 31, 2016	$ **390**	$ **56**	$ **10**	$ **456**

Environmental Liabilities

The Company has recorded a liability for the estimated future environmental expenditures related to present or past activities of the Company. 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. 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. 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 2017 and 2045, is approximately $453 million and was determined based on current cost estimates. A range of discount rates between 0.5 to 2.1 per cent were used to calculate the net present value of the obligations.

Decommissioning Obligations

The Company's decommissioning obligation provision consists of estimated removal and destruction costs associated with certain PCB contaminated assets and certain submarine cables. The Company has determined its best estimate of the undiscounted amount of cash flows required to settle remediation obligations at $85 million (2015 – $84 million), which will be settled between fiscal 2017 and 2054. The undiscounted cash flows are then discounted by a range of discount rates between 0.5 to 2.1 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 per cent to 5.0 per cent. 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 per cent to 9.3 per cent with contract terms of 25 years expiring from 2018 until 2036. Finance lease liabilities are payable as follows:

(in millions)	**Future minimum lease payments 2016**	**Interest 2016**	**Present value of minimum lease payments 2016**	Future minimum lease payments 2015	Interest 2015	Present value of minimum lease payments 2015
Less than one year	**$ 40**	**$ 20**	**$ 20**	$ 40	$ 21	$ 19
Between one and five years	**103**	**63**	**40**	143	83	60
More than five years	**312**	**132**	**180**	312	132	180
Total minimum lease payments	**$ 455**	**$ 215**	**$ 240**	$ 495	$ 236	$ 259

Other Liabilities

Other liabilities consist of a contractual obligation associated with the construction of assets. The contractual obligation has an implied interest rate of 7 per cent and a repayment term of 15 years commencing in fiscal 2019. The liability is measured at amortized cost and not re-measured for changes in discount rates.

NOTE 21: COMMITMENTS AND CONTINGENCIES

Energy Commitments

BC Hydro (excluding Powerex) has long-term energy and capacity 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 $56,336 million of which approximately $157 million relates to the purchase of natural gas and natural gas transportation contracts. The remaining commitments are at predetermined prices. Included in the total value of the long-term energy purchase agreements is $455 million accounted for as obligations under capital leases. The total BC Hydro combined payments are estimated to be approximately $1,472 million for less than one year, $6,592 million between one and five years, and $48,272 million for more than five years and up to 55 years.

Powerex has energy purchase commitments with an estimated minimum payment obligation of $1,971 million extending to 2034. The total Powerex energy purchase commitments are estimated to be approximately $446 million for less than one year, $834 million between one and five years, and $691 million for more than five years. Powerex has energy sales commitments of $602 million extending to 2026 with estimated amounts of $381 million for less than one year, $208 million between one and five years, and $13 million for more than five years.

Lease and Service Agreements

The Company has entered into various agreements to lease facilities or assets classified as operating leases, or support operations. The agreements cover periods of up to 70 years, and the aggregate minimum payments are approximately $755 million. Payments are $127 million for less than 1 year, $182 million between one and five years, and $446 million for more than five years.

Contingencies and Guarantees

a) 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.

b) 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.

c) The Company and its subsidiaries have outstanding letters of credit totaling $1,065 million (2015 - $822 million), of which there is US $ 30 million (2015 – US $44 million).

NOTE 22: RELATED PARTY TRANSACTIONS

Subsidiaries

The principal subsidiaries of BC Hydro are Powerex, Powertech, and Columbia.

All companies are wholly owned and incorporated in Canada and all ownership is in the form of common shares. Powerex is an active participant in western energy markets, buying and selling wholesale power, natural gas, ancillary services, clean and renewable power, and environmental products 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 a Crown corporation, 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)		**2016**		2015
Consolidated Statement of Financial Position				
Accounts receivable	$	**103**	$	91
Accounts payable and accrued liabilities		**381**		320
Amounts incurred/accrued during the year include:				
Water rental fees		**327**		334
Cost of energy sales		**116**		130
Taxes		**132**		125
Interest		**720**		674
Payment to the Province		**326**		264

The Company's debt is either held or guaranteed by the Province (see Note 16). 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, 2016, the aggregate exposure under this indemnity totaled approximately $62 million (2015 - $74 million). The Company has not experienced any losses to date under this indemnity.

The Company and British Columbia Investment Management Corporation (bcIMC) are related parties and are both wholly owned by the Province. The Company has responsibility for administration of the British Columbia Hydro and Power 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 18 for the Company contributions to the pension plan for 2016 and 2015.

Key Management Personnel and Board Compensation

Key management personnel and board compensation includes compensation to the Company's executive management team and board of directors.

(in millions)	**2016**	2015
Short-term employee benefits	**$ 4**	$ 4
Post-employment benefits	**1**	1

Capital Plan and Major Projects

Planned Projects over $50 million

BC Hydro has planned for the following projects, each with capital costs expected to exceed $50 million, listed according to targeted completion date. These projects have been approved by the Board of Directors. *Appendix D: Capital Project Descriptions* provides further details on each $50 million project.

Major Capital Projects (Project descriptions can be found in Appendix D)	**Targeted Completion Date** (calendar year)	**Approved Anticipated Total Cost of Project** ($ millions)	**Project Cost to March 31, 2016** ($ millions)
Projects Recently Put Into Service			
Gordon M. Shrum Units 1 to 5 Turbine Replacement	October 2015, In-Service	$185	$169
Long Beach Area Reinforcement	October 2015, In-Service	**$38***	$36
Merritt Area Transmission Project	November 2015, In-Service	**$60***	$55
Dawson Creek/Chetwynd Area Transmission Project	November 2015, In-Service	$296	$281
Interior to Lower Mainland Transmission Line Project	December 2015, In-Service	$743	$706
Smart Metering & Infrastructure Program**	December 2015, In-Service	$780	$779
Hugh Keenleyside Spillway Gate Reliability Upgrade	December 2015, In-Service	**$115***	$107
Upper Columbia Capacity Additions at Mica – Units 5 & 6	December 2015, In-Service	**$627***	$575
Surrey Area Substation Project	March 2016, In-Service	$94	$77

**The approved anticipated total cost of the project has been reduced to the current total project forecast amount as the project is expected to come in under budget (Long Beach from $56M to $38M; Merritt from $65M to $60M; Hugh Keenleyside from $123M to $115M; and Upper Columbia from $714M to $627M).*

****Smart Metering & Infrastructure Program includes both capital costs and operating expenditures subject to regulatory deferral and the total authorized cost has been reduced to the total project forecast amount as the project is expected to come in under budget.*

Major Capital Projects (Project descriptions can be found in Appendix D)	**Targeted Completion Date** (calendar year)	**Approved Anticipated Total Cost of Project** ($ millions)	**Project Cost to March 31, 2016** ($ millions)
Ongoing and Planned			
Big Bend Substation	2017 Targeted In-Service	$67	$40
Ruskin Dam Safety and Powerhouse Upgrade	2017 Targeted In-Service	$748	$418
Horne Payne Substation	2018 Targeted In-Service	$93	$5
John Hart Generating Station Replacement	2019 Targeted In-Service	$1,093	$441
Cheakamus Unit 1 and Unit 2 Generator Replacement	2019 Targeted In-Service	$74	$9
Fort St. John and Taylor Electric Supply	2019 Targeted In-Service	$53	$ nil
Gordon M. Shrum G1-G10 Control System Upgrade	2021 Targeted In-Service	$60 (Partial Implemen-tation Funding)	$8
Site C Clean Energy Project	2024* Targeted In-Service	$8,335**	$950

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

***Site C total cost excludes the Project Reserve of $440 million (established by the British Columbia Government to account for events outside of BC Hydro's control that could occur during construction) which is held by the Treasury Board.*

Appendix A: Subsidiaries and Operating Segments

Active Subsidiaries

BC Hydro has created or retained a number of subsidiaries for various purposes, including holding licenses in other jurisdictions, to manage real estate holdings and to manage various risks.

Powerex Corp.

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 and low-carbon energy and products, natural gas, ancillary services, and financial energy products. 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 necessary in addition to meeting its own trade commitments. Powerex also markets, through an agreement with 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. The Board of Directors, the Chair of the Powerex Board, and the Powerex CEO, ensure the Board of BC Hydro is informed of Powerex's key strategies and business activities. The Powerex CEO also works closely with the BC Hydro CEO and Executive Team and informs the BC Hydro CEO and Executive Team of Powerex's business activities.

Powerex operates in complex and volatile energy-markets, which can cause net income in any given year to vary significantly. 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. Over the previous five years, Powerex income has ranged from $61 million to $142 million (2011/12 to 2015/16). The Service Plan forecast includes annual net income from Powerex of approximately $120 million per year for 2016/17 to 2018/19. For more information, visit powerex.com.

Powertech Labs Inc.

Powertech Labs, operating in Surrey since its inception in 1979, is a wholly-owned subsidiary of BC Hydro. Powertech is internationally recognized as holding expertise in various fields including: research and development, testing, technical services and advanced technology services to the international energy community including BC Hydro.

The Powertech Chief Executive Officer (CEO) reports to the BC Hydro Executive Vice President Transmission, Distribution and Customer Services. The Powertech Board is chaired by BC Hydro's President and CEO and its Directors include senior Executive of BC Hydro.

Over the last five years Powertech's revenue has ranged from $26 million to $36 million (2010/11 to 2015/16) with a net income in the range of $2 million to $4 million. The Service

Plan forecast includes annual net income from Powertech ranging from $4 million to $6 million for 2016/17 to 2018/19. For more information, visit powertechlabs.com.

Other Active Subsidiaries
All the staff and management needs of the active subsidiaries below are fulfilled by BC Hydro employees, who perform these duties without additional remuneration. Three of these subsidiaries are considered active:

BCHPA Captive Insurance Company Ltd.
Procures insurance products and services on behalf of BC Hydro.

Columbia Hydro Constructors Ltd.
Administers and supplies the labour force to specified projects.

Tongass Power and Light Company
Provides electrical power to Hyder, Alaska from Stewart, BC, due to Hyder's remoteness from the Alaska electrical system.

Nominee Holding Companies and/or Inactive/Dormant Subsidiaries

BC Hydro's remaining subsidiaries either serve as nominee holding companies (indicated with an *) or are considered to be inactive/dormant. The inactive/dormant subsidiaries do not carry on active operations. As of March 31, 2016, these other subsidiaries consisted of the following:

1. British Columbia Hydro International Limited
2. British Columbia Power Exchange Corporation
3. British Columbia Power Export Corporation
4. British Columbia Transmission Corporation
5. Columbia Estate Company Limited*
6. Edmonds Centre Developments Limited*
7. Fauquier Water and Sewerage Corporation*
8. Hydro Monitoring (Alberta) Inc.*
9. Victoria Gas Company Limited
10. Waneta Holdings (US) Inc.*

Appendix B: Additional Information

Organizational Overview

BC Hydro has offices in more than 100 communities throughout British Columbia and our employees operate in some of the most difficult terrain in the world. Our transmission system connects with transmission systems in Alberta and Washington State, which improves overall reliability of the system and provides opportunities for trade. Our largest offices are located in Burnaby, Cranbrook, Kamloops, Nanaimo, Prince George, Revelstoke, Surrey, Vancouver, Vernon and Victoria. Information about BC Hydro's organization and operating environment can be found at:
http://www.bchydro.com/about/accountability_reports/financial_reports/service_plan.html.

Corporate Governance

BC Hydro is governed by a Board of Directors that is accountable to the Minister Responsible for the implementation of government direction. The Board's direction is implemented by management, who carries out the day-to-day operations of the Corporation under the supervision of the Chief Executive Officer. For more information on Corporate Governance, please refer to our web page at:
http://www.bchydro.com/about/accountability_reports/financial_reports/service_plan.html.

To support Director training and development, an orientation program is aimed at increasing their familiarity with the Corporation, our industry, and the unique responsibilities of Crown Corporation Directors, as well as equipping them with sufficient information and resources to make fully-informed decisions. The program utilizes materials and resources that inform Directors on the Corporation's corporate governance framework, its businesses, operations, and current issues and strategies. Directors are also provided with ongoing development opportunities that educate and inform them on issues that are of strategic importance to the Corporation. These include special site visits to provide Directors with additional insight into the Corporation's operations.

To promote awareness and understanding of the standards of conduct that BC Hydro expects, the Board of Directors has approved a Code of Conduct as well as Contractor Standards for Ethical Conduct. These documents provide general guidance on standards of conduct, including guidelines on conflict of interest, as well as requirements associated with confidential information, entertainment and gifts, environment and safety, and use of BC Hydro property. The Code also allows exemptions from its requirements to be granted in extraordinary circumstances, and where it is clearly in the best interests of BC Hydro to do so. This is supplemented by guidance available from BC Hydro's Ethics Officer, as well as an independent Code Advisor for Directors and senior members of the executive.

Contact Information

See Page 2 for full contact information. More information on BC Hydro can be found at www.bchydro.com.

Appendix C: Crown Corporations Mandate and Actions Summary

In the 2015/16 Government Mandate Letter, BC Hydro received direction on strategic priorities for the 2015/16 fiscal year. These priorities and the Crown Corporation's resulting actions are summarized below:

Mandate Letter Direction	Crown Corporation's Action
1. To efficiently and responsibly manage the business, deliver value and maintain competitive rates by implementing the Integrated Resource Plan and the 10 Year Rates Plan.	In 2015/16 BC Hydro initiated a workforce optimization program to convert external contractors to internal staff in cases where it reduces costs or improves outcomes and continued our Work Smart program. The savings from these initiatives and others have helped to fund important investments in key priority areas like customer service, safety, maintenance and capital project planning. BC Hydro also conducted a review of our conservation programs and identified opportunities to reduce costs, and take advantage of new technologies, such as smart meters, to better respond to customer and system needs. BC Hydro developed a debt management strategy and one component, a Debt Management Regulatory Account, was approved by the BC Utilities Commission which will lock-in low long-term interest rates to protect customers from the risk of rising interest rates. All of these actions support the achievement of the 10 Year Rates Plan and will help to keep rates as low as possible for our customers.
2. Continue to develop the Site C project.	BC Hydro's Site C Clean Energy Project will meet the future electricity needs of British Columbia's growing population and economy. Site preparation and construction has commenced with vegetation clearing, building of access roads, a construction bridge, and worker accommodations. Procurement activities have resulted in the award of many small and large contracts with commitments totaling approximately $3.8 billion as of March 31, 2016. Thousands of people have attended Site C job fairs and the number of on-site workers peaked at 691 this past year, of which 492 were from British Columbia. Specific to aboriginal business opportunities and employment, in fiscal 2016 there has been $90 million in procurement commitments to First Nations companies, and joint ventures including First Nations companies, and more than 50 First Nations employees and contractors are working on the project.

Mandate Letter Direction	Crown Corporation's Action
3. Deliver BC Hydro's $2 billion per year capital plan, in addition to Site C, to support British Columbia's economic growth and meet the needs of BC Hydro customers by refurbishing, replacing and building generation and transmission infrastructure, on time and on budget.	From fiscal 2012-2016, BC Hydro completed 563 capital projects at a total cost of $6.48 billion which is 0.18 percent under budget overall. Capital expenditures for 2015/16 were $2.3 billion and capital in-service additions were $2.8 billion. The list of projects above $50 million which came into service in 2015/16 is included in the Financial section of the Annual Service Plan Report.
4. Continue to develop and promote positive, long-term and mutually beneficial relationships with First Nations through agreements related to BC Hydro's capital projects and power procurement under the Standing Offer Program.	BC Hydro achieved a gold level certification for best practices under the Progressive Aboriginal Relations program through the Canadian Council for Aboriginal Business and we continue to work on our Aboriginal Employment and Business Development strategy which is focused on serving communities impacted by our capital plan and operating footprint. In October 2015, BC Hydro, the Province and Clean Energy BC signed a Memorandum of Understanding to secure opportunities that can both benefit ratepayers and grow the independent power sector. This includes a process to optimize the Standing Offer Program to better incent projects that best meet system needs. BC Hydro has also launched a new Micro-Standing Offer Program targeting First Nations and communities focused on smaller clean and renewable energy projects (100 kilowatts up to 1 megawatt in size). A framework to identify key information requirements, milestones, and processes to most effectively advance potential renewable energy projects was developed for First Nations communities that are part of the non-integrated areas. An Energy Purchase Agreement was signed with the Kwadacha First Nation in January 2016 for a clean and renewable biomass project that will displace diesel generation in the community.

Appendix D: Capital Project Descriptions

Projects Recently Put Into Service

Gordon M. Shrum Units 1 to 5 Turbine Replacement

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

Long Beach Area Reinforcement

Expanded the Long Beach and Great Central Lake substations with two new transformers at each and capacitor banks at Long Beach to support the load growth and provide voltage support in the area.

Merritt Area Transmission Project

Constructed a new 138 kV transmission line between the Merritt and Highland substations; added a new Merritt Substation and new equipment at the Highland Substation to meet the increased demand for power in the Merritt area.

Dawson Creek/Chetwynd Area Transmission Project

The project expanded the Peace Region 230 kV transmission system to the Dawson Creek/Chetwynd Area to supply the area's load growth. The solution includes the construction of new 230 kV lines between Dawson Creek and Bear Mountain Terminal (BMT), and from BMT to a new substation called Sundance Lake Substation, located approximately 19 km east of Chetwynd.

Interior to Lower Mainland Transmission Line Project

Constructed a new 500 kV transmission line, approximately 247 km in length, between the Nicola Substation near Merritt and the Meridian Substation in Coquitlam, and a new series capacitor station at Ruby Creek near Agassiz to help meet domestic load growth in the Lower Mainland.

Smart Metering & Infrastructure Program

The Smart Metering and Infrastructure Program included the installation of 1.9 million smart meters in homes and businesses across the province, 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.

Hugh Keenleyside Spillway Gate Reliability Upgrade

Upgraded the spillway gates at the Hugh Keenleyside Dam to increase public and employee safety by ensuring the gates meet flood discharge reliability requirements.

Spillway gates control the amount of water that can be discharged from the reservoir. They are generally used in times of flooding to pass high inflows.

Upper Columbia Capacity Additions at Mica – Units 5 & 6

Installed two additional 500 MW generating units into existing unit bays at the Mica Generating Station. The new units are similar to the four existing units, but with more efficient turbines.

Surrey Area Substation Project

Constructed a new 200 MVA 230/25 kV substation in the Fleetwood area of Surrey. The station is supplied from the adjacent 230 kV transmission line and allows for future expansion to 400 MVA to service high load growth in the Fraser Valley West area. Construction of this new Fleetwood Substation allows for the decommissioning of four aging substations in the Surrey/Langley area.

Ongoing and Planned

Big Bend Substation

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

Ruskin Dam Safety and Powerhouse Upgrade

Improve seismically deficient dam and rehabilitation/replacement of powerhouse equipment that was brought into service between 1930 and 1950. The project includes: upgrading of the right abutment; redeveloping the dam and powerhouse to meet current seismic standards for earthquakes; and replacement of major generation equipment which is in poor unsatisfactory condition.

Horne Payne Substation

Expand the Horne Payne Substation with the addition of two 230/25kV, 150MVA transformers, gas-insulated (GIS) feeder sections, and a new control building. This project will increase the firm capacity of the substation, add needed feeder positions, facilitate the gradual conversion of the area supply voltage from 12kV to 25kV, and allow for the implementation of an open-loop distribution system.

John Hart Generating Station Replacement

Replace the existing six-unit 126 MW generating station (in operation since 1947), add integrated emergency bypass capability to ensure reliable long-term generation, and mitigate earthquake risk and environmental risk to fish and fish habitat.

Cheakamus Unit 1 and Unit 2 Generator Replacement

Replace the two generators at Cheakamus generating station (in operation since 1957) to address the poor condition and known deficiencies which will increase the capacity of each unit from 70 MW to 90 MW.

Fort St. John and Taylor Electric Supply

This project will maintain adequate supply capability, reduce line losses and improve reliability to the loads in the Fort St. John and Taylor areas by re-terminating 138kV transmission lines 1L360 and 1L374 at the new Site C switchyard.

Gordon M. Shrum G1-G10 Control System Upgrade

The condition of the legacy controls for the GMS generating units, which were originally installed in the 1960s and 1970s, is of growing concern due to increasing maintenance requirements, lack of spare parts availability and decreasing reliability. The controls are well beyond their expected life, cause operating problems and increase the risk of damage to major equipment. The project will replace the controls equipment, provide full remote control capability from the remote control center and rectify deficiencies in the current system.

Site C Clean Energy Project

Site C will be a third dam and 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 1,100 megawatts of capacity. Site C project was approved by the Provincial Government in December 2014. Site C will provide clean, renewable and cost-effective power in B.C. for more than 100 years.

Appendix E: Financial and Operating Statistics

FINANCIAL STATISTICS

for the years ended or as at March 31 (in millions)	**2016**	2015	2014	2013	2012
Revenues					
Domestic	**$ 5,056**	$ 4,829	$ 4,319	$ 4,038	$ 3,748
Trade	**601**	919	1,073	860	982
Expenses					
Domestic energy costs	**1,425**	1,458	1,252	1,123	1,100
Trade energy costs	**427**	745	894	683	776
Other operating expenses [1]	**937**	918	901	894	820
Amortization and depreciation	**1,241**	1,205	995	953	793
Grants and taxes	**220**	209	203	196	184
Finance charges	**752**	632	598	540	499
	5,002	5,167	4,843	4,389	4,172
Net Income	**$ 655**	$ 581	$ 549	$ 509	$ 558
Property, Plant and Equipment & Intangible Assets					
At cost	**$ 25,183**	$ 22,998	$ 20,897	$ 18,932	$ 17,161
Less: Accumulated depreciation	**3,189**	2,518	1,863	1,268	758
Net Book Value	**$ 21,994**	$ 20,480	$ 19,034	$ 17,664	$ 16,403
Property, Plant & Equipment and Intangible Asset Expenditures					
Sustaining	**$ 1,136**	$ 1,005	$ 979	$ 1,009	$ 956
Growth	**1,170**	1,164	1,057	920	747
Total Property, Plant & Equipment and Intangible Asset Expenditures [2]	**$ 2,306**	$ 2,169	$ 2,036	$ 1,929	$ 1,703
Net Long-Term Debt [3]	**$ 18,002**	$ 16,682	$ 15,461	$ 13,962	$ 12,833
Retained Earnings	**$ 4,397**	$ 4,068	$ 3,751	$ 3,369	$ 3,075
Debt to Equity Ratio	**80 : 20**	80 : 20	80 : 20	80 : 20	80 : 20

1 Personnel, materials & external services, capitalized costs and other costs, as per the operating expenses note in the consolidated financial statements.

2 Total property, plant and equipment and intangible asset expenditures are different from the amount of property, plant and equipment and intangible asset expenditures in the Consolidated Statements of Cash Flows due to the effect of accruals related to these expenditures.

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

OPERATING STATISTICS

for the years ended or as at March 31	2016	2015	2014	2013	2012
Generating Capacity (megawatts)					
Hydroelectric	**11,869**	11,379	10,927	10,927	10,923
Thermal	**175**	1,120	1,120	1,120	1,117
Total	**12,044**	12,499	12,047	12,047	12,040
Peak One-Hour Integrated System Demand (megawatts)	**9,602**	9,441	10,072	9,345	9,929
Customers					
Residential	**1,751,296**	1,727,945	1,709,071	1,689,050	1,671,412
Light industrial and commercial	**205,615**	203,466	201,812	199,981	197,821
Large industrial	**185**	183	177	172	168
Other	**3,459**	3,474	3,489	3,482	3,490
Trade	**214**	226	239	249	264
Total	**1,960,769**	1,935,294	1,914,788	1,892,934	1,873,155
Domestic Electricity Sold (gigawatt-hours)					
Residential	**17,331**	17,047	17,965	17,703	18,395
Light industrial and commercial	**18,421**	18,564	18,501	18,384	18,005
Large industrial	**13,669**	14,020	13,994	13,508	13,522
Other	**7,879**	1,582	2,558	7,417	2,275
Total	**57,300**	51,213	53,018	57,012	52,197
Revenues (in millions)					
Residential	**$ 1,842**	$ 1,712	$ 1,663	$ 1,612	$ 1,581
Light industrial and commercial	**1,685**	1,597	1,489	1,436	1,327
Large industrial	**766**	748	687	642	598
Other energy sales	**464**	280	275	322	236
Total Domestic Revenue Before Regulatory Transfer	**4,757**	4,337	4,114	4,012	3,742
Regulatory transfer	**299**	492	205	26	6
Total Domestic	**5,056**	4,829	4,319	4,038	3,748
Trade - electricity	**460**	775	866	727	712
Trade - gas	**141**	144	207	133	270
Total Revenues	**$ 5,657**	$ 5,748	$ 5,392	$ 4,898	$ 4,730
Average Revenue (per kilowatt-hour) [1]					
Residential	**10.6¢**	10.0¢	9.3¢	9.1¢	8.6¢
Light industrial and commercial	**9.1**	8.6	8.0	7.8	7.4
Large industrial	**5.6**	5.3	4.9	4.8	4.4
Average Annual Kilowatt-Hour Use Per Residential Customer	**9,958**	9,919	10,571	10,534	11,067
Lines In Service					
Distribution (kilometres)	**58,765**	58,518	58,317	58,115	57,914
Transmission (circuit kilometres)	**20,176**	19,792	19,322	19,163	18,864

[1] *Average revenues are before regulatory transfers.*

TOTAL REQUIREMENTS FOR ELECTRICITY, SOURCES OF SUPPLY AND WATER INFLOWS

for the years ended March 31	2016			2015			2014			2013			2012		
	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	12,044	57,300	73.7	12,499	51,213	66.0	12,047	53,018	65.0	12,047	50,992	58.5	12,040	52,197	62.2
Electricity trade		14,732	18.9		21,928	28.2		23,806	29.2		30,975	35.6		26,908	32.1
		72,032	92.6		73,141	94.2		76,824	94.2		81,967	94.1		79,105	94.3
Line loss and system use		5,713	7.4		4,486	5.8		4,733	5.8		5,159	5.9		4,783	5.7
		77,745	100.0		77,627	100.0		81,557	100.0		87,126	100.0		83,888	100.0
Sources of Supply															
Hydroelectric generation															
Gordon M. Shrum	2,730	14,274	18.4	2,730	10,801	13.9	2,730	13,650	16.7	2,730	15,878	18.2	2,730	14,447	17.2
Revelstoke	2,480	9,805	12.6	2,480	7,297	9.4	2,480	8,121	10.0	2,480	9,760	11.2	2,480	8,756	10.4
Mica	2,747	9,451	12.2	2,257	6,028	7.8	1,805	7,030	8.6	1,805	7,873	9.0	1,805	7,943	9.5
Kootenay Canal	583	2,837	3.6	583	3,304	4.4	583	2,935	3.6	583	3,595	4.1	583	3,108	3.7
Peace Canyon	694	3,470	4.5	694	2,678	3.4	694	3,423	4.2	694	3,902	4.5	694	3,613	4.3
Seven Mile	805	2,666	3.4	805	3,907	5.0	805	3,183	3.9	805	3,176	3.6	805	3,491	4.2
Bridge River	478	2,582	3.3	478	2,093	2.7	478	2,397	2.9	478	2,626	3.0	478	2,732	3.3
Other	1,352	4,267	5.5	1,352	5,122	6.6	1,352	4,589	5.6	1,352	5,304	6.1	1,348	5,743	6.9
	11,869	49,352	63.5	11,379	41,230	53.2	10,927	45,328	55.5	10,927	52,115	59.8	10,923	49,833	59.5
Thermal generation															
Burrard	0	24	0.0	950	26	0.0	950	84	0.1	950	25	0.0	950	19	0.0
Other	175	191	0.2	170	187	0.2	170	184	0.2	170	97	0.1	167	124	0.1
Purchases under long-term commitments		18,441	23.7		17,510	22.6		15,300	18.8		15,003	17.2		15,317	18.3
Purchases under short-term commitments		10,713	13.8		18,586	23.9		20,764	25.5		19,858	22.8		18,640	22.2
Other		(976)	(1.2)		88	0.1		(103)	(0.1)		28	0.0		(45)	(0.1)
	12,044	77,745	100.0	12,499	77,627	100.0	12,047	81,557	100.0	12,047	87,126	100.0	12,040	83,888	100.0
Water inflows (% of average)			97			102			95			109			108

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☐ Other:

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Deputy Minister

Enclosures

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Explanation Continued

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Communications Plan

Revenue Requirements Application

July 2016

Approval Schedule

LEGEND	DRAFT PROVIDED	COMMENTS BACK	FINAL APPROVAL	BRIEFING / EVENT

July

ITEM	DESCRIPTION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Chapter 1	Introduction																												
Chapter 2	Legal Framework for Application																												
Chapter 3	Load and Revenue Forecast																												
Chapter 4	Cost of Energy																												
Chapter 6	Capital Expenditures and Additions																												
Chapter 7	Regulatory Accounts																												
Chapter 8	Other Revenue Requirements (Finance Charges, etc.)																												
Chapter 5	Operating Costs																												
Chapter 9	Transmission Revenue Requirements																												
Chapter 10	Demand Side Management Expenditures																												
Briefing	Board Briefing												12																
Briefing	Minister's Briefing on Chapters 1, 3, 4,														14														
Briefing	Minister's Briefing on Chapters 5, 7, 10																					21							
External Comms	Media Briefing Presentation														14														
External Comms	Communications Plan														14														
External Comms	News Release and Backgrounders																					21							
External Comms	Questions and Answers																					21							
External Comms	Pre-RRA Presentation to BCBC (July 21, 9:00 - 10:30 a.m.)																					21							

Regulatory Schedule

	DATE		ACTION
	Please note that dates are BC Hydro estimates based on high level discussions with Commission staff. Final determination of the proceeding dates is up to the Commission and dates could vary from those indicated below.		
2016	June 29	**SAP**	BC Hydro filing of consolidated information
2016	July 6	**RDA**	RDA Module 1 - Rebuttal of Intervener Evidence (filing)
2016	July 28	**RRA**	F2017 - F2019 RRA Filed
2016	July 28	**SAP**	Commission and Intervener Information Request No. 1
2016	August 16-18	**RDA**	RDA Module 1 - Oral Hearing
2016	August 23-24	**RDA**	RDA Module 1 - Oral Hearing
2016	August 25-26	**RDA**	RDA Hearing (if additional days are required)
2016	August 31	**RRA**	Registration of Interveners and Interested Parties
2016	Summer	**RDA**	Module 2 - EV Rates / EV Fast Charging (Preparation / Engagement)
2016	Summer / Fall	**RDA**	Module 2 - Jurisdictional Reviews (workshops, meetings, focus groups, surveys)
2016	September 8	**RRA**	Procedural / Scoping Conference
2016	September 9	**SAP**	BC Hydro Response to Information Request No. 1
2016	September 16	**RRA**	Commission Information Request No. 1 to BC Hydro
2016	September 23	**RRA**	Intervener Information Request No. 1 to BC Hydro
2016	Late September	**RDA**	Module 1 - Final Argument (BC Hydro & Interveners); BC Hydro reply filed
2016	September 30	**SAP**	Submission deadline for comments on further process
2016	October 6	**SAP**	Procedural Conference
2016	October 21	**RRA**	BC Hydro responds to Commission and Intervener Info Request No. 1
2016	October 28	**RRA**	Procedural Conference No. 2 (?)
2016	November 10	**RRA**	Commission and Intervener Information Request No. 2
2016	December 16	**RRA**	BC Hydro responds to Commission and Intervener Info Request No. 2
2016	December TBD	**RDA**	Module 2 - EV Rates / EV Fast Charging Applications Filed
2017	Late 2016 / early 2017	**RDA**	Module 1 - BCUC Decision
2017	Mid-February	**RRA**	Oral Hearing
2017	Mid-March	**RRA**	Arguments (*timing dependent on when oral hearings finish*)
2017	March - May	**RRA**	Drafting of Decision (*Commission to issue decisions w/in 90 days of close of evidence*)
2017	April 1	**RDA**	Module 1 - BCUC Decision Implementation
2017	Mid-June	**RRA**	Decision (*assuming evidence phase that ends in late Feb/early March*)
2017	Early Summer	**RDA**	Module 2 - Rate Design Application
2017	Summer 2017 - 2018	**RDA**	Module 2 - Regulatory Proceeding
2017	Summer 2017	**RDA**	Cost of Service Study for F2019
2018	Late 2018 / early 2019	**RDA**	Module 2 - BCUC Decision

The **Rate Design Application (RDA)** reviews and determines rate structures for residential, business and industrial customers based on extensive stakeholder and customer feedback on our current rate designs and on potential rate

The **Revenue Requirements Application (RRA)** reflects the expenditures BC Hydro requires to cover our costs, which includes things like operating expenses, cost of energy and DSM expenditures. BC Hydro is filing its F2017 to F2019

An inquiry to review BC Hydro's expenditures related to the adoption of the **SAP Platform** was established in May 2016 and is currently underway

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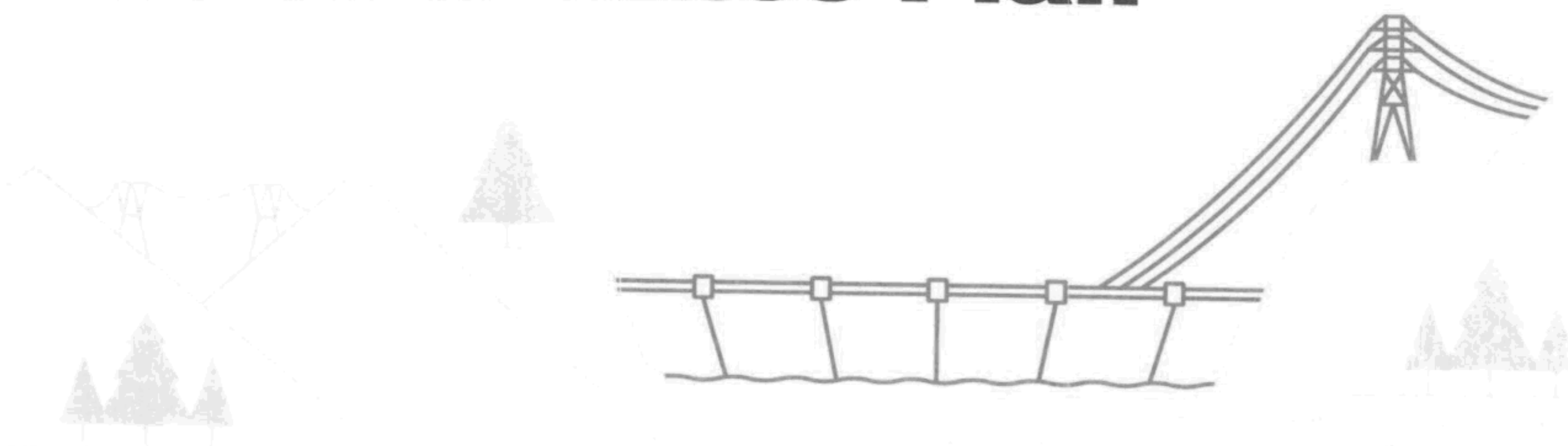
Investing in our system & staying on track to meet the 10 Year Rates Plan



BC Hydro
Power smart

Highlights

In February, BC Hydro announced that we would delay filing our fiscal 2017 – 2019 Revenue Requirements Application, pending an update to the load forecast that would reflect developments in the mining and Liquefied Natural Gas (LNG) sectors.

The BC Utilities Commission (BCUC) approved an interim rate increase of 4.0%, effective April 1, 2016.

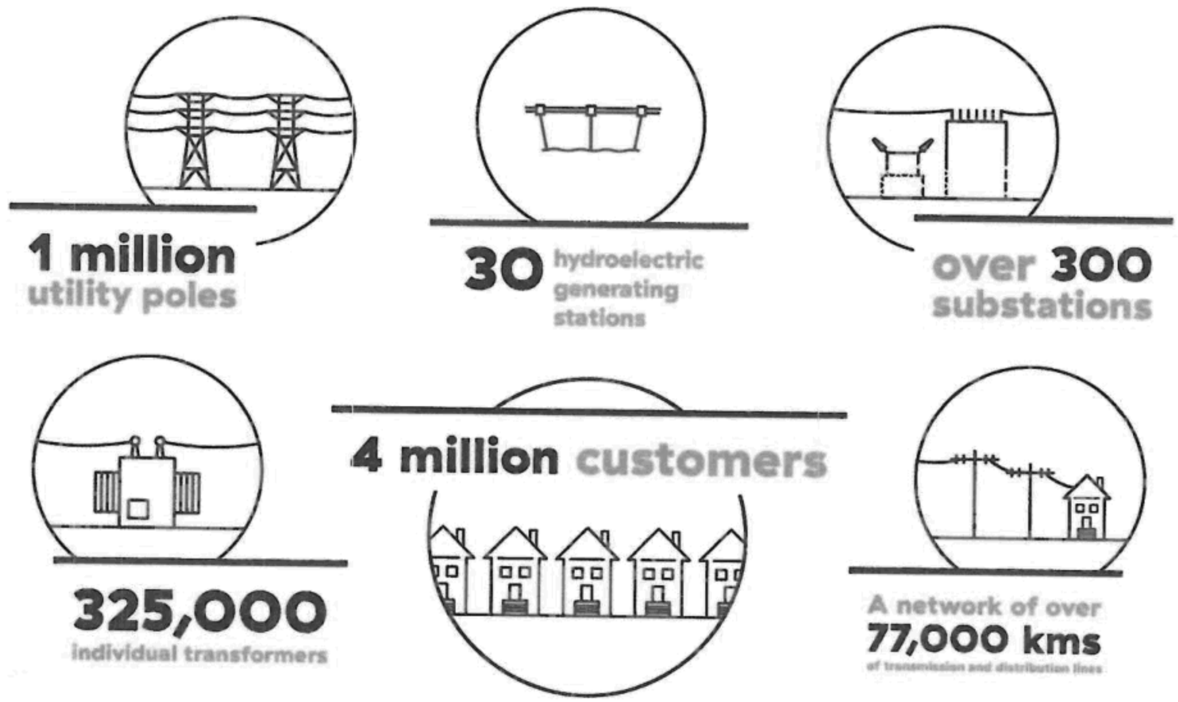
Later today, we will be filing a full three-year Revenue Requirements Application with the BCUC, requesting rate increases of 4.0%, 3.5% and 3.0% per year for fiscal 2017, 2018 and 2019. These increases align with the 10 Year Rates Plan.

We continue to forecast significant long-term growth across all customer sectors and remain on track with the 10 Year Rates Plan.

BC Hydro
Power smart

BC Hydro's system

We have a large and complex system serving 95% of the province's population and 4 million customers.



BC Hydro
Power smart

Reliable, clean, affordable

- **B.C.'s power supply is more reliable than the Canadian average.**
- 98% of the energy generated in B.C. is from clean or renewable sources.
- Our rates are among the lowest in North America.

outage & duration numbers to be verified

BC Hydro
Power smart

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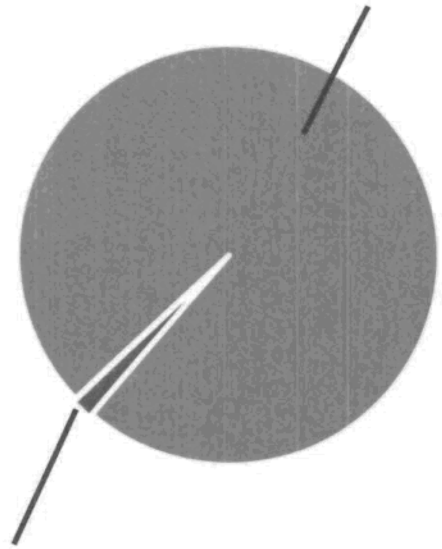

BC Hydro
Power smart

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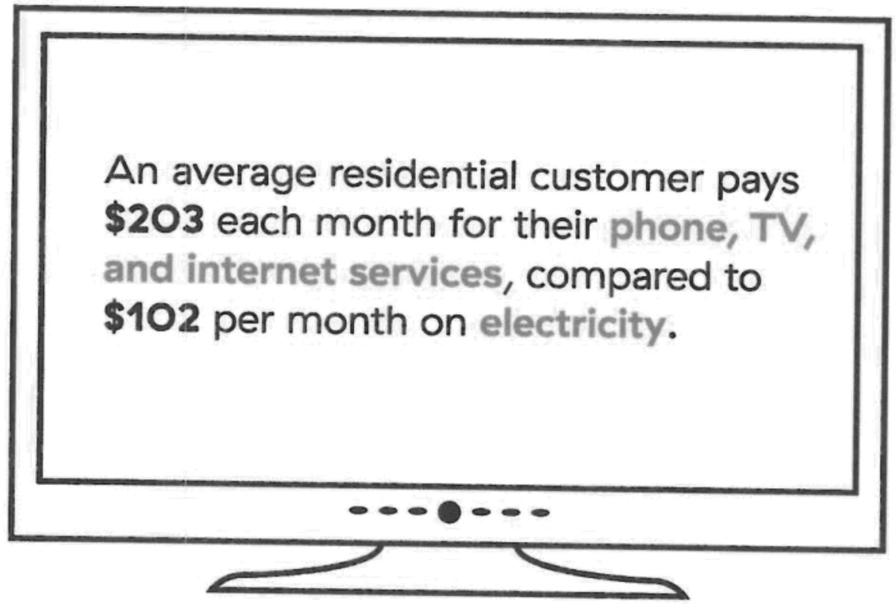
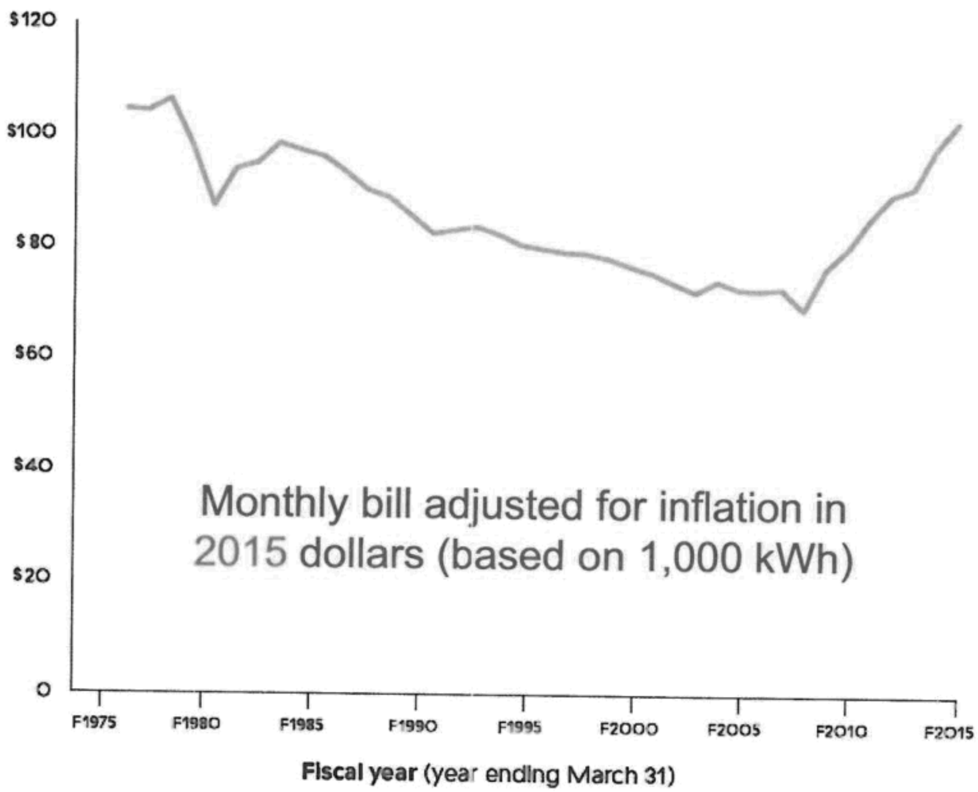


BC Hydro
Power smart

Adjusting for inflation, electricity costs the same today as it did back in 1976.



Inflation-adjusted average monthly residential bills	
1976	$104.55
2015	$102.92

BC Hydro
Power smart

We're doing everything we can to keep rates low for our customers.

BC Hydro
Power smart

Since 2013

+ Placeholder

- A lot has changed since the 10 Year Rates Plan was introduced (2013)
  - Commodity prices have gone down
  - Etc.
- Despite this we are not passing any of this on to customers

BC Hydro
Power smart

By finding **operational savings**, locking in low interest rates, prioritizing our spending, and optimizing our energy resources.

- ✓ From fiscal 2012 to fiscal 2014, we found **$391 million** in operating cost savings;
- ✓ In fiscal 2015 and fiscal 2016, BC Hydro found a further **$27 million** in savings that were reinvested in priority areas; and,
- ✓ This year, we've identified a further **$34 million** in cost reductions to be re-deployed to priority areas like **maintenance**, **capital project planning**, **storm response**, **customer service** and **safety**.
- ✓ We've limited base operating cost increases to an average of **1.2% per year** for fiscal 2017 to fiscal 2019

BC Hydro
Power smart

By finding operational savings, locking in low interest rates, prioritizing our spending, and optimizing our energy resources.

- ✓ We're managing our future debt in the best interest of our customers by taking advantage of historically low interest rates and locking them in.
- ✓ Expect to achieve approximately $45 million in savings over the next three years.

BC Hydro
Power smart

By finding operational savings, locking in low interest rates, prioritizing our spending, and optimizing our energy resources.

- ✓ We've prioritized our capital spending, reducing planned expenditures by about $380 million over the next 3 years. [to be confirmed]
- ✓ We've updated our conservation programs, reducing the average program cost to $22 per megawatt hour.
- ✓ Over the past 5 years, we've completed 563 capital projects at a total cost of $6.48 billion which is 0.18% under budget overall.

BC Hydro
Power smart

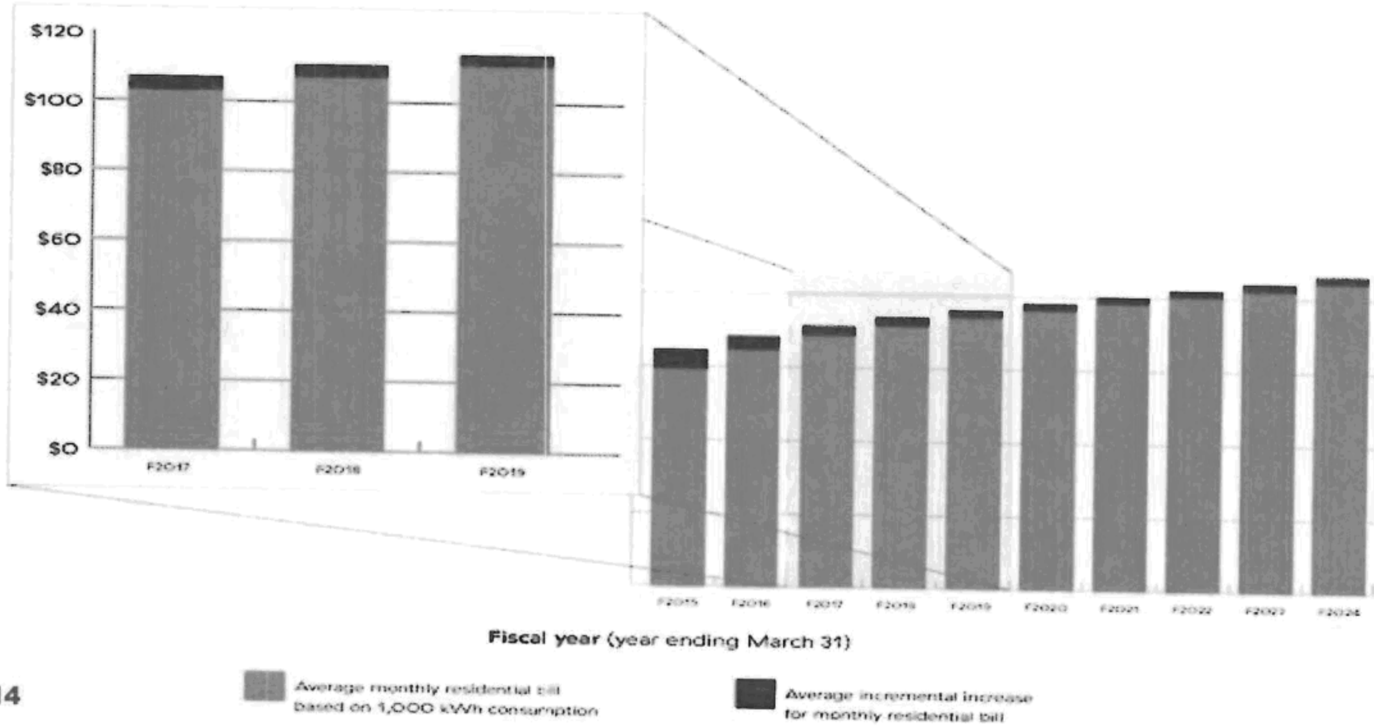
By finding operational savings, locking in low interest rates, prioritizing our spending, and optimizing our energy resources.

- ✓ We're taking a strategic approach to the renewal of contracts with independent power producers to secure renewal prices that are lower than current rates. All IPP renewals will be subject to BC Utilities Commission approval.
- ✓ We're reviewing the Standing Offer Program to reflect the declining cost of new power technology and to better meet system needs.

BC Hydro
Power smart

Keeping rates low and predictable

Over the next three years, rates will increase by 4%, 3.5% and 3%, consistent with the 10 Year Rates Plan.

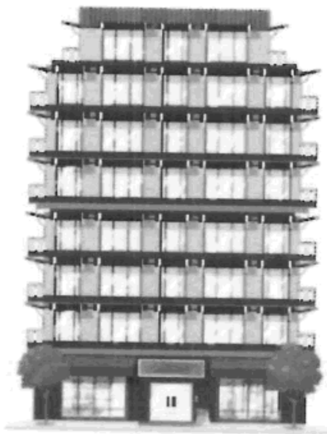


BC Hydro
Power smart

A 4% rate increase means...

$4.56

extra per month
for a family of four
living in a single-family
detached home.



$1.41

extra per month
for a single person
living in an apartment.

$2.88

extra per month
for a couple
living in a townhouse.

BC Hydro
Power smart

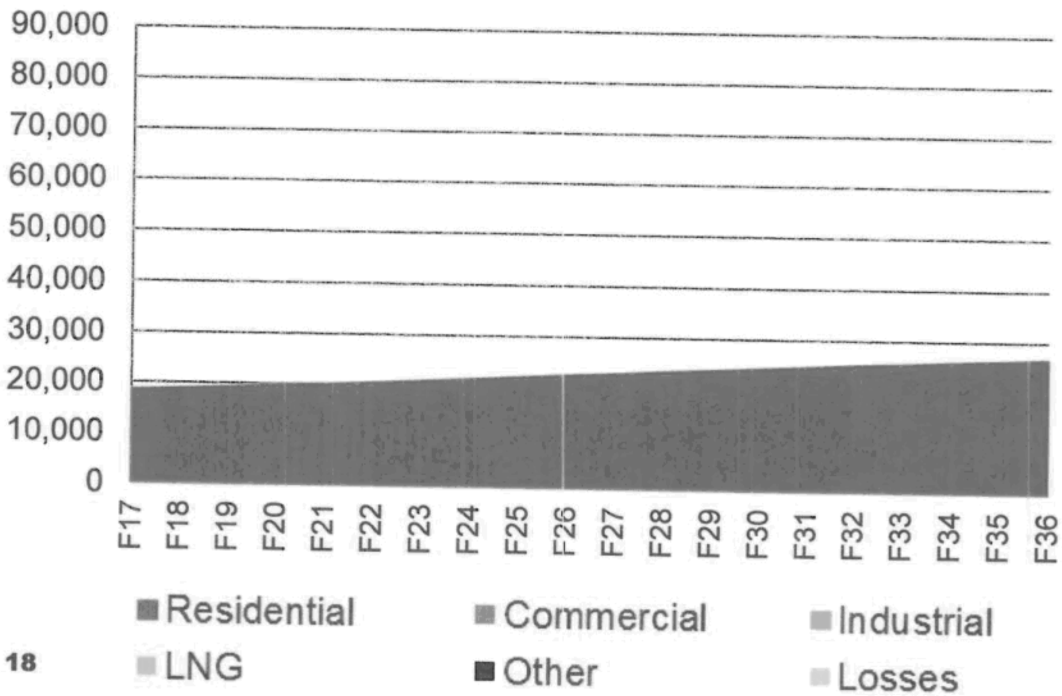
Demand for electricity is growing

While growth has slowed in the near term, we still expect significant growth in the long term. Demand is expected to grow by almost 40% over the next 20 years.

BC Hydro
Power smart

Long-term growth

We continue to forecast significant long-term growth in our load forecast for all customer sectors.

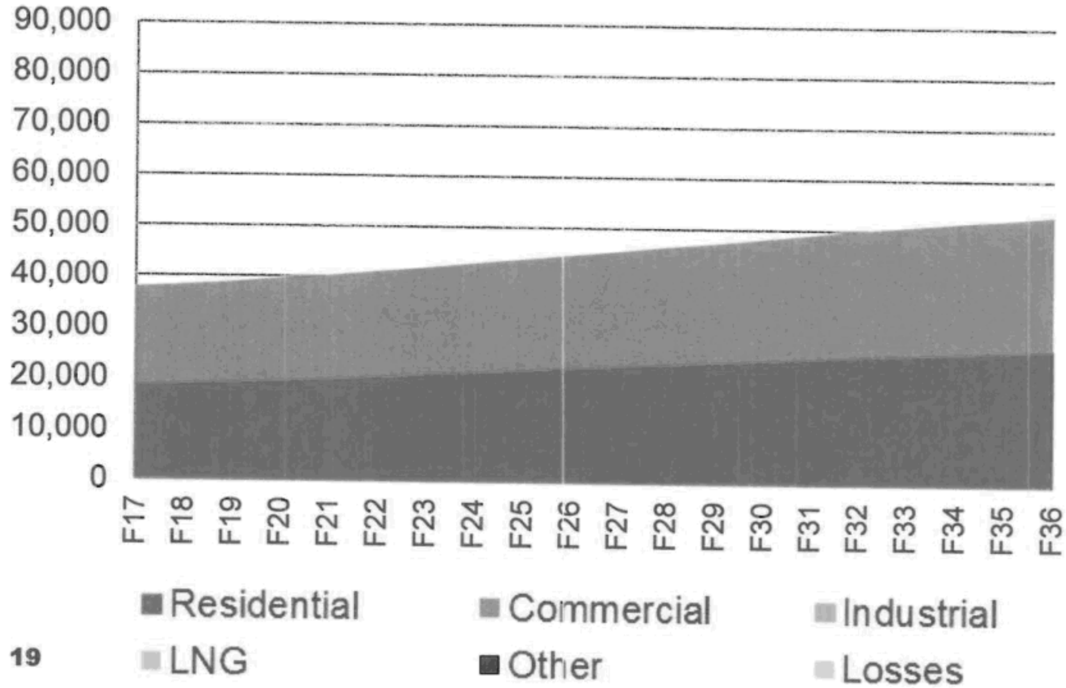


- BC's population is forecast to grow by over 1 million people to 5.8 million by 2035.
- Over 80,000 homes will be built in the next three years alone.

BC Hydro
Power smart

Long-term growth

We continue to forecast significant long-term growth in our load forecast for all customer sectors.

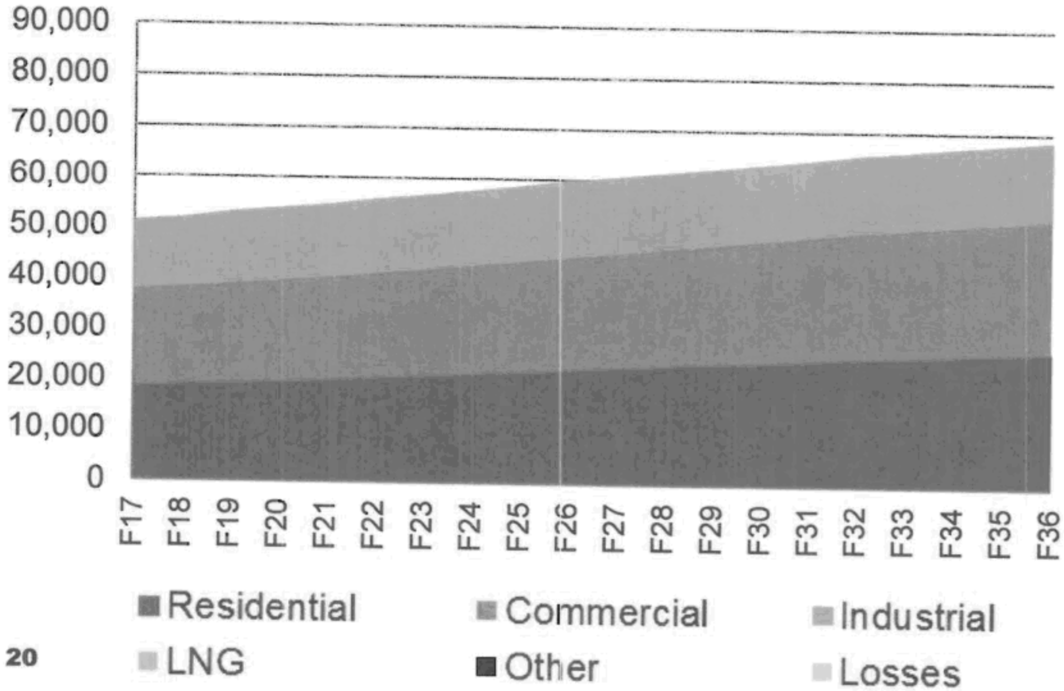


- BC's GDP growth is forecast to lead the country.
- *+ additional information*

BC Hydro
Power smart

Long-term growth

We continue to forecast significant long-term growth in our load forecast for all customer sectors.

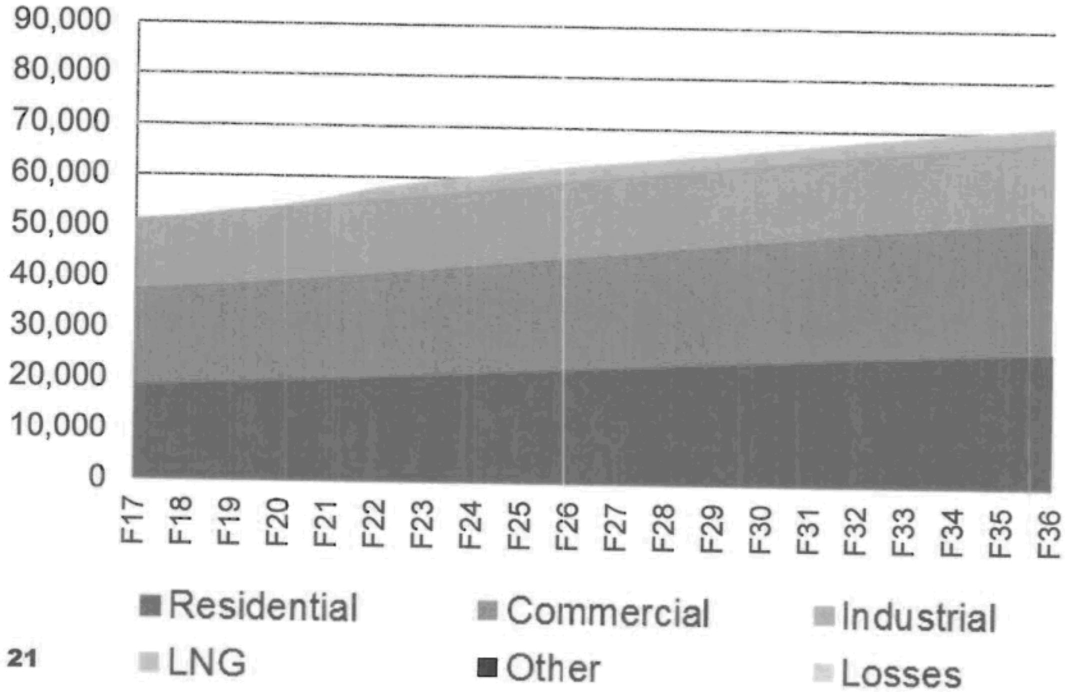


- B.C.'s mining sector's electricity consumption grew by 40% between fiscal 2012 and 2015.
- Oil & gas sector electricity consumption is up X since fiscal 2013 and is forecast to increase by nearly 15% over the next 3 years.

BC Hydro
Power smart

Long-term growth

We continue to forecast significant long-term growth in our load forecast for all customer sectors.

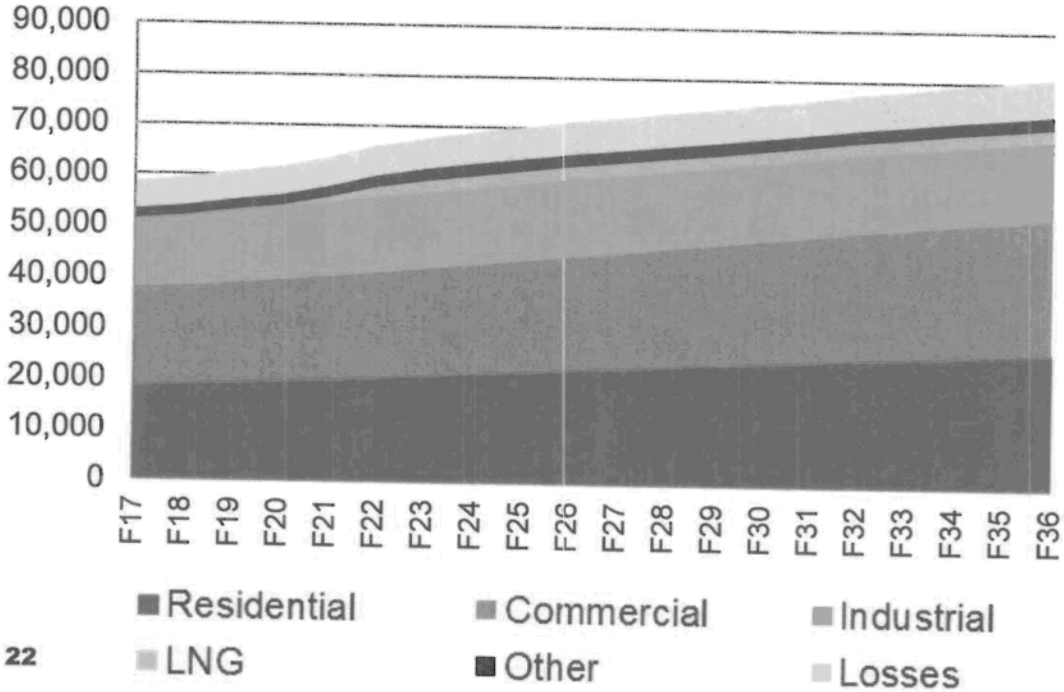


- Fortis Tilbury, LNG Canada and Woodfibre LNG have confirmed their intent take service from BC Hydro.

BC Hydro
Power smart

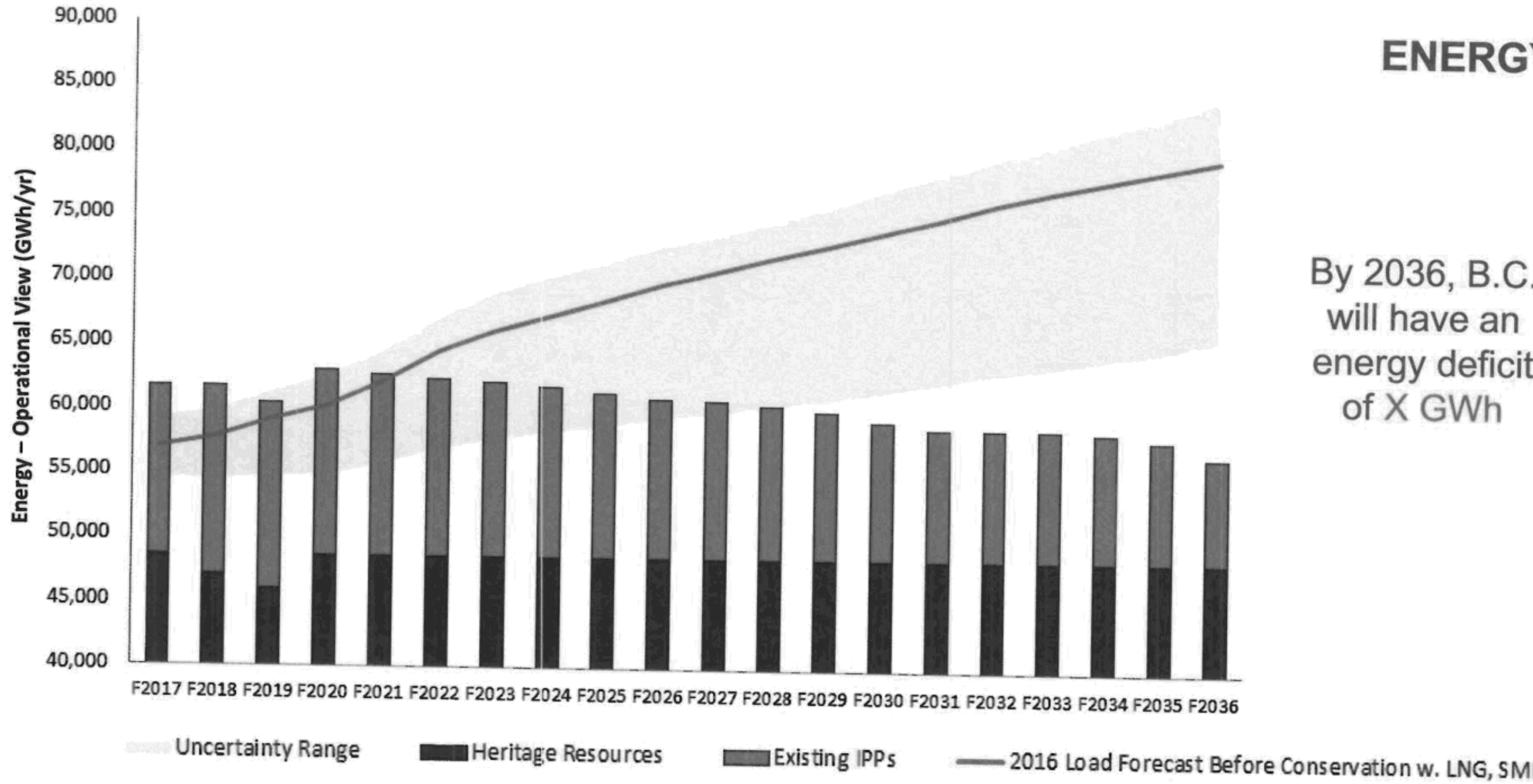
Long-term growth

We continue to forecast significant long-term growth in our load forecast for all customer sectors.



- Line losses & Other

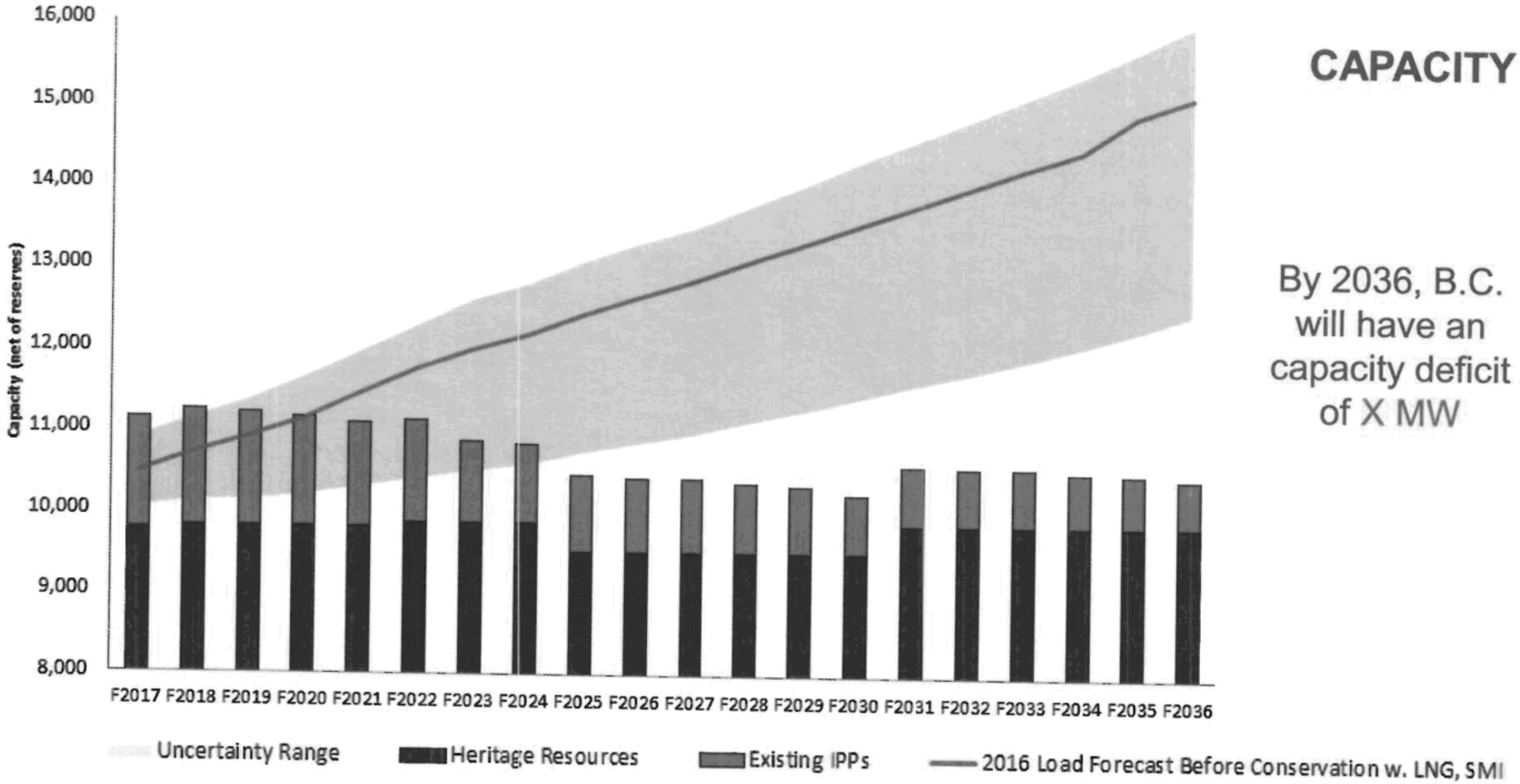
BC Hydro
Power smart



ENERGY

By 2036, B.C. will have an energy deficit of X GWh

BC Hydro
Power smart



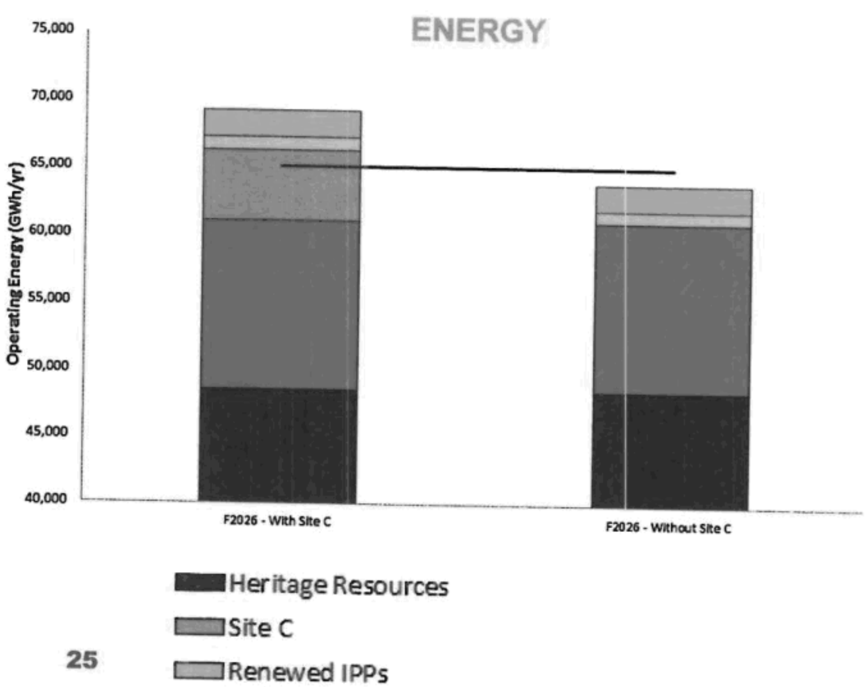
CAPACITY

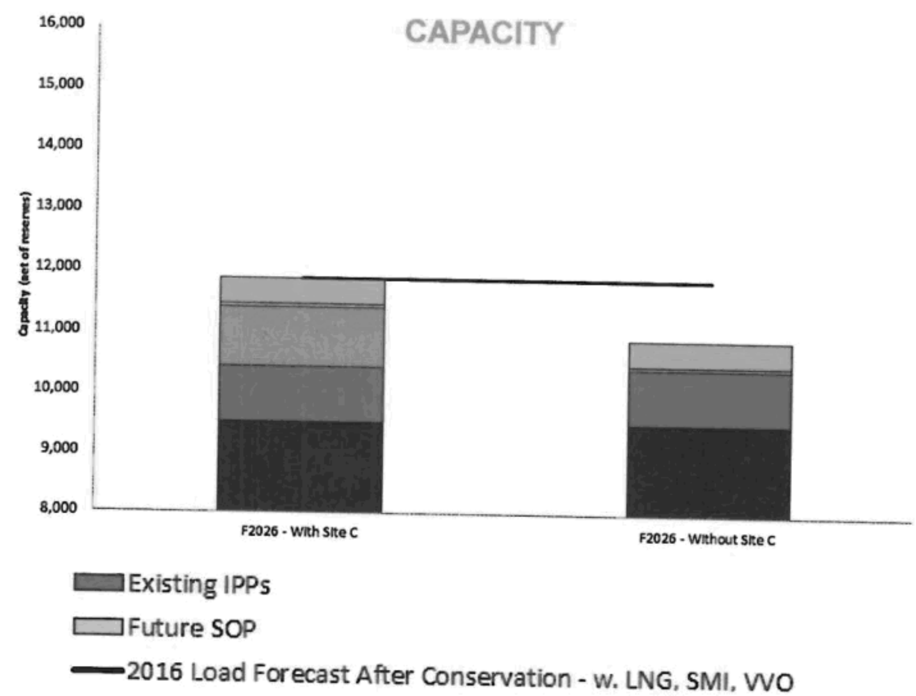
By 2036, B.C. will have an capacity deficit of X MW

BC Hydro
Power smart

Without Site C, British Columbia would have a capacity deficit of over 950 MW (8%) and an energy deficit of over 1100 GWh (2%) in fiscal 2026

This is equivalent to the energy needed to power ## homes.





Independent Power Producers

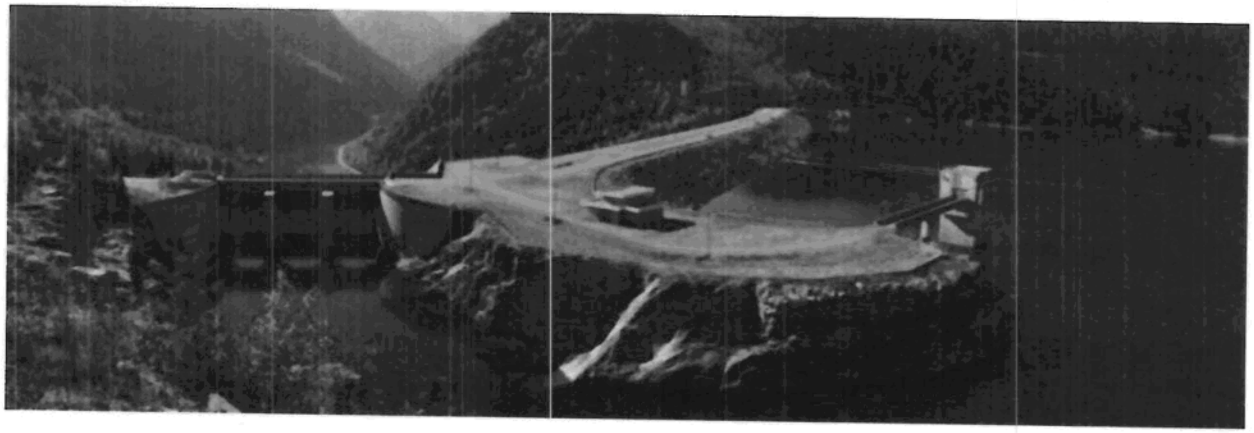
[Hold for: list of the IPP projects coming into commercial operation in F17 to F19]

Site C Clean Energy Project

- There are now more than **1,000 British Columbians** working on the Site C Clean Energy Project
- July marks one year since the beginning of construction
- The main civil works contract with Peace River Hydro Partners Main is valued at approximately $1.75 billion and will create 8,000 person-years of employment over the eight-year contract

BC Hydro
Power smart

Major Maintenance at Mica

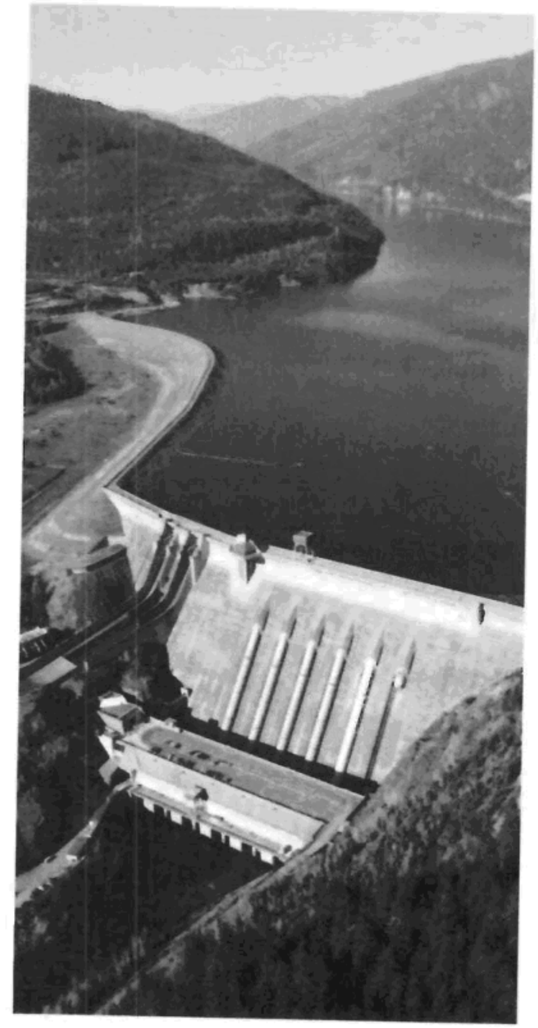


- Holding maintenance outages for Mica generating station units 1 to 4 until Site C comes online.
- It is currently estimated that the units will be out of service for **12 to 18 months each**.
- **410 MW** reduction in capacity for a period of approximately four to six years, which will advance BC Hydro's need for new capacity resources after Site C.

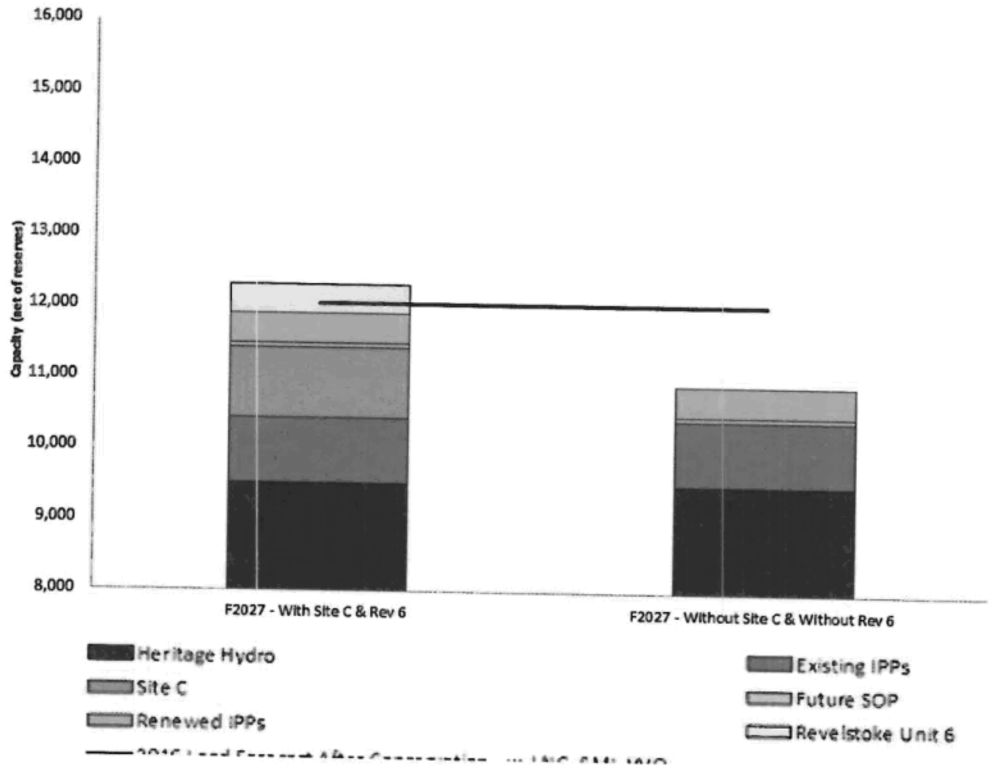
BC Hydro
Power smart

Revelstoke Unit 6 Project

- Starting planning work to install a sixth generating unit at Revelstoke Generating Station.
- Need Revelstoke Unit 6 by fiscal 2027.
- Unit 6 will provide another 500 megawatts of dependable capacity.



In fiscal 2027, without Site C and Revelstoke 6, British Columbia would have a capacity deficit of over 1100 MW (9%)



Spending money where it matters most

BC Hydro
Power smart

Building for the future

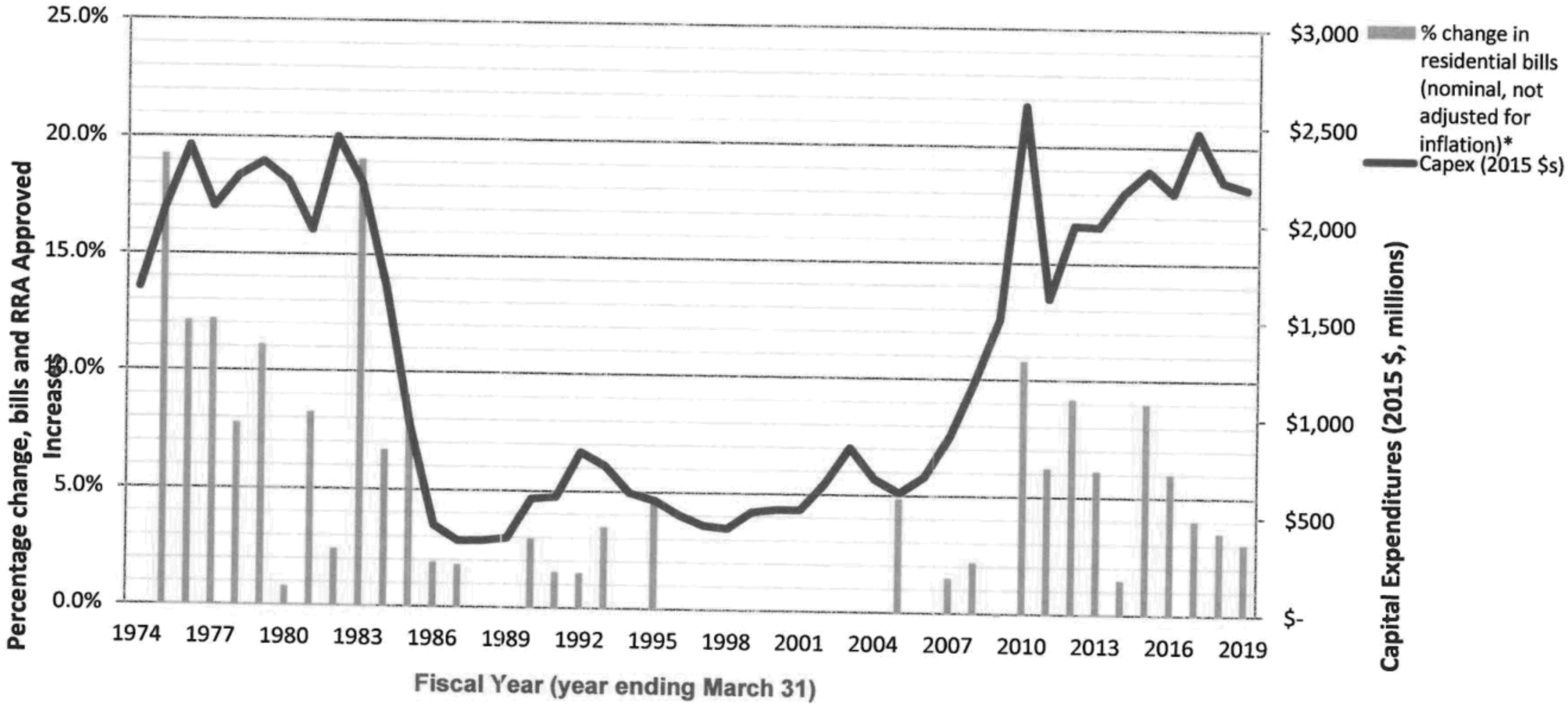
As our province grows, we are making necessary investments in the system.

- We are investing more than **$2 billion per year over the next 10 years** to upgrade aging assets and build new infrastructure.

- Over the next decade, BC Hydro's capital projects are expected to generate a total **provincial economic impact of $13 billion** and create over **100,000 person-years of employment**.

BC Hydro
Power smart

Residential Bill Increases and Capital Expenditures (1973 to 2018)

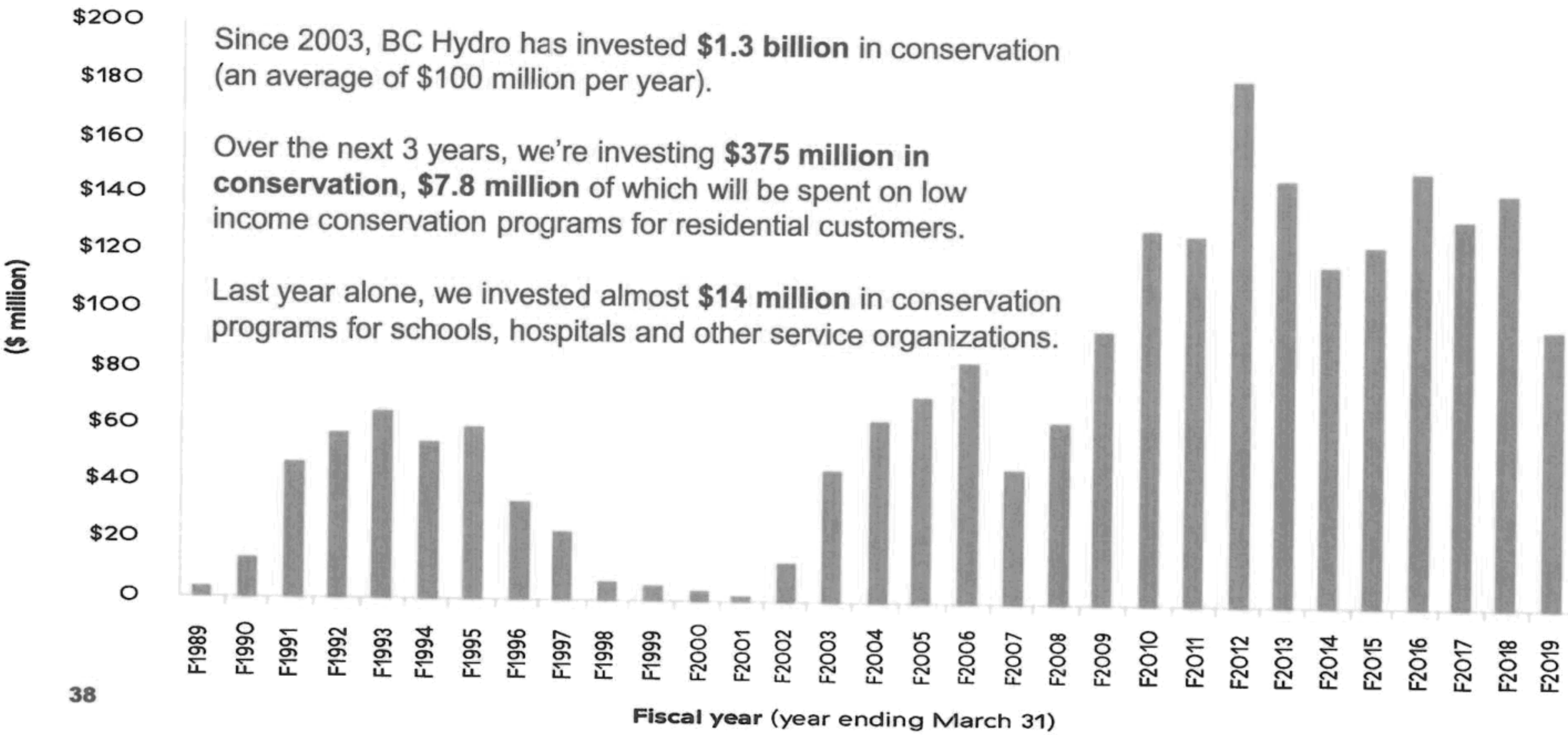


10 Year Cumulative Bill Impact:

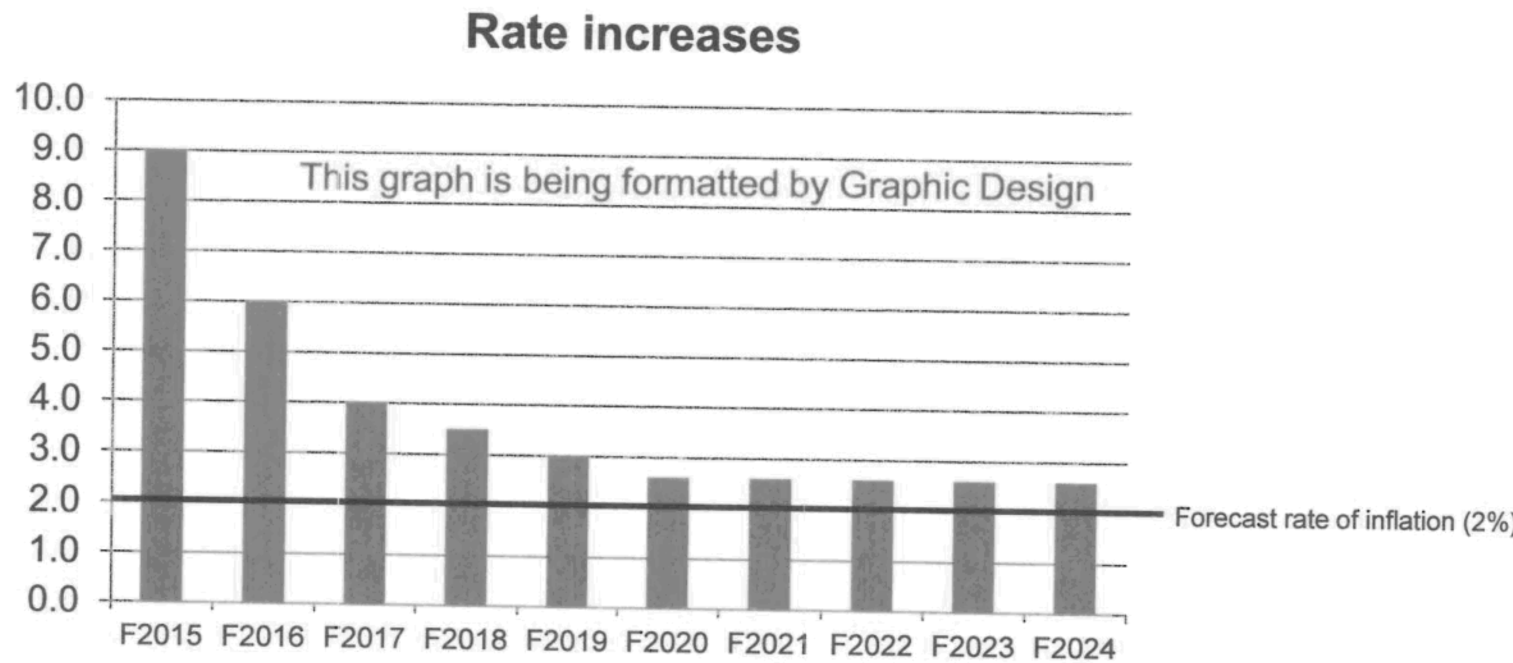
37

- 1973 to 1982 - 113% and 2008 to 2017 – 67%

Conservation Investment 1989 to 2019



On track to meet the 10 Year Rates Plan



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BC Hydro
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BC Hydro
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NR

SCHEDULE

1 *Part 10 of the Health, Safety and Reclamation Code for Mines in British Columbia is repealed and the following is substituted:*

TABLE OF CONTENTS

Definitions

"*best available technology*" means the site specific combination of technologies and techniques that most effectively reduce the physical, geochemical, ecological and social risks associated with tailings storage during all stages of operation and closure.

"*dam*" means a barrier on the surface preventing uncontrolled release of either water, slurry or solids or a barrier underground to prevent the uncontrolled flow of water, slurry or solids.

"*dump or stockpile*" means the accumulation of deposited rock fragments or other unconsolidated material

"*engineer of record*" means the Professional Engineer who is retained under section 10.1.5 (1) of this code.

"*environmental design flood*" means the hydrological event that is to be managed without release of untreated water to the environment.

"*fill*" means a deposit of discrete particles, either loose or well-compacted, placed in layers or dumped into a ravine, valley, or depression.

"*HSRC Guidance Document*" means the guidance document prepared by the chief inspector in consultation with the health safety and reclamation code committee for the purposes of this code.

"*impoundment*" means a body of water, slurry or solids that is confined by natural barriers or constructed dams and includes those barriers, dams and related items.

"*inflow design flood*" means the flood into the impoundment resulting from the design hydrologic event.

"*land capability*" means the capability of achieving a specified land use estimated by limitations as a result of climate, topography and soils.

"*landform*" means a designated structure that can be considered to have a risk profile similar to the surrounding environment.

"*major dump*" means a dump that contains a volume of dumped material that exceeds one million cubic metres, or has a dump height greater than 50 metres, or has an area that is covered by a dump that exceeds one hectare, or is founded upon natural or trimmed slopes that are sometimes steeper than 20 degrees from a horizontal plane, or contains material dumped or placed in a water course having a potential peak flow greater than one cubic metre per second, once in every 200 years, or any other mine dumps so declared the chief inspector.

"*overburden*" means all unconsolidated naturally occurring material overlying bedrock.

"*permit*" means a permit issued pursuant to section 10 (3) of the *Mines Act*.

"*probable maximum flood*" means the hypothetical most severe flood that may credibly be expected to occur at a particular location resulting from the seasonal maximum combination of precipitation and snowmelt.

"*qualified professional*" means an individual who

(a) is registered, and in good standing, with a professional organization in British Columbia governed under an enactment, and

(b) is acting within his or her area of professional expertise.

"*quantifiable performance objectives*" means measureable monitoring parameters that are identified and required to be maintained within predetermined limits for tailings storage facility safety.

"*surficial soil material*" means those soils commonly contained in the upper layers of the overburden mass, which are suitable for use in reclamation, either as growth medium, soil covers and seals, or other reclamation requirements.

"*tailings*" means the residue remaining from the preparation of a concentrate of minerals or coal.

"*tailings storage facility*" or "*TSF*" means a facility that stores tailings.

"*TSF qualified person*" means the person designated under section 10.4.2 (1) (b) of this code.

"*watercourse*" means a natural stream or source of water, whether usually containing water or not, and includes any lake, river, creek, spring, ravine, swamp, and gulch.

Mine Plan and Reclamation Program Information

Proposed Placer Mines, Gravel Pits and Quarries

10.1.1 (1) The proposed mine plan and reclamation program filed with the inspector in compliance with section 10 (1) of the *Mines Act*, shall consist of the appropriate Notice of Work forms together with such other information as the inspector may require, for approval of placer mining, sand and gravel pits, rock quarries and industrial mineral quarries.

(2) No work shall proceed without the inspector granting a permit or authorization or the chief inspector granting an exemption under section 10 (2) of the *Mines Act*.

Proposed Coal and Mineral Mines, Major Modifications to Existing Mines & Major Exploration and Development

Permit Application

10.1.2 (1) The owner, agent or manager shall submit in writing, an application to the chief inspector for a permit under section 10 (1) of the *Mines Act* for

(a) surface or underground development or production for coal and mineral mines, or major expansions or major modifications of existing producing coal and mineral mines, or

(b) underground exploration requiring excavation, large pilot projects, bulk samples, trial cargos or test shipments.

(2) No work shall proceed without the chief inspector granting a permit or authorization.

(3) The chief inspector shall determine the number of copies of the application required.

Application Requirements

10.1.3 The application shall include the following unless otherwise authorized by the chief inspector:

(a) a regional map showing the location of the mine property, along with a map or air photo showing the location and extent of the mine;

(b) the present use and condition of the land and watercourses including

(i) land ownership, including surface and mineral rights, licensed or permitted users such as water users, guides, outfitters, trappers and grazing licenses,

(ii) climate,

(iii) general geology and detailed geological descriptions of the deposit,

(iv) surface water and groundwater quality and flow,

(v) fisheries and aquatic resources,

(vi) air quality,

(vii) surficial geology and terrain mapping,

(viii) soil survey and soil characterization,

(ix) vegetation,

(x) wildlife,

(xi) land capability and present land uses such as agriculture, forestry, fisheries, wildlife, recreation, industrial, commercial and residential, and

(xi) inhabited places in the vicinity of the mine;

(c) established and asserted aboriginal and treaty rights;

(d) a mine plan including

(i) a map at a scale of 1:10,000 or less showing topographic contours, surface drainage features, claims, leases or licences, buildings, roads, railways, power transmission lines, pipelines, and other relevant features and the locations of all proposed or existing surface and underground mining developments, waste disposal areas, stockpiles, processing facilities, mine buildings and other mining related disturbances or infrastructure,

(ii) an inventory of areas disturbed to date, and projected over the next 5 years and over the projected life of the mine,

(iii) descriptions of mining methods, mining rates, projected mine life, processing methods and infrastructure requirements,

(iv) development schedule for construction and mine sequencing,

(v) detailed geology and ore reserves, and projected volumes of ore and waste to be produced and relative time of production,

(vi) designs and details for dumps, open pits, impoundments, underground workings including areas that may be affected by subsidence, stockpiles, processing facilities, water management structures, water storage and water treatment facilities, haulage roads, road construction and significant transportation or utilities infrastructure, compatible with environmental protection, reclamation and mine closure,

(vii) designs and details for tailings storage and a description of proposed quantifiable performance objectives,

(viii) designs for material handling and waste disposal procedures,

(ix) salvaging and stockpiling of surface soils and overburden materials,

(x) source, use and water balance for any water required in the operation,

(xi) overall site water balance, and

(xii) a traffic control procedure as required under section 6.8.3 of this code.

(e) a program for the environmental protection of land and watercourses during the construction and operational phases of the mining operation, including plans for

(i) prediction, identification and management of physical, chemical, and other risks associated with tailings storage facilities and dams,

(ii) prediction, and if necessary, prevention, mitigation and management of metal leaching and acid rock drainage,

(iii) erosion control and sediment retention, and

(iv) environmental monitoring and surveillance designed to demonstrate that

(A) the objectives of section 10.5.1 of this code are being met,

(B) the reclamation standards as outlined in section10.7 of this code are being met, and

(C) environmental protection of land and watercourses required under paragraph (f) (i) and (ii) of this section are being achieved and maintained,

(f) an alternatives assessment for the proposed tailings storage facilities that assesses best available technology,

(g) a conceptual reclamation plan for the closure or abandonment of all aspects of the mining operation, including

(i) plans for long term post-closure maintenance of facilities,

(ii) proposed use and capability objectives for the land and watercourses, and

(h) a closure plan for the tailings storage facility,

(i) an estimate of the total expected costs of outstanding reclamation obligations over the planned life of the mine, including the costs of long term monitoring and maintenance which, with the approval of the chief inspector, may be filed in a separate confidential report, and

(j) any other relevant information required by the chief inspector.

Design Standards

10.1.4 (1) Impoundments, tailings storage facilities and water management facilities and dams shall be designed by a Professional Engineer.

(2) The Professional Engineer shall develop design criteria for each facility referred to in subsection (1) that considers the HSRC Guidance Document.

(3) Site characterizations for support of the design of a tailings storage facility or dam shall be carried out by a Professional Engineer and in consideration of the HSRC Guidance Document.

Engineer of Record

10.1.5 (1) The manager shall ensure that a Professional Engineer is retained as the engineer of record for each tailings storage facility and dam under their management.

(2) The engineer of record, as a qualified professional, has professional responsibility for assuring that a tailings storage facility or dam has been designed and constructed in accordance with the applicable guidelines, standards and regulations.

(3) The manager shall notify the chief inspector of the retained engineer of record, of changes in the engineer of record, and the notification shall include an acknowledgement by the engineer of record.

Duty to Report Safety Issues at Tailings Storage Facilities

10.1.6 (1) The engineer of record shall immediately notify the manager in writing of any unresolved safety issue that compromises the integrity of a tailings storage facility.

(2) If the engineer of record and manager are unable to resolve the safety issue, the manager must report the issue to the chief inspector and provide a copy of the report to the engineer of record.

(3) If the manager does not provide the report under subsection (2) in a timely fashion, the engineer of record shall report the issue to the chief inspector.

Consequence Classification

10.1.7 The consequence classification for a tailings storage facility shall be determined by the engineer of record in consideration of the HSRC Guidance Document.

Seismic and Flood Design Criteria

10.1.8 (1) Seismic and flood design criteria for tailings storage facilities and dams shall be determined by the engineer of record based on the consequence classification determined under section 10.1.7 of this code in consideration of the HSRC Guidance Document, subject to the following criteria:

(a) for tailings storage facilities that store water or saturated tailings,

(i) the minimum seismic design criteria shall be a return period of 1 in 2475 years,

(ii) the minimum flood design criteria shall be a return period 1/3rd of the way between the 1 in 975-year event and the probable maximum flood, and

(iii) a facility that stores the inflow design flood shall use a minimum design event duration of 72 hours;

(b) for tailings storage facilities that cannot retain water or saturated tailings,

(i) the minimum seismic design criteria shall be a return period of 1 in 975 years, and

(ii) the water management design shall include an assessment of tailings facility erosion and surface water diversions as well as measures to prevent impounded tailings from becoming saturated that consider the consequence classification as determined under section 10.1.7 of this code.

(2) The environmental design flood criteria shall be determined by a Professional Engineer in consultation with other qualified professionals.

Design Slopes

10.1.9 For a tailings storage facility design that has an overall downstream slope steeper than 2H:1V, the manager shall submit justification by the engineer of record for the selected design slope and receive authorization by the chief inspector prior to construction.

Minimum Static Factor of Safety

10.1.10 For a tailings storage facility design that has a calculated static factor of safety of less than 1.5, the manager shall submit justification by the engineer of record for the selected factor of safety and receive authorization by the chief inspector prior to construction.

Breach and Inundation Study/Failure Runout Assessment

10.1.11 A tailings storage facility shall have a breach and inundation study or a failure runout assessment prior to commencing operation, or as required by the chief inspector.

Water Balance and Water Management Plan

10.1.12 (1) The manager shall ensure that a tailings storage facility has a water balance and water management plan for the permitted life of mine that is prepared by a qualified person.

(2) The manager shall notify the chief inspector if any unpermitted discharge of water occurs or is required.

Quantifiable Performance Objectives

10.1.13 The manager shall ensure that quantifiable performance objectives for a tailings storage facility are determined and reviewed by the engineer of record and the TSF qualified person.

Underground Openings and Workings

10.1.14 (1) Tailings storage facility designs that use underground openings shall comply with 6.14.1 of this code.

(2) Tailings storage facility designs shall consider the potential effects on and interactions with underground workings.

Major Dumps

10.1.15 A major dump shall be designed

(a) in consideration of the Interim Guidelines of the British Columbia Mine Waste Rock Pile Research Committee, and

(b) so as to allow for re-contouring such that final reclamation is consistent with the approved end land use.

Metal Leaching and Acid Rock Drainage

10.1.16 Plans for the prediction, and if necessary, the prevention, mitigation and management of metal leaching and acid rock drainage shall be prepared in consideration of the Guidelines for Metal Leaching and Acid Rock Drainage at Mine sites in British Columbia.

Preparation of Plans and Programs

10.1.17 Mine, environmental protection, reclamation and closure plans required under sections 10.1.1, 10.1.3, 10.1.16 and 10.6.3 of this code shall

(a) be prepared taking into consideration the health and safety of the public and persons involved in the work,

(b) be designed so as to make it as practicable as possible in the future to mine zones affected by the plan,

(c) be designed to protect the land and watercourses, and

(d) be prepared in consideration of the HSRC Guidance Document, by qualified professionals or persons who in the opinion of the chief inspector are qualified to perform the work.

Departure from Approval

10.1.18 The owner, agent or manager shall notify the chief inspector in writing of any intention to depart from the mine plan and reclamation program authorized under sections 10.1.1 or 10.1.3 of this code to any substantial degree; and shall not proceed to implement the proposed changes without the written authorization of the chief inspector.

Exceptions

10.1.19 (1) Sections 10.1.2 through 10.1.17 of this code do not apply to placer mines, sand and gravel pits, and quarries unless required by the chief inspector

(2) Sections 10.1.8, 10.1.9 and 10.1.10 of this code do not apply to mines with respect to which the chief inspector has received an application for a permit before the date on which this subsection comes into force.

Notice of Filing

Publication

10.2.1 When required by an inspector, notice of filing an application under section 10 (1) of the *Mines Act* shall be published, by the person filing it, in the Gazette and in local newspapers.

Written Response

10.2.2 Where a notice of filing has been published under section 10.2.1 of this code, a person affected by, or interested in, the application has 30 days after the last date on which the notice was published to view the application and make written representations to the chief inspector.

Referral of Permit Application to Other Agencies

Mine Development Review Committee

10.3.1 (1) The chief inspector may refer to the advisory committee or the regional advisory committee established pursuant to section 9 of the *Mines Act*, applications submitted under section 10.1.2 of this code and may, where the chief inspector considers it to be appropriate, refer any Notice of Work submitted under section 10.1.1 of this code.

(2) The advisory committee or regional advisory committee shall review every application referred to them and make recommendations to the chief inspector within 60 days following application.

(3) If no recommendations under subsection (2) have been received within 60 days, the chief inspector will deem that there are no concerns.

Circulation of Application

10.3.2 (1) If a permit application under section 10.1.1 of this code is not referred to a committee for review under section 10.3.1, an inspector may circulate it to other ministries and agencies and they will have 30 days following referral to make written representations to the inspector.

(2) If no written representations have been received within 30 days, the inspector will deem that there are no concerns.

Permit

10.3.3 A permit issued under section 10 (1) of the *Mines Act* shall take into consideration

(a) any written representations received under section 10.2.2 of this code,

(b) any recommendations made by a committee under section 10.3.1 of this code, and

(c) any written representations received under section10.3.2 of this code.

Permitted Sites

Updated Plans

10.4.1 (1) After commencement of operations, mine plans, including programs for reclamation and closure, shall be updated, at a minimum, every 5 years.

(2) Reclamation plans shall outline progressive reclamation activities for the 5 years following the date on which the plans are updated in accordance with subsection (1).

(3) After commencement of operations, the water balance and water management plans under section 10.1.11 of this code shall be reconciled annually and updated as required.

Governance

10.4.2 (1) The manager of a mine with one or more tailings storage facilities shall

(a) develop and maintain a Tailings Management System that considers the HSRC Guidance Document and includes regular system audits,

(b) designate a TSF qualified person for safe management of all Tailings Storage Facilities,

(c) establish an Independent Tailings Review Board, unless exempted by the chief inspector,

(d) review annually the tailings storage facility risk assessment to ensure that the quantifiable performance objectives and operating controls are current and manage the facility risks,

(e) maintain tailings storage facility emergency preparedness and response plans integrated into the Mine Emergency Response Plan required under section 3.7.1 of this code, and

(f) ensure document records for key information are maintained and readily available for tailings storage facilities..

(2) The composition of an Independent Tailings Review Board established under subsection (1) (c) shall be commensurate with the complexity of the tailings storage facility in consideration of the HSRC Guidance Document.

(3) The manager shall submit the terms of reference for the Independent Tailings Review Board including the qualifications of the board members to the chief inspector for approval.

(4) The terms of reference for the Independent Tailings Review Board shall be developed or updated as required in consideration of the review under subsection (1) (d).

Register of Tailings Storage Facilities and Dams

10.4.3 (1) The manager of a mine with one or more tailings storage facilities shall maintain a Register of Tailings Storage Facilities and Dams.

(2) The register shall be reviewed and updated at least annually.

Annual Reporting

10.4.4 The owner, agent or manager shall submit one or more annual reports in a summary form specified by the chief inspector or by the conditions of the permit by March 31 of the following year on the following:

(a) reclamation and environmental monitoring work performed under section 10.1.3 (e) of this code;

(b) tailings storage facility and dam safety inspections performed under section 10.5.3 of this code;

(c) a report of the activities of the Independent Tailings Review Board established under section 10.4.2 (1) (c) of this code that describes the following:

(i) a summary of the reviews conducted that year, including the number of meetings and attendees;

(ii) whether the work reviewed that year meets the Board's expectations of reasonably good practice;

(iii) any conditions that compromise tailings storage facility integrity or occurrences of non-compliance with recommendations from the engineer of record;

(iv) signed acknowledgement by the members of the Board, confirming that the report is a true and accurate representation of their reviews;

(d) a summary of tailings storage facility and dam safety recommendations including a scheduled completion date;

(e) performance of high-risk dumps under section 10.5.5 of this code;

(f) updates to the tailings storage facilities register as required;

(g) other information as directed by the chief inspector.

Other Reporting

10.4.5 The owner, agent or manager shall submit the following periodic reports with the annual reporting in a form specified by the chief inspector or by the conditions of the permit by March 31 of the year following their completion:

(a) mine plan, reclamation plan and closure plan updates under section 10.4.1 of this code;

(b) dam safety review reports performed under section 10.5.4 of this code;

(c) "as built" reports for tailings storage facilities and dams under section 10.5.1 of this code.

Operations

Construction of Tailings and Water Management Facilities

10.5.1 (1) The manager shall submit issued for construction drawings, specifications and quality assurance/quality control plans as well as a summary construction schedule to the chief inspector prior to commencing construction of a tailings storage or water management facility.

(2) The manager shall ensure that the initial operation of a tailings storage or water storage facility does not commence until an "as built" report under subsection (3) certifying that the facility was designed in accordance with this code and constructed according to design has been submitted to the chief inspector and a permit has been received.

(3) The manager shall prepare "as built" reports for each stage of construction of a tailings storage or water storage facility that include, as a minimum, the following:

(a) geotechnical foundation conditions;

(b) geometry;

(c) quality assurance/quality control data prepared by a Professional Engineer.

(4) The manager shall ensure that the engineer of record has certified that the tailings storage facility or dam has been constructed in a manner consistent with the design and specifications and that the structures are suitable for the intended use.

Operations, Maintenance and Surveillance (OMS) Manual

10.5.2 (1) An Operations, Maintenance and Surveillance Manual shall be prepared by one or more qualified person and submitted to the chief inspector prior to operation of the Tailings Storage Facility or dam.

(2) The Operations, Maintenance and Surveillance Manual shall be reviewed by the engineer of record and approved by the manager prior to implementation.

(3) All employees involved in the operation of a tailings storage facility or dam shall be trained and qualified, based on the OMS requirements, prior to commencing work at the facility.

(4) The Operations, Maintenance and Surveillance Manual shall be reviewed annually and revised as required during operations of a tailings storage facility or dam.

Annual Dam Safety Inspection

10.5.3 Tailings storage and water management facilities and associated dams shall be inspected annually and a report shall be prepared by the engineer of record in consideration of the HSRC Guidance Document

Dam Safety Reviews

10.5.4 A Dam Safety Review Report on the tailings storage, water management facilities and associated dams shall be prepared by an independent Professional Engineer in consideration of the HSRC Guidance Document at least every 5 years or as directed by the chief inspector.

Major Dumps

10.5.5 Major dumps shall be operated and monitored in accordance with the Interim Guidelines of the British Columbia Mine Waste Rock Pile Research Committee

Spontaneous combustible material

10.5.6 Material with a high probability of spontaneous combustion shall be placed in a separate dump.

Materials Inventory

10.5.7 (1) Where required for the control of metal leaching and acid rock drainage, the owner, agent or manager shall maintain an inventory of identified material that includes

(a) composition, mass, volume, surface area, and storage locations,

(b) history and timing of excavation,

(c) monitoring data, and

(d) any other information required by the chief inspector.

(2) Upon closure, the manager shall submit the material inventory to the chief inspector.

Excavations Near Property Boundaries

10.5.8 The excavation of soil material such as clay, silt, earth, sand or gravel, in a surface mine shall not be carried on within a setback distance of at least 5 metres horizontal from the vertical plane of the property boundary, and

(a) there shall be no excavation of soil material below a surface sloping downwards into the property from the inside edge of the setback no steeper than 1.5 horizontal to 1 vertical, and

(b) material that sloughs from within this distance shall not be removed without the written approval of the inspector.

Excavation before April 1, 1997

10.5.9 The chief inspector may direct that any excavation that exists in soil materials on or before April 1, 1997 will not be considered to be out of compliance for not meeting setback requirements providing that all further excavation is conducted in a manner consistent with the requirements of section 10.5.8 of this code.

Alternative setbacks and slopes

10.5.10 Notwithstanding sections 10.5.8 and 10.5.9 of this code, the chief inspector may approve a mine plan, prepared by a Professional Engineer, with alternative setbacks and slopes that ensure that the property boundary will be adequately protected.

Rock excavation

10.5.11 Rock shall not be excavated within a distance of 5 m from the property boundary.

Waiver by adjoining property owners

10.5.12 The owners of adjoining properties may, be agreement in writing, waive the provisions of sections 10.5.8, 10.5.9 and 10.5.11 of this code.

Mine Closure

Notice Required

10.6.1 The owner, agent, or manager shall provide written notice of not less than 7 days to an inspector of intention to stop work in, on, or about a mine.

Cessation of operations

10.6.2 (1) If a mine ceases operation, the owner, agent, or manager shall

(a) continue to carry out the conditions of the permit, and

(b) carry out a program of site monitoring and maintenance.

(2) If a mine ceases operation for a period longer than one year, the owner, agent, or manager shall

(a) apply for an amendment to the permit setting out a revised program for approval by an inspector,

(b) identify the hazards and provide detailed engineered plans and drawings respecting the hazards to local emergency agencies, and update the drawings as required, and

(c) if practicable, make the plans and drawings available on site in a conspicuous location.

Filing of Plans

10.6.3 (1) On the closure of a mine, the owner, agent or manager shall, within 90 days, file with the chief inspector accurate drawings, on a scale consistent with good engineering practice, showing

(a) on a plan view

(i) the surface and underground workings of the mine up to the time of closure and the boundaries of the mineral claims, licenses, or leases in which the workings are situated, and

(ii) identification of underground workings that come to within 25 meters of the surface,

(b) a general long section and several cross section views of the surface and underground mine workings, and

(c) any other plans that may be requested by the chief inspector.

(2) The filed plans shall be preserved as a permanent record in the office of the chief inspector.

Securing of Openings

10.6.4 When a mine is closed for an indefinite period, or otherwise left unattended for any length of time, the owner, agent or manager shall take all practicable measures to prevent inadvertent access to mine entrances, pits and openings that are dangerous by reason of their depth or otherwise, by unauthorized persons and ensure that the mine workings and fixtures remain secure.

Major Dumps

10.6.5 The long-term stability of exposed slopes of any major dump shall meet the criteria provided in the Interim Guidelines of the British Columbia Mine Waste Rock Pile Research Committee at the time of permitting or as amended by the chief inspector.

Impoundments

10.6.6 (1) The long-term stability of exposed slopes of impoundments shall meet the criteria provided in the design at the time of permitting or as determined by the engineer of record.

(2) Impoundments not operated for a period of 12 or more months may be declared as closed by the chief inspector.

Closure of a tailings storage facility or dam

10.6.7 (1) Prior to closure or upon declared closure of a tailings storage facility or dam, the manager shall submit a final detailed closure plan to achieve the approved end land and water use objectives.

(2) The closure plan shall include a detailed construction cost estimate, schedule and monitoring plan for implementation.

(3) The closure plan shall be prepared by one or more qualified professionals in consideration of the HSRC Guidance Document.

Tailings Storage Facility Closure OMS Manual

10.6.8 (1) The manager shall submit a Tailings Storage Facility Operations, Maintenance and Surveillance Manual for closure and review and update the plans regularly to reflect significant ongoing changes during closure.

(2) The Tailings Storage Facility Operations, Maintenance and Surveillance Manual shall include requirements for monitoring and shall define appropriate resources and staffing to carry out the works and monitoring associated with closure.

On-going Management Requirements

10.6.9 Where a mine requires on-going mitigation, monitoring or maintenance, the owner, agent, or manager shall submit a closure management manual that

(a) describes and documents key aspects of the ongoing mitigation, monitoring and maintenance requirements, and

(b) tracks important changes to components of the system that effect long-term mitigation, monitoring and maintenance requirements.

Permanent Spillways

10.6.10 Permanent spillways shall be designed by a Professional Engineer in consideration of the HSRC Guidance Document and installed prior to the completion of closure of the tailings storage facility or dam.

Permit amendment or variance after closure

10.6.11 The manager of a tailings storage facility or dam that has completed closure but not achieved the release of permit obligations may apply for permit amendments or variances including but not limited to reduced frequency of monitoring, dam safety inspections and dam safety reviews.

Landforms

10.6.12 The manager of a tailings storage facility or dam that can be considered a landform may apply to the chief inspector for the release of permit obligations under the *Mines Act*.

Reactivation of Impoundment

10.6.13 The owner, agent or manager may make an application for a permit to reactivate a closed or abandoned impoundment.

Decommissioning of Water Structures

10.6.14 A water reservoir or pond which is closed or declared inoperative by the chief inspector shall be breached or otherwise disposed of in accordance with the license under the *Water Sustainability Act* or permit under the *Environmental Management Act*.

Security

10.6.15 On the closure of a mine, and on the chief inspector being satisfied that some or all the conditions of the permit have been complied with, the person who deposited a security under section 10 (4) or 10 (5) of the *Mines Act* shall be entitled to refund of some or all of the security and any accumulated interest, less any amount paid out under section 10 (8) of the *Mines Act*.

Application for security release

10.6.16 An application for security release or a partial security release, that details the reclamation activities that have been completed under the requirements of the act, the code, and approved reclamation plan, shall be submitted to the chief inspector.

Reclamation Standards

Reclamation Defined

10.7.1 It is the duty of every owner, agent, and manager to institute and, during the life of the mine, to carry out a program of environmental protection and reclamation, in accordance with the standards described in section 10.7.4 to 10.7.21 of this code.

Pre-legislation Disturbances

10.7.2 Where environmental disturbance occurred at a site prior to the enactment of reclamation legislation in 1969, and has remained inactive since this time, the portion of environmental disturbance, which occurred before the enactment of reclamation legislation in 1969, is exempt from the re-vegetation provisions.

Exclusions

10.7.3 A reclamation standard prescribed under section 10.7.4 to 10.7.21 of this code does not apply where

(a) a mine is specifically excluded by a condition of its permit from complying with a particular standard, or

(b) a disturbance created by a mining activity has been reclaimed, inspected, and found to be satisfactory to an inspector.

Land Use

10.7.4 The land surface shall be reclaimed to an end land use approved by the chief inspector that considers previous and potential uses.

Capability

10.7.5 Excluding lands that are not to be reclaimed, the average land capability to be achieved on the remaining lands shall be similar to the average that existed prior to mining, unless the land capability is not consistent with the approved end land use or compromises long-term physical and/or geochemical stability.

Long Term Stability

10.7.6 Land, watercourses and access roads shall be left in a manner that ensures long-term physical and geochemical stability.

Re-vegetation

10.7.7 On all lands to be re-vegetated, land shall be re-vegetated to a self-sustaining state using appropriate plant species.

Growth Medium

10.7.8 On all lands to be re-vegetated, the growth medium shall satisfy land use, capability, and water quality objectives. All surficial soil materials removed for mining purposes shall be saved for use in reclamation programs unless these objectives can be otherwise achieved.

Landforms

10.7.9 Where practicable, land and watercourses shall be reclaimed in a manner that is consistent with the adjacent landforms.

Structures and Equipment

10.7.10 Prior to abandonment, and unless exempted by the chief inspector,

(a) all machinery, equipment and building superstructures shall be removed,

(b) concrete foundations shall be covered and re-vegetated, and

(c) all scrap material shall be disposed of in a manner acceptable to an inspector.

Dumps

10.7.11 Dumps shall be reclaimed to ensure long-term stability, and long-term erosion control.

Watercourses

10.7.12 Watercourses shall be reclaimed to a condition that ensures

(a) drainage is restored either to original watercourses or to new watercourses that will sustain themselves without maintenance, and

(b) the level of productive capacity shall not be less than existed prior to mining, unless the owner, agent or manager can provide evidence which demonstrates, to the satisfaction of the chief inspector, the impracticality of doing so.

Open Pits

10.7.13 (1) Pit walls constructed in overburden shall be reclaimed in the same manner as dumps unless an inspector is satisfied that to do so would be unsafe or conflict with other proposed land uses.

(2) Pit walls including benches constructed in rock, or steeply sloping footwalls, are not required to be re- vegetated.

(3) Where the pit floor is free from water, and safely accessible, vegetation shall be established.

(4) Where the pit floor will impound water and it is not part of a permanent water treatment system, provision must be made to create a body of water where use and productivity objectives are achieved.

Blocking Access Roads

10.7.14 All access roads to surface areas of the mine that may be dangerous shall be effectively blocked to prevent inadvertent vehicular access.

Securing openings

10.7.15 (1) All shafts, raises, stope openings, adits, or drifts opening to the surface shall be either capped with a stopping of reinforced concrete or filled with material so that subsidence of the material will not pose a future hazard.

(2) In the case of shafts or raises, the stopping shall be secured to solid rock or to a concrete collar secured to solid rock and capable of supporting a uniformly distributed load of 12 kPa or a concentrated load of 24 kN, whichever is greater.

(3) Where there is evidence or a potential for use by wildlife, mine openings may be fitted with a barrier that allows wildlife passage but prevents human entry.

Drains

10.7.16 When mine openings are permanently closed and where it may be possible for mine water to build dangerous pressures and cause a blow-out of the fill or concrete with sudden and dangerous force, a permanent and effective drain shall be installed.

Metal Uptake

10.7.17 When required by the chief inspector, vegetation shall be monitored for metal uptake.

Ecological Risk Assessment

10.7.18 (1) When required by the chief inspector, the owner, agent or manager shall commission an ecological risk assessment.

(2) Where there is a significant ecological risk, reclamation procedures shall ensure that levels are safe for plant and animal life and, where this cannot be achieved, other measures shall be taken to protect plant and animal life.

Disposal of Chemicals and Reagents

10.7.19 Chemicals or reagents, which cannot be returned to the manufacturer, shall be disposed of in compliance with municipal, regional, provincial and federal statutes.

Water Quality

10.7.20 If water quality from any component of the mine results in exceedances of applicable provincial water quality standards in the receiving environment, when required by the chief inspector, remediation strategies shall be implemented for as long as is necessary to mitigate the problem.

Monitoring

10.7.21 The owner, agent, or manager shall undertake monitoring programs, as required by the chief inspector, to demonstrate that reclamation and environmental protection objectives including land use, productivity, water quality and stability of structures are being achieved.

Release of Obligations

10.7.22 If all conditions of the Act, code and permit have been fulfilled to the satisfaction of the chief inspector and there are no on-going inspection, monitoring, mitigation or maintenance requirements, the owner, agent or manager will be released from all further obligations under the *Mines Act*.

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s.12;s.14;s.13

BRITISH COLUMBIA

NEWS RELEASE

For Immediate Release
004
Feb. 3, 2000

Ministry of Employment and Investment

HYDRO RATE FREEZE WILL BE EXTENDED UNTIL SEPTEMBER 2001

VICTORIA — British Columbians will continue to enjoy some of the lowest electricity rates in North America until Sept. 30, 2001, Mike Farnworth, minister responsible for BC Hydro, said today in announcing plans to extend the current rate freeze beyond March 31 of this year.

"BC Hydro rates have not increased since 1993, and the inflation-adjusted cost of electricity for its customers has actually decreased by 5.9 per cent since then," he said. "By maintaining competitive electricity rates and reliable service, we are making sure our investment climate is stable and positive so we can create more jobs for British Columbians."

Farnworth noted BC Hydro is well positioned to meet British Columbians' power needs over the next 10 years at competitive rates, based on existing power production and the construction of more facilities planned and under way around the province. He referred to the detailed BC Hydro supply and demand forecasts available in its update to the 1995 Integrated Electricity Plan released earlier this week.

"As an added assurance to its customers, BC Hydro is setting aside funds in the rate stabilization account during high-income years to offset the potential of rate increases in lower-income years," Farnworth said.

"However, I am serving notice that today's rates will not be extended beyond September 30, 2001, unless the B.C. Utilities Commission approves them," Farnworth added. "BC Hydro will begin preparations for rate hearings before the commission."

Farnworth said that the government plans to address a number of issues relating to the structure and regulation of BC Hydro in advance of those hearings, including co-ordination of BC Hydro's activities with the goals of the provincial green economy initiative. The initiative is a long-term provincial strategy to grow B.C.'s environmental industry and promote sustainable development.

He noted that while British Columbians want the lowest possible electricity rates, they also want the utility company they own to make a fair return on the province's resources and investments to help provide services — such as health care and education — for all British Columbians.

He said he expects the hearings to include arguments that rates should be lowered, as well as arguments that lowering rates could reduce investment in energy efficiency and conservation.

- more -

BRITISH COLUMBIA

Backgrounder

BC Hydro Rate Freeze

Rate freeze:

- BC Hydro rates have not increased since 1993.
- In April 1998, the BC Hydro and Power Authority Rate Freeze and Profit Sharing Act froze all BC Hydro rates until March 31, 2000.
- BC Hydro rebated $32 million to customers — two per cent for residential and one per cent for commercial and industrial — after the rate freeze came into effect.
- Due to high water conditions and strong market prices, BC Hydro forecasts a $98-million contribution to the rate stabilization account in 1999-2000 to offset potential future rate increases.
- The B.C. Utilities Commission will resume full responsibility for regulatory oversight of BC Hydro rates after the freeze extension expires on Sept. 30, 2001.

Competitive hydro rates:

- Because BC Hydro rates have not increased since 1993 and with 5.9 per cent inflation since 1993, the real cost of electricity for BC Hydro customers has actually gone down.
- By comparison, market prices for electricity have increased in the last three years. BC Hydro's power consumers at present pay about $400 million per year less than the market value of the electricity they consume.
- BC Hydro rates are extremely competitive, according to U.S. Department of Energy (1997) and Hydro Quebec (1999) studies. Among selected major North American cities, BC Hydro is consistently rated among the top three utilities for price competitiveness. In May 1999, BC Hydro was ranked:
    - *Third lowest* after Winnipeg and Montreal in its rate for residential customers (1,000 kWh/month).
    - *Third lowest* after Seattle and Winnipeg for small power customers (10,000 kWh/month).
    - *Lowest* for medium power customers (100,000 kWh/month); *second lowest* after Seattle (400,000 kWh/month) and *second lowest* after Winnipeg (1,170,000 kWh/month).
    - *Second lowest* after Winnipeg for large power customers (30,600,000 kWh/month) and tied with Montreal for *third lowest*, after Winnipeg and Edmonton (3,060,000 kWh/month).
- B.C.'s industries have a competitive advantage in national and international markets in terms of power costs.
- Even with some of the lowest electricity rates in the world, BC Hydro can make a fair return on the province's resources and investments to its owners — all British Columbians — through water rentals, dividends, taxes and grants. This return helps to provide services, such as health care and education, for all British Columbians.

HONOURABLE PAUL RAMSEY
MINISTER OF FINANCE AND
CORPORATE RELATIONS

BILL 3 -- 2000

BUDGET MEASURES IMPLEMENTATION ACT, 2000

HER MAJESTY, by and with the advice and consent of the Legislative Assembly of the Province of British Columbia, enacts as follow:

Hydro Rate Freeze

Hydro rate freeze

98 Despite the *Utilities Commission Act,* the rates and rate schedules that were in effect on December 10, 1997 and that are prescribed by B.C. Reg. 190/98 are the only lawful, enforceable and collectable rates that the British Columbia Hydro and Power Authority may collect, charge or enforce from December 10, 1997 to September 30, 2001 for the services to which those rates apply.

Explanatory Notes

Hydro Rate Freeze

SECTION 98: ***[Hydro rate freeze]*** extends the freeze on hydro rates until September 30, 2001.

Vancouver Sun, Page F01, Friday, February 4, 2000

B.C. Hydro rates to stay frozen until fall 2001

The Province

Vancouver Province, Page A04, Friday, February 4, 2000

Industrial customers cool to Hydro rate freeze

By Brian Lewis, Staff Reporter

Victoria Times Colonist, Page A01, Friday, February 4, 2000

Hydro rates to stay frozen despite heat from activists

By Malcolm Curtis

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BRITISH COLUMBIA

NEWS RELEASE

For Immediate Release
03/01
Feb. 7, 2001

Office of the Premier
Ministry of Finance and Corporate Relations

B.C. HELPS FAMILIES WITH ENERGY COSTS, CONSERVATION
Surplus and debt repayment forecast remain on track

VICTORIA – B.C. families will receive up to $300 in energy rebates and will be eligible for rebates on energy conservation products as part of a $404-million rebate and conservation package announced today by Premier Ujjal Dosanjh and Finance Minister Paul Ramsey.

"Increased energy costs are hurting many B.C. families," the premier said. "Today we are taking steps to help British Columbians with their energy costs in the short term and to reduce their energy use and costs in the long term.

"High energy prices have allowed us to make major new investments in health care while forecasting a budget surplus," Dosanjh added. "We want to help B.C. families make ends meet, especially those who have the tightest household budgets."

"In the second quarterly report, the Finance Ministry forecast a $625-million surplus and B.C.'s first decline in its debt for more than a decade," said Ramsey. "Given the state of public finances, we are able to offer this short- and long-term assistance while keeping our surplus and debt-reduction forecast intact."

The energy rebate and conservation package includes:

- A $200 credit on the electricity bills of all B.C. residential customers, worth roughly 30 per cent of the average residential customer's annual bill: $305 million.
- An income-tested rebate of $50 per single person or $100 per family: $78 million.
- Grants to B.C.'s public schools, hospitals, colleges and universities to ensure rising energy costs don't interfere with the quality of health care or education: $21 million.
- An enhanced BC Hydro Power Smart program offered in co-operation with B.C.'s private electric and gas utilities to help British Columbians identify energy savings in their homes and to provide rebates on energy-saving products and home alterations.
- Continuation of the Green Buildings BC program that is helping schools, hospitals and other public facilities to reduce their energy use and energy costs.

Ramsey noted that B.C.'s three gas distribution companies have undertaken to help customers who are making good-faith efforts to deal with higher utility bills and to work with government on energy conservation and other energy issues.

-more-

"I'm pleased at the approach the companies have taken," said Ramsey. "I commend their willingness to help people deal with gas bills and reduce energy use – and their willingness to communicate this to their customers."

"We can expect natural gas prices to remain steady for the time being," said the premier. "This package will help B.C. families deal with energy costs in the short term, but – as I announced last Thursday – we must continue our work on conserving energy and expanding our use of renewable power."

Last week the premier said BC Hydro should double its current target of meeting 10 per cent of future electricity demand from renewable energy sources.

Dosanjh also said Energy Minister Glenn Robertson will start discussions with the energy industry about strategies for ensuring B.C. maintains a reliable and affordable supply of energy for the future.

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Backgrounder: Assisting B.C. Families With Energy Costs and Energy Conservation

Contact: Ministry of Finance and Corporate Relations
Communications Branch
(250) 387-3347

BRITISH COLUMBIA

BACKGROUNDER

Feb. 7, 2001

Ministry of Finance and Corporate Relations

ASSISTING B.C. FAMILIES WITH ENERGY COSTS AND CONSERVATION

Electricity Rebates for Residential Customers:

- $200 rebate to residential customers worth about 30 per cent of the average residential bill.
- Available to customers of BC Hydro, West Kootenay Power and municipal electrical utilities by agreement between Hydro and its utility customers.
- Uses BC Hydro net income above what was projected for 2000-01. BC Hydro's rate stabilization account has grown faster than projected in this year's budget.
- It is not additional government spending requiring a new appropriation. It represents $305 million of BC Hydro net income that would have been revenue in the government's summary accounts.

Heating Assistance for Low-Income British Columbians:

- $50 per person and $100 per family for 1.1 million British Columbians eligible for GST rebates.
- The benefit is non-taxable and not deductible from income assistance payments.
- Cheques will be mailed in April. There is no need to apply. Individuals and families will receive a payment if they are eligible for the GST credit based on their 1999 incomes and meet provincial residency requirements.
- The cost to government is estimated at $78 million. This will be split roughly 40 per cent for foregone revenue representing reduced taxes for GST rebate recipients with employment income, and 60 per cent in spending grants to GST rebate recipients who have no employment income.

Protecting Health and Education:

- $21 million in grants to universities, schools and hospitals to defray added energy costs and ensure dollars budgeted for services are used for services.
- Grants are in addition to $7 million targeted for energy costs in B.C.'s health action plan approved by the legislature in December.

Expansion of Power Smart Program in Co-operation with B.C.'s Gas and Electrical Utilities:

- BC Hydro will work with B.C. Gas, Centra Gas, Pacific Northern Gas, W.K.P. and local utilities to expand and enhance opportunities for energy efficiency and conservation.
- British Columbians will be able to do energy audits online and receive conservation home advice tailored to their energy-use patterns, as well as expanded rebates on energy-saving devices and fixtures.
- B.C.'s gas utilities will communicate with their customers about the energy cost and conservation program and opportunities for energy audits and energy efficiency rebates.

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Contact: Ministry of Finance and Corporate Relations
Communications Branch
(250) 387-3347

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PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 106 *, Approved and Ordered* FEB - 7 2001

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that Special Directive No. 5 attached to this order is issued to the British Columbia Hydro and Power Authority.

Paul Ramsey
Minister of Finance and Corporate Relations

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order)

Authority under which Order is made:

Act and section:- *Hydro and Power Authority Act, RSBC 1996, c. 212, s.35*

Other (specify):-

~~60/01/13~~
187/01/12

SPECIAL DIRECTIVE NO. 5 TO THE BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Application

1 This Directive is issued by the Lieutenant Governor in Council to the British Columbia Hydro and Power Authority (the "Authority") under section 35 of the *Hydro and Power Authority Act*.

Definition

2 In this Directive, "Hydro rate schedule" means a rate schedule of the Authority that is identified in the Schedule by the number under which it was filed with and approved by the British Columbia Utilities Commission.

Direction

3 Pursuant to section 35 of the *Hydro and Power Authority Act*, the Lieutenant Governor in Council directs the Authority to pay

(a) to each person who, at 12:00 p.m. on December 31, 2000, was receiving residential electricity service from the Authority pursuant to one of the Hydro rate schedules listed in the Schedule, an amount of $200,

(b) subject to section 4, to the Corporation ("New Westminister") of the City of New Westminster, an amount equal to $200 multiplied by the number of customers receiving residential electricity service from New Westminister at 12:00 p.m. on December 31, 2000, and

(c) subject to section 5, to West Kootenay Power Ltd. ("WKP"), an amount equal to $200 multiplied by the number of customers who, at 12:00 p.m. on December 31, 2000, were receiving residential electricity service from

(i) WKP, or

(ii) one of the 6 municipal electric utilities in WKP's service territory for the communities of Grand Forks, Kelowna, Nelson, Penticton, Princeton, or Summerland.

Limitations

4 The Authority is not required to pay New Westminister unless New Westminister agrees in writing with the Authority by February 16, 2001, to pass through any payments received from the Authority pursuant to this Directive so that each residential customer specified in section 3(b) receives $200.

5 The Authority is not required to pay WKP unless WKP and its municipal electric utilities agree in writing with the Authority by February 16, 2001, to pass through any payments received from the Authority pursuant to this Directive so that each residential customer specified in section 3 (c) receives $200.

Method of Payment

6 The Authority may comply with this Directive by crediting the bills of its customers, New Westminister or WKP in the amounts set out in this Directive.

SCHEDULE

Residential Service

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Page 328 to/à Page 361

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s.12;s.13;s.17

ELECTRICITY SALES
Issue: in fiscal 2016, electricity sales were 3,351 gigawatt hours or about six per cent below BC Hydro's forecast.

- While our market purchases and surplus sales fluctuate from year-to-year based on a number of factors, including industrial activity, water inflows and weather, we plan for average years. This helps us ensure that the power is there for our customers during the cold winter months.
- Residential sales were lower than expected in fiscal 2016 because of warmer than average temperatures.
- While we continue to see steady growth in electricity demand from the residential and commercial sectors due to population growth and economic expansion, there has been some volatility in the industrial sector, which can cause fluctuations in energy demand.
- In fiscal 2016, some large industrial customers from the mining and pulp and paper sector reduced or closed their operations due to low commodity prices.
    - These are cyclical industries. We expect to see recovery in the long term.
- Actual electricity sales were about six per cent below our original forecast.

SURPLUS SALES
Issue: in fiscal 2016, BC Hydro was a net exporter of electricity

- We've been a net importer of electricity for eight of the last 12 years. Inflows into our reservoirs are by far the largest factor in determining whether we will need to import or export power. While we plan for average inflows on a long-term basis, there can be significant variability (up to 15 per cent) each year depending on the amount precipitation.
- In fiscal 2016, BC Hydro was a net exporter of electricity. Reservoir levels were significantly higher than normal because of the wet fall and warm winter in fiscal 2015 that resulted in higher than expected water inflows and lower heating loads. We stored the excess water in our reservoirs and increased exports to manage the higher reservoir levels.
- In addition, BC Hydro increased exports to support the management of obligations under the Columbia River Treaty. The Treaty provides for increased releases of water from the Canadian Columbia basin when the US basin finds itself in severe drought conditions as it did in the spring and summer of 2015. Ultimately, the increased release meant additional generation at Mica which resulted in more energy available for export.
- Surplus sales vary year to year based on level and timing of inflows, risk of spill, and market conditions.
- Fiscal 2014 is a good example of how inflow variability can impact whether we are a net importer or exporter. Based on normal inflows, BC Hydro forecasted a surplus of about 1000

gigawatt hours. We ended up purchasing 1,116 gigawatt hours because inflows were approximately five per cent less than forecast.

- Conversely, in fiscal 2012 and 2013, inflows were significantly above average, and this surplus was sold into the market.

Why are you building Site C if you have surplus energy?

- Surplus sales vary year to year based on level and timing of inflows, risk of spill, and market conditions. The planning, development and construction of Site C takes more than 10 years. The project is being advanced to ensure we have the power British Columbians will need in the future.

- While we may have short-term surpluses of energy, we are forecasting that B.C.'s electricity needs will grow by almost 40 per cent over the next 20 years due to a projected population increase of more than one million residents and economic expansion. We're building Site C to meet long-term electricity needs.

- In 20 years (F2036), B.C. would have an energy deficit of 9,300 gigawatt hours without Site C. That means, without it, we wouldn't be able to provide power to about 850,000 homes. Further, we would have a capacity deficit of 1,100 megawatts in ten years without Site C and Revelstoke 6.

REGULATORY ACCOUNTS

Issue: in fiscal 2016 BC Hydro's our overall regulatory account balance increased by $475 million. The balance in the non-heritage deferral account increased by nearly $400 million.

- BC Hydro's use of regulatory accounts is open, transparent and in line with International Accounting Standards. Our approach to recovering regulatory accounts provides the appropriate balance between achieving equity for current and future ratepayers while keeping electricity rates at a reasonable level.

- Regulatory accounts are commonly used by utilities across North America to help manage rate increases for customers over time. That's the case for BC Hydro and it reflects the long-term nature of our business.
    - For example, some accounts are used to match the costs associated with major projects with the benefits received from that project – meaning that customers who receive the benefit over many years are the ones who pay for it. Other accounts can help to smooth or spread out the rate impact of large one-time costs.

- The accounts are reviewed by our regulator, the BC Utilities Commission. The accounts play an important role in helping BC Hydro make investments in the electricity system to ensure we can deliver safe, reliable power. We have a reasonable, responsible plan to recover the balances in these accounts and already have mechanisms in place to recover 88 per cent of the current balance in the accounts.

- By the end of fiscal 2024, the total balance of our regulatory accounts is forecast to decrease by approximately 39 per cent from the end of fiscal 2016 ($5.9 billion vs $3.6 billion).

- Our approach to recovering regulatory accounts was reviewed by the Auditor General's office in 2014 and in a June 26, 2014 news release, Auditor General Russ Jones noted that he "is encouraged by BC Hydro's progress in implementing the recommendation related to the recovery plans for regulatory accounts balances…"

Why did the balance in the non-heritage deferral account almost double in size in fiscal 2016 (from $524 million to $917 million)?

- The Non-Heritage Deferral account, like all regulatory accounts, helps us manage rate increases for customers over time by allowing BC Hydro to defer the variance between forecast and actual net energy costs not included as heritage assets. These included IPP purchases and load (customer demand).

- In fiscal 2016, the Non-Deferral Heritage Account increased for several reasons, including:
    - Lower residential revenues due to warmer than average temperatures ($98 million)
    - Lower industrial revenues due to delays in oil and gas start-ups and lower mining sales due to low commodity prices ($96 million)
    - Higher energy costs related to the Alcan smelter upgrade delay, which increased energy sales to BC Hydro and increased our IPP costs ($132 million)

- The deferred variances are recovered through a 5 per cent Deferral Account Rate Rider, which is an existing charge that appears on customers' bills to recover the balances in the energy deferral accounts.

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BC Hydro
Power smart

CONFIDENTIAL

Event: Background briefing for RRA filing

Contacts: Simi Heer, Media Relations, BC Hydro 604-375-2746
Mora Scott, Media Relations, BC Hydro 604-880-3863

Date: Thursday, July 28

Time: 1 p.m.

Location: Galiano Room, Hotel Grand Pacific
463 Belleville Street, Victoria, B.C.

Security: Hotel security available; event deemed low risk (invite only); not advertised in lobby

Speakers: Jessica McDonald, President & CEO
Chris O'Riley, Deputy CEO
Cheryl Yaremko, Executive Vice-President Finance and CFO

Media: Legislative reporters (briefing)
News media province wide (news release)

Legislative reporters (invited):

- Keith Baldrey, Global TV
- Bhinder Sajan, CTV
- Tom Fletcher, Black Press
- Dirk Meissner, Canadian Press
- Rob Shaw, Vancouver Sun
- Vaughn Palmer, Vancouver Sun
- Richard Zussman, CBC BC
- Andrew McLeod, The Tyee
- Justine Hunter, Globe & Mail
- Les Leyne, Victoria Times Colonist
- Sophie Rousseau, Radio Canada
- Mike Smyth, The Province
- Lindsay Kines, Victoria Times Colonist
- Mary Griffin, CHEK TV

Format

- In-person technical briefing followed by facilitated Q&A with Jessica with support from Chris & Cheryl.
- Province-wide rollout of media material followed by one-on-one interviews by Jessica (if requested)

Set-up

Holding area

- Space for speakers (Saltspring room) is located directly next to presentation room (available first thing in the morning)

Presentation area

- Smaller, intimate room
- Table at front for all speakers with classroom style set up for reporters (two people per table)
- 70-inch LED screen to display PowerPoint to the right of the speaker table
- No microphones, speakers or telephone lines

Media tactics

- Media calls/invites — Tuesday
- Presentation & speaking notes — Thursday
- News release — Thursday
- Social media (news release, facts) — Thursday
- Media take away material: news release, presentation — Thursday

Timeline

Technical briefing		
11 a.m.	set up of Galiano room	Simi, Mora
12:00 p.m.	pre-brief, practice in Saltspring room	Jessica, Chris O, Cheryl, Chris S.
12:45 p.m.	media arrive	
12:55 p.m.	speakers take their seats	Jessica, Chris O, Cheryl
1 p.m.	briefing begins	Jessica, Chris O, Cheryl, Simi
1:20 p.m.	Q&A	Jessica, Chris O, Cheryl, Simi
1:35 p.m.	event concludes; speakers to holding area	Jessica, Chris O, Cheryl
Announcement		
2 p.m.	RRA filed & posted to .com (TBC)	Regulatory, Leela
2 p.m.	news release distributed; social media push	Kevin, Leela
2:30 - 3 p.m.	media interviews	Jessica

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Page 431 to/à Page 436

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Page 437 to/à Page 492

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